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ACCESSION NBR:8308230292 DOC.DATE: 83/08/19 NOTARIZED: NO DOCKET #
FACIL:50-388 Susquehanna Steam Electric Station, Unit 2, Pennsylva 05000388

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SUBJECT: Forwards rev to FSAR Chapter 18 reflecting responses to TMI items Chapter will be included in next FSAR amend. see rpt

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AUG 19 1983

Director of Nuclear Reactor Regulation
Attention: Mr. A. Schwencer, Chief
Licensing Branch No. 2
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

SUSQUEHANNA STEAM ELECTRIC STATION
TMI RESPONSE FOR UNIT 2
ER 100508 FILE 841-1
PLA-1785

Docket No. 50-388

Dear Mr. Schwencer:

Attached are revised pages to the Susquehanna SES FSAR Chapter 18. These pages reflect the responses to the TMI Items for Unit 2. Also included are administrative changes to update the TMI Items for Unit 1. Where no specific mention of a particular unit is made, the response is applicable to both units. It should also be noted that unless otherwise specified the equipment and modifications will be installed and operational prior to fuel load on Unit 2.

The following is an explanation of the changes:

18.0 - This section has been revised to reflect the fact that the responses in Chapter 18 are applicable to both units. It was also revised to clarify equipment identification numbers for Unit 2.

18.1.1.3 - This section has been revised to incorporate the Nuclear Training Instruction for the qualification of the STA's. It was also revised to state that the STA's have been trained and are on shift.

18.1.4.3 - This section has been revised to incorporate the reference to NTI-QA-3005. It was revised to state that the initial startup crews have been trained.

18.1.7.3 - This section has been revised to state that the Nuclear Safety Assessment Group (NSAG) is functional.

18.1.8.3 - This section was revised to state that the emergency procedures have been developed using the BWR Emergency Procedure Guidelines.

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18.1.12.3 - This section has been revised to state that Administrative Procedure AD-QA-406 has been developed.

18.1.13.3 - This section has been revised to state that Administrative Procedure AD-QA-306 has been developed.

18.1.16.3 - This section has been revised to state that the modifications that were required to be implemented prior to fuel load on Unit 1 will be inplemented on Unit 2 prior to fuel load. It was also revised to reference our response to Generic Letter 82-33.

18.1.17.3 - This section has been revised to reference our response to Generic Letter 82-33 which states our position on SPDS.

18.1.19.3 - This section contained typographical errors which were corrected.

18.1.21.3.1 - This section has been revised to delete the first paragraph of this section. This paragraph was deleted since it contained a commitment to install a sampling system and it has been installed.

18.1.21.3.2 - In this section, the reference to Figure 18.1-11 was revised to reference Figure 9.3-9a.

18.1.21.3.2.1 - This section was revised to state that all sample points have been installed.

18.1.21.3.2.2 - In this section, the reference to Figure 18.1-11 was revised to reference Figure 9.3-9a.

18.1.21.3.2.3 - This section has been revised to state that the piping station has been installed. Also the reference to Figure 18.1-12 was revised to reference Figure 1.2-20.

18.1.21.3.2.4 - In this section, the reference to Figure 18.1-13 has been revised to reference Figure 1.2-4.

18.1.21.3.2.4.3- This section has been revised to state that the sample station enclosure has been vented.

18.1.21.3.3 - This section has been revised to state that the sample facilities have been provided.

18.1.21.3.3.1 - This section has been revised to state that the on-site facilities have been provided.

18.1.21.3.3.2 - This section has been revised to state that the EOF facilities have been provided.

18.1.21.3.3.3 - This section has been revised to state that arrangements have been made for off-site analyses.

18.1.21.3.4.2.3- In this section, the reference to Figure 18.1-14 has been revised to reference Figure 18.1-11. Also the reference to Figure 18.1.21-4 has been revised to reference Figure 18.1-11.

18.1.21.3.4.5 - This section was added to state that the procedure for core damage estimation will be completed prior to the startup following the first refueling outage of Unit 1.

18.1.22.3 - This section has been revised to state that the "Mitigating Core Damage" course has been developed and is available.

18.1.24.3 - This section has been revised to state that the acoustic monitoring system has been installed.

18.1.29.3 - This section has been revised to state that the valves in the Liquid Radwaste, Reactor Water Sample and Reactor Building Chilled Water systems have been modified so that they do not automatically reopen on logic reset. Also this section has been revised to state that the purge and vent valves for Unit 2 will be fully qualified to Branch Technical Position CSB6-4 prior to fuel load and for Unit 1 prior to startup following the first refueling outage. This section has also been revised to state that the high radiation monitors have been installed and are operational.

18.1.30.3.1 - This section has been revised to state that the noble gas monitors have been installed.

18.1.30.3.2 - This section has been revised to clarify from what sources the radiation exposures were calculated. In a recent reevaluation, PP&L has determined that access to these monitors is not possible if airborne contamination is taken into account. The previous access study was based on the shielding study (Item II.B.2) which did not include airborne contamination. As a result of this reevaluation, the filters will be moved to a location which is accessible. This relocation will be completed prior to the start-up following the first refueling outage of Unit 1.

18.1.30.3.3 - This section has been revised to state that the containment high-range radiation monitor has been installed.

18.1.30.3.4 - This section has been revised to state that the containment pressure monitor has been installed.

18.1.30.3.5 - This section has been revised to state that the containment water level monitor has been installed.

18.1.30.3.6 - This section has been revised to state that the containment hydrogen monitor has been installed.

18.1.31.3 - This section has been revised to update this response to the present BWR Owners Group position.

18.1.51.3 - This section has been revised to state that the time delay relay has been installed.

18.1.54.3 - This section has been revised to state that the ADS logic modification selected has been approved and that additional information is needed.

18.1.56.3 - This section has been revised to state that the automatic switchover of the RCIC suction from the condensate storage tank (CST) to the suppression pool on low CST level has been installed.

18.1.58.3 - This section has been revised to state that the cooling water to the recirculation pump seals have been modified to receive emergency power for Unit 1. This modification will be made to Unit 2 in order to keep the two units the same even though this modification is not required to be made on Unit 2. The Unit 2 modification will not be made prior to fuel load.

18.1.59.3 - This section has been revised to state that all reactor water level indications use the same reference point.

18.1.67.3 - This section has been revised to eliminate the reference to Appendix I of the Emergency Plan since Appendix I has been eliminated from the Emergency Plan.

18.1.68.3 - This section has been revised to state that the response to the requirements are contained in the Emergency Plan.

18.1.69.3 - Item 4 in this section has been revised to state that the Technical Specifications include the 5 gpm criteria.

18.1.70.3 - This section has been revised to delete the last line of this section.

18.1.71.3 - This section has been revised to reference Section 2.2 for the evaluation of potential hazards from nearby facilities. Also this section adds a reference to Table 18.1-17 which

references information required for the NRC control room habitability evaluation.

Table 18.1-10 - This table has been revised to correct typographical errors.

Table 18.1-17 - This table was added to provide references to applicable sections of the FSAR, Emergency Plan and Technical Specifications for use in the control room habitability evaluation.

Table 18.1-18 - This table was added to provide a listing of possible ICC detection devices.

Figure 18.1-11 - This figure titled "PASS P&ID" has been deleted.

Figure 18.1-12 - This figure titled "Location of PASS - El 719'-1" " has been deleted.

Figure 18.1-13 - This figure titled "Location of PASS - El 729'" has been deleted.

Figure 18.1-14 - This figure titled "Specific Conductance of pH of Aqueous Solutions at 25°C" has been renumbered as Figure 18.1-11.

Figure 18.1-15 - This figure titled "Typical HPCI/RCIC Steamline Break Detection Logic" has been renumbered as Figure 18.1-12.

Figure 18.1-16 - This figure titled "Typical Reactor Water Level Display" has been renumbered as Figure 18.1-13.

\- - New Figure 18.1-14 titled "Downcomer Water Level History" has been added.

\- - New Figure 18.1-15 titled "Water Level As An Indicator of Core Overheating" has been added.

\- - New Figure 18.1-16 titled "Cladding Temperature Sensitivity to Core Uncovery Time" has been added.

18.2.2.3 - This section has been revised to state that the Vice President-Nuclear Operations reviews and approves the Shift Supervisor's responsibilities.

18.2.9.3 - This section has been revised to state that the Senior Vice President-Nuclear has issued a statement of policy establishing the primary responsibility of the Shift Supervisor for safe operation.

18.2.12.3 - This section has been revised to state that General Electric Company has reviewed all startup tests associated with NSSS systems for Unit 1.

18.2.15.3 - This section has been revised to state that a safety analysis on station blackout has been submitted and that Generic Letter 83-24 has been issued.

18.2.33.3 - This section has been revised to state that the Technical Specifications include these reporting requirements.

18.2.38.3 - This section has been revised to delete the reference to Appendix I of the Emergency Plan since this appendix does not exist.

Table 18.2-1 - This table has been revised to delete the commitment for writing a station blackout test procedure.

These changes to Chapter 18 will be included in the next revision to the FSAR.

If you have any questions, please call.

Very truly yours,

N W Curtis

N. W. Curtis
Vice President-Engineering & Construction-Nuclear

cc: R. L. Perch-NRC
G. G. Rhoads-NRC

18.0 ORGANIZATION

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 Unit 1 and Unit 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 0 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 STA's is detailed in NTI-QA-3030, "Initial Training and Certification of Shift Technical Advisors".

STA coverage is provided on operating shifts in accordance with Subsection 6.2.2 of the Technical Specifications. STA's perform

the duties and have the responsibilities outlined in plant procedure AD-OA-40, "Conduct of Technical Support."

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 bewteen 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 6.2.2 of the Technical Specifications. These requirements are consistent with those given in Table 18.1-1.

The plant policy on operations personnel working hours is discussed in administrative procedure AD-QA-300, "Conduct of Operations."

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.

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

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.

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 NTI-QA-3005, "Licensed Operator Training Program-Implementation". Administrative procedure AD-QA-304, "Operator Selection Training and Qualifications," 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.

Training center and facility instructors who teach systems, integrated responses, transient and simulator courses shall demonstrate their competence to NRC by successful completion of a senior operator examination. 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 be enrolled in appropriate requalification programs to 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 ISEG are performed by the Nuclear Safety Assessment Group (NSAG). PP&L's commitment to the NSAG is addressed in a letter from N. W. Curtis to B. J. Youngblood on December 8, 1980 (PLA-585) and are further addressed in Nuclear Department Instruction NDI-1.1.2.

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 noncondensibles; reestablishment 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 BWP 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 developed a comprehensive program for feedback of operating experience. Components of the program are as follows.

Operating experience from other utilities and other industry sources is initially reviewed and dispositioned by the Industry Events Review Program (IERP). The IERP is designed to assure plant personnel do not routinely receive extraneous and unimportant information, that information is not contradictory or conflicting, that information is resolved prior to dissemination and that important information is rapidly routed to the appropriate personnel. A description of the organization, responsibilities and procedures of the IERP can be found in Nuclear Department Instruction NDI-QA-6.2.2.

The Shift Technical Adviser (STA) as part of the Operations Assessment Function will be the focal point for dissemination of

operating experience information to appropriate plant personnel. This will include:

- Feedback of pertinent information to operators and other station personnel and transmittal of information to the Nuclear Training Group for incorporation into appropriate training programs.
- Initiating, when required, plant procedure changes and/or plant modification requests.
- Discussing with shift personnel operating experience information of sufficient importance that it cannot be deferred to the retraining program.
- Editing information provided to plant personnel to minimize excessive or conflicting information and distributing information to appropriate functional units.

Administrative Procedure AD-QA-406 further defines this function and the interfaces among the STAs and the Nuclear Safety Assessment Group, Nuclear Training, Operations and the Industry Events Review Program.

General information from the nuclear industry and information of general interest from inside the company will be disseminated to appropriate personnel. The details of this program are described in Nuclear Department Instruction NDI-QA-6.2.1.

The NQA organization will selectively audit portions of the feedback program to assure it functions effectively at all levels.

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 AD-QA-306, "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. The procedure defines circumstances when independent human verification is required. The procedure also 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 deficiences. 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 0700 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 PP&L'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 realtime 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 nonsafety systems to ensure the integrity of the SPDS upon failure of nonsafety 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

Details on the SPDS are presented in the Emergency Plan and our response to Generic Letter 82-33 (PLA-1621, dated 4/15/83).

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 noncondensible 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 Figure 5.1-3a).

2. Normally open reactor head vent line 2 DBA-112 which discharges to main steam line "A". (Subsection 5.1 and Figure 5.1-3a).

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 Figures 5.4-9a and 6.3-1a).

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 mainsteam 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 mainsteam line break. Mainsteam 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 postaccident 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 postaccident 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 postaccident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas thorughout 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 jusitification 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 MSIV Leakage Control System

Subsequent to a postulated accident, system operation may begin upon actuation of the manual switches in the control room. This system may only be activated upon a permissive reactor pressure signal (35 psig). The method used to depressurize the reactor to this level has a large effect on the amount of activity potentially available for passage through this system. For example, the HPCI system can deplete the reactor steam activity considerably with only a few minutes operation. Whichever depressurization method is chosen, the MSIV-LCS system remains as one that must be included in the shielding review.

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 and the Post-Accident Sampling System. 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 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 100% of the core noble gases and 25% of the core halogens. 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 50% of the core halogens and 1% of the core particulates post-accident. 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, 25% halogens

Source B: Reactor Liquids: 100% noble gases, 50% halogens, 1% solids

Source C: Suppression Pool Liquid: 50% halogens, 1% solids

Source D: Reactor Steam: 100% noble gases, 25% halogens

The above release fractions were applied to the total curies available for the particular chemical species (i.e., noble gas, halogen, or solid) for an equilibrium fission product inventory for Susquehanna as listed in Table 18.1-2.

The Regulatory Guide 1.7 solids release fraction of 1% was used for Cs and Rb on this review. Further evaluations of the TMI radioactivity releases may conclude that higher release fractions are appropriate. However, until the release mechanisms and release fractions have been quantified, the existing regulatory guidance will be followed. No noble gases were included in the suppression pool liquid (Source C) because Regulatory Guide 1.7 has also set this precedent in modeling liquids in the pool (See References 18.1-4 and 18.1-10). Furthermore, cursory analyses have indicated that the halogens dominate all shielding requirements and that contributions to the total dose rates from noble gases are negligible for the purposes of shielding design review.

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

For the first stage of the shielding design review process, minimal decay time credit was used with the above releases. The primary reason for this was to develop a set of accident radiation zone maps normalized to 1 hour decay.

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

- o Main Steam Isolation Valve-Leakage Control System

Steam: Source D (with credit for steam specific Activity reduction due to RCIC turbine operation).

- o 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)

- o 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).

- o Drywell: Source A

- o Wetwell: Source C

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

Cummulative 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 cummulative 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 one hour after the accident due to the sources described in Subsection 18.1.20.3.2.4 in various areas of the plant site. 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 whole body, or its equivalent to any part of the body, 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 postaccident 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.

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.

Plant effluent monitoring stations are located at five (5) plant vents: two (2) for the Reactor Building, two (2) for the Turbine

Building, and one (1) for the Standby Gas Treatment System. The reactor building monitors are automatically isolated post-LOCA and will contain no post-accident activity. The SGTS effluent sample station will contain post-accident activity in sample cartridges: one (1) volumetric and one (1) charcoal filter. The samples are locally shielded and present no access problems in the area of the station. However, transportation and handling of the filter cartridges will require local shielding.

The Turbine Building Plant Vent Sample Station (PVSS) may also contain post-accident activity. Doses, if any, will be of a lower magnitude than that of the SGTS effluent filters because of environmental dispersion and re-entry to the Turbine Building ventilation system. In the worse case, the Turbine Building PVSS doses will be much lower than those of the SGTS. In the best case, control room personnel may shut down the Turbine Building HVAC system (which is non-safety related). In this case, the Turbine Building PVSS may be void of post-accident activity.

18.1.20.3.4 Results

18.1.20.3.4.1 Radioactive Decay Effects

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. This table can be used in conjunction with the decay curves (Figures 18.1-9 and 10) to estimate radiation levels at times other than one hour. The procedure for times less than one day, is to multiply the radiation level (i.e., radiation zone limit) by the decay factor given in Figure 18.1-9. For times greater than one day, it is necessary to multiply by the decay factor in Figure 18.1-9 at 24 hours and by the decay factor in Figure 18.1-20 at the desired decay time. This procedure is conservative for areas in which the sources are shielded because it does not rigorously take into account the softening of the energy spectrum an consequent increase in attenuation for longer decay times. A decay curve for source D, reactor steam, is not included because the depletion effects due to steam usage by HPCI or RCIC removes much of this source shortly after the accident. In addition, HPCI and RCIC piping containing source D is run in shielded cubicles and does not contribute significantly outside those cubicles.

18.1.20.3.4.2 Integrated Personnel Exposures

Personnel integrated exposures in continuously occupied areas were calculated based on 100% occupancy for the first day, 60% occupancy from day one through four and 40% occupancy for the duration (1 year). These calculations showed that personnel exposures would be within the design objective of 5 Rem. Exposures in Zones I, II and III of the control structure are 0.24, 1.6 and 3.1 Rem, respectively. These doses do no include the shielding effects of interior walls, equipment, etc., therefore they represent the maximum dose to control building personnel due to contained sources. Personnel doses to the North Gate House (ASCC) and Security Control Center from contained sources were found to be insignificant (i.e, < 0.1 Rem). These areas are a minimum of 300 feet from the reactor building whose walls are a minimum of 2.5 feet of concrete.

Personnel doses at the Post-Accident Sample Station, Chemistry Laboratory, and Plant Vent Sample Station are calculated based on an estimated task duration at specified times post-accident for a one person task force (Refer to Table 18.1-4)

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.

Exceptions to these general Zone IV levels are areas in the vicinity of reactor coolant and containment atmosphere sampling lines which are routed to the reactor building sample station at Elevation 779'-0". The dose rate 10 feet from the reactor coolant sampling line one hour after the postulated accident may exceed 100 R/hr.

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 Requirement

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18-3/4 rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hours) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases (which indicate cladding failure), iodines and cesiums (which indicate high fuel temperatures), and nonvolatile isotopes (which indicate fuel melting). The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, then design modifications for equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift).

The following items are clarifications of requirements identified in NUREG-0578, NUREG-0660, or the September 13 and October 30, 1979 clarification letters.

(1) The licensee shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 hours or less from the time a decision is made to take a sample.

(2) The licensee shall establish an onsite radiological and chemical analysis capability to provide, within the 3-hour time frame established above, quantification of the following:

(a) certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases; iodines and cesiums, and nonvolatile isotopes);

(b) hydrogen levels in the containment atmosphere;

(c) dissolved gases (e.g., hydrogen), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids.

(d) Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.

(3) Reactor coolant and containment atmosphere sampling during postaccident conditions shall not require an isolated auxiliary system (e.g., the letdown system, reactor water cleanup system to be placed in operation in order to use the sampling system.

(4) Pressurized reactor coolant samples are not required if the licensee can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or hydrogen gas in reactor coolant samples is considered adequate. Measuring the oxygen concentration is recommended, but is not mandatory.

(5) The time for a chloride analysis to be performed is dependent upon two factors: (a) if the plant's coolant water is seawater or brackish water and (b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions the licensee shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the licensee shall provide for the

analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

(6) The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding the criteria of GDC 19 (Appendix A, 10 CFR Part 50) (i.e., 5 rem whole body, 75 rem extremities). (Note that the design and operational review criterion was changed from the operational limits of 10 CFR Part 20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979 letter from H.R. Denton to all licensees).)

(7) The analysis of primary coolant samples for boron is required for PWRs. (Note that Revision 2 of Regulatory Guide 1.97, when issued, will likely specify the need for primary coolant boron analysis capability at BWR plants.)

(8) If inline monitoring is used for any sampling and analytical capability specified herein, the licensee shall provide backup sampling through grab samples, and shall demonstrate the capability of analyzing the samples. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.

(9) The licensee's radiological and chemical sample analysis capability shall include provisions to:

(a) Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guide 1.3 or 1.4 and 1.7. Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 μCi/g to 10 Ci/g.

(b) Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be

accomplished through the use of sufficient shielding around samples and outside sources, and by the use of ventilation system design which will control the presence of airborne radioactivity.

(10) Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.

(11) In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:

(a) Provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment, for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The postaccident reactor coolant and containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.

(b) The ventilation exhaust from the sampling station should be filtered with charcoal adsorbers and high-efficiency particulate air (HEPA) filters.

Operating License Applicants--Provide a description of the implementation of the position and clarification including P&IDs, together with either (a) a summary description of procedures for sample collection, sample transfer or transport, and sample analysis, or (b) copies of procedures for sample collection, sample transfer or transport, and sample analysis, in accordance with the proposed review schedule but in no case less than four months prior to the issuance of an operating license.

18.1.21.2 Interpretation

None required.

18.1.21.3 Statement of Response

18.1.21.3.1 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 the required 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.

18.1.21.3.2 Description of Sampling System

The underlying philosophy in the design of the sampling system is to meet the requirements of item II.B.3, 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. The system is designed to provide useful samples under all conditions, ranging from normal shutdown and power operation to post-accident conditions.

The P&ID for the PASS is shown in Figure 9.3-9a. The equipment includes isolation and control valves, piping station, sample station, and control panels.

18.1.21.3.2.1 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 will 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. This sample point location is preferred over the normal reactor sample points on the reactor water clean up system inlet line and recirculation line since the reactor clean-up system is expected to remain isolated under accident conditions, and it is possible that the recirculation line containing the sample line may be secured. The jet pump instrument line has been determined to be the optimum sample point for accident conditions since: 1) the pressure taps are well protected from damage and debris, 2) if the recirculation pumps are secured, there is normally excellent circulation of the bulk of the coolant past these taps (natural circulation), and 3) the taps are located sufficiently low to permit sampling at a reactor water level which is even below the lower core support plate.

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.

18.1.21.3.2.2 Isolation Valves and Sample Lines

Containment isolation for the drywell and wetwell gas sample lines is provided by the existing containment air monitoring sample line isolation valves. 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 Figure 9.3-9a 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. The gas sample lines are heat traced to prevent precipitation of moisture and the resultant loss of iodine in the sample lines.

18.1.21.3.2.3 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 Figure 1.2-20. 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 Figure 1.2-4. 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. A graphic display directly below the main control panel which shows the status of the pumps and valves at all times. The panel also indicates the relative position of the pressure gauges and other items of concern to the operator. The use of this panel will improve operator comprehension and assist in trouble shooting operations. 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.

18.1.21.3.2.4.1 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 samples may be passed through a particulate filter and silver zeolite cartridge for determination of particulate activity and total iodine activity by subsequent gamma spectroscopic analysis. A radiation monitor is mounted close to the filter tray to measure the activity buildup on the cartridges. Alternately, the sample flow bypasses the iodine sampler, 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. 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.

18.1.21.3.2.4.2 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 conductivity cell (0.1 to 1000 micromhos/cm and 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, connected to a line external to the panel, is used to flush the sample plus a measured volume of diluent (generally 10 milliliters) through the valve and into the sample bottle. This provides an initial dilution of up to 100:1. 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, the sample can be diverted through a 70 milliliter bomb to obtain a large pressurized volume. This 70 milliliter volume can be circulated and depressurized into a gas sampling chamber. A 15 milliliter gas sample can then be obtained through a hypodermic needle for gas chromatographic and radioisotopic analyses of the dissolved gases associated with the 70 milliliter liquid volume. Ten milliliter aliquots of this degassed liquid can then be taken for off-site (or on-site depending on activity level) analyses which require a relatively large undiluted sample. This sample is obtained remotely using the large volume cask and cask positioner through needles on the underside of the sample station enclosure.

18.1.21.3.2.4.3 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.

18.1.21.3.2.4.4 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 sample station liquid return line to and hence into the suppression pool.

18.1.21.3.2.4.5 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 particulate and iodine cartridges are removed via a drawer arrangement. The quantity of activity which is accumulated on the cartridge is controlled by a combination of flow orificing and time control of the flow valve opening. In addition, the deposition of iodine is monitored during sampling using a radiation detector installed in the sample station next to the cartridge. These samples will hence be limited to activity levels which will not require shielded sample carriers.

The small volume (diluted) 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 undiluted 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.

18.1.21.3.2.4.6 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 and backed up by batteries. 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 air for the air-operated valves comes from compressed

air cylinders, thus eliminating any dependence on the plant compressed air system.

18.1.21.3.3 Description of Sample Preparation/Chemistry and Nuclear Counting Facilities

After the samples are obtained from the sample station, they will be transported to a sample preparation/chemistry area. There they will be diluted as necessary and appropriate aliquots taken for chemical and radioisotopic analyses. The radioisotopic analysis will be done in a separate counting area where background radiation can be kept to a minimum. Two different facilities will be available to plant personnel to perform the above tasks. The primary facility is the existing chemistry laboratory and counting room which is at elevation 676', the ground level of the control structure. A backup sample preparation/chemistry area and counting room is provided in the Emergency Operations Facility (EOF) which is located 2500 feet south-west of the control structure. In addition to these on-site and near-site facilities, which are intended to handle the gas samples and the diluted liquid samples, prior arrangements have been made with an independent off-site laboratory for analysis of the undiluted 10 ml liquid samples.

18.1.21.3.3.1 On-Site Chemistry Laboratory and Counting Room

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 (≤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 (≤15 mR/h) following an accident. The chemistry laboratory is equipped to provide the capability to handle the gas samples and the 0.1 ml diluted liquid samples. The maximum activity of these samples will be 0.7 Ci and 0.3 Ci, respectively, using one-hour decay and the fractional releases of core inventory specified by NUREG-0578 (see Section 18.1.21.3.5).

The laboratory maintains a dedicated inventory of items such as lead bricks for shielding, gas syringes, gloves, reagents for analyses, etc., which will be needed in case of an accident. The laboratory is equipped with a gas chromatograph, pH meter, conductivity meter, turbidimeter and other instrumentation needed to perform the required analyses. This equipment however, may not be dedicated exclusively to post-accident analysis. Supplied air or self-contained breathing masks will be available in the

event of high activity levels in the ventilation supply or accidental spills in the laboratory.

The existing counting facility located adjacent to the chemistry laboratory is well equipped to handle the gamma spectra analyses required for post-accident samples. The counting room is equipped with two Ge (Li) detectors with four inch lead shields connected to a computer based analyzer system. The system has automatic peak search and isotope identification capabilities. The Ge(Li) detector and shelf assembly in the lead shield can be well isolated and the capability to purge the volume within the shield with compressed gas will be provided. This will help prevent atmospheric noble gas activity released during an accident from swamping the detector.

18.1.21.3.3.2 EOF Sample Preparation/Chemistry and Counting Facilities

The sample preparation and counting rooms located in the near-site EOF serve as backups to the on-site facilities. The EOF is 2500 feet from the control structure and is directly accessible from the site by road. Travel time from the sample station to the EOF is less than 30 minutes. The backup facilities will be activated whenever the on-site facility becomes inaccessible or if additional lab space or counting equipment is needed to handle the increased work load in the on-site facility resulting from an accident. The sample preparation/chemistry room is furnished with a radicisotope laboratory hood, about 14 feet of laboratory cabinets and benchtop working space, a small sink draining to a removable carboy, and at least a 5-gallon supply of demineralized water in plastic carboy mounted on the wall over the sink. The hood is equipped with a HEPA filter unit. Although some analytical instrumentation may be kept in this room, it is not meant to completely duplicate that in the on-site laboratory. However, the facility is fully equipped to handle the necessary dilutions and manipulations to prepare samples which come directly from the sample station for gamma spectroscopic analysis. Additional instrumentation for the required chemical analyses will be brought from the on-site laboratory as needed. Chemical reagents, glassware and other miscellaneous equipment will be stocked in the facility. A supply of lead bricks is also kept in this room for use as temporary shielding. A lead brick cave for storage of samples is also provided. The EOF counting room will contain as a minimum a high resolution gamma-ray spectrometer system. The system is capable of characterizing and quantifying the gamma activities of reactor coolant and containment atmosphere samples. The intent is to make this system similar to the on-site system.

The EOF has its own diesel generator which will be capable of supplying the electrical power needs for the facility during loss of off-site power.

18.1.21.3.3.3 Arrangements for Off-Site Analyses

A key part of the SSES approach to post-accident sampling is the establishment of prior arrangements with an off-site independent laboratory for confirmatory and supplemental analyses. The capability of the off-site laboratory will also be used to meet the requirement for chloride analysis. The reason for using the off-site laboratory for chloride and as a backup for other analyses is to prevent having to handle and analyze undiluted coolant samples which may have activity levels in the curie per milliliter range. The on-site and EOF facilities are not designed to handle sources of this magnitude. The analyses of undiluted samples can be done in a safer manner by laboratories with facilities and personnel specifically built and trained to handle high-activity sources. The following is a description of the significant features of the off-site laboratory:

a) A formal mechanism exists to allow for initiation of post-accident services at any time (24 hours/day).

b) Written procedures must be controlled and maintained for each of the analyses described in Table 18.1-6. The analysis procedures must be qualified for use at the activity levels given in the table. This requirement may be satisfied by referencing the appropriate literature, by calculations, or by undertaking a testing program.

c) Laboratory equipment and facilities for the required analyses must be available and maintained in working order such that analyses may be completed within 24 hours of the receipt of the sample.

d) Provision will be made for the practice or exercise of each aspect of the off-site analysis work at the option of the utility.

e) Equipment will be available for the timely transmission and receipt of information and results (telecopier and/or telex)

18.1.21.3.4 Summary Description of Procedures

18.1.21.3.4.1 Sample Collection and Transport Procedures

After a decision is made to obtain a sample, the designated sample station operators (2) will proceed to the sample station with the necessary equipment.

Since all the post-accident sample lines (except for the secondary containment atmosphere) tap off-lines which are isolated following a containment isolation signal, the sample station operator must confirm with the control room that the necessary isolation valves are open. (A telephone extension to the control room will be installed close to the sample control panels for this purpose). The control room must also activate the "Accident Sample Station Permissive Switch" to allow the sample station operator control of the "isolation and control valves" which are part of the post-accident sampling system.

After switching the "Master Shutoff Valve Control" to the "open" position, the operator is ready to open the valve(s) controlling flow from the desired source to the sample station. After opening the necessary control valve(s), the operator goes to the "sample station control panel". This panel controls the valves which are part of the piping station and those in the sample station enclosure in the turbine building.

Following a series of presampling checks and procedures including: adjustment of the enclosure damper to insure adequate cooling, checks of demineralized water and nitrogen supplies, flushing of system with demineralized water, draining the trap and sump, etc., the system is ready for obtaining the samples.

18.1.21.3.4.1.1 Procedure for Obtaining Gas Sample

A standard 14.7 milliliter off-gas vial is placed in the gas vial positioner and inserted into the gas port on the front of the sample station. The desired sample location is selected by switch and the gas is circulated until the sample lines are flushed out with the gas being sampled. The vial and a small volume of tubing remains unflushed; however, the vial and this tubing volume are then evacuated. The sample is then drawn into the vial by pressing and holding a pushbutton switch. If cross-contamination is suspected due to incomplete evacuation of the vial, the evacuation and fill sequence can be repeated using air or nitrogen flush before taking the final sample, or the sequence can be repeated with the desired sample gas until the operator is assured that he has a representative sample. Following an air or

nitrogen purge of the sample lines, the gas vial positioner is then removed from the port and the vial inserted into the gas vial cask. The length of the vial positioner allows the operator to remain about three feet from the vial during this operation. The cask has a 10-inch carrying handle and can be easily carried by one person down the stairs in the turbine building to the chemistry laboratory.

18.1.21.3.4.1.2 Procedure for Obtaining an Iodine Particulate Sample

The desired filter cartridge(s) are placed into a cartridge retainer which is placed into the gas filter drawer. This drawer slides into an opening in the front of the sample station enclosure. The appropriate critical orifice is also chosen and placed in the cartridge retainer. This will determine the flow rate through the sampler and thereby control the amount of activity deposited on the filters. The operator then selects a sample location and flushes the sample line except for a short piece of tubing going to the sample drawer. However, this line can be flushed with air or nitrogen prior to sampling if cross-contamination between samples is suspected. In addition, as part of the normal sampling procedures, this line is flushed with air or nitrogen after completion of each sample sequence and should therefore be free of contamination for the following sample. The operator has the option of using an automatic timer to obtain samples with collection times between 0 and 30 seconds or of manually timing the sample for longer collection times. After starting the sample collection sequence, the operator will be able to follow activity buildup on the filters by observing the radiation level readout on the control panel from the probe inserted next to the cartridges in the gas sample panel. After sample collection is completed, the cartridges are evacuated using the vacuum from the gas pumps and then flushed with air or nitrogen to remove the noble gases. The filter drawer is withdrawn and the cartridge retainer with filters is placed in a plastic bag. The bag is then closed, and depending on the measured dose rate, it is carried by hand or attached to a pole and carried to the chemistry laboratory. No shielding cask is provided for these samples since it is possible to regulate the amount of activity deposited on them. In addition, for ease of counting, it is desirable to keep the activity levels on these samples low.

18.1.21.3.4.1.3 Procedure for Obtaining a Diluted Liquid Sample

A 15 milliliter sample bottle with a neoprene cap is placed in the small volume cask which is then placed into a positioner

attached to the sample station support frame. The sample needles are exposed by pulling out the lead shielding drawer under the sample station enclosure. The cask holding the sample bottle is then swung into position under the sample station and the sample bottle raised into position so the needles penetrate the neoprene cap. After aligning the proper valves, the sample lines from the selected source through the piping station are flushed with return flow to the wetwell. After these lines are flushed, the bypass valve in the piping station is closed and the sample flows to the sample station through the calibrated volume sample valve and back to the wetwell. After sufficient flushing, the calibrated valve is rotated 90°, into alignment with the line to the sample bottle. A syringe filled with up to 10 ml of demineralized water is connected onto a line at the front of the sample station and this water is injected to wash the sample captured in the ball valve into the sample bottle. The syringe is then removed, filled with air, re-attached and the air injected to force out all water remaining in the line through the sample needle and into the sample bottle. The rinsing action of the water followed by the air purge of the line should reduce cross-contamination between different samples. The calibrated sample valve is returned to the purge position and the sample lines, from the second cooler in the piping station, through the sample valve and back to the suppressor pool are rinsed with demineralized water. The operator then returns to the sample station, remotely lowers the sample bottle into the cask, screws a top plug with carrying handle into the cask. The cask is then carried down the stairs to the chemistry laboratory. Although one person can carry the cask, a pole with a hook in the middle will be available to allow two people to carry the cask more easily.

18.1.21.3.4.1.4 Procedure for Obtaining a Large Liquid Sample (undiluted) and/or a Dissolved Gas Sample

A standard off-gas sample vial is placed in the gas vial positioner and inserted into the dissolved gas sampling port on the front of the liquid sample panel and a 15 milliliter sample bottle is placed in the large volume sample cask. The sample cask is positioned under the sample enclosure using a four-wheeled cart. The cask is raised into position and the sample bottle raised out of the cask and onto two needles using a remote mechanism. When the cask is properly positioned, the operators will be shielded from the sample during all subsequent operations. After attaining the proper valve lineup, the sample lines are first flushed through the piping station and then through the sample station lines including the 70 milliliter hold up cylinder and gas breakdown circulation loop. After completing the flush cycle a fixed volume of the pressurized liquid is isolated and a measured amount of a tracer gas is injected. The

isolated volume is then depressurized by opening a valve to a previously evacuated 15 milliliter gas collection chamber. The operator now has the option of either collecting the dissolved gas sample in an evacuated vial or releasing it to the suppression pool atmosphere. If a dissolved gas sample is collected, it is handled and transported in the same manner as the containment gas sample discussed previously. The operator also has the option of collecting a 10 milliliter sample of the degassed liquid or allowing it to be flushed to the suppression pool during the subsequent demineralized water flush cycle. If a large volume sample is desired, it is drawn into the evacuated 14.7 milliliter sample bottle. To minimize cross-contamination, the system can be cycled several times through all the above steps before taking the final large volume sample. The dissolved gas and liquid sample system is then flushed with demineralized water to minimize radiation levels while removing samples from the station.

The sample bottle is then remotely lowered from the needles into the shielded sample cask which is lowered on the cart and pulled out from under the sample enclosure. A lead plug is then inserted in the opening of the cask and the cask can be easily moved to the elevator in the control structures using the positioning cart. By using this elevator no steps are encountered when moving the cask from the sample station to ground level. The shielding study results (see Subsection 18.1.20.3) indicate that this elevator should be accessible from a radiation level standpoint. In case of loss of off-site power, the elevator will be out of service since no emergency power is provided. However, the undiluted sample is only essential for determining the chloride concentration which is not required until four days after sampling. This will allow a reasonable time for the restoration of off-site power. However, if after two days off-site power is not restored, arrangements can be made to lower the sample cask from the turbine operating floor to ground level through one of three open hatches. Since the undiluted sample is to be sent to an off-site laboratory, prior arrangements will be made to have a shipping container sent from the off-site laboratory or have one available on-site. The current intent is to have several shipping containers built which will hold the large volume casks, thus avoiding the exposure which would result from trying to transfer the sample from the sampling cask to another container.

18.1.21.3.4.2 Chemical/Radiochemical Procedures

18.1.21.3.4.2.1 Introduction

The PASS provides a means of obtaining primary coolant, suppression pool, and primary and secondary containment air samples for radiochemical and chemical analysis following a major reactor accident. Because of the extremely high radioactivity levels associated with extensive fuel damage, the PASS and its auxiliary support was developed with the philosophy of providing the capability of obtaining the necessary samples and of performing on a timely basis those analyses, as required, for immediate plant needs, or as defined by regulatory requirements. Procedures and arrangements will be established for shipping samples to facilities having the experience and equipment appropriate to performing detailed and accurate chemical analyses on multi-Curie level samples.

The analytical procedures chosen will satisfy the philosophy of performing only those analyses as required for operational support, of minimizing personnel exposure and contamination hazards, and of depending upon outside analysis for extensive analysis and long-range operational needs. Tests were performed by General Electric to assess the effects of high fission product levels on the suggested analytical methods. The type of fuel damage associated with the release of megacurie quantities of iodine and other activities also has the potential for releasing kilogram quantities of stable or very long lived fission products. It is conceivable that the primary coolant might contain 10-20 ppm of iodide and bromide. Also, the release of a major fraction of the core inventory of cesium and rubidium may slightly raise the primary coolant pH. Such releases will also cause an increase in the coolant conductivity while radiolysis of the water will probably contribute to the formation of low levels of hydrogen peroxide. Depending upon the concentrations, these are all possible analytical interferences with the required analysis. Of these, the iodide/bromide interference with the chloride procedure is probably the most severe. However, since the requirement for chloride analysis will be satisfied by sending the samples to an off-site laboratory, the chloride procedure being proposed for the on-site laboratory is only to obtain a rough upper limit. The effects of radiation interference have been generally evaluated and are summarized in Subsection 18.1.21.3.6.

18.1.21.3.4.2.2 Sample Preparation

All sample bottles, iodine cartridges, etc., will be numbered or otherwise identified prior to sampling. This will eliminate unnecessary exposure as a result of handling high level samples for the purpose of attaching labels. A centralized logging system will be developed to keep track of sample aliquot identification, dilution factors, sample disposition, etc.

Liquid samples will be taken at the sample station in septum type bottles and transported to the analysis facility in lead containers. Sample aliquots are then taken from the septum bottles for analysis or further dilution. Aliquoting and transfer will be performed using shielded containers, or behind a lead brick pile. Calibrated hypodermic syringes will be used for aliquoting the higher activity samples. Tongs or other holding/clamping devices will be available for holding the sample bottle during the transfer and dilutions to reduce hand and body exposure. Unless prohibited by the intended analysis, dilutions will be done using very dilute (about 0.01N) nitric acid as the diluent to minimize sample plate-out problems.

Reactor coolant activity levels on the order of 1 to 3 Curies per gram would require a dilution factor of $1x10^5$, or larger, for gamma ray spectroscopy samples. As an example, a typical series of dilutions might be 0.1 ml (100 lambda) added to 10.0 ml at the sample station, followed by further diluting of 0.1 ml to 100 ml in the laboratory. An aliquot of 0.1 ml would then be taken from the second dilution for counting purposes.

Gas samples are taken at the sample station in the same 14.7 ml septum bottle used in the normal offgas sampler. A lead carrier is furnished 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.

Samples taken from the gas sample bottle wil either be injected into a gas chromatograph for analysis or used to dilute the gaseous activity for gamma spectroscopy purposes. The dilutions will be performed in a manner analoguous to the liquid samples. Fractional milliliter samples can be transferred to new 14.7 ml gas bottles without concern for sample leakage due to pressurization. For larger volume aliquots a gas syringe will be used to draw a partial vacuum in the bottle prior to sample transfer.

Since there is no initial dilution of the gaseous activity at the sample station, extensive dilution may be required in the laboratory.

18.1.21.3.4.2.3 Chemical Analysis

a. Introduction

The chosen procedures are not necessarily the most sensitive nor the most accurate. They were chosen primarily on the basis of simplicity, stability and availability of reagents, minimum radiation exposure, and least likely to cause major contamination problems. They have been tested for radiation sensitivity and are suitable for use at the PASS design basis source term of 2.8 Ci/gm, and where applicable, with the design basis 0.1 ml to 10 ml dilution at the sample station.

b. Boron Analysis - Carminic Acid Method

The chosen HACH method closely follows the ASTM D3082-74, "Standard Test Method for Boron in Water, Method A - Carminic Acid Colorimetric Method." The HACH procedure is suggested because the reagents and standards are available in small quantities, are conveniently packaged, and can be quickly prepared. It is estimated that the complete analysis, including reagent preparation, can be performed in 40 minutes.

This method was tested to be satisfactory for use at the maximum expected activity levels. The analysis is designed for boron concentrations in the range of 0.1 to 10 ppm of boron. This sensitivity is particularly suited to the sample station's 0.1 ml to 10.0 ml dilutions since this corresponds to a range of 100 to 1000 ppm in the undiluted coolant.

c. Chloride Analysis - Turbidimetric Method (see also the discussion on conductivity)

The chosen method was developed by the General Electric Reactor Chemistry Training group. The procedure is very similar to a HACH Chemical Co. procedure, "Turbidimetric Determination of Trace Chloride in Water".

The minimum quantity of measurable chloride by this procedure is 0.5 g. If 5 ml of the 0.1 to 10 ml primary coolant dilution is used for analysis, the minimum measurable concentration would be 10 ppm.

Using the 10 ml. direct primary coolant sample greatly increases the sensitivity for measuring chloride. A one ml of aliquot of this sample could be analyzed at the 0.5 to 1.0 ppm level.

Tests of the radiation sensitivity of the method showed that activity levels comparable to the PASS design basis source terms resulted in the equivalent of 1.8 ppm Cl^- in the primary coolant

for the 0.1 to 10 ml dilution. This was deemed to be insignificant, as it is below the sensitivity limit, and more importantly, interference from the large amount of stable fission product halides potentially associated with the source terms will far out-shadow the radiation effect itself.

Tests were also performed on the addition of 500 μg of boron added to 0.5 to 20 μg of chloride. No interference was observed with the turbidimetric procedure.

d. Measurement of pH

Indicator paper for pH will be used for activity levels below 10% of the design basis source terms.

The irradiation tests indicated that at 10% of the design basis source terms, the color stability was adequate given only a drop of solution and less than a 5-minute exposure.

Using this method, pH measurements can be taken at the small volume sampler by placing a piece of the paper into the sample bottle and using an air filled syringe to blow several approximately 0.1 ml aliquots from the sample valve into the bottle to moisten the paper.

This type of sampling approach can also be used to obtain a small sample for possible electrochemical pH measurement. Lazar Research Labs, Inc. manufactures a micro-pH electrode which functions on microliter samples. This electrode or similar micro-probe is currently being evaluated for use at source term greater than 10% of design basis.

Indicator paper for pH can cover the range from 1-11 and distinguish differences of 0.25 pH units.

At very low conductivities, conductivity itself may be the best indicator of the pH. For instance, at 0.2 micromho/cm, the pH is bounded by 6.3 to 7.6, which is well within the technical specifications for normal operaton. Thus, the conductivity should serve as an adequate indicator of pH as long as conductivity is sufficiently low that it is impossible to be outside the technical specifications limit.

e. Conductivity Measurements

The Post Accident Sample Station is equipped with a 0.1 cm^{-1} conductivity cell. The conductivity meter has a linear scale with a six position range selector switch to give conductivity ranges of 0-3, 0-10, 0-30, 0-100, 0-300, and 0-1000 micromho/cm when using the 0.1 cm^{-1} cell. This conductivity measurement system will be used to determine the primary coolant or suppression pool conductivity. During normal operation the BWR

technical specifications require maintaining the primary coolant below 1 micromho/cm, and conductivity measurements are the primary method of coolent chemical control.

Conductivity measurements are, of course, non-specific, but they serve the important function of indicating changes in chemical concentrations and conditions. Perhaps even more important, in the case of the BWR primary coolant, the conductivity measurements can establish upper limits of possible chemical concentrations and can eliminate the need for additional analyses. For example, if the conductivity is measured to be 5.0 micromho/cm, the upper limit on the chloride concentration is 1.4 ppm.

The conductivity measurement can also be used to bound the possible range of pH values. This relationship is shown in Figure 18.1-11.

At a specific conductance of 1.0 micromho/cm the pH must be between 5.6 and 8.7. Furthermore, a pH of 5 and a specific conductance of 1.0 is an impossible situation since the conductivity is not large enough to support a hydrogen ion concentration of 10^{-5}N. Figure 18.1-11 can, therefore, be used to great advantage in checking on agreement between pH and conductivity measurements and possibly eliminating the need for pH measurement if the conductivity is very low. In general, accurate pH measurements are difficult to make in very low conductivity water as the impedance of the solution may be significant compared to the impedance of the measuring device, and conductivity measurements are usually considered a better indicator of the maximum H^+ or OH^- concentration.

18.1.21.3.4.2.4 Radiochemical Analysis--Gamma Ray Spectroscopy

After the samples have been brought to the chemistry laboratory and appropriately diluted, they can be carried without shielding to the counting room which is adjacent to the chemistry laboratory. The appropriate dilution factors will be somewhat dependent upon the detector and shelf arrangements available. A prior determination of the maximum desirable dose rates for the various shelf configuration will be made to minimize this problem. The present high resolution, high efficiency Ge(Li) detectors, coupled with the multichannel analyzers, and computer data reduction in the on-site counting room will easily handle the analysis of these samples.

The gas samples will be counted in the standard off-gas sample vials and the liquid samples will be counted in the standard sample bottles used during normal operation since calibration curves for these geometries will be available and regularly

updated. Calibration curves will also be available for the particulate filter and iodine cartridge geometries. In general, the counting of the post-accident samples will follow the normal counting room procedures. A special post-accident library will have to be developed for use by the computer peak search and identification routine to supplement the normal isotope library. The post-accident peak search and identification library will contain the principal gamma rays of the following isotopes in addition to the standard activated corrosion products:

Noble gases:	Kr-85, Kr-85m, Kr-87, Kr-88, Xe-131m, Xe-133, Xe-133m, Xe-135
Iodines:	I-131, I-132, I-133, I-135
Cesiums:	Cs-134, Cs-137
Others:	Ba/La-140, Ce-141, Ce-144, Ru-106, Te-129, Te-129m, Te-131, Te-131m, Np-239

If the levels of noble gases in the ambient atmosphere surrounding the detector is high enough to cause significant interference or overload the detector, a compressed air or nitrogen purge of the detector shield volume will be maintained.

18.1.21.3.4.2.5 Gas Analysis-Gas Chromatography

A gas chromatograph will be used to measure hydrogen, nitrogen and oxygen concentrations in containment atmosphere and dissolved gas samples. The gas chromatograph will be located in the chemistry laboratory and vented to a laboratory hood. Samples for gas analysis will be used undiluted from the sample vials and injected into the gas chromatograph. Since the sample sizes needed for the analysis will range from 0.1 to 1 milliliter, it may be necessary to place a temporary lead shield around the instrument. The analysis of the drywell, wetwell, and secondary containment samples will be done using standard procedures. Calibration curves for the instrument will be prepared and periodically updated.

In the mixture of hydrogen, oxygen, nitrogen, and possibly krypton, the analysis sensitivity should be sufficient to detect any of these constituents at the 0.1% by volume level, or lower, providing the Kr:N ratio in this mixture does not vary by more than a factor of 10 in either direction. At the 0.5% level the analysis should be accurate to within 20% of the measured concentration. At concentrations above 1%, the analysis should be accurate to within 5% of the measured concentration.

The dissolved gas sample will contain krypton or other tracer in addition to oxygen, nitrogen, and possibly hydrogen. Although the analysis of the dissolved gas sample for hydrogen should be

reliable, the analysis for oxygen and nitrogen presents several difficulties. The major problem is due to the incomplete evacuation of the sample vial which initially contains air. A partial vacuum (4-5 psia) is drawn on the vial before the sample is taken, however, this leaves a significant amount of air in the vial. This may not be a significant problem if the amount of dissolved oxygen or nitrogen stripped from the coolant is large compared to that left in the evacuated vial, since a correction can be made based on the pressure measurements taken before and after taking the sample. However, dissolved oxygen and nitrogen is not required by NUREG-0737, which states that determination of dissolved hydrogen gas in the coolant is adequate. In case the need should arise, a procedure will be established to tap off the sample line in the sample station and run this to an in-line oxygen monitor. The flow would then return to the liquid return line to the wetwell.

18.1.21.3.4.3 Storage and Disposal of Sample

Short term sample storage areas will be provided in the chemistry laboratory and counting rooms in both the on-site and EOF facilities. An area for long term storage of the samples will be designated at a later date. Low level wastes generated by the chemistry procedures will be flushed to radwaste in the on-site chemistry laboratory and collected in removable carboys in the EOF. The carboys will then be taken to an on-site location for disposal to the radwaste system. Ultimate procedures for disposal of the samples will be determined later; however, after a sufficiently long decay period, the activity levels will be significantly reduced. This will ease exposure problems during disposal.

18.1.21.3.4.4 System Testing and Operator Training

To ensure the long-term operability of the PASS, it will be tested semiannually. Samples will be taken from all gas sample points; however, the number and type of liquid samples taken will be based on the operating status of the reactor at the time. The semiannual functional testing will also serve to maintain operator proficiency. In addition to the scheduled tests, the system will be used for operator training on an as-needed basis.

To ensure an adequate pool of qualified PASS operators, a formal training program will be established. This program will be part of the chemistry technician qualification program. All plant chemistry technicians and chemistry management personnel will be required to show competence in the operation of the sample station and the chemical analysis procedures.

18.1.21.3.4.5 Core Damage Estimation Procedure

A revised core damage estimation procedure to be used on both units will be developed prior to the start up following the first refueling outage of Unit 1.

18.1.21.3.5 Dose Rate Analysis

Radioactivity source terms were calculated for use in design of the PASS shielding. These source terms are for a LOCA assuming a release of fission product activity as defined by NUREG 0578. Source terms were calculated for a three year reactor operation at 3293 MWt. For the purposes of specifying shielding design source terms, a decay period of one hour has been assumed between reactor shutdown and initial sampling. Although there is no decay period specified in NUREG 0578 the source terms calculated for PASS still result in a conservative design. The PASS is designed to limit operator whole body exposure to 100 mRem as a result of taking and analyzing the sample. NUREG 0737, on the other hand, limits the operator exposure to less than 5 Rem whole body exposure for the entire operation.

Using a one hour decay and the fractional releases of core inventory specified by NUREG 0578, the primary coolant and primary containment atmosphere fission product concentrations are calculated to be 2.6 Ci/gm and 0.046 Ci/cc, respectively. Using these fission product concentrations, gamma radiation source terms were determined in terms of MeV/sec for ten gamma energy groups. These radiation source terms were used for shielding design and sample dose rate calculations. Assuming point sources, the calculated dose rates per unit volume of coolant and containment atmosphere are 125 R/h/gm and 1.8 R/h/cc at 4 inches, respectively.

Thus, the 0.1 milliliter reactor sample would have a maximum exposure rate of about 12 R/h at 4 inches and 14.7 milliliter vial of containment atmosphere at STP would have an exposure rate of 25 R/h at 4 inches. Using the calculated source terms, dose rate estimates resulting from activity in the sample station and sample casks were calculated for various distances. The results are given in Table 18.1-7. These dose rates will be used in a time-motion study to estimate the total integrated dose expected during sampling and analysis after the sample station is operational.

18.1.21.3.6 Irradiation Effect On Analytical Procedures

Some scoping tests were performed to study the effect of high fission product levels on the proposed analytical procedures. The core inventory of individual nuclide beta energies in terms of MeV/second/MWt after one hour decay was taken from the same CINDER run as used to calculate the PASS activity source terms. The NUREG-0578 release fractions were used to determine the fraction of the core inventory dissolved in the primary coolant. The "all other" category was ignored as at a 1% release fraction the dose contribution from these nuclides is negligible compared to the 50% halogen and 100% noble gas releases. The results are shown in Table 18.1-13. For the sake of simplicity, it was assumed that the gamma energy deposition in the sample was negligible compared to the beta energy deposition. It was also assumed that 100% of the beta energy was absorbed in the sample. The net result, 1.92×10^6 Rads/hr, is conservative as the gamma energy absorption for small samples would be much less than the beta energy escaping the solution.

Dose rates approaching 2×10^6 R/h are available in the VNC Co-60 irradiation facility. At 93 ergs/g/R/h, this corresponds to 1.8×10^6 Rads/hr, and approximates the calculated maximum energy deposition possible for the reactor coolant. Tests were run to determine the effects of radiation on the conductivity, pH, chloride, and boron analytical procedures. The true energy deposition within the irradiated sample holders was determined by Fricke dosimetry using the sample holders as dosimeters. Except for conductivity and pH measurements, the dose rates were considerably larger than would be encountered with the PASS source terms. These higher dose rates were used to achieve a better measurement of the radiation effect, and it was then assumed that this effect would be linear with dose rate. It is hoped to verify this assumption in later studies.

18.1.21.3.6.1 Conductivity Cell

A 0.1 cm Balsbaugh conductivity cell and stainless steel holder was irradiated at various positions in the 4 1/4-in. dia. Co-60 irradiation tube. The flow path from this conductivity cell was connected to a 0.1 cm Beckman conductivity cell downstream of the cell under irradiation. Both static and flowing irradiation tests were performed. The flow tests were performed at ca. 125 cc/min with a 3 to 4 min flow delay between the Balsbaugh and Beckman cells. The Beckman cell, therefore, served to determine if there were any relatively long lived radiation products remaining in solution. An in-line thermometer was mounted in the flow system downstream of the Beckman cell.

18.1.21.3.6.2 Purification

A Gelman Water-I^R purification unit was installed in the conductivity cell flow loop. The output conductivity of the water from the purification unit was 0.055 µS/cm, as indicated by the purification units built in the conductivity meter. The water flow was from the purification unit through the two conductivity cells under study and back to the reservoir of the purification unit. The output of the conductivity meter associated with the irradiated cell was continuously recorded. The highest radiation field in the 4 1/4 in. irradiation tube, as measured by a Victoreen R Meter, was 7.4×10^5 R/h. The actual cell energy absorbtion rate at this position was determined by removing the conductivity element and using the cell holder as a Fricke dosimeter container. The result, 9.8×10^5 Rads/hr was also used to convert the R/h measurements at the other elevations to Rads/hr by assuming a constant ratio between the field intensity and the energy absorbtion. (This is not strictly true as the photon energy distribution varies with the elevation in the irradiation facility. Consequently, the fraction of the photons penetrating the stainless steel cell holder will vary slightly.)

The results of these experiments are summarized in Table 18.1-14. There was apparently some pickup of impurities from the flow loop materials as 0.10 µS/cm was the lowest loop conductivity observed. The 0.06 µS/cm at the output of the purification unit was confirmed by connecting one of the flow cells immediately as the output.

In the case of the flowing measurements, there was a steady increase in conductivity from 0.11 to 0.65 µS/cm as the irradiation intensity increased from 1.3×10^4 to 6.6×10^5 Rads/hr. The conductive species which were formed were relatively stable as there was little difference between the conductivity as measured at the irradiated cell and the downstream cell. In fact, when the flow was stopped and the conductivity of the irradiated cell was allowed to come to equilibrium, the cell could be removed from the radiation field and the conductive would remain constant, at least up to several hours, the longest period observed. The flow was secured at each irradiation intensity and the conductivity was monitored until a steady-state condition was attained. From the data in Table 2 it would appear that a maximum conductivity is attained at about 2.2 µS/cm, and that the conductivity diminishes with increasing radiation intensity. The steady-state difference in cell behavior at 6.6×10^5 and 9.8×10^5 Rads/hr is unexplained.

It is suspected that the conductivity is due to the formation of hydrogen peroxide, but this has not been confirmed. It is obvious that there will be some radiation effect on the conductivity at very high fission product concentrations. This

does not appear too serious, however, as 2.2 μS/cm corresponds to a NaCl concentration of 1.0 ppm. The concentration of stable fission products, particularly I-127 and I-129, associated with the high Curie concentrations will at the same time result in considerably higher conductivities.

18.1.21.3.6.3 Conductivity of 10 ppm Chloride (Cl^-) Solution

Irradiation tests were performed to determine the radiation effect on the conductivity of a dilute NaCl solution. It was anticipated that if the pure water conductivity increases under irradiation were due to the formation of H_2O_2, this might be suppressed by the presence of the Cl^- ions. In this experiment the NaCl solution was pumped from a reservior through the two conductivity cells and back to the reservior. A common conductivity bridge was used to alternately determine the conductance of each cell, and thereby eliminate any bias between different bridges. The testing was done at the highest available irradiation level, $9.8x10^5$ Rads/hr. The solution temperature, as indicated by a flow thermometer downstream of the unirradiated cell, ranged from 59.5 to 60.2°F. Several alternate conductivity readings were taken on each cell approximately five minutes after each change in condition, and when the cell conductances had reached a steady value. The average result for each condition is given in Table 18.1-15. The difference between the cell readings for any given set conditions is attributed to errors in the stated cell constants. The conductivity of the flowing stream increased by approximately 0.6 μS/cm for both cells before and after irradiation, which may be the result of the generation of some long lived species. This possibly is supported by the Beckman cell, which although located outside the radiation field, showed a 0.6 μS/cm increase in conductivity during irradiation. The puzzling observation was the large drop in conductivity of the static solution during irradiation. This should be investigated further.

18.1.21.3.6.4 pH

Solutions of pH 3.8 and 10.0 were made up using HCl and NaOH, respectively. LO-Ion pH test paper was placed in aliquots of these solutions and the solution was inserted into the $9.8x10^5$ Rads/hr position (as determined by Fricke dosimeter). A 10.0 minute exposure for a total dose of $1.6x10^5$ Rads completely destroyed the color in the acid solution and reduced the color intensity of the basic solution to a pale green. This test was then repeated using a 1.0 min exposure at the same intensity level for an exposure of $1.6x10^4$ Rads. This exposure shifted both solutions about 1/2 pH unit to the more acid side. The

results would not necessarily indicate that pH indicator paper cannot be used at the highest dose rates, but more importantly, that the paper cannot be immersed in a relatively large volume of solution. If the paper were merely moistened by a drop or so of solution, most of the beta particles would escape the paper with little energy deposition and the paper would not be surrounded by a highly radioactive solution with the resultant beta field and water excitation products. This subject is still under consideration.

At source terms on the order of 10% or less of the maximum*, the irradiation effect, for even an immersed strip, would be tolerable at exposures less than 5 min, as it would result in less than an 0.5 pH unit shift.

Some measurements were also made to determine the effect of irradiation on pH electrodes. Long leads are needed on the pH electrodes in order to reach in the Co-60 irradiation facility, and these electrodes were not available. We intend to order some new electrodes and will continue this study. In the meantime, we have irradiated a glass membrane pH electrode to 1.6x10^7 Rads at a 9.85x10^7 Rad/hr intensity and found it still functions following irradiation.

18.1.21.3.6.5 Turbidmetric Chloride Procedure

Using the maximum source term of 2x10^7 Rads/hr, ml diluted primary coolant sample would have an internal beta exposure of 2x10^7 Rad/hr. The turbidimetric method calls for a total volume of 25 ml. Therefore, even if the entire 10 ml of diluted sample were used, the dose rate of the final analysis solution would be less than 8x10^7 Rad/hr. Test solutions containing 0, 1, 5, and 20 /gm of chloride in 25 ml were processed through the chloride test methods in pairs. During the 15 min turbidity-formation period, one sample of each set was irradiated at an absorbed dose rate of 4.4x10^7 Rad/hr as determined by Fricke dosimetry. The

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* The originally calculated source term was 1.9x10^7 Rads/hr. Thirty-five percent of this source intensity, however, is due to noble gases which would escape solution in the sampling process. A 10% source term for pH measurement would then be approximately 1.2x10^7 Rads/hr and a 5-min exposure would correspond to a 1x10^7 Rad energy absorption, which is approximately the exposure causing a 0.5 pH shift.

maximum observed radiation effect was a difference of about 10 turbidity units between the irradiated and unirradiated 1 gm Cl solutions. This difference is equivalent to about 10 μ/gm of chloride in the 25 ml of solution being processed. Assuming this increase in turbidity is proportional to the dose, the maximum effect would be (10 μgm)($8x10^3/4.4x10^5$) = 0.18 μgm. If only 0.1 ml of reactor water were used for the original sample, this would be equivalent to 1.8 ppm of Cl^- in the primary coolant. This error is probably insignificant as the interference from all the stable iodine associated with the high radiation intensity is likely to be far larger.

The test data also indicates that as little as 5 μgm of Cl^- in the 25 ml of test solution inhibits the formation of the radiation-induced turbidity. It is suspected that the increased turbidity is due to the precipitation of silver peroxide and the 5 μgm Cl^- inhibited the formation of hydrogen peroxide. In any event, it was concluded that the test method is useful for highyly radioactive solutions above the 10 ppm level, or for less radioactive solutions above the 1 ppm level. For low activity samples which do not need to be diluted and where at least a 1 ml of sample is available, the method is useful above the 100 ppb level.

18.1.21.3.6.6 Carminic Acid Boron Analysis

Using the maximum source term of $2x10^6$ Rad/hr, an 0.1 ml to 10 ml diluted primary coolant sample would have an internal beta exposure of ca. $2x10^4$ Rad/hr. The colorimetric method calls for a total volume of 25 ml. Therefore, even if the entire 10 ml of diluted solution were used, the dose rate of the final analysis solution would be less than $8x10^3$ Rad/hr. Test solutions containing 0 and 20 μgm of boron were processed through the boron test methods in pairs. During the 40-min color development phase, one sample of each pair was irradiated at an absorbed gamma-radiation dose level of $4.4x10^5$ Rad/hr as determined by Fricke dosimetry. The maximum irradiation effect observed was a difference of 0.854 absorbance units between the irradiated an unirradiated blank solutions. This difference is equivalent to about 27 μgm of boron in 25 ml of solution being processed. Assuming this difference is absorbance is proportional to the dose, the maximum affect would be (27 μgm)($8x10^3/4.4x10^5$) = 0.49 gm. If only 0.1 ml of reactor water were used for the original sample, this is equivalent to a 5 ppm error in the primary coolant analysis. This error is totally negligible in terms of the levels of boron required for reactor shutdown.

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 qualificaiton shall include qualification of associated control circuitry, piping, and supports, as well as the valves themselves.

Preimplementation 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

Postimplementation 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-20-81).

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 a safety grade 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. This equipment has been qualified to IEEE-344-1975, IEEE-323-1974 and NUREG-0588 in accordance with the Commission order on May 23, 1980 (CLI-20-81).

Additional design information is presented in Subsection 7.6.1b.1.7.

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 Requirment

Plants using external recombiners or purge systems for postaccident 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 an 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 postaccident 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 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 3.3.2-1 in the Technical Specifications). 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.

(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 (G33-1FC042 and 1F104 receive auto-isolation signals (refer to Table 18.1-10). The isolation function for the RWCU discharge lines is provided by three series check valves (141-1F010A,B, HV-14107A,B and G33-1F039A,B) which prevents back flow from the reactor vessel. 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 April 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. A high radiation level trips 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-15736A, SV-15737, SV-15767 and SV-15776A.

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 postaccident 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 µ Ci/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 postaccident 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 postaccident 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 postaccident 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 operaitng 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.

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 an Eberline Model FAAM (Fixed Airborne Activity Monitor). The FAAM's analyze representative samples which are provided by isokinetic probes which are in compliance with ANSI 13.1-1969. Each FAAM has three noble gas detectors which provide overlapping ranges of 1 x 10^{-7} Ci/cc to 1 x 10^{5} μCi/cc for Xe-133 gas. The sample stream is filtered by a HEPA filter and a charcoal filter, which are contained in a SA-13 assembly before passing the noble gas detectors. The charcoal filter can be replaced with a silver zeolite filter when required.

The plant effluent noble gas data is continuously monitored and stored in solid state memory. The flow through the sample line is also measured and stored in solid state memory. The FAAM then calculates and stores activity per unit of volume. This information can be displayed upon request and is periodically printed out for record keeping purposes. This information is displayed and recorded on backrow panel 1C669.

High activity alarms for the reactor and turbine buildings are annunciated on control room front row panel 1C651. High activity alarms for the Standby Gas Treatment System are annunciated on control room front row panel 1C601.

The low-range noble gas channel is calibrated using Kr 85 and Xe 133 gas standards traceable to the National Bureau of Standards.

The mid-range noble gas channel is calibrated using a Cs 137 stick source. The high-range noble gas channel is calibrated using a Kr 85 gas standard traceable to the National Bureau of Standards.

The system is powered from non-class IE instrument AC power. An independent battery backup is provided which is capable of providing power for 8 hours.

18.1.30.3.2 Sampling and Analysis of Plant Effluents

Each of the five plant vents has a continuous isokinetic sample drawn from it in accordance with ANSI-N13.1. Each sample is then taken through short runs of heat traced tubing to a Eberline Model FAAM (Fixed Airborne Activity Monitor). In the FAAM the sample stream then passes through a HEPA filter which removes particulates. Upon leaving the HEPA filter the sample stream passes through a charcoal filter which removes iodines. When required this filter can be replaced with a silver zeolite filter. Capabilities for purging the sample line with compressed air are provided under manual control. The sample stream is next measured for noble gas activity and then returned to the plant vent. During normal operation the HEPA and charcoal filters are monitored by radiation detectors and this information is presented to the operator in the control room. Under accident conditions these detectors will saturate and the filters must be removed, placed in a shielded container, and analyzed in a laboratory. The FAAM also has provisions for obtaining a grab samples.

The isokinetic sample is in compliance with ANSI-N13.1-1969. To accomplish this, each vent has an air profile (final gas treatment) station to eliminate turbulent and rotating gas flow. The average stack velocity and volume are then measured by means of a multipoint, self-averaging Pitot transverse station. An air flow controller then simultaneously withdraws a multipoint sample under isokinetic flow conditions by means of an isokinetic sample rack. This isokinetic sample is then directed to the Final Airborne Activity Monitor.

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 3 rem whole-body exposure and 18.5 rem to the extremities 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. An accuracy of ± 20% is obtained on lower decades.

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-1588 in accordance with the Commission order on May 23rd, 1980 (CLI-20-81).

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 psia
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 are qualified to IEEE-344-1975, IEEE-323-1974 and NUREG 0588 in accordance with the Commission order on May 23rd, 1980 (CLI-20-81).

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 from the lowest ECCS suction to 5 feet above normal water level. Normal water level is approximately 23 feet.

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

18.1.30.3.6 Containment Hydrogen Monitor

Continuous and redundant indication and recording of hydrogen are provided on control room front row panel 1C601. These instruments have a range of 0 to 30%.

The containment hydrogen monitoring system is designed to be safety grade. The equipment are qualified to IEEE-344-1975, IEEE-323-1974 and NUREG-0588 in accordance with the Commission order on May 23rd, 1980 (CLI-20-81).

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 of ICC and due to the complexity of the isue, 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 temperaturesin 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 powerdistribution, and reactor trip systems. This

rationale is extended down to zero flow and zero powerincluding 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 BWR's 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 conservativeas 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 overal 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 18.1-16 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 backup, 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.1.

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.

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).

18.1.51 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 RICI 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 nonsafety-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 31.5 psig (70% of 45 psig) 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 replaced 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 six 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 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 30 days after a postulated DBA. However, these nitrogen bottles could be replaced periodically by bringing portable N -bottles to provide long-term operation of the ADS. (At Susquehanna, these bottles are located in an area that is accessible following a loss-of-coolant accident.)

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 evalaution 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; <u>a-date</u>, <u>b-activity</u>, <u>c-minimum acceptance criteria</u>. 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 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:

- o 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.

- o 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.

- o 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.

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

- o It shall be a reportable occurence 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," Secton 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 each item):

A.	Residual Heat Removal	(18 months)
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	"
I.	Post Accident Sampling	"

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

* NOTE: 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.

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

A. Main Steam - identified by NEDO-24782 as not to be regarded as containing highly radioactive fluid following an accident.

B. Feed water - same justification as A.

C. Main Steam Line Drain - this system is isolated following a LOCA.

D. Reactor Water Sample - this system will not be used following an accident, a separate

post-accident sampling station is being developed in response to item II.B.3.

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

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

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

1.3 Method for obtaining actual leak rates

A. Water - leakage will be collected in a graduated measuring device and timed to determine 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.

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 while the system is under normal running conditions by checking each mechanical joint with liquid soap.

3. Consideration was given to the Standby Gas system regarding the incident at North Anna Unit 1 in 1979. The standby gas piping and duct work 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 duct work 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 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 4.6.5.3 and

   B. The containment air monitors - which has an acceptance criteria of zero leakage as determined by a liquid soap test.

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.

Grap 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 8.1.2 (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";

(b) Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accident Chlorine Release"; and,

(c) 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 isoaltion 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. 2) 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 and toxic gases. Subsection 6.4 provides a description of this system and compliance to habitability requirements. Potential hazards from nearby 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., <u>Table of Isotopes</u>, Lawrence Radiation Laboratory, University of California, March 1968.

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

18.1-15 D. S. Duncan and A. B. Spear, <u>GRACE II - An IBM 709 Program for Computing Gamma Ray Attenuation and Heating in Cylindrical and Spherical Gecmetries</u>, 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	Curies	Isotope	Curies	Isotope	Curies
I--131	8.66+7(2)	Y---93	1.82+8	TE-129	2.38+7
I--132	1.29+8	Y---94	1.61+8	TE131M	1.31+7
I--133	1.99+8	Y---95	1.84+8	TE-131	7.74+7
I--134	2.32+8	ZR--95	1.84+8	TE-132	1.29+8
I--135	1.82+8	ZR--97	2.86+8	TE133M	1.40+8
I--136	9.22+7	NB-95M	3.81+6	TE-133	8.93+7
BR--83	1.52+7	NB--95	1.91+6	TE-134	2.05+8
BR--84	2.74+7	NB-97M	1.78+8	CS-137	1.13+7
BR--85	3.84+7	NB--97	1.85+8	CS-138	1.90+8
KR-83M	1.55+7	MO--99	1.84+8	CS-139	1.93+8
KR-85M	3.87+7	MO-101	1.49+8	CS-140	1.76+8
KR--85	1.31+6	MO-102	1.19+8	CS-142	9.22+7
KR--87	7.44+7	MO-105	2.05+7	BA137M	1.75+8
KR--88	1.04+8	TC-99M	1.63+8	BA-139	1.87+8
KR--89	1.37+8	TC-101	1.49+8	BA-140	1.87+8
XE133M	5.06+6	TC-102	1.23+8	BA-141	1.87+8
XE-133	1.98+8	TC-105	2.65+7	BA-142	1.71+8
XE135M	5.36+7	RU-103	8.93+7	LA-140	1.87+8
XE-135	1.87+8	RU-105	2.68+7	LA-141	1.90+8
XE-137	1.79+8	RU-106	9.84+7	LA-143	1.74+8
XE-138	1.76+8	RU-107	5.65+6	LA-142	1.74+8
SE--81	4.17+6	RH103M	8.93+7	CE-141	1.90+8
SE-83M	8.63+6	RH105M	5.62+6	CE-143	1.75+8
SE--83	6.55+6	RH-105	2.68+7	CE-144	1.45+8
SB--84	2.92+7	RH-106	1.16+7	CE-145	1.15+8
RB--88	1.07+8	RH-107	5.65+6	CE-146	8.81+7
RB--89	1.42+8	SN-127	3.27+6	PR-143	1.75+8
RB--90	1.72+8	SN-126	1.75+1	PR-144	1.49+8
RB--91	1.62+8	SN-128	1.10+7	PR-145	1.15+8
RB--92	1.31+8	SN-130	5.95+7	PR-146	9.14+7
SR--89	1.42+8	SB-127	3.87+6	ND-147	6.70+7
SR--90	1.14+7	SB-128	1.64+7	ND-149	3.24+7
SR--91	1.73+8	SB-129	2.20+7	ND-151	1.19+7
SR--92	1.58+8	SB-130	5.95+7	PM-147	3.45+7
SR--93	1.67+8	SB-131	8.03+7	PM-149	3.24+7
SR--94	1.28+8	SB-132	9.97+7	PM-151	1.25+7
Y---90	1.72+8	SB-133	1.01+8	SM-151	2.70+5
Y--91M	1.01+8	TE127M	1.04+6	SM-153	4.70+6
Y---91	1.70+8	TE-127	3.87+6		
Y---92	1.76+8	TE129M	1.04+7		

(1) Based on 1000 reactor operating days at 3440 MWt. Reference GE Internal Report Document, "Summary of Fission Yield for U-235, U-238, and PU-239," published by Meek and Rider, June, 1977.

(2) $8.66+7 = 8.66 \times 10^7$.

TABLE 18.1-3

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	Radiation Zone	TID (rem)
Continuous				
Main Control Room	18.1-5	A.1	I	0.24
Technical Support Center	18.1-5	A.2	II	1.6
Operations Support Center	18.1-5	A.3	II	1.6
North Gate House (ASCC)	18.1-1	A.4	I	0.1
Security Control Center	18.1-1	A.5	I	0.1
Emergency Operations Facility(1)	18.1-1	A.6	I	0.1
As Required				
Post-Accident Sampling				
1) Sample Station	18.1-5	B.1	I	0.1(2)
2) Chemistry Lab	18.1-3	B.2	II	0.1(3)
3) Plant Vent Sample Station	18.1-8	B.3	III	0.1(4)

(1) Information regarding the EOF may be found in Appendix I of the SSES Emergency Plan.

(2) TID is determined per event, that is, for a one time, one man task initially performed 1 hour post-accident and lasting 30 minutes.

(3) TID is determined per event, that is for a one time one man task initially performed 2 hours post-accident.

(4) TID is determined per event. Duration is thirty (30) minutes for filter removal and transport. Task initially performed 24 hours post-accident.

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	Suppression pool water (C)
	HPCI	HPCI (C, D)[1]
	RCIC	RCIC (C, D)[1]
	Core Spray	Core Spray (C)
	Sump Room	RHR Cooling Mode (B)
Elev. 670'-0" to 683'-0"	Wetwell	Drywell (A)
	RHR	RHR Cooling Mode (B)
	Access Corridor	RCIC (C)
	Truck Port	RHR Cooling Mode (B)
	Railroad Port	RHR Cooling Mode (B)
	Other Areas	Core Spray[2] (C), RCIC (C), HPCI (C)
Elev. 683'-0" to 719'-1"	Drywell	Drywell (A)
	Equip. Areas	RHR Cooling Mode (B)
	Equip. Removal Areas	RHR Cooling Mode (B)
	Core Spray Piping Area	Core Spray (C)
Elev. 719'-1" to 749'-1"	Drywell	Drywell (A)
	Main Steam Tunnel	Core Spray (C)
	NE Equipment Airlock	RHR Spray Mode (C)
	SW Equipment Airlock	Core Spray (C)
	South Switch Gear Room	RHR Spray Mode (C)
	CRD Hatch	RHR Spray Mode (C)
Elev. 749'-1" to 770'-1"	Drywell	Drywell (A)
	Penetration Rooms and other Areas	Core Spray[2] (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

TABLE 18.1-5 (page 2 of 2)

NOTES:

(1) At one hour post-accident, the steam source (D) will dominate area radiation levels. Following reactor steam activity depletion, radiation levels will be due to contained source (C).

(2) Radiation levels are based on system/source proximity, however, in this case each system noted contains source (C). Therefore, radiation levels may be determined as a function of time by referring to the same curve on figures 18.1-9 and 18.1-10 for source (C).

TABLE 18.1-6

CHEMICAL AND RADIOCHEMICAL ANALYTICAL CAPABILITIES REQUIRED OF OFF-SITE LABORATORY

A. Liquid Samples

The laboratory must be capable of handling up to 10 ml of undiluted reactor coolant/suppression pool water with activity levels up to 3.0 curies per ml. The laboratory will be required to perform the following analyses within the range and accuracy indicated.

1. Radioisotopic Analysis

a. Gamma-Ray Spectroscopy

Identify and quantify with accuracy of ± 20% all isotopes which have gamma-ray peaks in the spectrum from 50 to 5000 keV with a net peak area of greater than 5% of the total spectrum counts within a ± 5 times full width at half maximum (FWHM) band about the centroid of the peak. The spectrometer system must be capable of analyzing samples with total concentration of gamma-ray emitting isotopes as low as 0.01 microcuries per ml.

b. Beta Activity

Gross beta and quantitative determination of Sr-89 Sr-90 (up to 10 days permitted for completion of this analysis).

c. Alpha Activity

Gross alpha count and relative alpha activities by alpha spectroscopy.

d. Uranium and Plutonium

Identify and perform semiquantitative analyses for these elements.

2. Conductivity

Range: 0.1 to 10,000 micromhos per cm.
Accuracy: ± 20%

3. pH

Range: 1 to 13
Accuracy: ± 0.3 pH units

TABLE 18.1-6 (page 2of2)

4. Chloride

Range: greater than 50 ppb
Accuracy: ± 10% if greater than 500 ppb
± 50 ppb if less than 500 ppb

5. Boron

Range: 0.1 to 10,000 ppm
Accuracy: ± 50% if less than 1 ppm
± 20% if greater than 1 ppm and less than 100 ppm
± 5 % if greater than 100 ppm

B. Gas Samples

Gas samples will be obtained from the following sources: drywell, wetwell, secondary containment, and dissolved gases from liquid samples. The laboratory must be able to handle 15 ml gas samples with activity levels up to 0.06 curies per ml. The laboratory will be required to perform the following analyses within the range and accuracy indicated:

1. Radioisotopic analysis by gamma-ray spectroscopy. See Section A.1.a for requirements.

2. Elemental Analysis

Identify and quantify by volume % the following: hydrogen, oxygen, nitrogen and krypton (spike added to dissolved gas samples). The analysis sensitivity should be sufficient to detect any of these constituents at the 0.1% by volume level. At the 0.1% level the analysis should be accurate to ± 20%. At concentrations above 0.5% the analysis should be accurate to within ± 5%.

C. Particulate and Iodine Cartridge Samples

The laboratory must be able to handle and perform gamma-ray spectroscopic analysis on particulate, silver zeolite, and charcoal filter cartridges. The maximum activity anticipated for any of these cartridges is 0.1 curies. The analysis should be able to identify and quantify with an accuracy of ± 50% all isotopes which have gamma-ray peaks in the spectrum from 100 to 4000 keV with a net peak area of greater than 5% of the total spectrum counts within a ± 5 times FWHM band about the centroid of the peak.

TABLE 18.1-7

DOSE RATES FROM PASS AND TRANSPORT CASKS[1]

Source	Thickness of Lead Shielding in Inches	Dose Rate in mR/h 0 ft	3 ft	8 ft
Liquid Sampler[2]	6	5300	310	55
Gas Sampler[2]	2	8800	220	110
Small Volume Cask (0.1 ml sample)	2	1600	4	<1
Large Volume Cask (10 ml sample)	5 1/2	260	5	<1
Gas Cask (14.7 cc. sample)	1 1/8	5500	50	<1

(1) Based on source term 1 hour following shutdown.

(2) Dose rates from the sample panels will be present for only a few minutes while the sample is flowing.

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 10.1-10
CONTAINMENT ISOLATION ACTUATION PROVISIONS

P&ID, SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUA-TION	AUTOMATIC ACTUATION SIGNALS (2)	ELECTRICAL SCHEMATIC DIAGRAM	GE ELEM & ACTUATING RELAY	AUTO OPEN ON ISO RESET	VALVE STATUS LOCATION INDICATION SOURCE	LOCAL PNL	CONTROL RM	HAND SWITCH NO.	TYPE (14)	POWER SOURCES (3) VALVE MOTOR	CONTROL	LOGIC	OTHER REMARKS
M-113	NE	1.	X-24	HY 11313	AI	Y	E-147 SH 4	B21-131 (K84)	NO	ZS	CB215A	–	11314	E-30AC MOM-MI	1B238	1Y216	RPS A	(10)
REAC				11345	"	Y	15	(K83)	"	"	CB216B	–	11346	"	1B246	1Y226	RPS B	(10)
BLDG	NE	1.	X-23	11314	"	Y	3	(K84)	"	"	CB216A	C668	11314	"	1B236	1Y216	RPS A	(10)
CCW				11346	"	Y	14	(K83)	"	"	CB216B	C668	11346	"	1B248	1Y226	RPS B	(10)
M-126	E	2.	X-41	SY-12654A	RM	–	E-172 SH 6	–	–	–	–	C601	12654A	E-30AB MOM	–	–	–	
INSTRUM				126154	CKV	–	–	–	–	–	–	–	–	–		–	–	
GAS	E	2.	X-21	SY-12654B	RM	–	SH 6	–	–	–	–	C601	12654B	E-30AB MOM	–	–	–	
				126152	CKV	–	–	–	–	–	–	–	–	–		–	–	
	NE	3.	X-10	SY 12651	AI	Y	SH 5	(K84)	NO	ZS	C201	C601	12651	E-30AB MOM	–	1Y236	RPS A	
				126074	CKV	–	–	–	–	–	–	–	–	–		–	–	
	NE	3.	X-83	SY 12661	AI	Y	SH 1	(K84)	NO	ZS	–	C601	12661	E-30AB MOM	–	1Y218	RPS A	
				126072	CKV	–	–	–	–	–	–	–	–	–		–	–	
	NE	3.	X-87	SY 12605	AI	Y	SH 5	(K83)	NO	ZS	C201	C601	12605	E-30AB MOM	–	1Y248	RPS B	
				HY 12603	AI	Y	SH 2	(K84)	NO	ZS	C201	C601	12603	E-30AB MOM	1B238	1Y236	RPS A	
	NE	3.	X-210	SY 12671	AI	Y	SH 1	(K84)	NO	ZS	–	C601	12671	E-30AB MOM	–	1Y216	RPS A	
				126164	CKV	–	–	–	–	–	–	–	–	–	–	–	–	
M-139, MSIV LEAKAGE CONTROL SYSTEM	NE	4.	X-7A	E32 1F001B	AC	(4)	E-189 SH 1	E32-18 (K108)	N/A	ZS	–	C844	13901B	CR2940 (KLRN) SRN	1B227		120VAC DIV 2	
M-141 NUCLEAR BOILER	NE	4.	X-7A	B21-1F028A	AI	B,C,D,E, P,UA	E-170 SH 1	B21-131(K7A-D)	NO	LS		C601	14128A	CR2940 MAINT	(17)	125VDC	RPS A	(5)
				-1F022A	AI	"	SH 7	(K7A-D)	NO	LS	C201	C601	14122A	CR2940 MAINT	(17)	1D814	RPS B	(5) (13)
	NE	4.	X-8	-1F016	AI	"	SH 2	(K56)	NO	ZS	–	C601	14116	CR2940 (KLRN) SRN	1B237		RPS A	(5)
				-1F019	AI	"	SH 3	(K57)	NO	ZS	–	C601	14119	CR2940 (KLRN) SRN	1D274		RPS B	(5)

TABLE 18.1-10 (CONTINUED)

P&ID, SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	ELECTRICAL SCHEMATIC DIAGRAM	GE ELEM & ACTUATING RELAY	AUTO OPEN ON ISO RESET	VALVE STATUS LOCATION INDICATION SOURCE	LOCAL PNL	CONTROL RM	HAND SWITCH NO.	TYPE (14)	POWER SOURCES (3) VALVE MOTOR	CONTROL	LOGIC	OTHER REMARKS
M-141 NUCLEAR BOILER (CONT.)	E	5.	X-9A	-1F032A	RM	–	E-181 SH 3	B21-96 –	–	ZS	–	C651	14132A	E-30AC MOM-MI	1B217		–	–
				-1F010A	CK	–	–	–	–	–	–	–	–	–	–	–	–	–
	E	5.	X-9B	-1F032B	RM	–	E-181 SH 3	B21-96 –	–	ZS	–	C651	14132B	E-30AC MOM-MI	1B217		–	
				-1F010B	CK	–	–	–	–	–	–	–	–	–	–	–	–	–
M-143 REACTOR RECIRC	NE	8.	X-60B	B31-1F019	AI	B,C	E-170 SH 1	B21-131 (K72)	NO	LS	–	C651	14319	CR2940 MAINT	(17)	1C622	RPS A	(6) (7)
				-1F020	AI	B,C	SH 1	(K73)	NO	LS	–	C651	14320	CR2940 MAINT	(17)	1C622	RPS B	(6) (7)
M-144 RWCU	NE	7.	X-14	G33-1F001	AI	A,J,W	E-164 SH 6	B21-131 (K26)	NO	ZS	–	C651	14401A	CR2940 SRN	1B236		RPS A	
				-1F004	AI	A,J,W	SH 7	B21-131 (K27)	NO	"	–	"	14404A	CR2940 SRN	1D274		RPS B	
	NE	7.	X-9A	-1F042	RM	–	SH 4	G33-153 –	–	"	–	"	144042	E-30AC MOM-MI	1B217		–	
				-1F104	RM	–	SH 4	G33-153 –	–	"	–	"	14404B	E-30AC MOM-MI	1B217		–	
M-148 STANDBY LIQUID CONTROL	E	9.	X-42	C41-1F007	CX	–	–	–	–	–	–	–	–	–	–	–	–	
				1F006	RM	–	E-186 SH 4	C41-36 –	–	ZS	–	C601	14806	CR2940 (KLRO) MAINT	1B236	–	–	
M-149 RCIC	E	6.	X-9A	E51-1F013	AC	I	E-154 SH 7	E51-90 (K2)	NO	ZS	C201	C601	14913A	CR2940 SRA	1D254		125 VDC BUS A	
	E	8.	X-10	-1F088	AI	K	18	(K50)	YES	"	–	"	14988	CR2940 MAINT	(17)		" B	
				-1F007	AI	K	4	(K33)	YES	"	C201	"	14907A	CR2940 (KLRO) MAINT	1B246		" B	
				-1F008	AI	K	3	(K15)	YES	"	"	"	14908A	CR2940 (KLRO) MAINT	1D254		" A	

P&ID. SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	ELECTRICAL SCHEMATIC DIAGRAM	GE ELEM & ACTUATING RELAY	AUTO OPEN ON ISO RESET	VALVE STATUS LOCATION INDICATION: SOURCE	VALVE STATUS LOCATION INDICATION: LOCAL PNL	VALVE STATUS LOCATION INDICATION: CONTROL RM	HAND SWITCH: NO.	HAND SWITCH: TYPE (14)	POWER SOURCES (3): VALVE MOTOR	POWER SOURCES (3): CONTROL	POWER SOURCES (3): LOGIC	OTHER REMARKS
M-149 RCIC (CONT.)	E	6.	X-216	-1F019	AC	LFRC	12	(K19)	N/A	ZS	C201	C601	14919A	CR2940 SRA	1D254		BUS A	
				-1F021	CK	-	-	-										
	E	6.	X-245	-1F084	AI	FA	E-154 SH 18	(K52)	N/A	"	"	"	14984A	" "	1D284		" A	
				-1F062	AI	FA	17	(K51)	N/A	"	"	"	14962A	" "	1D254		" B	
	E	6.	X-215	-1F059	RM	-	14	-	-	"	"	"	14959A	CR2940 (KLRO) MAINT	1D254		" A	
				-1F040	CK	-	-	-	-									
	E	6.	X-217	-1F060	RM	-	E-154 SH 13	-	-	"	"	"	14960A	" " "	1D254		-	
				-1F028	CK	-	-	-	-									
	E	6.	X-214	-1F031	RM	-	E-154 SH 10	-	-	"	"	"	14931A	CR2940 SRA	1D254		-	
M-151 RHR	NE	10.	X-17	E11-1F023	AI	M,UB,Z	E-153 SH 38	B21-101 (K30)	NO	ZS	C201	C601	15123A	CR2940 (KLRN) SRN	1D274		RPS B	
				-1F022	AI	M,UB,Z	37	B21-101 (K29)	NO	"	"	"	15192A	CR2940 SRN	1B237		RPS A	
	E	11.	X-39A	-1F016A	AC	G	95	E11-88 (K61A)	(15)	"	-	"	15116A	CR2940 (KLRC) MAINT	1B217		125 VDC BUS A	
	E	12.	X-13A	-1F015A	AC	G&T&Z&UB	25	(K66A)	NO	"	-	"	15115A	" "	1B219		"	(8)
				-1F050A	AC	Z	30	(K108)	NO	"	-	"	15115A	CR2940 MAINT	(17)	1Y216	"	(9)
				-1F122A	AC	Z	30	(K108)	NO	"	-	"	15115A	" "	(17)	1Y216		(9)
	E	11.	X-205A	-1F028A	AC	G	96	(K61A)	(15)	"	-	"	15128A	CR2940 (KLRC)	1B216		"	
	NE	13.	X-205A	-1F011A	AI	B,C	22	(K73A)	NO	"	-	"	15111A	CR2940 SRN	1B216		BUS A	
	E	13.	X-204A	-1F028A	AC	G	96	(61A)	(15)	"	-	"	15128A	CR2940 (KLRC)	1B216		BUS A	
	NE	13.	X-204A	-1F011A	AI	B,C	22	(K73A)	NO	"	-	"	15111A	CR2940 SRN	1B216		BUS A	
	E	14.	X-226A	-1F007A	AC	LFRH	26	(K84A)	N/A	"	-	"	15107A	CR2940 SRA	1B219		BUS A	
	E	15.	X-246A	-1F055A	PSV	-	-	-	-	"	-	-	-	-	-		-	
				-15106A	PSV	-	-	-	-	"	-	-	-	-	-		-	
				-1F103A	RM	-	E-153 SH 27	E11-88 -	-	"	-	C601	15113A	CR2940 SRN	1B237		-	
	E	15.	X-246B	-1F055B	PSV	-	-	-	-	"	-	-	-	-	-		-	
				-15106B	PSV	-	-	-	-	"	-	-	-	-	-		-	
				-1F103B	RM	-	E-153 SH 94	E11-88 -	-	"	-	C601	15113B	CR2940 SRN	1B247		-	
				-1F097	PSV	-	-	-	-	-	-	-	-	-	-		-	
	E	18.	X-203A	-1F004A	RM	-	19	E11-88 -	-	"	-	C601	15104A	CR2940 (KLRO)	1B216			
	E	18.	X-203C	-1F004C	RM	-	19	E11-88 -	-	"	-	"	15104C	" "	1B237			
	E	11.	X-39B	E11-1F016B	AC	G	E-153 SH 95	E11-88 (K61B)	(15)	ZS	-	C601	15116B	CR2940 (KLRC) MAINT	1B226		125 VDC BUS B	
	E	12.	X-13B	-1F015B	AC	G&T&UB&Z	16	(K67B)	NO	"	C201	"	15115B1	CR2940 SRA	1B229		"	
				-1F050B	AC	Z	30	(K108)	NO	LS	-	"	15150B	CR2940 MAINT	(17)		"	
				-1F122B	AC	Z	30	(K108)	NO	ZS	-	"	15150B	" "	(17)		"	
	E	12.	X-12	-1F008	AI	M,UB,Z	15	B21-131 (K30)	NO	ZS	C201	"	15108B1	CR2940 SRN	1D274		RPS B	
				-1F009	AI	M,UB,Z	17	B21-131 (K29)	NO	ZS	C201	"	15109B1	CR2940 SRN	1B236		RPS A	
				-1F126	PSV	-	-	-	-	-	-	-	-	-	-		-	

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TABLE 18.1-10 (CONTINUED)

P&ID. SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	ELECTRICAL SCHEMATIC DIAGRAM	GE ELEM & ACTUATING RELAY	AUTO OPEN ON ISO RESET	VALVE STATUS LOCATION INDICATION: SOURCE	VALVE STATUS LOCATION INDICATION: LOCAL PNL	VALVE STATUS LOCATION INDICATION: CONTROL RM	HAND SWITCH: NO.	HAND SWITCH: TYPE (14)	POWER SOURCES (3): VALVE MOTOR	POWER SOURCES (3): CONTROL	POWER SOURCES (3): LOGIC	OTHER REMARKS
M-151 RHR (CONT.)	E	11.	X-205B	-1F028B	AC	G	E-153 SH 12	E11-66 (K61B)	(15)	ZS	C201	C601	15128B	CR2940 (KLRC)	1B228		125 VDC BUS B	
	NE			1F011B	AI	B,C	92	(K73B)	NO	"	-	"	15111B	CR2940 SRA MAINT	1B226	1B228		
	E	13.	X-204B	-1F028B	AC	G	12	(K61B)	(15)	"	C201	"	15128B	CR2940 (KLRC)	1B226		"	
	NE			1F011B	AI	B,C	92	(K73B)	NO	"	-	"	15111B	CR2940 SRA MAINT	1B226	1B228	"	
	E	14.	X-226B	-1F007B	AC	LFRH	93	(K84B)	N/A	"	C201	"	15107B	CR2940 SRA	1B229		"	
	E	16.	X-203D	-1F004D	RM	-	19	E11-66 -	-	"	-	"	15104D	CR2940 (KLRO) MAINT	1B247		"	
	E	16.	X-203B	-1F004B	RM	-	10	E11-66 -	-	"	C201	"	15104B1	CR2940 (KLRO) MAINT	1B226		"	
M-152 CORE SPRAY	E	17.	X-16A	E21-1F005A	AC	G&T	E-155 SH 3	E21-35 (K13A)	(16)	ZS	-	C601	15205A	CR2940 SRA	1B217		125 VDC BUS A	
				-1F006A	RM	-	6	E21-35 -	-	"	-	"	15206A	CR2940 (PB)	(17)	1Y218	-	
				-1F037A	RM	-	7	E21-35 -	-	"	-	"	15206A	" "	(17)	1C628	-	
	E	17.	X-16B	-1F005B	AC	G&T	3	E21-35 (K13B)	(16)	"	-	"	15205B	CR2940 SRA	1B227		BUS B	
				-1F006B	RM	-	6	E21-35 -		"	-	"	15206B	CR2940 (PB)	(17)	1Y226	B	
				-1F037B	RM	-	7	E21-35 -		"	-	"	15206B	"	(17)	1C626	B	
	NE	18.	X-207A	-1F015A	AC	G	5	E21-35 (K10A)	(16)	"	-	"	15215A	CR2940 SRA	1B237		A	
	NE	18.	X-207B	-1F015B	AC	G	5	E21-35 (K10B)	(16)	"	-	"	15215B	" "	1B247		B	
	E	19.	X-208A	-1F031A	AC	LFCS	2	E21-35 (N006A)	N/A	"	-	"	15231A	" "	1B218		A	
	E	19.	X-208B	-1F031B	AC	LFCS	2	E21-35 (N006B)	N/A	"	-	"	15231B	" "	1B228		B	
	E	20.	X-206A	-1F001A	RM	-	4	E21-35 -		"	-	"	15201A	CR2940 (KLRO)	1B218		-	
	E	20.	X-206B	-1F001B	RM	-	4	E21-35 -		"	-	"	15201B	" "	1B228		-	
M-155 HPCI	E	21.	X-11	E41-1F002	AI	L	E-152 SH 16	E41-69 (K44)	YES	ZS	-	C601	15502	CR2940 (KLRO) MAINT	1B237		125 VDC BUS A	
				-1F003	AI	L	13	(K34)	"	"	-	"	15503	CR2940 (KLRO) MAINT	1D264		BUS B	
				-1F100	AI	L		(K36)	"	"	-	"	15521	CR2940 MAINT	(17)		BUS A	
	E	22.	X-211	-1F012	AC	LFHP	10	(K10)	N/A	"	-	"	15512	CR2940 SRA	1D264		BUS B	
				-1F048	CK	-	-	-	-	-	-	-	-	-	-	-	-	
	E	21.	X-244	-1F079	AI	FB	E-152 SH 17	E41-69 (K18A)	N/A	"	-	"	15579	CR2940 SRA	1D254		BUS A	
				-1F075	AI	FB	17	(K18B)	N/A	"	-	"	15575	CR2940 SRA	1D264		BUS B	

P&ID. SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUA-TION	AUTOMATIC ACTUATION SIGNALS (2)	ELECTRICAL SCHEMATIC DIAGRAM	GE ELEM & ACTUATING RELAY	AUTO OPEN ON ISO RESET	VALVE STATUS LOCATION INDICATION SOURCE	LOCAL PNL	CONTROL RM	HAND SWITCH NO.	TYPE (14)	POWER SOURCES (3) VALVE MOTOR	CONTROL	LOGIC	OTHER REMARKS
M-155 HPCI (CONT.)	E	21.	X-210	-1F066	RM	-	15	-		ZS	-	C601	15566	CR2940 (KLRO) MAINT	1D274		-	
				-1F049	CK	-	-	-	-	-	-	-	-	-	-	-	-	
	E	23.	X-209	-1F042	AI	L	E-152 SH 14	E41-69 (K34)	NO	"	-	"	15542	CR2940 SRA	1D264		BUS B	
	E	5.	X-9B	-1F006	AC	G	9	(K2)	(16)	"	-	"	15508	CR2940 SRA	1D264		BUS B	
M-157 CONTMT ATMOS CONTROL	NE	24.	X-26	HY 15711	AI	Y (11),R	E-171 SH 19	B21-131 (K83)	NO	ZS	-	C601	15711	E-30AB MCM	1Y226		RPS B	(17)
				HY 15713	"	Y ",R	8	(K84)	"	"	-	"	15713	"	1Y216		RPS A	"
				HY 15714	"	Y -,R	3	(K83)	"	"	-	"	15714	"	1Y226		RPS B	"
	E	25.	X-60A	SY 15740A	"	Y (12)	4	(K83)	"	"	CB220A	"	15740A	"	"	1D624	"	(13)
				SY 15742A	"	Y "	"	(K83)	"	"	"	"	15742A	"	"	"	"	"
	E	25:	X-60A	SY 15750A	"	Y "	"	(K83)	"	"	"	"	15740A	"	"	"	"	"
				SY 15752A	"	Y "	"	(K83)	"	"	"	"	15742A	"	"	"	"	"
	NE	24.	X-202	HY 15703	"	Y (11),R	8	(K84)	"	"	-	"	15703	"	"	"	"	(17)
				HY 15704	"	Y -,R	3	(K83)	"	"	-	"	15704	"	1Y226		RPS B	"
				HY 15705	"	Y (11),R	19	(K83)	"	"	-	"	15705	"	1Y226		"	"
	E	25.	X-221A	SY 15780A	"	Y (12)	4	(K83)	"	"	CB220A	"	15740A	"	"	1D624	"	(13)
				SY 15782A	"	Y "	"	(K83)	"	"	"	"	15742A	"	"	"	"	"
	E	25.	X-238A	SY 15736A	"	Y "	"	(K83)	"	"	"	"	15740A	"	"	"	"	"
				SY 15734A	"	Y "	"	(K83)	"	"	"	"	15742A	"	"	"	"	"
	E	25.	X-80C	SY 15740B	"	Y "	"	(K84)	"	"	CB220B	"	15740B	"	1Y216	1D614	RPS A	"
				SY 15742B	"	Y "	"	(K84)	"	"	"	"	15742B	"	"	"	"	"
	E	25.	X-80C	SY 15750B	"	Y "	"	(K84)	"	"	"	"	15740B	"	"	"	"	"
				SY 15752B	"	Y "	"	(K84)	"	"	"	"	15742B	"	"	"	"	"
	E	25.	X-80C	SY 15776B	"	Y ",R	"	(K84)	"	"	"	"	15740B	"	"	"	"	"
				SY 15774B	"	Y "	"	(K84)	"	"	"	"	15742B	"	"	"	"	"
				SY 15767	"	Y -,R	9	(K83)	"	"	-	"	15767	"	1Y226		RPS A	-
	NE	24.	X-25	HY 15722	"	Y -,R	3	(K84)	"	"	-	"	15722	"	1Y216		"	(17)
				HY 15723	"	Y -,R	"	(K83)	"	"	-	"	15723	"	1Y226		RPS B	"
				HY 15721	"	Y R	"	(K83)	"	"	-	"	15721	"	1Y226		"	"
				HY 15724	"	Y - R			"	"		"		"				
	NE	24	X-201A	HY 15725	"	Y R	"	(K84)	"	"	-	"	15725	"	1Y216		RPS A	"
				HY 15724	"	Y -,R	"	(K83)	"	"	-	"	15724	"	1Y226		RPS B	"
				HY 15721	"	Y,R			"	"		"		"				
				HY 15723	"	Y,R			"	"		"		"		1D614		
	E	25.	X-238B	SY 15734B	"	Y (12)	4	(K84)	"	"	CB220B	"	15742B	"	1Y216	"	" A	(13)
				SY 15736B	"	Y ",R	4	(K84)	"	"	"	"	15740B	"	1Y216		" A	"
				SY 15737	"	Y ",R	9	(K83)	"	"	-	"	15737	"	1Y226	1D614	" B	"
	E	25.	X-233	SY 15780B	"	Y "	4	(K84)	"	"	CB220B	"	15740B	"	1Y216	"	" A	"

TABLE 18.1-10 (CONTINUED)

P&ID. SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	ELECTRICAL SCHEMATIC DIAGRAM	GE ELEM & ACTUATING RELAY	AUTO OPEN ON ISO RESET	VALVE STATUS LOCATION INDICATION SOURCE	LOCAL PNL	CONTROL RM	HAND SWITCH NO.	TYPE (14)	POWER SOURCES (3) VALVE MOTOR	CONTROL	LOGIC	OTHER REMARKS
				SY 15782B	••	Y ••	4	(K84)	••	••	••	••	15747B	••	1Y216	••	•• A	••
	E	25.	X-88B	SY 15776A	••	Y ••	4	(K83)	••	••	CB220A	••	15740A	••	1Y226	1D614	RPS B	••
				SY 15774A	••	Y ••	4	(K83)	••	••	CB220A	••	15742A	••	1Y226	1D614	RPS B	••

TABLE 18.1-10 (CONTINUED)

P&ID, SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	ELECTRICAL SCHEMATIC DIAGRAM	GE ELEM & ACTUATING RELAY	AUTO OPEN ON ISO RESET	VALVE STATUS LOCATION INDICATION: SOURCE	LOCAL PNL	CONTROL RM	HAND SWITCH NO.	HAND SWITCH TYPE (14)	POWER SOURCES (3) VALVE MOTOR	CONTROL	LOGIC	OTHER REMARKS
M-157 CONTMT ATMOS CONTROL (CONT.)	NE	26.	X-243	HV 15766	AI	Y -	5	(K84)	NO	ZS	-	C601	15766	E-30AC MOM-MI	1B237		RPS A	-
				HV 15768	"	Y -	6	(K83)	"	"	-	"	15768	E-30AC MOM-MI	1D274		RPS B	-
M-161 LIQUID RADWASTE CONTROL	NE	27.	X-72B	HV 16108A1	AI	Z	E-159 SH 6	B21-131 (K59)	NO	ZS	C209	C601	16108A1	E-30AB MOM	1Y236	1Y219	RPS A	(17)
				HV 16108A2	"	"	8	(K60)	"	"	"	"	16108A2	"	"	"	RPS B	"
	NE	27.	X-72A	HV 16116A1	"	"	8	(K59)	"	"	"	"	16116A1	"	"	"	RPS A	"
				HV 16116A2	"	"	9	(K60)	"	"	"	"	16116A2	"	1Y226	"	RPS B	"
M-187 REACTOR BLDG CHILLED WATER	NE	1.	X-85B	HV 18791A2	AI	Y	E-216 SH 11	B21-131 (K84)	NO	ZS	-	C601	18791A	CR2840 MAINT	1Y238	1D634	RPS A	(17) (18)
	"	"		HV 18792B2	"	Y	23	(K83)	"	"	-	"	18792B	"	1Y246		RPS B	" "
	"	"	X-85A	HV 18791A1	"	Y	11	(K84)	"	"	-	"	18791A	"	1Y236	1D634	RPS A	" "
	"	"		HV 18792B1	"	Y	23	(K83)	"	"	-	"	18792B	"	1Y246		RPS B	" "
	"	"	X-54	HV 18781B2	"	Y	11	(K83)	"	"	-	"	18781B	"	1Y246	1D634	RPS B	" "
	"	"		HV 18782A2	"	Y	23	(K84)	"	"	-	"	18782A	"	1Y236		RPS A	" "
	"	"	X-53	HV 18781B1	"	Y	11	(K83)	"	"	-	"	18781B	"	1Y246	1D634	RPS B	" "
	"	"		HV 18782A1	"	Y	23	(K84)	"	"	-	"	18782A	"	1Y236		RPS A	" "
	"	"	X-88B	HV 18791B2	"	Y	11	(K83)	"	"	-	"	18791B	"	1Y246	1D634	RPS B	" "
	"	"		HV 18792A2	"	Y	23	(K84)	"	"	-	"	18792A	"	1Y236		RPS A	" "
	"	"	X-88A	HV 18791B1	"	Y	11	(K83)	"	"	-	"	18791B	"	1Y246	1D634	RPS B	" "
	"	"		HV 18792A1	"	Y	23	(K84)	"	"	-	"	18792A	"	1Y236		RPS A	" "
	"	"	X-58	HV 18781A2	"	Y	11	(K84)	"	"	-	"	18781A	"	1Y236	1D634	RPS A	" "
	"	"		HV 18782B2	"	Y	23	(K83)	"	"	-	"	18782B	"	1Y246		RPS B	" "
	"	"	X-55	HV 18781A1	"	Y	11	(K84)	"	"	-	"	18781A	"	1Y236	1D634	RPS A	" "
	"	"		HV 18782B1	"	Y	23	(K83)	"	"	-	"	18782B	"	1Y246		RPS B	

TABLE 18.1-10 (Page 8 of 9)

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.

(3) Where the control power source is left blank, the control power source is the same as the valve motor power source.

(4) E32-1F001B automatic actuation signal is dependent upon action of MSIV's, time, RPV pressure. The valve is normally closed and interlocked when RPV pressure is greater than 35 psig. The valve cannot be opened unless the inboard MSIV is closed. Information presented is representative of that for main steam lines B, C and D.

(5) Automatic signal code UA prevents operation of condenser low vacuum bypass.

(6) 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.

(7) Hand Switch Nos. are from the P&ID rather than referenced Schematic Diagram.

(8) Automatic actuation signals for E11-1F015A and B: codes UB and Z are isolation signals; codes G and T are initiation signals.

(9) Automatic actuation signals for E11-1F050A and B, and 1F122A, B: code Z is an isolation signal; no initiation signals.

(10) 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.

(11) Closes on "LOCA" signal but can be reopened after 60 minutes. Valves can be administratively reopened if the high drywell pressure is due to plant heat up or loss of drywell cooler.

(12) Closes on "LOCA" signal but can be reopened after 10 minutes.

TABLE 18.1-10 (Page 9 of 9)

(13) Power source 1Y226 is for control. 1D614 or 1D624 is for status indication lights.

(14) Switch types:

E-30AC Cutler Hammer two button operater momentary with MI = mechanical interlock
E-30AB Cutler Hammer, momentary

CR2940 GE: KL = keylock
RO = key removable in open position
RC = key removable in close position
RN = key removable in normal position
SRN = spring return to Normal
SRA = spring return to Auto
MAINT = maintained contacts
PB = pushbutton

(15) Initiation reset will automatically reopen valve if valve handswitch is in open position.

(16) Initiation reset will not automatically reopen valve.

(17) Pneumatic actuated valve.

(18) Power sources 1Y236 and 1Y246 are AC control power, and 1D634 is DC control power.

TABLE 18.1-11

ESSENTIAL/NON-ESSENTIAL PENETRATION CLASSIFICATION BASIS

(1) Closed Cooling Water - Non-essential since used during normal operation only for reactor recirculation pump cooling, reactor water cleanup and other system components. Not required for design basis accident situation.

(2) Containment Intstrument Gas - Essential to support safety equipment.

(3) Instrument Gas - Non-essential support to non-safety related equipment, and for testing of safety related equipment.

(4) Main Steam Line and MSIV Leakage Control System - Non essential for shutdown.

(5) Feedwater Line - Not essential for shutdown but desirable for makeup water to vessel. Portion between reactor vessel and outermost containment isolation valve is essential for HPCI and RCIC injection.

(6) Reactor Core Isoltion Cooling - Essential for core cooling following isolation from turbine condenser and feedwater makeup.

(7) Reactor Water Cleanup - Not essential during or immediately following an accident. Maybe important in long term recovery operations.

(8) Reactor Water Sampling - Not essential for safe shutdown. Post-accident samples will be taken utilizing the post-accident sampling system developed in response to item II.B.3.

(9) Standby Liquid Control - Essential as backup to CRD system.

(10) Residual Heat Removal (RHR) Head Spray - Not essential for safe shutdown.

(11) RHR Containment/Suppression Pool Spray - Essential for pressure control.

(12) RHR Shutdown Cooling - Essential to achieve cold shutdown.

(13) RHR Steam Condensing Recirc./Test Return Line - Not essential since not a safety function. Used during hot standby and pump tests.

(14) RHR Pump Minimum Flow Recirculation - Essential for protect pumps for safety function.

TABLE 18.1-11 (page 2of2)

(15) RHR heat Exchanger Relief Valve Discharge Line - Essential to protect HX from overpressurization for use in safety function.

(16) RHR Suppression Pool Suction - Essential for vessel injection and pool cooling safety functions.

(17) Core Spray Injection - Essential safety function.

(18) Core Spray Pump Test Return Lines - Non-essential. Used only during testing of pumps.

(19) Core Spray Pumps Min. Flow Bypass - Essentail to protect pumps for safety function.

(20) Core Spray Suppression Pool Suction - Essential for vessel injection safety function.

(21) High Pressure Coolent Injection (HPCI) Turbine Steam Supply and Exhaust-Essential to drive HPCI pump for vessel injection safety function.

(22) HPCI Pump Min. Recirc. - Essential to protect pump for safety function.

(23) HPCI Suppression Pool Suction - Essential for vessel injection safety function. Backup to Condensate Storage Tank supply.

(24) Containment Atmospheric Purge - Non-essential vent path to Standby Gas Treatment System. Backup to four hydrogen recombiners.

(25) Containment Atmoshere Sampling - Essential. Not required for shutdown, but would be necessary for post-accident assessment.

(26) Suppression Pool Water Filtration - Not essential. Used only for periodic cleanup of pool water.

(27) Liquid Radwaste Collection - Non-essential for safe shutdown.

(28) Reactor Bldg. Chilled Water - Non-essential supply to recirculation pump motor coolers, drywell coolers.

TABLE 18.1-12

ACTUATION/ISOLATION SIGNAL CODES & CORRESPONDING ACTUATING SWITCHES

*ISOLATION FUNCTIONS: OTHER CODES FOR INFORMATION ONLY.

A*	Reactor Vessel low water level 3	B21-N024A or B
B*	Reactor Vessel low water level 2	B21-N026A or B
C*	Main Steam line high radiation	D12-K603A (typ. of 4)
D*	Main Steam line high flow (any one of four) (typical for MSL "A")	B21-N006A B21-N007A B21-N008A B21-N009A
E*	Main Steam line leak/high temp (either)	B21-N600A (typ. of 4) B21-N603A (typ. of 4) TSH-10100A (typ. of 4)
FA*	High drywell pressure - Reactor/ RCIC Steam line low pressure (both required)	E11-N010A or C E51-N019A or C
FB*	High drywell pressure - Reactor/ HPCI Steam line low pressure (both required)	E11-N010A or C E41-N001A or C
G	Reactor Vessel low level 1RHR, Core Spray (level 2 RCIC, HPCI), or Drywell high pressure (one of two twice), Bypass Switch E11A-S18A for E11-F016A, F021A, F028A (typ. for B)	B21-N031A or C E11-N011A or C
I	Reactor Vessel low water level 2 (one of two twice)	B21-N031A-D
J*	RWCU line break/high flow RWCU high flow differential (either)	G33-N044A G33-N603A

K*	RCIC Steam line leak/high temp:	
	Equip room area high temp	E51-N600B
	Equip room vent air high Δ temp	E51-N601B
	Emer area cooler high temp	E51-N602B
	Pipe routing area high temp	E51-N603B, D
	Pipe routing area high Δ temp, after time delay (any one of 5), Bypass Switch B21B-S3BI	E51-N604B, D (typ. for HV-F007)
	RCIC steam line break/high Δ P	E51-N018 (for HV-F007) (N017 for HV-F008)
	Reactor/RCIC Steam line low pressure	E51-N019B & D (typ. for HV-F007)
	Turbine exhaust diaphragm high pressure	E51-N012B & D (typ. for HV-F007)
L*	HPCI Steam line leak/high temp:	
	Equip room area high temp	E41-N600A
	Equip room vent air high Δ temp	E41-N601A
	Emer area cooler high temp	E41-N602A
	Pipe routing area high temp	E51-N603A, C
	Pipe routing area high Δ temp, after time delay (any one of 5) Bypass Switch B21B-S4A	E51-N604A, C (typ. for HV-F002)
	HPCI Steam line break/high Δ P	E41-N004 (for HV-F002) (N005 for HV-F003)
	HPCI Steam supply low pressure	E41-N001A & C
	Turbine exhaust diaphragm high pressure	E41-N0012A & C (typ. for HV-F002)
LFCS	CS pump discharge low flow (with CS pump running)	E21-N006A
LFHP	HPCI pump discharge low flow (with HPCI pump running)	E41-N006
LFRC	RCIC pump discharge low flow (with RCIC Pump running)	E51-N002
LFRH	RHR pump discharge low flow (with RHR Pump running)	E11-N021A

M	RHR Shutdown cooling and Head Spray line break: Equip area ambient high temp Equip area vent air high Δ temp Bypass switch B21B-S6A Cooling line high Δ P (any of the above) (all typical for HV-F009 and -F022)	E11-N600A or C E11-N601A or C E11-N019A
P*	Main Steam line low pressure Run Mode Only - Bypassed on Start & Hot Stdby, Refuel or Shutdown modes	B21-N015A (typ. of 4)
R*	High-high radiation in SGTS exhaust vent	D12-K617A, B
T	Reactor Vessel low pressure (permissive, one of two twice)	B21-N021A-D
UA	Main condenser vacuum low-Bypassed when Condenser Bypass switch is in "BYPASS" and turbine stop valves not open, or Reactor Vessel pressure above Low Pressure Interlock setpoint	B21-N056A B21-N020A (typ. of 4)
UB	Reactor Vessel low pressure	B31-N018A
W*	RWCU leak detection ambient high temperature vent air high temp (any one of six)	G33-N600A, C, E G33-N602A, C, E
Z*	Reactor Vessel low water level 3 Drywell high pressure	B21-N024A, B C72-N002A, B (typ. for outboard valves)
Y*	Reactor Vessel low water level 2 Drywell high pressure	B21-N026A, B C72-N002A, B (typ. for outboard valves)

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

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TABLE 18.1-14

CALCULATION OF COOLANT BETA DOSE
RAD/HR AT 1 HR DECAY

	1 B MeV/s[(a)] per MWt at One Hour	2 Col.1*F[(b)] B MeV/s per MWT, T= 1 hr Released	3 Col.2*M[(c)] Coolant Rad/Hr
I-131	1.78E14	8.88E13	6.28E4
I-132	7.26E14	3.63E14	2.57E5
I-133	8.15E14	4.08E14	2.89E5
I-134	1.06E15	5.30E14	3.75E5
I-135	6.67E14	3.33E14	2.36E5
Br-83	2.04E13	1.02E13	7.22E3
Br-84	7.72E13	3.86E13	2.73E4
Xe-133	2.06E14	2.06E14	1.46E5
Xe-135	1.16E14	1.16E14	8.18E4
Xe-138	5.85E13	5.85E13	4.14E4
Kr-85	2.55E12	2.55E12	1.80E3
$Kr-85^m$	4.95E13	4.95E13	3.50E4
Kr-88	1.33E14	1.33E14	9.40E4
Kr-87	3.71E14	3.71E14	2.63E5
		9.71E15	1.92E6

(a) From CINDER run 8/18/80, SNUMB 2100T, Core Inventory 3 yr burn

(b) F = 1.0 for noble gases and 0.5 for halogens

(c) $M = \dfrac{3293 \text{ MWt}*3600 \text{ s/h}*1.6\text{E-6 erg/MeV}}{(2.68\text{E8 g})*(100 \text{ erg/g/Rad})} = 7.077 \times 10^{-10}$

TABLE 18.1-15

CONDUCTIVITY OF PURE WATER UNDER IRRADIATION

		Temp. °F	IRRADIATED CELL (0.1 cm Balsbaugh) μS/cm	UNIRRADIATED CELL (0.1 cm Beckman) μS/cm
No Irradiation	Flow	63.5	0.10	0.11
	No Flow	--	0.14	0.11
$1.3x10^4$Rad/hr	Flow	65.0	0.11	0.12
	No Flow	--	1.4	--
$6.6x10^4$Rad/hr	Flow	65.5	0.13	0.14
	No Flow	--	2.2	--
$1.3x10^5$Rad/hr	Flow	65.8	0.18	0.20
	No Flow	--	2.2	--
$2.6x10^5$Rad/hr	Flow	66.0	0.31	0.37
	No Flow	--	2.1	--
$6.6x10^5$Rad/hr	Flow	64.5	0.65	0.64
	No Flow	--	1.8 to 1.4*	--
$9.8x10^5$Rad/hr	Flow	65.5	0.65	0.66
	No Flow	--	1.7**	--

* Still dropping slowly after 5 min

** Very steady value

TABLE 18.1-16

CONDUCTIVITY OF 10 ppm Cl^- SOLUTION NaCl

		Unirradiated Cell (0.1 cm Beckman) μs/cm	Irradiated Cell (0.1 cm Balsbaugh) μs/cm
	Flow	27.7	32.1
No Irradiation	No Flow	27.7	32.0
	Flow	27.4	32.7
	Flow	27.9	33.6
$9.8x10^5$ Rads/hr	No Flow	28.0	25.1
	Flow	28.0	34.0
No Irradiation	Flow	28.0	33.4
	No Flow	28.1	32.2

TABLE 18.1-17

INFORMATION REQUIRED FOR CONTROL ROOM HABITABILITY EVALUATION

Data	Reference*
1. Control Room Mode of Operation, (i.e., pressurization and filter recirculation for radiological accident isolation or chlorine 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, and chlorine 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. chlorine detectors or toxic gas (local or remote);	9.4.1
k. self-contained breathing apparatus availability (number);	E.Plan, App. D
l. bottled air supply (hours supply);	E.Plan, App. D

TABLE 18.1-17 (Continued)

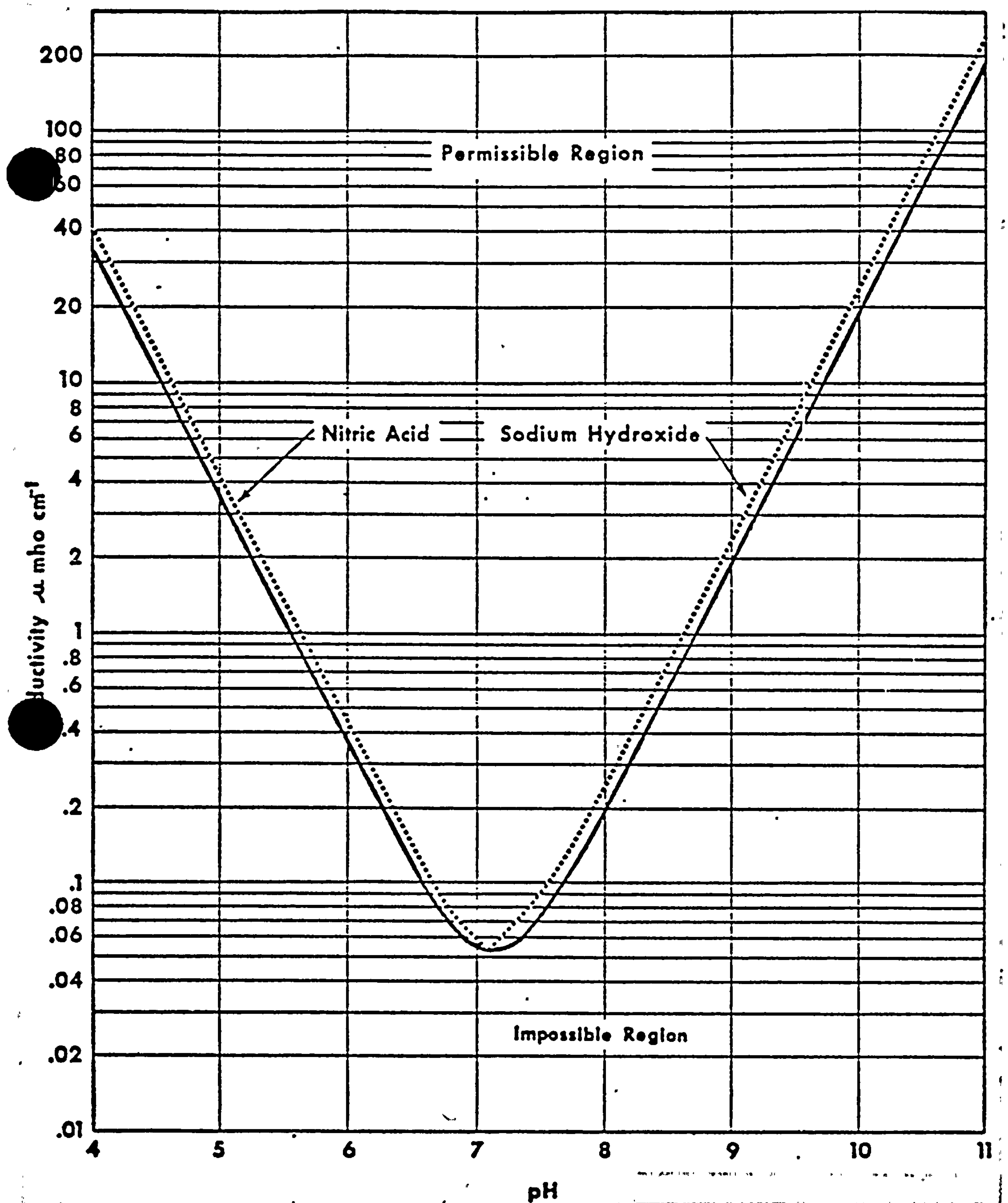
Data	Reference*
m. emergency food and potable water supply (how many days and how many people);	E.Plan, App. D
n. control room personnel capacity (normal and emergency); and,	6.4.1
o. potassium iodide drug supply.	E.Plan, App. D
3. On-site storage of chlorine and other hazardous chemicals:	
a. total amount and size of container; and,	Fig. 6.4-2
b. closest distance from control room air intake.	Fig. 6.4-2
4. Off-site manufacturing, storage or transportation facilities of hazardous chemicals:	
a. identify facilities within a five-mile radius;	Table 2.1-17
b. distance from control room;	Table 2.1-17
c. quantity of hazardous chemicals in one container; and,	55 gallon drums
d. frequency of hazardous chemical transportation traffic (truck, rail, and barge).	PLA-694
5. Technical Specifications:	
a. chlorine detection system; and,	TS 3/4.3.7.8
b. control room emergency filtration system including the capability to maintain the control room pressurization at 1/8 inch water gage, verification of isolation by test signals and damper closure time and filter testing requirements.	TS 3/4.7.2

*All references are in the FSAR unless otherwise noted.

TABLE 18.1-18

POSSIBLE ICC DETECTION DEVICES

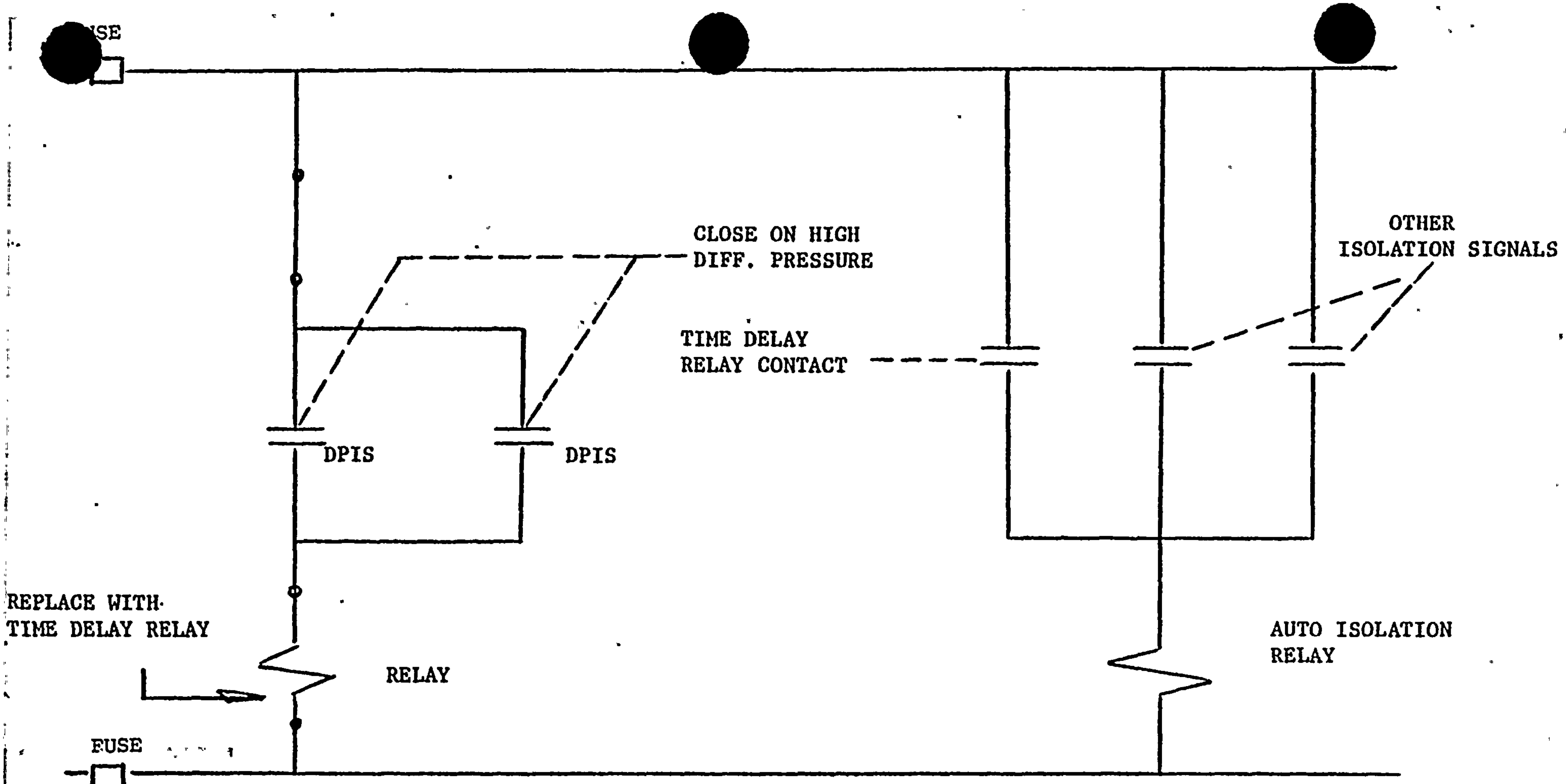
Name of Device	Reference Number
Source Range Monitor	1
Intermediate Range Monitor	2
Local Power Range Monitor	3
Traveling Incore Probe	4
Gamma-Neutron Reaction Detector	5
Gamma Attenuation	6
Gamma Void Meter	7
Neutron Modulation Void Meter	8
Core Reactivity Detector	9
Fuel Plenum Tracer	10
Primary System 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



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

SPECIFIC CONDUCTANCE AND pH OF AQUEOUS SOLUTIONS AT 25°C

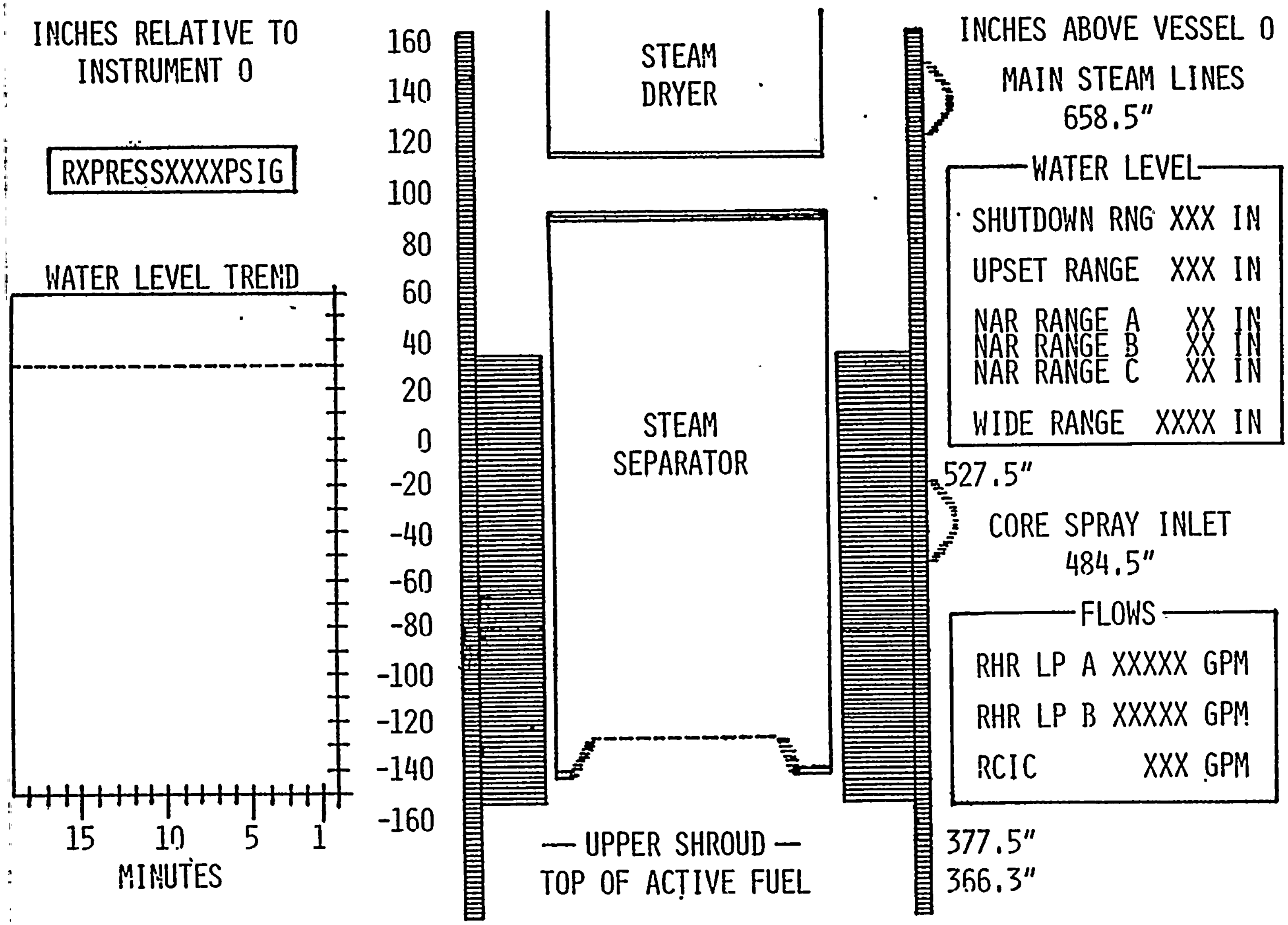
FIGURE 18.1-11



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

TYPICAL HPCI/RCIC STEAMLINE
BREAK DETECTION LOGIC

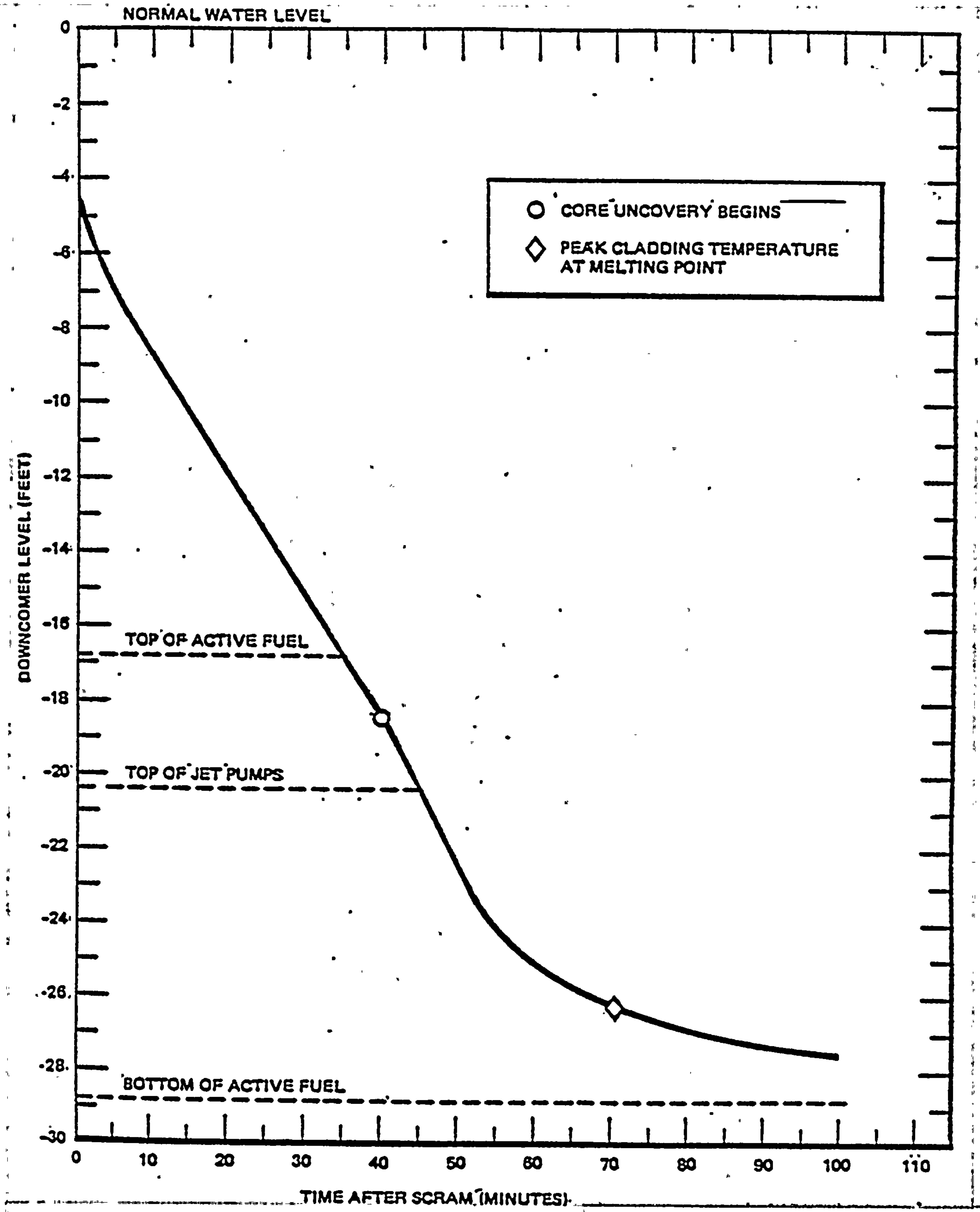
FIGURE 18.1-12



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

TYPICAL REACTOR WATER LEVEL DISPLAY

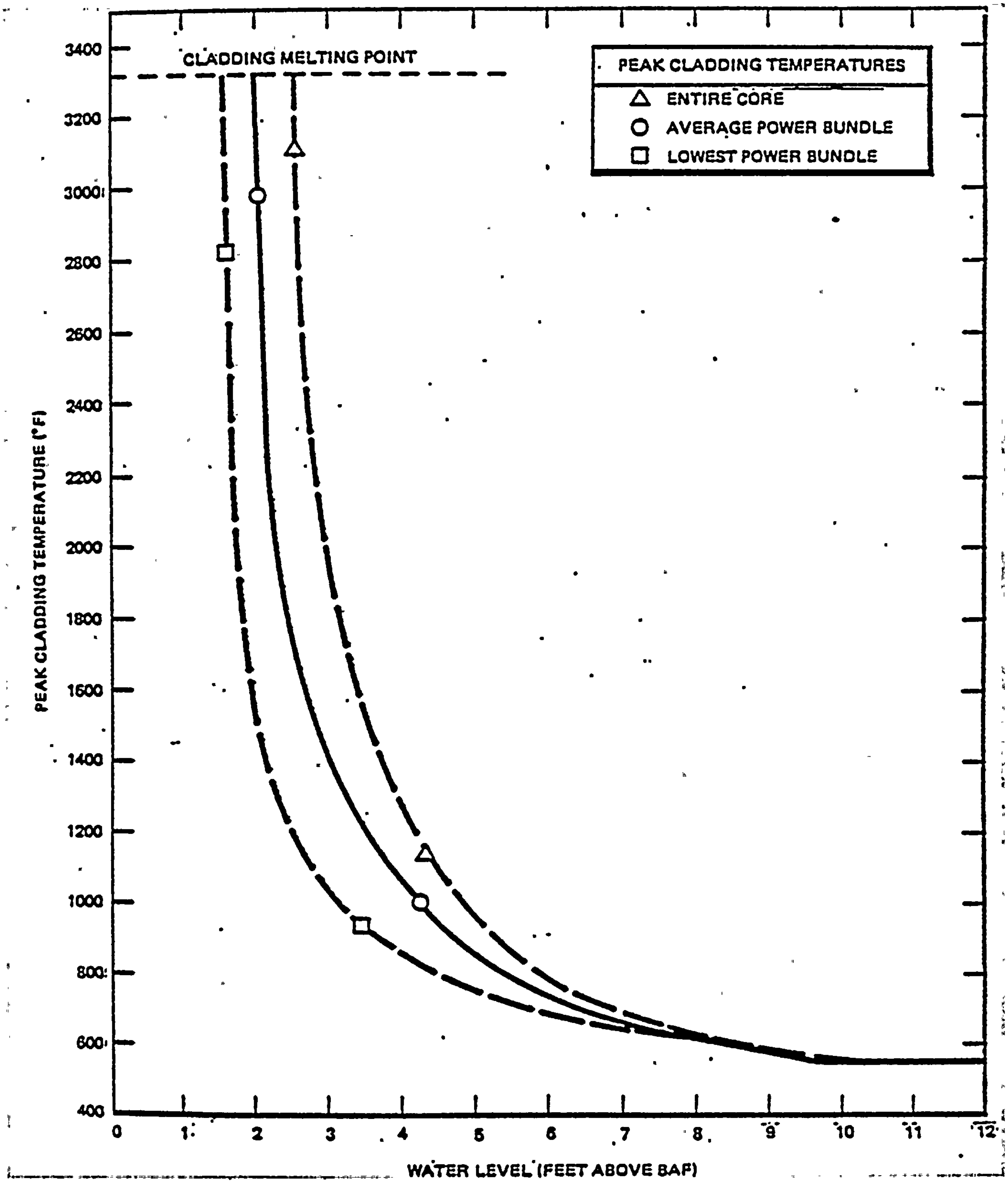
FIGURE 18.1-13



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

DOWNCOMER WATER LEVEL HISTORY

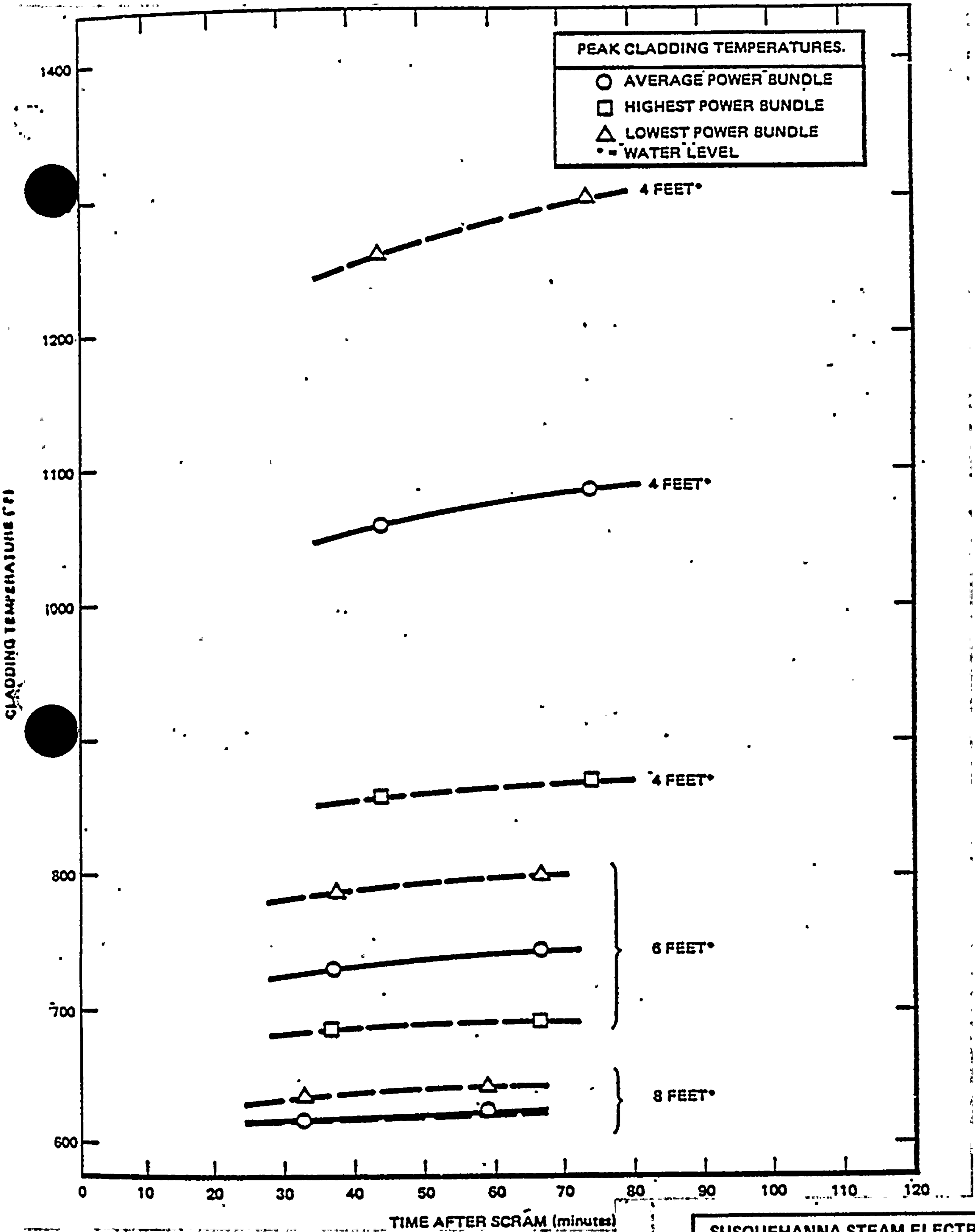
FIGURE 18.1-14



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

WATER LEVEL AS AN INDICATOR OF CORE OVERHEATING

FIGURE 18.1-15



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

CLADDING TEMPERATURE SENSITIVITY TO CORE UNCOVERY TIME

FIGURE 18.1-16

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 AD-QA-300, "Conduct of Operations," implements this policy.

The Vice President - Nuclear Operations 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 procedure AD-QA-300, "Conduct of Operations," discusses operations personnel responsibilities at shift turnover. Administrative procedure AD-QA-303, "Shift Routine," specifically defines 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 - Nuclear 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 - Nuclear shall re-issue this statement of policy on an annual basis.

Administrative Procedure AD-QA-300, "Conduct of Operations," sets forth the plant policy on Shift Supervisor duties.

Training for Shift Supervisors includes plant Administrative Procedures, and will encompass AD-QA-300.

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 AD-QA-300, "Conduct of Operations," 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 FOR 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 guidelines 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.I)

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 jeoparidzes 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 POSTACCIDENT 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 AD-QA-422. This procedure, which is currently being drafted, will require that 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 AD-QA-306, "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 I. A plant specific description is provided below.

If the main feedwater system is not operable, a reactor scram will be automatically initiated 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 isolaticn 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 nonaccident case, the reactor core isolation cooling system is utilized to furnish subsequent makeup water two the reactor pressure vessel. The Reactor core isolaticn 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 steam condensing mode of the residual heat removal system is initiated by the operator. This involves remote manual alignment of the residual heat removal system valves. If the

steam condensing mode is unavailable for any reason, 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 depressurzation 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 I.

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.