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SUBJECT: Forwards rev 22 to "WNP-2 Emergency Plan." Submittal reduces number of on-shift HP Technicians from 3 to 2 & moves third HP Technician to 60 minute responder category.Approval requested prior to implementation.

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WASHINGTON PUBLIC POWER SUPPLY SYSTEM

P.O. Box 968 • Richland, Washington 99352-0968

March 8, 1999
GO2-99-045

Docket No. 50-397

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Gentlemen:

Subject: **WNP-2 OPERATING LICENSE NPF-21**
TRANSMITTAL OF THE WNP-2 EMERGENCY PLAN REQUESTING REDUCTION IN ON-SHIFT HP STAFFING

In accordance with 10 CFR 50.4(b), 50.54(q), and 10 CFR 50 Appendix E, attached is the signed original of the WNP-2 Emergency Plan. A detailed synopsis and justification of the changes are also provided.

This submittal reduces the number of on-shift Health Physics Technicians from 3 to 2, and moves the third Health Physics Technician to a 60 minute responder category. These changes were evaluated pursuant to the requirements of 10 CFR 50.54(q), and the changes were determined to potentially reduce the effectiveness of the plan as previously approved. Approval of these changes is requested prior to implementation.

Should you have any questions or desire additional information regarding this matter, please contact me or Tim Messersmith at (509) 377-8568.

Respectfully,

D. K. Atkinson for

R.L. Webring (Mail Drop PE08)
Vice President, Operations Support/PIO

Attachments

250006

A045 1/1

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CONDUCT OF OPERATIONS

13.1 ORGANIZATION STRUCTURE

The organizational structure of the Supply System and the line of responsibility for the operation of WNP-2 is in accordance with established administrative and quality standards that apply to this operation. The applicable organization charts are shown in Figures 13.1-1 through 13.1-11.

13.1.1 MANAGEMENT AND TECHNICAL SUPPORT ORGANIZATION

The Washington Public Power Supply System (Supply System) is a municipal corporation and a joint operating agency of the State of Washington. Its membership is made up of a limited number of operating public utility districts and cities, all located in the State of Washington. The management and control of the Supply System is vested in the Executive Board.

The Executive Board consists of five members of the Supply System Board of Directors and six outside directors. Three outside directors are selected by the Board of Directors, and three directors are appointed by the Governor of the State of Washington.

The full Board of Directors has members representing each of the Supply System's member utilities, and has the authority to select the inside members of the Executive Board and to terminate existing projects or authorize new projects.

Certain responsibilities for day-to-day management of the Supply System have been delegated to the Chief Executive Officer (the chief administrative officer).

The staff of the Supply System includes senior management level positions (Vice Presidents), which are responsible to the Chief Executive Officer for performance of specialized work by their respective groups. The Chief Executive Officer retains the title of Chief Nuclear Officer. See Figure 13.1-1 for an organization chart.

13.1.1.1 Technical Support for Operations

Technical support for the nuclear organization is the responsibility of the Vice President, Nuclear Operations.

The Vice President, Nuclear Operations, is responsible for the safe, reliable, and efficient operation and maintenance of WNP-2 and for providing major services which support plant operation.

Reporting to the Vice President, Nuclear Operations, are departments which provide support in the areas of Engineering and Nuclear Training (see Figure 13.1-2).

The Engineering General Manager is responsible for design control of all authorized plant modifications, technical expertise in the fundamental engineering disciplines such as mechanical, electrical, civil, chemical, etc., as well as specialty areas such as materials, welding, and inservice inspection engineering. The Engineering General Manager is also responsible for providing technical support in the areas of system engineering, technical programs, nuclear fuel management, and equipment engineering. An organization chart for Engineering is shown in Figure 13.1-3.

The responsibilities of the Nuclear Training Organization are described in Section 13.2. An organization chart is shown in Figure 13.1-4.

The Vice President, Operations Support/Public Information Officer, is responsible for Security Programs; Quality; Regulatory Affairs; Emergency Preparedness, Industrial Safety, and Occupational Health; Communications and External Affairs; Nuclear Safety Issues Program; and Procurement (see Figure 13.1-5).

The Quality Manager's responsibilities are described in the WPPSS Operational Quality Assurance Program Description (OQAPD), WPPSS-QA-004. An organization chart is provided in Figure 13.1-6.

Support and refueling operations are provided by personnel from all of the support organizations and are directed by the plant staff.

13.1.1.2 Organizational Arrangement

Figures 13.1-1 through 13.1-6 provide the current corporate structure as applicable to WNP-2 support organizations. The number of personnel to be assigned to each of the working level organizations will be determined based on workload and need for pertinent expertise. If the need arises, qualified outside contractors will be used to support the Supply System staff.

The Plant General Manager, to whom the responsibility of safe and efficient plant operation is delegated, reports to the Vice President, Nuclear Operations.

13.1.1.3 Qualifications

Qualification requirements for key technical support personnel who fulfill the responsibilities identified in Section 13.1.1.1 shall meet the criteria of Regulatory Guide 1.8, Revision 1, 1977 (see the OQAPD). The WNP-2 personnel qualification and training programs are under continuing review and modification to reflect the changes following the TMI accident. The

Manager of Design and Projects Engineering meets the definition and qualifications of "Engineer in Charge."

Any Vice President or Manager listed in Section 13.1.1.1 may authorize deviations from the qualification requirements for subordinate positions when, in their judgment, the combined education, experience, and managerial competency of a particular individual are sufficient to ensure adequate performance of assigned responsibilities. Such exceptions will be documented in writing and will not be used as a means to degrade the overall qualifications of the support staff. Deviations are not authorized for those positions whose qualifications are described in the Technical Specifications and the OQAPD.

13.1.2 OPERATING ORGANIZATION

13.1.2.1 Plant Organization

This section describes the structure, functions, and responsibilities of the onsite organization established to operate and maintain the WNP-2 Plant. Figures 13.1-7 through 13.1-11 show the WNP-2 plant organization. The principal departments that function directly under the supervision of the Plant General Manager are Operations, Maintenance, Chemistry, and Health Physics (see Figure 13.1-7).

The Security Force Lieutenant is responsible to the Plant General Manager for day-to-day operation of the WNP-2 Plant Security Program and receives functional supervision from Operations Support management.

Position titles, NRC licenses required, and lines of functional reporting, as well as direct lines of communications, are indicated on the organization charts.

13.1.2.2 Plant Personnel Responsibilities and Authorities

13.1.2.2.1 Plant Management

The Plant General Manager has direct responsibility and authority for all plant activities. The Plant General Manager reports directly to the Vice President, Nuclear Operations.

The Plant General Manager has the responsibility for management of the following plant departments: Operations under the direction of an Operations Manager; Maintenance, along with Planning, Scheduling, and Outage, are under the direction of a Maintenance Manager; Chemistry under the direction of a Chemistry Manager; and Health Physics under the direction of a Radiation Protection Manager.

A Security Force Lieutenant exercises supervision and authority over the onsite security personnel. The Security Force Lieutenant reports to the Plant General Manager or the

designated representative on day shifts and to the Shift Manager during other than normal working hours (i.e., backshifts, weekends, and holidays).

In the event of incapacitation of key plant personnel or unexpected contingencies of a temporary nature, the line of succession of authority and responsibility for all plant activities is as follows:

a. Plant General Manager,
b. Operations Manager,
c. Assistant Operations Manager, and
d. Duty Shift Manager.

13.1.2.2.2 Operations Supervision

Operations is under the direction of the Operations Manager. The Operations Manager is responsible for overall plant operation. The Operations Manager directs and manages the activities of operations to ensure safe plant operation and control of plant systems in compliance with licensing documents.

The Operations Manager is responsible for being cognizant of and complying with the OQAPD.

The Operations Manager is responsible for the day-to-day routine as well as the abnormal or emergency operating situations that may arise. The Operations Manager is responsible to see that all operations are carried out in a safe, efficient manner and that the plant is operated in strict conformance to the Operating License, Technical Specifications, and in accordance with approved written procedures. Additionally, the Operations Manager is responsible for operating personnel schedules, development, and periodic review of plant operating procedures and instructions, and the preparation of operating records and reports.

The Assistant Operations Manager supports and assists the Operations Manager in the performance of these duties. The Assistant Operations Manager is responsible to the Operations Manager for the immediate supervision of the unit staff, and as such, he receives direction from the Operations Manager for the day-to-day routine and supervises implementation. The individual normally maintains a current Senior Reactor Operator (SRO) license. During periods of transition such as promotion, the individual with a current SRO, either the Operations Manager or the Assistant Operations Manager, will have the responsibility for immediate supervision of the unit staff. In either case, the individual with the SRO may only be relieved by another individual possessing a current SRO. The Assistant Operations Manager assumes total responsibility for the Operations Manager's duties during periods when the Operations Manager is temporarily absent from the plant. (See Figure 13.1-8 for an organization chart of the Operations Department.)

The plant Fire Marshall assists the Operations Manager in the implementation of the Fire Protection Program. Responsibilities include ensuring that the fire protection systems and components are maintained and that the Fire Brigade is adequately trained and staffed. More detailed information is contained in Section 13.2.2.5.2.

13.1.2.2.3 Operating Shift Crew Supervision

Within the Operations Department are a minimum of five shift crews during normal operations. In some situations, such as refueling outages, these may be reduced to four shift crews. Plant management and technical support will be present or on call at all times to provide advice to the shift personnel.

The Shift Manager holds an SRO license and is directly responsible to the Operations Manager. The Shift Manager is in charge of all plant operations on shift and is directly in charge of and responsible for the shift crew assigned to his specific shift. The Shift Manager has the authority to institute immediate action in any given situation to shut the plant down, or eliminate difficulties to preclude violation of the operating license or Technical Specifications, or to avert possible injury or undue radiation exposure of personnel. Additionally, the Shift Manager may at times direct the activities of other personnel during tasks such as backshift maintenance, health physics, chemistry control, and security implementation. The Shift Manager also keeps plant management appraised of situations that may affect plant safety and/or constitute a hazard to the general public. During other than normal working hours, the Shift Manager assumes responsibility for all plant operations in the absence of senior plant management personnel.

The Control Room Supervisor holds an SRO license and assists the Shift Manager in the performance of duties and assumes those duties during periods when the Shift Manager is unavailable. The Control Room Supervisor is responsible for supervising the activities of the Control Room Operators and other assigned personnel (i.e., equipment operators and maintenance support personnel) required to operate the plant safely and efficiently. The Control Room Supervisor is directly responsible to the Shift Manager.

The Shift Support Supervisor assists the Shift Manager in the performance of his duties. The Shift Support Supervisor is responsible for the supervision and direction of personnel assigned to perform balance-of-plant (BOP) operating functions such as operations of makeup water treatment system, radwaste processing systems, and other plant support systems. The individual is responsible for performing administrative duties as assigned.

All core alterations are observed and directly supervised by either a licensed SRO, or licensed SRO limited to fuel handling, who has no concurrent responsibilities during the performance of the core alterations.

13.1.2.2.4 Shift Technical Advisor

The Shift Technical Advisor (STA) assists the Shift Manager in the performance of his duties. The STA provides engineering expertise on shift pursuant to safe and efficient operation of the plant. Also, the STA monitors reactor core operations, and core management and reactivity controls as directed by the Control Room Supervisor and by a qualified reactor/fuels engineer.

13.1.2.2.5 Licensed Operators

In addition to the licensed supervisors listed above, there are a minimum of two reactor operators on each shift. The reactor operator holds a reactor operator (RO) license and is responsible to the Control Room Supervisor for the safe and efficient operation of the plant from the central control room. The RO follows approved procedures in performing work and is responsible for taking the immediate action required to maintain or bring the plant to a safe condition during abnormal and/or emergency conditions. However, if a particular situation is not covered by a procedure, the individual may seek advice from the Control Room Supervisor, or if the situation is critical, may use his or her own judgment to prevent damage to equipment, injury to personnel, or undue radiation exposure of plant personnel and the general public. The RO directs and supports the activities of other operators in the performance of their duties and works cooperatively with all plant service groups that interface with plant operation.

13.1.2.2.6 Nonlicensed Operators

The equipment operators (EO) are responsible to the Control Room Supervisor or Shift Support Supervisor for assisting in the plant operation and performing work assignments from local control stations and all other defined areas outside of the central control room. The EO follows approved procedures in doing work and does not deviate from those procedures except as authorized. The EO performs assigned routine inspections and manipulates equipment without close supervision. The EO also performs special assignments as directed.

13.1.2.2.7 Engineering Management

Reporting to the Engineering General Manager are the Technical Services/Systems Engineering Manager, Reactor/Fuels Engineering Manager, and Design and Projects Engineering Manager (see Figure 13.1-3 for organization chart).

They are responsible for developing and implementing plant programs and procedures which provide proper management control in the above areas and thus ensure compliance with the conditions of the operating license and proper plant safety. They interface with technical support organizations to support plant operations.

The engineering organizations are responsible for being cognizant of and complying with the Operational Quality Assurance Program.

13.1.2.2.7.1 Technical Services/Systems Engineering Manager. The Technical Services/Systems Engineering Manager is responsible for overall direction of the system engineering program in support of plant operation, maintenance, and chemistry in the areas of NSSS systems, control/electrical systems, and BOP systems.

The Technical Services/Systems Engineering Manager is responsible for system management functions in support of operations including operability determination, evaluation of Technical Specifications requirements, developing long range plans for system improvement and performance, and providing troubleshooting expertise to operations and maintenance.

The Technical Services/Systems Engineering Manager is responsible for the development, implementation, and execution of programs to monitor system performance, to conduct inspections, and to perform specialized testing. The objective is to identify potential component degradation, minimize threats to successful operation of systems and the plant, and to identify opportunities for improvement.

The Technical Services/Systems Engineering Manager is the primary interface with Design and Projects Engineering in support of maintaining plant compliance with design and licensing requirements. This includes interfacing with other technical support organizations in preparation of design changes, evaluation of plant systems, and implementation of new system programs and processes.

The Technical Services/Systems Engineering Manager is responsible for implementation of field testing and performance monitoring of plant systems and critical plant programmatic processes such as the fuse control program, instrumentation enhancement program, and valve programs. This includes providing recommendations to plant management for implementation of new program requirements, performing periodic assessments of existing programs, and recommending component or system improvements.

Reporting to the Technical Services/Systems Engineering Manager are the Systems Engineering Supervisors for nuclear steam supply systems (NSSS), BOP systems, instrument and control systems, electrical systems, major maintenance, and performance engineering. Systems Engineering Supervisors direct the activities of the Systems Engineering staff in support of plant operation in the functional areas of mechanical engineering, instrumentation and control engineering, and electrical engineering. Activities include initiating engineering design changes, making recommendations for improved operation, and providing operating and maintenance support for instrumentation and control systems, mechanical systems, electrical systems, plant water systems, and waste handling systems. The Systems Engineering staff represent the plant in assigned licensing areas with all state and federal licensing

authorities (through responsible corporate organizations). They evaluate, interpret, or prepare licensing documents (e.g., FSAR).

13.1.2.2.7.2 Reactor/Fuels Engineering Manager. The Reactor/Fuels Engineering Manager is responsible for fuel design, overall management of the reactor core, and monitoring of core parameters.

The Reactor/Fuels Engineering Manager is responsible for providing technical support to Operations in management of refueling floor activities, support to Maintenance in resolving refueling equipment problems, providing technical resources for resolution of vessel hardware problems and concerns with interfacing systems which influence or monitor core reactivity, for maintaining involvement in applicable industry initiatives affecting core reactivity issues and new developments in core operation, providing recommendations to plant management on operating strategies in support of normal and off-normal operating situations, and planned shutdown and startup activities.

The Reactor/Fuels Engineering Manager ensures sound fuel design philosophy is followed and that fuel designs provide no unreasonable challenges to safe plant operation.

Reporting to the Reactor/Fuels Engineering Manager are the Fuel Design Supervisor, Reactor Engineering Supervisor, as well as computer engineering and other technical support specialists.

The Reactor Engineering Supervisor and staff are responsible for performing periodic core physics evaluations to monitor the operation, burnup, and thermal/hydraulic performance of the reactor core. They provide and maintain plant operating curves and reactivity data for use by shift operation personnel and are responsible for the onsite accountability of nuclear fuel and special nuclear materials.

The Fuel Design Supervisor and staff are responsible for core design, fuel planning, licensing support (e.g., COLR, accident/transient analysis), and analytical work necessary to support cycle operation (e.g., control rod pattern recommendations).

13.1.2.2.7.3 Design and Projects Engineering Manager. The Design and Projects Engineering Manager is responsible for plant design and configuration control; technical design and engineering expertise in the fundamental engineering disciplines (e.g., mechanical, electrical, civil, fire protection, etc.); and engineering/management of projects.

13.1.2.2.8 Nuclear Engineering Supervision

See Section 13.1.2.2.7.2.

13.1.2.2.9 Health Physics Supervision

See Section 12.5.1 for a description of duties, responsibilities, and reporting relationships. See Figure 13.1-9 for an organization chart.

13.1.2.2.10 Chemistry Supervision

Chemistry is under the direction of the Chemistry Manager, who reports to the Plant General Manager. The group provides plant oversight for system chemistry optimization and control, gaseous, and liquid effluent releases, Radwaste Processing and Chemical Control, the Offsite Dose Calculation Manual, the Radiological Environmental Monitoring Program (REMP), and Radiological Effluent Report. See Figure 13.1-10 for an organization chart.

13.1.2.2.11 Maintenance Supervision

Maintenance is under the direction of the Maintenance Manager. The Maintenance Manager is responsible for the WNP-2 Maintenance Program and for the development and implementation of maintenance processes and procedures which will ensure the safe and reliable operation of plant equipment. The Maintenance Manager reports to the Plant General Manager. The organization is shown in Figure 13.1-11.

The Maintenance Manager manages the activities of the following groups: Electrical, Instrument and Control, Mechanical, Standards Lab, Coatings, and other teams, such as Fix-It-Now and Multidiscipline, when such teams are formed to address specific maintenance or business needs. Shops and/or teams may be combined as long as supervisory qualifications are maintained as described in Section 13.1.3.4. The Maintenance Manager is also responsible for planning, scheduling, and coordination of work during operation and outage periods.

All plant modifications are accomplished through this department either directly or through the actions of the Site Support Services contractor. Engineering, Training, and Support Services, as discussed in Section 13.1.1.1, provide support for this department. Other support is provided when needed in the form of vendor representatives for technical guidance on maintenance of major components of the plant.

Maintenance Supervisors are responsible for the day-to-day implementation of the Maintenance Program. They are responsible for maintaining plant electrical, instrumentation, and mechanical systems through preventive and corrective maintenance and surveillance programs.

The Coatings Program Supervisor is responsible for ensuring continued as-left appearance of painted areas and components. Responsibilities also include implementation of a quality labeling program for plant structures and components.

The Standards Lab group is responsible for maintenance and calibration of measuring and test equipment.

13.1.2.2.12 Quality Supervision

A description of duties and responsibilities for the Quality Department is contained in the OQAPD.

13.1.2.3 Operating Shift Crews

13.1.2.3.1 Shift Crew Composition

Shift coverage is provided by using a rotating shift schedule depending on operating needs. The schedules are based on a 40-hr work week and shifts are normally of 8 or 12 hr duration (excluding shift turnover time).

During normal operations, a minimum of five crews provide 24 hr/day, 7 day/week coverage. Table 13.1-1, as well as the Technical Specifications and the Emergency Plan, identify the minimum number and type of licensed and unlicensed personnel required to be onsite.

For those operations that involve core alterations, direct supervision of all fuel movements is provided by an individual holding an SRO license. This person has no other concurrent responsibilities during this assignment.

It is WNP-2 policy to maintain an adequate number of personnel in the Shift Manager, Control Room Supervisor, Shift Support Supervisor, STA (if required), Control Room Operator, and Equipment Operator positions such that the use of overtime is not routinely required to compensate for inadequate staffing.

13.1.2.3.2 Shift Responsibility for Radiation Protection

A minimum of one Health Physics Technician is assigned to each operating shift to provide radiological surveillance/control (see Table 13.1-1).

All shift personnel are instructed in the fundamentals of health physics such as implementing radiation protection procedures, radiation and contamination surveys, use of protective barriers and signs, use of protective clothing and breathing apparatus, radiation monitoring, and accumulated dose.

Shift personnel are responsible for immediately informing the on-duty Shift Manager if conditions develop that exceed or are likely to exceed preestablished radiation levels or exposure limits or if they believe that unsafe or hazardous conditions exist. The Shift Manager

will evaluate the situation and if a radiological condition exists that warrants attention and investigation, the appropriate Health Physics personnel will be called for assistance.

13.1.2.3.3 Shift Maintenance Support

Craftsmen and technicians, as required, are assigned to each operating shift for the purpose of providing maintenance support and surveillance testing in the areas of instrumentation and controls and mechanical and electrical equipment.

13.1.2.3.4 Shift Fire Brigade

A Shift Fire Brigade, consisting of a minimum of five members of the nominal shift complement, shall have advanced fire training and be equipped for fire fighting. This select group on each operating shift will have primary response capabilities and will respond to emergencies involving fire and/or emergencies where life threatening danger exists.

The brigade shall not include the minimum shift crew complement required to safely shut down the unit. At a minimum the brigade leader and two brigade members shall have sufficient knowledge of plant fire safe shutdown systems. The balance of the fire brigade shall be composed of Fire Brigade trained support personnel. See Section 13.2.2.5 for the qualification requirements for fire brigade members.

13.1.2.3.5 Shift Chemistry Support

At least one qualified chemistry technician is assigned to each operating shift for the purpose of providing chemistry support in the area of chemical surveillances while the plant is in Modes 1, 2, or 3.

13.1.3 QUALIFICATIONS OF NUCLEAR PLANT PERSONNEL

The minimum educational and experience qualifications for the onsite plant personnel are based on Regulatory Guide 1.8, Revision 1, 1977. If an individual who does not meet the minimum qualification criteria is placed in a discipline, it will be specifically pointed out and justification or explanation provided. See Section 13.1.1.3. Personnel qualification and training programs are under continual review and modification to reflect the changes following TMI. The minimum qualification requirements identified in Section 13.1.3.1 will be revised accordingly. The licensed ROs and SROs meet or exceed the minimum qualifications of the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980, NRC letter to all licensees.

13.1.3.1 Plant Management

Plant General Manager

The Plant General Manager shall have 10 years of responsible power plant experience of which a minimum of 3 years shall be nuclear power plant experience. A maximum of 4 years of the remaining 7 years of experience may be fulfilled by academic training on a one-for-one time basis. This academic training shall be in an engineering or scientific field generally associated with power production. The Plant General Manager shall have acquired the experience and training normally required for examination by the NRC for an SRO license, whether or not the examination is taken. The Plant General Manager should have a recognized baccalaureate or higher degree in an engineering or scientific field generally associated with power production.

13.1.3.2 Operations Department

13.1.3.2.1 Operations Manager

The Operations Manager shall have a minimum of 8 years of responsible power plant experience of which a minimum of 3 years shall be nuclear power plant experience.

A maximum of 2 years of the remaining 5 years of power plant experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time basis. The Assistant Operations Manager shall have qualifications similar to those of the Operations Manager. The Operations Manager or Assistant Operations Manager shall hold an SRO license.

13.1.3.2.2 Shift Manager

The Shift Manager shall have a minimum of a high school diploma or equivalent and 4 years of responsible power plant experience of which a minimum of 1 year shall be nuclear power plant experience. At least 6 months of nuclear plant experience will be at WNP-2. A maximum of 2 years of power plant experience may be fulfilled by academic or related technical training on a one-for-one time basis. The Shift Manager shall hold an SRO license. For NRC license eligibility guidelines (experience, training, and education) for an SRO license, see NUREG-1021, section ES-202.

13.1.3.2.3 Control Room Supervisor

The Control Room Supervisor shall have a minimum of a high school diploma or equivalent and 4 years of responsible power plant experience, of which a minimum of 1 year shall be nuclear power plant experience. At least 6 months of nuclear plant experience will be at WNP-2 site. A maximum of 2 years of power plant experience may be fulfilled by academic

or related technical training on a one-for-one time basis. The Control Room Supervisor shall hold an SRO license. For NRC license eligibility guidelines (experience, training, and education) for an SRO license, see NUREG-1021, section ES-202.

13.1.3.2.4 Shift Technical Advisor

The STA possesses a bachelor's degree in engineering or science with sufficient courses to provide a sound background for understanding the design and operation of a BWR power plant. The STA shall have a minimum of 2 years of power plant experience with at least 6 months of nuclear plant experience at WNP-2.

13.1.3.2.5 Shift Support Supervisor

The Shift Support Supervisor shall have a high school diploma or equivalent. The individual shall have 4 years of power plant experience of which 1 year shall be nuclear power plant experience. This position does not require an RO license.

13.1.3.2.6 Reactor Operator

The RO shall have a minimum of a high school diploma or equivalent of which a minimum of 1 year shall be nuclear power plant experience. At least 6 months of the nuclear experience shall be at the WNP-2 site unless the incumbent has an equal amount of nuclear experience acquired on a similar unit. The individual shall hold an RO license. For NRC license eligibility guidelines (experience, training, and education) for an RO license, see NUREG-1021, section ES-202.

13.1.3.2.7 Equipment Operator

Before assuming the full responsibilities of the position in the plant, the Equipment Operator shall have a minimum of a high school diploma or equivalent and shall have completed the Supply System training program for Equipment Operators. This position does not require an RO license.

13.1.3.3 <u>Engineering</u>

13.1.3.3.1 Technical Services/Systems Engineering Manager, Reactor/Fuel Engineering Manager, and Design and Projects Engineering Manager

The Technical Services/Systems Engineering Manager, Design and Projects Engineering Manager, and Reactor/Fuel Engineering Manager shall have a minimum of 8 years of related technical experience of which 1 year should be nuclear power plant experience. A maximum of 4 years of the remaining 7 years may be fulfilled by satisfactory completion of academic

training. A bachelor of science degree in engineering or physical sciences suitable to the nuclear power field is required. The Reactor/Fuel Engineering Manager shall have a minimum of 2 years of experience in areas such as reactor/core physics, measurements, heat transfer, and physics testing.

13.1.3.3.2 Engineering Supervisors

The Engineering Supervisors in System Engineering, Engineering Programs, and Design and Projects Engineering shall have a minimum of 8 years of related technical experience of which 1 year shall be nuclear power plant experience. A maximum of 4 years of the remaining 7 years may be fulfilled by satisfactory completion of academic training. A bachelor of science degree in engineering or physical sciences or the equivalent is required. The Reactor Engineering and Fuel Design Supervisors shall have a minimum of 2 years experience in areas such as reactor/core physics, measurements, heat transfer, and physics testing.

13.1.3.3.3 Fire Protection Engineer

The qualified Fire Protection Engineer meets the qualifications of member grade in the Society of Fire Protection Engineers or is a registered Fire Protection Engineer.

13.1.3.4 Maintenance

13.1.3.4.1 Maintenance Manager

The Maintenance Manager shall have a minimum of 7 years of responsible power plant experience or applicable industrial experience, a minimum of 1 year of which shall be nuclear power plant experience. A maximum of 2 years of the remaining 6 years of power plant or industrial experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time basis. He further should have nondestructive testing familiarity, craft knowledge, and an understanding of electrical, pressure vessel, and piping codes.

13.1.3.4.2 Maintenance Supervisors

Maintenance Supervisors shall each have a high school diploma or equivalent and should have a minimum of 4 years experience in the craft or discipline that they supervise in accordance with ANSI 18.1, 1971. In cases where a supervisor does not have a minimum of 4 years of experience in the discipline of the craft being supervised, technical direction for the craft will be given by a qualified supervisor.

13.1.3.5 Health Physics

13.1.3.5.1 Radiation Protection Manager

The Radiation Protection Manager shall, at a minimum, meet the qualifications defined in Regulatory Guide 1.8, Revision 1-R, May 1977. This individual shall have a bachelor's degree or the equivalent in a science or engineering subject including some formal training in radiation protection. The Radiation Protection Manager shall have at least 5 years of professional experience in applied radiation protection. (A master's degree may be considered equivalent to 1 year of professional experience and a doctor's degree may be considered equivalent to 2 years of professional experience where course work related to radiation protection is involved.) At least 3 years of this professional experience shall be in applied radiation protection work in a nuclear facility dealing with radiological problems similar to those encountered in nuclear power stations, preferably in an actual nuclear power station.

13.1.3.5.2 Assistant Radiation Protection Department Manager

The Assistant Radiation Protection Department Manager shall meet the qualification requirements of ANSI N18.1-1971, section 4.2.4. This includes a minimum of 8 years of responsible positions, of which a minimum of 1 year shall be nuclear power plant experience. A maximum of 4 years of the remaining 7 years of experience should be fulfilled by satisfactory completion of academic training.

13.1.3.5.3 Health Physics Supervisors

Health Physics Supervisors shall, in accordance with ANSI 18.1-1971, have a high school diploma or equivalent and a minimum of 4 years of related experience.

13.1.3.6 Chemistry

13.1.3.6.1 Chemistry Manager

The Chemistry Manager shall, in accordance with ANSI 18.1-1971, have a minimum of 5 years experience in chemistry of which a minimum of 1 year shall be in radiochemistry. A minimum of 2 years of this 5 years experience should be related technical training. A maximum of 4 years of this 5 years experience may be fulfilled by related technical or academic training.

13.1.3.6.2 Chemistry Supervisors

Chemistry Supervisors who are responsible for directing the actions of technicians shall, in accordance with ANSI 18.1-1971, have a high school diploma or equivalent and a minimum of 4 years of related experience.

13.1.3.7 Quality

See the OQAPD for a description of qualification requirements.

TABLE 13.1-1

MINIMUM SHIFT CREW COMPOSITION[a]

		Minimum Number of Personnel per Position per Shift	
Position Title[b]	Type of License	Modes 1, 2, and 3[c]	Modes 4 and 5[c]
SM	SRO	1	1
CRS	SRO	1	None
RO	RO	2	1
EO	None	2	1
STA	None	1	None
HP	None	1	1

[a] This table represents the minimum number of personnel required to fill any particular position. It does not provide a total staffing level for an operating shift. Additional staff for safe shutdown and fire brigade must also be satisfied.

[b] Position title abbreviations are as follows:

SM	Shift Manager with SRO on WNP-2
CRS	Control Room Supervisor with SRO on WNP-2
RO	Reactor Operator with RO or SRO on WNP-2
EO	Equipment Operator
STA	Shift Technical Advisor
HP	Health Physics Technician

[c] Modes

1. Power operation
2. Startup
3. Hot shutdown
4. Cold shutdown
5. Refueling

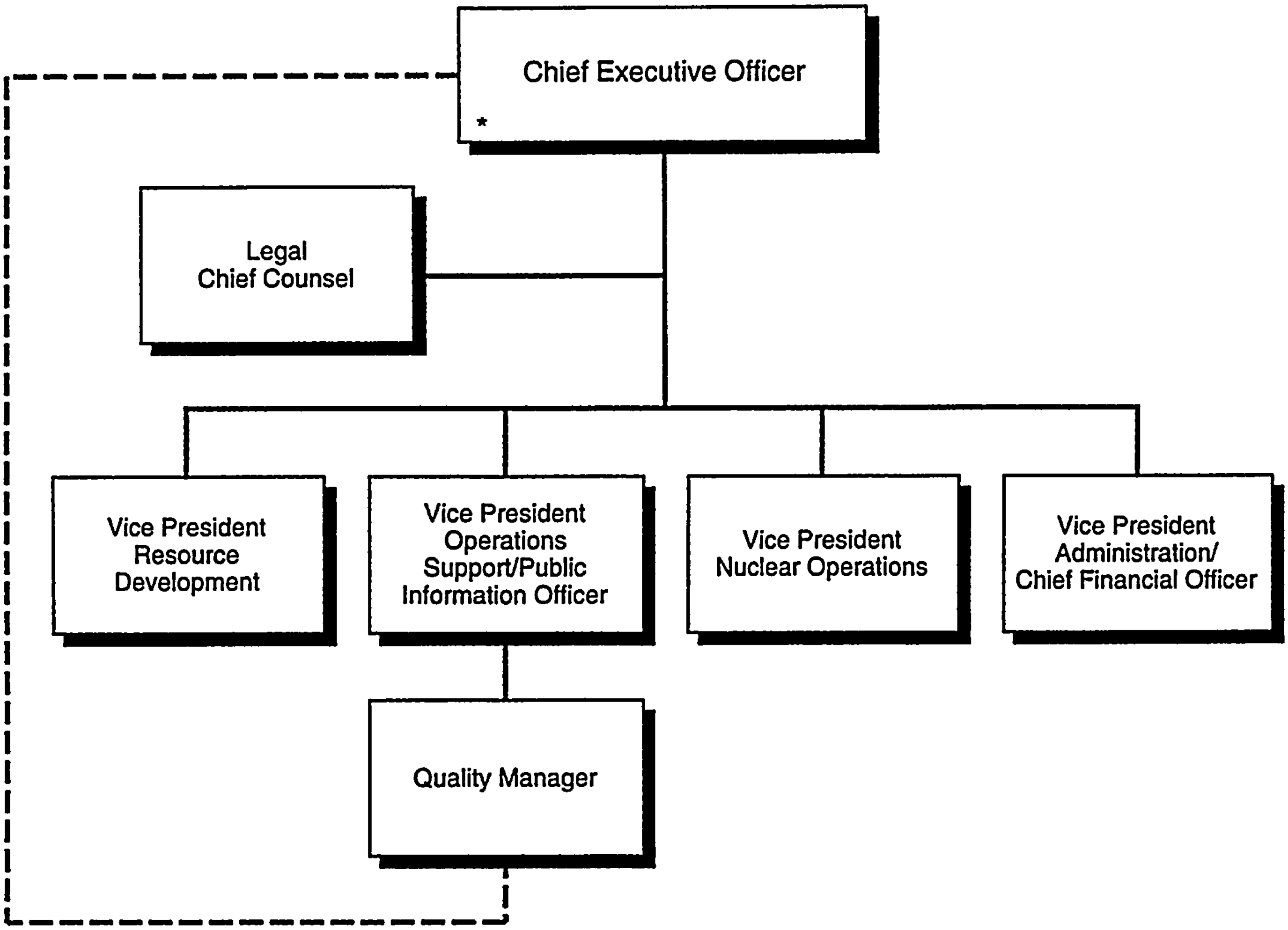
Except for the Shift Manager, the shift crew composition may be one less than the minimum requirements for a period not to exceed 2 hr to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to

TABLE 13.1-1

MINIMUM SHIFT CREW COMPOSITION (Continued)

within the minimum requirements. This provision does not permit any shift crew position to be unmanned on shift change due to an oncoming shift crewman being late or absent.

During any absence of the Shift Manager from the control room while the unit is in Operational Condition 1, 2, or 3, an individual (other than the STA) with a valid SRO license shall be designated to assume the control room command function. During any absence of the Shift Manager from the control room while the unit is in Operational Condition 4 or 5, an individual with a valid SRO license or RO license shall be designated to assume the control room command function.

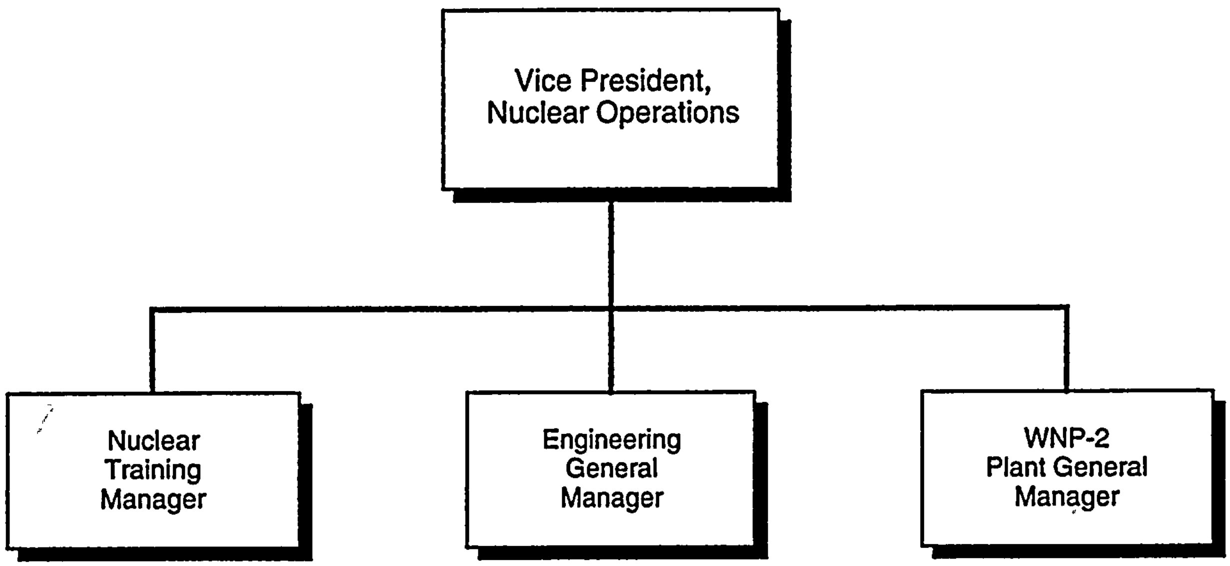


Legend

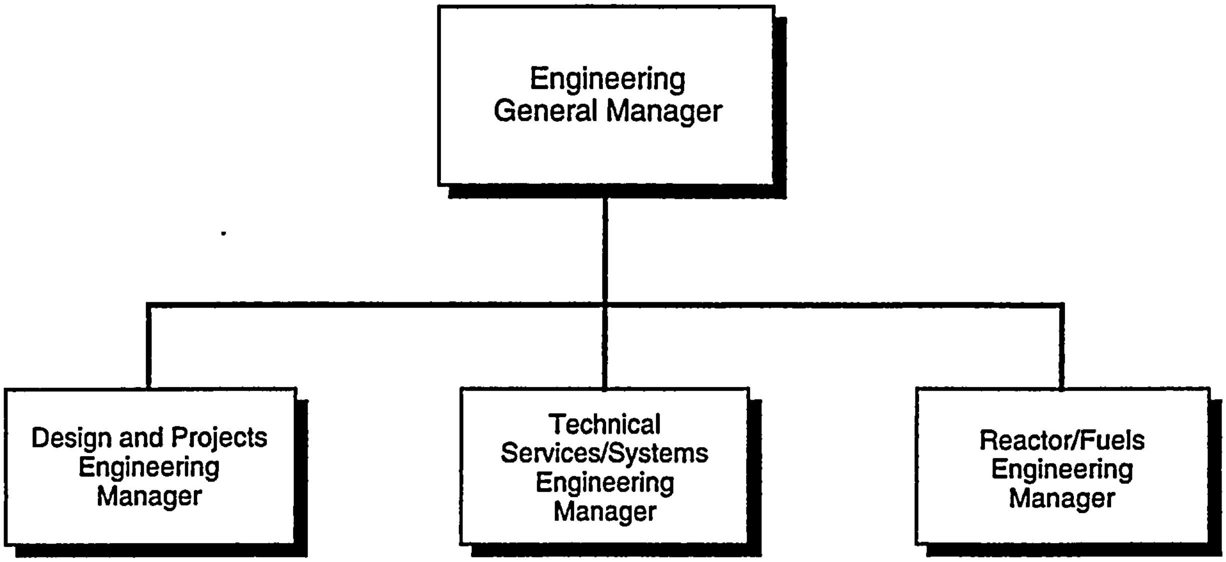
* Chief Nuclear Officer

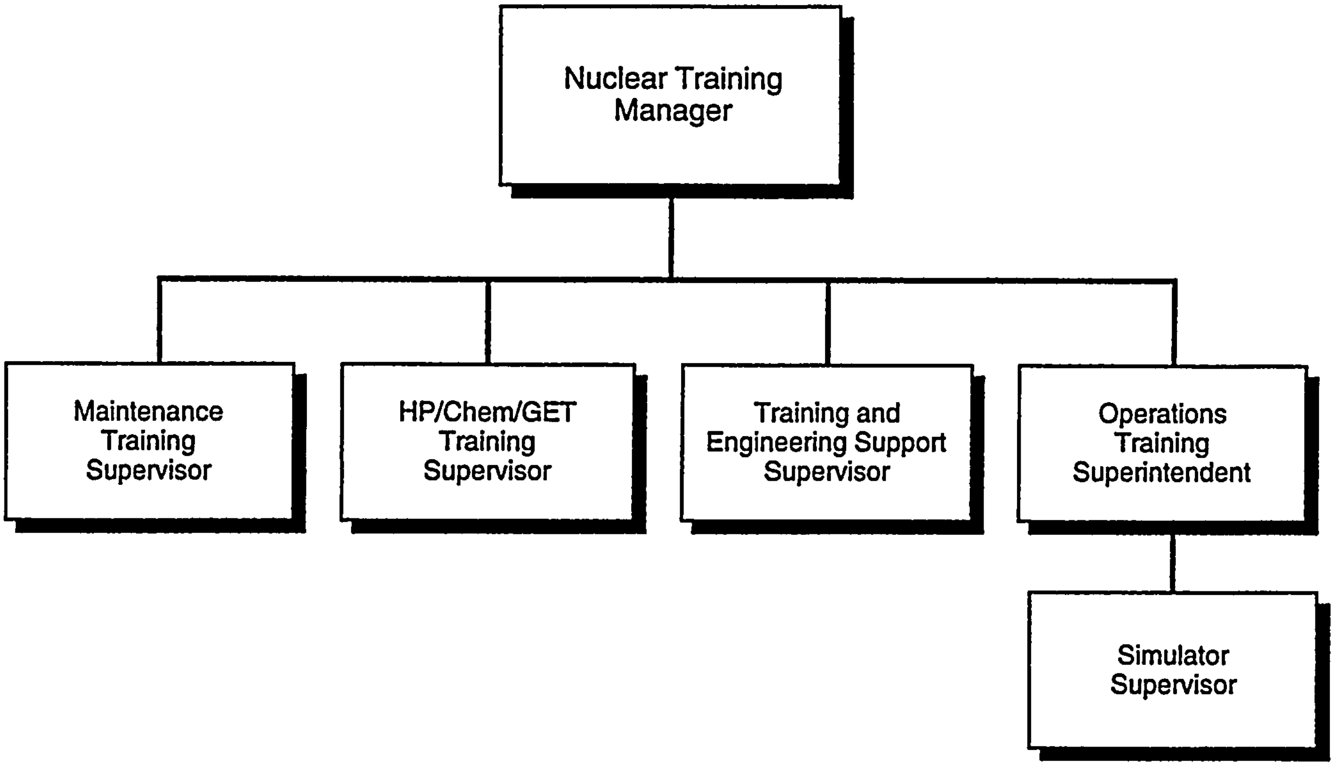
Administrative and Functional Reporting

Communications Lines



Vice President, Nuclear Operations Organization


Engineering
General Manager
Design and Projects
Engineering
Manager
Technical
Services/Systems
Engineering
Manager
Reactor/Fuels
Engineering
Manager



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NUCLEAR PLANT 2 FSAR

Nuclear Training Department

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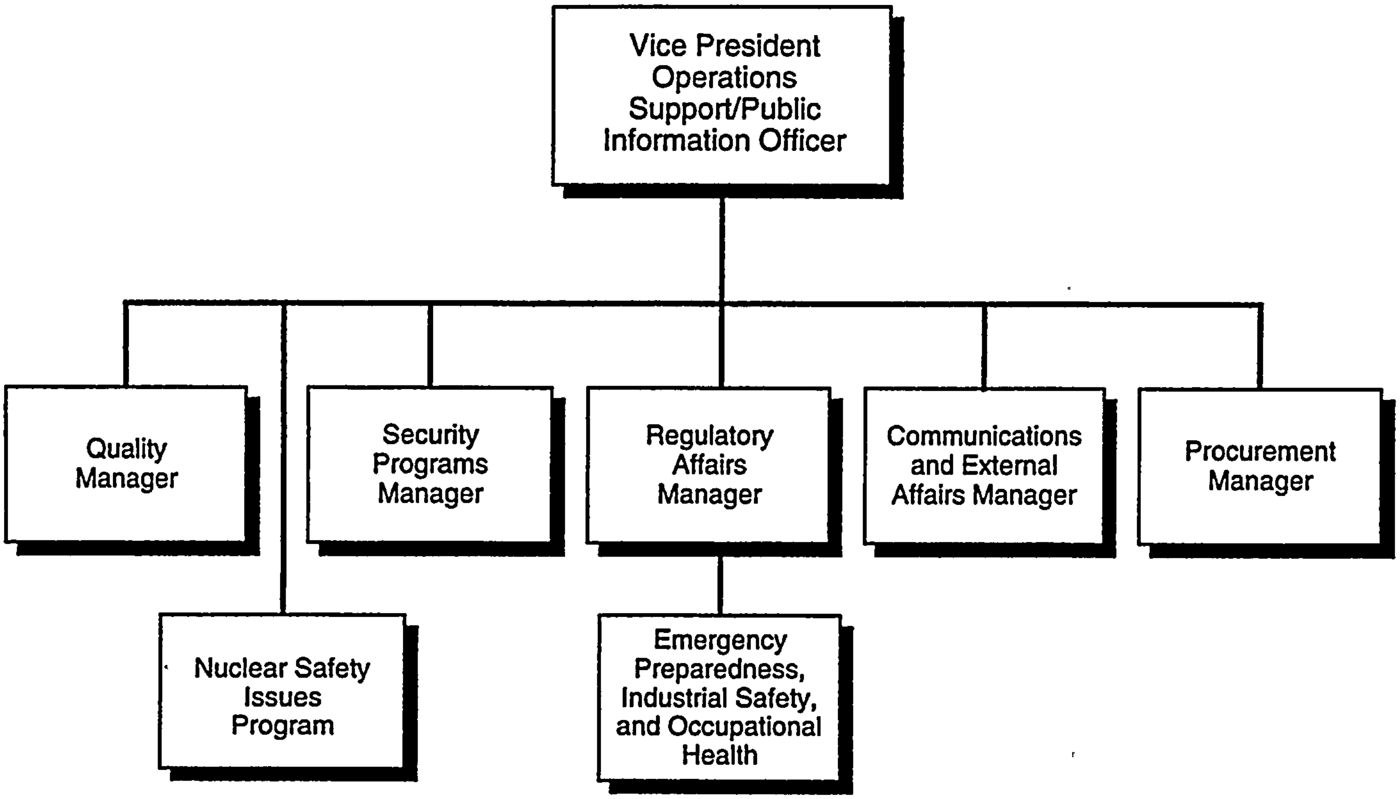

WASHINGTON PUBLIC POWER
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NUCLEAR PLANT 2 FSAR

Operations Support/Public Information Officer Organization

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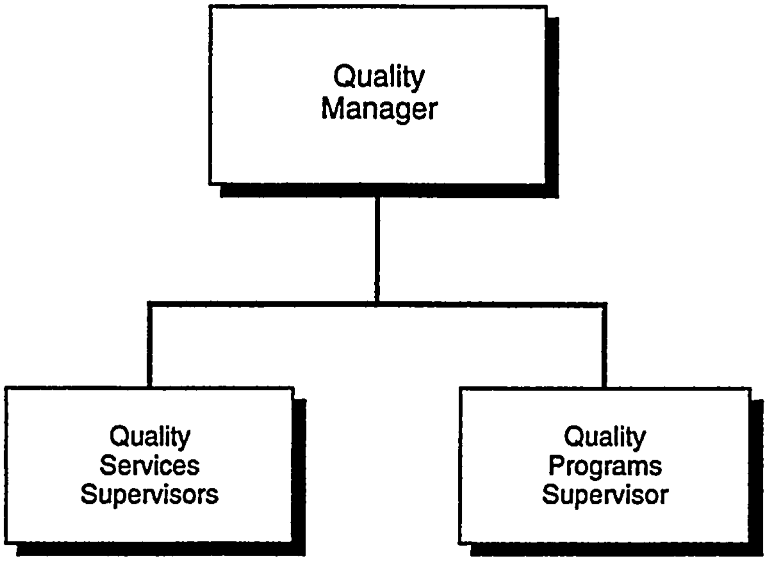

WASHINGTON PUBLIC POWER
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NUCLEAR PLANT 2 FSAR

Quality Department

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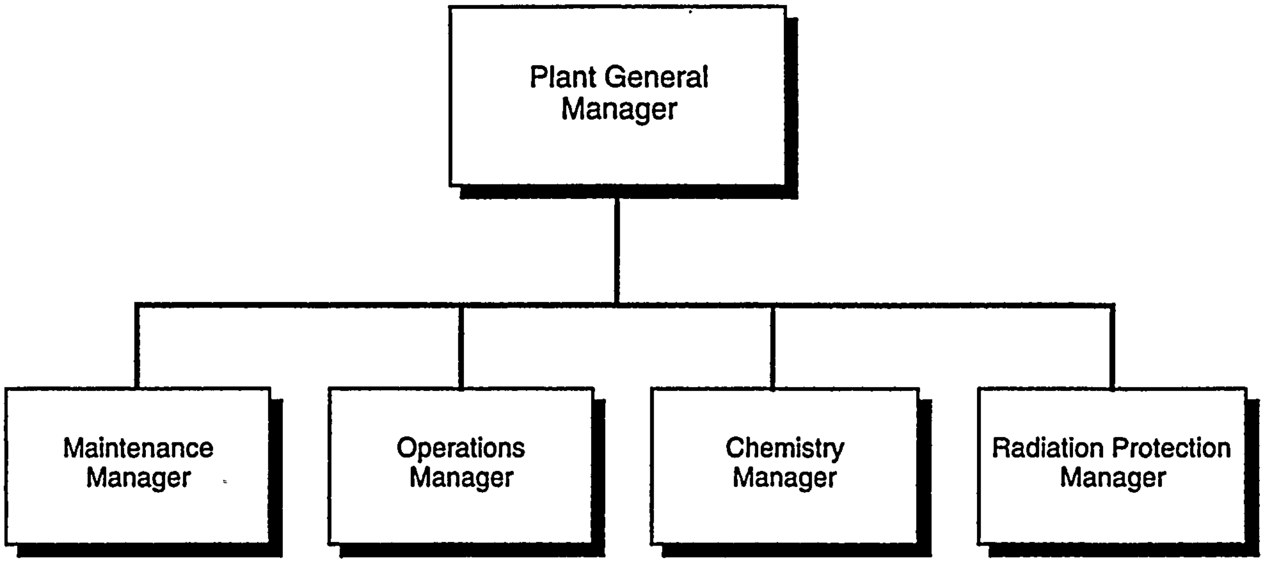

WNP-2 Plant Management Organization

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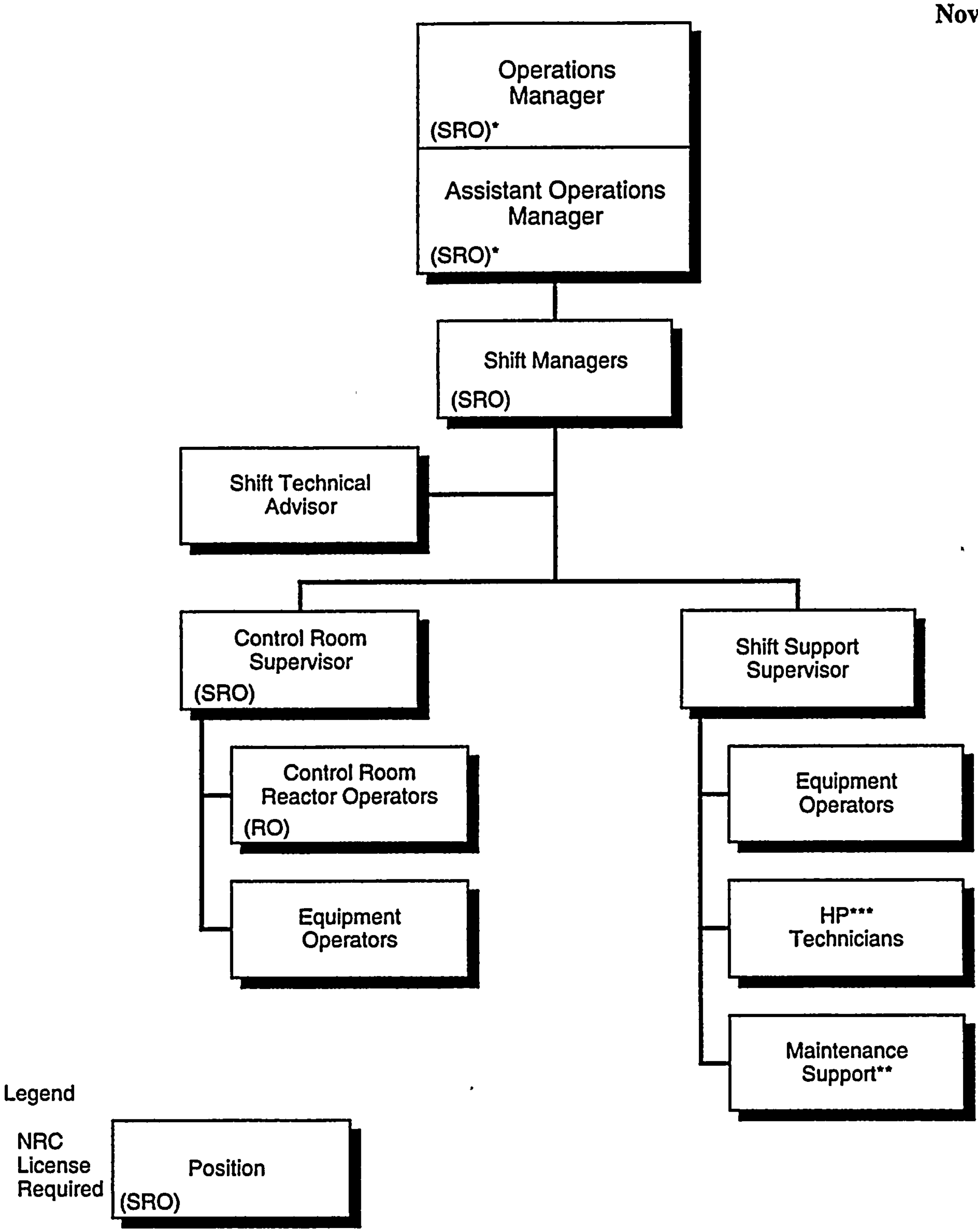
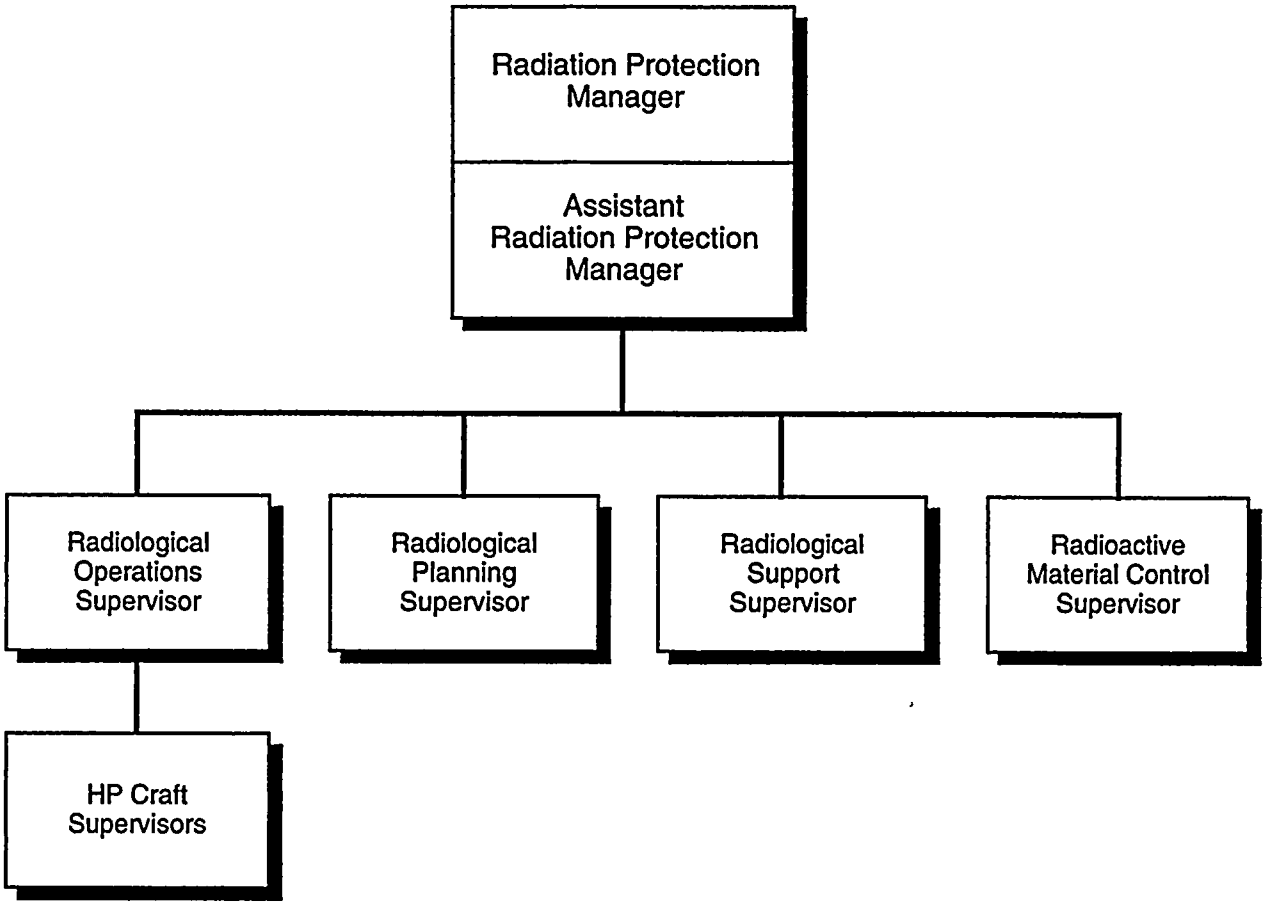


* Operations Manager or Assistant Operations Manager

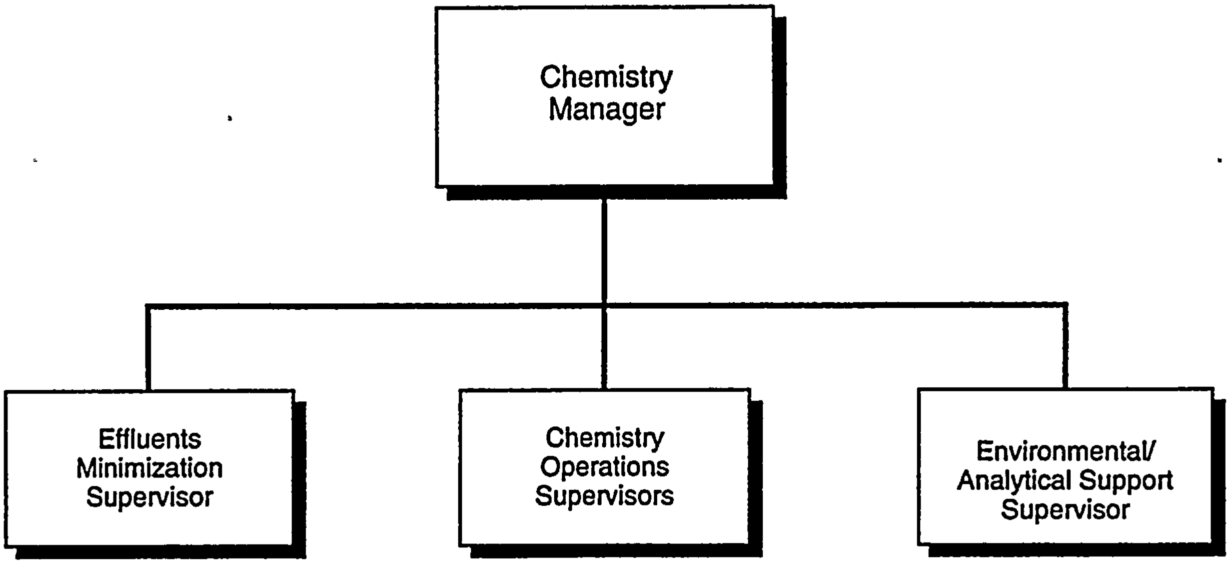
** To be provided from Maintenance Department as required

*** To be provided from HP Department as required



WNP-2 Health Physics Department

Draw. No. 970187.11	Rev.	Figure 13.1-9



WNP-2 Chemistry Department

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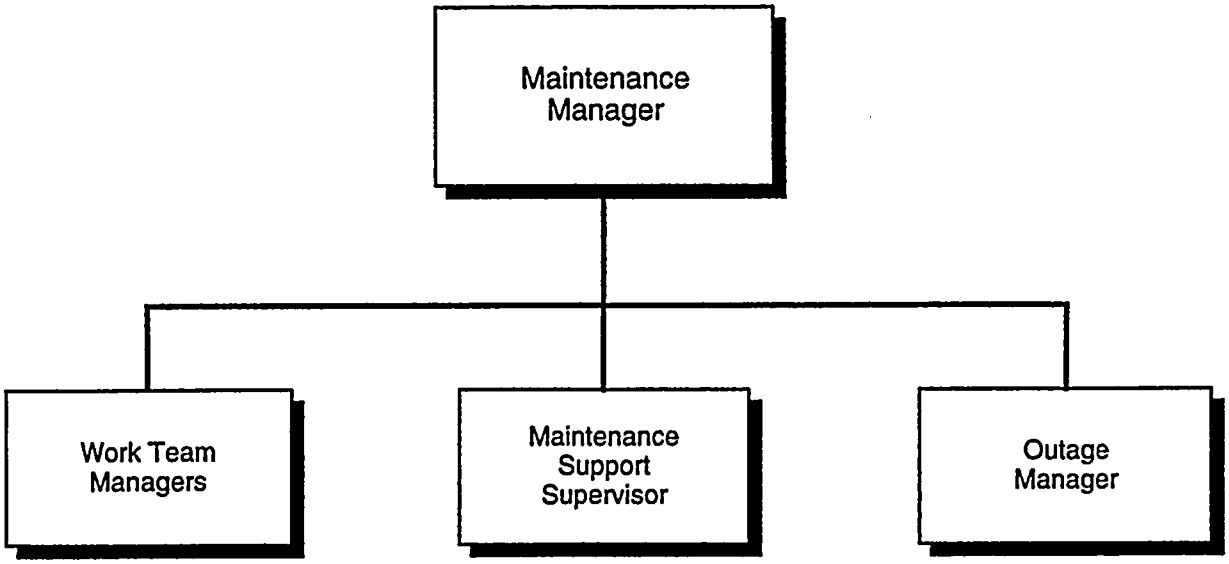


WNP-2 Plant Maintenance Department

13.2 TRAINING

13.2.1 PLANT STAFF TRAINING PROGRAM

In accordance with applicable federal guidelines, the WNP-2 Training Program has been designed to provide plant personnel with sufficient knowledge, training, and experience to enable them to safely and efficiently operate and maintain the plant and to protect the health and safety of the public.

The overall training program has been developed and coordinated by the Supply System, utilizing courses and programs produced by the nuclear steam supply system (NSSS) supplier, training consultant organizations, the training staff, and other employees of the Supply System possessing expertise in related disciplines.

The training program will provide sufficient qualified reactor operators, senior reactor operators, equipment operators, shift technical advisors, maintenance, health physics, chemistry, and engineering support personnel to fully staff WNP-2.

Initial training programs provide qualified replacement personnel and continuing training programs provide ongoing training for all plant staff commensurate with their area of responsibility and knowledge level.

The Plant General Manager is responsible for overall conduct and administration of the WNP-2 plant training program. The development and implementation of that program may be delegated to the Nuclear Training Organization or other members of the plant staff.

a. General Employee Training - Program Description

   All personnel granted unescorted access to the station will be trained in the following areas:

   1. Appropriate plant security and emergency procedures,
   2. General radiological protection,
   3. Industrial safety,
   4. Fire protection, and
   5. Quality assurance program.

   Written or oral exams will be required for selected classes to determine successful completion.

b. General Employee Training - Fire Protection Program

1. Plant employees

Employees receiving an unescorted security clearance will be provided training to include orientation to the fire protection plans, evacuation signals and procedures, and the procedure for reporting a fire.

2. Contractor personnel

Training will be provided to contractors as part of their access status--escorted or unescorted.

3. Security personnel

Training will be provided to plant security personnel that addresses

(a) Entry procedures for offsite fire department,
(b) Personnel control during emergency evacuation, and
(c) Basic fire hazard recognition.

13.2.2 INITIAL AND CONTINUING TRAINING

13.2.2.1 Licensed Operators

13.2.2.1.1 Initial Training

Under the normal progression of an individual through the various levels of operator qualification, much of the material and experience will have been previously obtained, and hence, the licensed operator replacement training program will emphasize topics pertinent to the control room operator job function and requirements necessary for fulfilling the NRC operator licensing qualifications. Replacement for licensed operators normally come from the ranks of "qualified" nonlicensed operators; however, personnel from other departments or from outside the utility may be trained as control room operators if they meet all requirements for the position.

The WNP-2 Operations Training Superintendent shall have the responsibility for establishing, supervising, and scheduling the initial licensed operator training program.

In accordance with 10 CFR 55.31(a)(4) the WNP-2 licensed operator initial training program has been reviewed and approved by the Commission and was developed using a systems approach to training.

The licensed operator initial training program has been accredited by the National Academy for Nuclear Training. The accreditation is renewed every 4 years. Accreditation is maintained in accordance with Institute of Nuclear Power Operation (INPO) Guidelines 91-015, "Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry," and 91-016, "The Process for Accreditation of Training in the Nuclear Power Industry."

13.2.2.1.2 Continuing Training

A requalification training program implementing the requirements of 10 CFR 55.59, will be conducted to maintain the knowledge level and operating proficiency of licensed personnel. The retraining program will be based on a 2-year cycle.

The WNP-2 Operations Training Superintendent shall have the responsibility for establishing, supervising, and scheduling the retraining program.

In accordance with 10 CFR 55.59(c) the WNP-2 licensed operator requalification training program has been reviewed and approved by the NRC and was developed using a systems approach to training.

The requalification program has been accredited by the National Academy for Nuclear Training. The accreditation is maintained in accordance with INPO Guidelines 91-015, "Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry," and 91-016, "The Process for Accreditation of Training in the Nuclear Power Industry."

The retraining and replacement program for the unit staff meets the requirements of Section 5.5 of ANSI/ANS N18.1-1971, Appendix A of 10 CFR Part 55, and the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980, NRC letter to all licensees, and includes familiarization with relevant industry operational experience.

13.2.2.2 Nonlicensed Operator Training

13.2.2.2.1 Initial Training

Normally replacements will be required to complete the following training prior to being placed into the equipment operator qualification sequence:

a. Basic fundamentals,
b. Basic boiling water reactor (BWR) systems,
c. Reactor plant equipment and component theory, and
d. Administrative procedures.

The training will emphasize topics pertinent to the equipment operator job function and requirements necessary for qualification.

13.2.2.2.2 Continuing Training Program

Continuing training of nonlicensed operators may be conducted in conjunction with the licensed operator requalification program. Nonlicensed operators shall be required to attend specific lecture topics that pertain to their job level requirements. At a minimum, nonlicensed operators shall participate in periodic reviews of systems and operating procedures for which continuous familiarization is important for safe and efficient operation of the plant. Specifically, the equipment operator retraining program consists of

a. Preplanned lecture series,
b. Update lecture series,
c. Normal/abnormal procedure review, and
d. Examinations/evaluations.

The WNP-2 Operations Training Superintendent has the responsibility for establishing, supervising, and scheduling the equipment operator training program.

The equipment operator training program has been accredited by the National Academy for Nuclear Training. The accreditation is renewed every 4 years. Accreditation is maintained in accordance with INPO Guidelines 91-015, "Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry," and 91-016, "The Process of Accreditation of Training in the Nuclear Power Industry."

13.2.2.3 Shift Technical Advisor Training

13.2.2.3.1 Initial Training

The initial shift technical advisor (STA) training program content will normally include training and qualification in the following subject areas:

a. Completion of the SRO replacement operator training program or equivalent
b. Plant transient/accident analysis, and
c. STA job specific training.

13.2.2.3.2 Continuing Training

Continuing training of the STAs is normally conducted in conjunction with the licensed operator requalification training program. The STAs shall be required to attend specific lecture topics that pertain to their job level requirements. At a minimum, STAs shall participate in periodic reviews of systems and operating procedures for which continuous

familiarization is important for safe and efficient operation of the plant. Specifically, the STA retraining program consists of

a. Preplanned lecture series,
b. Update lecture series,
c. Normal/abnormal procedure review, and
d. Examinations/evaluations.

The WNP-2 Operations Training Superintendent has the responsibility for establishing, supervising, and scheduling the STA training program.

The STA training program has been accredited by the National Academy for Nuclear Training. The accreditation is renewed every 4 years. Accreditation is maintained in accordance with INPO Guidelines 91-015, "Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry," and 91-016, "The Process for Accreditation of Training in the Nuclear Power Industry."

13.2.2.4 Other Plant Personnel (Maintenance, Health Physics, Chemistry, Technical)

13.2.2.4.1 Initial Training

Replacement personnel, when hired, will be given training commensurate with their job responsibilities as determined necessary by the respective Department Manager and the appropriate Training Supervisor after a review of past experience and training.

13.2.2.4.2 Continuing Training

Continuing training is conducted on a regular basis and consists of pertinent operating experience and designated requalification topics. The continuing training will be commensurate with their assigned job responsibilities as determined necessary by their respective Department Manager and Training Coordinator.

13.2.2.5 Fire Brigade

13.2.2.5.1 Initial and Continuing Training

Each assigned member of the Fire Brigade will complete initial and continuing Fire Brigade training courses to provide the knowledge and skills necessary to accomplish the expected fire fighting activities. The scope of this training will be described and implemented by plant procedures.

One assigned member will be designated as the Fire Brigade leader to direct the actual fire fighting forces. This individual will receive the training necessary to effectively carry out this function.

The Fire Brigade leader and two additional members will be knowledgeable of plant fire safe shutdown equipment.

a. Planned meetings

Regular planned meetings for each Fire Brigade member will be held each quarter to review changes in the program and other subjects, as necessary.

During these planned meetings, the initial training program content will be reviewed for all Fire Brigade members over a 2-year period.

b. Practice sessions

Practice sessions will be held for each Fire Brigade member annually on the proper methods of fighting the various types of fires that could occur in a nuclear power plant.

c. Drills

Planned drills will be conducted for practice in responding as a team to areas of the plant site where the Fire Brigade may be required to respond. Each Fire Brigade member will be required to participate in semiannual drills unless the member was certified after the first semiannual drill period in conjunction with the training cycle has been completed. Brigade members certifying after the second drill period has been completed are not required to participate in a fire drill for that calendar year.

One drill for each shift Fire Brigade per year will be unannounced and one drill for each shift Fire Brigade per year will be on a back shift.

13.2.2.5.2 Offsite Fire Department

The offsite fire department that supplements the Fire Brigade will attend familiarization training associated with the WNP-2 plant layout, operational precautions, radiation protection, and special hazards associated with fires at a nuclear power plant. This offsite fire department will participate in at least one fire drill each year.

13.2.3 TRAINING PROGRAM EFFECTIVENESS

The effectiveness of the Training Program will be evaluated by the following methods:

a. Satisfactory job performance as determined by periodic line management evaluations and observations,

b. Satisfactory performance of plant personnel on various oral and or written examinations administered by the Supply System or NRC, and

c. Periodic reviews of instructors, programs, and training material as conducted by Training and Engineering Support Section.

13.2.4 PLANT TRAINING RECORDS

The Nuclear Training Manager maintains complete qualification records on each member of the plant staff.

All records necessary to support requests for NRC reactor operator and senior reactor operator licenses are included in these files. Records to be maintained are as follows:

a. Lecture series attendance,
b. Lecture examinations and answers by the licensees,
c. Annual examinations and answers by the licensees,
d. Simulator performance evaluation results,
e. Control Manipulations Tracking System Form, and
f. Additional training for deficiencies.

13.2.5 OTHER TRAINING DOCUMENTS

For compliance with other applicable documents see Sections 1.8 and 12.5.3.8.

13.3 EMERGENCY PLANNING

The detailed emergency plan is included as a separate volume in the WNP-2 Emergency Plan.

13.4 REVIEW AND AUDIT

The following sections describe the conduct of reviews and audits of operating activities that are important to safety. The review and audit program is consistent with the requirements of ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants."

Periodic reviews of plant operations are performed by the plant operating staff. In addition, the Supply System uses a formal onsite committee (see Section 13.4.1) and an independent group (see Section 13.4.2) for review.

The Quality Department staff has formulated and executed an audit program for the plant activities as defined in the Operational Quality Assurance Program Description (OQAPD).

The organization for review and audit and its relationship to other organizations is shown in Figures 13.1-1, 13.1-5, and 13.1-6.

13.4.1 ONSITE REVIEW

Onsite reviews are consistent with Regulatory Guide 1.33 (see Section 1.8). The plant operating staff provides, as part of the normal duties of plant supervisory personnel, timely and continuing monitoring of operating activities to assist the Plant General Manager in keeping abreast of general plant conditions and to verify that the day-to-day operating activities are conducted safely and in accordance with applicable administrative controls. These continuing monitoring activities are an integral part of the routine supervisory function and are important to the safety of plant operation.

Additionally, in accordance with the OQAPD, the Plant Operations Committee (POC) serves as a review and advisory organization to the Plant General Manager on all matters related to nuclear and radiological safety.

A written administrative procedure describes the responsibility and authority of the POC. The POC activities and review are described in the OQAPD. The results of POC review activities are documented.

13.4.2 INDEPENDENT REVIEW

In accordance with the OQAPD, the Corporate Nuclear Safety Review Board (CNSRB) is responsible for an independent review program. The CNSRB reports to and advises the Chief Nuclear Officer on the adequacy and implementation of Supply System nuclear and radiological safety policies and programs.

Documentation defining CNSRB membership, responsibilities, authority, and method of operation is contained in a Site Wide Procedure. Significant organizational features and review responsibilities are also described in the OQAPD. Conclusions of the independent reviews are transmitted to the appropriate members of management.

An independent onsite review is provided by Quality Services which reports to the Manager, Quality. Quality Services performs continuing review and assessment of plant activities including operations experience to provide added assurance that these activities are performed correctly, that human errors are reduced as far as practical, and to identify areas for improving plant safety. Quality Services ensures that the following operating experience information is reviewed:

a. Plant operating characteristics,

b. NRC Bulletins and Information Notices,

c. CFR Part 21 Reports,

d. INPO Significant Operating Experience Reports,

e. INPO Significant Event Reports,

f. Equipment Manufacturers Vendor data, and

g. Letters from architect-engineer, contractor, and equipment manufacturers that concern defects in analysis, services, equipment, and parts or recommendations for modifying, operating, or maintaining supplied equipment, which may indicate areas for improving plant nuclear safety.

The objectivity of Quality Services is maintained based on a charter and reporting relationship independent of plant line management, without precluding participation in plant activities and tasks.

13.4.3 AUDIT PROGRAM

A comprehensive program of audits is carried out to verify compliance to the OQAPD. These audits are performed by or under the direct cognizance of the Quality Services staff. Written reports of such audits are reviewed by the CNSRB, Plant General Manager, and other management as appropriate. Timely resolution of any deficiencies noted during audits is required to be by those organizations having responsibility for the area audited. Details of those areas to be audited are described in the OQAPD.

13.5 PLANT PROCEDURES

The administrative controls and quality assurance program for plant operation are carried out in accordance with approved written procedures. All activities affecting nuclear safety are conducted by written and approved procedures of a type appropriate to the circumstances, and these activities are accomplished in accordance with these procedures.

13.5.1 ADMINISTRATIVE PROCEDURES

13.5.1.1 Conformance With Regulatory Guide 1.33, Revision 2

ANSI N18.7-1976 and Regulatory Guide 1.33 including Appendix A are followed in accordance with the Supply System position discussed in the Operational Quality Assurance Program Description (OQAPD).

13.5.1.2 Preparation of Procedures

The Site Wide Procedures (SWP) Program provides the administrative controls necessary to prepare, review, and approve the procedures required for plant operating activities.

The Chief Nuclear Officer has the overall responsibility for the procedures program and its implementing procedures. The Plant General Manager is responsible for the procedures that are required by ANSI N18.7-1976 and Regulatory Guide 1.33 and Appendix A. The preparation and review of the procedures are the responsibility of various plant staff personnel. All procedures are approved according to the SWP Program and the OQAPD.

13.5.1.3 Procedures

The SWP Program for Administrative Procedures defines the responsibility, methods used, and procedural action required to help ensure that the plant will be managed in a safe and dependable manner.

Administrative Procedures establish rules and instructions pertaining to activities such as procedure preparation, records management, plant reporting requirements, plant personnel responsibilities and authorities, plant modification, corrective and preventive maintenance, clearance orders, temporary changes to approved procedures, reviews of plant documents, surveillance testing and inservice inspection, equipment control, and material control.

Administrative Procedures governing standing orders to shift operations include the reactor operator's authority and responsibilities; the senior reactor operator's authority and responsibilities; the logbook use and control; issuance and updating of special orders; and the plans for meeting the requirements of 10 CFR 50.54(i), (j), (k), (1), and (m). This includes a

diagram of the control room that illustrates the area designated as "at the controls" as shown in Figure 13.5-1.

13.5.2 OPERATING AND MAINTENANCE PROCEDURES

13.5.2.1 Control Room Operating Procedures

Detailed procedures used by the control room operators ensure plant safety and reliability. These procedures are categorized and described as follows:

System Operating Procedures

The System Operating Procedures provide instructions pertinent to the various normal operating modes of startup, operation, and shutdown of each system or subsystem. Checkoff lists are included, where appropriate, with each procedure to delineate the proper equipment lineup that is required.

General Operating Procedures

General Operating Procedures provide the instructions for the integrated operation of plant systems during startup, shutdown, power operations, and power changes. Checkoff lists, as appropriate, are included to ensure that necessary prerequisites to integrated operation have been completed. Checklists may also be used to confirm completion of major steps in the proper sequence.

Abnormal Condition Procedures

Abnormal Condition Procedures specify operator actions for restoring selected equipment or systems to their normal controlled status on a failure or to restore normal operating conditions following a perturbation. These procedures are not emergency procedures but are written to aid the operator in determining if a true emergency exists.

Abnormal Condition Procedures also contain response instructions for annunciator alarms and for abnormal conditions within the major systems covered in System Operating Procedures. Each safety-related annunciator is addressed in a written procedure which contains (1) meaning of annunciator, (2) the source of the signal, (3) the immediate action that is to occur automatically, (4) immediate operator actions, and (5) subsequent operator actions. Those procedures that require the Immediate Operator Action steps to be memorized are given adequate identification.

Emergency Operating Procedures/Severe Accident Guidelines

Emergency Operating Procedures/Severe Accident Guidelines are provided to guide operations during potential emergencies. These procedures specify actions, including manipulation of controls, to avoid further degradation of abnormal conditions or to reduce the consequences of an accident or hazardous condition that has already occurred.

13.5.2.2 Other Procedures

Other safety-related activities conducted in accordance with approved procedures are categorized and described as follows (radioactive waste system operating procedures are covered by System Operating Procedures and the other aspects of radioactive waste management are covered by Health Physics and Chemistry Procedures).

Fuel Handling and Refueling Activities Procedures

Fuel Handling and Refueling Activities Procedures provide instructions for fuel and core component accountability, new fuel handling, refueling operations, defective fuel handling, reactor core component handling, and irradiated fuel shipment.

Surveillance Procedures (both Operational Surveillance and Instrument and Electrical Surveillance)

Surveillance Procedures provide instructions for performing periodic tests to verify and document that safety-related structures, systems, and components continue to function properly to remain in a state of readiness to perform their intended safety functions. Surveillance Procedures cover systems operability tests, logic system functional tests, and instrument and/or electrical functional tests and calibrations for the various surveillance requirements listed in the Technical Specifications.

Operating and Engineering Test Procedures

Operating and Engineering Test Procedures provide instructions for performing special tests on both safety and non-safety-related systems and components. These procedures contain tests such as power ascension, turbine efficiency, system hydrostatic tests, and reactor steam quality.

Nuclear Performance Evaluation Procedures

The Nuclear Performance Evaluation Procedures provide instructions for Engineering and Operations in the performance of the following types of evaluations: core thermal power evaluations, core thermal-hydraulic evaluations, intermediate range monitor, local power range monitor, and average power range monitor calibration and criticality predictions.

Maintenance Programs and Procedures

Maintenance Procedures provide instructions for performance of maintenance on safety-related equipment or systems and selected non-safety-related equipment and systems. Maintenance procedures cover mechanical, electrical, instrument and control, coatings, and refueling activities.

Health Physics Procedures

Health Physics Procedures establish the administrative and technical controls for the Radiation Protection Program and the implementing procedures for accomplishing the program. Descriptions of the activities covered by these procedures are included in Chapter 12.

Chemistry Procedures

Chemistry Procedures establish the administrative and technical controls for water quality analysis. Chemical and radiochemical determination procedures and associated instrument operation and calibration procedures are provided.

Emergency Plan Implementing Procedures

Detailed procedures prescribe the appropriate course of action necessary to limit or mitigate the consequences for each classification of incidents described in the Emergency Plan. An index of the Emergency Plan Implementing Procedures is included in Appendix II to the Emergency Plan.

Security Programs Implementing Procedures

Detailed security procedures prescribe the course of action necessary for compliance with the policies of the Security Plan. The Security Plan and associated implementing procedures that contain safeguards information are withheld from public disclosure (see Section 13.6).

Fire Protection Procedures

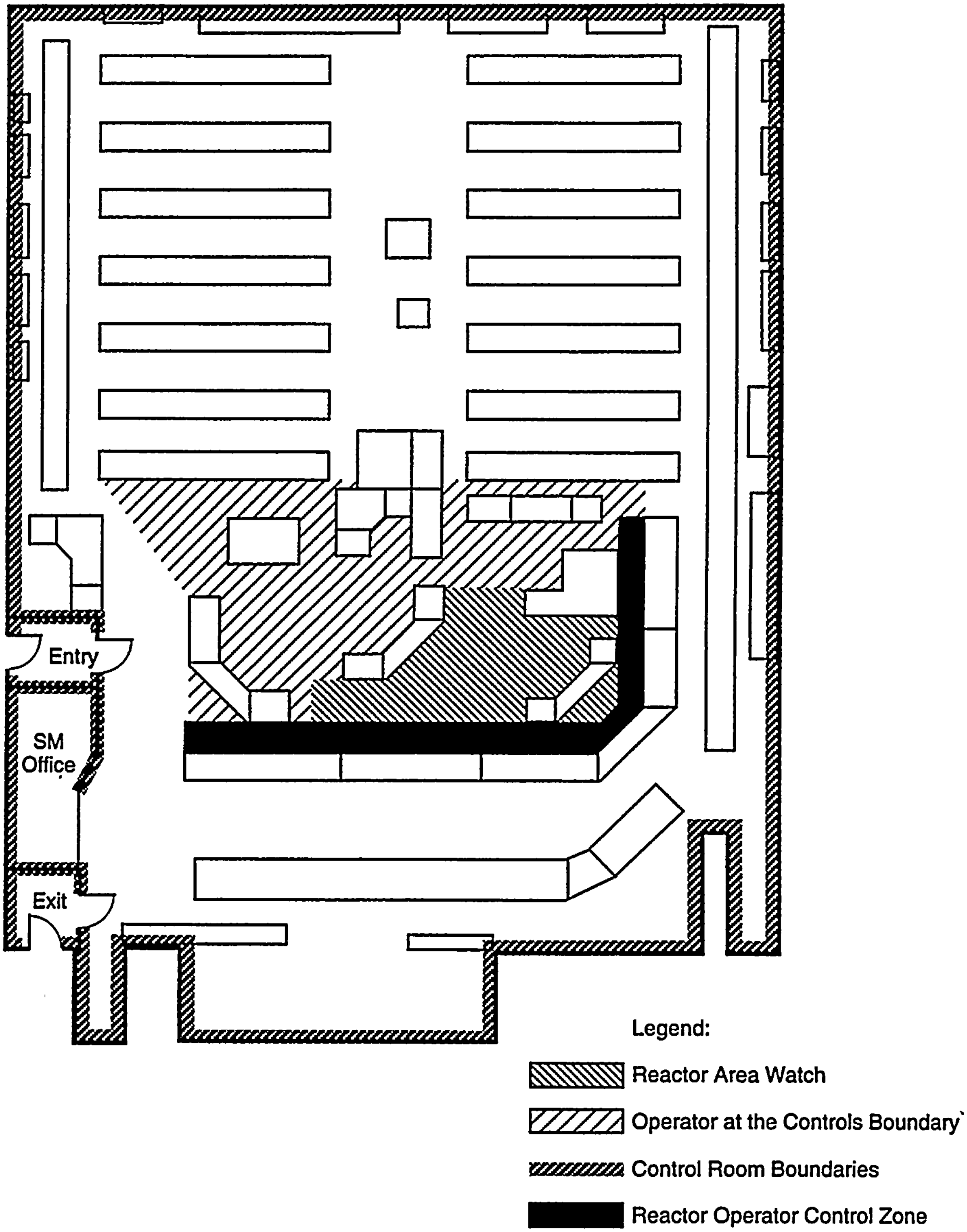
Fire Protection Procedures provide instructions for performing tests, inspections, and scheduled maintenance on fire protection equipment and systems and actions required for degraded systems.

ODCM Implementing Procedures

The ODCM Implementing Procedures prescribe the action necessary to implement the requirements of the Offsite Dose Calculation Manual (ODCM), including effluent monitoring, instrument calibration, and reporting requirements.

Environmental Compliance Procedures

Environmental Compliance Procedures establish the administrative and technical controls for environmental compliance. These procedures provide instructions for the management of solid wastes, pollution prevention and waste minimization, chemical storage and use, and hazardous substance spills and cleanup.



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WNP-2 Control Room "At the Controls" Area

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Form No. 960690

13.6 INDUSTRIAL SECURITY

The WNP-2 Physical Security Plan contains a description of the physical protection program for the facility as required by 10 CFR 50.54(p) and 10 CFR 73.55. The contents of this plan are safeguards information and are withheld from public disclosure pursuant to Section 2.790(a)(3) of 10 CFR Part 2.

Chapter 14

INITIAL TEST PROGRAM

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INITIAL TEST PROGRAM

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INITIAL TEST PROGRAM

14.1 SPECIFIC INFORMATION INCLUDED IN PRELIMINARY SAFETY ANALYSIS REPORTS

The initial test program overall test objectives and general prerequisites were previously provided in the Preliminary Safety Analysis Report (PSAR). The technical aspects of the initial test program are described in Section 14.2 in sufficient detail to show that the test program adequately verifies the functional requirements of plant structures, systems, and components such that the safety of the plant will not be dependent on untested structures, systems, or components.

14.2 SYSTEM LINEUP, PREOPERATIONAL, AND INITIAL STARTUP TEST PROGRAM

The italicized information is historical and was provided to support the application for an operating license.

The initial test program consisted of a series of tests categorized as system lineup testing, preoperational, and initial startup tests. The system lineup testing determines correct installation and functional operability of equipment. Preoperational tests are those tests normally conducted prior to fuel loading to demonstrate the capability of plant systems to meet performance requirements. Initial startup tests began with fuel loading and demonstrated the capability of the integrated plant to meet performance requirements.

14.2.1 SUMMARY OF TEST PROGRAM AND OBJECTIVES

14.2.1.1 Initial Test Program Objectives

The objectives of the initial test program are to

a. Ensure that the construction is complete and acceptable,

b. Demonstrate the capability of structures, components, and systems to meet performance requirements,

c. Effect fuel loading in a safe manner,

d. Demonstrate, where practical, that the plant is capable of withstanding anticipated transients and postulated accidents,

e. Evaluate and demonstrate, to the extent possible, plant operating procedures to provide assurance that the operating group is knowledgeable about the plant and procedures and fully prepared to operate the facility in a safe manner, and

f. Bring the plant to rated capacity and sustained power operation.

14.2.1.2 Initial Test Program Summaries

The three categories of tests in the initial test program are summarized below:

a. System lineup tests such as pump and valve tests, mechanical actuation to verify proper installation, and electrical continuity verifications, are those tests which demonstrate that components are correctly installed and operational.

b. *Preoperational tests conducted prior to fuel loading to demonstrate that the plant systems have been properly designed and that they meet performance requirements.*

c. *Startup tests consist of fuel loading, precritical tests, low power tests, and power ascension tests that ensure fuel loading in a safe manner, confirm the design bases, demonstrate where practical that the plant is capable of withstanding the anticipated transients and postulated accidents, and ensure that the plant is safely brought to rated capacity and sustained power operation.*

14.2.1.3 <u>*Description of System Lineup Tests*</u>

Typical system lineup tests generally include but are not limited to the following:

a. *Chemical cleaning and flushing of systems, tanks, and vessels,*

b. *Electrical equipment to test and/or energize, e.g., grounding, relays, circuit breaker operation and controls, continuity, megger, phasing, high potential measurements, and buses,*

c. *Initial adjustment, bumping, and running of rotating equipment,*

d. *Checking control and interlock functions of instruments, relays, and control devices,*

e. *Calibrating instruments and checking or setting initial trip setpoints,*

f. *Pneumatic testing of instruments and service air system and cleanout of lines,*

g. *Checking and adjusting relief and safety valves,*

h. *Complete tests of safety-related motor-operated valves including adjusting torque switches and limit switches, checking all interlocks and controls, measuring motor current and operating speed, and checking leaktightness of stem packing and valve seat during hydrotests; and complete tests of the nuclear steam supply system (NSSS) control systems including checking all interlocks and controls, adjusting limit switches, measuring operating speed, checking leaktightness of pneumatic operators, and checking for proper operation of controllers, pilot solenoids, etc., and*

i. *Other tests and verifications such as structural, leaktightness, and vibration.*

14.2.1.4 Description of Preoperational Tests

A listing of the preoperational tests is provided in Table 14.2-1. The general objectives of the preoperational test phase are as follows:

a. *Ensure that test acceptance criteria are met,*

b. *Provide documentation of the performance and safety of equipment and systems,*

c. *Provide baseline test and operating data on equipment and systems for future reference,*

d. *Run-in of a system for a sufficient period so that any design, manufacturing, or installation defects can be detected and corrected,*

e. *Ensure that plant systems operate together on an integrated basis to the extent possible,*

f. *Give maximum opportunity to the permanent plant operating staff to obtain practical experience in the operation and maintenance of equipment and systems,*

g. *Establish safe and efficient normal, abnormal, and emergency operating procedures, to the extent possible,*

h. *Establish and evaluate surveillance testing procedures, and*

i. *Demonstrate that systems and safety equipment are operational and that it is possible to proceed to fuel loading and to the Startup Phase.*

14.2.1.5 Description of Startup Tests

The Power Ascension Test Phase (PATP) begins after the Preoperational Test Phase has been completed. The Power Ascension Test Phase begins with fuel loading and extends to commercial operation. This phase is subdivided into the following four parts:

a. *Open vessel testing (fuel loading and shutdown power level tests),*
b. *Initial heatup,*
c. *Power testing, and*
d. *Warranty demonstration.*

The tests conducted during the Power Ascension Test Phase consist of major plant transients (Table 14.2-2), stability tests (Table 14.2-3), and a remainder of tests which are directed

towards demonstrating correct performance of the nuclear boiler and numerous auxiliary plant systems while at power. Certain tests may be identified with more than one class of test. Table 14.2-4 shows the complete Power Ascension Test Program. Figure 14.2-1 provides test conditions region definition.

The general objectives of the Power Ascension Test Phase are as follows:

a. *Achieve an orderly and safe initial core loading,*

b. *Accomplish all testing and measurements necessary to determine that the approach to initial criticality and subsequent power ascension is safe and orderly,*

c. *Conduct low power physics tests sufficient to ensure that test acceptance criteria have been met,*

d. *Conduct initial heatup and hot functional testing so that hot integrated operation of all systems is shown to meet test acceptance criteria,*

e. *Conduct an orderly and safe power ascension program, with requisite physics and systems testing, to ensure that the plant operating at power meets test acceptance criteria, and*

f. *Conduct a successful warranty demonstration program.*

14.2.2 ORGANIZATION AND STAFFING

14.2.2.1 General

The Supply System Test and Startup Program is administered by two entities with distinct levels of responsibility and two distinct organizations.

For the system lineup test phase and the preoperational test phase, the Test Working Group (TWG) provides review, approval, and planning of general Test and Startup Program activities and the results of those activities. The Test and Startup organization and qualified members of other organizations represented on the TWG provide the necessary development, implementation, and analysis of Test and Startup Program activities at the working level.

For the Power Ascension Test Phase, the Plant Operations Committee (POC) provides review and planning of the test program and evaluates the test results. The Plant Manager approves the procedures and final test reports. The implementation of the PATP is achieved with the normal plant operations crew operating the plant and test engineers under the direction of the Reactor Engineering Supervisor coordinating the test activities.

14.2.2.2 Definitions

The definitions of phrases used in this section and throughout this chapter are as follows:

a. *Test Working Group (TWG) - a project onsite administrative body whose membership consists of personnel representing organizations directly responsible for preparation and performance of testing and startup during the system lineup and preoperational test phases. This group provides review and approval of test preparation and performance activities.*

b. *Power Generation - a Supply System organization within the Operations Directorate with responsibility for development and implementation of the Test and Startup Program.*

c. *WNP-2 Test and Startup - a Power Generation division with responsibility for development and implementation of the WNP-2 Test and Startup Program.*

d. *WNP-2 Plant Organization - a Power Generation division with responsibility to startup, operate, and maintain WNP-2 in compliance with Federal, State, local, and owner requirements.*

e. *Plant Operations Committee (POC) - refer to definition in Section 13.4.1. The POC reviews the activities of the Power Ascension Test Phase.*

f. *Test and Startup Manager - the Power Generation Division Manager with responsibility for implementation of the WNP-2 Test and Startup Program.*

g. *Test and Startup Program - the program that encompasses the transition from construction to commercial operation and consists of system lineup testing, preoperational testing, and power ascension testing.*

h. *Test and Startup Program Manual - the manual that defines generic administrative policy and procedures for the initial testing and startup of WPPSS nuclear facilities.*

i. *Test and Startup Instructions - the specific instructions required to implement the Test and Startup Program for an individual project.*

j. *Plant Procedure Manual (PPM) - the Plant Manager approved procedures for operating the plant. The PPMs include the test procedures for the PATP.*

14.2.2.3 *Test and Startup Program Organization and the System Lineup and Preoperational Test Program*

14.2.2.3.1 *General*

Power Generation is an organization within the Supply System Operations Directorate. Relative to the Program, Power Generation is responsible for development and administration of plans, policies, and administrative procedures; procurement of test equipment and other test-related resources, and assignment of the WNP-2 Test and Startup Manager. The Power Generation organization and its relationship to other Supply System organizations is shown in Figure 14.2-2.

14.2.2.3.2 *Responsibilities of WNP-2 Test and Startup Division*

WNP-2 Test and Startup is a Division of the Power Generation organization. The WNP-2 Test and Startup Manager manages an organization comprised of Supply System test engineers and test technicians augmented by test personnel from the architect-engineer, the NSSS supplier, and others as contractually established. The WNP-2 Test and Startup Manager is responsible for the development and implementation of the WNP-2 Test and Startup program and those responsibilities are described in Section 14.2.2.3.3. The WNP-2 Test and Startup staff organization is shown in Figure 14.2-3.

14.2.2.3.3 *WNP-2 Test and Startup Department Position Responsibilities*

14.2.2.3.3.1 *WNP-2 Test and Startup Manager.*

a. *Chairman, TWG;*

b. *Develop plans, schedules, methods, procedures, and data systems for the testing and evaluation of all plant equipment and systems to permit acceptance and licensing;*

c. *Administer and coordinate the testing activities with other organizations involved in the Test and Startup Program;*

d. *Manage and direct assigned test personnel in activities relating to the attainment of Test and Startup Program objectives;*

e. *Manage and direct assigned test personnel to establish qualitative and quantitative acceptance criteria and develop test procedures to direct and guide performance of testing, and*

f. *Provide recommendations and effect actions to eliminate equipment or system deficiencies as determined by Test and Startup Program criteria which could adversely affect performance of safety-related functions.*

14.2.2.3.3.2 WNP-2 Test Group Manager.

a. *Represent Test and Startup on the TWG;*

b. *Coordinate the activities of Test Group Supervisors and test engineers during the Test and Startup Program;*

c. *Develop, monitor, and coordinate the preparation and implementation of plans, schedules, methods, and procedures for testing and evaluation of plant systems and components for verification of performance and acceptance;*

d. *Maintain surveillance over testing performed by Supply System and others, including system and equipment tests, and calibration of instrumentation;*

e. *Identify problem areas and recommend actions where deficiencies could adversely affect the performance, safety-related functions, or operating efficiency;*

f. *Assist in preparation of program status and other Test and Startup Program related reports, and*

g. *Assume the responsibilities of the Test and Startup Manager as described in the Test and Startup Program Manual (TSPM) during his absence and all other responsibilities specifically delegated.*

14.2.2.3.3.3 WNP-2 Test Group Supervisor. Test Group Supervisors are assigned lead technical responsibility for testing. General Test Group Supervisors' duties are as follows:

a. *Supervise the activities of assigned test engineers;*

b. *Review and, where appropriate, approve test procedures, field changes to procedures and test results, and make recommendations to the Test Group Managers or Startup Manager, as appropriate;*

c. *Set schedules and priorities for assigned Test Engineers and assist them with problem resolution;*

d. With other Test Group Supervisors and the Test Group Manager or Startup Manager, as appropriate, plan and coordinate startup activities and provide assistance;

e. Advise the Test Group Manager or Test and Startup, as appropriate, on all matters concerning testing within their group and if required, attend TWG meetings for this purpose;

f. Act for the Test Group Manager or Test and Startup Manager, as appropriate, when so delegated;

g. Prepare for and perform testing as required to support the Test and Startup Program;

h. Coordinate the identification and documentation of design problems and their resolution, and

i. Advise the Test Group Manager or Test and Startup Manager, as appropriate, regarding current and future manpower requirements impacting the testing effort.

14.2.2.3.3.4 WNP-2 Test Engineers. Test engineers provide for the routine development and implementation of testing. General test engineer duties are as follows:

a. Prepare assigned test procedures,

b. Review tests and inspections prepared by others for application to assigned testing responsibilities,

c. Provide direction during performance of system and component testing, and

d. Identify problem areas and recommend actions where deficiencies could adversely affect performance of safety-related functions or operating efficiency.

14.2.2.4 Plant Operations Organization and the Power Ascension Test Program

The PATP will be carried out by the plant operations organization using test procedures developed and approved according to the requirements of the PPM. The PATP procedures were prepared by members of the plant technical department under the supervision of the Reactor Engineering Supervisor. Technical expertise from other Supply System organizations and from the General Electric Company (GE), the NSSS vendor, was used whenever necessary. Review of these procedures and scheduling of the test activities will be carried out by the POC

and approved by the Plant Manager. The Reactor Engineering Supervisor will direct the PATP test engineers in the completion of testing according to the POC schedule.

14.2.2.5 *Test Working Group*

14.2.2.5.1 *System Lineup and Preoperational Test Program*

The purpose of the TWG, a composite of representatives from organizations directly responsible for preparation, performance, and review of Test and Startup Program activities, is to provide a means for a coordinated review of all testing concerns and ensuring all obligations to the Test and Startup Program are met by the organizations represented.

The TWG provides review and approval of all activities proposed and the results thereof as appropriate. All decisions and approvals or recommendations of the group are included in the minutes of the meetings. Matters requiring approval by the TWG includes, but are not limited to

a. System lineup procedures,
b. Preoperational test procedures,
c. Changes to test procedures, and
d. Results of testing.

14.2.2.5.2 *Membership and Responsibility of the Test Working Group*

The TWG membership consist of organizations that have a direct support function for conduct or development of testing.

The WNP-2 Test and Startup Manager is Chairman of the TWG and is responsible for convening and conducting TWG meetings on the administrative and technical content of program activities.

The Test Group Manager is responsible for providing a technical review of the proposed activities, technical documents, and their results. The Test Group Manager serves as Chairman during the absence of the Test and Startup Manager.

The WNP-2 Plant Manager is responsible for providing an operational review of test documents and for submitting safety-related documents to the POC for review and for communicating the committee's decisions to the TWG. The Plant Manager provides detailed plant operating procedures and surveillance procedures to be used for plant operation and testing during the Test and Startup Program system lineup and preoperational test phase.

The plant quality assurance representative to the TWG shall be responsible for review of proposed activities, test procedures, and test results as required by the Operational Quality Assurance Program Description (OQAPD).

The project engineering representative is responsible for obtaining a technical review of proposed activities and test documents by assigned project engineers and for providing a working relationship with Supply System and architect-engineering organizations to aid resolution of testing concerns.

Conditional Members are representative of any organization having responsibility and/or expertise in the area of the TWG meeting agenda. In this situation the representative will be requested to attend the meeting by the TWG chairman.

14.2.2.6 *Plant Organization Functions and Responsibilities During All Testing and Plant Operations*

The plant organization has overall responsibility for the safe and efficient operation of plant systems and equipment, from provisional acceptance through commercial operation including responsibility for maintenance and operational control. Plant organization responsibilities in supporting the Test and Startup Program are discussed in Section 14.2.2.7.1.

The responsibility of the plant organization representative to the TWG is defined in Section 14.2.2.5.2.

14.2.2.7 *Supply System Support of the Test and Startup Program*

14.2.2.7.1 *Plant Organization*

In addition to the responsibilities described in Section 14.2.2.6, the plant operating, technical, and maintenance sections provide manpower for development, implementation, and review of testing.

14.2.2.7.1.1 *Support During Test and Startup Program Development. Assistance during the development of the Test and Startup Program is provided formally through the plant organization's TWG representative and through the POC. Input to test procedures and other testing documentation by the plant staff ensures that*

a. *The operational requirements of the test procedures are based on the knowledge and experience of the operating staff,*

b. *The technical considerations receive the review of the Plant Technical Staff, and*

c. *Important nuclear and operational safety considerations receive attention by the plant organization.*

14.2.2.7.1.2 Support During Testing. Detailed review and analysis of system lineup and preoperational test results will be performed by the plant technical section and/or plant operations section where their particular expertise is deemed necessary by the plant representative to the TWG to support approvals of completed system lineup and preoperational tests.

Detailed review and analysis of PATP test results will be carried out by the test engineers of the plant operations technical department and will receive final review through the POC and final approval by the Plant Manager.

14.2.2.7.2 WNP-2 Program

The WNP-2 Program Director is responsible for the performance of the organizations involved in the design, procurement, and construction of generating projects. The Program Director supports the Test and Startup Program by providing and implementing project control systems, project engineering services, and engineering support services.

The WNP-2 Program Director supports the Test and Startup Program by maintaining a high level of current status information available to the startup program organizations to ensure that all startup program scheduling and preparation is based on an accurate assessment of the condition of systems and equipment being readied for testing. The Program Director provides liaison with Construction Management for the provision of construction craft support for the implementation of various system lineup and preoperational tests.

14.2.2.7.3 Plant Quality Assurance

The functions of the plant Quality Assurance organization during the Test and Startup Program will be to survey ongoing efforts to determine that the controls required by various regulations, guides, and standards are effectively implemented. The activities of the TWG will be monitored to ensure that the proper degrees of control for safety-related activities are being maintained and that required activities are completed when they are prerequisite to another testing activity.

14.2.2.8 Architect-Engineer Support of the Test and Startup Program

Burns and Roe, Inc., is responsible for providing engineering services required to ensure timely completion of construction testing and equipment turnover for provisional acceptance and system turnover. Burns and Roe also provides system-oriented engineers to assist the WNP-2 Test and Startup Divisions, as requested by the Supply System technical direction

and/or advice and consultation during system and component testing through preoperational testing.

14.2.2.9 General Electric Support of the Test and Startup Program

General Electric is the supplier of the boiling water reactor (BWR) NSSS for the WNP-2 plant. General Electric is responsible for generic and specific WNP-2 designs and for the supply of the NSSS. During the construction phase of the plant cycle, the GE Resident Site Manager is responsible for all NSSS equipment disposition. When the startup testing phase of the project begins after fuel load, the responsibility of GE-NSSS activities are assigned to the Preoperational and Startup group. The GE Preoperational and Startup staff responsibilities are outlined below.

14.2.2.9.1 Staff Responsibilities

14.2.2.9.1.1 General Electric Operations Manager. The GE Operations Manager is the senior NSSS vendor representative onsite at or near official fuel loading, and is the official site spokesman for GE for preoperational and startup testing concerns and requirements. The Operations Manager coordinates with the Startup Superintendent for the performance of his duties, which are as follows:

a. *Reviewing all NSSS test procedures, including changes to test procedures, and test results as a conditional member of TWG and POC,*

b. *Providing technical direction to the station staff,*

c. *Managing the activities of the GE site personnel in providing technical direction to WNP-2 personnel in the testing and operation of GE-supplied systems,*

d. *Providing liaison between the site and the GE San Jose home office to provide rapid and effective solution to problems that cannot be solved onsite,*

e. *Participating as a conditional member of the TWG when required, and*

f. *Reviewing test procedures for the POC.*

14.2.2.9.1.2 General Electric Operations Superintendent. The GE Operations Superintendent is responsible to the GE Operations Manager for supervising the activities of GE Shift Superintendents. He works directly with the WNP-2 Operations Manager in providing GE technical direction to the operating organization.

14.2.2.9.1.3 General Electric Shift Superintendents. The GE shift superintendents provide technical direction to WNP-2 shift personnel in the testing and operation of GE-supplied

systems. They provide 24-hr per day shift coverage as required beginning with fuel loading. They report to the GE Operations Superintendent.

14.2.2.9.1.4 General Electric Lead Engineer - Startup Test, Design, and Analysis. The GE lead engineer - Startup Test, Design, and Analysis, is responsible to the GE Operations Manager for supervising the GE shift engineers and for verifying core physics parameters and characteristics and documenting that performance of the NSSS and components conform to test acceptance criteria.

The lead engineer works with the WNP-2 technical department to coordinate and effect implementation of the PATP instrumentation including special test equipment required to confirm these acceptance criteria.

14.2.2.10 Qualifications of Personnel Supporting the Test and Startup Program

The qualifications described in this section are for those persons having authority to direct testing, review and approve test documentation and results, or otherwise have direct influence on the conduct of testing and quality of acquired data. Although other personnel, specifically GE, Burns and Roe, and Supply System technical specialists, are also involved in these processes, they are under the direction of individuals whose qualifications are described herein and who review and approve all Test and Startup Program activities.

14.2.2.10.1 Test and Startup Program Department Personnel Qualifications

a. *At the time of appointment to the active position, the WNP-2 Test and Startup Manager shall have 10 years of responsible thermal power plant experience such as, but not limited to, managerial, technical, or administrative positions, of which a minimum of 3 years shall be nuclear power plant experience. A maximum of 4 years of the remaining 7 years of experience may be fulfilled by academic training on a one-to-one basis. This academic training shall be in engineering or the individual shall have acquired the experience and training normally required for examination by the NRC for a senior operator license whether or not the examination is taken.*

b. *Minimum qualifications for Test Group Manager are a B.S. degree in engineering or related field and 6 years of applicable experience, at least 3 of which are in testing or operation of nuclear power generation, propulsion, or similar scale test or production facilities. Related experience may be substituted for academic requirements when the candidate's professional background and level of achievement clearly demonstrate capabilities to fill the position. Previous preoperational testing experience is required. A good understanding of quality assurance and regulatory requirements and an ability to effectively communicate with others are necessities. A demonstrated technical leadership*

in his discipline and necessary work experience at the Test Group Supervisor or equivalent level is evidence of required proficiency.

c. *Minimum qualifications for Test Group Supervisor are a B.S. degree in engineering or related field and 5 years of applicable experience, at least 2 of which are in testing or operation of nuclear power generation, propulsion, or similar scale test or production facilities. Related experience may be substituted for academic requirements when the candidate's professional background and level of achievement clearly demonstrate capabilities to fill the position. Previous preoperational testing experience is required. A good understanding of quality assurance and regulatory requirements and an ability to effectively communicate with others are necessities. A demonstrated technical leadership in his discipline and necessary work experience at the Senior Test Engineer or equivalent level is evidence of required proficiency.*

d. *Minimum qualifications for a Test Engineer directing preoperational tests are a B.S. degree in engineering or related field or a graduate of a technical or vocational school in an engineering or related field and 2 years of related experience. Related experience above the required minimum may be substituted for academic requirements when the candidate's record for performance clearly indicates the ability to fill the position without question. A good understanding of engineering principles and the ability to understand new concepts and to effectively communicate with others is a necessity.*

Minimum requirements for a Test Engineer directing startup tests are a B.S. degree in engineering or related field and 2 years of related experience or a graduate of a technical or vocational school in an engineering or related field, and 3 years of related experience. Related experience above the required minimum may be substituted for academic requirements when the candidate's record for performance clearly indicates the ability to fill the position without question. A good understanding of engineering principles and the ability to understand new concepts and to effectively communicate with others is a necessity.

14.2.2.10.2 Plant Organization Personnel Qualifications

Qualifications of some plant personnel are discussed in Section 13.1.3.

14.2.3 TEST PROCEDURES

14.2.3.1 Development of Test Procedures

Test Procedures are developed by the WNP-2 Test and Startup or Plant Operations Department to provide a detailed method to demonstrate the capability of the system to perform its design function under anticipated operating and accident condition.

General Electric Company as supplier of the NSSS provides test program specifications and instructions from which the Supply System prepares the preoperational and initial startup test procedures for systems supplied by GE.

Architect-Engineer and Vendors

Technical assistance is provided by Burns and Roe and vendor technical representatives as deemed necessary.

14.2.3.1.1 Incorporation of Plant Procedures

The following program will be implemented at WNP-2 to utilize and qualify plant operating procedures during testing.

- *a. Plant procedures required to support testing will have been prepared and approved before preoperational testing begins on the system using the best information available from the principal designer and responsible equipment suppliers.*
- *b. Preoperational test procedures will use plant operating and emergency procedures as nearly as possible.*
- *c. Using the results of preoperational testing, including the use-testing of plant procedures where practical, the plant procedures required to support startup testing will be updated and revised before startup testing of applicable systems. Exceptions to this program will be those approved plant procedures required to be verified during the startup phase.*
- *d. Startup test procedures will be developed using the results of preoperational testing and updated plant procedures.*

14.2.3.1.2 Format of Test Procedures

14.2.3.1.2.1 Preoperational Test Phase. The minimum content requirements for WNP-2 Preoperational test procedures are specified in the Supply System TSPM. The format for

WNP-2 test procedures is specified in the WNP-2 TSPM. The resulting format and content is the following:

a. *Preoperational Test Procedure Format*

1. *Purpose*

A concise description of the objectives of the test, including such test requirements as component functions to be checked and testing under normal or simulated conditions to verify readiness for system startup and operation, and system tests to confirm that the performance of the system is in compliance with all applicable design requirements.

2. *Prerequisites*

Provisions necessary for performance of the test. Conditions that should exist prior to start of the test. Instructions given to identify required operational status of the plant and interfacing systems, environmental conditions, and individual component status requirements, including verification of the following:

(a) *Components and systems being tested have been turned over and open deficiencies will not affect the performance of the test,*

(b) *System lineup testing on components, included in the test, is complete,*

(c) *Necessary support systems are available, and*

(d) *For control system testing, the other principal control systems are in appropriate operating modes for the given test conditions.*

3. *Limits and Precautions*

Special precautions required for safety of personnel and equipment or needed to ensure a meaningful test and satisfactory performance of testing.

4. *Special Equipment*

A list of special material and equipment for the performance of the test.

5. Procedure

A step by step procedure for performing the test. Plant operating procedures will be utilized whenever practicable for the operation of systems and equipment during testing and for returning the system to normal after completion of testing. Abnormal procedures will be utilized as required to supplement normal plant operating procedures. Data collection will be part of the procedure steps.

6. Restoration

Includes those steps necessary to return the system to a normal operating or tagged status. This may include removal of special test instruments, temporary equipment, electrical jumpers, valve lineups, etc.

7. Acceptance Criteria

The criteria against which the success or failure of the test will be judged must be identified. In some instances, these will be qualitative criteria, e.g., given event does or does not occur. In other cases, quantitative values can be designated as acceptance criteria.

(a) *All quantitative acceptance criteria shall include suitable tolerances, and*

(b) *A readily apparent correlation should exist to cross-reference among procedure steps, data, and acceptance criteria.*

8. References

A listing of all material required for the preparation and performance of the test. This should include piping and instrumentation drawings, electrical elementary drawings, vendor instruction manuals, applicable FSAR sections, contract specifications, and applicable codes, standards or guides, and applicable plant procedures.

14.2.3.1.2.2 Power Ascension Test Phase. All PATP procedures will be formatt

14.2.3.2 Review of Test Procedures

Each member of the TWG ensures test procedures will provide for review with respect to that member's organizational area of responsibility. Power ascension test procedures will be reviewed by the POC.

Comments submitted by TWG members will be evaluated by the TWG and the test procedure revised accordingly. After discussion of the resulting version, the decision to reject, accept, or accept with modification, will be obtained by consensus of the membership of the TWG. In the event the TWG cannot reach a consensus, the Chairman shall provide resolution or a method for resolving the issue to the appropriate division management for review and concurrence.

The results of the POC review of PATP will be approved by the Plant Manager.

The qualifications of the individuals or organization representatives reviewing test procedures are described in Section 14.2.2.10.

The administrative procedures governing the test procedure review process are contained in the WNP-2 TSPM. These procedures cover the mechanism for review and comment resolution, documentation of this review, and method of indication for the review status of a test procedure.

14.2.3.3 Approval of Test Procedures

Test procedures will be approved by the TWG Chairman by means of consensus of the TWG membership after review of the test procedure as described in Section 14.2.3.2. Power ascension test procedures will be reviewed by the POC in a similar manner.

Individual test procedures will be approved by the chairman of the TWG or POC/Plant Manager, as appropriate. The consensus of the two committees were contained in the meeting minutes.

The administrative procedures governing the exercise of approval of test procedures are contained in the WNP-2 TSPM or the PPM.

14.2.4 CONDUCT OF TEST PROGRAM

14.2.4.1 Administrative Procedures for Preoperational Testing

14.2.4.1.1 Test Performance Authorization

A significant period of time may have elapsed between the time a preoperational test procedure was approved and the time a test is performed. The test procedure is therefore reviewed just

prior to initiating the test. Any changes in the system since original approval of the test procedure will be thoroughly researched and the test procedure revised and approved in accordance with Sections 14.2.3.2 and 14.2.3.3. The WNP-2 Test and Startup Manager will then approve the test procedure for performance of the test.

14.2.4.1.2 Preoperational Test Prerequisites

Approval by the Test and Startup Manager to perform a preoperational test also requires consideration of the prerequisite testing required to qualify components and systems for operation. In general, completion of the system lineup testing (see Section 14.2.1.3) will qualify the system for preoperational testing. System lineup testing, as a prerequisite to preoperational testing, includes the following:

a. Instrumentation and protective relay checks, including calibration, setpoint adjustments, logic verification, and line checks;

b. Component operability checks, including valve stroking, motor rotation, ventilation system balancing, rotating equipment run-in and pipe support inspection and adjustment;

c. Flushing, including proof flushes, flow instrumentation response, and pump performance and capacity checks;

d. Electric component and system checks, including breaker trip setpoints; and

e. Hydrostatic or pneumatic pressure tests and systems where dynamic testing, such as pump runs, are required to allow performance of pressure tests. Pressure integrity tests are otherwise performed during construction testing.

Verification that required system lineup tests have been or can be successfully completed prior to preoperational testing is performed by the respective test group manager prior to recommending turnover of a system or component from a contractor to the Supply System. Verification that the system is actually ready for preoperational testing will be performed as described in Section 14.2.4.3.

14.2.4.1.3 Conduct of Preoperational Testing

a. Implementation responsibilities for scheduling all tests are assigned to the WNP-2 Test and Startup Manager. The TWG will be kept informed of the scheduled activities.

b. *The satisfaction of prerequisites to commencement of the test, as indicated in the test procedure, will be verified by the test engineer prior to performance of the test.*

c. *The assigned test engineer is responsible for directing the performance of each test. Testing is performed in direct coordination between the test engineer and shift supervision.*

d. *All testing will be conducted in accordance with approved test procedures. If, during the performance of a test the procedure is unacceptable, the test engineer can propose changes by use of a "Test Change Notice" (see Section 14.2.4.4). This provided both documentation of the change and confirmation by the TWG.*

e. *All test data will be entered on or attached to the record copy of the test procedure.*

14.2.4.1.4 Deficiency Reporting

Deficiencies or discrepancies identified during testing will be reported individually as described in Section 14.2.5.2.

Corrective action or satisfactory disposition shall be taken on all deficiencies and discrepancies in equipment and procedures prior to final approval of the preoperational test results. All deficiencies or discrepancies identified during the test, or which have not been resolved on completion of the test, will be recorded in the record copy of the preoperational test.

14.2.4.1.5 Equipment Maintenance and Modifications During Preoperational Testing

Modifications or repair to safety-related systems will be implemented as a result of a formal system of problem and deviation reporting. Disposition of problems requiring mechanical or electrical changes or repairs by contractors will be implemented by work requests.

a. *Startup Problem Reports (SPR), Startup Deficiency Reports (SDR), and Startup Work Requests (SWR) are administered through closed-loop procedural controls to ensure resolutions. A completed SPR, SDR, and SWR is approved for closure by the respective Test Group Manager.*

b. *Startup Problem Reports are used to report design deficiencies and are coordinated by the Supply System project engineering organization for resolution by the responsible design organization or qualified alternate. The SPRs are reviewed by engineering and a Project Engineering Directive (PED) is issued to define plant modifications or changes that are required. An SWR is*

then issued to perform the plant modification by contractor personnel or an SDR is issued to defer the work or have it performed by startup personnel.

c. *Startup Deficiency Reports (SDR) are used to report and track non-design-related deficiencies. If required, an SWR will be issued to perform the repair work to resolve the non-design-related deficiency by contractor personnel. Work accomplished by startup personnel can be accomplished by the SDR without issuing an SWR.*

d. *Retest requirements will be identified on the SWR or SDR and attached to, or referenced by the work request number in test files.*

e. *Startup Problem Reports, SDR, SWR, design change documentation, retest results, and procurement records for safety-related systems will be filed in assembled packages or with appropriate cross-referencing for retrievability.*

14.2.4.1.6 Preoperational Test Summary

During the preoperational test, the test engineer will prepare a test report which includes a summary of the conduct of the test, evaluation of the test results with reference to the acceptance criteria, and a description of problems encountered and corrective actions taken or proposed. This report will be attached to the record copy of the test.

14.2.4.1.7 Evaluation of Preoperational Test Data

On completion of the test, a copy of the official test procedure, data, the test summary, and other applicable attachments will be transmitted to each member of the TWG responsible for review.

14.2.4.1.8 Preoperational Test Records

The Test and Startup Manager will maintain all official test records (the copy of the test procedure containing the original test data and signatures and all attachments) until completion of the test program. See Section 14.2.6 for details of the test records handling and retention program.

14.2.4.2 Administrative Procedures for Power Ascension Testing

14.2.4.2.1 Plant Operation During Power Ascension Testing

During initial startup tests and operations, the plant procedures are followed except as specifically modified by approved test procedures. In addition, special safety precautions and limitations are included in the test procedures. Approved test procedures will be used to

control test conditions outside of the Technical Specifications limits where allowed for test purposes.

Certain individual tests or power escalations may require authorization by both the POC and the Plant Manager immediately prior to implementation and will be so identified in the applicable test procedure.

The final authority to start or continue a test is the responsibility of the Shift Manager after all previous approvals have been exercised. Testing is performed in direct coordination between the test engineer and Shift Manager.

14.2.4.2.2 Power Ascension Test Scheduling and Sequencing

Scheduling and sequencing of testing during startup is performed under the direction of the Plant Manager by POC.

The startup or power ascension test sequence is described in terms of individual test evolutions and specific power plateaus due to interfaces with other simultaneous tests, requirements for continuous data review, and plant administrative requirements for authorization to proceed or continue. The test sequence identifies hold points for data review and authorization to proceed and establishes the general plant conditions for each group of tests.

14.2.4.2.3 Power Ascension Test Performance

Before starting each test, the assigned shift test engineer will review the test procedure to ensure that prerequisite activities of conditions have been satisfied as described in Section 14.2.4.3.

The test will be stopped or curtailed if it cannot be performed safely or in accordance with the approved test procedure. Required test procedure deviations or changes may be effected in accordance with PPM 1.2.3, "Use of Plant Procedures," as described in Section 14.2.4.4.2.

Should apparent deviations of test results from performance requirements or acceptance criteria be revealed, or should other apparent anomalies develop, the plant will be placed in a safe condition and relevant test data will be reviewed by the test engineer and Shift Manager. If the apparent discrepancy or anomaly is substantiated, the situation will be reviewed by the POC to ascertain if a plant safety question is involved. Control of any identified nonconformance or noncompliance will be in accordance with the plant administrative procedures.

Evaluation of the effect of the discrepancy or anomaly on plant safety will be performed at the appropriate level of review, and appropriate corrective actions will be taken before resumption of the test or test conditions at which the problem was revealed.

At the completion of an entire test procedure, the test engineer will assemble all of the data and supporting information, nonconformance documentation, and test results evaluations for review by the POC. Any data reduction or analysis required will be done as soon after the data is available as is practical so that the results of the analysis may be included in the complete test package.

Test records will be maintained as described in Section 14.2.6.

14.2.4.3 Control of Test Prerequisites

Conditions and activities prerequisite to a given test will be identified in the applicable test procedure. Prior to commencement of the particular test, the test engineer will verify that the identified prerequisites have been satisfied. The verifications will be recorded and retained as part of the test record.

The test engineer will verify that

a. *The test procedure has been approved by the appropriate committee and Plant Manager, Test and Startup Manager, or Startup Superintendent as required. The test procedure is compatible with the latest versions of material referenced in the test procedure;*

b. *The record copy of the test procedure is identical to that contained in the master file or PPM, including the latest TWG/POC approved revisions or test procedure field changes (see Section 14.2.4.4);*

c. *Prerequisite tests have been completed. If TWG and/or Plant Manager approval of a completed test is also a prerequisite, that approval will have been obtained;*

d. *The test procedure has been made available for shift operator review and familiarization. Operator support has been scheduled, as necessary;*

e. *Test equipment is available or in place as required. Calibration or other readiness requirements have been completed. System instrumentation to be used in the test has been calibrated within the required time period established for surveillance testing and/or preventative maintenance; and*

f. *Test and operating personnel involved in the performance of the test have been briefed immediately prior to starting the test.*

14.2.4.4 Modification of Test Procedures During Testing

14.2.4.4.1 System Lineup and Preoperational Test Phase

The TSPM provides a means of controlling modifications to TWG-approved test procedures during testing. This administrative procedure, contained in the WNP-2 TSPM, applies to changes made to an approved test procedure during preoperational and startup testing. The procedure does not apply to revisions made during the preparation of test procedures.

The procedure provides control of revisions which change the intent or the acceptance criteria of the test procedure.

The required changes, when identified by the responsible test engineer, are described on a special form (Test Change Notice/Procedure Deviation Form) which identifies the affected test procedure or plant procedure, justifies the change, and contains spaces for the appropriate approvals. The Test Change Notice forms became a permanent part of the test record.

A Test Change Notice for a preoperational test is reviewed by the TWG and approved by the Test and Startup Manger, TWG Chairman.

14.2.4.4.2 Power Ascension Test Phase

All test procedure details or changes must be made in accordance with PPM 1.2.3, "Use of Plant Procedures." This process requires documentation on the required forms, signatures of authorized individuals, and subsequent full POC review. The PPM 1.2.3 forms became a permanent part of the test record.

14.2.5 REVIEW, EVALUATION, AND APPROVAL OF TEST RESULTS

14.2.5.1 Control of Test Results Review

The individuals responsible for reviewing the results of particular tests will be designated by the POC or the Test and Startup Manager. These reviews will be obtained through TWG or POC members in accordance with their represented areas of responsibility. TWG members will provide names of individuals in their represented organizations who meet the requirements of Regulatory Guide 1.58, Revision 0, for evaluation of inspection and test results.

Based on the recommendations of the qualified reviewers, the completed preoperational test will be approved by the TWG. Plant Operating Committee review and Plant Manager approval of power ascension test results is required.

14.2.5.2 Design Organization Participation in Problem Resolution

Failures of tests to meet acceptance criteria and other problems discovered in the course of testing will be documented as deficiencies in accordance with the requirements of the TSPM for System Lineup and Preoperational Tests and in accordance with PPM 1.3.12, "Plant Nonconformances," for the power ascension tests. Reports of such deficiencies will indicate the parties or organizations deemed responsible for providing an acceptable resolution of the deficiency. The responsible organization will be requested to provide a resolution of the defined problem.

Documentation of the final resolution will include the recommendation of the responsible organization and a description of the measures implemented in accordance with that recommendation. Design problems will require resolution by the appropriate Supply System Technical Division Department, Project Engineering, Plant Technical Staff, or original design organization, depending on the technical nature of the problem.

14.2.5.3 Results Analysis Prerequisites to Continuation of Startup Testing

The POC will establish prerequisites for various tests, test conditions, and test phases in consideration of system or component qualification for subsequent testing. The control or prerequisites to an individual test will be as described in Section 14.2.4.3.

The POC will also require an evaluation of the data acquired during a particular test phase or plateau. The items considered in this evaluation will include, but are not limited to the following:

a. *The need for additional testing or retesting to improve assurance that a particular system or component will perform as required in subsequent testing, especially under more demanding conditions such as higher power levels,*

b. *The need for analysis of certain data to qualify measured variables or parameters for use in subsequent measurements,*

c. *The completeness of testing up to the point in question as evidenced by the documentation of the completed tests, and*

d. *The need for specific reviews and approvals of particular sets of data to satisfy the above.*

14.2.6 TEST RECORDS

14.2.6.1 System Lineup and Preoperational Test Phase

14.2.6.1.1 General

The TSPM contains a generic procedure regarding filing and recordkeeping to be applied to testing documentation. This procedure is intended to ensure compliance of Supply System project startup programs with the applicable provisions of ANS N45.2.9-1974, "Requirements for Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records," as required by Regulatory Guide 1.88, Revision 1, December 1975.

The following sections describe the provisions of the aforementioned procedure, which will be contained in specific detail in the WNP-2 Test and Startup Instructions.

14.2.6.1.2 Test Record Responsibilities

The Test and Startup Manager is responsible for identifying the responsibilities, controls, and requirements for establishing and implementing a Test and Startup Program filing and recordkeeping system, in accordance with 10 CFR 50 Appendix B, ANSI N45.2.9, and the Supply System Quality Assurance Program Manual. The Test and Startup Manager will ensure that adequate procedures are prepared and maintained within the Test and Startup Instructions. The Test and Startup Manager will ensure that trained and qualified personnel maintain the Test and Startup Program files.

14.2.6.1.3 Types of Documents and Records Requiring Test Record File Retention

Documentation and records that will be maintained within Test and Startup Program files are:

- *a. Test and Startup program records as specified by ANSI N45.2.9, and*
- *b. All records and documents as specified by the Test and Startup Program and instruction manuals.*

Other records, documents, correspondence, etc., may be maintained at the discretion and approval of the Startup Program Manager, provided their access requirements do not compromise the security of the mandatory files.

14.2.6.2 Power Ascension Test Phase

All test records and data shall be kept and filed in accordance with the PPM 1.6 series of procedures which detail the requirements for all plant recordkeeping.

14.2.7 CONFORMANCE OF TEST PROGRAMS WITH REGULATORY GUIDES

14.2.7.1 Conformance with Regulatory Guide 1.68

The WNP-2 Test and Startup Program conforms to the requirements of Regulatory Guide 1.68, Revision 0, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," except where specifically noted otherwise. The Regulatory Guide has been reviewed by the Supply System for applicability of individual items in the guide to WNP-2 and its systems. The applicability to this plant has determined the nature and scope of testing to be performed. Actual exceptions to the testing required by this guide have been specifically addressed and are discussed in Section 14.2.7.2. Areas where the guide does not apply are not considered to be exceptions.

14.2.7.2 Exceptions to Regulatory Guide 1.68

The exceptions to Regulatory Guide 1.68 are listed below with an explanation of the justification for the exception.

a. *Exception to Format of Test Procedures*

   The format of the test procedures is different from that found in Appendix C of Regulatory Guide 1.68, but the format difference is not considered an exception to the regulatory guide since the guide specifies required elements of a test procedure while merely implying but not requiring a format.

b. *See Section 1.8.2 for a delineation of specific exceptions to the requirements of Regulatory Guide 1.68.*

14.2.7.3 Conformance With or Exceptions to Regulatory Guides Other Than 1.68

a. *Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants" will be complied with for the section that pertains to the Test and Startup Program,*

b. *Regulatory Guide 1.33, "Quality Assurance Program Requirements" will be complied with in "Quality Assurance During the Operations Phase," Section 17.2, of the FSAR for the Test and Startup Program,*

c. *All other regulatory guides pertaining to individual testing will be complied with unless noted otherwise in Section 14.2.12, and*

d. *Regulatory Guide 1.58 "Qualifications of Nuclear Power Plant Inspection, Examination, and Testing Personnel." Supply System Test and Startup personnel involved in testing meet the requirements of Regulatory Guide 1.58.*

14.2.8 UTILIZATION OF REACTOR OPERATING AND TESTING EXPERIENCES IN THE DEVELOPMENT OF THE TEST PROGRAM

As a matter of Supply System policy, a continuous program of review of reactor operating experience is coordinated by the Operations Division of the Supply System. The sources of information reviewed in compliance with this policy are NRC Information Notices and Bulletins, operating experience reports, preoperational test summaries and startup reports from other plants, administrative and test procedures from other plants' startup programs, personal contacts with other nuclear plant licensees or applicants, and additional information supplied by Supply System Technical and Operations Division members. All available sources are utilized; relevance to particular Supply System nuclear projects is determined in the review process.

The information is reviewed by WNP-2 Startup Program personnel for applicability to the WNP-2 Test and Startup Program, for incorporation into test procedures, or for consideration in the administrative control of testing.

14.2.9 TRIAL USE OF PLANT OPERATING AND EMERGENCY PROCEDURES

To the extent practical throughout the preoperational and initial PATP, test procedures utilize operating, emergency, and abnormal procedures where applicable in the performance of tests. The use of these procedures is intended to do the following:

a. *Prove the specific procedure or illustrate changes which may be required,*
b. *Provide training of plant personnel in the use of these procedures, and*
c. *Increase the level of knowledge of plant personnel on the systems being tested.*

Test procedures may use operating, emergency, and abnormal procedures in several ways: the test procedure may reference the procedure directly; the test procedure may extract a series of steps from the procedure; the test procedure may use a combination of the first two methods; or the test procedure may require system and plant conditions that will be obtained by the use of plant operating or emergency procedures.

14.2.10 INITIAL FUEL LOADING AND INITIAL CRITICALITY

14.2.10.1 Fuel Loading and Shutdown Power Level Tests

Fuel loading and initial criticality is conducted in accordance with written procedures after all prerequisite tests are satisfactorily completed and an operating license has been issued. Prior

to approving fuel loading, the plant must be verified as ready to load fuel. This verification is accomplished by the following steps, which are performed at the completion of a majority of the preoperational testing.

14.2.10.1.1 Loss of Power Demonstration-Standby Core Cooling Required

This test demonstrates the capability of each emergency diesel generator to start automatically and assumes all of its emergency core cooling loads in a loss of normal auxiliary power.

14.2.10.1.2 Cold Functional Testing

The cold functional testing defined here is an integrated system operation of various plant systems that can be operated as systems prior to fuel loading. The intent is to observe any unexpected operational problems from either an equipment or a procedural source and to provide an opportunity for operator familiarizations with the system-operating procedures under operating conditions.

Some of the cold functional testing will be accomplished during the preoperational test program. For example, integrated and simultaneous operation of the following systems may take place during the flush of the total system: condensate system, condensate demineralizer system, low-pressure coolant injection (LPCI) system, core spray system, reactor water cleanup (RWCU) system, service water system, closed cooling water (RCC) system, and others. As required, additional integrated systems performance will be demonstrated prior to fuel loading.

14.2.10.1.3 Routine Surveillance Testing

Because of the interval between completion of a preoperational test on a system and the requirement for that system to be operated may be of considerable length, a number of routine surveillance tests must be performed prior to fuel loading and must be repeated on a routine basis. The Technical Specifications described the test frequency. In general, this Surveillance Test Program (specified in the Technical Specifications) is instituted prior to fuel loading by the plant operating staff.

14.2.10.1.4 Master Startup Checklist

A detailed list of items that must be complete, including the preoperational tests, work requests, design changes, and proper dispositioning of all exceptions noted during preoperational testing listed in Table 14.2-1 is rechecked to verify completion just prior to the final approvals for fuel loading and at each significant new step such as heat up, opening main steam isolation valves (MSIVs), and power operation.

14.2.10.1.5 Initial Fuel Loading

Fuel loading requires the movement of the full core complement of assemblies from the fuel pool to the core, with each assembly identified by number before being placed in the correct coordinate position. The procedure controlling this movement is arranged so that shutdown margin and subcritical checks are made at predetermined intervals throughout the loading, thus ensuring safe loading increments. Specially sensitive invessel neutron monitors that are maintained at the loading face as loading progresses serve to provide indication for the shutdown margin measurements, and also to allow the recording of the core flux level as each assembly is added. A complete check is made of the fully loaded core to ascertain that all assemblies are properly installed, correctly oriented, and are occupying their designated positions.

14.2.10.1.6 Zero Power Level Tests

At this point in the program, a number of tests are conducted which are best described as initial zero power level tests. Chemical and radiochemical tests are made to check the quality of the reactor water before fuel is loaded, and to establish base and background levels required to facilitate later analysis and instrument calibrations. Plant and site radiation surveys are made at specific locations for later comparison with the values obtained at the subsequent operating power levels. Shutdown margin checks are repeated for the fully loaded core, and criticality is achieved with each of the two prescribed rod sequences in turn, the data being recorded for each rod withdrawn. Each rod drive is subjected to scram and performance testing. The initial setting of the intermediate range monitors (IRMs) is at maximum gain.

14.2.10.2 <u>Initial Heatup to Rated Temperature and Pressure</u>

Heatup follows the satisfactory completion of the fuel loading and zero power level tests (Sections 14.2.10.1.5 and 14.2.10.1.6) and further checks are made of coolant chemistry together with radiation surveys at the selected plant locations. All control rod drives (CRDs) are scram-timed at rated temperature and pressure, with selected drives timed at two intermediate reactor pressures and for different accumulator pressures. The process computer checkout continues as more process variables become available for input. The reactor core isolation cooling (RCIC) system will complete controlled starts at low reactor pressure and at rated conditions, with testing in the quick-start mode at 150 psig and 1000 psig. Correlations are obtained between reactor vessel temperatures at several locations and the values of other process variables as heatup continues. The movements of NSSS piping in the drywell mainly as a function of expansion are recorded for comparison with design data.

14.2.10.3 <u>Power Testing From 25% to 100% of Rated Output</u>

The power test phase comprises the following tests, many of which are repeated several times at the different test levels; consequently, see Table 14.2-4 for the series. While a certain basic

order of testing is maintained relative to power ascension, there is, nevertheless, considerable flexibility in the test sequence at a particular power level which may be used whenever it becomes operationally expedient. In no instance, however, is nuclear safety compromised.

a. *Coolant chemistry tests and radiation surveys are made at each principal test level to preserve a safe and efficient power increase,*

b. *Selected CRDs are scram-timed at various power levels to provide a correlation with the initial data,*

c. *The effect of control rod movement on other parameters (e.g., electrical output, steam flow, and neutron flux level) is examined for different power conditions,*

d. *Following the first reasonable, accurate heat balance (25% power) the average power range monitors (APRMs) are calibrated and IRMs are reset if necessary,*

e. *At each major power level (25%, 60%, and 100%), the low pressure range monitors (LPRMs) are calibrated,*

f. *The APRMs are calibrated initially at each new power level and following LPRM calibration,*

g. *Completion of the process computer checkout is made for all variables, and the various options are compared with hand calculations as soon as significant power levels are available,*

h. *Further tests of the RCIC are made with and without injection into the reactor pressure vessel (RPV),*

i. *Collection of data from the system expansion tests is completed for those piping systems which had not previously reached full operating temperatures,*

j. *The axial and radial power profiles are explored fully by means of the traversing in-core probe (TIP) system at representative power levels during the power ascension, and*

k. *Core performance evaluations are made at all test points above the 10% power level and for selected flow transient conditions; the work involves the determination of core thermal power, maximum fuel rod surface heat flux, and minimum critical power ratio (MCPR), and other thermal parameters.*

l. *Overall plant stability in relation to minor perturbations is shown by the following group of tests which are made at selected test points:*

1. *Core power-void mode response,*
2. *Pressure regulator setpoint change,*
3. *Water level setpoint change,*
4. *Turbine valve surveillance, and*
5. *Recirculation flow setpoint change.*

For the first of these tests, a centrally located control rod is moved and the flux response is noted on a selected LPRM chamber. The next two tests require that the changes made should approximate as closely as possible a step change in demand, while for the next test the turbine stop, control, and bypass valves are opened to verify stability and power level for surveillance testing. The remaining test is performed to properly adjust the control loop of the recirculation system. For all of these tests the plant performance is monitored by recording the transient behavior of numerous process variables, the one of principal interest being neutron flux. Other imposed transients are produced by step changes in demand core flow, partial loss of feedwater heating, and simulating failure of the operating pressure regulator to permit takeover by the backup regulator. Table 14.2-3 shows the power and flow levels at which all these stability tests are performed.

m. *The category of major plant transients includes full closure of all the MSIVs, fast closure of turbine generator control valves, fast closure of turbine generator stop valves, loss of the main generator and offsite power, tripping a feedwater pump, and several trips of the recirculation pumps. The plant transient behavior is recorded for each test and the results may be compared with the acceptance criteria and the predicted design performance. Table 14.2-2 shows the operating test condition for all the proposed major transients;*

n. *A test is made of the relief valves in which leaktightness and general operability are demonstrated;*

o. *At some major power levels the jet pump flow instrumentation is calibrated;*

p. *The as-built characteristics of the recirculation system are investigated as soon as operating conditions permit full core flow; and*

q. *The local control loop performance, based on the drive pump, jet pumps, and control equipment is checked.*

14.2.11 TEST PROGRAM SCHEDULE

The test program schedule for preoperational and startup tests are indicated in Table 14.2-4 and Figure 14.2-4. These schedules are preliminary and will be adjusted to consider actual construction and testing progress; they are included to provide general information but are not considered to be identical to the schedules in use during the startup program. The test procedures will be made available for review at least 30 days prior to the test date or fuel load.

14.2.12 INDIVIDUAL TEST DESCRIPTIONS

14.2.12.1 Preoperational Test Procedures

The following general descriptions are the specific objectives of each preoperational test. During the final construction phase, it may be necessary to modify the preoperational test methods as operating and preoperational test procedures are developed. Consequently, methods described in the following descriptions are general, not specific.

Specific acceptance criteria for each preoperational test are in accordance with the detailed system and equipment specifications for equipment in those systems. The tests demonstrate that the installed equipment and systems perform within the limits of these specifications.

In addition to the prerequisites listed on each on the following preoperational tests, there will be electrical power available to each of the systems.

Table 14.2-1 lists the preoperational tests anticipated for this facility.

14.2.12.1.1 Reactor Feedwater System Preoperational Test

a. Purpose

To verify the operation of the reactor feedwater system, including pumps, valves, turbines, turbine auxiliaries, and turbine control systems.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The condensate system, control air system, and service water system must have a readiness verification.

c. *General Test Methods and Acceptance Criteria*

The performance of the reactor feedwater system is verified within the limitations of the auxiliary steam supply by the demonstration of the proper operation of the following:

1. *Valves and related controls, interlocks, and position indicators,*
2. *Reactor feedwater pumps, turbines, and auxiliaries,*
3. *Control logic, and*
4. *Annuciators and protective devices.*

14.2.12.1.2 Condensate System Preoperational Test

a. *Purpose*

To verify the operation of the condensate system, including pumps, valves, and control systems.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The condenser, condensate filter demineralizers, feedwater, and control air systems are capable of supporting this test as necessary.

c. *General Test Methods and Acceptance Criteria*

The performance of the condensate system is verified by the demonstration of the proper operation of the following:

1. *Valves and related controls, interlocks, and positions indicators,*
2. *Condensate pumps, condensate booster pumps and auxiliaries,*
3. *Control logic, and*
4. *Annuciators and protective devices.*

14.2.12.1.3 Fire Protection System Preoperational Test

a. *Purpose*

To verify the operation of the fire protection system including the diesel engine, pumps, valves, detection and alarm circuits, and control and instrumentation circuits. To verify the location and status of all portable equipment.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The circulating water system, control and service air system, and electrical distribution system are available to support operation.

c. *General Test Methods and Acceptance Criteria*

Verification of the fire protection system capability is demonstrated by the proper integrated operation of the following:

1. *Diesel engine and pump operation and related control and logic,*
2. *Fire alarm and detection circuits,*
3. *Fire control panel in the main control room,*
4. *Deluge, wet pipe and preaction sprinkler systems, and*
5. *Carbon dioxide and Halon systems.*

In addition, portable equipment and hose station capability will be verified.

14.2.12.1.4 Reactor Water Cleanup System Preoperational Test

a. *Purpose*

To verify the operation of the RWCU system, including pumps, valves, and filter/demineralizer equipment.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Filter aid, and anion and cation resin should be available. The RCC system and instrument air system must have readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the RWCU system capability is demonstrated by the proper integrated operation of the following:

1. *Drain flow regulator flow interlocks,*
2. *System isolation and logic,*
3. *Valve-operating sequence,*
4. *Pump operation and related control and logic,*

5. *Annuciators, and*
6. *Filter/demineralizer system operation.*

14.2.12.1.5 Standby Liquid Control System Preoperational Test

a. *Purpose*

To verify the operation of the standby liquid control (SLC) system including pumps, tanks, control, logic, and instrumentation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Valves should be previously bench tested and other precautions relative to positive displacement pumps taken. The reactor vessel should be available for injecting demineralized water.

c. *General Test Methods and Acceptance Criteria*

Verification of the SLC system capability is demonstrated by the proper integrated operations of the following:

1. *SLC system tank level instrumentation,*
2. *Heaters,*
3. *Alarms and logic,*
4. *Relief valves,*
5. *Pumps and related controls and logic, and*
6. *Flow testing with different flow paths.*

14.2.12.1.6 Nuclear Boiler System Preoperational Test

a. *Purpose*

To verify proper operation of the nuclear boiler system including safety/relief valves (SRVs) and related controls and logic.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Verify that all SRVs have been previously bench tested.

c. *General Test Methods and Acceptance Criteria*

Functional and capacity tests of SRVs are not performed; verification of the NSSS capability is demonstrated by the proper integrated operation of the following:

1. *System valves and related sensors and logic,*
2. *Vacuum breaker in relief valve discharge lines,*
3. *Automatic isolation function of reactor water sample isolation valves,*
4. *Isolation and leak detection systems,*
5. *Automatic depressurization system logic,*
6. *Reactor vessel actuators accumulator capacity test,*
7. *Safety/relief valves air piston operation,*
8. *Reactor head seal leak detection, and*
9. *Alarms and annunciators.*

14.2.12.1.7 Residual Heat Removal System Preoperational Test

a. *Purpose*

To verify the operation of the residual heat removal (RHR) system under its various modes of operation: LPCI, shutdown cooling and vessel head spray, containment spray, and suppression pool water cooling.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The RHR service water system must have readiness verification. The reactor vessel and recirculation loops shall be intact and capable of receiving water.

c. *General Test Methods and Acceptance Criteria*

Verification of the RHR system capability is demonstrated by the proper integrated operation of the following:

1. *System isolation valve control and logic tests,*

2. *RHR and RHR service water pump and motor operation, controls, and related logic features,*

3. *Automatic LPCI initiation logic,*

4. *Verification of all flow paths. The time from initiation signal to full flow should be verified, and*

5. *Alarms and annunciators.*

14.2.12.1.8 Reactor Core Isolation Cooling System Preoperational Test

a. *<u>Purpose</u>*

To verify the operation of the RCIC system including turbine, pump, valves, instrumentation, and control.

b. *<u>Prerequisites</u>*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The turbine, disconnected from the pump, shall be tested. The turbine instruction manual shall be reviewed in detail in order that precautions relative to turbine operation are followed. Then the system shall be tested within the capability of a temporary steam supply with the pump coupled to the turbine.

c. *<u>General Test Methods and Acceptance Criteria</u>*

1. *All valves and related controls, interlocks, and indicators,*
2. *Manual and automatic initiation,*
3. *Automatic isolation, including leak detection system logic,*
4. *Turbine speed control, trip, mode selection, and test mode,*
5. *Barometric condenser condensate pump, and vacuum pump controls,*
6. *Flow path verification, and*
7. *Annunciators.*

14.2.12.1.9 Reactor Recirculation System and Control Preoperational Test

a. *<u>Purpose</u>*

To verify the operation of the reactor recirculation system including pumps and their associated motors, valves, instrumentation, and controls. The rated conditions tests will be conducted during the startup testing program.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The RCC system must receive readiness verification. All required testing of equipment up to the operation of the recirculation pump has been completed, including recirculation pump motor (uncoupled) and all control loops.

c. *General Test Methods and Acceptance Criteria*

After prerequisite testing, verification of system capability is demonstrated by the proper integrated operation of the following:

1. *System valves,*
2. *Logic and interlocks,*
3. *Recirculation pumps, valves, and related controls and interlocks,*
4. *Annunciators, and*
5. *Low frequency motor generator (LFMG) set.*

14.2.12.1.10 Reactor Manual Control System Preoperational Test

a. *Purpose*

To verify the operation of the reactor manual control (RMC) system, including relays, control circuitry, switches and indicating lights, and control valves.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The CRD pump will not be operational during this test.

c. *General Test Methods and Acceptance Criteria*

Verification of RMC system capability is demonstrated by the proper integrated operation of the following:

1. *Rod blocks, alarms, and interlocks for all modes of the reactor mode switch,*

2. *Rod position information system,*

3. *Rod drift alarm circuit, and*

4. *Rod directional control valve time sequence for insert and withdraw commands.*

14.2.12.1.11 Control Rod Drive Hydraulic System Preoperational Test

a. Purpose

To verify the operation of the CRD hydraulic system including CRD mechanisms, hydraulic control units, hydraulic power supply, instrumentation, and controls.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The CRD manual control system preoperational test must be completed on associated CRDs. The RCC system and instrument air system must receive readiness verification.

c. General Test Methods and Acceptance Criteria

Verification of CRD system capability is demonstrated by the proper integrated operation of the following:

1. *Logic and interlocks,*

2. *CRD pumps and related controls and interlocks,*

3. *Flow controller, pressure control valves, and stabilizer valves,*

4. *Scram discharge level switches and CRD position indication, alarms, and interlocks,*

5. *CRDs functional testing including latching and position indication,*

6. *Scram testing of control rods at atmospheric pressure, and*

7. *Annunciators.*

14.2.12.1.12 Fuel Handling and Vessel Servicing Equipment Preoperational Test

a. Purpose

To verify the operation of the fuel handling and vessel servicing equipment including tools used in the servicing of control rods, fuel assemblies, LPRMs and dry tubes, and vacuum cleaning equipment.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the refueling platform, fuel preparation machine, and fuel racks must be installed and operational; all slings and lifting devices must be certified at their design load, at least by the vendor.

c. General Test Methods and Acceptance Criteria

Verification of the fuel handling and vessel servicing equipment is demonstrated by dry operation of the following equipment:

1. *Cell disassembly tools,*
2. *Channel replacement tools,*
3. *Instrument handling tools,*
4. *Vacuum cleaning equipment,*
5. *Interlocks and logic associated with the refueling and service platform are verified, and*
6. *Proper operation of refueling and service platforms are verified.*

14.2.12.1.13 Low-Pressure Core Spray System Preoperational Test

a. Purpose

To verify the operation of the low-pressure core spray system (LPCS), including spray pumps, sparger ring, spray nozzles, controls, valves, and instrumentation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The reactor vessel must be available and ready to receive water.

c. *General Test Methods and Acceptance Criteria*

Verification of the LPCS system capability is demonstrated by the proper integrated operation of the following:

1. *Logic and interlocks,*
2. *Low-pressure core spray system pumps, including auto initiation,*
3. *Flow path verification, including determination of system hydraulic performance to verify proper sizing of restricting orifice in LPCS discharge line to vessel (see Section 6.3.2.2.3),*
4. *Annunciators,*
5. *The time for initiation signal to full flow should be verified, and*
6. *Photographs to prove acceptability of core spray patterns.*

14.2.12.1.14 High-Pressure Core Spray System Preoperational Test

a. *Purpose*

To verify the operation of the high-pressure core spray (HPCS) system, including diesel generator and related auxiliary equipment, pumps, valves, instrumentation, and control.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The HPCS diesel generator must be installed and be operational.

c. <u>*General Test Methods and Acceptance Criteria*</u>

Verification of HPCS system capability is demonstrated by the proper integrated operation of the following:

1. *Valve controls and interlocks,*

2. *HPCS electrical system tests, including dc and ac,*

3. *HPCS diesel generator functional tests including starting, rated load, load rejection,*

4. *Pump and motor tests with normal power supply and with diesel generator,*

5. *HPCS flow path and flow rate verification,*

6. *Annunciators,*

7. *The time from initiation signal to full flow should be verified, and*

8. *Photographs to prove acceptability of HPCS spray pattern.*

14.2.12.1.15 Fuel Pool Cooling and Cleanup System Preoperational Test

a. <u>*Purpose*</u>

To verify the operation of the fuel pool cooling and cleanup system including the pumps, heat exchangers, controls, valves, and instrumentation.

b. <u>*Prerequisites*</u>

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The instrument air, service air, fuel pool emergency makeup, service water, and RHR systems must be available.

c. <u>*General Test Methods and Acceptance Criteria*</u>

Verification of the fuel pool system capability is demonstrated by the integrated operation of the following:

1. *Logic and interlocks,*
2. *Interconnection to RHR system,*
3. *Pump operation and related controls,*
4. *Cleanup subsystem operation, and*
5. *Annunciators.*

14.2.12.1.16 Leak Detection System Preoperational Test

a. Purpose

To summarize the test requirements and verify the leak detection test data for each of the nuclear systems.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The prerequisites are included in the preoperational test specifications for each of the nuclear systems listed below.

c. General Test Methods and Acceptance Criteria

As an integral part of each of the following system preoperational tests, the nuclear systems leak detection is verified by the proper operation of the leak detection features of the following nuclear systems:

1. *Feedwater control system,*
2. *RWCU system,*
3. *NSSS,*
4. *RHR system,*
5. *RCIC system,*
6. *Recirculation system, and*
7. *Radwaste system.*

14.2.12.1.17 Liquid and Solid Radwaste System Preoperational Test

a. Purpose

To verify that the radioactive waste system will perform its design functions of processing liquid and solid radioactive wastes.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. *General Test Methods and Acceptance Criteria*

Testing will demonstrate that the pumps, tanks, controls, and valves including automatic isolation, diversion and protection features, and instrumentation and alarms will operate and function in accordance with design requirements.

Testing will also verify that the WNP-2 Process Control Program results in an acceptable waste form as required by 10 CFR 61. Simulated waste will be verified to form a free-standing monolithic solid with no free liquid prior to implementation of the solidification process on radioactive waste. Liners containing solidified waste will be inspected prior to shipment to the disposal site to verify compliance with 10 CFR 61 requirements.

14.2.12.1.18 Reactor Protection System Preoperational Test

a. *Purpose*

To verify the proper operation of the reactor protection system (RPS), including sensor logic and their respective scram relays, scram reset time delay, the annunciators, and motor generator set power supply.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. *General Test Methods and Acceptance Criteria*

Verification of the RPS capability is demonstrated by the proper integrated operation of the following:

1. *Motor generator set performance,*
2. *Sensor logic and scram relay logic,*
3. *Scram reset time delay,*

4. *Sensors input-to-scram trip actuator response time on all channels of each function for which response times are required by the Technical Specifications,*

5. *Annunciators,*

6. *Mode switch tests, and*

7. *Auxiliary sensor operation.*

The ability of the system to scram the reactor within a specified time must be demonstrated in the CRD hydraulic system preoperational test (see Section 14.2.12.1.11).

14.2.12.1.19 Neutron Monitoring System Preoperational Test

a. *Purpose*

To verify the operation of the neutron monitoring system (NMS) including startup, intermediate, and power range detectors, and their related equipment.

b. *Prerequisites*

The system lineup tests have been complete, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, all source range monitors (SRMs) and pulse preamplifiers, IRMs and voltage preamplifiers, and APRMs will have been calibrated according to the vendor's instructions.

c. *General Test Methods and Acceptance Criteria*

Verification of the NMS capability is demonstrated by the proper integrated operation of the following:

1. *All SRM detectors, and their respective insert and retract mechanisms, and cables;*

2. *SRM channel including pulse preamp, remote meter and record, trip logic, logic bypass and related lamps and annunciators, control system interlocks, refueling instrument trips, and power supply;*

3. *All IRM detectors and their respective insert and retract mechanisms and cables;*

4. *IRM channels including voltage preamps, remote recorders, RMC system interlocks, RPS trips, annunciators and lamps, and power supplies;*

5. *All LPRM detectors and their respective cables, and power supplies;*

6. *All APRM channels including trips, trip bypasses, annunciators and lamps, remote recorders, RMC system interlocks, RPS trips, and power supplies;*

7. *Recirculation flow bias signal including flow unit, flow transmitters, and related annunciators, interlocks, and power supplies, and*

8. *Both rod block monitor (RBM) channels including trips, trip bypasses, annunciators and lamps, remote recorders, RMC system interlocks, and power supplies.*

14.2.12.1.20 Traversing In-Core Probe System Preoperational Test

a. *Purpose*

To verify the operation of the traversing in-core probe (TIP) system including the TIP detector, controls and interlocks, containment secure lamp, and containment isolation circuits.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. (Additionally, the TIP detector and dummy detector, ball valve time delay, core top and bottom limits, clutch, x-y recorder, and purge system will have been shown to be operational.)

c. *General Test Methods and Acceptance Criteria*

With the exception of the shear valve, which is not tested, verification of the TIP system is demonstrated by the proper integrated operation of the following:

1. *Indexer cross-calibration interlock,*

2. *Shear valve control monitor lamp, and*

3. *Drive motor manual control and override, automatic control and stop, and low speed control.*

14.2.12.1.21 Rod Worth Minimizer System Preoperational Test

a. Purpose

To verify the operation of the rod worth minimizer (RWM) system under its various modes of operation.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the rod position indication system (RPIS) will have been shown to be operational, rod sequence control (RSC) system bypassed, and computer diagnostic and special tests completed.

c. General Test Methods and Acceptance Criteria

Verification of the RWM system is demonstrated by the proper integrated operation of the following:

1. *Rod test option,*
2. *System initialization both above and below the low power setpoints, and above and below the low power alarm points,*
3. *RWM program,*
4. *Rod withdrawal and insertion error block, and*
5. *Rod drift scan, and annunciation.*

The RWM program acceptance of an operator-supplied rod position value must be demonstrated.

14.2.12.1.22 Process Radiation Monitoring System Preoperational Test

a. *Purpose*

To verify the operation of the process radiation monitoring (PRM) system, including the offgas vent, offgas, main steam line, liquid process, and building ventilation radiation monitoring subsystems.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the process radiation monitors, pulse preamplifiers, power supplies, indicator and trip units, are calibrated. Insulation resistance and high potentiometer tests will have been completed.

c. *General Test Methods and Acceptance Criteria*

Verification of the PRM system is demonstrated by the proper integrated operation of the following:

1. *Vent preamps, channels, trip points, annunciators and lamps, sample rack, and check source,*

2. *Offgas vial sampler, log radiation monitor (LRM) and their related annunciators, lamps and recorders, and high/low flow detector,*

3. *Main steam and LRM channels, trip points, and annunciators and lamps, High-High and Inop trip, and recorders,*

4. *Liquid process preamps, channels, trip points, and annunciators and lamps, and recorders,*

5. *Building ventilation system sensors, channels, trip points, and annunciators and lamps, recorders, and SGTS interlock, and*

6. *Control center air monitoring sensors, channels, annunciators, and indicators.*

14.2.12.1.23 Area Radiation Monitoring System Preoperational Test

a. Purpose

To verify the operation of the area radiation monitoring (ARM) system, including channels, trip points, alarms, and recorder.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, indicator, trip units, and power supplies are calibrated.

c. General Test Methods and Acceptance Criteria

Verification of the ARM system capability is demonstrated by the proper integrated operation of the following:

1. *Monitor channels,*
2. *Channel trip points,*
3. *Alarm annunciators and lights, and*
4. *Recorder.*

14.2.12.1.24 Process Computer Interface System Preoperational Test

a. Purpose

To verify the operation of the process computer interface (PCI) system including computer inputs and printout.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, computer diagnostic checks and programming are completed.

c. General Test Methods and Acceptance Criteria

Verification of the PCI system is demonstrated by the proper integrated operation of the following:

1. *Analog input signals,*
2. *Computer printout,*
3. *Digital input signals, and*
4. *Digital output signals.*

14.2.12.1.25 Rod Sequence Control System Preoperational Test

a. *Purpose*

To verify the operation of the RSC system under its various modes of operation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the self-test feature of the RSC system is verified.

c. *General Test Methods and Acceptance Criteria*

Verification of the RSC system is demonstrated by the proper integrated operation of the following:

1. *Low power setpoint and low power alarm point tests,*
2. *RSC system status displays and annunciators,*
3. *Reactor mode switch test,*
4. *System diagnostic and data quality tests,*
5. *Rod position data tests,*
6. *Single rod bypass provision,*
7. *Rod sequences tests,*
8. *Rod group assignment,*
9. *Constraints of rod movement tests,*
10. *100% to 75% control rod density tests,*
11. *5% to 50% control rod density tests, and*
12. *0% control rod density to low power setpoint tests.*

14.2.12.1.26 Remote Shutdown Preoperational Test

a. *Purpose*

To verify the feasibility and operability of the shutdown functions from the remote shutdown panel and its ability to bring the reactor to a cold condition in an orderly fashion.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the control power should be supplied to the remote shutdown panel, and the independence of power supply voltage, and fuses should be verified.

c. *General Test Methods and Acceptance Criteria*

Verification of the remote shutdown system is demonstrated by the proper integrated operation of the following tests:

1. *Operation of valves, controls, instruments, and pumps on systems available from this panel, and*

2. *Transfer switch operation from the control room panels to the remote shutdown panel.*

14.2.12.1.27 Offgas System Preoperational Test

a. *Purpose*

To verify the operation of the offgas system including valves, recombiner, condensers, coolers, filters, and hydrogen analyzers.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager (Assistant Plant Manager) has approved the initiation of testing. Additionally, the instrument air system, electrical power, and cooling water should be operational.

c. *General Test Methods and Acceptance Criteria*

Verification of the offgas system is demonstrated by the following tests:

1. *Valve operation including fail safe and isolation features and valve status lights indicate the correct valve position,*

2. *Pump operation,*

3. *Level and temperature control and indication,*

4. *Recombiner and preheater tests,*

5. *Condenser, cooler, and moisture separator tests,*

6. *Gas dryer and cooler tests,*

7. *Filter efficiency,*

8. *Hydrogen analyzer performance test, and*

9. *Purge and bleed air rate test.*

14.2.12.1.28 Environs Radiation Monitoring Preoperational Test

a. *Purpose*

To verify the operation of the environs radiation monitoring system, including dosimeters, sampling pump, and filter equipment.

b. *Prerequisites*

System lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, indicator power supplies are calibrated according to the vendor's instruction manual.

c. *General Test Methods and Acceptance Criteria*

Verification of the environs radiation monitoring system capability is demonstrated by the proper operation of the following:

1. *Air sample equipment, and*
2. *Thermoluminescent detector (TLD) (passive dosimeters).*

14.2.12.1.29 Main Steam System Preoperational Test

a. *Purpose*

To verify the proper operation of the MSIVs and related controls.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. *General Test Methods and Acceptance Criteria*

Verification of the main steam system is demonstrated by the proper integrated operation of the following:

1. *Automatic isolation of the MSIVs,*

2. *Minimum closing times are met,*

3. *MSIV accumulator capacity tests are satisfactory, and*

4. *Valves, heaters, blowers, and initiating logic of the MSIV leakage control system.*

14.2.12.1.30 Radwaste Building Heating, Ventilating, and Air Conditioning System Preoperational Test

a. *Purpose*

To verify that the radwaste building heating, ventilating, and air conditioning (HVAC) system will function in accordance with the design requirements as set forth in the design specifications.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 480-V ac power system, control air supply service air system, and the turbine service water system is capable of supporting this test as necessary.

c. *General Test Methods and Acceptance Criteria*

Verification of the radwaste building HVAC system is demonstrated by the proper integrated operation of the following:

1. *Ventilation fans and their related controls,*
2. *Filters and instrumentation,*
3. *Dampers and controls, and*
4. *Annunciators and protective devices.*

14.2.12.1.31 Closed Cooling Water System Preoperational Test

a. *Purpose*

To verify the operation of the RCC system including pumps, valves, logic, and annunciator.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following support systems must have received readiness verifications:

1. *Control and service air (CAS/SA),*
2. *Makeup water treatment,*
3. *Essential 480-V ac power, and*
4. *Instrumentation power.*

c. *General Test Methods and Acceptance Criteria*

Verification of the RCC system is demonstrated by the proper integrated operation of the following:

1. *Surge tank level control,*
2. *System pumps and control logic,*
3. *Chemical addition pump and control, and*
4. *Remote-operated valves.*

12.2.12.1.32 Primary Containment Atmospheric Control System Preoperational Test

a. *Purpose*

To verify the operation of the primary containment atmospheric control (CAC) system including blowers, coolers, valves, instruments, and alarms.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Primary containment, essential 480-V ac power, standby service water (SW), instrument power, and control air systems must have received readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the primary CAC system is demonstrated by the proper integrated operation of the following:

1. *Isolation and control valves,*
2. *Blowers,*
3. *Instrumentation,*
4. *Alarms, and*
5. *Recombiner components to the extent that flow paths are verified.*

Primary CAC system hydrogen/oxygen recombining performance capabilities are not demonstrated during the preoperational test.

14.2.12.1.33 Primary Containment Cooling System Preoperational Test

a. *Purpose*

To verify the operation of the primary containment cooling system including fans, dampers, related controls, and instrumentation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 480-V ac power, instrument power, and RCC systems must have received readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the primary containment cooling system is demonstrated by the proper integrated operation of the following:

1. *Fans and control logic,*
2. *Cooling coils,*

3. *Dampers, cooling water flow control valves and related controls,*
4. *Instrumentation,*
5. *Related loss-of-power logic, and*
6. *Annunciators.*

Primary containment cooling system heat removal capabilities are not demonstrated during the preoperational test.

14.2.12.1.34 Primary Containment Instrument Air Preoperational Test

a. *Purpose*

To verify proper operation of the containment instrument air (CIA) system, including compressors, dryers, valves, and related controls and logic.

b. *Prerequisites*

The system lineup tests have been completed, and the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The plant service water supply system must receive a readiness classification.

c. *General Test Methods and Acceptance Criteria*

Verification of the CIA system capability is demonstrated by the proper integrated operation of the following:

1. *Logic and interlocks,*

2. *CIA system air compressors,*

3. *CIA system air dryers,*

4. *System nonreturn check valves,*

5. *Alarms and controls,*

6. *Nitrogen backup supply, and*

7. *Valve/component failure modes for those valves/components supplied by the CIA system to simulated loss of air supply.*

14.2.12.1.35 Primary Containment Atmospheric Monitoring System Preoperational Test

a. Purpose

To verify the capability of the primary containment atmospheric monitoring system to monitor and display containment atmospheric conditions.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Instrument power is available to system components.

c. General Test Methods and Acceptance Criteria

Verification of the primary containment atmospheric monitoring system capability is demonstrated by the proper integrated operation of the following:

1. *Samples and controls,*
2. *Analyzers,*
3. *Pressure and temperature instrumentation,*
4. *Radiation monitors,*
5. *Indicating/recording instrumentation, and*
6. *Annunciators.*

12.2.12.1.36 Standby Gas Treatment System Preoperational Test

a. Purpose

To verify the reliable operation of the standby gas treatment system (SGTS), including fans, filter trains, and related controls.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following systems must have readiness verification:

1. *Essential 480-V ac power,*
2. *Instrument power,*
3. *Control air, and*
4. *Reactor building heating and ventilation.*

c. *General Test Methods and Acceptance Criteria*

Verification of the SGTS is demonstrated by the proper integrated operation of the following:

1. *SGTS fans and control logic,*
2. *Filter trains and related instruments,*
3. *Automatic valves and control logic,*
4. *System interconnections to reactor building heating and ventilation and primary containment atmospheric control system, and*
5. *Annunciators.*

14.2.12.1.37 Loss of Power and Safety Testing Preoperational Test

a. *Purpose*

To verify the operation of the 230/115-kV, 6.9-kV, 4.16-kV, and 480-V distribution systems.

To verify the integrated ability of the plant electrical distribution and safety systems to operate on normal and standby power sources during accident conditions.

To verify that loss of a single ac or dc distribution system division (exclusive of the HPCS diesel generator and batteries) will not prevent the remaining systems from actuating during an accident condition.

b. *Prerequisites*

The system lineup tests and the 69/N (N = number of diesels) consecutive starts from the emergency diesel generators have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 125-V dc system and the emergency core cooling systems (ECCS) are available to support testing.

c. *General Test Methods and Acceptance Criteria*

Verification of the 230/115-kV, 6.9-kV, 4.16-kV, and 480-V distribution systems operability shall be demonstrated by the following:

1. *Demonstration of circuit integrity and integrated operation of circuit breakers, controls and interlocks, instrumentation, automatic transfer features, and protective devices and alarms.*

2. *Demonstration of proper system response to a loss of the 230-kV and 115-kV distribution systems independently and simultaneously both with and without loss-of-coolant accident (LOCA)/containment isolation signals.*

3. *Demonstration of proper system response to a loss of the 230/115-kV distribution systems and one individual standby diesel generator during an ECCS/containment isolation actuation.*

   Signals for these tests shall be simulated from the actual initiating devices when this is practical.

4. *Testing of the diesel generators will include the following:*

   (a) *Sequential loading of each diesel generator unit,*

   (b) *Maintenance of specified frequency and voltage during the loading sequence,*

   (c) *Capability to reject and restart their largest single load any time after the design loading sequence is complete, and*

   (d) *Capability to supply power to vital equipment during loss of station normal power conditions.*

5. *Electrical independence will be verified during testing by*

   (a) *Verifying that operation of the division/equipment being tested and the nonactuation of deenergized buses/equipment does not affect the proper operation of the remaining buses/equipment.*

   (b) *Monitoring of the major distribution buses to ensure absence of voltage.*

   Main power transformers supplying power from the offsite system cannot be full load tested; they are tested according to this procedure to the design emergency load. All other in-plant

power sources are load tested in their individual preoperational tests.

14.2.12.1.38 Instrument Power Preoperational Test

a. Purpose

To verify the operation of the instrument power systems.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

The 125-V dc and the 480-V ac power systems are energized and capable of supplying power to the instrument power systems.

c. General Test Methods and Acceptance Criteria

Verification of the instrument power systems shall be accomplished by demonstrating circuit integrity and integrated operation of

1. *Static inverters, transformers, and buses,*
2. *Controls and interlocks,*
3. *Transfer features,*
4. *Instrumentation, and*
5. *Protective devices and alarms.*

14.2.12.1.39 Emergency Lighting System Preoperational Test

a. Purpose

To verify the operation of the emergency lighting system within the design requirements of the system.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 125-V dc system has received a readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the emergency lighting system is to demonstrate proper automatic operation of the system and to provide sufficient lighting during loss of normal lighting.

14.2.12.1.40 Standby Alternating Current Power System Preoperational Test

a. *Purpose*

To verify the operation of the standby ac power system including diesel engines, auxiliaries, generators, controls, and instrumentation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

The following support systems or components must have received readiness verification:

1. *Standby service water,*
2. *125/250-V dc power,*
3. *Instrument power, and*
4. *Essential 4160-V ac power.*

c. *General Test Methods and Acceptance Criteria*

Verification of the standby ac power system is demonstrated by the proper integrated operation of the following:

1. *The diesel engines and auxiliaries,*
2. *The generators, exciters, and voltage regulators,*
3. *Fuel storage and supply system,*
4. *Start and control logic circuitry and interlocks,*
5. *Protective devices,*
6. *Instrumentation, and*
7. *Annunciators.*

Testing will be performed to demonstrate the following design features.

1. *The diesel generator's performance capability to establish frequency, voltage, and load acceptance with a specified time interval on initiation of an automatic start signal under both cold and hot conditions.*

2. *Specified full- and over-load performance capabilities.*

3. *The diesel generator's capability to reject the maximum rated load without exceeding speeds or voltage which will cause tripping.*

14.2.12.1.41 250-V Direct Current Power System Preoperational Test

a. Purpose

To verify the operation of the 250-V dc power system including batteries, chargers, controls, interlocks, instruments, and protective devices.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Battery room ventilation and 480-V ac power supply to the chargers have received readiness verification.

c. General Test Methods and Acceptance Criteria

Verification of the 250-V dc power system is demonstrated by the proper integrated operation of the following:

1. *Battery chargers including capability to recharge the battery in accordance with Section 8.3.2.1.4.3,*

2. *Batteries (including charge and discharge rate/capacity tests and load profiles described in Table 8.3-18),*

3. *Protective relays and devices,*

4. *System control logic,*

5. *Instrumentation (including ground detection),*

6. *Breakers, and*

7. *Annunciators.*

14.2.12.1.42 125-V Direct Current Power System Preoperational Test

a. Purpose

To verify the operation of the 125-V dc power system including batteries, chargers, controls, interlocks, instruments, and protective devices.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Battery room ventilation and 480-V ac power supply to the chargers have received readiness verification.

c. General Test Methods and Acceptance Criteria

Verification of the 125-V dc power system is demonstrated by the proper integrated operation of the following:

1. *Battery chargers including capability to recharge the battery in accordance with Section 8.3.2.1.1.3,*
2. *Batteries (including charge and discharge rate/capacity tests and load profiles described in Tables 8.3-15 and 8.3-16),*
3. *Protective relays and devices,*
4. *System control logic,*
5. *Instrumentation (including ground detection),*
6. *Breakers, and*
7. *Annunciators.*

14.2.12.1.43 24-V Direct Current Power System Preoperational Test

a. Purpose

To verify the operation of the 24-V dc power system.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. *General Test Methods and Acceptance Criteria*

Verification of the 24-V dc power system shall include demonstrations of battery capacity and battery charger capabilities described in Section 8.3.2.1.3.3.

14.2.12.1.44 Plant Service Water System Preoperational Test

a. *Purpose*

To demonstrate the proper operation of the plant service water system, including pumps, valves, and related controls.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

The following support systems or components must have received readiness verification:

1. *4160-V ac power,*
2. *480-V ac power,*
3. *Instrument power,*
4. *Service water pump house structure,*
5. *Various heat exchangers or coolers utilizing service water, and*
6. *Tower makeup (TMU).*

c. *General Test Methods and Acceptance Criteria*

Verification of the plant service water system is demonstrated by the proper operation and performance of the service water pumps, the operation of filters, remote-operated valves, related controls, and instrumentation.

14.2.12.1.45 Standby Service Water System Preoperational Test

a. Purpose

To verify the proper operation of the SW system for normal and abnormal plant operating modes.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following support systems or components must have received readiness verification:

1. *Essential 4160-V ac power,*
2. *Instrument power,*
3. *Control air,*
4. *Standby service water pump house structure,*
5. *Various heat exchangers or coolers utilizing SW, and*
6. *Tower makeup (TMU).*

c. General Test Methods and Acceptance Criteria

Verification of this system is demonstrated by the proper integrated operation and performance of the following:

1. *Pumps and related controls,*
2. *Remote-operated valves and controls,*
3. *Automatic-operated valves and control logic,*
4. *Instrumentation,*
5. *Annunciators,*
6. *Standby service water system control logic response to a simulated loss of normal station power event,*
7. *Pumps net positive suction head (NPSH) adequate and no vortexing,*
8. *Proper operation of basin siphon cross connection, and*

9. *The preoperational test program includes tests to confirm the performance characteristics of the spray ponds (see Section 9.2.5).*

14.2.12.1.46 Plant Communications System Preoperational Test

a. Purpose

To demonstrate that the plant communications and evacuation alarm system will provide effective communication between various plant locations and to verify proper operation of the emergency evacuation alarm components and system.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. General Test Methods and Acceptance Criteria

Proper operation of all the communication system components and the emergency evacuation alarm system and components will be demonstrated.

14.2.12.1.47 Reactor Building Emergency Cooling System Preoperational Test

a. Purpose

To demonstrate the proper integrated operation of the reactor building emergency equipment cooling system including fans, cooling coils, instrumentation, and controls.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following support systems or components must have received readiness verification:

1. *Electrical power to motors, control circuits, and instrumentation, and*
2. *Standby service water system.*

c. *General Test Methods and Acceptance Criteria*

Verification of this system is demonstrated by the proper integrated operation of the fan coil units, their associated controls, interlocks, and annunciators.

14.2.12.1.48 Control, Cable, and Critical Switchgear Rooms Heating, Ventilating, and Air Conditioning System Preoperational Test

a. *Purpose*

To verify that the control, cable, and critical switchgear rooms HVAC systems will function in accordance with the design requirements as set forth in the design specifications.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following support systems have received readiness verification:

1. *480-V ac power,*
2. *Instrument power, and*
3. *Chilled water.*

c. *General Test Methods and Acceptance Criteria*

Verification of the control, cable, and critical switchgear rooms HVAC system is demonstrated by the proper integrated operation of the following:

1. *Supply and exhaust fans and their related controls,*
2. *Filters, dampers, valves, and related instrumentation and control logic,*
3. *Coolers, and*
4. *Annunciators.*

14.2.12.1.49 Standby Service Water Pump House Heating and Ventilating System Preoperational Test

a. *Purpose*

To verify that the SW pump house heating and ventilating system will function in accordance with the design requirements as set forth in the design specifications.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 480-V ac power system must have received readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the SW pump house heating and ventilating system is demonstrated by the proper integrated operation of the following:

1. *Ventilation fans and their related controls,*
2. *Filters and instrumentation,*
3. *Dampers and controls, and*
4. *Annunciators.*

14.2.12.1.50 Reactor Building Crane Preoperational Test

a. *Purpose*

To verify the operation of the reactor building crane.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Construction load tests of 125% static and 100% operational are complete.

Contractor use of the reactor building crane for construction purposes is complete.

c. *General Test Methods and Acceptance Criteria*

Verification of the reactor building crane is demonstrated by the proper integrated operation of the following:

1. *Crane traverse components,*
2. *Hook traverse and hoist components,*
3. *Controls and indicators,*

4. *Safety devices, and*
5. *Instrumentation.*

14.2.12.1.51 *Primary Containment Integrated Leak Rate Preoperational Test*

a. *Purpose*

To verify overall primary containment integrity by pressurizing to specified test pressures and conducting integrated leak rate measurements.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following supporting activities, systems, or components must have been completed or received readiness verification:

1. *All type B and C local leak testing completed, documented, and verified as a system lineup test; see Section 6.2.6.1,*

2. *All containment isolation valves fully operable and closed in the normal manner,*

3. *All containment-associated piping hangers, supports, restraints, and anchors have been installed and properly set,*

4. *Residual heat removal and core spray systems preoperational tests complete, and*

5. *A containment area survey completed to locate, isolate, or remove any instrumentation, light bulbs, etc., which may be damaged by high external pressure.*

c. *General Test Methods and Acceptance Criteria*

Verification of primary containment integrity is demonstrated by pressurizing to the required test pressure. See Section 6.2.6.1 for a detailed test description.

The drywell-wetwell leakage test will be performed as part of this test to verify the acceptance criteria described in Section 3.8.3.7.

14.2.12.1.52 Secondary Containment Integrated Leak Rate Preoperational Test

a. Purpose

To verify overall secondary containment integrity by subjecting the reactor building to a specified negative pressure and measuring the inleakage.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following supporting activities or systems/components must have been completed or received readiness verification:

1. *Reactor building structure complete with personnel and railroad air lock doors installed and operable,*
2. *Reactor building conduit, pipe, and other structural penetrations sealed, and*
3. *Standby gas treatment system.*

c. General Test Methods and Acceptance Criteria

Verification of secondary containment integrity is demonstrated by operating the SGTS at a specific capacity while maintaining the reactor building internal structure at a specified negative pressure.

14.2.12.1.53 Diesel Generator Building Heating and Ventilating System Preoperational Test

a. Purpose

To verify that the diesel generator building heating and ventilating system will function in accordance with the design requirements as set forth in the design specifications.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 480-V ac power system must have received readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the diesel generator building heating and ventilating system is demonstrated by the proper integrated operation of the following:

1. *Ventilation fans and their related controls,*
2. *Filters and instrumentation,*
3. *Dampers and controls, and*
4. *Annunciators.*

14.2.12.1.54 Seismic Monitoring System Preoperational Test

a. *Purpose*

To verify the operation of the seismic monitoring system.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. *General Test Methods and Acceptance Criteria*

Verification of the seismic monitoring system is demonstrated by the proper integrated operation of the following:

1. *Annunciators, and*
2. *Instrumentation.*

14.2.12.2 General Discussion of Startup Tests

All those tests comprising the startup test phase (Table 14.2-4) are discussed in this section. For each test a description is provided for test purpose, test prerequisites, test description, and statement of test acceptance criteria, where applicable.

In describing the purpose of a test, an attempt is made to identify those operating and safety-oriented characteristics of the plant which are being explored.

Where applicable, a definition of the relevant acceptance criteria for the test is given and is designated either Level 1 or Level 2. A Level 1 criterion normally relates to the value of a process variable assigned in the design of the plant, components, systems, or associated

equipment. If a Level 1 criterion is not satisfied, the plant will be placed in a suitable hold-condition until resolution is obtained. Tests compatible with this hold-condition may be continued. Following resolution, applicable tests must be repeated to verify that the requirements of the Level 1 criterion are now satisfied.

A Level 2 criterion is associated with expectations relating to the performance of systems. If a Level 2 criterion is not satisfied, operating and testing plans would not necessarily be altered. Investigations of the measurements and of the analytical techniques used for the predictions would be started.

For transients involving oscillatory response, the criteria are specified in terms of decay ratio (defined as the ratio of successive maximum amplitudes of the same polarity). The decay ratio must be less than unity to meet a Level 1 criterion and less than 0.25 to meet a Level 2 criterion.

14.2.12.3 Startup Test Procedures

14.2.12.3.1 Test Number 1 - Chemical and Radiochemical

14.2.12.3.1.1 Purpose. The principal objectives of this test are to (a) secure information on the chemistry and radiochemistry of the reactor coolant, and (b) determine that the sampling equipment, procedures, and analytic techniques are adequate to supply the data required to demonstrate that the chemistry of all parts of the entire reactor system meet specifications and process requirements.

Specific objectives of the test program include evaluation of fuel performance, evaluations of demineralizer operations by direct and indirect methods, measurements of filter performance, confirmation of condenser integrity, demonstration of proper steam separator-dryer operation, measurement and calibration of the offgas system, and calibration of certain process instrumentation. Data for these purposes is secured from a variety of sources: plant operating records, regular routine coolant analysis, radiochemical measurements of specific nuclides, and special chemical tests.

14.2.12.3.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.1.3 Description. Prior to fuel loading a complete set of chemical and radiochemical samples will be taken to ensure that all required sample stations are functioning properly and to determine initial concentrations. Subsequent to fuel loading during reactor heatup and at each major power level change, samples will be taken and measurements will be made to determine the chemical and radiochemical quality of reactor water and reactor

feedwater, amount of radiolytic gas in the steam, gaseous activities leaving the air ejectors, decay times in the offgas lines and performance of filters and demineralizers.

Calibrations will be made of monitors in the stack, liquid waste system, and liquid process lines.

14.2.12.3.1.4 Criteria.

Level 1

Chemical factors defined in the Technical Specifications and Fuel Warranty must be maintained within the limits specified.

The activity of gaseous liquid effluents must conform to license limitations.

Water quality must be known at all times and should remain within the guidelines of the Water Quality Specifications.

Level 2

Not applicable.

14.2.12.3.2 Test Number 2 - Radiation Measurements

14.2.12.3.2.1 Purpose. The purposes of this test are to (a) determine the background radiation levels in the plant environs prior to operation for base data on activity buildup, and (b) monitor radiation at selected power levels to ensure the protection of personnel during plant operation.

14.2.12.3.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.2.3 Description. A survey of natural background radiation throughout the plant site will be made prior to fuel loading. Subsequent to fuel loading, during reactor heatup and at nominal power levels of 25%, 60%, and 100% of rated power, gamma dose rate measurements and where appropriate, neutron dose rate measurements will be made at significant locations throughout the plant. All potentially high radiation areas will be surveyed.

14.2.12.3.2.4 Criteria.

Level 1

The radiation doses of plant origin and the occupancy times of personnel in radiation zones shall be controlled consistent with the guidelines of the Standards for Protection Against Radiation outlined in 10 CFR 20 and the NRC General Design Criteria in 10 CFR 50, Appendix A.

Level 2

Not applicable.

14.2.12.3.3 Test Number 3 - Fuel Loading

14.2.12.3.3.1 Purpose. The purpose of this test is to load fuel safely and efficiently to the full core size.

14.2.12.3.3.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Also the following prerequisites will be met prior to commencing fuel loading to ensure that this operation is performed in a safe manner:

- *a. The status of all systems required for fuel loading will be specified and will be in the status required;*
- *b. Fuel and control rod inspections will be complete. Control rods will be installed and tested;*
- *c. At least three movable neutron detectors will be calibrated and operable. At lease three neutron detectors will be connected to the high flux scram trips. They will be located so as to provide acceptable signals during fuel loading;*
- *d. Nuclear instruments will be source checked with a neutron source prior to loading or resumption if sufficient delays are incurred;*
- *e. The status of secondary containment will be specified and established;*
- *f. Reactor vessel status will be specified relative to internal component placement and this placement established to make the vessel ready to receive fuel;*
- *g. Reactor vessel water level will be established and minimum level prescribed;*

h. *The standby liquid control system will be operable and in readiness;*

i. *Fuel handling equipment will have been checked and dry runs completed;*

j. *The status of protection systems, interlocks, mode switches, alarms, and radiation protection equipment will be prescribed and verified. The high flux trip points will be set for a relatively low power level;*

k. *Water quality must meet required specifications; and*

l. *A neutron source will be installed near the center of the core.*

14.2.12.3.3.3 Description. Prior to fuel loading, control rods and neutron sources and detectors will be installed and tested. Fuel loading will begin at the center of the core and will proceed radially to the fully loaded configuration.

Control rod functional tests, subcriticality checks, and shutdown margin demonstrations will be performed periodically during the loading.

14.2.12.3.3.4 Criteria.

Level 1

The partially loaded core must be subcritical by at least 0.38% $\Delta k/k$ with the analytically strongest rod fully withdrawn.

Level 2

Not applicable.

14.2.12.3.4 Test Number 4 - Full Core Shutdown Margin

14.2.12.3.4.1 Purpose. The purpose of this test is to demonstrate that the reactor will be subcritical throughout the first fuel cycle with any single control rod fully withdrawn.

14.2.12.3.4.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Also the following prerequisites will be complete prior to performing the full core shutdown margin test:

a. *The predicted critical rod position is available,*

b. *The standby liquid control system is available,*

c. *Nuclear instrumentation is available with neutron count rate of at least 0.5 counts per sec and signal to noise ratio greater than two, and*

d. *High-flux scram trips are set conservatively low.*

14.2.12.3.4.3 Description. This test will be performed in the fully loaded core in the xenon-free condition. The shutdown margin test will be performed by withdrawing the control rods from the all-rods-in configuration until criticality is reached. If the highest worth rod will not be withdrawn in sequence, other rods may be withdrawn providing that the reactivity worth is equivalent. The difference between the measure K_{eff} and the calculated K_{eff} for the in sequence critical will be applied to the calculated value to obtain the true shutdown margin.

14.2.12.3.4.4 Criteria.

Level 1

The shutdown margin of the fully loaded, cold (68°F or 20°C), xenon-free core occurring at the most reactive time during the cycle must be at least 0.38% Δk/k with the analytically strongest rod (or its reactivity equivalent) withdrawn. If the shutdown margin is measured at some time during the cycle other than the most active time, compliance with the above criterion is shown by demonstrating that the shutdown margin is 0.38% Δk/k plus an exposure dependent correction factor which corrects the shutdown margin at that time to the minimum shutdown margin.

Level 2

Criticality should occur within ±1% Δk/k of the predicted critical (predicted critical to be determined later).

14.2.12.3.5 Test Number 5 - Control Rod Drive System

14.2.12.3.5.1 Purpose. The purposes of the CRD system test are to (a) demonstrate that the CRD system operates properly over the full range of primary coolant temperatures and pressures from ambient to operating, and (b) determine the initial operating characteristics of the entire CRD system.

14.2.12.3.5.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. The RMC system preoperational testing must be completed on CRDs being tested. The reactor vessel, RCC system, condensate supply system, and instrument air system must be operational to the extent required to conduct the test.

14.2.12.3.5.3 Description. The CRD tests performed during the startup test program are designed as an extension of the tests performed during the preoperational CRD system tests. Thus, after it is verified that all CRDs operate properly when installed, they are tested periodically during heatup to ensure that there is not significant binding caused by thermal expansion of the core components.

		Test Conditions Reactor Pressure with Core Loaded psig (kg/cm^2)			
Action	*Accumulator Pressure*	*0*	*600 (42.2)*	*800 (56.2)*	*Rated*
Position indication		*All*			
Normal stroke times insert/withdraw		*All*			*4**
Coupling		*All***			*4**
Friction		*All*			*4**
Scram	*Normal*	*All*	*4**	*4**	*All*
Scram	*Minimum*	*4**			
Scram	*Zero*				*4**
Scram	*Normal*				*4****

NOTE: Single CRD scrams should be performed with the charging valve closed. (Do not ride the charging pump head.)

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* *Refers to four CRDs selected for continuous monitoring based on slow normal accumulator pressure scram times, or unusual operating characteristics, at zero reactor pressure or rated reactor pressure when this data is available. The "four selected CRDs" must be compatible with the RWM, RSC system, and CRD sequence requirements.*

** *Established initially that this check is normal operating procedures.*

*** *Scram times of the four slowest CRDs (based on scram data at rated pressure will be determined at test condition 2, 3, and 6 during planned reactor scram).*

14.2.12.3.5.4 Criteria.

Level 1

a. *Each CRD must have a normal withdraw speed less than or equal to 3.6 in./sec (9.14 cm/sec), indicated by a full 12-ft stroke in greater than or equal to 40 sec.*

b. *The mean scram time of all operable CRDs with functioning accumulators must not exceed the following times (scram time is measured from the time the pilot scram valve solenoids are deenergized):*

Position Inserted From Fully Withdrawn	*Scram Time (sec)*
45	0.430
39	0.868
25	1.936
05	3.497

c. *The mean scram time of the three fastest CRDs in a two-by-two array must not exceed the following times (scram time is measured from the time the pilot scram valve solenoids are deenergized):*

Position Inserted From Fully Withdrawn	*Scram Time (sec)*
45	0.455
39	0.920
25	2.052
05	3.706

Level 2

a. *Each CRD must have normal insert or withdraw speed of 3.0 ± 0.6 in./sec (7.62 ± 1.52 cm/sec), indicated by a full 12-ft stroke in 40 to 60 sec.*

b. *With respect to the CRD friction tests, if the differential pressure variation exceeds 15 psid (1.1 kg/cm^2) for a continuous drive in, a settling test must be performed, in which case the differential settling pressure should not be less than 30 psid (2.1 kg/cm^2) nor should it vary by more than 10 psid (0.7 kg/cm^2) over a full stroke.*

Level 3

a. *On receipt of a simulated or actual scram signal (maximum error), the flow control valve must close to its minimum position within 10 sec to 30 sec.*

b. *The CRD system flow should not change by more than ± 3.0 gpm as reactor pressure varies from 0 to rated pressure.*

c. *The decay ratio of any oscillatory controlled variable must be ≤0.25 for any flow setpoint changes or for system disturbances caused by the CRDs being stroked.*

14.2.12.3.6 Test Number 6 - Source Range Monitor Performance and Control Rod Sequence

14.2.12.3.6.1 Purpose. The purpose of this test is to demonstrate that the operational sources, SRM instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality and increase power in a safe and efficient manner. The effect of typical rod movements on reactor power will be determined.

14.2.12.3.6.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. The CRD system must be operational.

14.2.12.3.6.3 Description. Source range monitor count-range data will be taken during rod withdrawals to critical and compared with stated criteria on signal count-to-noise count ratio.

A withdrawal sequence has been calculated which completely specifies control rod withdrawals from the all-rods-in condition to the rated power configuration. Critical rod patterns will be recorded periodically as the reactor is heated to rated temperature.

Movement of rods in a prescribed sequence is monitored by the rod control and information system, which will prevent out of sequence withdrawal. Also not more than two rods may be inserted out of sequence.

As the withdrawal of each rod group is completed during the power ascension, the electrical power, steam flow, control valve position, and APRM response will be recorded.

14.2.12.3.6.4 Criteria.

Level 1

There must be a neutron signal-to-noise ratio of at least 2 to 1 on the required operable SRMs or fuel loading chambers.

There must be a minimum count rate of 0.5 counts/sec on the required operable SRMs or fuel loading chambers.

The IRMs must be on scale before the SRMs exceed the rod block setpoint.

Level 2

Not applicable.

14.2.12.3.7 Test Number 7

Not applicable.

14.2.12.3.8 Test Number 8

Not applicable.

14.2.12.3.9 Test Number 9

See test number 16B in Section 14.2.12.3.16.2.

14.2.12.3.10 Test Number 10 - Intermediate Range Monitor System Performance

14.2.12.3.10.1 Purpose. The purpose of this test is to adjust the IRM system to obtain an optimum overlap with the SRM and APRM systems.

14.2.12.3.10.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All SRMs and pulse preamplifiers, IRMs and voltage preamplifiers, and APRMs have been calibrated in accordance with the vendor's instructions.

14.2.12.3.10.3 Description. Initially the IRM system is set to maximum gain. After the APRM calibration, the IRM gains will be adjusted to optimize the IRM overlap with the SRMs and APRMs.

14.2.12.3.10.4 Criteria.

Level 1

Each IRM channel must be on scale before the SRMs exceed their rod block setpoint. Each APRM must be on scale before the IRMs exceed their rod block setpoint.

Level 2

Each IRM channel must be adjusted so that a half decade overlap with the SRMs and one decade overlap with the APRMs are ensured.

14.2.12.3.11 Test Number 11 - Local Power Range Monitor Calibration

14.2.12.3.11.1 Purpose. The purpose of this test is to calibrate the LPRM system.

14.2.12.3.11.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation for calibration has been checked and installed.

14.2.12.3.11.3 Description. The LPRM channels will be calibrated to make the LPRM readings proportional to the neutron flux in the LPRM water gap at the chamber elevation. Calibration factors will be obtained through the use of either an off-line or a process computer calculation that relates the LPRM reading to average fuel assembly power at the chamber height.

14.2.12.3.11.4 Criteria.

Level 1

Not applicable.

Level 2

Each LPRM reading will be within 10% of its calculated value.

14.2.12.3.12 Test Number 12 - Average Power Range Monitor Calibration

14.2.12.3.12.1 Purpose. The purpose of this test is to calibrate the APRM system.

14.2.12.3.12.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation for calibration has been checked and installed.

14.2.12.3.12.3 Description. A heat balance will generally be made each shift and after each major power level change. Each APRM channel reading will be adjusted to be consistent with the core thermal power as determined from the heat balance. During heatup a preliminary calibration will be made by adjusting the APRM amplifier gains so that the APRM readings agree with the results of a constant heatup rate heat balance. The APRMs should be recalibrated in the power range by a heat balance as soon as adequate feedwater indication is available. Recalibration of the APRM system will not be necessary from safety considerations if at least two APRM channels per RPS trip circuit have readings greater than or equal to core power.

14.2.12.3.12.4 Criteria.

Level 1

The APRM channels must be calibrated to read equal to or greater than the actual core thermal power.

Technical Specifications and Fuel Warranty Limits on APRM scram and rod block shall not be exceeded.

In the startup mode, all APRM channels must produce a scram at less than or equal to 15% of rated thermal power.

Level 2

If the above criteria are satisfied then the APRM channels will be considered to be reading accurately if they agree with the heat balance or the minimum value required based on peaking factor maximum linear heat generation rate (MLHGR) and fraction of rated power to within (+7, -0)% of rated power.

14.2.12.3.13 Test Number 13 - Process Computer

14.2.12.3.13.1 Purpose. The purpose of this test is to verify the performance of the process computer under plant operating conditions.

14.2.12.3.13.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Computer diagnostic testing has been completed. Construction and construction testing on each input instrument and its cabling has been completed.

14.2.12.3.13.3 Description. Computer system program verifications and calculational program validations at static and at simulated dynamic input conditions will be

preoperationally tested at the computer supplier's site and following delivery to the plant site. Following fuel loading, during plant heatup and the ascension to rated power, the NSSS and the balance-of-plant system process variables sensed by the computer as digital or analog signals will become available. Verify that the computer is receiving correct values of NSSS process variables and that the results of performance calculations of the NSSS is correct. At steady-state power conditions the dynamic system test case will be performed.

As discussed in Test 19 the BUCLE offline computation system will be used to evaluate core performance until the process computer performance is verified. A manual computation method is available at the site if both the process computer and BUCLE are not available.

14.2.12.3.13.4 Criteria.

Level 1

Not applicable.

Level 2

Programs OD-1, P1, and OD-6 will be considered operational when

a. *The MCPR calculated by BUCLE and the process computer either*

   1. *Are in the same fuel assembly and do not differ in value by more than 2%, or*

   2. *For the case in which the MCPR calculated by the process computer is in a different assembly than that calculated by BUCLE, for each assembly, the MCPR and CPR calculated by the two methods shall agree within 2%.*

b. *The MLHGR calculated by BUCLE and the process computer either*

   1. *Are in the same fuel assembly and do not differ in value by more than 2%, or*

   2. *For the case in which the MLHGR calculated by the process computer is in a different assembly than that calculated by BUCLE, for each assembly, the MLHGR and LHGR calculated by the two methods shall agree within 2%.*

c. *The maximum average planar linear heat generation rate (MAPLHGR) calculated by BUCLE and the process computer either*

1. *Are in the same fuel assembly and do not differ in value by more than 2%, or*

2. *For the case in which the MAPLHGR calculated by the process computer is in different assembly than that calculated by BUCLE, for each assembly, the MAPLHGR and APLHGR calculated by the two methods shall agree within 2%.*

d. *The LPRM gain adjustment factors calculated by BUCLE and the process computer agree to within 2%.*

e. *The remaining programs will be considered operational on successful completion of the static and dynamic testing.*

14.2.12.3.14 Test Number 14 - Reactor Core Isolation Cooling System

14.2.12.3.14.1 Purpose. The purpose of this test is to verify the proper operation of the RCIC system over its expected operating pressure range.

14.2.12.3.14.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing.

14.2.12.3.14.3 Description. The RCIC system test consists of two parts: Injection to the condensate storage tank and injection to the reactor vessel. The initial condensate storage tank (CST) injections consist of manual and automatic starts at 150 psi and at rated reactor pressure. The pump discharge pressure during these tests is throttled to 100 psi above reactor pressure. This initial testing is done to demonstrate system operability and making initial controller adjustments. This is followed by vessel injections beginning with cold RCIC hardware; "cold" being defined as a minimum of 3 days without any kind of RCIC operation.

The vessel injections verify the adequacy of the startup transient and also include steady-state controller adjustments. Five consecutive successful system initiations starting from cold condition and with the same equipment settings are necessary to demonstrate system reliability. Two of these initiations are vessel injection tests with one performed using the controllers on the remote shutdown panel.

After final controller settings are determined, three CST injections at rated pressure and/or 150 psig pressure are done with initially cold RCIC equipment. These runs provide a bench mark for future surveillance testing and provide further assurance of system reliability.

A demonstration of extended operation of 30 minutes of continuous running until pump and turbine oil temperature is stabilized is scheduled at a convenient time during the test program,

probably in conjunction with one of the system reliability tests. During this demonstration, automatic RCIC suction transfer from the CST to the suppression pool will be performed to confirm system stability in this configuration.

During vessel injections all reactor steam is routed to the turbine bypass valves. The steam admission valves of the main and feedwater turbines should be closed whenever the moisture carryover threshold is reached.

14.2.12.3.14.4 *Criteria.*

Level 1

The average pump discharge flow must be equal to or greater than 600 gpm after 30 sec have elapsed from automatic initiation at any reactor pressure between 150 psig and rated.

The RCIC turbine must not trip off or isolate during auto or manual start tests.

If any Level 1 criteria are not met, the reactor operation will be restricted to the power level defined by Figure 14.2-5. This restriction is in addition to any restrictions defined by the Technical Specifications.

Level 2

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere.

The differential pressure switch for the RCIC steam supply line high flow isolation trip shall be adjusted to actuate at the valve specified in the Technical Specifications (about 300%).

The speed and flow control loops shall be adjusted so that the decay ratio of any RCIC system related variable is not greater than 0.25.

To provide an overspeed trip avoidance margin, the transient start first and subsequent speed peaks shall not exceed 5% above the rated RCIC turbine speed.

14.2.12.3.15 Test Number 15

Not applicable.

14.2.12.3.16 Test Numbers 16A and 16B

14.2.12.3.16.1 Test Number 16A - Selected Process Temperatures.

14.2.12.3.16.1.1 Purpose. The purpose of this test is to (a) ensure that the measured bottom head drain temperature corresponds to bottom head coolant temperature during normal operations, (b) identify any reactor operating modes that cause temperature stratification, (c) determine the proper setting of the low flow control limiter for the recirculation pumps to avoid coolant temperature stratification in the RPV bottom head region, and (d) familiarize the plant personnel with the temperature differential limitations of the reactor system.

14.2.12.3.16.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing.

14.2.12.3.16.1.3 Description. The adequacy of bottom drain line temperature sensors will be determined by comparing it with recirculation loop coolant temperature when core flow is 100% of rated.

During initial heatup while at hot standby conditions, the bottom drain line temperature, recirculation loop suction temperature, and applicable reactor parameters are monitored as the recirculation flow is slowly lowered to either minimum stable flow or the low recirculation pump speed minimum valve position, whichever is the greater. The effects of cleanup flow will be investigated as operational limits allow. Using this data it can be determined whether coolant temperature stratification occurs and if so, what minimum recirculation flow will prevent it.

Monitoring the preceding information during planned pump trips will determine if temperature stratification occurs in the idle recirculation loops or in the lower plenum when one or more loops are inactive.

All data will be analyzed to determine if changes in operating procedures are required.

14.2.12.3.16.1.4 Criteria.

Level 1

a. *The reactor recirculation pumps shall not be started nor flow increased unless the coolant temperatures between the steam dome and bottom head drain are within 145°F (81°C).*

b. *The recirculation pump in an idle loop must not be started, active loop flow must not be raised, and power must not be increased unless the idle loop suction temperature is with in 50°F (28°C) of the active loop suction temperature. If*

two pumps are idle, the loop suction temperature must be within 50°F (28°C) of the steam dome temperature before pump startup.

Level 2

During two-pump operation at rated core flow, the bottom head temperature as measured by the bottom drain line thermocouple should be within 30°F (17°C) of the recirculation loop temperatures.

14.2.12.3.16.2 Test Number 16B - Water Level Reference Leg Temperature Measurement.

14.2.12.3.16.2.1 Purpose. The purpose of this test is to measure the reference leg temperature and recalibrate the affected level instruments if the measured temperature is different than the value assumed during the initial calibration.

14.2.12.3.16.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All applicable system instrumentation is installed and calibrated.

14.2.12.3.9.16.2.3 Description. To monitor the reactor vessel water level, five level instrument systems are provided. These are

a. Shutdown range level system,
b. Narrow range level system,
c. Wide range level system,
d. Fuel zone level system, and
e. Upset range.

These systems are used respectively as follows:

a. Water level measurement in cold shutdown conditions (shutdown range level system),

b. Feedwater flow and water level control functions in hot operating conditions (narrow range level system),

c. Safety functions in hot operating conditions (wide range level system),

d. Safety functions in cold shutdown conditions (fuel zone level system), and

e. High water level protection, hot operating condition (upset range).

The test will be done at rated temperature and pressure and under steady-state conditions and will verify that the reference leg temperature of the level instrument is the value assumed during initial calibration. If not, the instruments will be recalibrated using the measured value.

14.2.12.3.16.2.4 Criteria.

Level 1

Not applicable.

Level 2

The indicator readings on the narrow range level system should agree with ± 1.5 in. of the average readings or the reading calculated from the correct reference leg temperatures.

The wide and upset range level system indicators should agree within ± 6 in. of the average readings or the readings calculated from the correct reference leg temperatures.

14.2.12.3.17 Test Number 17 - System Expansion

14.2.12.3.17.1 Purpose. The purpose of this test is to (a) verify that piping systems and components are unrestrained with respect to thermal expansion, (b) verify that suspension components are functioning in the specified manner, (c) provide confirmatory data for the calculated stress levels in nozzles and weldments, (d) perform an inspection to satisfy ASME Section XI, IWF-220 post heatup (shakedown) inspection requirements, and (e) satisfy the inspection requirements for the condensate and feedwater systems according to Regulatory Guide 1.68.1.

14.2.12.3.17:2 Prerequisites. Necessary preoperational tests have been completed. The preheatup examination program relating to component supports as contained in the WNP-2 Preservice Inspection Program Plan has been completed. The POC has reviewed and the Plant Manager has approved the test procedure and initiation of testing. Instrumentation has been installed and calibrated.

14.2.12.3.17.3 Description. A significant mechanical design objective for nuclear piping support systems is to provide for unrestricted thermal expansion of piping and components, from ambient to rated temperature. The combination of visual and remote monitoring of selected piping systems will provide the data necessary to evaluate the support system. The criteria used for system selection is Standard Review Plan Section 3.9.2 and those systems with a normal operating temperature greater than 250°F. The drywell piping systems selected for visual inspection and remote monitoring are the following:

a. Reactor recirculation,
b. Main steam,
c. Feedwater,
d. Residual heat removal (shutdown cooling supply and return line),
e. Reactor core isolation cooling (steam supply and head spray line),
f. Safety/relief valve discharge piping, and
g. Reactor water cleanup.

In addition, visual inspections only of the following drywell systems will be conducted:

a. High-pressure core spray,
b. Low-pressure core spray,
c. Sacrificial shield wall penetrations,
d. Residual heat removal (LPCI) injection lines,
e. Main steam flow instrumentation piping,
f. Main steam drain piping,
g. Reactor head vent piping,
h. Reactor coolant sample piping, and
i. Standby liquid control injection piping.

Piping support system components (hangers, sway struts, boxes, snubbers, and whip restraints) for the systems listed will be visually inspected at ambient (less than or equal to 200°F), during the initial heatup cycle at an intermediate temperature (200°F to 300°F, equivalent to 30 psig reactor pressure) and at normal operating temperature (545°F, equivalent to 1000 psig reactor pressure). Data from the remote monitoring instrumentation will be recorded and evaluated at similar intervals. Exceptions to this are feedwater, main steam relief valve (MSRV) discharge piping, and the reactor head spray and vent piping above the drywell bulkhead. The feedwater piping will attain rated temperatures only at higher reactor power levels, which precludes drywell entry. The MSRV piping is only heated up during valve actuation, which also represents a potential inspection personnel hazard. The area above the bulkhead is considered hazardous due to confinement and high temperatures. The methods used to evaluate these are as follows:

a. Feedwater drywell piping is instrumented and will be evaluated at 25% and 100% reactor power using the data collected by the lanyard potentiometers.

b. Two MSRV lines will be instrumented allowing data evaluation to be applied to all lines during SRV actuation.

c. The piping above the bulkhead will be visually inspected prior to drywell head installation.

Feedwater and the SRV piping systems will also be inspected during the shakedown inspection.

The instrumented nodes will be provided with three sensors to indicate movement in three orthogonal plans. The actual node locations will be selected through a coordinated effort between the WNP-2 Plant Technical and Technology organizations. In this way the analytically best suited node will be coupled with accessible locations. General Electric will provide locations and acceptance criteria for the recirculation and main steam systems. The Supply System Mechanic's Department will provide similar information for the remainder of the systems tested. The instruments will provide thermal movement and vibration data that will be compared with predicted values. If these measured displacements confirm the calculated values, coupled with acceptable visual inspections, the piping system will be considered to have responded as designed. The type of lanyard potentiometer monitors used enable the collection of thermal movement and vibration data. With the acceptance criteria for all testing based on the system design, conformance to the acceptance criteria indicates adherence to the analytical limits.

On completion of the startup test, the piping response data and the completed test procedure will be reviewed by the Supply System Engineering Department responsible for the Stress Report Review and GE. The review will determine if the test results indicate the piping responded in a manner consistent with the Stress Report predictions and the ASME Code limits. A Supply System Level 3 inspector and the American Nuclear Insurers (ANI) will sign all data sheets performing ASME Section XI inspections.

The drywell piping testing/inspections will be conducted during the PATP as follows:

a. The visual inspections and thermal expansion data will be taken during the initial reactor heatup at thermal equilibrium conditions,

b. During the course of the PATP, data will be collected during steady state and transient conditions for vibration level evaluation, and

c. Near the end of the PATP a final drywell entry and inspection is scheduled.

Visual inspections will be conducted on selected piping systems outside the drywell during thermal equilibrium, steady-state operation, and selected transient conditions. The systems selected are:

a. Main steam,
b. Condensate and feedwater,
c. RCIC steam supply and exhaust,
d. RCIC injection piping,
e. RHR shutdown cooling supply and return,
f. Reactor water cleanup, and
g. Main steam leakage control system.

14.2.12.3.17.4 Criteria.

Level 1

Thermally induced displacement of system components shall be unrestrained with no evidence of binding or impairment.

Spring hangers shall not be bottomed out or have the spring fully stretched.

Snubbers shall not reach the limits of their travel. The displacements at the established transducer locations used to measure pipe deflections shall not exceed the allowable values. The allowable values of displacement shall be based on not exceeding ASME Section III Code Stress allowables.

Level 2

Spring hangers will be in their operating range (between the hot and cold settings).

Snubber settings must be within their expected operating range.

The displacements at the established transducer locations shall not exceed the expected values.

14.2.12.3.18 Test Number 18 - Core Power Distribution

14.2.12.3.18.1 Purpose. The purpose of this test is to determine the reproducibility of the TIP system readings.

14.2.12.3.18.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. The TIP detector and dummy detector, ball valve time delay, core top and bottom limits, clutch, x-y recorder, and purge system will have been shown to be operational. Instrumentation has been calibrated and installed.

14.2.12.3.18.3 Description. The TIP reproducibility consists of a random noise component and a geometric component. The geometric component is due to variation in the water gap geometry and TIP tube orientation from TIP location to location. Measurement of these components is obtained by taking repetitive TIP readings at a single TIP location, and by analyzing pairs of TIP readings taken at TIP locations which are symmetrical about the core diagonal of fuel loading symmetry.

One set of TIP data will be taken at the 50% power level and at least one other set at 75% power or above.

The TIP data will be taken with the reactor operating with an octant symmetric rod pattern and at steady-state conditions.

The total TIP reproducibility is obtained by dividing the standard deviation of the symmetric TIP pair nodal ratios by two. The nodal TIP ratio is defined as the nodal base value of the TIP in the lower right half of the core divided by its symmetric counterpart in the upper left half. The total TIP reproducibility value that is compared with the test criterion is the average value of the data sets taken.

The random noise uncertainty is obtained from successive TIP runs made at the common hole, with each of the TIP machines making six runs. The standard deviation of the random noise is derived by taking the square root of the average of the variances at nodal levels 5 through 22, where the nodal variance is obtained from the fractional deviations of the successive TIP values about their nodal mean value.

The geometric component of TIP reproducibility is obtained by statistically subtracting the random noise component from the total TIP reproducibility.

14.2.12.3.18.4 Criteria.

Level 1

Not applicable.

Level 2

The total TIP uncertainty (including random noise and geometrical uncertainties) obtained by averaging the uncertainties for all data sets shall be less than 6.0%.

The data acquired for random noise uncertainty does not have specific acceptance criteria value and is used only to aid in the analysis of the TIP uncertainty.

14.2.12.3.19 Test Number 19 - Core Performance

14.2.12.3.19.1 Purpose. The purposes of this test are to (a) evaluate the core thermal power, and (b) evaluate the following core performance parameters are within limits: (a) maximum linear heat generation rate (MLHGR), (b) minimum critical power ratio (MCPR), and (c) maximum average planar linear heat generation rate (MAPLHGR).

14.2.12.3.19.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing.

System instrumentation has been installed and calibrated, and test instrumentation has been calibrated.

14.2.12.3.19.3 Description. The core performance evaluation is employed to determine the principal thermal and hydraulic parameters associated with core behavior. These parameters are

a. *Core flow rate,*
b. *Core thermal power level,*
c. *MLHGR,*
d. *MAPLHGR, and*
e. *MCPR.*

The core performance parameters will be evaluated by manual calculation techniques described in Startup Test Instruction 19 or may be obtained from the process computer.

If the process computer is used as a primary means to obtain these parameters, it must be proven that it agrees with BUCLE within 2% on all thermal parameters (see Test Number 13). If both BUCLE and the process computer are not available, the manual calculation techniques described in Startup Test Instruction 19 can be used for the core performance evaluation.

14.2.12.3.19.4 Criteria.

Level 1

The MLHGR of any rod during steady-state conditions shall not exceed the limit specified by the Technical Specifications.

The steady-state MCPR shall not exceed the minimum limits specified by the Technical Specifications.

The MAPLHGR shall not exceed the limits specified by the Technical Specifications.

Steady-state reactor power shall be limited to the rated MWt and values on or below the design flow control line. Core flow shall not exceed its rated value.

Level 2

Not applicable.

14.2.12.3.20 Test Number 20 - Steam Production

14.2.12.3.20.1 Purpose. The purpose of performing this test is to demonstrate that the NSSS is providing steam sufficient to satisfy all appropriate warranties as defined in the contract.

14.2.12.3.20.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing.

14.2.12.3.20.3 Description. Warranty demonstration consists of recording sufficient data under steady-state conditions to determine the reactor power level, the pressure and quality of the steam, and the steam flow rate from the reactor.

These measurements will include the temperature, pressure, and flow rate of feedwater entering the reactor; the energy added to the reactor water by the recirculation drive pumps; the flow rate through and temperature entering and leaving the reactor cleanup system; the flow rate and temperature of the CRD cooling water; the carryover of reactor water into the steam lines, and the steam pressure outside the drywell near the MSIV.

Each set of measurements shall be taken at frequent intervals, every 5 or 10 minutes as appropriate, for a total test run duration of 4 hr. The average measure quantity, suitably corrected for all calibration factors, is used to determine NSSS output during the test run. Where the contract requires a 100-hr demonstration, two test runs shall be made, one in the first 50 hr and one in the second 50 hr. The demonstrated output is the average of the values from the two test runs. During the balance of the 100-hr demonstration, the NSSS output shall be held constant within ± 5% of the nominal steam flow rate as indicated by the installed plant feedwater instrumentation.

14.2.12.3.20.4 Criteria.

Level 1

a. *The NSSS parameters as determined by using normal operating procedures shall be within the appropriate license restrictions.*

b. *The NSSS will be capable of supplying steam in an amount and quality corresponding to the final feedwater temperature and other conditions shown on the rated steam output curve in the NSSS technical description. The rated steam output curve provides the warrantable reactor vessel steam output as a function of feedwater temperature, as well as warrantable steam conditions at the outboard MSIVs.*

c. *Thermodynamic parameters are consistent with the 1967 ASME steam tables. Correction techniques for conditions that differ from the contracted conditions will be mutually agreed to prior to the performance of the test.*

Level 2

Not applicable.

14.2.12.3.21 Test Number 21 - Core Power-Void Mode

14.2.12.3.21.1 Purpose. The purpose of this test is to measure the stability of the core power-void dynamic response and to demonstrate that its behavior is within specified limits.

14.2.12.3.21.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. System instrumentation has been installed and calibrated, and test instrumentation calibrated.

14.2.12.3.21.3 Description. The core power void loop mode that results from a combination of the neutron kinetics and core thermal hydraulic dynamics is least stable near the natural circulation end of the rated 100% power rod line. A fast change in the reactivity balance is obtained by a pressure regulator step change (see test 22) and by moving a very high worth rod only 1 or 2 notches. Both local flux and total core response will be evaluated by monitoring selected LPRMs during the transient.

14.2.12.3.21.4 Criteria.

Level 1

The transient response of any system-related variable to any test input must not diverge.

Level 2

The decay ratio for each system-related variable containing oscillatory modes must be less than or equal to 0.5.

14.2.12.3.22 Test Number 22 - Pressure Regulator

14.2.12.3.22.1 Purpose. The purposes of this test are to: (a) determine the optimum settings for the pressure control loop by analysis of the transients induced in the reactor pressure control system by means of the pressure regulators, (b) demonstrate the backup capability of the pressure regulators via simulated failure of the controlling pressure regulator and to set the regulating pressure difference between the two regulators at an appropriate value, (c) demonstrate smooth pressure control transition between the control valves and bypass

valves when reactor steam generation exceeds steam used by the turbine, and (d) demonstrate that affected parameters are within acceptable limits during pressure-regulator-induced transient maneuvers.

14.2.12.3.22.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.22.3 Description. The pressure setpoint will be decreased rapidly and then increased rapidly by about 10 psi (0.7 kg/cm^2) and the response of the system will be measured in each case. It is desirable to accomplish the setpoint change in less than 1 sec. At specified test conditions the load limit setpoint will be set so that the transient is handled by control valves, bypass valves, and both. The regulators will be tested by simulating a failure of a selected pressure regulator so that the other regulator will take over control. The response of the system will be measured and evaluated and regulator settings will be optimized.

14.2.12.3.22.4 Criteria.

Level 1

The transient response of any pressure control system related variable to any test input must not diverge.

Level 2

a. *Pressure control system variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25,*

b. *The pressure response time from initiation of pressure setpoint change to the turbine inlet pressure peak shall be ≤10 sec,*

c. *Pressure control system deadband, delay, etc., shall be small enough that steady-state limit cycles (if any) shall produce steam flow variations no larger than ± 0.5% of rated steam flow,*

d. *For all pressure regulator transients the peak neutron flux and/or peak vessel pressure shall remain below the scram settings by 7.5% and 10 psi respectively (maintain a plot of power versus the peak variable values along the 100% rod line), and*

e. *The variation in incremental regulation (ratio of the maximum to the minimum valve of the quantity, "incremental change in pressure control*

signal/incremental change in steam flow," for each flow range) shall meet the following:

Steam Flow Obtained With Valves Wide Open (%)	*Variation*
0 to 90	*≤4:1*
90 to 97	*≤2:1*
90 to 99	*≤5:1*

Level 3

a. *Additional dynamics of the control system, outside of the regulator compensation filters, shall be equivalent to a time constant no greater than 0.10 sec. This also includes any dead time which may exist,*

b. *Control or bypass valve motion must respond to pressure inputs with deadband (insensitivity) no greater than ± 0.1 psi, and*

c. *Dynamics of both pressure regulators will be essentially identical.*

14.2.12.3.23 Test Number 23 - Feedwater System

14.2.12.3.23.1 23A - Water Level Setpoint and Manual Flow Changes.

14.2.12.3.23.1.1 Purpose. The purpose of this test is to verify that the feedwater system has been adjusted to provide acceptable reactor water level control.

14.2.12.3.23.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.23.1.3 Description. Reactor water level setpoint changes of approximately 3 in. to 6 in. (8 cm to 15 cm) will be used to evaluate (and adjust if necessary) the feedwater control system settings for all power and feedwater pump modes. The level setpoint changes will also demonstrate core stability to subcooling changes.

14.2.12.3.23.1.4 Criteria.

Level 1

The transient response of any level control system-related variable to any test must not diverge.

<u>Level 2</u>

a. *Level control system-related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25;*

b. *The open loop dynamic flow response of each feedwater actuator (turbine or valve) to small (<10%) step disturbances shall be*

1.	*Maximum time to 10% of a step disturbance*	*≤1.1 sec*
2.	*Maximum time from 10% to 90% of a step disturbance*	*≤1.9 sec*
3.	*Peak overshoot (% of step disturbance)*	*≤15%*
4.	*Settling time, 100%, ±5%*	*≤14 sec*

c. *The average rate of response of the feedwater actuator to large (>20% of pump flow) step disturbances shall be between 10% and 25% rated feedwater flow/sec. This average response rate will be assessed by determining the time required to pass linearly through the 10% and 90% response points; and*

d. *At steady-state generation for the 3/1 element system, the input scaling to be mismatch gain should be adjusted such that level error due to biased mismatch gain output should be within ± 1 in.*

<u>Level 3</u>

a. *The dynamic response of each individual level or flow sensor shall be as fast as possible. Band width must be at least 4.0 radians/sec (faster than 0.25 sec equivalent time constant), except for the steam flow sensors which must have band width of at least 1.0 radian/sec (faster than 1.0 sec equivalent time constant);*

b. *Vessel level, feedwater flow, and steam flow sensors must be installed with sufficiently short lines and proper damping adjustment so that no resonances exist;*

c. *Initial settings of the function generators should give a straight line. The function generators must be adjusted so that the change in slope (actual fluid flow change divided by demand change for small disturbances) shall not exceed a factor of 2 to 1 (maximum slope versus minimum slope) over the entire 20% to*

100% feed flow range. Also the function generators should be used to minimize the differences between feedwater actuators (pumps and/or valves); and

d. *All auxiliary controls which have direct impact on reactor level and feedwater control (e.g., feed pump minimum recirculation flow valve control) should be functional, responsive, and stable. The minimum low valve control should be fast enough to avoid pump trips and yet slower than the feedwater startup valve to avoid possible reactor flux scram due to a cold water slug.*

14.2.12.3.23.2 23B - Loss of Feedwater Heating

14.2.12.3.23.2.1 Purpose. The purpose of this test is to demonstrate adequate response to a feedwater temperature loss.

14.2.12.3.23.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.23.2.3 Description. The condensate/feedwater system will be studied to determine the single failure that will cause the largest loss in feedwater heating. This event will then be performed at between 80% and 90% power with the recirculation flow near its rated value.

14.2.12.3.23.2.4 Criteria.

Level 1

a. *For the feedwater heater loss test, the maximum feedwater temperature decrease due to a single failure case must be ≤100°F. The resultant MCPR must be greater than the fuel thermal safety limit; and*

b. *The increase in simulated heat flux cannot exceed the predicted Level 2 valve by more than 2%. The predicted valve will be based on the actual test values of feedwater temperature change and power level.*

Level 2

The increase in simulated heat flux cannot exceed the predicted value in the Transient Safety Analysis Design Report referenced to the actual feedwater temperature change and power level.

14.2.12.3.23.3 22C - Feedwater Pump Trip.

14.2.12.3.23.3.1 Purpose. The purpose of this test is to demonstrate the capability of the automatic core flow runback feature to prevent low water level scram following the trip of one feedwater pump.

14.2.12.3.23.3.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.23.3.3 Description. One of the two operating feedwater pumps will be tripped and the automatic recirculation runback circuit will act to drop the power to within the capacity of the remaining feedwater pump. Prior to the test a simulation of the feedwater pump trip will be done to verify the runback capability of the recirculation system. This test should be performed after test 23D (limiting pump speeds).

14.2.12.3.23.3.4 Criteria.

Level 1

Not applicable.

Level 2

The reactor shall avoid low water level scram by a 3-in. margin from an initial water level halfway between the high- and low-level alarm setpoints.

14.2.12.3.23.4 23D - Maximum Feedwater Runout Capability.

14.2.12.3.23.4.1 Purpose. This test calibrates the feedwater flow and determines if the maximum feedwater runout capability is compatible with the licensing.

14.2.12.3.23.4.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.23.4.3 Description. The test is divided into two parts: first, the initial calibration of the speed controller and second, verification of calibration by measured data which includes a verification that the maximum feedwater flows do not exceed the flows (different flows at different vessel pressures) in the FSAR.

a. *The speed controller calibration is done by first obtaining vendor pump performance curves. The pump performance curves are then used to determine*

the turbine speed corresponding to the maximum allowable flow rated vessel pressure specified by the FSAR and the minimum speed that corresponds to 0% flow at 865 psia. Additionally, for good level control system performance it should reach 115% nuclear boiler rated (NBR) flow at 1080 psia and 90% NBR flow at 1024 psi in the one pump tripped condition. Adjustable equipment (i.e., feed pump turbine speed loops, mechanical limiters, and feedwater control system function generator, etc.) are set to prevent the feedwater pumps from exceeding their maximum allowed output and yet allow the desirable performance; and

b. *During the data collection and verification of calibration portion of the test, pressure, flow, and controller data will be collected between 60%-100% power. Measured data will be compared against expected values to ensure proper calibration. The measured maximum flow will be adjusted to the FSAR pressures using the measured data. The maximum flows stated in the FSAR are used as licensing assumptions; therefore, the FSAR maximum flows should not be exceeded. If, however, the FSAR maximum flows are exceeded two options exist. The system can be adjusted so that the licensing assumption is not exceeded or an additional penalty can be applied to the CPR. The CPR can be revised by applying a 0.01 adder for each 5% of rated feedwater flow difference (between the determined actual maximum flow and the FSAR maximum flow).*

14.2.12.3.23.4.4 Criteria.

Level 1

Maximum speed attained shall not exceed the speeds which will give the following flows with the normal complement of pumps operating.

a. *F% NBR at P psia, and*
b. *[F% + A(P-P rated)] % NBR at P rated, psig*
where: F = 135%, P = 1075 psia, A = 0.2%/psig.

Level 2

The maximum speed must be greater than the calculated speeds required to supply:

a. *With rated complement of pumps -115% NBR at 1075 psi, and*
b. *One feedwater pump tripped condition -68% NBR at 1025 psia.*

NOTE: *Level 1 test criteria are originated from NSSS transient Performance Engineering Unit. Level 2 test criteria are originated from the Control System Design Unit.*

14.2.12.3.24 Test Number 24 - Turbine Valve Surveillance

14.2.12.3.24.1 Purpose. The purpose of this test is to demonstrate the acceptable procedures and maximum power levels for recommended periodic surveillance testing of the main turbine, control, and stop and bypass valves without producing a reactor scram.

14.2.12.3.24.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.24.3 Description. Individual main turbine control and stop and bypass valves are tested routinely during plant operation as required for turbine surveillance testing. At several test points the response of the reactor will be observed. It is recommended that the maximum possible power level for performance of these tests along the 100% load line be established. First, actuation should be between 45% and 65% power and used to extrapolate to the next test point between 75% and 90% power and ultimately to the maximum power test condition with ample margin to scram. Note the proximity to APRM flow bias scram point and preconditioning cladding interim operating management recommendation (PCIOMR) envelope. Each valve test will be manually initiated and reset. The rate of valve stroking and timing of the close-open sequence will be such that the minimum practical disturbance is introduced and that PCIOMR limits are not exceeded.

14.2.12.3.24.4 Criteria.

Level 1

Not applicable.

Level 2

a. *Peak neutron flux must be at least 7.5% below the scram trip setting. Peak vessel pressure must remain at least 10 psi below the high pressure scram setting. Peak heat flux must remain at least 5.0% below its scram trip point; and*

b. *Peak steam flow in each line must remain 10% below the high flow isolation trip setting.*

14.2.12.3.25 Test Number 25 - Main Steam Isolation Valves

14.2.12.3.25.1 25A - Main Steam Isolation Valve Function Tests.

14.2.12.3.25.1.1 Purpose. The purposes of this test are to (a) functionally check the MSIVs for proper operation at selected power levels, (b) determine isolation valve closure times, and (c) determine a maximum power at which full closures of a single valve can be performed without a scram.

14.2.12.3.25.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.25.1.3 Description. At 5% and greater reactor power levels, individual fast closure of each MSIV will be performed to verify their functional performance and to determine closure times. The times to be determined are (a) the time from deenergizing the solenoids until the valve is 100% closed (t_{sol}), and (b) the valve stroke time (t_s) Time t_{sol} equals the interval from deenergizing the solenoids until the valve reaches 90% closed plus 1/8 times the interval from 10% to 90% closure. Time t_s equals the interval from when the valve starts to move until it is 100% closed and is based on the interval from 10% to 90% closure and linear valve travel from 0% to 100% closure.

To determine the maximum power level at which full individual closures can be performed without a scram, first actuation will be performed between 40% to 55% power and used to extrapolate to the next test point between 60% and 85% power and ultimately to the maximum power test condition with ample margin to scram.

14.2.12.3.25.1.4 Criteria.

Level 1

The MSIV stroke time (t_s) shall be not faster than 3.0 sec (average of the fastest valve in each steam line) and for any individual valve 2.5 sec $\leq t_s \leq 5$ sec. Total effective closure time for any individual MSIV shall be t_{sol} plus the maximum instrumentation delay time as determined in preoperational test GE-4 and shall be ≤ 5.5 sec.

Level 2

a. *The reactor shall not scram or isolate, and*

b. *During full closure of individual valves, peak valve pressure must be 10 psi (0.7 kg/cm^2) below scram, peak neutron flux must be 7.5% below scram, and*

steam flow in individual lines must be 10% below the isolation trip setting. The peak heat flux must be 5% less than its trip point.

14.2.12.3.25.2 <u>25B - Full Reactor Isolation</u>.

14.2.12.3.25.2.1 <u>Purpose</u>. The purpose of this test is to determine the reactor transient behavior that results from the simultaneous full closure of all MSIVs.

14.2.12.3.25.2.2 <u>Prerequisites</u>. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.25.2.3 <u>Description</u>. A test of the simultaneous full closure of all MSIVs will be performed at > 75% of rated thermal power. Correct performance of the RCIC and relief valves will be shown. Reactor process variables will be monitored to determine the transient behavior of the system during and following the main steam line isolation.

14.2.12.3.25.2.4 <u>Criteria</u>.

<u>Level 1</u>

a. Reactor must scram to limit the severity of the neutron flux and simulated fuel surface heat flux transient,

b. Feedwater system settings must prevent flooding of the steam lines,

c. The recorded MSIV full closure times must meet the previously stated timing specifications (test 25A), and

d. The positive change in-vessel dome pressure occurring within 30 sec after closure of all MSIV valves must not exceed the Level 2 criteria by more than 25 psi. The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2% of rated value.

<u>Level 2</u>

a. The temperature measured by the thermocouples on the discharge side of the SRVs must return to within 10°F of the temperature recorded before the valve was opened. If pressure sensors are available, they shall return to their initial state upon valve closure;

b. For the full MSIV closure from full power predicted analytical results based on beginning-of-cycle design basis analysis, assuming no equipment failures and

applying appropriate parametric corrections, will be used as the basis to which the actual transient is compared.

c. *Initial action of RCIC and HPCS shall be automatic if low water level (L2) is reached, and system performance shall be within specification, and*

d. *Recirculation pump trip shall be initiated if low water level (L2) is reached. Recirculation pump power will shift to the LFMGs if low water level (L3) is reached.*

14.2.12.3.26 Test Number 26 - Relief Valves

14.2.12.3.26.1 Purpose. The purposes of this test are to (a) verify the proper operation of the main system relief valves, (b) verify that the discharge piping is not blocked, (c) verify their proper seating following operation, (d) obtain signature information of relief valve response for subsequent comparisons, and (e) determine their capacities.

14.2.12.3.26.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.26.3 Description. The main steam relief valves will each be opened using the "manual" control mode so that at any time only one is open. During heatup at 250 psig (17.5 kg/cm^2), each valve will be opened and closed to demonstrate proper functioning. Flow verification of each relief valve will be determined at rate pressure by observing bypass or control valve motion and by observing a change in discharge thermocouple readings. Proper reseating of each relief valve will be verified by observation of temperatures in the relief valve discharge piping. At selected test conditions each valve will be manually actuated and appropriate system parameters recorded during the transient. Data analysis will include a comparison of the system response during each of the valve actuations. Capacity of each relief valve will be determined at rated pressure by the amount of bypass or control valve closure required to maintain reactor pressure.

14.2.12.3.26.4 Criteria.

Level 1

There should be positive indication of steam discharge during the manual actuation of each valve.

The sum of capacity measurements from all relief valves shall be equal to or greater than 15.8 x 10^6 lb/hr at an inlet pressure of 103% at 1205 psig. The total flow capacity of the SRVs used in the automatic depressurization system must be equal to or greater than 4.8 x 10^6 lb/hr

at 1125 psig when the valve having the highest measured capacity is assumed to be out of service.

Level 2

Relief valve leakage shall be low enough that the temperature measured by the thermocouples in the discharge side of the valves returns to within 10°F (5.6°C) of the temperature recorded before the valve was opened. The thermocouples are expected to be operating properly.

The pressure regulator must satisfactorily control the reactor transient and close the control valves or bypass valves by an amount equivalent to the relief valve discharge. The valve transients recorder signatures for each valve must be returned to GE in San Jose for relative system response comparison.

Each relief valve shall have a capacity between 90% and 122.5% of its expected value corrected to an inlet pressure of 103% at 1205 psig.

No more than 25% of the relief valves may have an individual corrected flow rate that is between 90% and 100% of their expected flow rates.

The transient recorder signatures for each valve must be analyzed for relative system response comparison.

14.2.12.3.27 Test Number 27 - Turbine Trip and Generator Load Rejection

14.2.12.3.27.1 Purpose. The purpose of this test is to demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator.

14.2.12.3.27.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All controls and interlocks are checked and instrumentation calibrated. The plant electrical system will be aligned in the normal mode for the operating condition at which the test is performed.

14.2.12.3.27.3 Description. Turbine trip (closure of the main turbine stop valves within 0.1 sec) and generator trip (closure of the main turbine control valves in about 0.1 sec to 0.2 sec) will be performed at selected power levels during the startup test program. At low power levels, reactor protection following the trip is provided by high neutron flux and vessel high pressure scram. For the protective trips occurring at intermediate and higher power levels, reactor will scram by relays, actuated by control or stop valve motion.

A generator trip will be performed at low power level such that nuclear boiler steam generation is just within the bypass valve capacity to demonstrate scram avoidance.

For the trips performed at intermediate power range, reactor scram is most important in controlling the transient peaks.

Above 40% power, the recirculation pump circuit breakers are both automatically tripped, and subsequent transient pressure rise will be limited by the opening of the bypass valves initially and the SRVs if necessary.

14.2.12.3.27.4 Criteria.

Level 1

a. *For turbine and generator trips at power levels greater than 50% NBR, there should be a delay of less than 0.1 sec following the beginning of control or stop valve closure before the beginning of bypass valve opening. The bypass valves should be opened to a point corresponding to greater than or equal to 80% of their capacity within 0.3 sec from the beginning of control or stop valve closure motion;*

b. *Feedwater system settings must prevent flooding of the steam line following these transients;*

c. *The two pump drive flow coastdown transient during the first 6 sec must be equal to or faster than that specified in test 30B (see Figure 14.2-6);*

d. *The positive change in vessel dome pressure occurring within 30 sec after either generator or turbine trip must not exceed the Level 2 criteria by more than 25 psi;*

e. *The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2% of the rated value; and*

f. *The total time delay from start of turbine stop valve motion or control valve motion to the complete suppression of electrical arc between the fully open contacts of the recirculation pump trip (RPT) circuit breakers shall be less than 190 msec.*

Level 2

a. *There shall be no MSIV closure during the first 3 minutes of the transient, and operator action shall not be required during that period to avoid the MSIV trip. (The operator may take action after the first 3 minutes, including switching out of run mode. The operator may also switch out of run mode in the first*

3 minutes if measured data confirms that his action did not prevent MSIV closure);

b. *The positive change in vessel dome pressure and in simulated heat flux which occurs within the first 30 sec after the initiation of either generator or turbine trip must not exceed the predicted values. [Predicted values will be referenced to actual test conditions of initial power life and dome pressure and will use beginning of life (BOL) nuclear data. Worst case design or Technical Specification values of all hardware performance shall be used in the prediction with the exception of control rod insertion time and the delay from beginning of turbine control valve or stop valve motion to the generation of the scram signal. The predicted pressure and heat flux will be corrected for the actual measured values of these two parameters];*

c. *For the generator grip within the bypass valves capacity, the reactor shall not scram for initial thermal power values within that bypass valve capacity;*

d. *The measured bypass capacity (in percent of rated power) shall be equal or greater than that used for the FSAR analysis (3,576,000 lb/hr);*

e. *Recirculation LFMG sets shall take over after the initial recirculation pump trips and adequate vessel temperature difference shall be maintained;*

f. *Feedwater level control shall avoid loss of feedwater due to possible high level (L8) trip during the event;*

g. *Low water level total recirculation pump trip, HPCS, and RCIC shall not be initiated; and*

h. *The temperature measured by thermocouples on the discharge side of the SRVs must return to within 10°F of the temperature recorded before the valve was opened. In addition the acoustical monitors should indicate the valve is closed after the transient is complete.*

14.2.12.3.28 Test Number 28 - Shutdown From Outside the Main Control Room

14.2.12.3.28.1 Purpose. The purpose of this test is to demonstrate that the reactor can be brought down from a normal initial steady-state power level to the point where cooldown is established and under control with reactor vessel pressure and water level controlled from outside the control room.

14.2.12.3.28.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.28.3 Description. The test will be performed at a low power level and will consist of demonstrating the capability to control reactor level and pressure from outside the control room. The reactor will be scrammed and isolated from the control room. Reactor pressure and water level will be controlled using SRVs, RCIC, and RHR from outside the control room during the subsequent cooldown. In addition, the RHR shutdown cooling mode will be placed in service from outside the control room. All other operator actions not directly related to maintaining vessel water level and pressure will be performed in the main control room. Operation from the main control room to protect or secure systems not related to the controlled cooldown of the reactor is permitted during this test. These actions are recorded and later evaluated to determine if they had bearing on the transient.

14.2.12.3.28.4 Criteria.

Level 1

Not applicable.

Level 2

During a simulated main control room evacuation, the reactor must be brought to the point where cooldown can be initiated, and the reactor vessel pressure and water level must be controlled using equipment and controls outside the main control room.

14.2.12.3.29 Test Number 29 - Recirculation Flow Control

14.2.12.3.29.1 29A - Valve Position Control.

14.2.12.3.29.1.1 Purpose. The purpose of this test is to demonstrate the recirculation flow control systems capability while in the valve position (POS) mode.

14.2.12.3.29.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All controls are checked and instrumentation calibrated.

14.2.12.3.29.1.3 Description. The testing of the recirculation flow control system follows a "building block" approach while the plant is ascending from low to high power levels: Components and inner control loops are tested first, followed by drive flow control and plant power maneuvers to adjust and then demonstrate the outer loop controller performance. Preliminary component and valve position loop tests will be run when the plant is in cold

shutdown to visually observe the hydraulic cylinder response. While operating at low power with the pumps using the low frequency power supply, small step changes will input into the position controller and the response recorded.

14.2.12.3.29.1.4 Criteria.

Level 1

The transient response of any recirculation system related variables to any test input must not diverge.

Level 2

a. *Recirculation system related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25,*

b. *Maximum rate of change of valve position shall be 10 ± 1% sec.*

   During TC-3 and TC-6 while operating on the high speed (60 Hz) source, gains and limiters shall be set to obtain the following response,

c. *Delay time for position demand step shall be*

   For step inputs of 0.5% to 5% ≤0.15 sec.
   For step inputs of 0.2% to 0.5%-

d. *Response time for position demand step shall be*

   For step inputs of 0.5% to 5% ≤0.45 sec.
   For step inputs of 0.2% to 0.5%-, and

e. *Overshoot after a small position demand input (1% to 5%) step shall be 10% of magnitude of input.*

Level 3

a. *Gains shall be set to give as fast a response as possible for small position demand input within the overshoot criterion (e) and without additional valve duty cycle. (See test 29B, Section 14.2.12.3.29.2, for valve duty cycle measurement.)*

b. *Position loop deadband shall be 0.2% of full valve stroke.*

<u>NOTE:</u> At a minimum, performing tests near the high and low end of the specified range is acceptable for verifying step input response.

14.2.12.3.29.2 <u>29B - Recirculation Flow Loop Control.</u>

14.2.12.3.29.2.1 <u>Purpose</u>. The purposes of this test are to (a) demonstrate the core flow system's control capability over the entire flow control range, including both core flow neutron flux and load following modes of operation, and (b) determine that all electrical compensators and controllers are set for desired system performance and stability.

14.2.12.3.29.2.2 <u>Prerequisites</u>. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All controls are checked and instrumentation calibrated.

14.2.12.3.29.2.3 <u>Description</u>. Following the initial position mode tests of 29A the final adjustment of the position loop gains, flow loop gains, and preliminary valves of the flux loop adjustments will be made on the mid-power line. This will be the most extensive testing of the recirculation control system. The core power distribution will be adjusted by control rods to permit broader range of maneuverability with respect to PCIOMR. In general, the controller dials and gains will be raised to meet the maneuvering performance objectives. Thus, the system will be set to be the slowest that will perform satisfactorily to maximize stability margins and to minimize equipment wear by avoiding controller overactivity.

Because of PCIOMR power maneuvering rate restrictions, the fast flow maneuvering adjustments are performed along a mid-power rod line, and extrapolation made to the expected results along the 100% rod line. The utility has the option to decide to

a. Perform the faster power changes on the 100% rod line that are greater than what the PCIOMR allow, or

b. To accept the mid-power load line demonstrations as acceptable proof of maneuverability.

For immediate commercial operation, the flux loop will be set slower and the operator will limit manual mode maneuvers. If PCIOMRs are ever withdrawn, the tested faster auto settings can be inserted onto the controller with only a brief dynamic test, rather than a full startup test.

14.2.12.3.29.2.4 *Criteria.*

Level 1

The transient response of any recirculation system related variable to any test input must not diverge.

Level 2

a. *The decay ratio of the flow loop response to any test inputs shall be <0.25,*

b. *The flow loops provide equal flows in the two loops during steady-state operation. Flow loop gains should be set to correct a flow imbalance in less than 25 sec,*

c. *The delay time for flow demand step (≤5%) shall be 0.4 sec or less,*

d. *The response time for flow demand step (≤5%) shall be 1.1 sec or less,*

e. *The maximum allowable flow over shoot for step demand of ≤5% of rated shall be 6% of the demand step, and*

f. *The flow demand step settling time shall be ≤6 sec.*

Level 3

a. *Incremental gain from function generator for valve position demand input to sensed drive flow shall not vary by more than 2 to 1 over the entire flow range, and*

b. *Flow loop upper limit should be checked for proper setting.*

Flux Loop Criteria

Level 1

The flux loop response to test inputs shall not diverge.

Level 2

a. *Flux over shoot to a flux demand step shall not exceed 2% of rated for a step demand of ≤20% of rated,*

b. *The delay time for flux response to a flux demand step shall be ≤0.8 sec,*

c. *The response time for flux demand stop shall be 2.5 sec, and*

d. *The flux setting time shall be ≤15 sec for a flux demand step ≤20% of rated.*

Scram Avoidance and General Criteria

Level 1

Not applicable.

Level 2

For any one of the above loops test maneuvers, the trip avoidance margins must be at least the following:

a. *For APRM ≥7.5%, and*
b. *For simulated heat flux ≥5.0%.*

Flux Estimator Test Criteria

Level 1

Not applicable.

Level 2

a. *Switching between estimated and sensed flux should not exceed 5 times/5 minutes at steady state, and*

b. *During flux step transient there should be no switching to sensed flux or if switching does occur, it should switch back to estimated flux within 20 sec of the transient.*

Flux Control Valve Duty Test Criteria

Level 1

Not applicable.

Level 2

The flow control valve duty cycle in any operating mode shall not exceed 0.2% Hz. Flow control valve duty cycle is defined as

$$\frac{\text{Integrated valve movement in percent (\% Hz)}}{\text{2x time span in seconds}}$$

14.2.12.3.30 Test Number 30 - Recirculation System

14.2.12.3.30.1 30A - One Pump Trip.

14.2.12.3.30.1.1 Purpose. The purposes of this test are to (a) obtain recirculation system performance data during the pump trip, flow coastdown, and pump restart, and (b) verify that the feedwater control system can satisfactorily control water level without a resulting turbine trip/scram.

14.2.12.3.30.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.1.3 Description. The reactor coolant recirculation system consists of the reactor vessel and two piping loops. Each loop contains a constant speed centrifugal recirculation pump, a flow control valve and two isolation valves located in the drywell, and 10 jet pumps in parallel, situated in the reactor downcomer and discharges through a manifold system to the nozzles of the 10 jet pumps. Here the flow is augmented by suction flow from the downcomer and delivered to the reactor inlet plenum.

A potential threat to plant availability is the high water level turbine trip scram caused by the level upswell that results after an unexpected recirculation one pump trip. The change in core flow and the resultant power decrease causes void formation which the level sensing system senses as a rise in water level. The one-pump trip tests are to prove that the water level will not rise enough to threaten a high level trip of the main turbine or the feedwater pumps.

14.2.12.3.30.1.4 Criteria.

Level 1

The reactor shall not scram during the one-pump trip recovery.

Level 2

The reactor water level margin to avoid a high level trip shall be ≥3.0 in. during the one-pump trip.

NOTE: Margin to trip is defined as

Margin (high level trip <8 setpoint) - (maximum water level reached ruing test) - (high level alarm <7 setpoint - initial water level)

a. *The simulated heat flux margin to avoid a scram shall be ≥5.0% during the one-pump trip and also during the recovery, and*

b. *The APRM margin to avoid a scram shall be ≥7.5% during the one-pump trip recovery.*

14.2.12.3.30.2 30B - Recirculation Trip of Two Pumps.

14.2.12.3.30.2.1 Purpose. The purpose of the test is to record and verify acceptable performance of the recirculation two pump circuit trip system.

14.2.12.3.30.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.2.3 Description. In case of higher power turbine or generator trips, there is an automatic opening of circuit breakers in the pump power supply. The result is a fast core flow coastdown that helps reduce peak neutron and heat flow in such events. This two-pump trip test verifies that this flow coastdown is satisfactory prior to the high power turbine/generator trip tests and subsequent operation.

14.2.12.3.30.2.4 Criteria.

Level 1

The two-pump-drive flow coastdown transient during the first 6 sec must be bounded by the limiting curves. (See Figure 14.2-6.)

(The limiting curves will be determined based on measurement of the recirculation flow delta P using the elbow flow meters, transmitter time delay, and time constant.)

Level 2

Not applicable.

14.2.12.3.30.3 30C - System Performance.

14.2.12.3.30.3.1 Purpose. The purpose of this test is to record recirculation system parameters during the power test program.

14.2.12.3.30.3.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.3.3 Description. Recirculation system parameters will be recorded at several power-flow conditions and in conjunction with single pump trip recoveries and internals vibration testing (if applicable).

14.2.12.3.30.3.4 Criteria.

Level 1

Not applicable.

Level 2

a. *The core flow shortfall shall not exceed 5% at rated power,* *

b. *The measured core delta P shall not be 70.6 psi above prediction,* *

c. *The calculated jet pump M ration shall not be 0.2 points below prediction,* *

d. *The drive flow shortfall shall not exceed 5% at rated power,* *

e. *The measured recirculation pump efficiency shall not be 78% points below the vendor tested efficiency, and*

f. *The nozzle and riser plugging criteria shall not be exceeded.*

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* *The GE Steam Generation System Design Unit will provide predictions for the comparisons for these criteria.*

14.2.12.3.30.4 30D - Recirculation Pump Runback.

14.2.12.3.30.4.1 Purpose. The purpose of this test is to verify the adequacy of the recirculation runback to mitigate a scram on the loss of one feedwater pump.

14.2.12.3.30.4.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.4.3 Description. While operating at near rated recirculation flow, a loss of a feedwater pump will be simulated. The transient and final condition will be studied to determine the adequacy of the system in preventing a scram during the scheduled loss of a single feedwater pump test (test 23C).

14.2.12.3.30.4.4 Criteria.

Level 1

Not applicable.

Level 2

The recirculation flow control valves shall runback on a trip of the runback circuit.

14.2.12.3.30.5 30E - Recirculation System Cavitation.

14.2.12.3.30.5.1 Purpose. The purpose of this test is to verify that no recirculation system cavitation will occur in the operable region of the power-flow map.

14.2.12.3.30.5.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.5.3 Description. Both the jet pumps and the recirculation pumps will cavitate at conditions of high flow and low power where NPSH demands are high and little feedwater subcooling occurs. However, the recirculation flow will automatically run back on sensing a decrease in subcooling (as measured by the difference between the steam and recirculation loop temperature), to lower the reactor power. The maximum recirculation flow is limited by approximate stops which will run back the recirculation flow away from the possible cavitation region. It will be verified that these limits are sufficient to prevent operation where recirculation pump or jet pump cavitation is predicted to occur.

The recirculation system flow control valves will cavitate at conditions of high differential pressure and low power (low subcooling). The recirculation flow will automatically run back on sensing a decrease in subcooling (as measured by a low feedwater flow). This limit will be verified to ensure that operation is prevented where flow control valve cavitation may occur.

In both the above cases, flow runback is caused by a shift in the power supply to the recirculation pump motors from normal power to the LFMGs.

14.2.12.3.30.5.4 Criteria.

Level 1

Not applicable.

Level 2

Runback logic shall have settings adequate to prevent operation in areas of potential cavitation.

14.2.12.3.31 Test Number 31 - Loss of Turbine-Generator and Offsite Power

14.2.12.3.31.1 Purpose. This test determines electrical equipment and reactor system transient performance during a loss of auxiliary power.

14.2.12.3.31.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate. The plant electrical system will be aligned in the normal mode for the operating condition at which the test is performed.

14.2.12.3.31.3 Description. The loss of auxiliary power test will be performed at 20% to 30% of rated power. The proper response of reactor plant equipment, automatic switching equipment, and the proper sequencing of the diesel generator load will be verified. Appropriate reactor parameters will be recorded during the resultant transient.

14.2.12.3.31.4 Criteria.

Level 1

a. *Reactor protection system actions shall prevent violation of fuel thermal limits.*

b. *All safety systems, such as the RPS, the diesel generators, and HPCS must function properly without manual assistance. The HPCS and/or RCIC system action, if necessary, shall keep the reactor water level above the initiation level*

of the LPCS, LPCI, automatic depressurization systems, and MSIV closure. Diesel generators shall start automatically and when they reach rated frequency and voltage the diesel breakers will close and restore power to the engineered safety features (ESF) buses.

Level 2

a. *Proper instrument display to the reactor operator shall be demonstrated, including power monitors, pressure, water level, control rod position, suppression pool temperature, and reactor cooling system status. Displays shall not be dependent on specially installed instrumentation, and*

b. *If SRVs open, the temperature measured by thermocouples on the discharge side of the SRVs must return to within 10°F of the temperature recorded before the valve was opened. If pressure sensors are available, they shall return to their initial state on valve closure.*

14.2.12.3.32 Not Applicable

14.2.12.3.33 Test Number 33 - Piping Vibration

14.2.12.3.33.1 Purpose. The purpose of this test is to verify that the design stress levels due to piping vibration are not exceeded and satisfy the inspection requirements for condensate and feedwater systems according to Regulatory Guide 1.68.1.

14.2.12.3.33.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been installed and calibrated.

14.2.12.3.33.3 Description. This test is an extension of test 17 and has been procedurally combined with the system expansion test. During reactor operation, it is desirable to show that destructive level piping vibrations do not occur during steady-state conditions and during planned transients. Acceptable vibration levels are verified by measurement (using the same sensors used in test 17) and by visual observation during system walkdowns for selected piping systems outside containment. See Section 14.2.12.3.17.2 for systems selected and selection criteria.

14.2.12.3.33.4 Criteria.

Level 1

The measured vibration amplitude (peak-to-peak) of the systems monitored shall not exceed the maximum allowable displacements.

Level 2

The measured amplitude (peak-to-peak) of vibration shall not exceed the expected values.

Visual Inspection Acceptance Criteria

The vibration levels experienced will be evaluated as acceptable if they are too small to be detected by the naked eye with consideration given to the following:

a. *Proximity to sensitive equipment (pumps, valves, motor control centers, control panels, etc.),*

b. *Branch connection behavior, and*

c. *Performance of nearby component supports.*

If an acceptable assessment of the observed deflections cannot be performed and corrective measures are not available, the inspector will then obtain the magnitude and frequency of the vibration using a portable vibration instrument. The information will then be evaluated by the piping design engineer to verify acceptance. Unacceptable vibration levels will be treated as a Level 1 violation.

14.2.12.3.34 Test Number 34 - Reactor Pressure Vessel Internals Vibration

14.2.12.3.34.1 Purpose. The purpose of this test is to provide information needed to confirm the similarity between the reactor internals design and the prototype with respect to flow-induced vibration. Testing is in response to Regulatory Guide 1.20 for a vibration measurement program for nonprototype, Category IV reactor internals, and the GE vibration test specification 22A6601, Revision 0.

14.2.12.3.34.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.34.3 Description. During operation, the reactor structure may be forced into many modes of vibrations. Analytical work indicates that unacceptable level vibrations will not occur.

Detailed descriptions of sensor locations are given in GE Test Specification 22A6601, Revision 0.

Sensors used for the measurements are resistance wire strain gauges and accelerometers with double integrating output signal conditioning. Sensors will be installed in a manner to sense the most probable mode of vibration as indicated by analysis.

The test program consists of at power tests performed with the system at normal operating pressure and temperature.

During the vibration test the vibration engineer will monitor and record vibrating amplitudes and frequencies obtained from the sensors mounted on the various components. The measured amplitudes and frequencies are then compared to the acceptance criteria to ensure that all measured vibration amplitudes are within acceptable levels.

14.2.12.3.34.4 Criteria.

Level 1

The peak stress intensity may exceed 10,000 psi (single amplitude) when the component deformed in a manner corresponding to one of its normal or natural modes, but the fatigue usage factor must not exceed 1.0.

Level 2

The peak stress intensity shall not exceed 10,000 psi (single amplitude) when the component is deformed in a manner corresponding to one of its normal or natural modes. This is the low stress limit which is suitable for sustained vibration in the reactor environment for the design life of the reactor components.

14.2.12.3.35 Test Number 35 - Recirculation System Flow Calibration

14.2.12.3.35.1 Purpose. The purpose of this test is to perform complete calibration of the installed recirculation system flow instrumentation.

14.2.12.3.35.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.35.3 Description. During the testing program at operating conditions, which allow the recirculation system to be operated at rated flow at rated power, the jet pump flow instrumentation will be adjusted to provide correct flow indication based on the jet pump flow. After the relationship between drive flow and core flow is established, the flow biased APRM/RBM system will be adjusted to match this relationship.

14.2.12.3.35.4 Criteria.

Level 1

Not applicable.

Level 2

Jet pump flow instrumentation shall be adjusted such that the jet pump total flow recorder will provide a correct core flow indication at rated conditions.

The APRM/RBM flow-bias instrumentation shall be adjusted to function properly at rated conditions.

The flow control system shall be adjusted to limit maximum core flow to 102.5% of rated by limiting the flow control valve opening position.

14.2.12.3.36 Test Number 70 - Reactor Water Cleanup System

14.2.12.3.36.1 Purpose. The purpose of this test is to demonstrate specific aspects of the mechanical operability of the RWCU system. (This test, performed at rated reactor pressure and temperature, is actually the completion of the preoperational testing that could not be done without nuclear heating.)

14.2.12.3.36.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.36.3 Description. With the reactor at rated temperature and pressure, process variables will be recorded during steady-state operation in three modes as defined by the system process diagram: hot shutdown with loss of RPV recirculation pumps, normal, and blowdown. A comparison of the bottom head flow indicator and the RWCU inlet flow indicator will be made. The RWCU system sample station shall be tested at hot process conditions.

14.2.12.3.36.4 Criteria.

Level 1

Not applicable.

Level 2

The temperature at the tube side outlet of the nonregenerative heat exchangers shall not exceed 130°F (54°C) in the blowdown mode and shall not exceed 120°F in the normal mode.

The pump available NPSH will be 13 ft or greater during the hot shutdown with loss of RPV recirculation pumps mode defined in the process diagrams.

The cooling water supplied to the nonregenerative heat exchangers shall be less than 6% above the flow corresponding to the heat exchanger capacity (as determined from the process diagram) and the existing temperature differential across the heat exchangers. The outlet temperature shall not exceed 180°F.

Recalibrate bottom head flow indicator (R610) against RWCU flow indicator (R609) if the deviation is greater than 25 gpm.

Pump vibration shall be less than or equal to 2 mils peak-to-peak (in any direction) as measured on the bearing housing and 2 mils peak-to-peak shaft vibration as measured on the coupling end.

14.2.12.3.37 Test Number 71 - Residual Heat Removal System

14.2.12.3.37.1 Purpose. The purpose of this test is to demonstrate the ability of the RHR system to remove heat from the reactor system so that the refueling and nuclear system servicing can be performed.

14.2.12.3.37.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.37.3 Description. During the first suitable reactor cooldown, the shutdown cooling mode of the RHR system will be demonstrated. Unfortunately, the decay heat load is insignificant during the startup test period. Use of the mode with low core exposure could result in exceeding the 100°F/hr cooldown rate of the vessel if both RHR heat exchangers are used simultaneously. Late in the test program after accumulating significant core exposure, this demonstration would more adequately demonstrate the heat exchanger capacity.

14.2.12.3.37.4 Criteria.

Level 1

Not applicable.

Level 2

The RHR system shall be capable of operating in the suppression pool cooling and shutdown cooling modes (with each heat exchanger) at the flow rates and temperature differentials determined by the flow rates and temperature differentials indicated on the process diagrams.

14.2.12.3.38 Test Number 72 - Drywell Atmosphere Cooling System

14.2.12.3.38.1 Purpose. The purpose of this test is to verify the ability of the drywell atmosphere cooling system to maintain design conditions in the drywell during operating conditions and post scram conditions.

14.2.12.3.38.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.38.3 Description. During heatup and power operation, data will be taken to ascertain that the drywell atmospheric conditions are within design limits.

14.2.12.3.38.4 Criteria.

Level 1

Not applicable.

Level 2

The drywell cooling system shall maintain drywell air temperatures at or below the design values as specified for the NSSS equipment.

14.2.12.3.39 Test Number 73 - Cooling Water Systems

14.2.12.3.39.1 Purpose. The purpose of the test is to verify that the heat removal performance of the SW system, the reactor building RCC system, and the plant service water (TSW) system is adequate.

14.2.12.3.39.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.39.3 Description. The SW, the RCC, and the TSW systems heat exchanger heat transport capabilities will be verified. Verification will be conducted in the following manner. The system water flow rate through each heat exchanger will be measured. The system water

temperature drop across each heat exchanger will also be measured. From these acquired water flow rates and temperature drop data, the heat transport rates will be calculated. Where available, the calculated heat transport data will be compared directly with design calculations to determine acceptability. For those systems in which no design calculations of the heat transport rate have been directly calculated, the heat removal performance of the particular heat exchanger will be considered acceptable if the components serviced by the cooling system exhibit proper operation. If proper performance is not experienced, adjustments in the heat transport capability (i.e., increased flow to the heat exchanger or increased flow to a particular load) would be made. In addition to the heat exchanger heat transport rate verification, the actual SW pump head will be determined for all three SW pumps. This actual SW pump head will be compared to the design requirements for acceptability.

14.2.12.3.39.4 <u>Criteria</u>.

<u>Level 1</u>

Not applicable.

<u>Level 2</u>

The system heat transport parameters either meet the requirements of the design specifications, or provide adequate cooling to the components serviced such that they operate satisfactorily.

14.2.12.3.40 Test Number 74 - Offgas System

14.2.12.3.40.1 <u>Purpose</u>. The purposes of this test are to verify the proper operation of the offgas system over its expected operating parameters and to determine the performance of the activated carbon adsorbers.

14.2.12.3.40.2 <u>Prerequisites</u>. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.40.3 <u>Description</u>. The pressure, temperature, relative humidity, system flow, and percentage of radiolytic hydrogen in the offgas are periodically monitored during startup and at steady-state conditions. Prior to initial steam flow to the main condenser, charcoal bed hold-up times will be measure experimentally using a pulsed Krypton-85 gas injection technique. The charcoal bed dynamic adsorption coefficient will then be determined by established analytical methods. The performance of the catalytic recombiner will be compared the catalytic recombiner guaranteed performance curve.

14.2.12.3.40.4 Criteria.

Level 1

The release of radioactive gaseous and particulate effluents must not exceed the limits specified in the Technical Specifications. There shall be no loss of flow of dilution steam to the noncondensing stage when the steam jet air ejectors are pumping.

Level 2

The system flow, pressure, temperature, and relative humidity shall comply with design specifications.

TABLE 14.2-1

PREOPERATIONAL TESTS

Section Reference	*Title*
14.2.12.1.1	*Reactor Feedwater System*
14.2.12.1.2	*Condensate System*
14.2.12.1.3	*Fire Protection System*
14.2.12.1.4	*Reactor Water Cleanup System*
14.2.12.1.5	*Standby Liquid Control System*
14.2.12.1.6	*Nuclear Boiler System*
14.2.12.1.7	*Residual Heat Removal System*
14.2.12.1.8	*Reactor Core Isolation Cooling*
14.2.12.1.9	*Reactor Recirculation System and Control*
14.2.12.1.10	*Reactor Manual Control System*
14.2.12.1.11	*Control Rod Drive Hydraulic System*
14.2.12.1.12	*Fuel Handling and Vessel Servicing Equipment*
14.2.12.1.13	*Low Pressure Core Spray System*
14.2.12.1.14	*High Pressure Core Spray*
14.2.12.1.15	*Fuel Pool Cooling and Cleanup System*
14.2.12.1.16	*Leak Detection System*
14.2.12.1.17	*Liquid and Solid Radwaste System*
14.2.12.1.18	*Reactor Protection System*
14.2.12.1.19	*Neutron Monitoring System*
14.2.12.1.20	*Traversing In-Core Probe System*
14.2.12.1.21	*Rod Worth Minimizer System*
14.2.12.1.22	*Process Radiation Monitoring System*
14.2.12.1.23	*Area Radiation Monitoring System*

TABLE 14.2-1

PREOPERATIONAL TESTS (Continued)

Section Reference	Title
14.2.12.1.24	Process Computer Interface System
14. 2.12.1.25	Rod Sequence Control System
14.2.12.1.26	Remote Shutdown
14.2.12.1.27	Offgas System
14.2.12.1.28	Environs Radiation Monitoring System
14.2.12.1.29	Main Steam System
14.2.12.1.30	Radwaste Building Heating, Ventilation, and Air Conditioning System
14.2.12.1.31	Closed Cooling Water System
14.2.12.1.32	Primary Containment Atmospheric Control System
14.2.12.1.33	Primary Containment Cooling System
14.2.12.1.34	Primary Containment Instrument Air System
14.2.12.1.35	Primary Containment Atmospheric Monitoring System
14.2.12.1.36	Standby Gas Treatment System
14.2.12.1.37	Loss of Power and Safety Testing
14.2.12.1.38	Instrument Power System
14.2.12.1.39	Emergency Lighting
14.2.12.1.40	Standby Alternating Current Power System
14.2.12.1.41	250-V Direct Current Distribution System
14.2.12.1.42	125-V Direct Current Distribution System
14.2.12.1.43	24-V Direct Current Distribution System
14.2.12.1.44	Plant Service Water System
14.2.12.1.45	Standby Service Water System
14.2.12.1.46	Plant Communication System

TABLE 14.2-1

PREOPERATIONAL TESTS (Continued)

Section Reference	*Title*
14.2.12.1.47	*Reactor Building Emergency Cooling System*
14.2.12.1.48	*Control Cable and Critical Switchgear Rooms Heating, Ventilation, and Air Conditioning System*
14.2.12.1.49	*Standby Service Water Pump House Heating and Ventilating System*
14.2.12.1.50	*Reactor Building Crane*
14.2.12.1.51	*Primary Containment Integrated Leak Rate Test*
14.2.12.1.52	*Secondary Containment Integrated Leak Rate Test*
14.2.12.1.53	*Diesel Generator Building Heating and Ventilating System*

TABLE 14.2-2

MAJOR PLANT TRANSIENTS

Test	Title		Test Condition		
		Approximate Power (% rated)	20-25	60-75	95-100
		Approximate Core Flow (% rated)	37	100	100
23C	Feedwater pump trip				X
23B	Loss of feedwater heating				X
25	MSIVs (all valves, full isolation)				X
27	T-G stop valve fast close			X	
27	T-G control valve fast close		X		X
28	Shutdown from outside control room		X		
30	Recirculation pump trips			X	X
31	Loss of generator and offsite power		X		
	Test condition		1, 2	3	6

TABLE 14.2-3

STABILITY TESTS

			Test Condition					
		Approximate Power (% rated)	20	40	60-75	60-75	95-100	40-50
Test	Title	Approximate Core Flow (% rated)	37	50	100	55	100	NC
21	Core power - void mode response					X		X
22	Pressure regulator setpoint changes		X	X	X	X	X	X
22	Pressure regulator backup regulator		X	X	X	X	X	X
23A	Feedwater system: water level setpoint change		X	X	X	X	X	X
23B	Feedwater system: heater loss						X	
24	Turbine valve surveillance					X[a]	X[b]	
29	Recirculation flow control system		X	X	X	X	X	X
	Test condition		1	2	3	5	6	4

[a] 45-65% Power
[b] 75-90% Power

TABLE 14.2-4

POWER ASCENSION TEST PROGRAM

				Test Conditions[a]						
Test	Name	Cold Test or Open RPV	Heat Up	1	2	3	4	5	6	Warranty
1	Chemical and radiochemical	X	X	X	X	X			X	
2	Radiation measurements	X	X	X	X	X			X	
3	Fuel loading	X								
4	Full core shutdown margin	X								
5	Control rod drive	X	X		X[b]	X[b]			X[b]	
6	SRM performance and control rod sequence	X	X	X	X			X	X	
7	Not applicable									
8	Not applicable									
9	See 16B									
10	IRM performance	X	X	X						
11	LPRM calibration		X	X		X			X	

TABLE 14.2-4

POWER ASCENSION TEST PROGRAM (Continued)

				Test Conditions[a]						
Test	Name	Cold Test or Open RPV	Heat Up	1	2	3	4	5	6	Warranty
12	APRM calibration		X	X	X	X		X	X	X
13	Process computer	X	X	X[c]						
14	RCIC		X	X						
15	Not applicable									
16A	Selected process temperatures		X	X	X	X	X		X	
16B	Water level reference leg temperature measurement		X	X	X	X	X	X	X	
17	System expansion and piping vibration	X	X	X	X	X			X	
18	Core power distribution					X			X	
19	Core performance			X	X	X	X	X	X	X
20	Steam production									X
21	Core power void mode response						X	X		

TABLE 14.2-4

POWER ASCENSION TEST PROGRAM (Continued)

Test	Name	Cold Test or Open RPV	Heat Up	Test Conditions[a] 1	2	3	4	5	6	Warranty
22	Pressure regulator: setpoint changes			X,BP	X,BP	X,NO BP,M	X,BP	X,BP, M	X,M, BP	
	Backup regulator			X,BP	X,BP	X,NO BP,M	X,BP	X,NO, BP,M	X,M, BP	
23	Feedwater system									
	C feedwater pump trip								M[d]	
	A water level setpoint change			X	X	X,M	X	X	X,M	
	B heater loss								X[e]	
	D maximum runout capability		X[f]	X[f]			X	X		
24	Turbine valve surveillance						X,[g,h] SP	X,[i,j] SP		
25	MSIVs: each valve		X	X,[c] S						
	one valve						X,[g,i,j] X,[k] SP			

TABLE 14.2-4

POWER ASCENSION TEST PROGRAM (Continued)

Test	Name	Cold Test or Open RPV	Heat Up	Test Conditions[a] 1	2	3	4	5	6	Warranty
	full isolation							X,[b] X,[l] SD		
26	Relief valves:									
	Flow demonstration			X[l,m]						
	Operational		X	X[m]						
27	Turbine stop valve					X[b,l]				
	Stop					SD				
	Generator load				X,BP				X[b,l]	
	Rejection								X,[n] SD	
28	Shutdown from outside control room			X					X[o]	

TABLE 14.2-4

POWER ASCENSION TEST PROGRAM (Continued)

				Test Conditions[a]						
Test	Name	Cold Test or Open RPV	Heat Up	1	2	3	4	5	6	Warranty
29	Recirculation flow control system	L		L	M,[m] X,[m] L[m]	X,[m] L,[m] M,[m] A[m]	L[g]	M,[g] X[g]	L,[g] X[g]	
30	Recirculation system:									
	Trip one pump					X[l,n]			X[l,n]	
	Trip two pumps					X[l,n]				
	System performance				X	X[l,m]	X[g]		X[l]	
	Runback					X[d]				
	Noncavitation verification					X				
31	Loss of T-G and offsite power				X,[b,l] SD					
32	Not applicable									
33	Not applicable									

TABLE 14.2-4

POWER ASCENSION TEST PROGRAM (Continued)

Test	Name	Cold Test or Open RPV	Heat Up	Test Conditions[a] 1	2	3	4	5	6	Warranty
34	RPV Internals				X[m]	X[m]		X[g]	X[g]	
36-69	Not applicable									
70	Reactor water cleanup system		X							
71	Residual heat removal system								X	
72	Drywell atmosphere cooling		X		X	X			X	
73	Cooling water system		X						X	
74	Offgas system	X	X	X		X			X	

[a] See Figure 14.2-1 for test conditions region map.

[b] Perform test 5, timing of four slowest control rods in conjunction with these scrams.

[c] Between test conditions 1 and 3.

[d] Demonstrate recirculation system runback feature.

[e] 80%-90% power.

[f] At either heatup or test condition 1.

TABLE 14.2-4

POWER ASCENSION TEST PROGRAM (Continued)

[g] *Between or at test conditions 5 and 6.*

[h] *Between 45% and 65% power on 100% load line.*

[i] *Future maximum power test point.*

[j] *Determine maximum power without scram.*

[k] *Between 40% and 55% power on the 100% load line.*

[l] *Do test 17 in conjunction with this test.*

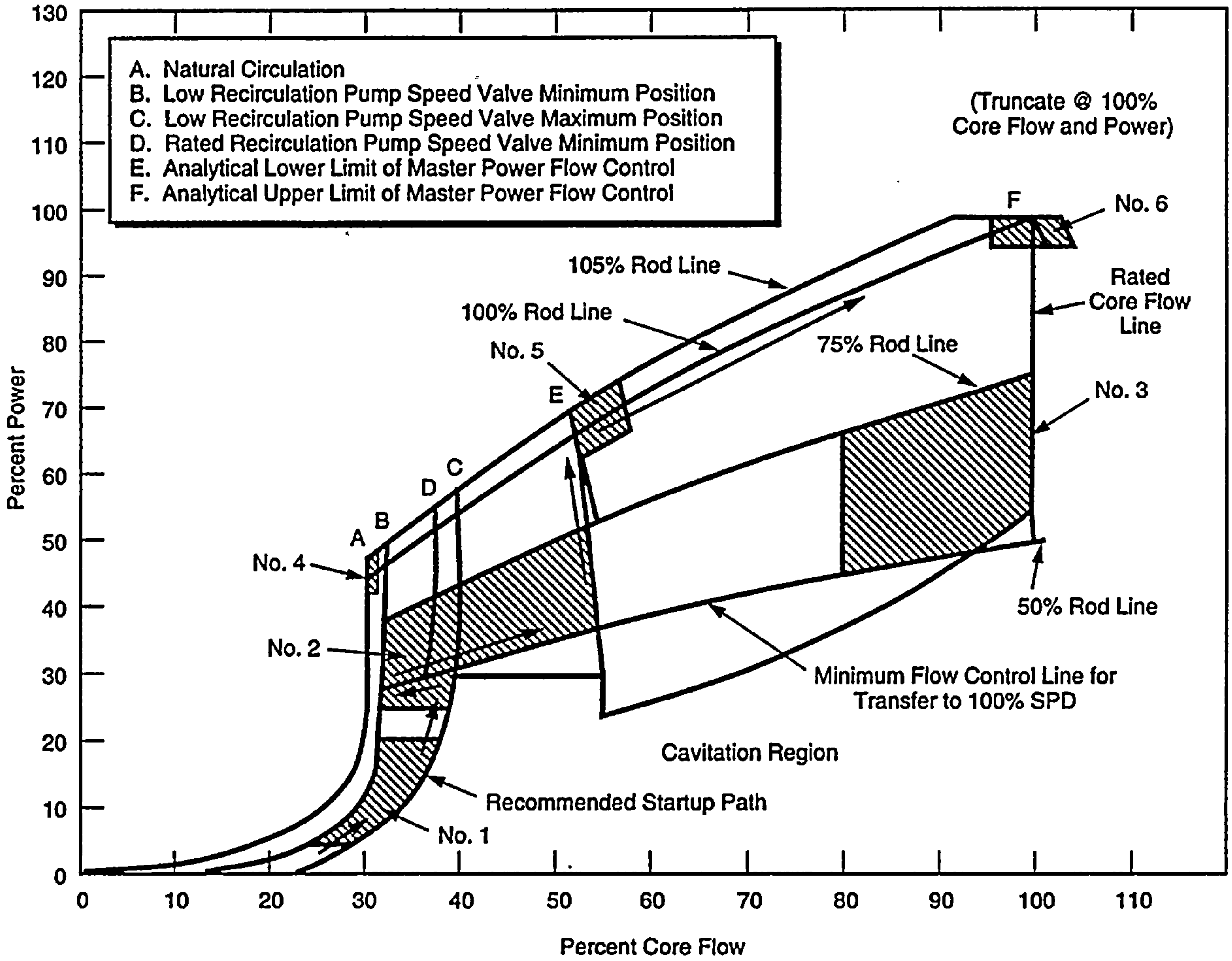
[m] *Between test conditions 2 and 3.*

[n] *Perform test 34 in conjunction with this test.*

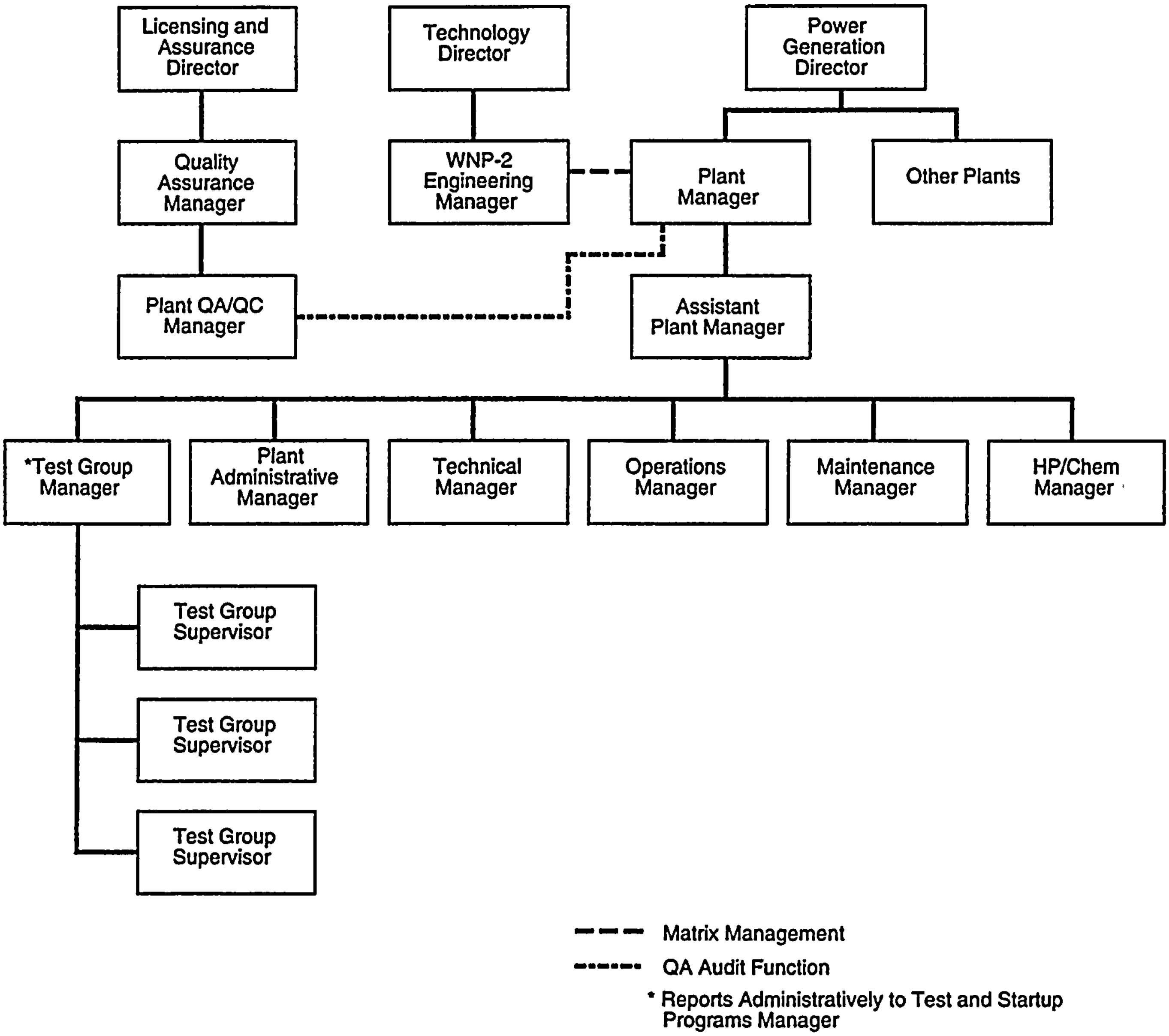
[o] *After one of the scram transients from test condition, during the reactor cooldown, the last part of the shutdown from outside the control room test will be completed by demonstrating the operation of the shutdown cooling mode of RHR from the remote shutdown panel.*

LEGEND

L = Local position command mode operation, POS
M = Flux command mode operation, FLX
X = Combined flow command mode operation, FLO
A = Automatic load following mode operation, ALF
SP = Scram possibility
SD = Scram definite
BP = Bypass valve response

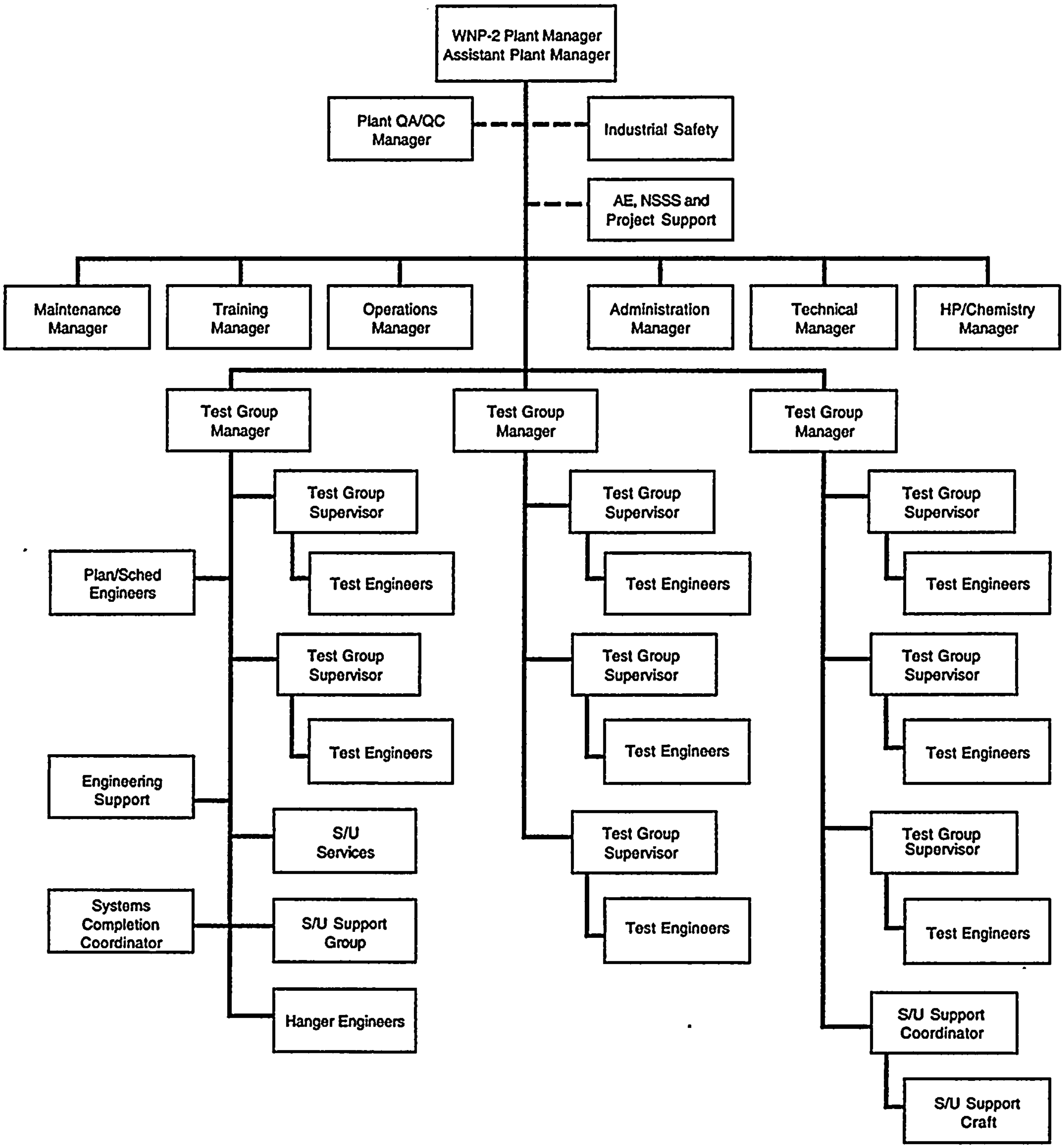


Condition (TC)	
1	Before main generator synchronization and recirc pumps operating on low frequency power supply from approximately 5 to 20 percent thermal power
2	Between 50% and 75% control rod lines, at or below the analytical lower limit of master flow control mode
3	From 50% to 75% control rod lines and core flow between 80% and maximum allowable
4	Natural circulation and within 5% of the intersection with 100% rod line
5	Mid-power range within 5% of 100% control rod line and 0 to +5% core flow of the minimum flow line, for master flow control in manual mode, and for automatic power control in auto mode
6	Within 0 to –5% of rated thermal power, and within 5% of rated core flow rate



Test and Startup Relation to Other Supply System Departments

Draw. No. 960222.77 | Rev. | Figure 14.2-2



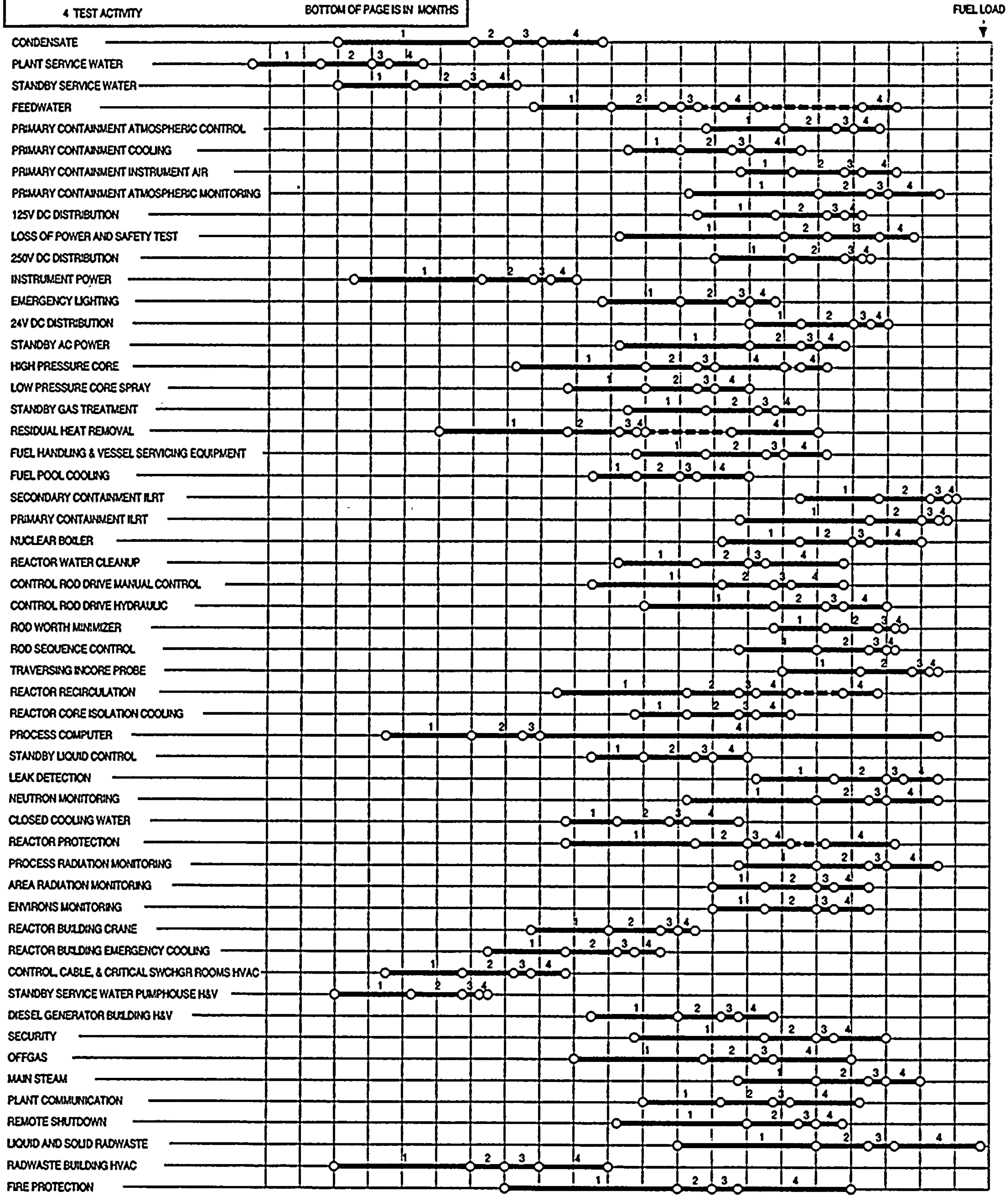
WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

WNP-2 Startup Organization

Draw. No. 960222.78	Rev.	Figure 14.2-3

LEGEND:
1 PREPARE PREOP TEST PROCEDURES
2 REVIEW
3 APPROVE
4 TEST ACTIVITY

NOTE: TIME SCALE LISTED ACROSS THE BOTTOM OF PAGE IS IN MONTHS

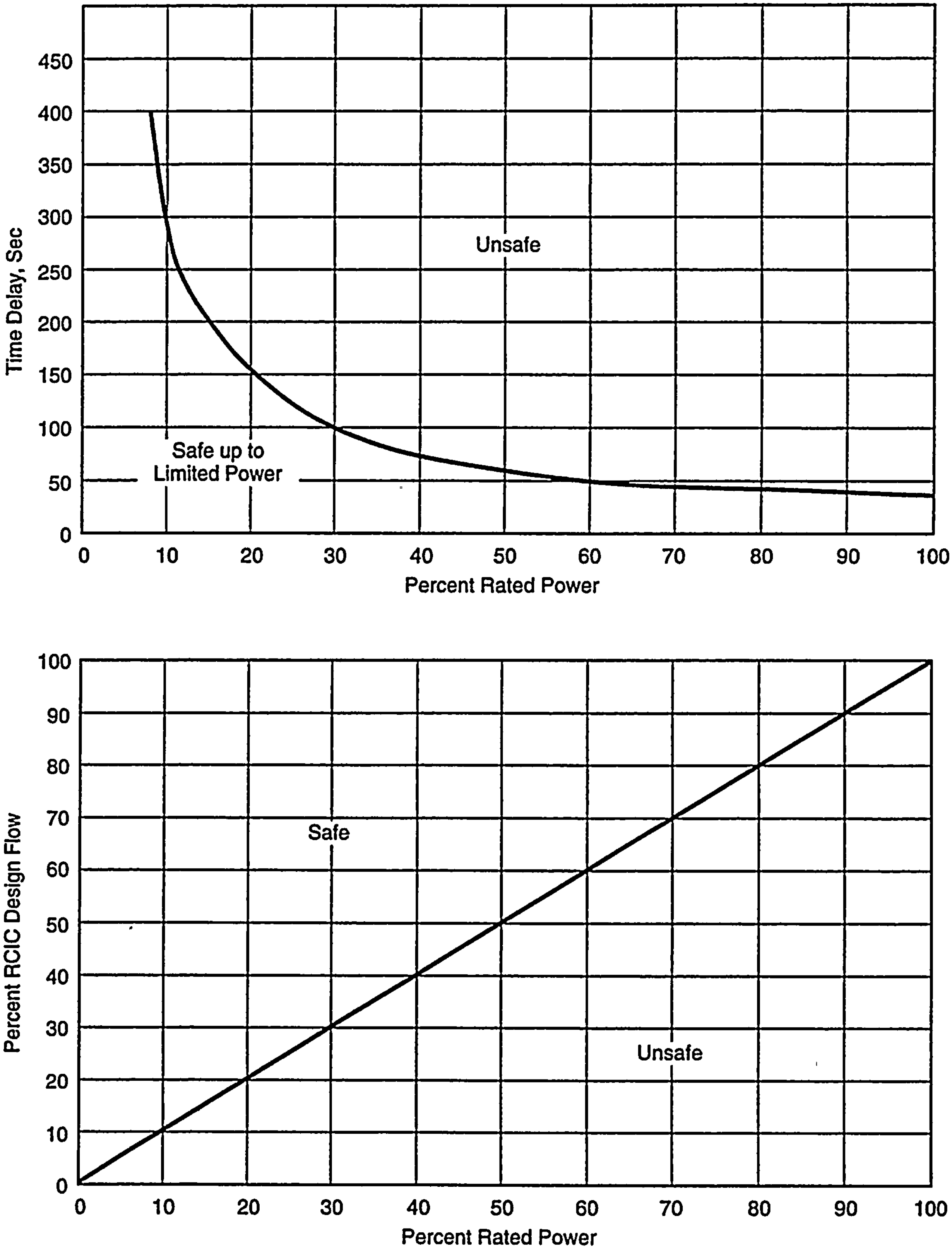


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Preoperational Test Schedule

Draw. No. 960690.83 | Rev. | Figure 14.2-4

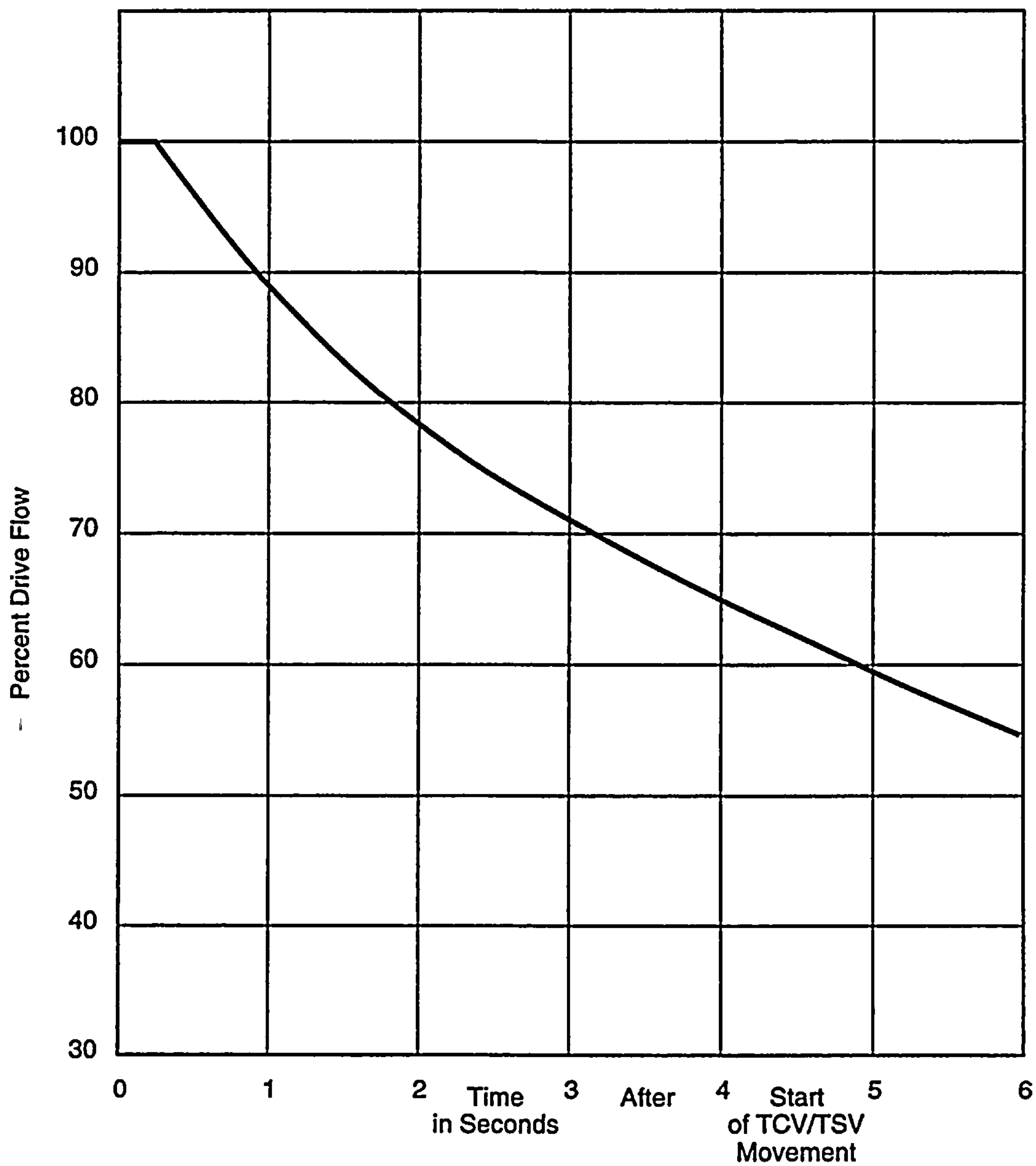
Form No. 960690



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

RCIC Acceptance Criteria Curves for Capacity and Actuation Time

Draw. No. 960690.82 | Rev. | Figure 14.2-5



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Maximum Acceptable Drive Flow Response

Draw. No. 960690.81	Rev.	Figure 14.2-6

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Chapter 15

ACCIDENT ANALYSES

15.0 GENERAL

This chapter contains the effects of anticipated process disturbances and postulated component failures, their consequences, and the capability built into the plant to control or accommodate such failures and events.

The scope of the situations analyzed includes anticipated (expected) operational occurrences, off-design abnormal (unexpected) transients that induce system operating condition disturbances, postulated accidents of low probability, and hypothetical events of extremely low probability.

The plant was originally licensed at 3323 MWt. In 1995, an amendment to the WNP-2 Operating License authorized an increase in power to 3486 MWt. The power uprate analysis was performed in accordance with the NRC-approved General Electric Company (GE) generic power uprate program for boiling water reactors (BWRs).

Several of the postulated events in this chapter were already bounded by the GE generic power uprate program or existing analyses. Therefore, they were not required to be reanalyzed for a power uprate condition. Those plant-specific analyses addressed in the generic program were performed for WNP-2 at the uprate condition. Where appropriate, reference is made as to whether the analysis was performed at original rated power or the uprated power condition.

Specific sections of this chapter have been updated as a result of the addition of adjustable speed drives (ASD) to control recirculation pump speed. The updated sections are 15.0, 15.3, and 15.4. Transients not directly impacted by the change in flow control process [ASD versus flow control valve (FCV)] were not recalculated. Along with the incorporation of the ASD was the deletion of automatic flow control. Transients not directly impacted by the ASD change but include consideration of automatic flow control are retained for historical value. It should be noted that the automatic flow control was not used in actual plant operation as the master controller was always set in the manual position. The automatic flow control function was eliminated by removing panel wiring.

The discussions are general in nature and are based on the Cycle 8 uprate analysis. The cycle-specific analysis is contained in Appendix 15F.

15.0.1 ANALYTICAL OBJECTIVE

The spectrum of postulated initiating events is divided into categories based on the type of disturbance and the expected frequency of the initiating occurrence. The limiting events in each combination of category and frequency are quantitatively analyzed.

15.0.2 ANALYTICAL CATEGORIES

Transient and accident events contained in this report are provided in individual categories as specified by Regulatory Guide 1.70, Revision 2. The results of the events are summarized in Table 15.0-1. Each event evaluated is assigned to one of the following applicable categories:

a. Decrease in core coolant temperature:

   Reactor vessel water (moderator) temperature reduction results in an increase in core reactivity. This could lead to fuel-cladding damage.

b. Increase in reactor pressure:

   Nuclear system pressure increases threaten to rupture the reactor coolant pressure boundary (RCPB). Increasing pressure also collapses the voids in the core-moderator, thereby increasing core reactivity and power level which could threaten fuel cladding due to overheating.

c. Decrease in reactor core coolant flow rate:

   A reduction in the core coolant flow rate could overheat the cladding as the coolant becomes unable to adequately remove the heat generated by the fuel.

d. Reactivity and power distribution anomalies:

   Transient events included in this category are those that could cause rapid increases in power due to increased core flow disturbance events. Increased core flow reduces the void content of the moderator increasing core reactivity and power level.

e. Increase in reactor coolant inventory:

   Increasing coolant inventory could result in excessive moisture carryover to components such as the main turbine, feedwater turbines, etc.

f. Decrease in reactor coolant inventory:

Reductions in coolant inventory could threaten the fuel as the coolant becomes less able to remove heat generated in the core.

g. Radioactive release from a subsystem or component:

Loss of integrity of a radioactive containment component is postulated.

h. Anticipated transients without scram:

To determine the capability of plant design to accommodate an extremely low probability event, a multi-system maloperation situation is postulated.

15.0.3 EVENT EVALUATION

15.0.3.1 Identification of Causes and Frequency Classification

Situations and causes that lead to the initiating event analyzed are described within the analytical categories. The frequency of occurrence of each event is summarized based on currently available operating plant history for the transient event. Events for which inconclusive data exists are discussed separately within each event section.

Each initiating event within the major groups is assigned to one of the following frequency groups:

a. Incidents of moderate frequency - these are incidents that may occur during a calendar year to once per lifetime. This event is referred to as an "anticipated (expected) operational transient."

b. Infrequent incidents - these are incidents that may occur during the life of the particular plant. This event is referred to as an "abnormal (unexpected) operational transient."

c. Limiting faults - these are occurrences that are not expected to occur but are postulated because their consequences may result in the release of significant amounts of radioactive material. This event is referred to as a "design basis (postulated) accident."

15.0.3.1.1 Unacceptable Results for Incidents of Moderate Frequency [Anticipated (Expected) Operational Transients]

The following are considered to be unacceptable safety results for incidents of moderate frequency:

a. Release of radioactive material to the environs that exceeds the limits of 10 CFR 20,

b. Reactor operation induced fuel cladding failure,

c. Nuclear system stresses in excess of that allowed for the transient classification by applicable industry codes, and

d. Containment stresses in excess of that allowed for the transient classification by applicable industry codes.

15.0.3.1.2 Unacceptable Results for Infrequent Incidents [Abnormal (Unexpected) Operational Transients]

The following are considered to be unacceptable safety results for infrequent incidents:

a. Release of radioactivity which results in dose consequences that exceed a small fraction of 10 CFR 100 values,

b. Fuel damage that would preclude resumption of normal operation after a normal restart,

c. Generation of a condition that results in consequential loss of function of the reactor coolant system, and

d. Generation of a condition that results in a consequential loss of function of a necessary containment barrier.

15.0.3.1.3 Unacceptable Results for Limiting Faults [Design-Basis (Postulated) Accidents]

The following are considered to be unacceptable safety results for limiting faults:

a. Radioactive material release which results in dose consequences that exceed the guideline values of 10 CFR 100,

b. Failure of fuel cladding which would cause changes in core geometry such that core cooling would be inhibited,

c. Nuclear system stresses in excess of those allowed for the accident classification by applicable industry codes,

d. Containment stresses in excess of those allowed for the accident classification by applicable industry codes when containment is required, and

e. Radiation exposure to plant operations personnel in the main control room in excess of 5 rem whole body, 30 rem thyroid, and 30 rem beta skin.

15.0.3.2 Sequence of Events and Systems Operation

Each transient or accident is discussed and evaluated in terms of

a. A step-by-step sequence of events from initiation to final stabilized condition,

b. The extent to which normally operating plant instrumentation and controls are assumed to function,

c. The extent to which plant and reactor protection systems are required to function,

d. The credit taken for the functioning of normally operating plant systems,

e. The operation of engineered safety systems that is required, and

f. The effect of a single failure or an operator error on the event.

15.0.3.2.1 Single Failures or Operator Errors

15.0.3.2.1.1 General. The events considered in this section were evaluated and are provided in this chapter in accordance with Regulatory 1.70, Revision 2.

15.0.3.2.1.2 Initiating Event Analysis.

a. The undesired opening or closing of any single valve (a check valve is not assumed to close against normal flow),

b. The undesired starting or stopping of any single component,

c. The malfunction or maloperation of any single control device,

d. Any single electrical component failure, or

e. Any single operator error.

Operator error is defined as an active deviation from written operating procedures or nuclear plant standard operating practices. The set of actions is limited as follows:

a. Those actions that could be performed by one person,

b. Those actions that would have constituted a correct procedure had the initial decision been correct, and

c. Those actions that are subsequent to the initial operator error and have an effect on the designed operation of the plant, but are not necessarily directly related to the operator error.

Examples of single operator errors are as follows:

a. An increase in power above the established flow control power limits by control rod withdrawal in the specified sequences,

b. The selection and complete withdrawal of a single control rod out of sequence,

c. An incorrect calibration of an average power range monitor (APRM), and

d. Manual isolation of the main steam lines as a result of operator misinterpretation of an alarm or indication.

15.0.3.2.1.3 Single Active Component Failure or Single Operator Error Analysis.

a. The undesired action or maloperation of a single active component, or

b. Any single operator error where operator errors are defined as in Section 15.0.3.2.1.2.

15.0.3.3 Core and System Performance

15.0.3.3.1 Introduction

Fuel thermal and hydraulic design are described in Section 4.4.

The fuel cladding integrity safety limit is set so that no fuel damage is calculated to occur if the limit is not violated.

The fuel cladding integrity safety limit is defined as the critical power ratio (CPR) in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition, considering the power distribution within the core and all uncertainties. This criterion is met by demonstrating that incidents of moderate frequency do not result in a minimum critical power ratio (MCPR) less than the safety limit MCPR prescribed by the Technical Specifications.

The WNP-2 cycle-specific core operating limits report (COLR) provides the average planar linear heat generation rate (APLHGR) limits, the MCPR limits, and the linear heat generation rate (LHGR) limits as required by the Technical Specifications.

15.0.3.3.2 Input Parameters and Initial Conditions for Analyzed Events

The Technical Specifications Bases define the methodology for determining the safety limit MCPR, including the statistical model and input uncertainties. A summary of input parameters is shown in Table 15.0-2.

Depending on the specific cycle, the COLR describes the turbine trip without bypass event as the limiting event for operation at rated power and flow or the load rejection without bypass event at end of cycle. Power dependent MCPR limits are specified to define operating limits at other than rated power conditions. The feedwater controller failure event from reduced power condition is calculated to be more severe than from full power conditions. A flow dependent MCPR is specified to define operating limits at other than rated flow conditions. The reduced flow MCPR limit provides bounding protection for the limiting recirculation flow increase event.

15.0.3.3.3 Initial Power/Flow Operating Constraints

The Technical Specifications and associated operating procedures provide power distribution limits and thermal power/core flow figures.

The COLR cycle specific reload licensing analyses provides operating limits for extended load line limit analysis (ELLA) operation.

15.0.3.3.4 Results

The COLR provides results of analytical evaluations. In addition critical parameters are shown in Table 15.0-1. From the data in Table 15.0-1, an evaluation of the limiting event for that particular category and parameter can be made. In Table 15.0-3, a summary of applicable accidents is provided.

15.0.3.4 Barrier Performance

This section addresses the performance of the RCPB and the containment system during transients and accidents.

During transients that occur with no release of coolant to the containment, only RCPB performance is considered. If release to the containment occurs as in the case of limiting faults, then challenges to the containment are evaluated as well.

Piping systems within the secondary containment structure (i.e., the reactor building) have been analyzed for pipe break effects including jet impingement, jet reaction, pipe whip, and subcompartment pressurization. Where necessary, these loads were included in the design of the structure to ensure that the secondary containment can perform its required functions as defined in Section 6.2.3.

15.0.3.5 Radiological Consequences

This section addresses the radiological release consequences during the incidents of moderate frequency (anticipated operational transients), infrequent incidents (abnormal operational transients), and limiting faults (design basis accidents) events. For all events where consequences are limiting a detailed quantitative evaluation is presented. For nonlimiting events, a qualitative evaluation is presented or the results are referenced from a more limiting or enveloping case or event.

For limiting faults (design basis accidents), conservative assumptions considered to be acceptable to the NRC for the purpose of worst case bounding of the event and determining the adequacy of the plant design to meet 10 CFR Part 100 guidelines are assumed. This is referred to as the "design basis analysis."

TABLE 15.0-1

RESULTS SUMMARY OF TRANSIENT EVENTS APPLICABLE TO WNP-2[a]

Paragraph I.D.	Figure I.D.	Description	Maximum Neutron Flux (%NBR)	Maximum Dome Pressure (psig)	Maximum Vessel Pressure (psig)	Maximum Steam Line Pressure (psig)	Maximum Core Average Surface Heat Flux (% of Initial)	DCPR[b]	Frequency Category
15.1		DECREASE IN CORE COOLANT TEMPERATURE							
15.1.1		Loss of Feedwater Heater, Manual Flow Control[c] Power Uprate						0.13	(d)
15.1.2	15.1-1	Feedwater Control Failure, Max Demand Power Uprate	248	1173	1200	1167	112	0.115[e]	(d)
15.1.3	15.1-1	Pressure Regulator Fail-Open	131	1151	1172	1151	100	<0.01	
15.1.4		Inadvertent Opening of Safety or Relief Valve	See text						
15.1.6		RHR Shutdown Cooling Malfunction Decreasing Temperature	See text						(d)
15.2		INCREASE IN REACTOR PRESSURE							
15.2.1		Pressure Regulator Fail-Closed	See Sections 15.2.2 and 15.2.3 with bypass on				(d)		
15.2.2	15.2-1	Generator, Load Rejection, Bypass-On[f]	See text						(d)
15.2.2	15.2-2	Generator Load Rejection, Bypass-Off Power Uprate	348	1205	1232	1196	114	0.15[e]	(d)
15.2.3	15.2-3	Turbine Trip, Bypass-On[f]	See text						(d)
15.2.3	15.2-4	Turbine Trip, Bypass-Off Power Uprate	341	1203	1231	1195	113	0.14[e]	(d)
15.2.4	15.2-5	Inadvertent MSIV Closure	206	1200	1234	1198	100	0.022	(d)
15.2.5	15.2-6	Loss of Condenser Vacuum	256	1173	1199	1166	111	0.12	(d)
15.2.6	15.2-7	Loss of Auxiliary Power Transformers	106[h]	1169	1185	1166	100	<0.01	(d)
15.2.6	15.2-8	Loss of All Grid Connections	196	1173	1196	1166	106	0.079	(d)
15.2.7	15.2-9	Loss of all Feedwater Flow	106[h]	1142	1152	1142	100	<0.01	(d)
15.2.8		Feedwater Piping Break	See Section 15.6.6						
15.2.9		Failure of RHR Shutdown Cooling	See text						

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TABLE 15.0-1

RESULTS SUMMARY OF TRANSIENT EVENTS APPLICABLE TO WNP-2[a] (Continued)

Paragraph I.D.	Figure I.D.	Description	Maximum Neutron Flux (%NBR)	Maximum Dome Pressure (psig)	Maximum Vessel Pressure (psig)	Maximum Steam Line Pressure (psig)	Maximum Core Average Surface Heat Flux (% of Initial)	DCPR[b]	Frequency Category
15.3		DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE							
15.3.1	15.3-1	Trip of One Recirculation Pump Motor	106[h]	1020	1059	1012	100	<0.01	(d)
15.3.1	15.3-2	Trip of Both Recirculation Pump Motors	106[h]	1077	1088	1076	100	<0.01	(d)
15.3.2	15.3-3	Speed Decrease of One Main Recirc Motor	106[h]	1020	1059	1012	100	<0.01	(d)
15.3.2	15.3-4	Speed Decrease of Two Main Recirc Motors	106[h]	1061	1072	1061	100	<0.01	(d)
15.3.3	15.3-5	Seizure of One Recirculation Pump	106[h]	1099	1110	1098	100	<0.01	(i)
15.3.4		Recirc Pump Shaft Break	See 15.3.3						
15.4		REACTIVITY AND POWER DISTRIBUTION ANOMALIES							
15.4.1.1		RWE - Refueling	See text						(j)
15.4.1.2		RWE - Startup	See text						(j)
15.4.2		RWE - At Power	See text						(d)
15.4.3		Control Rod Misoperation	See Sections 15.4.1 and 15.4.2						
15.4.4	15.4-1	Abnormal Startup of Idle Recirculation Loop	124[c]	1004	1026	998	190	0.53	(d)
15.4.5	15.4-2	Speed Increase of One Main Recirc Motor	136[c]	990	1009	986	127	0.15	(d)
15.4.5	15.4-3	Speed Increase of Both Main Recirc Motors	153[c]	1006	1033	1001	149	0.27	(d)
15.4.7		Misplaced Bundle Accident	See text						(j)
15.4.9		Rod Drop Accident							(i)
15.5		INCREASE IN REACTOR COOLANT INVENTORY							
15.5.1	15.5-1	Inadvertent HPCS Pump Start[f]	106[h]	1020	1059	1011	100	<0.01[g]	(d)
15.5.3		BWR Transients	See appropriate events in Sections 15.1 and 15.2						

[a] WNP-2 Power Uprate Transient Analysis Task Report: GE-NE-208-08-0393.

[b] For conservatism, MCPR = Safety Limit (Technical Specifications) + ΔCPR.

[c] Event analyzed with different model for power uprate conditions.

TABLE 15.0-1

RESULTS SUMMARY OF TRANSIENT EVENTS APPLICABLE TO WNP-2[a] (Continued)

[d] Moderate frequency.

[e] This value is only for the more limiting 9 X 9 fuel.

[f] Non-limiting event under power uprate conditions (event not reanalyzed).

[g] ODYN results without the adjustment factors delineated in the ODYN Report NEDO-24154, NEDE-24154P

[h] No increase from initial value.

[i] Limiting fault.

[j] Infrequent incident.

TABLE 15.0-2

INPUT PARAMETERS AND INITIAL CONDITIONS FOR TRANSIENTS

		REDY (ASD Events)	REDY[a]	ODYN
1.	Thermal power level, MWt			
	Licensed value	3486	3323	3486
	Analysis value	3702	3464	3629
2.	Steam flow, lbs/hr analysis value	16.09×10^6	14.98×10^6	15.73×10^6
3.	Core flow, lbs/hr	108.5×10^6	108.36×10^6	$95.5\text{-}115.0 \times 10^6$
4.	FW flow rate, lb/sec analysis value	4471	4161	4362
5.	Feedwater temperature, °F	426	424	426
6.	Vessel dome pressure, psig	1020	1020	1020
7.	Vessel core pressure, psig	1031	1031	1031
8.	Turbine bypass capacity, %NBR	22.7	25	22.7
9.	Core coolant inlet enthalpy, Btu/lb	528.3	529.3	529.6
10.	Turbine inlet pressure, psig	992	975	997
11.	Fuel lattice	8 x 8/9 x 9	8x8	Simulated 8x8/9x9
12.	Core average fuel cladding gap conductance, Btu/sec-ft^2-°F	0.3608	0.1667	Fuel specific
13.	Core leakage flow, %	10.20	11.84	Cycle specific
14.	Required MCPR operating limit	(b)	1.24	(c)
15.	MCPR safety limit	(b)	1.06	(c)
16.	Doppler coefficient (-)¢/°			
	Nominal EOC-1	0.311	0.227	(d)
	Analysis data ASD events			
	1. Increase power	0.295	0.215	
	2. Decrease power	0.327		
17.	Void coefficient (-)¢/% Rated			
	Nominal EOC-1		7.48	(d)
	Analysis data for power increase events	15.93	12.70	(d)
	Analysis data for power decrease events	12.10	7.065	(d)
18.	Core average rated void fraction, % (Steady state)	41.24	41.32	43.1
19.	Scram reactivity, \$k analysis data	Figure 15.0-1	Figure 15.0-1	(d)
20.	Control rod drive speed, position versus time	Figure 15.0-1	Figure 15.0-1	Figure 15.0-1
21.	Jet pump ratio, M	2.36	2.41	2.39

TABLE 15.0-2

INPUT PARAMETERS AND INITIAL CONDITIONS FOR TRANSIENTS (Continued)

		REDY (ASD Events)	REDY[a]	ODYN
22.	Safety/relief valve capacity, % NBR			
	safety valve capacity @ 1241 psig	108.6	111.5	108.6
	Relief valve capacity @ setpoint values in item 25 of this table	@ 1121 psig 98.3	101.8	98.3
		@ 1131 psig 99.1	102.8	99.1
		@ 1141 psig 100.0	103.7	100
		@ 1151 psig 100.9	104.6	100.9
		@ 1161 psig 101.7	105.5	101.7
	Manufacturer		Crosby	Crosby
	Quantity installed		18	18
23.	Relief function delay, sec	0.4	0.4	0.4
24.	Relief function response, sec	0.15	0.1	0.15
25.	Setpoints for safety/relief valves			
	Safety function, psig	1200, 1210 1221, 1231 1241	1177, 1187, 1197, 1207, 1217	1200, 1210 1221, 1231 1241
	Relief function, psig	1121, 1131 1141, 1151 1161	1091, 1101, 1111, 1121, 1131	1121, 1131 1141, 1151 1161
26.	Number of valve groupings simulated			
	Safety function, number		5	5
	Relief function, number		5	5
27.	High flux trip analysis setpoint (123 x 1.041), % NBR	128.0	126.20	128[e]
28.	High pressure scram setpoint, psig	1086	1017	1086
29.	Vessel level trips, inches with respect to dryer skirt bottom			
	Level 8 - (L8), in.	59.5	55.5	59.5
	Level 4 - (L4), in.		31.5	30
	Level 3 - (L3), in.	7.5	12.5	(f)
	Level 2 - (L2), in.		(-38)	(f)
30.	APRM thermal trip analysis setpoint (117 x 1.041)% NBR @ 100% core flow	121.8	122.030	121.8[e]
31.	Recirculation pump trip delay, sec	0.190	0.140	0.190
32.	Recirculation pump trip inertia time constant for analysis, sec	6[g]	6[g]	6[g]
33.	RPS response time delay	(h)	(h)	(h)

TABLE 15.0-2

INPUT PARAMETERS AND INITIAL CONDITIONS FOR TRANSIENTS (Continued)

[a] REDY values reflect the pre-uprate initial conditions. Only limiting events were analyzed for power uprate conditions with FCV.

[b] See COLR.

[c] Not applicable to reload 7/cycle 8 simulation.

[d] ODYN values are calculated within the code.

[e] The thermal multiplier (1.041 = 3629/3486) is used to give a conservative margin that is proportional to the core power.

[f] Parameter not used in the analysis.

[g] The inertia time constant is defined by the expression:

$$t = \frac{2 \pi J_o n}{g T_o}$$

where

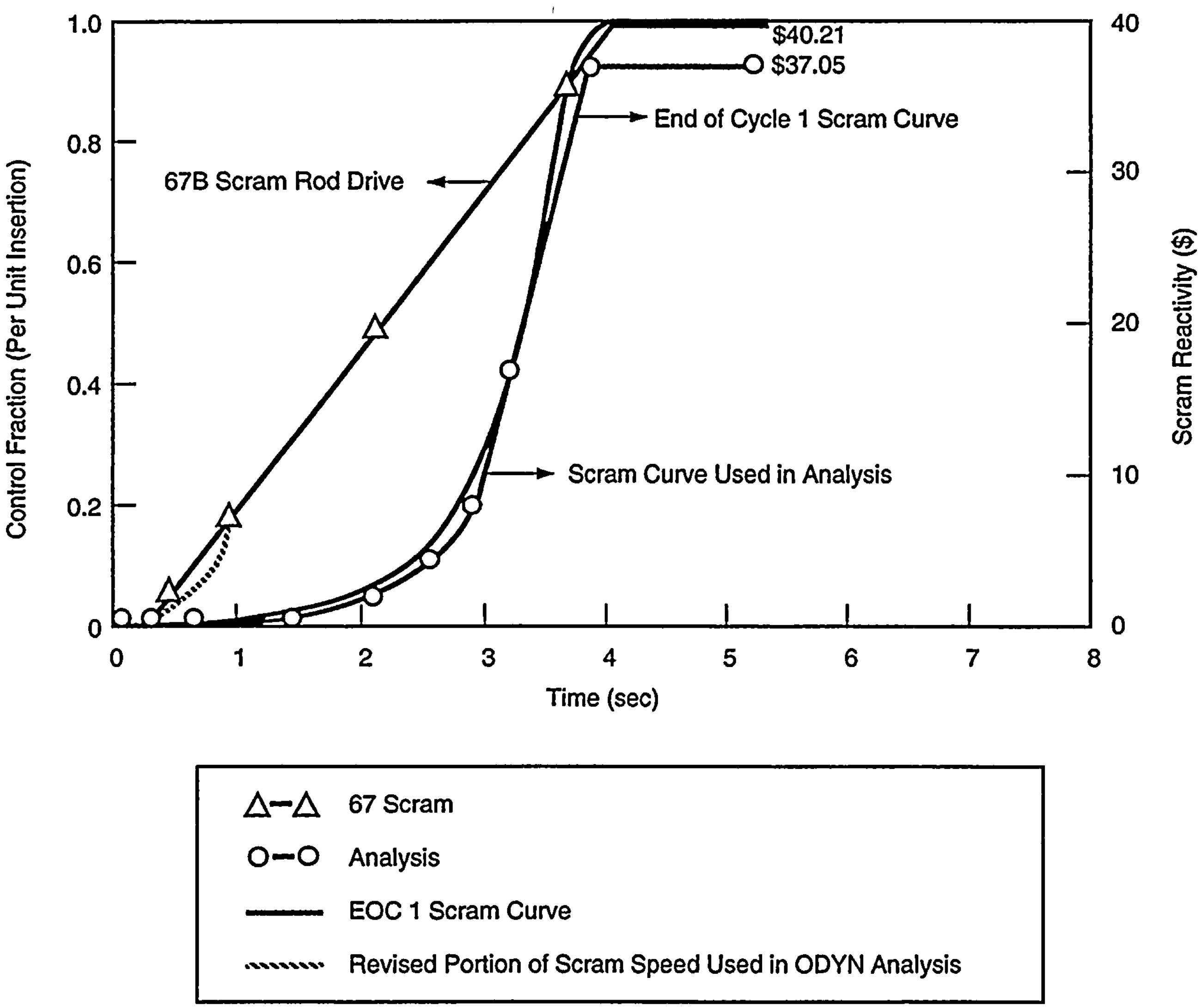
t = inertia time constant (sec)
J_o = pump motor inertia ($lb\text{-}ft^2$)
n = rated pump speed (rps)
g = gravitational constant (ft/sec^2)
T_o = pump shaft torque (lb-ft)

[h] The "maximum overall response time" as addressed in the LCS is utilized for each scram encountered in the Chapter 15 events.

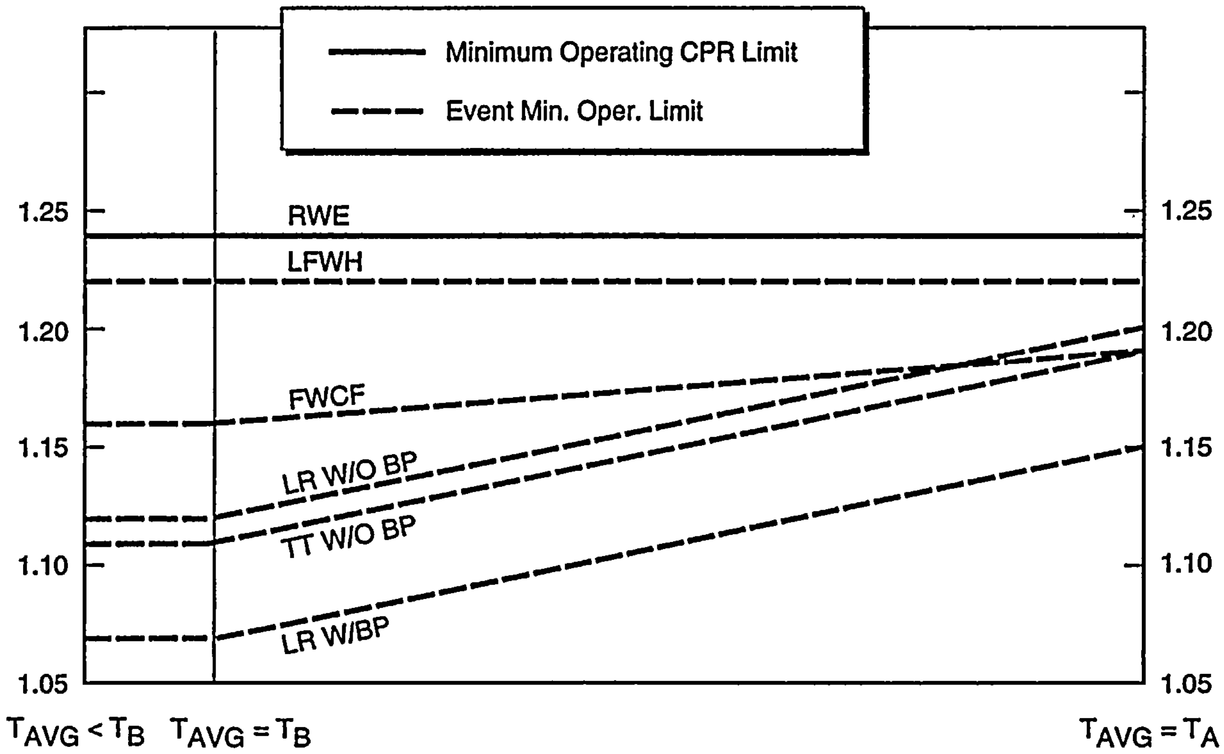
TABLE 15.0-3

SUMMARY OF ACCIDENTS

Paragraph I.D.	Title	Failed Fuel WNP-2 Calculated Value
15.3.3	Seizure of one recirculation pump	None
15.3.4	Recirculation pump shaft break	None
15.4.9	Rod drop accident	850 rods
15.6.2	Instrument line break	None
15.6.4	Steam system pipe break outside containment	None
15.6.5	Loss-of-coolant accident within RCPB	100%
15.6.6	Feedwater line break	None
15.7.1.1	Main condenser gas treatment system failure	N/A
15.7.3	Liquid radwaste tank failure	N/A
15.7.4	Fuel handling accident	250 rods
15.8	Anticipated transients without scram	None



Scram Position and Reactivity Characteristics



Minimum Operating CPR Limit Versus Scram Speed

15.1 DECREASE IN REACTOR COOLANT TEMPERATURE

15.1.1 LOSS OF FEEDWATER HEATING

15.1.1.1 Identification of Causes and Frequency Classification

15.1.1.1.1 Identification of Causes

A feedwater heater can be lost in at least two ways:

a. Steam extraction line to heater is closed, and
b. Steam is bypassed around heater.

The first case produces a gradual cooling of the feedwater. In the second case, the steam bypasses the heater and no heating of that feedwater occurs. In either case, the reactor vessel receives cooler feedwater. The maximum number of feedwater heaters which can be tripped or bypassed by a single event represents the most severe transient for analysis considerations. This event has been conservatively estimated to incur a loss of up to 100°F of the feedwater heating capability of the plant and causes an increase in core inlet subcooling. This increases core power due to the negative void reactivity coefficient. The event can occur with the reactor in either the automatic or manual control mode.

15.1.1.1.2 Frequency Classification

This event is considered to be an incident of moderate frequency and is analyzed under worst case conditions of a 100°F loss at full power.

15.1.1.2 Sequence of Events and Systems Operation

15.1.1.2.1 Sequence of Events

The analytical dynamic behavior for power uprate has been determined using the GE three-dimensional boiling water reactor (BWR) simulator computer code. This code does not provide plots of the dynamic behavior of basic parameters as a function of time nor does it provide information for a sequence of events table. Therefore, no figures or tables for the uprate condition are available.

15.1.1.2.1.1 Identification of Operator Actions. An average power range monitor (APRM) neutron flux or thermal power alarm will alert the operator that flow must be reduced if in the manual mode. The operator must determine from operating procedures the maximum allowable turbine generator (TG) output with feedwater heaters out of service. If reactor scram occurs, as it does in manual flow control mode, the operator must monitor the reactor water level and pressure controls and the TG auxiliaries during coastdown.

15.1.1.2.2 Systems Operation

In establishing the expected sequence of events and simulating the plant performance, it was assumed that normal functioning occurred in the plant instrumentation and controls, plant protection, and reactor protection systems.

The APRM is the primary protection system trip in mitigating the consequences of this event. A description of the APRM is provided in Sections 7.2.1.1.1.2 and 7.6.1.4.3.

Required operation of engineered safety features (ESF) is not expected for either of these transients.

15.1.1.2.3 The Effect of Single Failures and Operator Errors

These two events generally lead to an increase in reactor power level. The APRM mentioned in Section 15.1.1.2.2 is the mitigating system and is designed to be single failure proof. Therefore, single failures are not expected to result in a more severe event than analyzed.

15.1.1.3 Core and System Performance

15.1.1.3.1 Mathematical Model

The predicted dynamic behavior for power uprate has been determined using the GE three-dimensional BWR simulator computer code. This model is described in Reference 15.1-1.

15.1.1.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

For power uprate the plant is assumed to be operating at 110% of original nuclear boiler rated (NBR) at 106% of rated core flow.

15.1.1.3.3 Results

For power uprate, the core average power is calculated to increase by 14.8% over its initial value of 3629 MWt. The reduction in thermal margin is 0.13 in minimum critical power ratio (MCPR) and 19.3% in linear heat generation rate (LHGR). This event is more limiting at the power uprate condition because the higher power results in higher initial feedwater flow, thus maximizing the core subcooling results in a greater power increase for the transient.

15.1.1.3.4 Considerations of Uncertainties

Factors such as reactivity coefficient, scram characteristics, and magnitude of feedwater temperature change are assumed to be at the worst configuration so that any deviations seen in the actual plant operation reduce the severity of the event.

15.1.1.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.1.1.5 Radiological Consequences

Since this event does not result in any additional fuel failures or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this event.

15.1.2 FEEDWATER CONTROLLER FAILURE - MAXIMUM DEMAND

15.1.2.1 Identification of Causes and Frequency Classification

15.1.2.1.1 Identification of Causes

This event is postulated on the basis of a single failure of a control device, specifically one that can directly cause an increase in coolant inventory by increasing the feedwater flow. The most severe applicable event is a feedwater controller failure during maximum flow demand. The feedwater controller is forced to its upper limit at the beginning of the event.

15.1.2.1.2 Frequency Classification

This event is considered to be an incident of moderate frequency.

15.1.2.2 Sequence of Events and Systems Operation

15.1.2.2.1 Sequence of Events

With excess feedwater flow the water level rises to the high-level reference point at which time the feedwater pumps and the main turbine are tripped and a scram is initiated. Table 15.1-1 lists the sequence of events for Figure 15.1-1. The figure shows the changes in variables during this transient.

15.1.2.2.1.1 Identification of Operator Actions.

a. Observe that high feedwater pump trip has terminated the failure event,

b. Switch the feedwater controller from auto to manual control in order to try to regain a correct output signal, and

c. Identify causes of the failure and report all key plant parameters during the event.

15.1.2.2.2 Systems Operation

In order to properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection and reactor protection systems. Important system operational actions for this event are high water level trip of the main turbine, turbine stop valve scram trip initiation, recirculation pump trip (RPT), and low water level initiation of the reactor core isolation cooling system and the high-pressure core spray (HPCS) system to maintain long-term water level control following tripping of feedwater pumps.

15.1.2.2.3 The Effect of Single Failures and Operator Errors

The first sensed event to initiate corrective action to the transient is the vessel high water level (L8) trip. Multiple level sensors are used to sense and detect when the water level reaches the L8 setpoint. At this point in the logic, a single failure will not initiate or prevent a turbine trip signal. Turbine trip signal transmission, however, is not built to single failure criterion. The result of a failure at this point would have the effect of delaying, but not impacting, the pressurization "signature."

Scram trip signals from the turbine are designed such that a single failure will neither initiate nor impede a reactor scram trip initiation.

15.1.2.3 Core and System Performance

15.1.2.3.1 Mathematical Model

The predicted dynamic behavior has been determined using a computer simulated, analytical model of a generic direct-cycle BWR. This model is described in detail in Reference 15.1-1.

The nonlinear computer simulated analytical model is designed to predict associated transient behavior of the reactor. Some of the significant features of the model are the following.

a. An integrated one-dimensional core model is assumed which includes a detailed description of hydraulic feedback effects, axial power shape changes, and reactivity feedbacks;

b. The fuel is represented by an average cylindrical fuel and cladding model for each axial location in the core;

c. The steam lines are modeled by eight pressure nodes incorporating mass and momentum balances which will predict any wave phenomena present in the steam line during a pressurization transient;

d. The core average axial water density and pressure distribution is calculated using a single channel to represent the heated active flow and a single channel to represent the bypass flow. A model, representing liquid and vapor mass and energy conservation and mixture momentum conservation, is used to describe thermal-hydraulic behavior. Changes in the flow split between the bypass and active channel flow are accounted for during transient events;

e. Principal controller functions such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand are represented together with their dominant nonlinear characteristics;

f. The ability to simulate necessary reactor protection system functions is provided; and

g. The control systems and reactor protection system models are, for the most part, identical to those employed in the point reactor model described in Reference 15.1-1.

15.1.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions in Table 15.0-2.

End of cycle (all rods out) scram characteristics are assumed. The safety/relief valve (SRV) action is conservatively assumed to occur with higher than nominal setpoints. The transient is simulated by programming an upper limit failure in the feedwater system such that 139% feedwater flow occurs at the nominal reactor operating pressure of 1035 psia, which corresponds to 129% at a design pressure of 1090 psia.

An increase in feedwater flow will cause a corresponding drop in feedwater temperature. However, the relatively large time constant of the feedwater heaters (order of minutes) plus the flow transport time (10 sec from heaters to vessel and 3 sec from sparger to core) would

preclude any effect of temperature reduction on the transient since the transient is essentially over in about 20 sec. Therefore, feedwater temperature is assumed to remain constant.

15.1.2.3.3 Results

The simulated feedwater controller transient at 106% of uprated NBR steam flow is shown in Figure 15.1-1. The high water level turbine trip and feedwater pump trip are initiated as stated in Table 15.1-1. A scram occurs simultaneously from stop valve closure and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs.

The turbine bypass system and the main steam SRVs open to limit the peak vessel bottom pressure, and the nuclear system process barrier pressure limit is not affected. The bypass valves subsequently close to reestablish pressure control in the vessel during shutdown. Events caused by low water level trips, including closure of main steam line isolation valves (MSIVs), and initiation of HPCS, reactor core isolation cooling (RCIC), automatic depressurization system (ADS), and low-pressure core cooling system functions are not included in the simulation. Should these events occur, they will follow after the primary concerns of fuel thermal margin and overpressure effects have occurred, and are expected to be less severe than those already experienced by the system.

15.1.2.3.4 Consideration of Uncertainties

All systems used for protection in this event were assumed to have the most conservative response characteristics. Therefore, actual plant behavior is expected to lead to a less severe transient.

15.1.2.4 <u>Barrier Performance</u>

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.1.2.5 <u>Radiological Consequences</u>

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no exposure to personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.1.3 PRESSURE REGULATOR FAILURE - OPEN

15.1.3.1 Identification of Causes and Frequency Classification

15.1.3.1.1 Identification of Causes

The total steam flow rate to the main turbine resulting from a pressure regulator malfunction is limited by a maximum flow limiter imposed at the turbine controls. This limiter is set to limit maximum steam flow demand to approximately 130% NBR.

If either the controlling pressure regulator or the backup regulator fails to the open position, the turbine admission valves will be fully opened and the turbine bypass valves will be partially opened until the maximum steam flow is established.

15.1.3.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.1.3.2 Sequence of Events and Systems Operation

15.1.3.2.1 Sequence of Events

Table 15.1-2 lists the sequence of events for Figure 15.1-2.

15.1.3.2.1.1 Identification of Operator Actions. When regulator trouble is preceded by spurious or erratic behavior of the controlling device, it may be possible for the operator to transfer operation to the backup controller in time to prevent the full transient. If the reactor scrams as a result of the isolation caused by the low pressure at the turbine inlet (<850 psia) in the run mode, the following is the sequence of operator actions expected during the course of the event. Once isolation occurs, pressure will increase to a point where the relief valves open. Operator actions for the case where high level (L8) trip occurs before the isolation are essentially identical.

a. Monitor that all rods are in,

b. Monitor reactor water level and pressure,

c. Observe turbine coastdown and break vacuum before the loss of steam seals. Check turbine auxiliaries,

d. Observe that the reactor pressure relief valves open at their setpoint,

e. Observe that HPCS and RCIC initiate on low water level,

f. Secure HPCS and RCIC when reactor pressure and level are under control, and

g. Monitor reactor water level and continue cooldown.

15.1.3.2.2 Systems Operation

In order to properly simulate the expected sequence of events, the analysis of this event assumed normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems except as otherwise noted.

Initiation of HPCS and RCIC system functions will occur when the vessel water level reaches the L2 setpoint although this is not included in the analysis. Normal startup and actuation can take up to 30 sec before effects are realized. If these events occur, they will follow some time after the primary concerns of fuel thermal margin and overpressure effects have occurred and are expected to be less severe than those already experienced by the system.

15.1.3.2.3 The Effect of Single Failures and Operator Errors

This transient leads to a loss of pressure control such that the increased steam flow demand causes a depressurization. Instrumentation for pressure sensing of the turbine inlet pressure is designed to be single failure proof for initiation of MSIV closure.

Reactor scram sensing, originating from limit switches on the MSIVs, is designed to be single failure proof. It is, therefore, concluded that the basic phenomenon of pressure decay is adequately terminated.

15.1.3.3 Core and System Performance

15.1.3.3.1 Mathematical Model

The dynamic model described in Reference 15.1-1 is used to simulate this event.

15.1.3.3.2 Input Parameters and Initial Conditions

This transient is simulated by setting the controlling regulator output to a high value, which causes the turbine admission valves to open fully and the turbine bypass valves to open partially. Since the controlling and backup regulator outputs are gated by a high value gate, the effect of such a failure in the backup regulator would be exactly the same. A regulator failure with 130% steam flow demand signal was simulated as a worst case since 130% is the normal maximum flow limit in order to conform with Table 15.1-2.

A 5-sec isolation valve closure is assumed when the turbine pressure decreases below the turbine inlet low pressure setpoint for main steam line isolation initiation.

Reactor scram is initiated when the isolation valves reach the 10% closed position. This is the maximum travel from the full open position allowed by specification. .

This analysis has been performed, unless otherwise noted, with the plant conditions listed in Table 15.0-2.

15.1.3.3.3 Results

Figure 15.1-2 depicts how the high water level turbine trip and isolation valve closure stops vessel depressurization and produces a normal shutdown of the reactor. Results are summarized in Table 15.0-1.

Depressurization results in formation of voids in the reactor coolant and causes a decrease in reactor power almost immediately. In this simulation, the depressurization rate is large enough such that water level swells to the sensed level trip setpoint (L8), initiating main turbine and feedwater turbine trips. Position switches on the turbine stop valves initiate a reactor scram and RPT and shut down the reactor. After the turbine trip, the failed pressure regulator signals the bypass to open to full bypass flow of 25% NBR steam flow. After the pressurization resulting from the turbine stop valve closure, pressure drops and continues to drop until turbine inlet pressure is below the low turbine pressure isolation setpoint when main steam line isolation limits the duration and severity of the depressurization. No significant reductions of fuel thermal margins occur. No significant thermal stresses are imposed on the reactor coolant pressure boundary (RCPB).

15.1.3.3.4 Consideration of Uncertainties

If the maximum flow limiter were set higher or lower than normal, a faster or slower loss in nuclear steam pressure would result. The rate of depressurization may be limited by the bypass capacity, but it is unlikely. For example, the turbine valves will open to the valves-wide-open state admitting slightly more than the rated steam flow, and with the limiter in this analysis set to fail at 130%, it is expected that less than 25% would be bypassed. This is, therefore, not a limiting factor for the plant. If the rate of depressurization does change, it will be terminated by the low turbine inlet pressure trip setpoint.

Depressurization rate has a proportional effect upon the voiding action in the core and the flashing in the vessel bulk water regions. If the rate is low enough, the water level may not swell to the high water level trip setpoint and the isolation will occur earlier when pressure at the turbine decreases below 850 psia. The reactor will scram as a result of the MSIV closure. Since power is being depressed as the pressure decreases (due to additional voiding in the

core), this transient is less severe when a slower depressurization rate is assumed. Therefore, the assumed L8 trip provides the most restrictive margins on MCPR and peak vessel pressure.

Barrier performance analyses were not required since the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which fuel, pressure vessel, or containment are designed. Peak pressure in the bottom of the vessel is below the ASME code upset limit for the RCPB.

15.1.3.4 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.1.4 INADVERTENT SAFETY/RELIEF VALVE OPENING

The event is defined as the inadvertent opening of an SRV which stays in the "open" position.

15.1.4.1 Identification of Causes and Frequency Classification

15.1.4.1.1 Identification of Causes

Cause of inadvertent opening is attributed to malfunction of the valve or an operator initiated opening. Opening and closing circuitry at the individual valve level (as opposed to groups of valves) is subject to a single failure impact. It is therefore simply postulated that a failure occurs and the event is analyzed accordingly. Detailed discussion of the valve is provided in Section 5.2.2.

15.1.4.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.1.4.2 Sequence of Events and Systems Operation

15.1.4.2.1 Sequence of Events

Table 15.1-3 lists the sequence of events.

15.1.4.2.1.1 Identification of Operator Actions. The plant operator must "reclose" the valve as soon as possible and check that reactor and TG output return to normal. If the valve cannot be closed, plant shutdown should be initiated. The operator must then start suppression pool heat removal using the residual heat removal (RHR) system.

15.1.4.2.2 Systems Operation

In this transient, the analysis assumes normal functioning of plant instrumentation and controls, specifically, the relief valve discharge line temperature sensors and the suppression pool temperature sensors and reactor pressure vessel level control systems. Additionally, minimum reactor and plant protection systems, emergency core cooling system flow, and RHR suppression pool cooling, are required.

15.1.4.2.3 The Effect of Single Failures and Operator Errors

From a core performance standpoint, a single failure or operator error would simply activate the reactor protection system resulting in a plant shutdown. A single failure or operator error cannot increase the severity of this event.

The instrumentation which detects and audibly alarms the resulting suppression pool temperature rise, and the RHR containment heat removal system are designed to meet the single failure criteria. The operator must manually initiate suppression pool cooling.

15.1.4.3 Core and System Performance

15.1.4.3.1 Mathematical Model

The reactor model described in Reference 15.1-1 is used to simulate this event. It was determined that this event is not limiting from a core performance standpoint.

15.1.4.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2. A discussion of the SRV is provided in Section 5.2.2.

15.1.4.3.3 Qualitative Results

The opening of an SRV allows steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a mild depressurization transient.

The pressure regulator senses the nuclear system pressure decrease and within a few seconds closes the turbine control valve far enough to stabilize reactor vessel pressure at a slightly

lower value and reactor power settles at nearly the initial power level. Thermal margins decrease only slightly through the transient, and no fuel damage results from the transient. The MCPR is essentially unchanged and, therefore, the safety limit margin is unaffected.

15.1.4.4 Barrier Performance

The transient resulting from a stuck open relief valve is a mild depressurization which is within the range of normal load following. Therefore, there is no significant effect on RCPB and containment design pressure limits.

Since quenchers are used as steam discharge devices on the steam relief lines, no unstable condensation oscillations are expected which could damage the containment vessel. This is discussed in Appendix 3A.

Therefore, barrier integrity and function is maintained.

15.1.4.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment there will be no exposures to operating personnel. Since this event does not result in an uncontrolled release to the environment the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.1.5 SPECTRUM OF STEAM PIPING FAILURES INSIDE AND OUTSIDE OF CONTAINMENT IN A PRESSURIZED WATER REACTOR

This event is not applicable to BWR plants.

15.1.6 INADVERTENT RESIDUAL HEAT REMOVAL SHUTDOWN COOLING OPERATION

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

15.1.6.1 Identification of Causes and Frequency Classification

15.1.6.1.1 Identification of Causes

At design power conditions no conceivable malfunction in the shutdown cooling system could cause temperature reduction.

In startup or cooldown operation, where the reactor is at or near critical, a very slow increase in reactor power could result. A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for the RHR heat exchangers. The resulting temperature decrease would cause a slow insertion of positive reactivity into the core. If the operator did not act to control the power level, a high neutron flux reactor scram would terminate the transient without violating fuel thermal limits and without any measurable increase in nuclear system pressure.

15.1.6.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.1.6.2 Sequence of Events and Systems Operation

15.1.6.2.1 Sequence of Events

A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for RHR heat exchangers. The resulting temperature decrease causes a slow insertion of positive reactivity into the core. Scram will occur before any thermal limits are reached if the operator does not take action. The sequence of events for this event is shown in Table 15.1-4.

15.1.6.2.2 System Operation

A shutdown cooling malfunction causing a moderator temperature decrease must be considered in all operating states. However, this event is not considered while at power operation since pressure is too high to permit operation of RHR shutdown cooling.

No unique safety actions are required to avoid unacceptable safety results for transients as a result of a reactor coolant temperature decrease induced by misoperation of the shutdown cooling heat exchangers. In startup or cooldown operation, where the reactor is at or near critical, the slow power increase resulting from the cooler moderator temperature would be controlled by the operator in the same manner normally used to control power in the source or intermediate power ranges.

15.1.6.2.3 Effect of Single Failures and Operator Action

No single failures can cause this event to be more severe.

If the operator takes action, the slow power rise will be controlled in the normal manner. If no operator action is taken, a scram will terminate the power increase before thermal limits are reached.

15.1.6.3 Core and System Performance

The increased subcooling caused by misoperation of the RHR shutdown cooling mode could result in a slow power increase due to the reactivity insertion. This power rise would be terminated by a flux scram before fuel thermal limits are approached. Therefore, only qualitative description is provided here.

15.1.6.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.1.6.5 Radiological Consequences

Since this event does not result in any fuel failures, no analysis of radiological consequences is required for this event.

15.1.7 REFERENCES

15.1-1 For Power Uprate: GE Nuclear Energy, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, September 1993 (Proprietary).

TABLE 15.1-1

SEQUENCE OF EVENTS FOR FIGURE 15.1-1

Feedwater Controller Failure
Uprated Power

Time (sec)	Event
0	Initiate simulated failure of 139% upper limit on feedwater flow.
12.57	L8 vessel level setpoint trips main turbine and feedwater pumps. Turbine bypass operation initiated.
12.57	Recirculation pump trip actuated L8 turbine trip.
12.58	Reactor scram trip actuated from main turbine stop valve position switches.
12.67	Turbine bypass valves start to open.
12.67	Main turbine stop valves closed.
12.76	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
14.66-14.92	Group 3-5[a] relief valves actuated due to high pressure.

[a] Group 1 and 2 out of service for this analysis.

TABLE 15.1-2

SEQUENCE OF EVENTS FOR FIGURE 15.1-2

Pressure Regulator Failure - Open Uprated Power

Time (sec)	Event
0	Simulate maximum limit on steam flow, (130%) to main turbine.
0.2	Main turbine bypass valves open.
3.31	Vessel water level (L8) trip initiates turbine and feedwater trips.
3.32	Main turbine stop valves reach 90% open position initiating a reactor scram.
3.50	Both recirculation pumps trip.
6.15	Feedwater recirculation valves trip.
6.95	Group 3 relief valves actuated.
7.40	Group 4 relief valves actuated.
10[a]	Pressure relief valves closed.
57.98[a]	Main steam line isolation valves closed on turbine inlet pressure (approximately 850 psia).
77	High-pressure core spray and RCIC system initiation on low level (L2).

[a] Estimated.

TABLE 15.1-3

SEQUENCE OF EVENTS FOR INADVERTENT
SAFETY/RELIEF VALVE OPENING

Uprated Power

Time	Event
0	Initiate opening of one SRV which remains open throughout the event.
1[a]	Reactor dome pressure decreases.
3[a]	Pressure regulator closes turbine control valve to stabilize reactor vessel pressure.
8+	Reactor power settles near the initial power level.

[a] Approximately.

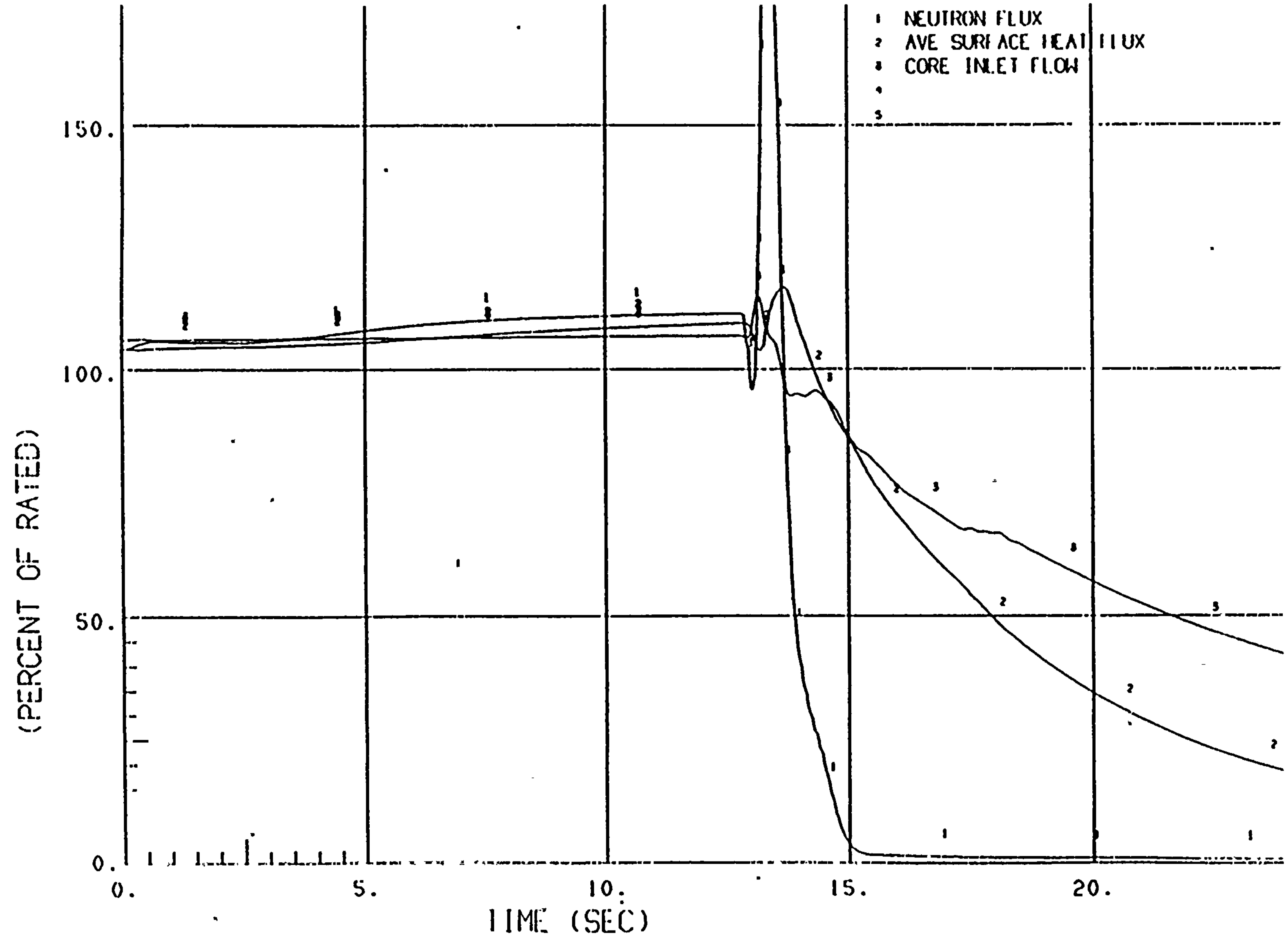
TABLE 15.1-4

SEQUENCE OF EVENTS FOR INADVERTENT
RESIDUAL HEAT REMOVAL SHUTDOWN COOLING OPERATION

Original Rated Power

Time[a]	Event
0	Residual heat removal shutdown cooling inadvertently activated.
0-10 minutes	Slow rise in reactor power.
+10 minutes	Operator may take action to limit power rise. Flux scram will occur if no action is taken.

[a] Approximately.



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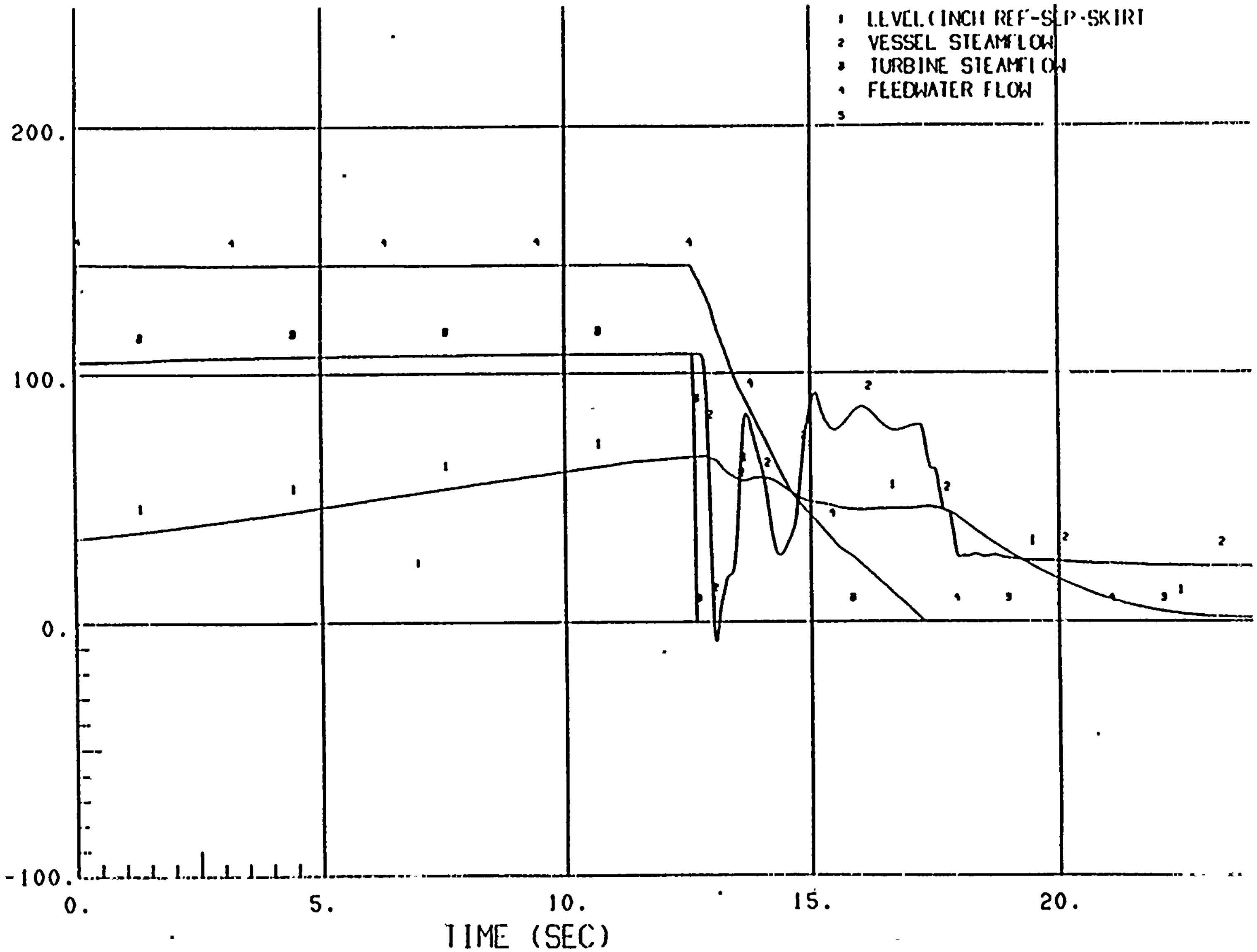
NUCLEAR PLANT 2 FSAR

Feedwater Controller Failure, Maximum Demand at 104.1% Uprated Power, 106% Flow at Normal Feedwater Temperature

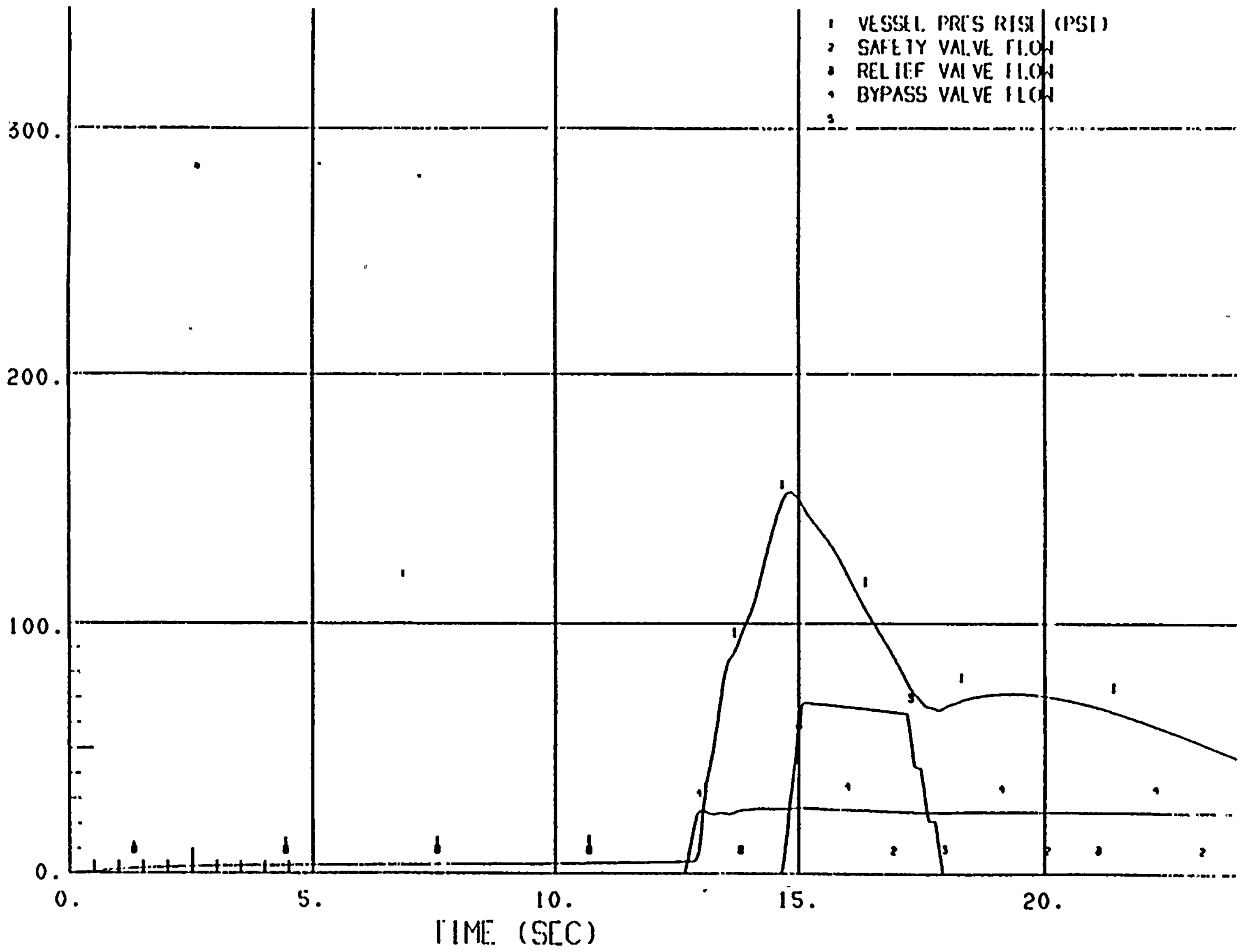
Draw. No.	Rev.	Figure
		15.1-1.1



Feedwater Controller Failure, Maximum Demand at 104.1% Uprated Power, 106% Flow at Normal Feedwater Temperature

Draw. No.	Rev.	Figure
		15.1-1.2

Amendment 53
November 1998



Amendment 53
November 1998

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Feedwater Controller Failure, Maximum Demand at 104.1% Uprated Power, 106% Flow at Normal Feedwater Temperature

Draw. No.	Rev.	Figure
		15.1-1.3

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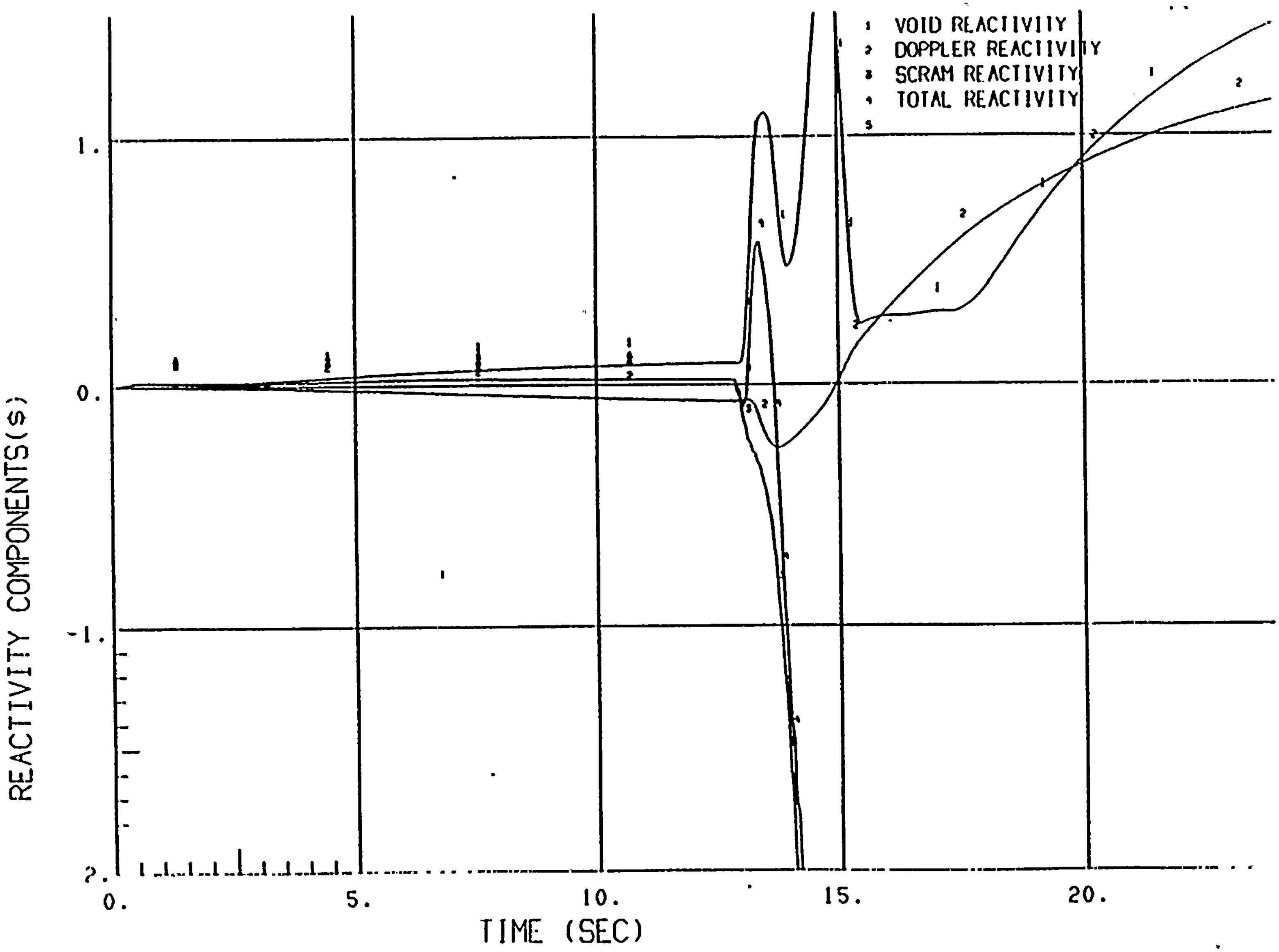

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NUCLEAR PLANT 2 FSAR

Feedwater Controller Failure, Maximum Demand at 104.1% Uprated Power, 106% Flow at Normal Feedwater Temperature

Draw. No.	Rev.	Figure
		15.1-1.4

Amendment 53
November 1998

Form No. 960690

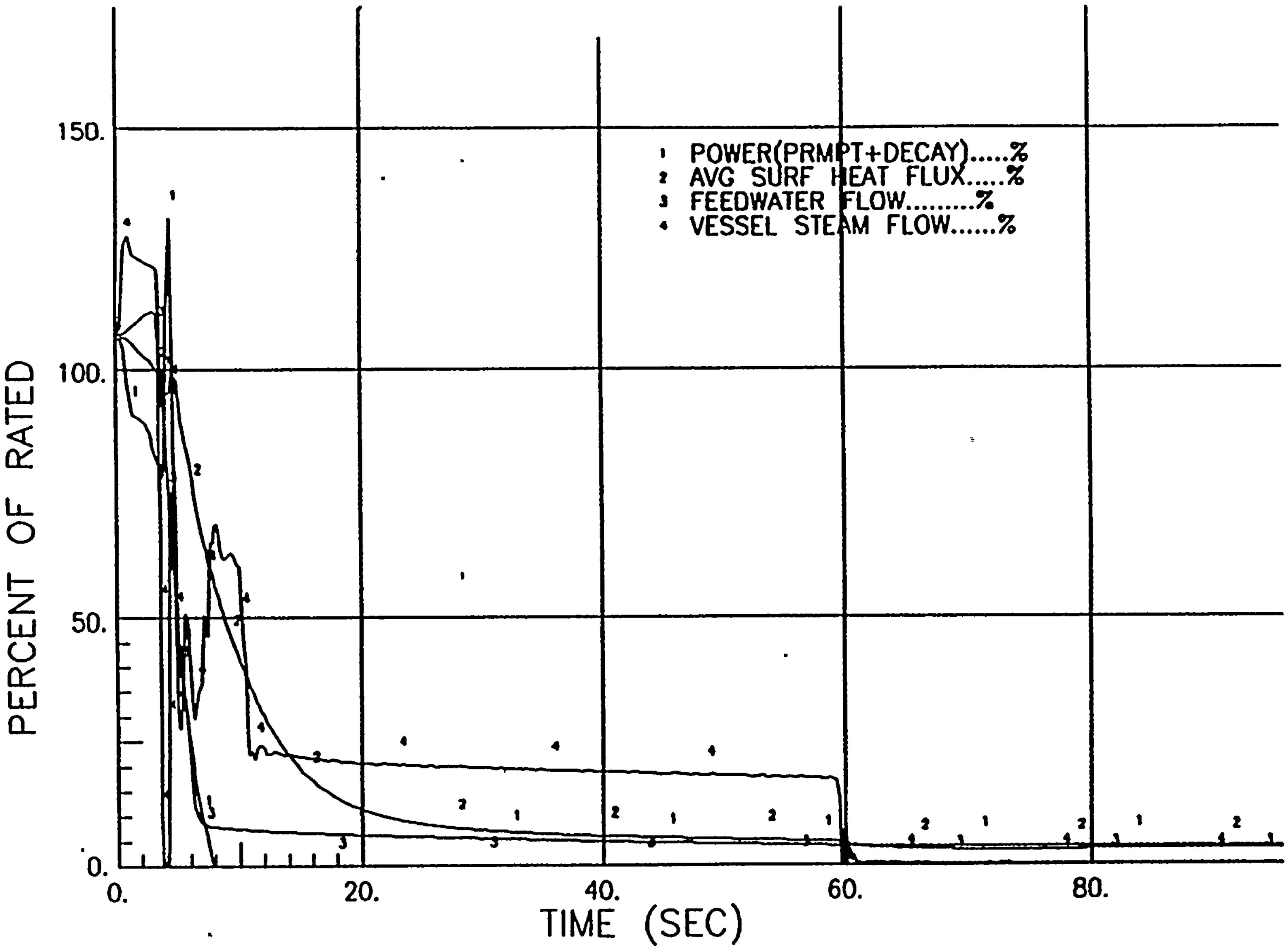

Figure 4-2a. Pressure Regulator Failure - Open at 106.2% Uprated Power, 100% Flow

Amendment 53
November 1998

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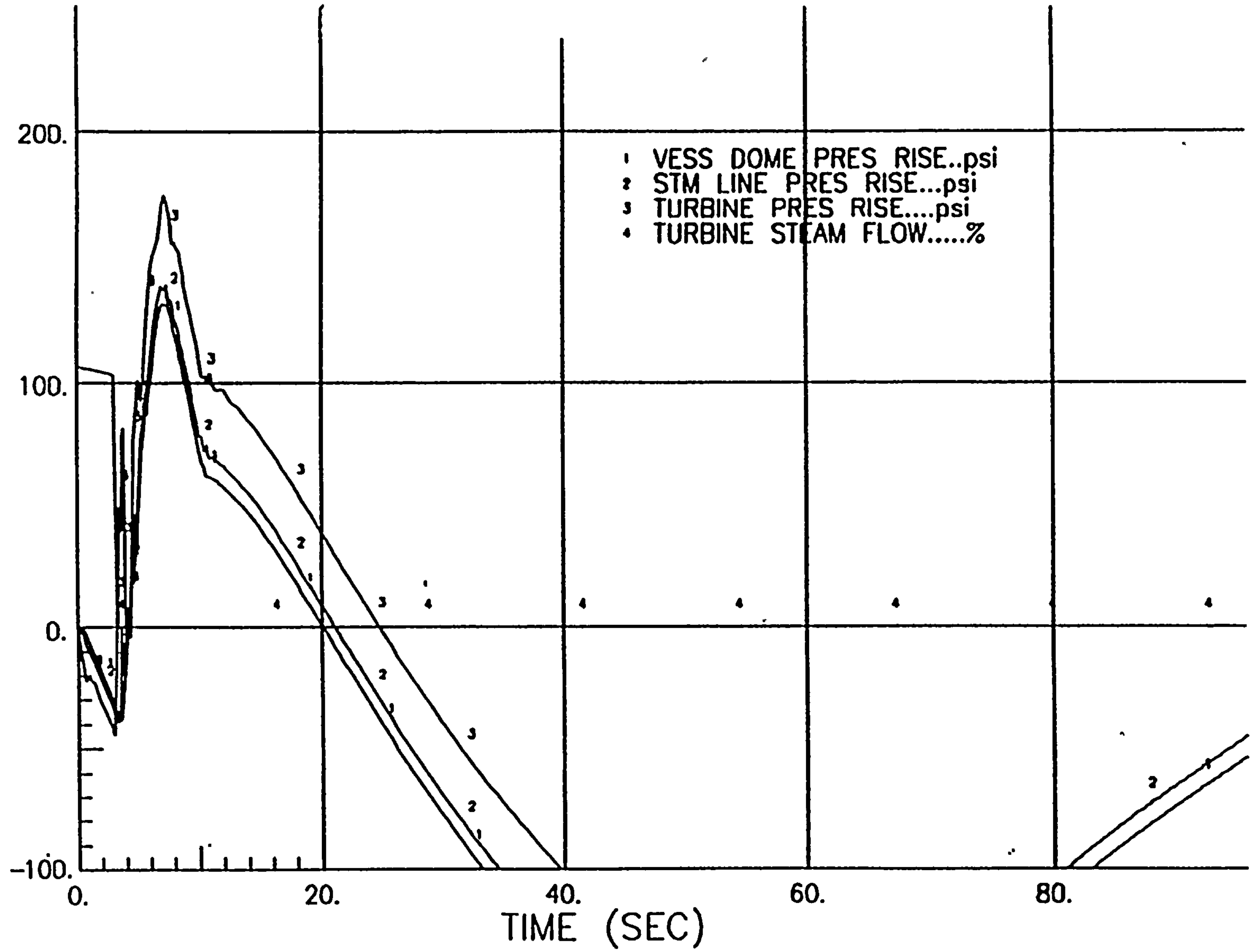
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.1

Form No. 960690



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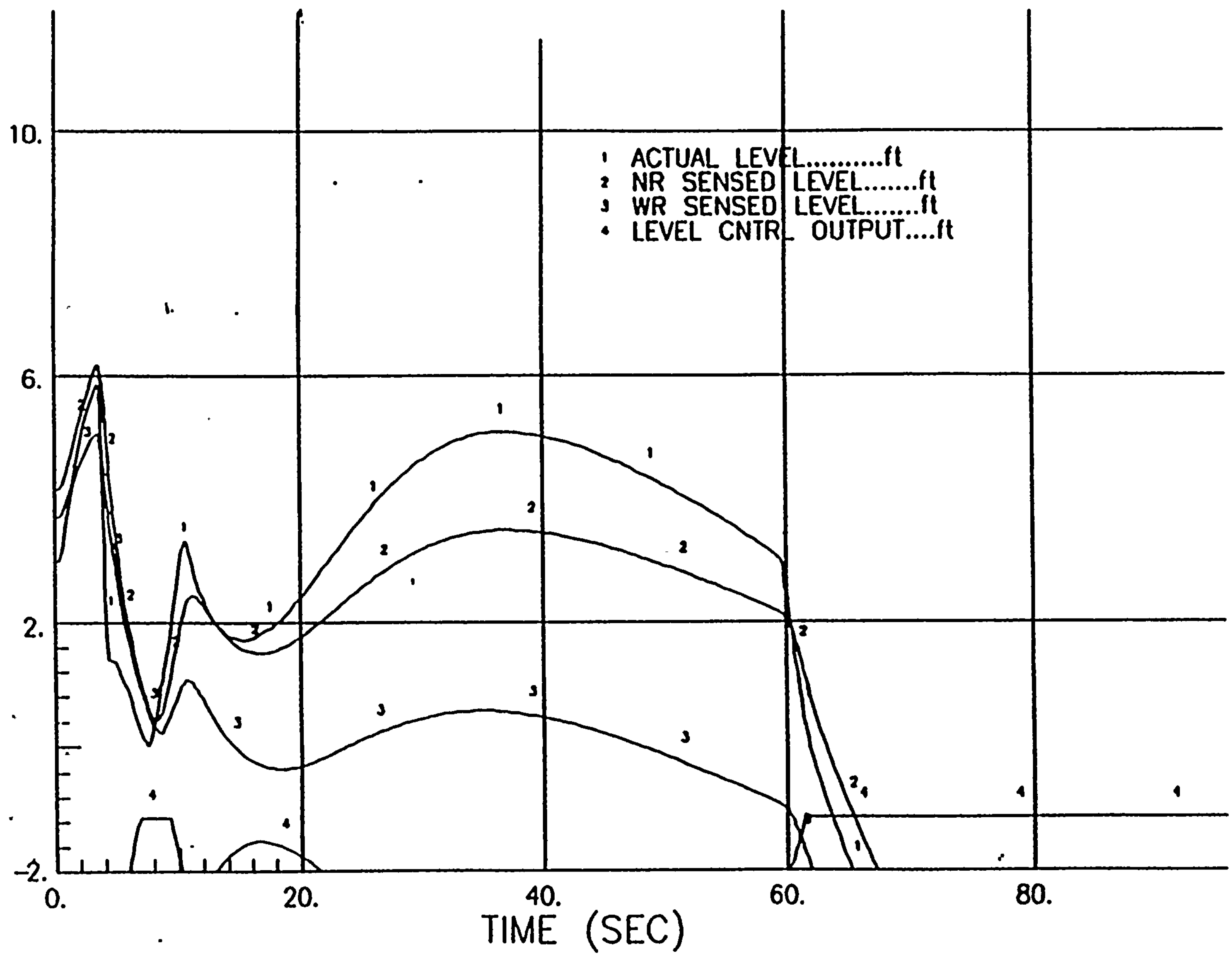
Pressure Regulator Failure - Open at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.2

Form No. 960690



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NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.3

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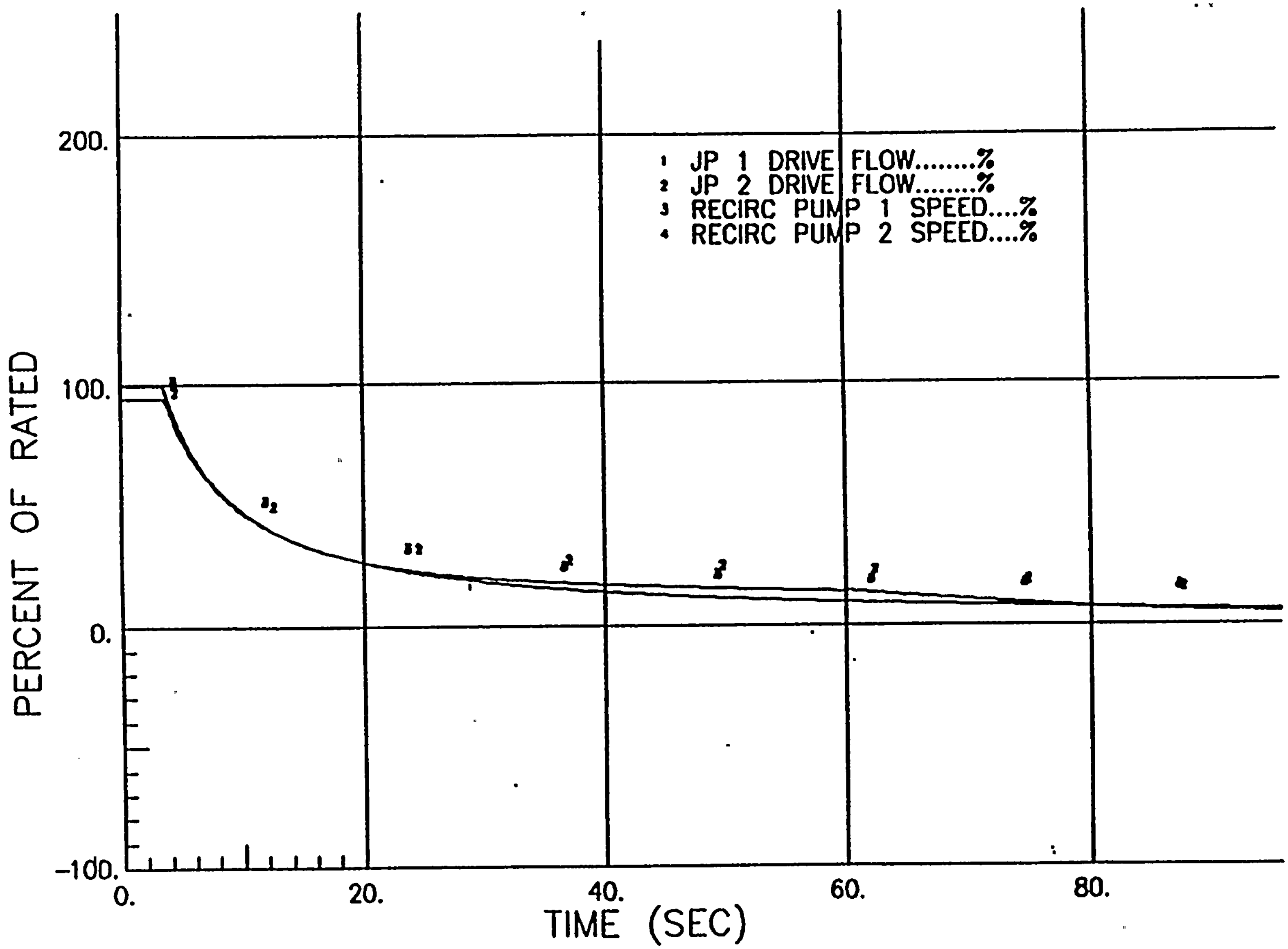

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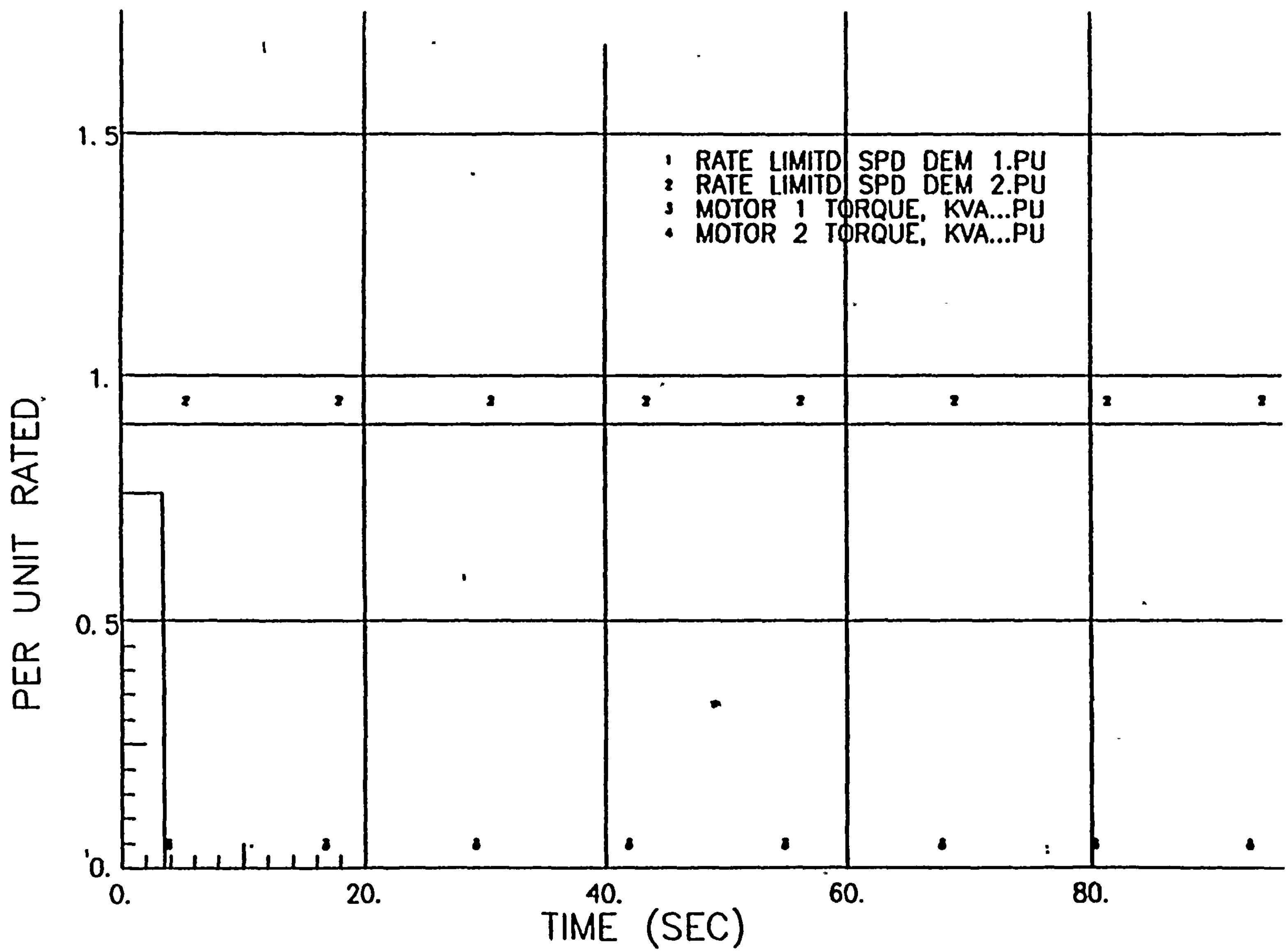
Pressure Regulator Failure - Open at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.4

Form No. 960690



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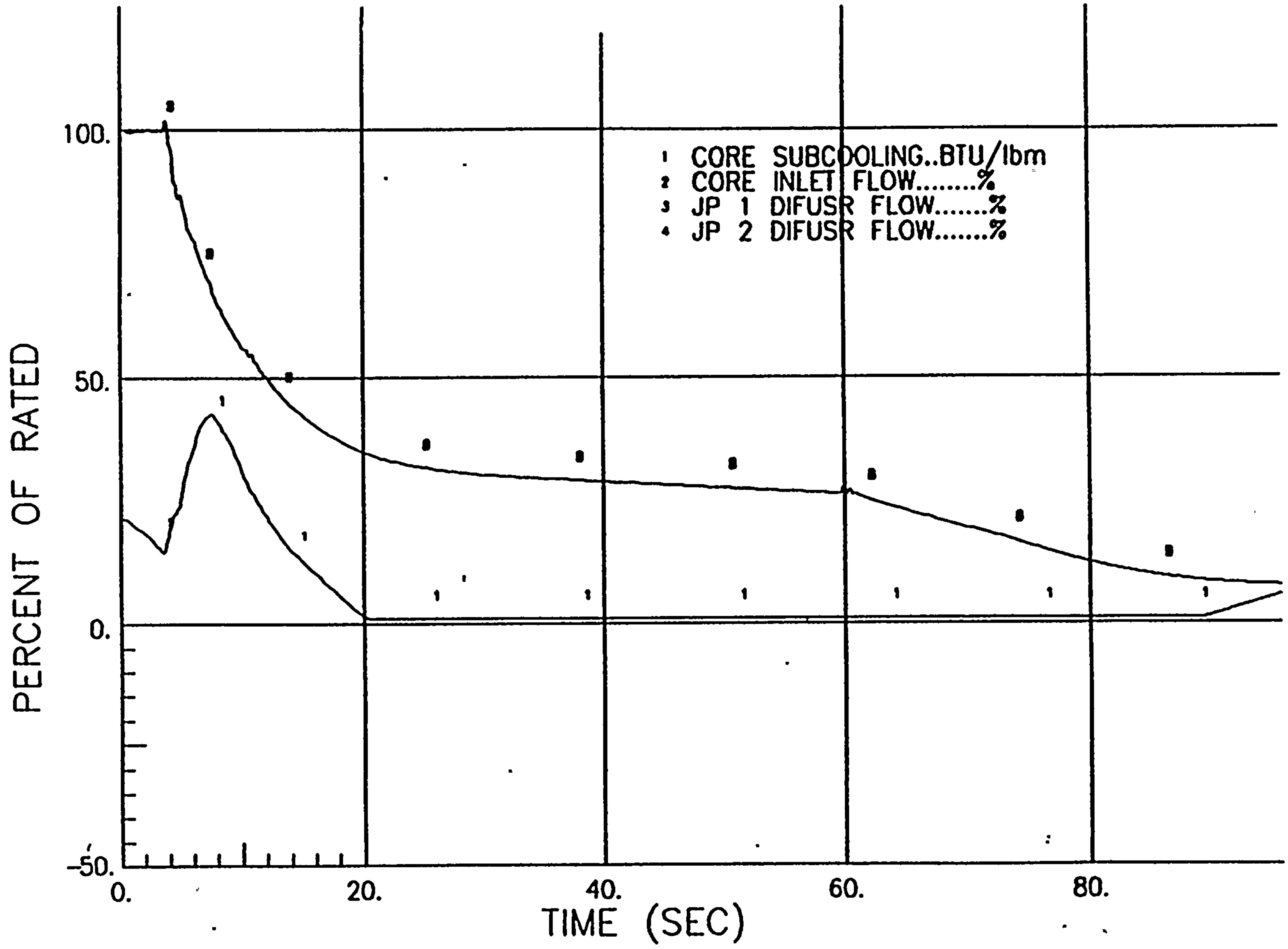
Pressure Regulator Failure - Open at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.5

Form No. 960690



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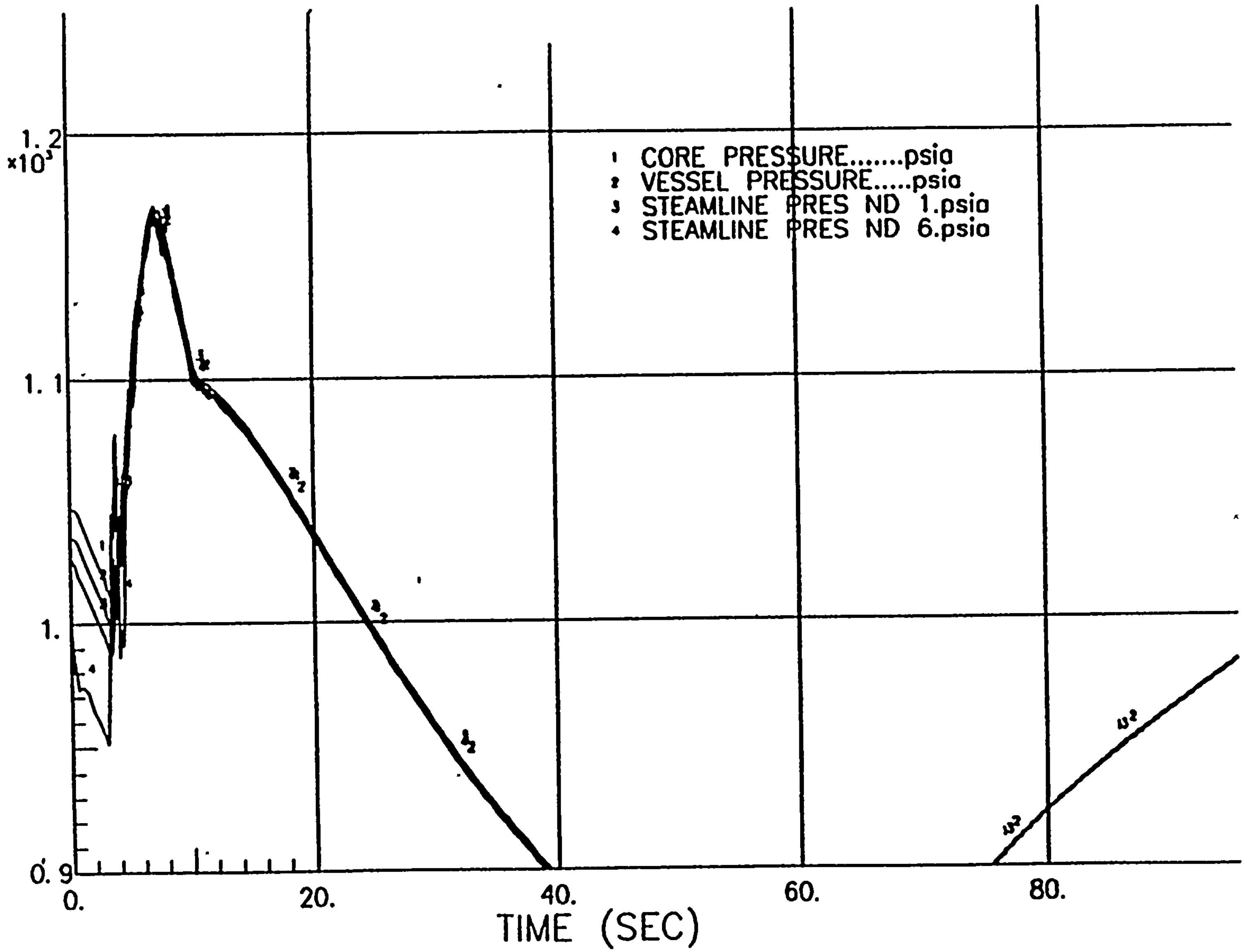
Pressure Regulator Failure - Open at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.6

Form No. 960690

Form No. 960690

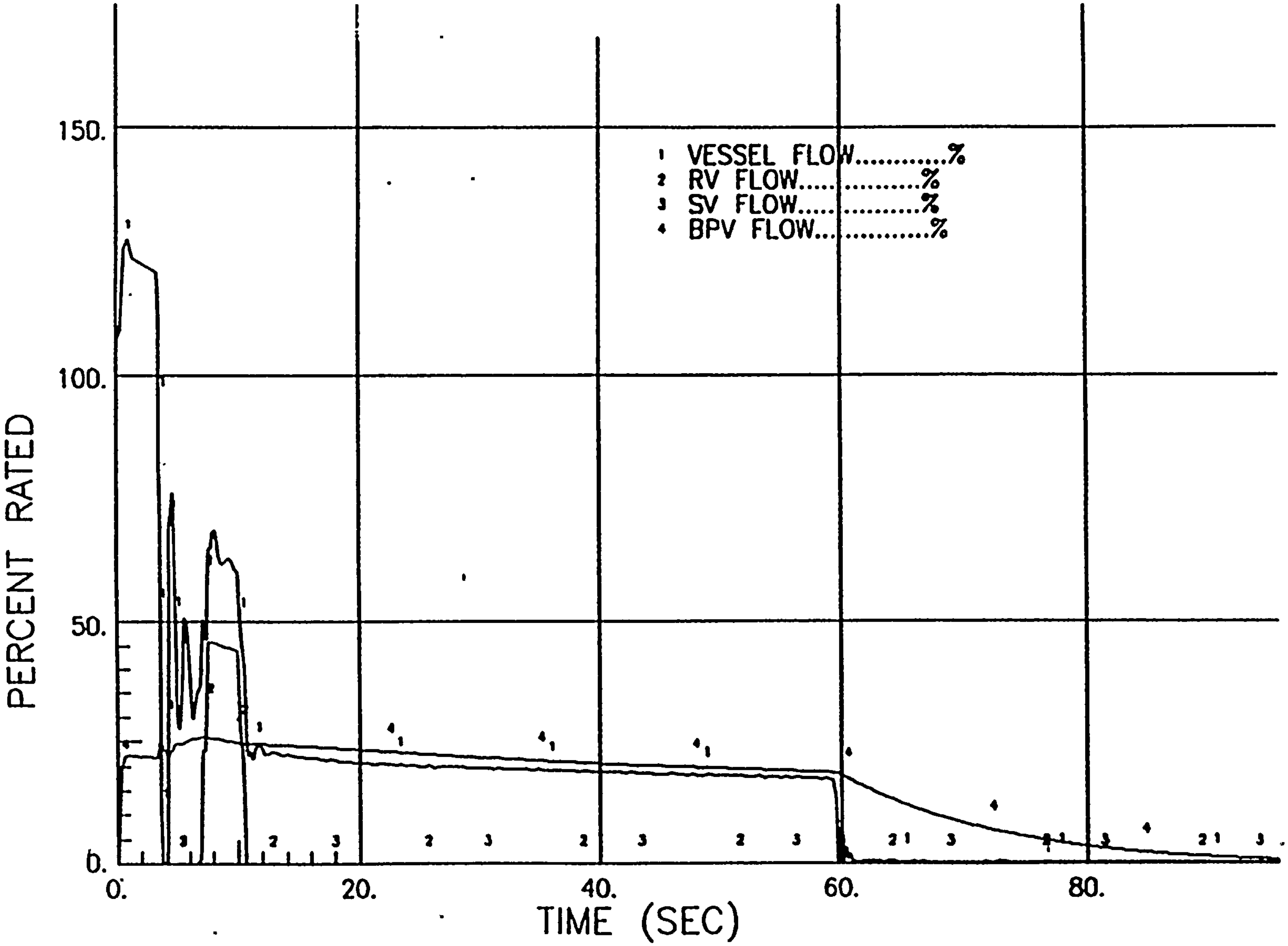


Pressure Regulator Failure - Open at 106.2% Uprated Power, 100% Flow

Draw. No.

Rev.

Figure 15.1-2.7



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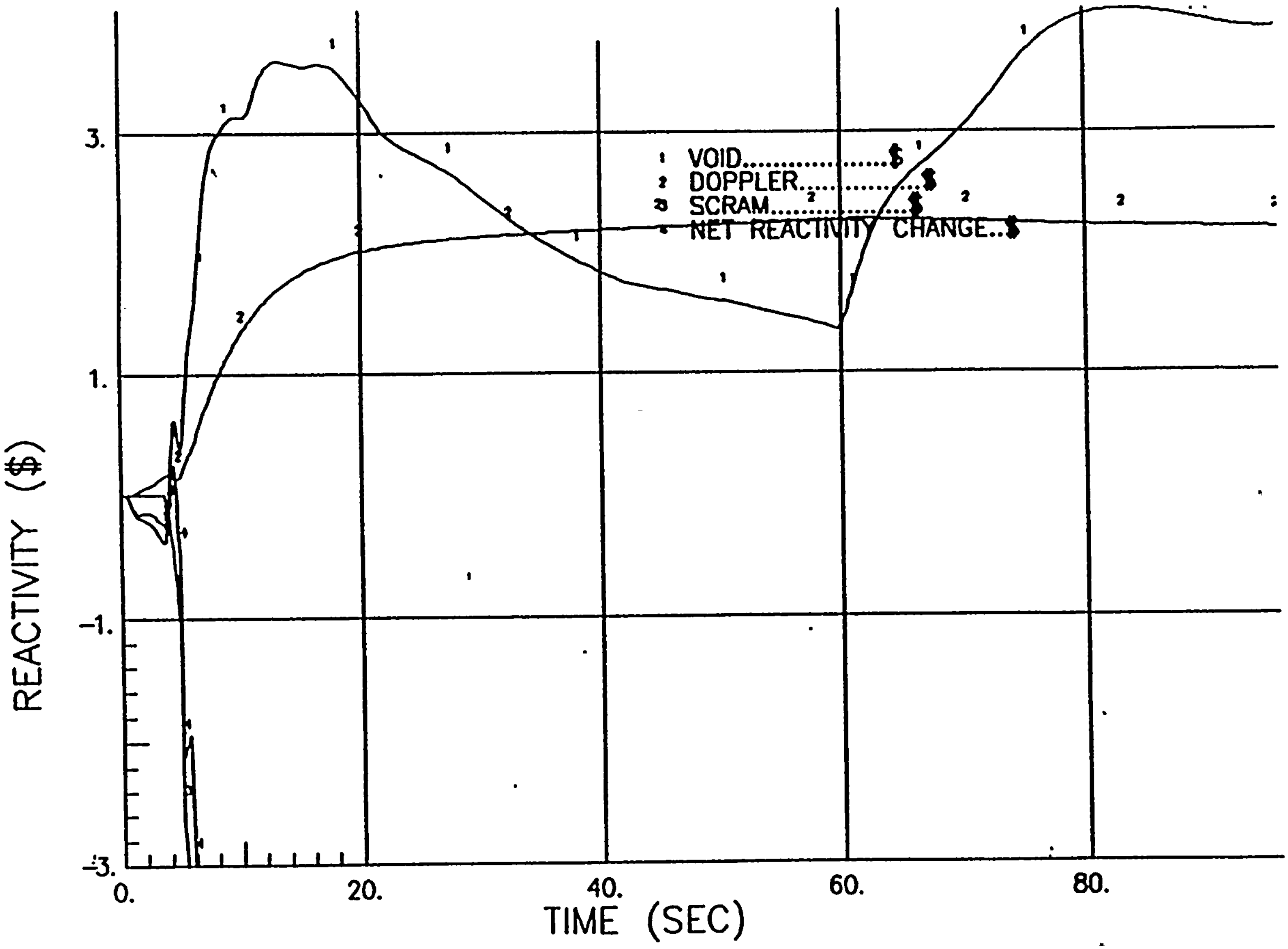
Pressure Regulator Failure - Open at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.8

Amendment 53
November 1998



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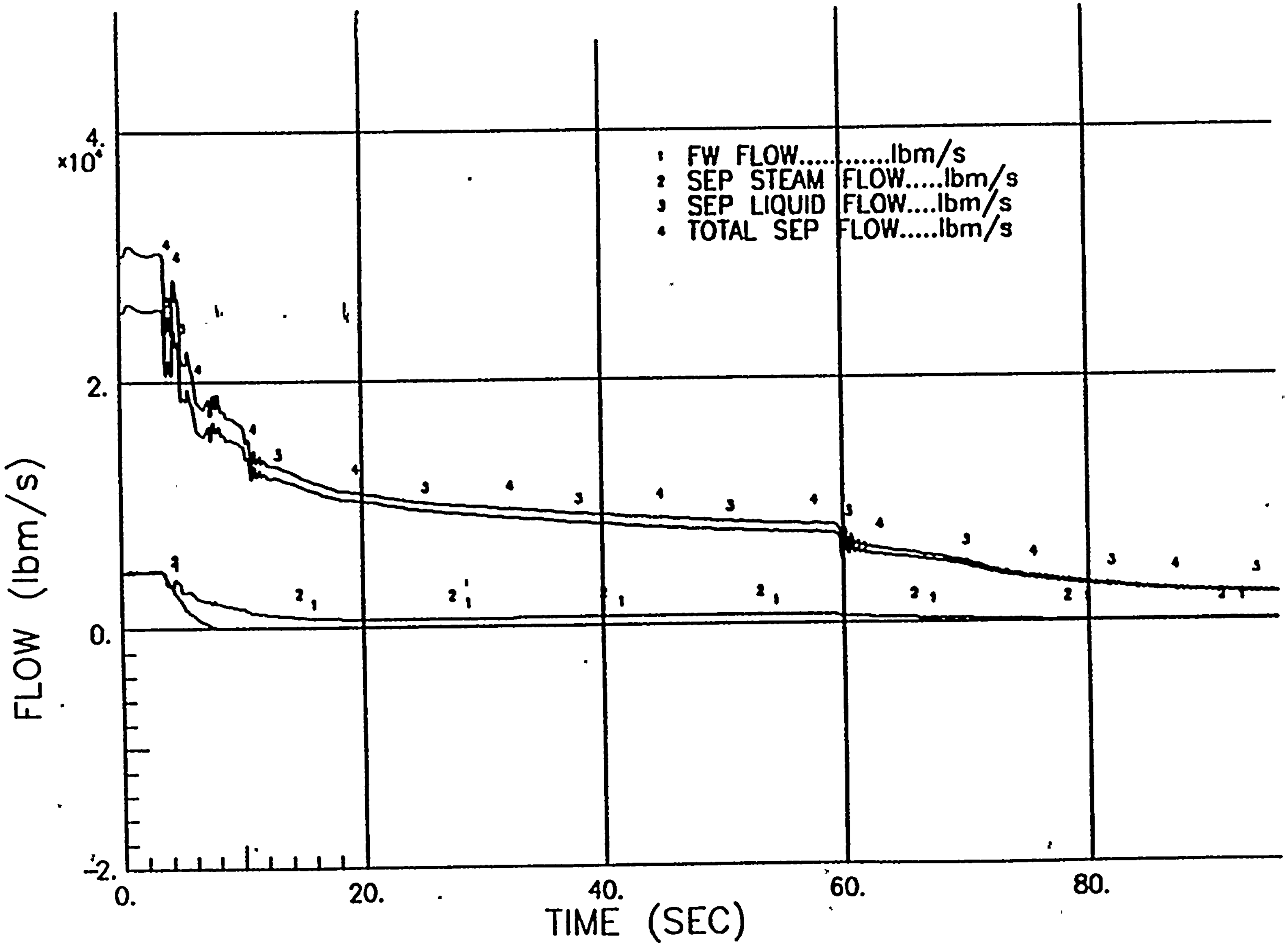
NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.9

Form No. 960690



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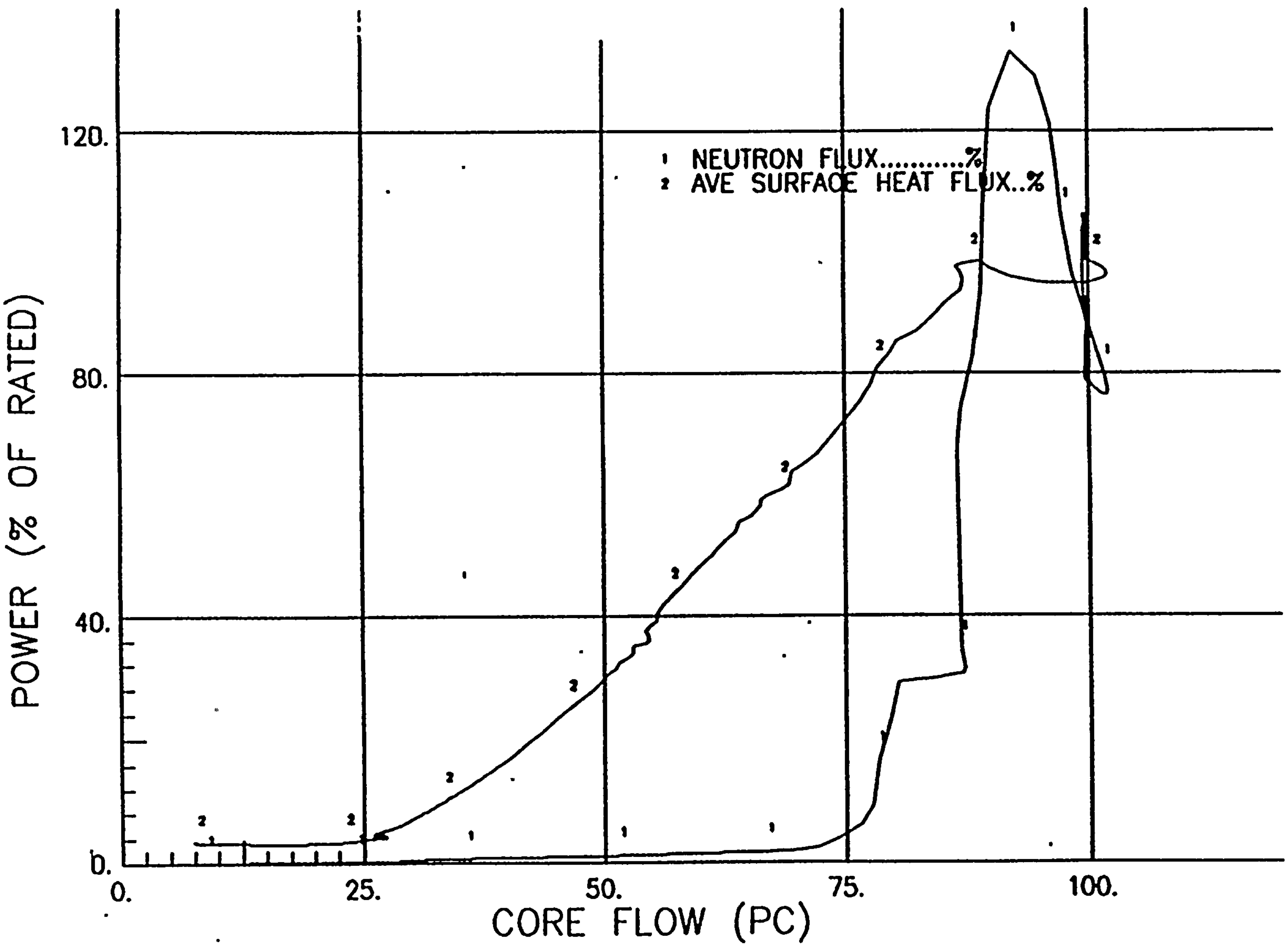
NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.10

Form No. 960690



WASHINGTON PUBLIC POWER SUPPLY SYSTEM

NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.1-2.11

Amendment 53
November 1998

15.2 INCREASE IN REACTOR PRESSURE

15.2.1 PRESSURE REGULATOR FAILURE - CLOSED

This transient is classified as a nonlimiting event for both original and uprated power conditions; therefore, no further analysis has been performed.

15.2.1.1 Identification of Causes and Frequency Classification

15.2.1.1.1 Identification of Causes

Two identical pressure regulators are provided to maintain primary system pressure control. They independently sense pressure upstream of the main turbine stop valves and compare it to two separate setpoints to create proportional error signals that produce each regulator output. The regulator with the highest output controls the main turbine control valves (TCVs). The lowest pressure setpoint gives the largest pressure error and, thereby, largest regulator output. The backup regulator is set 5 psi higher which provides for a slightly smaller error and effective output of the controller.

It is assumed for purposes of this transient analysis that a single failure occurs which erroneously causes the controlling regulator to close the main TCVs and thereby increases reactor pressure. If this occurs, a backup regulator is available.

15.2.1.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.1.2 Sequence of Events and Systems Operation

15.2.1.2.1 Sequence of Events

A failure of the primary or controlling pressure regulator in the closed mode will cause the valves to close momentarily. The pressure will increase because the reactor is still generating the initial steam flow. The backup regulator will reopen the valves and reestablish steady-state operation above the initial pressure equal to the setpoint difference of 5 psi.

15.2.1.2.1.1 Identification of Operator Actions. The operator will verify that the backup regulator assumes proper control. However, this action is not required.

15.2.1.2.2 Systems Operation

Normal plant instrumentation and control is assumed to function. This event requires no protection system operation.

15.2.1.2.3 The Effect of Single Failures and Operator Errors

The first assumed failure produces a slight pressure increase in the reactor until the backup regulator gains control. No other action is significant in restoring normal operation if the backup regulator fails at this time. For a backup regulator failure, the control valves would start to close, raising the reactor pressure to the point where a flux or pressure scram trip would be initiated to shutdown the reactor. This event is less severe than the turbine trip for the following reasons:

a. For the pressure regulator failure-closure event the reactor scrams on high neutron flux or pressure but the recirculation pumps do not trip. As a result, core flow remains at 100% or greater throughout the critical portion of the transient with respect to the critical power ratio (CPR). This provides improved heat transfer capability in relation to the turbine trip transient; and

b. Since the control valves close in response to a pressure error signal, their closure rate is not as fast as the turbine stop or control valve response to a trip signal. This produces a slower pressurization rate for the regulator failure relative to the turbine trip event. This in turn results in a lower peak neutron flux and therefore a lower peak surface heat flux than the turbine trip event.

15.2.1.3 <u>Core and System Performance</u>

The disturbance is mild and similar to a pressure setpoint change. No significant reductions in fuel thermal margins occur. This transient is much less severe than the generator and turbine trip transients.

15.2.1.3.1 Mathematical Model

Qualitative evaluation provided only.

15.2.1.3.2 Input Parameters and Initial Conditions

Qualitative evaluation provided only.

15.2.1.3.3 Results

Response of the reactor during this regulator failure is such that pressure at the turbine inlet increases quickly, less than 2 sec, due to the sharp closing action of the TCVs which reopen when the backup regulator gains control. This pressure disturbance in the vessel is not expected to exceed flux or pressure scram trip setpoints.

15.2.1.3.4 Consideration of Uncertainties

All systems used for protection in this event were assumed to have the poorest allowable response. Expected plant behavior is, therefore, expected to reduce the actual severity of the transient.

15.2.1.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient (see Table 15.0-1) in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.2.1.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this event.

15.2.2 GENERATOR LOAD REJECTION

15.2.2.1 Identification of Causes and Frequency Classification

15.2.2.1.1 Identification of Causes

Fast closure of the TCVs is initiated whenever electrical grid disturbances occur which result in significant loss of electrical load on the generator. The TCVs are required to close as rapidly as possible to prevent excessive overspeed of the turbine-generator rotor. Closure of the main TCVs will cause a sudden reduction in steam flow which results in an increase in system pressure, which may cause a reactor shutdown due to high flux or high steam flow condition.

15.2.2.1.2 Frequency Classification

15.2.2.1.2.1 Generator Load Rejection. This event is categorized as an incident of moderate frequency.

15.2.2.1.2.2 Generator Load Rejection with Bypass Failure. This event is categorized as a moderate frequency event.

15.2.2.2 Sequence of Events and System Operation

15.2.2.2.1 Sequence of Events

15.2.2.2.1.1 Generator Load Rejection - Turbine Control Valve Fast Closure. This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

A loss of generator electrical load from high power conditions produces the sequence of events listed in Table 15.2-1.

15.2.2.2.1.2 Generator Load Rejection with Failure of Bypass. A loss of generator electrical load at high power with bypass failure produces the sequence of events listed in Table 15.2-2.

15.2.2.2.1.3 Identification of Operator Actions.

a. Verify proper bypass valve performance,

b. Observe that the feedwater/level controls have maintained the reactor water level at a satisfactory value,

c. Observe that the pressure regulator is controlling reactor pressure at the desired value,

d. Record peak power and pressure, and

e. Verify relief valve operation.

15.2.2.2.2 System Operation

15.2.2.2.2.1 Generator Load Rejection with Bypass. To properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems (RPS) unless stated otherwise.

Turbine control valve fast closure initiates a scram trip signal for power levels greater than 30% nuclear boiler rated (NBR). In addition, recirculation pump trip (RPT) is initiated. Both of these trip signals satisfy single failure criterion and credit is taken for these protection features.

The pressure relief system which operates the relief valves independently when system pressure exceeds relief valve instrumentation setpoints is assumed to function normally during the time period analyzed.

15.2.2.2.2.2 Generator Load Rejection with Failure of Bypass. Same as Section 15.2.2.2.2.1 except that failure of the main turbine bypass valves is assumed for the entire transient.

15.2.2.2.3 The Effect of Single Failures and Operator Errors

Mitigation of pressure increase, the basic nature of this transient, is accomplished by the RPS functions. Turbine control valve trip scram and RPT are designed to satisfy the single failure criterion. An evaluation of the most limiting single failure (i.e., failure of the bypass system) was considered in this event.

15.2.2.3 Core and System Performance

15.2.2.3.1 Mathematical Model

The computer model described in the Code Operating Limits Report (COLR) is used to simulate this event.

15.2.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2.

The turbine digital electrohydraulic control system power/load imbalance device detects load rejection before a measurable speed change takes place.

The closure characteristics of the TCVs are assumed such that the valves operate in the full arc (FA) mode and have a full stroke closure time, from fully open to fully closed, of 0.15 sec. Sensitivity study has shown that the most severe initial condition for this transient is the assumption of FA operation at 105% NBR steam flow, since the pressurization rate is higher at high initial power level. The TCV closure time for power uprate is conservatively assumed to operate in FA mode with a full stroke closure time of 0.15 sec. The actual closure time during the event at power uprate conditions is 0.10 sec for the limiting transient without bypass as shown in Table 15.2-2. The nonlimiting case with bypass available was not reanalyzed; however, a closure time of 0.07 sec was calculated for that event.

Auxiliary power would normally be independent of any turbine generator overspeed effects and continuously supplied at rated frequency as automatic fast transfer to auxiliary power supplies normally occurs. The recirculation pumps are assumed to remain tied to the main generator and thus increase in speed with the turbine-generator overspeed until tripped by the RPT system.

The reactor is operating in the manual flow-control mode when load rejection occurs. Results do not significantly differ if the plant had been operating in the automatic flow-control mode.

The bypass valve opening characteristics are simulated using the specified delay together with the specified opening characteristic required for bypass system operation.

Events caused by low water level trips, including closure of main steam line isolation valves (MSIVs), and initiation of high-pressure core spray (HPCS) and reactor core isolation cooling (RCIC) are not included in the simulation. Should these events occur, they will follow after the primary concerns of fuel thermal margin and overpressure effects have occurred, and are expected to be less severe than those already experienced by the system.

15.2.2.3.3 Results

15.2.2.3.3.1 Generator Load Rejection with Bypass. Figure 15.2-1 shows the results of the generator trip from original rated power. Peak neutron flux rises 156.8% above NBR conditions.

The average surface heat flux peaks at 102.9% of the initial value and minimum critical power ratio (MCPR) does not significantly decrease below its initial value.

15.2.2.3.3.2 Generator Load Rejection with Failure of Bypass. This event is a limiting transient, therefore, analysis was performed for the uprated power condition. Figure 15.2-2 shows that, for the case of bypass failure, peak neutron flux reaches about 348% of uprated power, average surface heat flux reaches 114% of its initial value. Results are presented in Table 15.0-1.

15.2.2.3.4 Consideration of Uncertainties

The full stroke closure time of the TCV of 0.15 sec is conservative. Typically, the actual closure time is closer to 0.2 sec. Clearly the less time it takes to close, the more severe the pressurization effect.

All systems used for protection in this event were assumed to have the poorest allowable response. Expected plant behavior is, therefore, expected to reduce the actual severity of the transient.

15.2.2.4 Barrier Performance

15.2.2.4.1 Generator Load Rejection

Peak pressure remains within normal operating range and no threat to the barrier exists.

15.2.2.4.2 Generator Load Rejection with Failure of Bypass

Peak pressure at the valves reaches 1196 psig. The peak nuclear system pressure reaches 1232 psig at the bottom of the vessel, well below the nuclear barrier transient pressure limit of 1375 psig.

15.2.2.5 Radiological Consequences

While the consequences of this event does not result in fuel failures, it does result in the discharge of normal coolant activity to the suppression pool by means of safety/relief valve (SRV) operation. Since this activity is contained in the primary containment, there will be no exposure to the public. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or filter the discharge prior to release to the environment when conditions permit in accordance with established requirements.

15.2.3 TURBINE TRIP

15.2.3.1 Identification of Causes and Frequency Classification

15.2.3.1.1 Identification of Causes

A variety of turbine or nuclear system malfunctions will initiate a turbine trip. Some examples are moisture separator high levels, operator lockout, loss of control fluid pressure, low condenser vacuum, and reactor high water level.

15.2.3.1.2 Frequency Classification

15.2.3.1.2.1 Turbine Trip. This event is categorized as an incident of moderate frequency. In defining the frequency of this event, turbine trips which occur as a by-product of other transients such as loss of condenser vacuum or reactor high level trip events are not included. However, spurious low vacuum or high level trip signals which cause an unnecessary turbine trip are included in defining the frequency.

15.2.3.1.2.2 Turbine Trip with Failure of Bypass. This transient disturbance is categorized as a moderate frequency incident.

15.2.3.2 Sequence of Events and Systems Operation

15.2.3.2.1 Sequence of Events

15.2.3.2.1.1 Turbine Trip. This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

Turbine trip at high power produces the sequence of events listed in Table 15.2-3.

15.2.3.2.1.2 Turbine Trip with Failure of Bypass. Turbine trip at high power with bypass failure produces the sequence of events listed in Table 15.2-4. Since this transient is a limiting event, analysis was performed for the power uprate condition.

15.2.3.2.1.3 Identification of Operator Actions.

a. Verify auto transfer of buses supplied by generator to incoming power. If automatic transfer does not occur, manual transfer must be made;

b. Monitor and maintain reactor water level at required level;

c. Check turbine for proper operation of all auxiliaries during coastdown;

d. Depending on conditions, initiate normal operating procedures for cooldown, or maintain pressure for restart purposes;

e. Put the mode switch in the startup position before the reactor pressure reaches < 850 psia;

f. Secure RCIC and HPCS operation if auto initiation occurred due to low water level;

g. Monitor control rod drive positions and insert both the intermediate range monitors (IRMs) and source range monitors (SRMs); and

h. Complete cooldown.

15.2.3.2.2 Systems Operation

15.2.3.2.2.1 Turbine Trip. All plant control systems maintain normal operation unless specifically designated to the contrary.

Turbine stop valve closure initiates a reactor scram trip by means of valve position signals to the protection system.

Turbine stop valve closure initiates RPT thereby terminating the jet pump drive flow.

The pressure relief system, which operates the relief valves independently when system pressure exceeds relief valve instrumentation setpoints, is assumed to function normally during the time period analyzed.

15.2.3.2.2.2 Turbine Trip with Failure of Bypass. Same as Section 15.2.3.2.2.1 except that failure of the main turbine bypass system is assumed for the entire transient time period analyzed.

15.2.3.2.2.3 Turbine Trip at Low Power with Failure of Bypass. Same as Section 15.2.3.2.2.1 except that failure of the main turbine bypass system is assumed.

It should be noted that below 30% NBR power level, a main stop valve scram trip inhibit signal derived from the first stage pressure of the turbine is activated. This is done to eliminate the stop valve scram trip signal from scramming the reactor provided the bypass system functions properly. In other words, the bypass would be sufficient at this low power to accommodate a turbine trip without the necessity of shutting down the reactor. All other protection system functions remain functional as before and credit is taken for those protection system trips.

15.2.3.2.3 The Effect of Single Failures and Operator Errors

15.2.3.2.3.1 Turbine Trips at Power Levels Greater Than 30% Nuclear Boiler Rated. Mitigation of pressure increase, the basic nature of this transient, is accomplished by the RPS functions. Main stop valve closure scram trip and RPT are designed to satisfy single failure criterion.

15.2.3.2.3.2 Turbine Trips at Power Levels Less Than 30% Nuclear Boiler Rated. Same as Section 15.2.3.2.3.1 except RPT and stop valve closure scram trip is normally inoperative. Since protection is still provided by high flux, high pressure, etc., these will continue to function and scram the reactor should a single failure occur.

15.2.3.3 Core and System Performance

15.2.3.3.1 Mathematical Model

The computer model described in Section 15.1.1.3.1 was used to simulate the turbine trip with bypass event, and the model in Section 15.1.2.3.1 was used for the turbine trip with failure of bypass event.

15.2.3.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

Turbine stop valves full stroke closure time is 0.1 sec.

A reactor scram is initiated by position switches on the stop valves when the valves are 90% open or less. This stop valve scram trip signal is automatically bypassed when the reactor is below 30% NBR power level.

Reduction in core recirculation flow is initiated by position switches on the main stop valves, which actuate trip circuitry which trips the recirculation pumps.

15.2.3.3.3 Results

15.2.3.3.3.1 Turbine Trip. A turbine trip with the bypass system operating normally is simulated at 105% of original NBR steam flow conditions in Figure 15.2-3.

Neutron flux increases rapidly because of the void reduction caused by the pressure increase. However, the flux increase is limited to 147.5% of rated by the stop valve scram and the RPT system. Peak fuel surface heat flux does not exceed 101.7% of its initial value.

15.2.3.3.3.2 Turbine Trip with Failure of Bypass. A turbine trip with failure of the bypass system is simulated at 110% of original NBR steam flow conditions in Figure 15.2-4.

Peak neutron flux reaches 341% of its rated value, and peak surface heat flux reaches 113% of its initial value.

5.2.3.3.3.3 Turbine Trip with Bypass Valve Failure, Low Power. This transient is less severe than a similar one at high power. Below 30% of rated power, the turbine stop valve closure and TCV closure scrams are automatically bypassed. At these lower power levels, turbine first stage pressure is used to initiate the scram logic bypass. The scram which terminates the transient is initiated by high vessel pressure. The bypass valves are assumed to fail; therefore, system pressure will increase until the pressure relief setpoints are reached. At this time, because of the relatively low power of this transient event, relatively few relief valves will open to limit reactor pressure. Peak pressures are not expected to greatly exceed the pressure relief valve setpoints and will be significantly below the reactor coolant pressure boundary (RCPB) transient limit of 1375 psig. Peak surface heat flux and peak fuel center temperature remain at relatively low values and MCPR remains well above the GETAB safety limit.

15.2.3.3.4 Considerations of Uncertainties

Uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses. For example:

a. Slowest allowable control rod scram motion is assumed,
b. Scram worth shape for all-rod-out conditions is assumed,

c. Minimum specified valve capacities are utilized for overpressure protection, and
d. Setpoints of the SRVs include errors and uncertainties (high) for all valves.

15.2.3.4 Barrier Performance

15.2.3.4.1 Turbine Trip

Peak pressure in the bottom of the vessel reaches 1163 psig, which is below the American Society of Mechanical Engineers (ASME) Code limit of 1375 psig for the RCPB. Vessel dome pressure does not exceed 1136 psig. The severity of turbine trips from lower initial power levels decreases to the point where a scram can be avoided if auxiliary power is available from an external source and the power level is within the bypass capability.

15.2.3.4.2 Turbine Trip with Failure of Bypass

The SRVs open and close sequentially as the stored energy is dissipated and the pressure falls below the setpoints of the valves. Peak nuclear system pressure reaches 1231 psig at the vessel bottom, therefore, the overpressure transient is clearly below the RCPB transient pressure limit of 1375 psig. Peak dome pressure does not exceed 1203 psig.

15.2.3.4.2.1 Turbine Trip with Failure of Bypass at Low Power. Qualitative discussion is provided in Section 15.2.3.3.3.3.

15.2.3.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.4 MAIN STEAM LINE ISOLATION VALVE CLOSURES

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

15.2.4.1 Identification of Causes and Frequency Classification

15.2.4.1.1 Identification of Causes

Various steam line and nuclear system malfunctions, or operator actions, can initiate MSIV closure. Examples are low-steam line pressure, high-steam line flow, low-water level, or manual action.

15.2.4.1.2 Frequency Classification

15.2.4.1.2.1 Closure of All Main Steam Line Isolation Valves. This event is categorized as an incident of moderate frequency. To define the frequency of this event as an initiating event and not the byproduct of another transient, only the following contribute to the frequency: Manual action (purposely or inadvertent); spurious signals such as low pressure, low reactor water level, and low condenser vacuum; and equipment malfunctions such as faulty valves or operating mechanisms. A closure of one MSIV may cause an immediate closure of all the other MSIVs depending on reactor conditions. If this occurs, it is also included in this category. During the MSIV closure, position switches on the valves provide a reactor scram when the valves in three or more main steam lines are less than 90% open (except for interlocks which permit proper plant startup). Protection system logic permits the test closure of one valve without initiating scram from the position switches.

15.2.4.1.2.2 Closure of One Main Steam Line Isolation Valve. This event is categorized as an incident of moderate frequency. One MSIV at a time may be manually closed for testing purposes. Operator error or equipment malfunction may cause a single MSIV to be closed inadvertently. If reactor power is greater than about 75% when this occurs, a high flux or high steam line flow condition may result in a scram. If all MSIVs close as a result of the single event, the event is considered as a closure of all MSIVs.

15.2.4.2 Sequence of Events and Systems Operation

15.2.4.2.1 Sequence of Events

Table 15.2-5 lists the sequence of events for Figure 15.2-5.

15.2.4.2.1.1 Identification of Operator Actions. The following is the sequence of operator actions expected during the course of the event assuming no restart of the reactor.

a. Observe that all rods have inserted,

b. Observe that the relief valves have opened for reactor pressure control,

c. Check that HPCS and RCIC auto start on the impending low reactor water level condition,

d. Switch the feedwater controller to the manual position,

e. Secure HPCS and RCIC when reactor vessel level has been restored to a satisfactory level,

f. Put residual heat removal (RHR) shutdown cooling in service when the reactor pressure has decayed sufficiently for RHR shutdown cooling operation,

g. Before resetting the MSIV isolation, determine the cause of valve closure,

h. Observe turbine coastdown and break vacuum before the loss of sealing steam. Check turbine-generator auxiliaries for proper operation,

i. Not reset and open MSIVs unless conditions warrant and be sure the pressure regulator setpoint is above vessel pressure, and

j. Complete cooldown.

15.2.4.2.2 Systems Operation

15.2.4.2.2.1 Closure of All Main Steam Line Isolation Valves. The MSIV closures initiate a reactor scram trip by means of position signals to the protection system. Credit is taken for successful operation of the protection system.

The pressure relief system which initiates opening of the relief valves when system pressure exceeds relief valve instrumentation setpoints is assumed to function normally during the time period analyzed.

All plant control systems maintain normal operation unless specifically designated to the contrary.

15.2.4.2.2.2 Closure of One Main Steam Line Isolation Valve. A closure of a single MSIV will not initiate a reactor scram by means of the position signal to the protection system. This is because the valve position scram trip logic is designed to accommodate single valve operation and testability during normal reactor operation at limited power levels. Credit is taken for the operation of the pressure and flux signals to initiate a reactor scram.

All plant control systems maintain normal operation unless specifically designated to the contrary.

15.2.4.2.3 The Effect of Single Failures and Operator Errors

Mitigation of pressure increase is accomplished by initiation of the reactor scram by means of MSIV position switches and the protection system. Relief valves also operate to limit system pressure. All of these aspects are designed to single failure criterion and additional single failures would not alter the results of this analysis.

Failure of a single relief valve to open is not expected to have any significant effect. Such a failure is expected to result in less than a 5 psi increase in the maximum vessel pressure rise. The peak pressure will still remain considerably below 1375 psig.

15.2.4.3 Core and System Performance

15.2.4.3.1 Mathematical Model

The computer model described in the COLR is used to simulate these transient events.

15.2.4.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

The MSIVs close in 3 to 5 sec. The worst case, the 3-sec closure time, is assumed in this analysis.

Position switches on the valves initiate a reactor scram when the valves are less than 90% open as described in Section 7.2. Closure of these valves inhibits steam flow to the feedwater turbines terminating feedwater flow.

Valve closure indirectly causes a trip of the main turbine and generator.

Because of the loss of feedwater flow, water level within the vessel decreases sufficiently to initiate trip of the recirculation pump and initiates the HPCS and RCIC systems.

15.2.4.3.3 Results

15.2.4.3.3.1 Closure of All Main Steam Line Isolation Valves. Figure 15.2-5 shows the changes in important nuclear system variables for the simultaneous isolation of all main steam lines while the reactor is operating at 105% of original NBR steam flow. Peak neutron flux reaches 186.2% of rated after approximately 2.3 sec. At this time, the nonlinear valve closure becomes a strong effect and the conservative scram characteristic assumption has not yet allowed credit for the full shutdown of the reactor.

Water level decreases sufficiently to cause a recirculation system trip and initiation of the HPCS and RCIC system at approximately 16.9 sec. There is a delay up to 30 sec before the water supply enters the vessel. There is no change in the thermal margins.

15.2.4.3.3.2 Closure of One Main Steam Line Isolation Valve. Only one isolation valve is permitted to be closed at a time for testing purposes to prevent scram. Normal test procedure requires an initial power reduction to approximately 65% to 70% of design conditions to avoid high-flux scram, high-pressure scram, or full isolation from a high-steam flow condition in the open steam lines. With a 3-sec closure of one MSIV during 105% of original rated power conditions, the steam flow disturbance raises vessel pressure and reactor power enough to initiate a high neutron flux scram. This transient is considerably milder than closure of all MSIVs at full power. No quantitative analysis is furnished for this event. No significant change in thermal margins is experienced and no fuel damage occurs. Peak pressure remains below SRV setpoints.

Inadvertent closure of one or all of the isolation valves while the reactor is shut down will produce no significant transient. Closures during plant heatup will be less severe than the maximum power cases (maximum stored and decay heat).

15.2.4.3.4 Considerations of Uncertainties

Uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses. For example:

a. Slowest allowable control rod scram motion is assumed,

b. Scram worth shape for all-rod-out conditions is assumed,

c. Minimum specified valve capacities are used for overpressure protection, and

d. Setpoints of the SRVs are assumed to be 15 psi higher than the valve's nominal setpoint.

15.2.4.4 Barrier Performance

15.2.4.4.1 Closure of All Main Steam Line Isolation Valves

The nuclear system relief valves begin to open at approximately 2.5 sec after the start of isolation. The valves close sequentially as the stored heat is dissipated but continue to discharge the decay heat intermittently. Peak pressure at the vessel bottom reaches 1191 psig, clearly below the pressure limits of the RCPB. Peak pressure in the main steam line is 1146 psig.

15.2.4.4.2 Closure of One Main Steam Line Isolation Valve

No significant effect is imposed on the RCPB, since if closure of the valve occurs at an unacceptably high operating power level a flux or pressure scram will result. The main turbine bypass system will continue to regulate system pressure by means of the other three steam lines.

15.2.4.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to the public. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.5 LOSS-OF-CONDENSER VACUUM

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

15.2.5.1 Identification of Causes and Frequency Classification

15.2.5.1.1 Identification of Causes

Various malfunctions which can cause a loss-of-condenser vacuum due to single equipment failure are designated in Table 15.2-6.

15.2.5.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.5.2 Sequence of Events and Systems Operation

15.2.5.2.1 Sequence of Events

Table 15.2-7 lists the sequence of events for Figure 15.2-6.

15.2.5.2.1.1 Identification of Operator Actions.

a. Verify auto transfer of buses supplied by generator incoming power. If automatic transfer has not occurred, manual transfer must be made,

b. Monitor and maintain reactor water level at required level,

c. Check turbine for proper operation of all auxiliaries during coastdown,

d. Put the mode switch in the "STARTUP" position before reactor pressure reaches 850 psia,

e. Secure HPCS and RCIC operation if auto initiation occurred due to low water level,

f. Monitor control rod drive positions and insert both the IRMs and SRMs, and

g. Cooldown the reactor if a restart is not intended.

15.2.5.2.2 Systems Operation

In establishing the expected sequence of events and simulating the plant performance, it is assumed that normal functioning occurred in the plant instrumentation and controls, plant protection, and reactor protection systems.

Tripping functions incurred by sensing main turbine condenser vacuum are designated in Table 15.2-8.

15.2.5.2.3 The Effect of Single Failures and Operator Errors

This event does not lead to a general increase in reactor power level. Mitigation of power increase is accomplished by the protection system initiation of scram.

Single failure will not effect the vacuum monitoring and turbine trip devices which are redundant. The protective sequences of the anticipated operational transient are shown to be single failure proof.

15.2.5.3 Core and System Performance

15.2.5.3.1 Mathematical Model

The computer model described in the COLR is used to simulate this transient event.

15.2.5.3.2 Input Parameters and Initial Conditions

This analysis was performed with plant conditions tabulated in Table 15.0-2 unless otherwise noted.

Turbine stop valves full stroke closure time used in this analysis is 0.1 sec.

A reactor scram is initiated by position switches on the stop valves when the valves are less than 90% open. This stop valve scram trip signal is automatically bypassed when the reactor is below 30% NBR power level.

The analysis presented here is a hypothetical case with a conservative 2 in. Hg/sec vacuum decay rate. Thus, the bypass system is available for several seconds since the bypass is signaled to close at a vacuum level of about 10 in. Hg less than the stop valve closure.

15.2.5.3.3 Results

Under this hypothetical 2 in. Hg/sec vacuum decay condition, the turbine bypass valve and MSIV would follow main turbine and feedwater turbine trips about 5 sec after they initiate the transient. This transient, therefore, is similar to a normal turbine trip with bypass. The effect of MSIV closure tends to be minimal since the closure of main turbine stop valves and subsequently the bypass valves have already shut off the main steam line flow. Figure 15.2-6 shows the transient expected for this event. It is assumed that the plant is initially operating at 105% of original NBR steam flow conditions. Peak neutron flux reaches 157.4% of NBR power while average fuel surface heat flux reaches 102.6% of rated value. The SRVs open to limit the pressure rise then sequentially reclose as the stored energy is dissipated.

15.2.5.3.4 Consideration of Uncertainties

The reduction or loss of vacuum in the main turbine condenser will sequentially trip the main and feedwater turbines and close the MSIVs and turbine bypass valves. While these are the major events occurring, other resultant actions will include scram (from stop valve closure) and bypass opening with the main turbine trip. Because the protective actions are actuated at various levels of condenser vacuum, the severity of the resulting transient is directly dependent upon the rate at which the vacuum is lost. Normal loss of vacuum due to loss-of-cooling water pumps or steam jet air ejector problem produces a very slow rate of loss of vacuum (minutes, not seconds). (See Table 15.2-6.) If corrective actions by the reactor operators are not successful, then simultaneous trips of the main and feedwater turbines, and ultimately complete isolation by closing the bypass valves (opened with the main turbine trip) and the MSIVs, will occur.

A faster rate of loss of the condenser vacuum would reduce the anticipatory action of the scram and the overall effectiveness of the bypass valves since they would be closed more quickly.

Other uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses. For example:

a. Slowest allowable control rod scram motion is assumed,

b. Scram worth shape for all-rod-out conditions is assumed,

c. Minimum specified valve capacities are utilized for overpressure protection, and

d. Setpoints of the SRVs are assumed to be 15 psi higher than the valve's nominal setpoint.

15.2.5.4 Barrier Performance

Peak nuclear system pressure is 1162 psig at the vessel bottom. Clearly, the overpressure transient is below the RCPB transient pressure limit of 1375 psig. Vessel dome pressure does not exceed 1135 psig. A comparison of these values to those for turbine trip with bypass at high power shows the similarities between these two transients. The prime differences are the loss of feedwater and main steam line isolation, and the resulting low water level trips.

15.2.5.5 Radiological Consequences

While the consequence of this event does not result in fuel failures, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no exposure to the public. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.6 LOSS OF ALTERNATING CURRENT POWER

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

15.2.6.1 Identification of Causes and Frequency Classification

15.2.6.1.1 Identification of Causes

15.2.6.1.1.1 Loss of Auxiliary Power Transformers. Causes for interruption or loss of the auxiliary power transformers can arise from normal operation or malfunctioning of transformer protection circuitry. These can include high transformer oil temperature, reverse of high current operation, and operator error which trips the transformer breakers.

15.2.6.1.1.2 Loss of All Grid Connections. Loss of all grid connections can result from major shifts in electrical loads, loss of loads, lightning, storms, wind, etc., which contribute to electrical grid instabilities. These instabilities will cause equipment damage if unchecked. Protective relay schemes automatically disconnect electrical sources and loads to mitigate damage and regain electrical grid stability.

15.2.6.1.2 Frequency Classification

15.2.6.1.2.1 Loss of Auxiliary Power Transformers. This event is categorized as an incident of moderate frequency.

15.2.6.1.2.2 Loss of All Grid Connections. This event is categorized as an incident of moderate frequency.

15.2.6.2 Sequence of Events and Systems Operation

15.2.6.2.1 Sequence of Events

15.2.6.2.1.1 Loss of Auxiliary Power Transformers. Table 15.2-9 lists the sequence of events for Figure 15.2-7.

15.2.6.2.1.2 Loss of All Grid Connections. Table 15.2-10 lists the sequence of events for Figure 15.2-8.

15.2.6.2.1.3 Identification of Operator Actions. The operator should maintain the reactor water level by use of the HPCS and RCIC systems and control reactor pressure by use of the relief valves. Verify that the turbine dc oil pump is operating satisfactorily to prevent turbine bearing damage. Also, the operator should verify proper switching and loading of the standby diesel generators.

The following is the sequence of operator actions expected during the course of the events when no immediate restart is assumed.

a. Following the scram, verify all rods in,

b. Check that diesel generators start and carry the vital loads,

c. Check that relays on the RPS drop out,

d. Check that HPCS and RCIC start when reactor vessel level drops to the initiation point,

e. Break vacuum before the loss of sealing steam occurs,

f. Check turbine-generator auxiliaries during coastdown,

g. When both the reactor pressure and level are under control secure HPCS and RCIC as necessary, and

h. Continue cooldown.

15.2.6.2.2 Systems Operation

15.2.6.2.2.1 Loss of Auxiliary Power Transformers. This event, unless otherwise stated, assumes and takes credit for normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems.

The reactor is subjected to a complex sequence of events when the plant loses all auxiliary power. Estimates of the responses of the various reactor systems (assuming loss of the auxiliary transformers) provide the following simulation sequence:

a. Recirculation pumps and condenser circulatory water pumps trip off at time = 0. Recirculation pumps coast down with the fastest rate specified in the design specifications;

b. Reactor scram and MSIV closure is initiated at 2 sec due to loss of power to the scram and MSIV relay solenoids; and

c. Feedwater turbines trip off at 4 sec due to MSIV closure at 2 sec.

Operation of the HPCS and RCIC are not simulated in this analysis. Their operation occurs at a time beyond the primary concerns of fuel thermal margin and overpressure effects of this analysis.

15.2.6.2.2.2 Loss of All Grid Connections. Same as Section 15.2.6.2.2.1 with the following additional concern.

The loss of all grid connections is another feasible, although improbable, way to lose all auxiliary power. This event would add a generator load rejection to the above sequence at time, t=0. The load rejection immediately causes the TCVs to close, causes a scram, and initiates RPT [already tripped at reference time t = 0].

15.2.6.2.3 The Effect of Single Failures and Operator Errors

Loss of the auxiliary power transformers in general leads to a reduction in power level due to rapid pump coastdown with pressurization effects due to MSIV closure resulting from loss of power to the solenoids. Additional failures of the other systems assumed to protect the reactor would not result in an effect different from those reported. Failures of the protection systems have been considered and satisfy single failure criteria and, as such, no change in analyzed consequences is expected.

15.2.6.3 Core and System Performance

15.2.6.3.1 Mathematical Model

The computer model described in the COLR is used to simulate this event.

15.2.6.3.2 Input Parameters and Initial Conditions

15.2.6.3.2.1 Loss of Auxiliary Power Transformers. These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2 and under the assumed systems constraints described in Section 15.2.6.2.2.

15.2.6.3.2.2 Loss of All Grid Connections. Same as Section 15.2.6.3.2.1

15.2.6.3.3 Results

15.2.6.3.3.1 Loss of Auxiliary Power Transformers. Figure 15.2-7 depicts the simulated transient. Between 0 and 4 sec an RPT, scram, MSIV closure, and feedwater turbine trip occur.

Sensed level drops to the HPCS and RCIC initiation setpoint approximately 48 sec after loss-of-auxiliary power.

There is no significant increase in fuel temperature or decrease in the operating MCPR value and fuel thermal margins are not impacted.

15.2.6.3.3.2 Loss of All Grid Connections. Loss of all grid connections is a more general form of loss of auxiliary power. It essentially takes on the characteristic response of the

standard full load rejection discussed in Section 15.2.2. Figure 15.2-8 depicts the simulated event. Peak neutron flux reaches 144.2% of original NBR power while fuel surface heat flux peaks at 101.6% of initial value

15.2.6.3.4 Consideration of Uncertainties

The most conservative characteristics of protection features are assumed. Any actual deviations in plant performance are expected to make the results of this event less severe.

Operation of the HPCS and RCIC systems are not included in the simulation of the first 50 sec of this transient. Startup of the pumps occurs in the latter part of this time period but the system has no significant effect on the results of this transient.

Following main steam line isolation and prior to RHR initiation the reactor pressure is expected to increase until the SRV setpoints are reached. During this time the valves operate in a cyclic manner to discharge decay heat to the suppression pool.

15.2.6.4 Barrier Performance

15.2.6.4.1 Loss of Auxiliary Power Transformers

The consequences of this event do not result in any significant temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore, barrier integrity and function is maintained.

15.2.6.4.2 Loss of All Grid Connections

Safety/relief valves open in the pressure relief mode of operation as the pressure increases beyond their setpoints. The pressure in the dome is limited to a maximum value of 1136 psig well below the vessel pressure limit of 1375 psig.

15.2.6.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no exposure to personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.7 LOSS-OF-FEEDWATER FLOW

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

15.2.7.1 Identification of Causes and Frequency Classification

15.2.7.1.1 Identification of Causes

A loss of feedwater flow could occur from pump failures, feedwater controller failures, operator errors, or reactor system variables such as a high vessel water level (L8) trip signal.

15.2.7.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.7.2 Sequence of Events and Systems Operation

15.2.7.2.1 Sequence of Events

Table 15.2-11 lists the sequence of events for Figure 15.2-9.

15.2.7.2.1.1 Identification of Operator Actions. The operator should verify MSIV closure, and ensure HPCS or RCIC actuation so that water inventory is maintained in the reactor vessel. Monitor reactor water level and pressure control, and turbine-generator auxiliaries during shutdown.

The following is the sequence of operator actions expected during the course of the event when no immediate restart is assumed.

a. Verify all rods in, following the scram,

b. Verify HPCS and RCIC initiation,

c. Verify MSIV closure,

d. Verify that the relief valves open on reactor high pressure,

e. Verify that the recirculation pumps trip on reactor low-low level,

f. Secure HPCS and RCIC when reactor level and pressure are under control,

g. Monitor the turbine coastdown and break vacuum before loss of sealing seam occurs, and

h. Continue cooldown.

15.2.7.2.2 Systems Operation

Loss of feedwater flow results in a proportional reduction of vessel inventory causing the vessel water level to drop. The first corrective action is the low level (L3) scram trip actuation. Reactor protection system responds within 1 sec after this trip to scram the reactor. The low level (L3) scram trip function meets single failure criterion.

Containment isolation, when it occurs, would also initiate a MSIV position scram trip signal as part of the normal isolation event. The reactor, however, is already scrammed and shut down by this time.

Credit is taken for operation of the pressure relief valve (low setpoint) operation of the SRVs to remove decay heat since the bypass becomes ineffective due to main steam line isolation.

15.2.7.2.3 The Effect of Single Failures and Operator Errors

The nature of this event results in a lowering of vessel water level. Key corrective efforts to shut down the reactor are automatic and designed to satisfy single failure criterion. Therefore, any additional failure in these shutdown methods would not aggravate or change the simulated transient.

The potential exists for a single relief valve failing to close once it is opened. This would result in a complete depressurization of the reactor. Either the RCIC or the HPCS system is capable of maintaining adequate core coverage and will provide long-term inventory control. For the complete loss of feedwater flow event, operation of RCIC or HPCS is sufficient to avoid initiation of ADS on low vessel level (L1).

15.2.7.3 Core and System Performance

15.2.7.3.1 Mathematical Model

The computer model described in the COLR is used to simulate this event.

15.2.7.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

15.2.7.3.3 Results

The results of this transient simulation are shown in Figure 15.2-9. Feedwater flow terminates at approximately 5 sec. Subcooling decreases causing a reduction in core power level and pressure. As power level is lowered, the turbine steam flow starts to drop off because the pressure regulator is attempting to maintain pressure for approximately the first 15 sec. Water level continues to drop until the vessel level (L3) scram trip setpoint is reached, whereupon the reactor is shut down.

Main steam line isolation occurs at 15.25 sec due to vessel water dropping to the L2 trip. Also at this time, the recirculation system is tripped and HPCS and RCIC operation is initiated. The MCPR remains considerably above the safety limit since increases in heat flux are not experienced.

15.2.7.3.4 Consideration of Uncertainties

End-of-cycle scram characteristics are assumed.

This transient is most severe from high power conditions, because the rate of level decrease is greatest and the amount of stored decay heat to be dissipated is highest.

Operation of the HPCS and RCIC systems is not included in the simulation of the first 50 sec of this transient since startup of the pumps occurs in the latter part of this time period. Therefore, the system has no significant effects on the results of this transient.

15.2.7.4 Barrier Performance

Peak pressure in the bottom of the vessel reaches 1107 psig, which is below the ASME Code limit of 1375 psig for the RCPB. Vessel dome pressure does not exceed 1095 psig. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function are maintained.

15.2.7.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no exposure to personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen the release will be in accordance with established requirements.

15.2.8 FEEDWATER LINE BREAK

See Section 15.6.6.

15.2.9 FAILURE OF RESIDUAL HEAT REMOVAL SHUTDOWN COOLING

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

Normally, in evaluating component failures associated with the RHR shutdown cooling mode of operation, active pumps or instrumentation (all of which are redundant for the safety related portions of the RHR system) would be assumed to be the component failure. For purposes of a worst case analysis, a valve on the single recirculation suction line to the otherwise redundant RHR shutdown cooling loops is assumed to fail. Manual attempts to open the valve are assumed unsuccessful. This failure disables the shutdown cooling mode but does not affect the remaining RHR modes of operation. Reference 15.2-1 establishes additional assumptions.

15.2.9.1 Identification of Causes and Frequency Classification

15.2.9.1.1 Identification of Causes

The plant is operating at 105% of original NBR steam flow when an event occurs, e.g., a long-term loss of offsite power, causing a plant shutdown. Reactor vessel depressurization is initiated to bring the reactor pressure to approximately 100 psig. Concurrent with the loss of offsite power a failure of a valve in the shutdown cooling suction line occurs which prevents the operator from establishing the normal shutdown cooling path through the RHR shutdown cooling lines. An additional failure is assumed which completely disables the RHR equipment in one division. The operator then establishes a shutdown cooling path for the vessel through the SRV valves.

15.2.9.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.9.2 Sequence of Events and Systems Operation

15.2.9.2.1 Sequence of Events

The sequence of events for this event is shown in Table 15.2-12.

15.2.9.2.1.1 Identification of Operator Actions. For the early part of the transient, the operator actions are those described in Section 15.2.6, loss of offsite power. The operator should reestablish reactor cooling by one or more of the following:

a. Maintain reactor water inventory with the RCIC (when single failure is not assumed to be a loss of Division 1 DC power) and HPCS system,

b. At approximately 10 minutes into the transient, initiate suppression pool cooling, it is assumed that only one RHR heat exchanger is available,

c. Initiate RPV shutdown depressurization by manual actuation of the SRVs,

d. Attempts to open one of the two RHR shutdown cooling suction valves are assumed unsuccessful (reactor pressure is approximately 100 psig), and

e. At 100 psig RPV pressure, actuate ADS to complete blowdown and establish a reactor cooling path as described in the notes for Figure 15.2-10.

Time required to initiate the necessary steps to maintain reactor pressure and level control is approximately 10 minutes.

15.2.9.2.2 Systems Operation

Plant instrumentation and control is assumed to be functioning normally except as noted. In this evaluation credit is taken for the plant and reactor protection systems and/or the ESF used.

15.2.9.2.3 The Effect of Single Failures and Operator Errors

The worst case single failure (loss of division power) has already been analyzed in this event. Therefore, no single failure or operator error can increase the consequences of this event.

15.2.9.3 Core and System Performance

The earliest time the shutdown cooling system can be actuated is 2 to 3 hr after shutdown is initiated. During this time MCPR remains high and nucleate boiling heat transfer is not exceeded at any time. Therefore, the core thermal safety margin remains essentially unchanged. The 10-minute time period approximated for operator action is an estimate of how long it would take the operator to initiate the necessary actions. It is not a time by which action must be initiated.

The transient behavior of the core during this event has been evaluated in Section 15.2.6.

15.2.9.4 Results

For most single failures that could result in loss of shutdown cooling, no unique safety actions are required. In these cases, shutdown cooling is simply reestablished using the redundant

shutdown cooling loop. In cases where the RHR shutdown cooling suction line valves cannot be opened, alternate paths are available to accomplish the shutdown cooling function (Figure 15.2-11). An evaluation has been performed assuming a failure that disables the RHR shutdown cooling suction line valves.

This evaluation demonstrates the capability to safety transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded.

The alternate cooldown path chosen to accomplish the shutdown cooling function uses the RHR and ADS or normal relief valve systems (see Reference 15.2-1 and Figure 15.2-10). The alternate shutdown systems are capable of performing the function of transferring heat from the reactor to the environment using only safety systems. The systems are capable of bringing the reactor to a cold shutdown in approximately 36 hr or less after the transient occurs.

The systems have suitable redundancy in components such that even for onsite electrical power operation (offsite power is not available), the safety function of the systems can be accomplished assuming an additional single failure. The systems can be fully operated from the main control room.

The design evaluation is divided into two phases: (a) full power operation to approximately 100 psig vessel pressure, and (b) approximately 100 psig vessel pressure to cold shutdown (14.7 psia 200°F) conditions.

15.2.9.4.1 Full Power to Approximately 100 psig

Independent of the event that initiated plant shutdown (whether it be a normal plant shutdown or a forced plant shutdown), the reactor is normally brought to approximately 100 psig using either the main condenser or, in the case where the main condenser is unavailable, the HPCS and RCIC systems together with the nuclear boiler pressure relief system and the RHR heat exchanger in the suppression pool cooling mode.

For evaluation purposes, however, it is assumed that plant shutdown is initiated by a transient event (loss of offsite power) which results in relief valve actuation and subsequent suppression pool heatup. For this postulated condition, the reactor is shut down and the reactor vessel pressure is reduced to approximately 100 psig. Manual operation of the SRVs is used to depressurize the reactor vessel. Reactor vessel makeup water is automatically provided by means of the RCIC (until reduced vessel pressure is reached) and HPCS system. While in this condition, the RHR system (suppression pool cooling mode) is used to maintain the suppression pool temperature within shutdown limits.

These systems are designed to routinely perform their functions for both normal and forced plant shutdown. Since the HPCS and RHR systems are divisionally separated and the HPCS and RCIC systems are divisionally separated, no single failure together with the loss of offsite power, is capable of preventing reaching the 100 psig level.

15.2.9.4.2 Approximately 100 psig to Cold Shutdown

The following assumptions are used for the analyses of the procedures for attaining cold shutdown from a pressure of approximately 100 psig:

a. The vessel is at 100 psig and saturated conditions,

b. A worst-case single failure is assumed to occur (i.e., loss of a division of emergency power), and

c. There is no offsite power available.

In the event that the RHRs shutdown suction line is not available because of single failure, the first action to be taken will be to maintain 100 psig level. If a single electrical failure caused the suction line to fail in the closed position, a hand wheel is provided on the valve to allow manual operation. If for some reason the normal shutdown cooling suction line cannot be restored to service, the capabilities described below will satisfy the normal shutdown cooling requirements and thus fully comply with GDC 34.

The RHR shutdown cooling line valves are in two divisions (Division 1 - the outboard valve, and Division 2 - the inboard valve) to satisfy containment isolation criteria. For evaluation purposes, the worst-case failure is assumed to be the loss of a division of emergency power, since this also prevents electrical actuation of one shutdown cooling line valve. Engineered safety features equipment and safe shutdown RCIC equipment (until reactor pressure is reached) available for accomplishing the shutdown cooling function includes (for the selected path):

ADS (dc Division 1 and dc Division 2)

RHR Loop A (Division 1)

HPCS (Division 3)

RCIC (dc Division 1)

LPCS (Division 1)

Since availability or failure of Division 3 equipment does not affect the normal shutdown mode, normal shutdown cooling is easily available through equipment powered from only Divisions 1 and 2. It should be noted that, HPCS is always available for coolant injection if either of the other two divisions fails. For failure of Division 1 or 2, the following systems are assumed functional:

a. Division 1 Fails, Division 2 and 3 Functional

Failed Systems	Functional Systems
RHR Loop A	HPCS
LPCS	ADS
RCIC	RHR Loops B and C

Assuming the single failure is a failure of Division 1 emergency power, the safety function is accomplished by establishing one of the cooling loops described in Activity C1 of Figure 15.2-10.

b. Division 2 Fails, Division 1 and 3 Functional

Failed Systems	Functional Systems
RHR Loop B and C	HPCS ADS RHR Loop A LPCS RCIC (until reduced reactor pressure is reached)

Assuming the single failure is the failure of Division 2, the safety function is accomplished by establishing one of the cooling loops described in Activity C2 of Figure 15.2-10. Figures 15.2-12 through 15.2-15 show RHR loops A, B, and/or C (simplified).

15.2.9.5 Barrier Performance

As noted above, the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Release of coolant to be containment occurs by means of SRV actuation.

15.2.9.6 Radiological Consequences

While the consequences of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment there will be no exposures to operating personnel. Since this event does not result in an uncontrolled release to the environment the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.10 REFERENCES

15.2-1 Letter - R. S. Boyd to I. F. Stuart; dated November 12, 1975. Subject: Requirements delineated for RHRS - Shutdown Cooling System - Single Failure Analysis.

TABLE 15.2-1

SEQUENCE OF EVENTS FOR FIGURE 15.2-1

Generator Load Rejection - Bypass On
Original Rated Power

Time (sec)	Event
(-)0.015[a]	Turbine generator detection of loss of electrical load.
0	Turbine generator power load unbalance (PLU) devices trip to initiate turbine control valve fast closure.
0	Turbine generator PLU trip initiates main turbine bypass system operation.
0	Fast control valve closure initiates scram trip.
0	Fast control valve closure initiates an RPT.
0.07	Turbine control valves closed.
0.11	Turbine bypass valves start to open.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
1.70	Group 1 relief valves actuated.
1.86	Group 2 relief valves actuated.
2.01	Group 3 relief valves actuated.
2.27	Group 4 relief valves actuated.

[a] Approximately.

TABLE 15.2-2

SEQUENCE OF EVENTS FOR FIGURE 15.2-2

Generator Load Rejection - Bypass Off
Uprated Power

Time (sec)	Event
(-)0.003[a]	Turbine generator detection of loss of electrical load.
0	Turbine generator PLU devices trip to initiate turbine control valve fast closure.
0	Turbine bypass valves fail to operate.
0	Fast control valve closure initiates scram trip.
0	Fast control valve closure initiates an RPT.
0.10	Turbine control valves closed.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
(b)	Group 1 relief valves actuated.
(b)	Group 2 relief valves actuated.
1.34	Group 3 relief valves actuated.
1.49	Group 4 relief valves actuated.
1.60	Group 5 relief valves actuated.

[a] Approximately.

[b] Not used - out of service for this analysis.

TABLE 15.2-3

SEQUENCE OF EVENTS FOR FIGURE 15.2-3

Turbine Trip - Bypass On
Original Rated Power

Time (sec)	Event
0	Turbine trip initiates closure of main stop valves.
0	Turbine trip initiates bypass operation.
0.01	Main turbine stop valves reach 90% open position and initiate reactor scram trip.
0.01	Main turbine stop valves reach 90% open position and initiate an RPT.
0.10	Turbine stop valves closed.
0.10	Turbine bypass valves start to open to regulate pressure.
0.20	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
1.63	Group 1 relief valves actuated.
1.78	Group 2 relief valves actuated.
1.94	Group 3 relief valves actuated.
2.14	Group 4 relief valves actuated.
2.50	Group 5 relief valves actuated.
4.67	Feedwater turbines trip on L8 high water level.
5.1[a]	Group 5 relief valves start to close.
7.2[a]	All relief groups closed.
31.0	Turbine bypass starts to close.
32.3[a]	Turbine bypass closed.
39.7	Turbine bypass reopens on pressure increase at turbine inlet.
45.3	Main steam line isolation, HPCS system initiation, and RCIC system initiation on low level (L2) (not included in simulation).
50+	Group 1 relief valves cycle open and close on pressure.

[a] Estimated.

TABLE 15.2-4

SEQUENCE OF EVENTS FOR FIGURE 15.2-4

Turbine Trip - Bypass Off
Uprated Power

Time (sec)	Event
0	Turbine trip initiates closure of main stop valves.
0	Turbine bypass valves fail to operate.
0.01	Main turbine stop valves reach 90% open position and initiate reactor scram trip.
0.10	Turbine stop valves closed.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
(a)	Group 1 relief valves actuated.
(a)	Group 2 relief valves actuated.
1.36	Group 3 relief valves actuated.
1.52	Group 4 relief valves actuated.
1.63	Group 5 relief valves actuated.

[a] Not used - out of service for this analysis.

TABLE 15.2-5

SEQUENCE OF EVENTS FOR FIGURE 15.2-5

Inadvertent Main Steam Line Isolation Valve Closure
Original Rated Power

Time (sec)	Event
0	Initiate closure of all MSIVs.
0.3	Main steam line isolation valves reach 90% open.
0.3	Main steam line isolation valve position trip scram initiated.
2.0	Loss of feedwater begins as turbines lose steam supply.
2.44 to 2.87	All five pressure relief valve groups actuated.
3.0	All MSIVs closed.
6.2[a]	Group 5 pressure relief valves start to close.
8.2[a]	All relief groups closed.
10.12	Group 1 pressure relief valves reactuated on high pressure.
10.77	Group 2 pressure relief valves reactuated on high pressure.
14.8[a]	Group 2 pressure relief valves start to close.
16.3[a]	Both relief groups closed.
16.9	Recirculation pump motors tripped and HPCS and RCIC systems initiated on low level (L2) (not assumed in simulation).
20.05	Group 1 pressure relief valves reactuated on high pressure.
28.4[a]	Pressure relief Group 1 closed.
35.22	Group 1 pressure relief valves reactuated on high pressure.
41.4[a]	Pressure relief Group 1 closed.
50+	Group 1 pressure relief valves cycle open and close on pressure.

[a] Estimated.

TABLE 15.2-6

TYPICAL RATES OF DECAY FOR CONDENSER VACUUM

Cause	Estimated Vacuum Decay Rate
Failure or isolation of steam jet air ejectors	<1 in. Hg/minute
Loss of sealing steam to shaft gland seals	1 to 2 in. Hg/minute[a]
Opening of vacuum breaker valves	2 to 12 in. Hg/minute[a]
Loss of one or more circulating water pumps	4 to 24 in. Hg/minute[a]

[a] Approximately.

TABLE 15.2-7

SEQUENCE OF EVENTS FOR FIGURE 15.2-6

Loss of Condenser Vacuum
Original Rated Power

Time (sec)	Event
0	Initiate simulated loss of condenser vacuum at 2 in. of Hg per second.
5.00	Low condenser vacuum main turbine trip and feedwater turbine trips initiated.
5.00	Main turbine trip initiates turbine bypass operation.
5.01	Main turbine stop valves reach 90% open position and initiates reactor scram trip and RPT.
5.10	Turbine stop valves closed and turbine bypass valves start to open to regulate pressure.
5.14	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
6.61	Group 1 relief valves actuated.
6.76	Group 2 relief valves actuated.
6.93	Group 3 relief valves actuated.
7.13	Group 4 relief valves actuated.
7.58	Group 5 relief valves actuated.
10.00	Low condenser vacuum initiates turbine bypass valve closure and MSIV closure.
10.1[a]	Group 5 relief valves start to close.
10.3[a]	Turbine bypass valves closed.
12.1[a]	All relief groups closed.

TABLE 15.2-7

SEQUENCE OF EVENTS FOR FIGURE 15.2-6 (Continued)

Loss-of-Condenser Vacuum
Original Rated Power

Time (sec)	Event
13.0	Main steam line isolation valves closed.
13.29	Group 1 relief valves reactuated on high pressure.
13.72	Group 2 relief valves reactuated on high pressure.
19.5[a]	Group 2 relief valves start to close.
20.3[a]	Group 1 relief valves start to close.
21.1	Both relief groups closed.
25.00	Group 1 relief valves reactuated on high pressure.
27.0[a]	High-pressure core spray and RCIC systems initiation on low level (L2). (Not included in simulation.)
32.3[a]	Relief Group 1 closed.
41.31	Group 1 relief valves reactuated on high pressure.
47.0[a]	Relief Group 1 closed.
50+	Group 1 relief valves cycle open and close on pressure.

[a] Estimated.

TABLE 15.2-8

TRIP SIGNALS ASSOCIATED WITH LOSS-OF-CONDENSER VACUUM

Vacuum[a]	Protective Action Initiated
27 to 30	Normal vacuum range.
20 to 23	Main turbine trip and feedwater turbine trip (stop valve closures).
7 to 10	Main steam line isolation valve closure and bypass valve closure.

[a] Inches of Hg.

TABLE 15.2-9

SEQUENCE OF EVENTS FOR FIGURE 15.2-7

Loss of Auxiliary Power Transformers
Original Rated Power

Time (sec)	Event
0	Loss of auxiliary power transformers occurs.
0	Recirculation system pump motors are tripped.
0	Condensate and booster pumps are tripped.
0	Condenser circulating water pumps are tripped.
2	Reactor scrams due to loss of power to the scram solenoid.
2	Main steam line isolation valve closure is initiated due to loss of power to MSIV solenoids.
4	Feedwater turbines trip off due to MSIV closure at 2 sec.
4.71	Group 1 SRVs actuated
4.84	Group 2 SRVs actuated.
4.98	Group 3 SRVs actuated
5.14	Group 4 SRVs actuated.
5.43	Group 5 SRVs actuated.
48.3[a]	High-pressure core spray and RCIC systems initiation on low water level (L2) [not simulated].
50+	Group 1 relief valves cycle open and close on pressure.

[a] Estimated.

TABLE 15.2-10

SEQUENCE OF EVENTS FOR FIGURE 15.2-8

Loss of All Grid Connections
Original Rated Power

Time (sec)	Event
(-)0.015[a]	Loss of grid causes turbine-generator to detect a loss of electrical load.
0	Turbine-generator PLU devices trip to initiate TCV fast closure and turbine bypass system operation.
0	Condenser circulating water pumps are tripped.
0	Recirculation system pump motors are tripped.
0	Fast control valve closure initiates a reactor scram trip.
0	Feedwater condensate and booster pumps are tripped.
0.002	Scram circuit is tripped on turbine-generator trip.
0.07	Turbine control valves closed.
0.10	Turbine bypass valves start to open to regulate pressure.
1.58	Group 1 SRVs actuated.
1.73	Group 2 SRVs actuated.
1.89	Group 3 SRVs actuated.
2.00	Main steam line isolation is initiated due to loss of power to the solenoids.
2.09	Group 4 SRVs actuated.
2.49	Group 5 SRVs actuated.
4.0	Feedwater turbines trip due to MSIV closure at 2 sec.
5.1[b]	Group 5 SRVs start to close.
7.2[b]	All relief groups closed.
35.7[b]	High-pressure core spray and RCIC systems operation initiated on low water level (L2) [not simulated].
50+	Group 1 relief valves cycle open and close on pressure.

[a] Approximately.
[b] Estimated.

TABLE 15.2-11

SEQUENCE OF EVENTS FOR FIGURE 15.2-9

Loss of All Feedwater Flow
Original Rated Power

Time (sec)	Event
0	Trip of all feedwater pumps initiated.
3.58	Recirculation runback initiated with narrow range sensed level less than L4 and feedwater pumps off.
5.0	Feedwater flow decays to zero.
7.36	Vessel water level (L3) trip initiates scram trip.
15.25	Vessel water level (L2) trip initiates recirculation pump system trip.
15.25	Vessel water level (L2) trip initiates main steam line isolation.
15.25	Vessel water level (L2) trip initiates HPCS and RCIC systems operation (not simulated).
18.25	Main steam line isolation valves fully closed.
26.07	Group 1 pressure relief valves actuated.
32.2[a]	Group 1 pressure relief valves closed.
41.27	Group 1 pressure relief valves actuated.
46.7[a]	Group 1 pressure relief valves closed.
50+	Group 1 pressure relief valves cycle open and close on pressure.

[a] Estimated.

TABLE 15.2-12

SEQUENCE OF EVENTS FOR FAILURE OF RESIDUAL HEAT REMOVAL SHUTDOWN COOLING

Original Rated Power

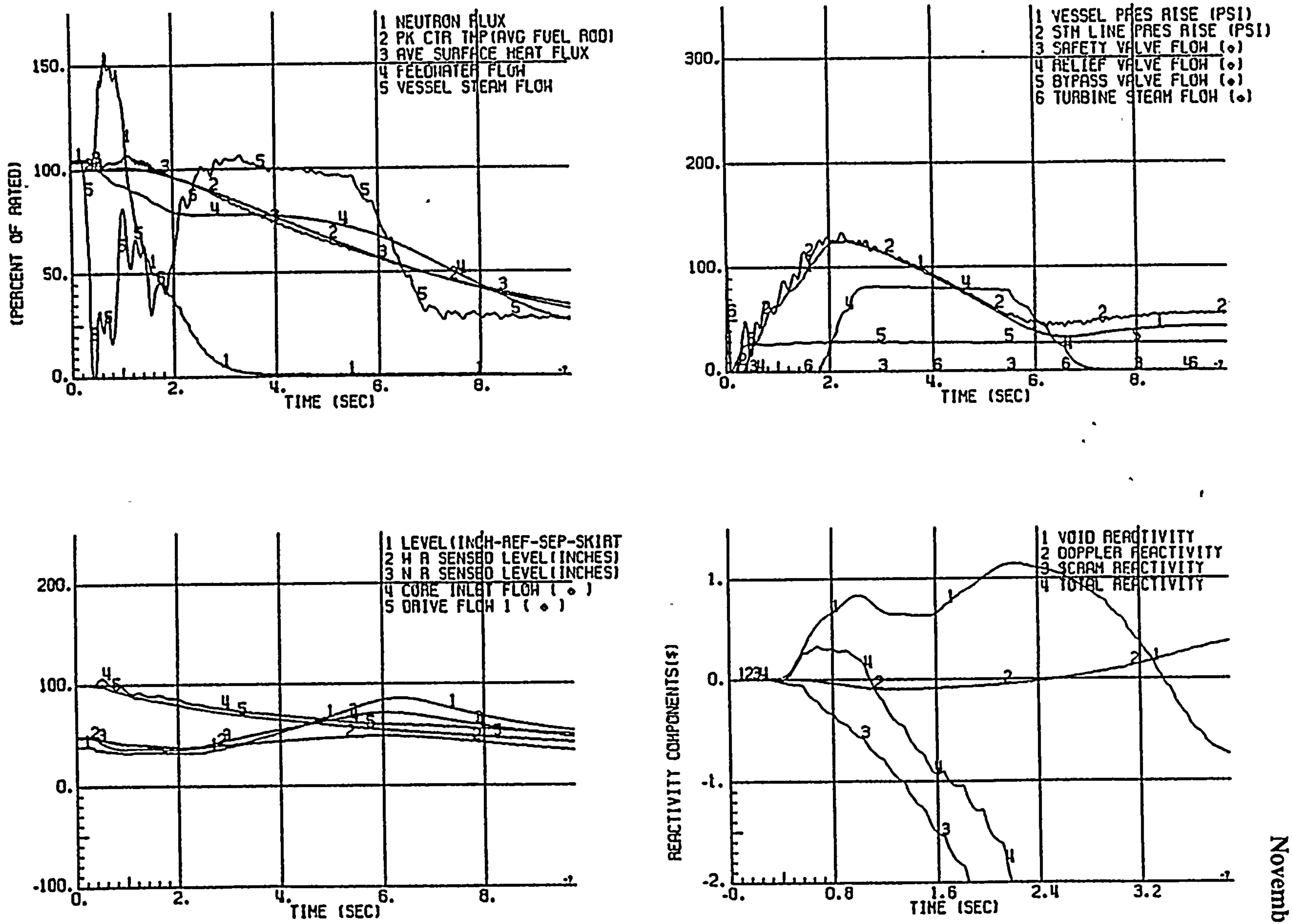
Time[a]	Event
0	Reactor is operating at 105% NBR steam flow when LOP transient occurs initiating plant shutdown.
0	Concurrently loss of division power occurs (i.e., loss of one diesel generator).
0	Initial suppression pool temperature at 95°F.
10 minutes	Suppression pool cooling initiated to prevent overheating from SRV actuation.
10 minutes	Controlled blowdown initiated.
2-3 hr	Blowdown to 100 psi completed.
2-3 hr	Personnel are sent in to open RHR shutdown cooling suction valve and fail.
2.5-3.5 hr	Actuate ADS and complete blowdown to suppression pool.
2.5-3.5 hr	Redirect RHR pump discharge from pool to vessel by means of the LPCI line. Alternate cooling path now established.
7 hr	Maximum suppression pool temperature attained.

[a] Approximately.

TABLE 15.2-13

EVALUATION OF FAILURE OF RESIDUAL HEAT REMOVAL SHUTDOWN COOLING

Parameter	Value
Initial power corresponding	105% original rated steam flow
To suppression pool mass (lbm)	8.52 E6
Residual heat removal (KHX value) (Btu/sec/°F)	289
Initial vessel condition	
Pressure (psia)	1055
Temperature (°F)	550.7
Initial primary fluid inventory (lbm)	7.016 E5
Initial pool temperature (°F)	95
Service water temperature (°F)	87
Vessel heat capacity (Btu/lbm/°F)	0.123
High-pressure core spray on-off water level (ft)	
HPCS ON	40.8
HPCS OFF	47
High-pressure core pray flow rate (lbm/sec)	868
Low-pressure coolant injection flow rate (lbm/sec)	982



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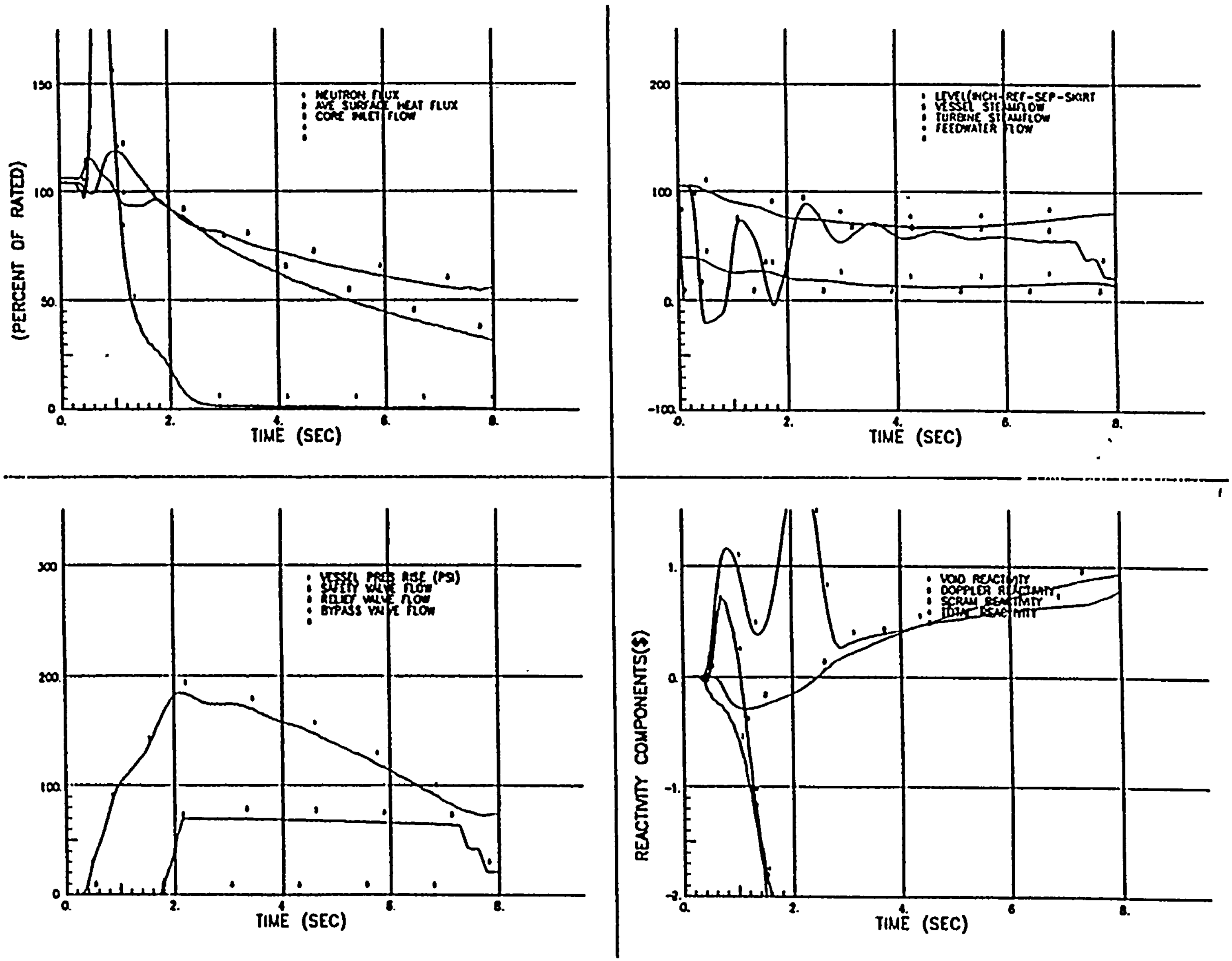
Generator Load Rejection with Bypass On - Original Rated Power

Draw. No.

Rev.

Figure 15.2-1



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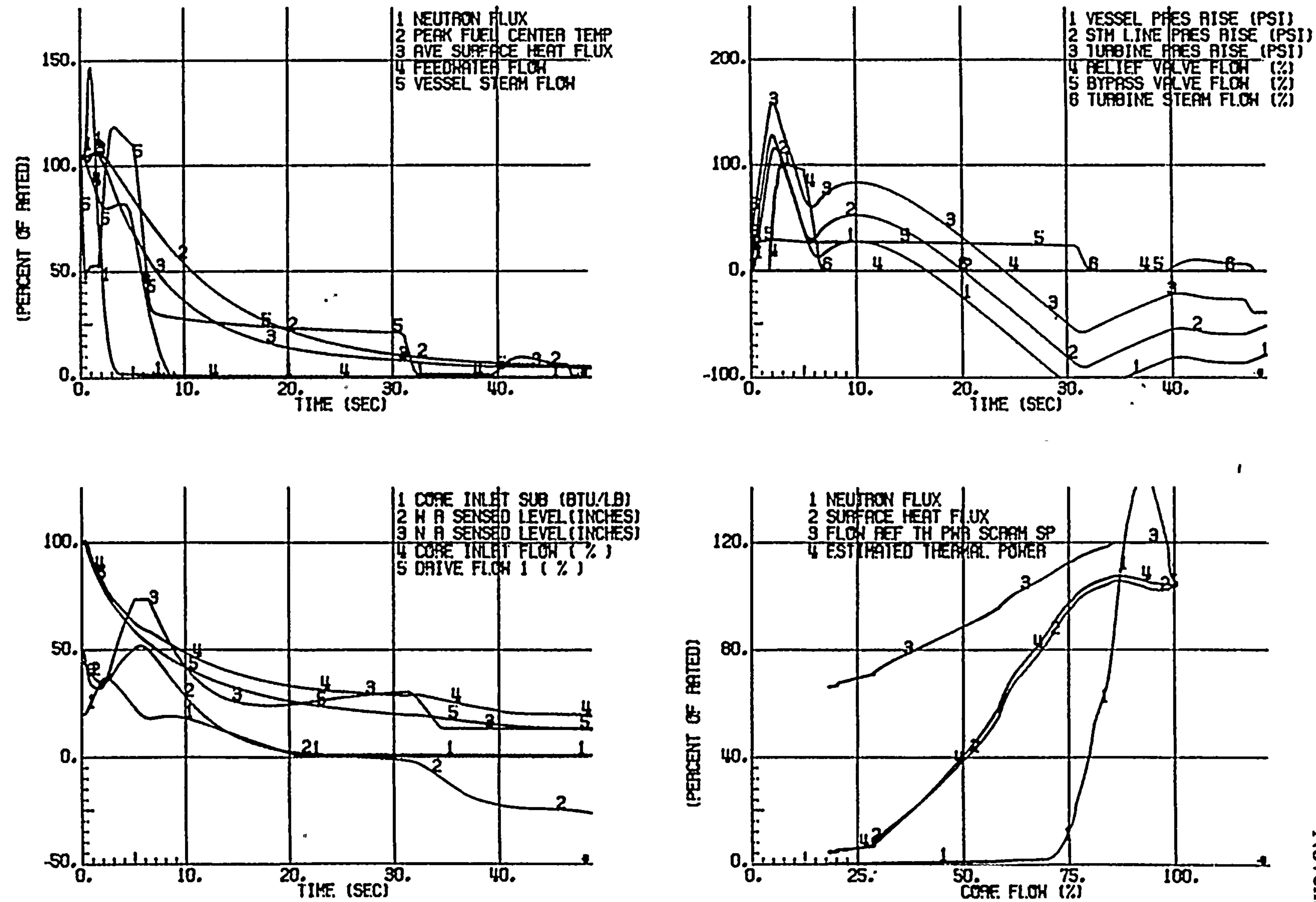
Generator Load Rejection with BP Failure at 110% of Original Rated Steam Flow/106% Core Flow

Draw. No.	Rev.	Figure
		15.2-2



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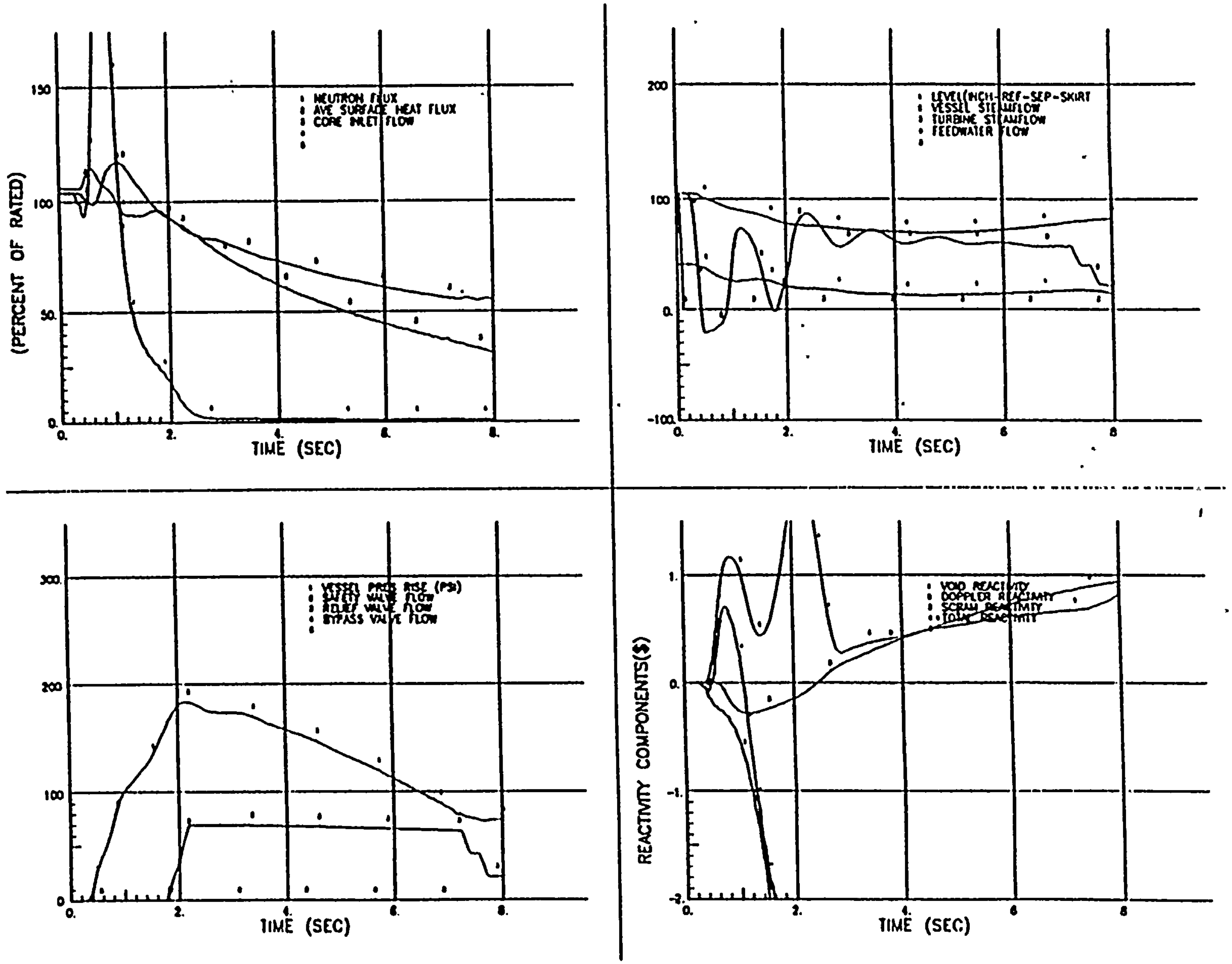
Turbine Trip, Trip Scram, Bypass and RPT - On

Draw. No.

Rev.

Figure 15.2-3

Form No. 960690



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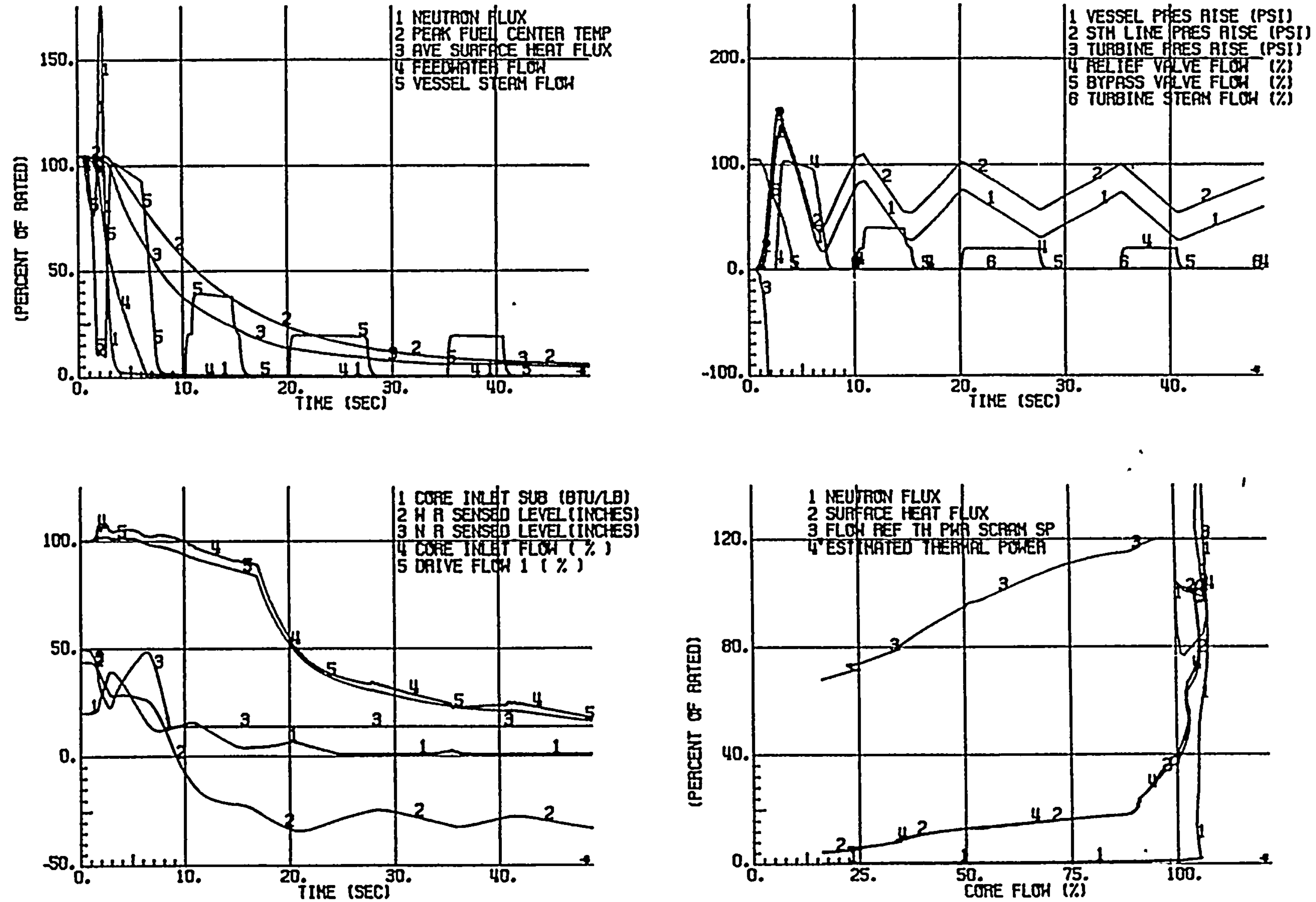
Turbine Trip with Bypass Failure at 110% of Original Rated Steam Flow/106% Core Flow

Draw. No.	Rev.	Figure
		15.2-4



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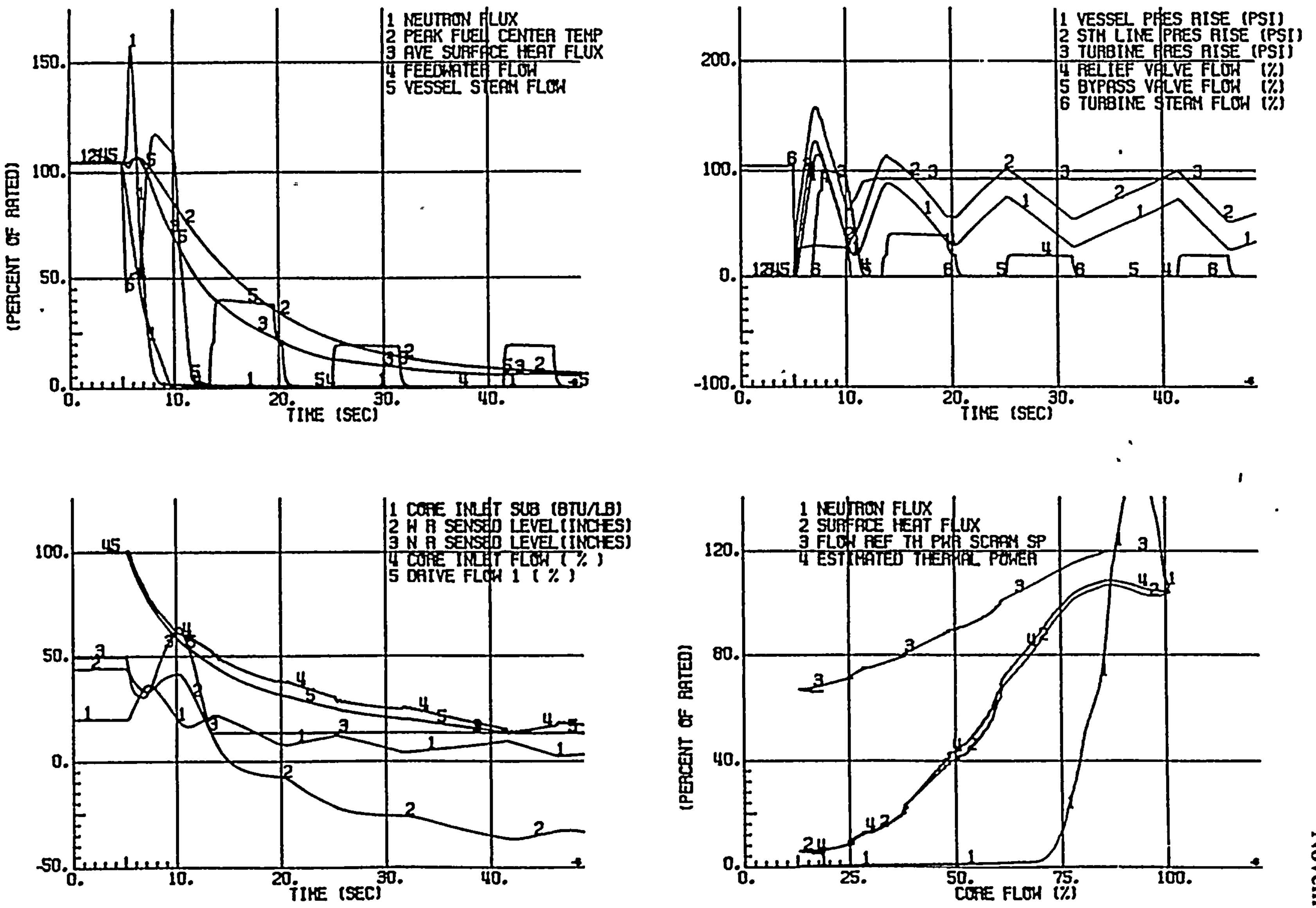
Three Second Closure of All Main Steam Line Isolation Valves with Position Switch Scram Trip - Original Rated Power

Draw. No.	Rev.	Figure
		15.2-5



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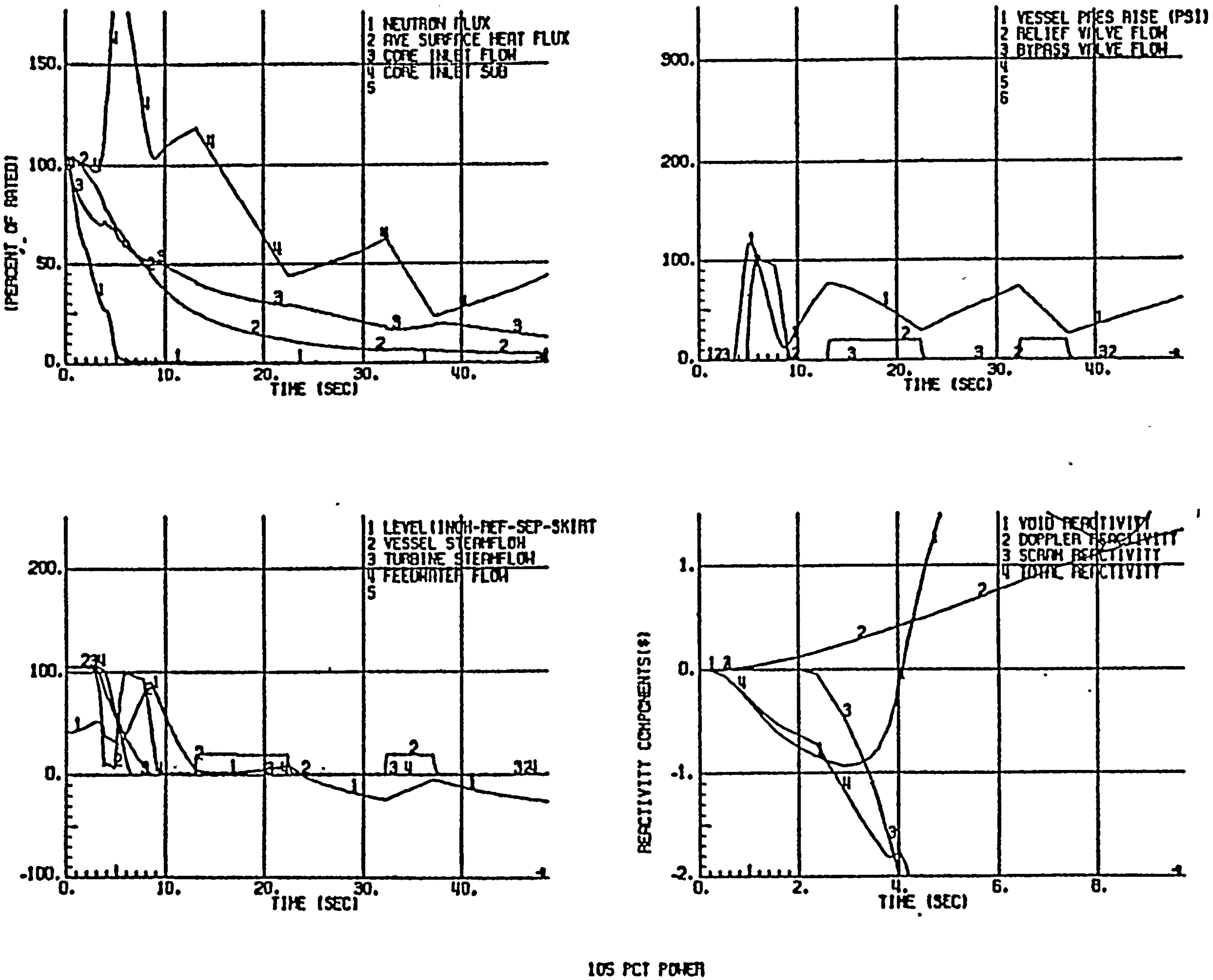
Loss of Condenser Vacuum at 2 in./Sec -
Original Rated Power

Draw. No.	Rev.	Figure
		15.2-6



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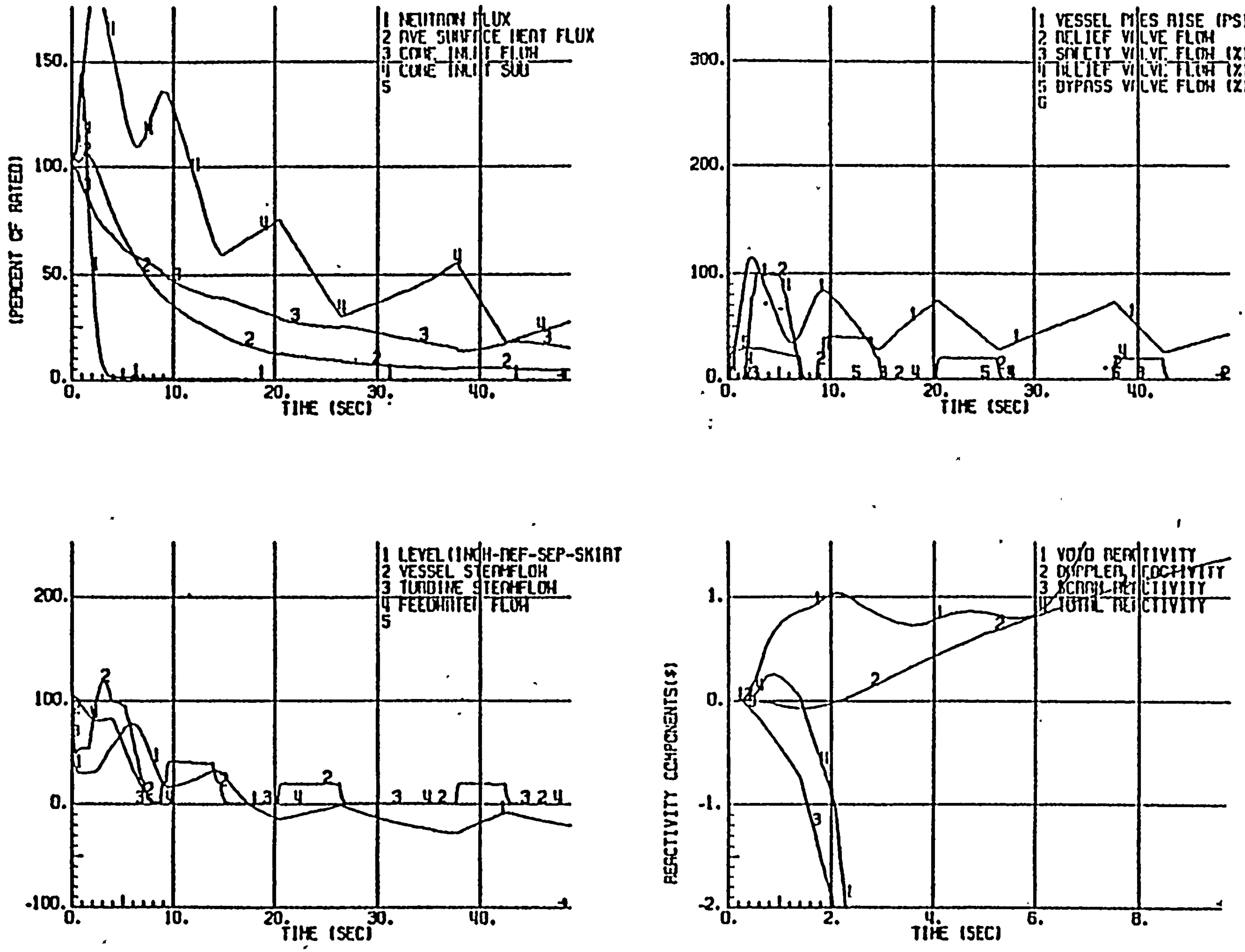
Loss of Auxiliary Power Transformers -
Original Rated Power

Draw. No.	Rev.	Figure
		15.2-7



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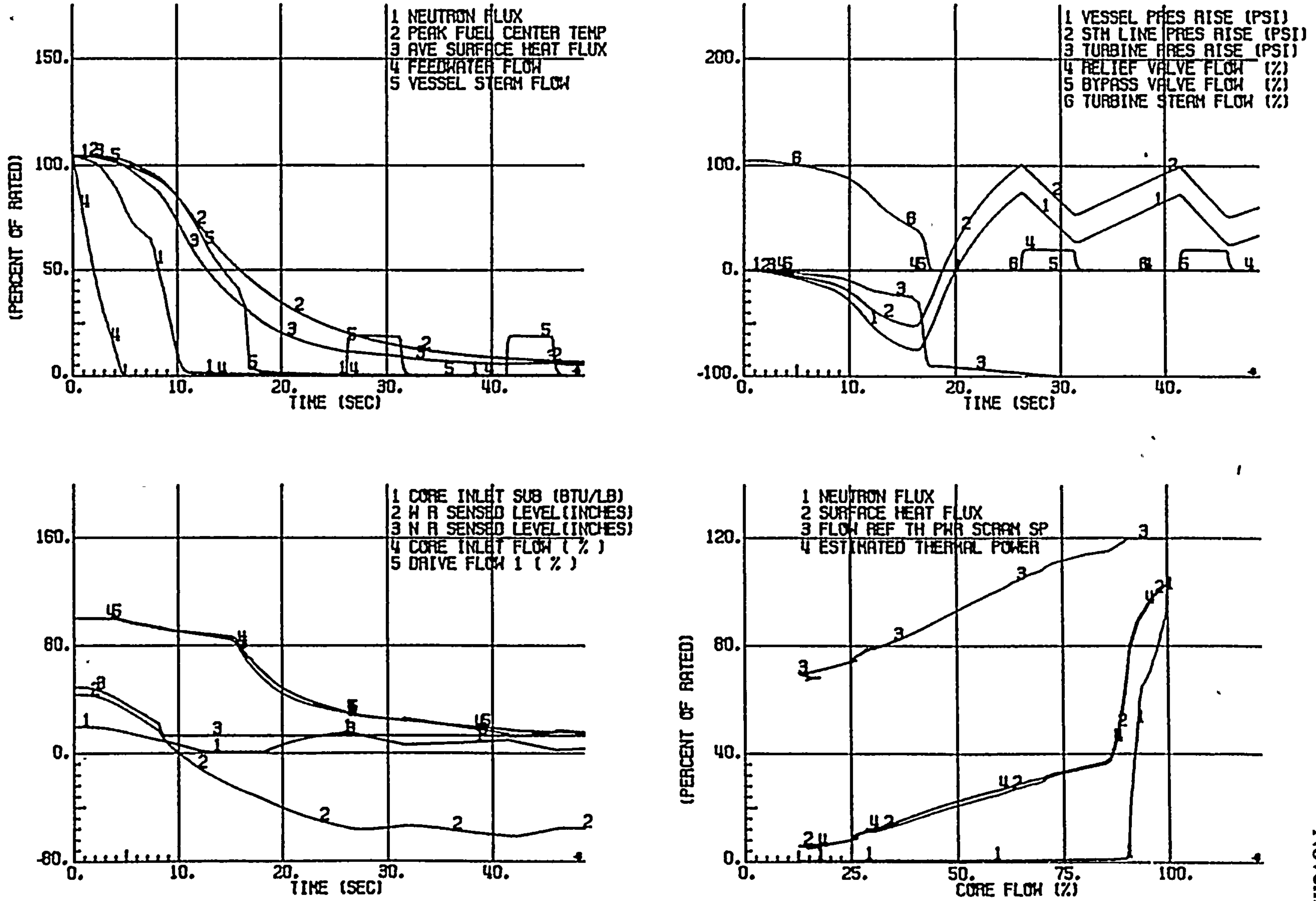
Loss of All Grid Connections -
Original Rated Power

Draw. No.	Rev.	Figure
		15.2-8

Form No. 960690



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Loss of All Feedwater Flow -
Original Rated Power

Draw. No.	Rev.	Figure
		15.2-9

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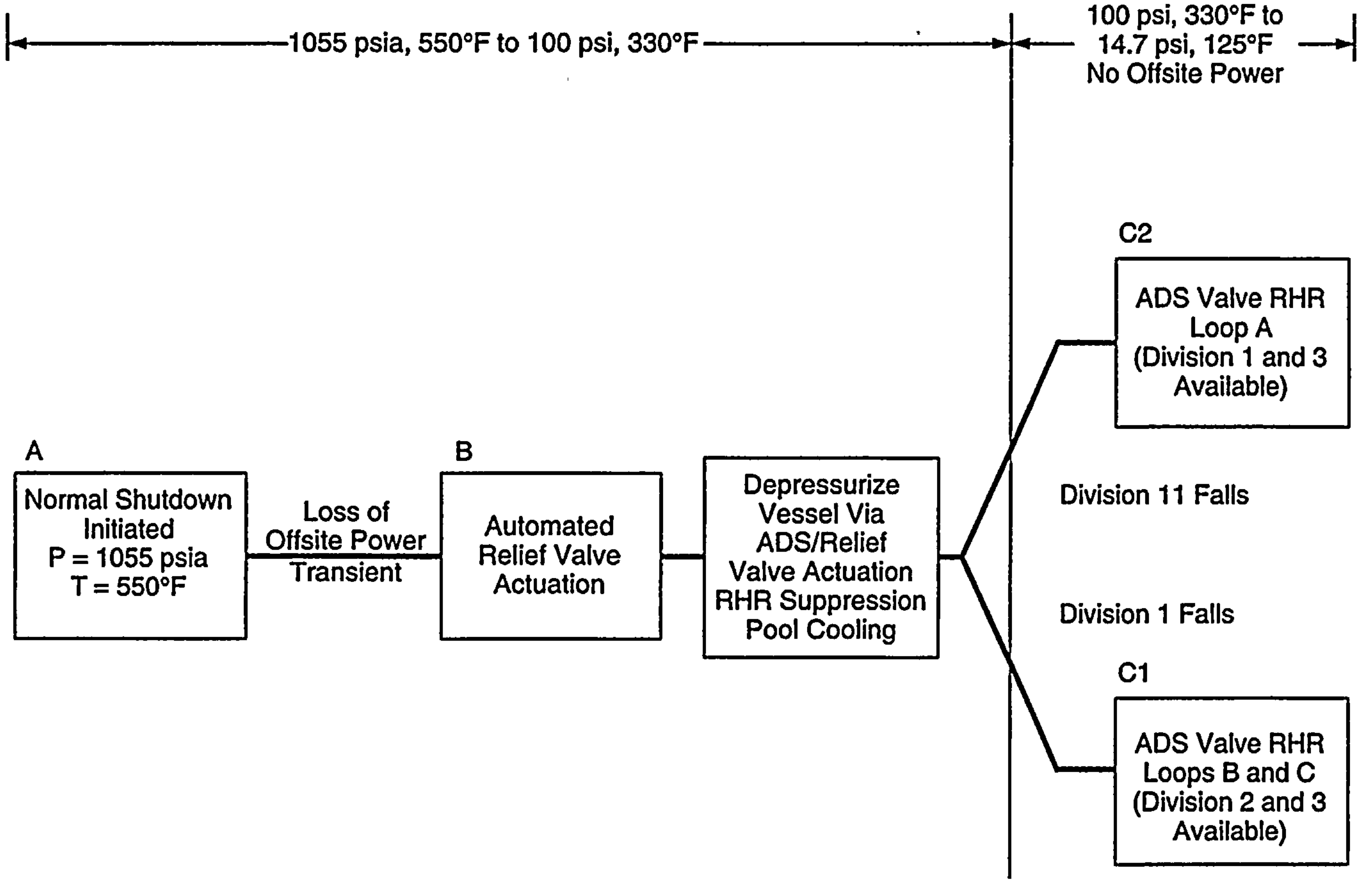

Automatic Depressurization System/Residual Heat Removal Cooling Loops

Draw. No. 900547.63 | Rev. | Figure 15.2-10.1

NOTES

ACTIVITY A
Initial pressure = 1055 psia
Initial temperature = 550°F

For purposes of this analysis, the following worst-case conditions are assumed to exist:

a. The reactor is assumed to be operating at 105% of original NBR steam flow,
b. A loss of power transient occurs,
c. A simultaneous loss of onsite power (Division 1 or Division 2), and
d. Operator unable to open one of the RHR shutdown cooling line suction valves.

ACTIVITY B
Initial system pressure = 1055 psia
Initial system temperature = 550°F

Operator Actions

During approximately the first 30 minutes, reactor decay heat is passed to the suppression pool by the automatic operation of the reactor relief valves. Reactor water level will be returned to normal by the HPCS system automatic operation.

After approximately 10 minutes, the operator initiates depressurization of the reactor vessel to control vessel pressure. Controlled depressurization procedure consists of controlling vessel pressure and water level by using the SRV or HPCS and/or RCIC systems. After approximately 15 minutes, it is assumed one RHR heat exchanger is placed in the suppression pool cooling mode to remove decay heat. At this time, the suppression pool will be 121°F.

When the reactor pressure approaches 100 psig, the operator would normally prepare for operation of the RHR system in the shutdown cooling mode. At this time (121 minutes), the suppression pool will be 186°F.

ACTIVITY C1 (Division 1 fails, Division 2 available)
System pressure = 100 psig
System temperature = 330°F

Operator Actions

The operator establishes a closed cooling path as follows:

a. A minimum of two ADS valves (dc Division 2) are powered open.
b. Either of the following cooling paths are established:
    1. Using RHR loop B, water from the suppression pool is pumped through the RHR heat exchanger (where a portion of the decay heat is removed) into the reactor vessel. The cooled suppression pool water flows through the vessel (picking up a portion of the decay heat) out the ADS valves and back to the suppression pool. This alternate cooling path is shown in Figure 15.2-12.
    2. Using RHR loops B and C together, water is taken from the suppression pool and pumped directly into the reactor vessel. The water passes through the vessel (picking up decay heat) and out the ADS valves returning to the suppression pool as shown in Figure 15.2-13. Suppression pool water is then cooled by operation of RHR loop B in the pool cooling mode (see Figure 15.2-14). In this alternate cooling path, RHR loop C is used for injection and RHR loop B for cooling. Cold shutdown is achieved approximately 36 hr after the transient occurs.

ACTIVITY C2 (Division 2 fails, Division 1 available) (Figure 15.2-15)
System pressure = 100 psig
System temperature = 330°F

Operator Actions

The operator establishes a closed cooling path as follows:

a. A minimum of two ADS valves (dc Division 1) are powered open, and
b. Using RHR loop A instead of loop B, an alternate cooling path is established as shown in Activity C1. Cold shutdown is reached in approximately 15 hr.

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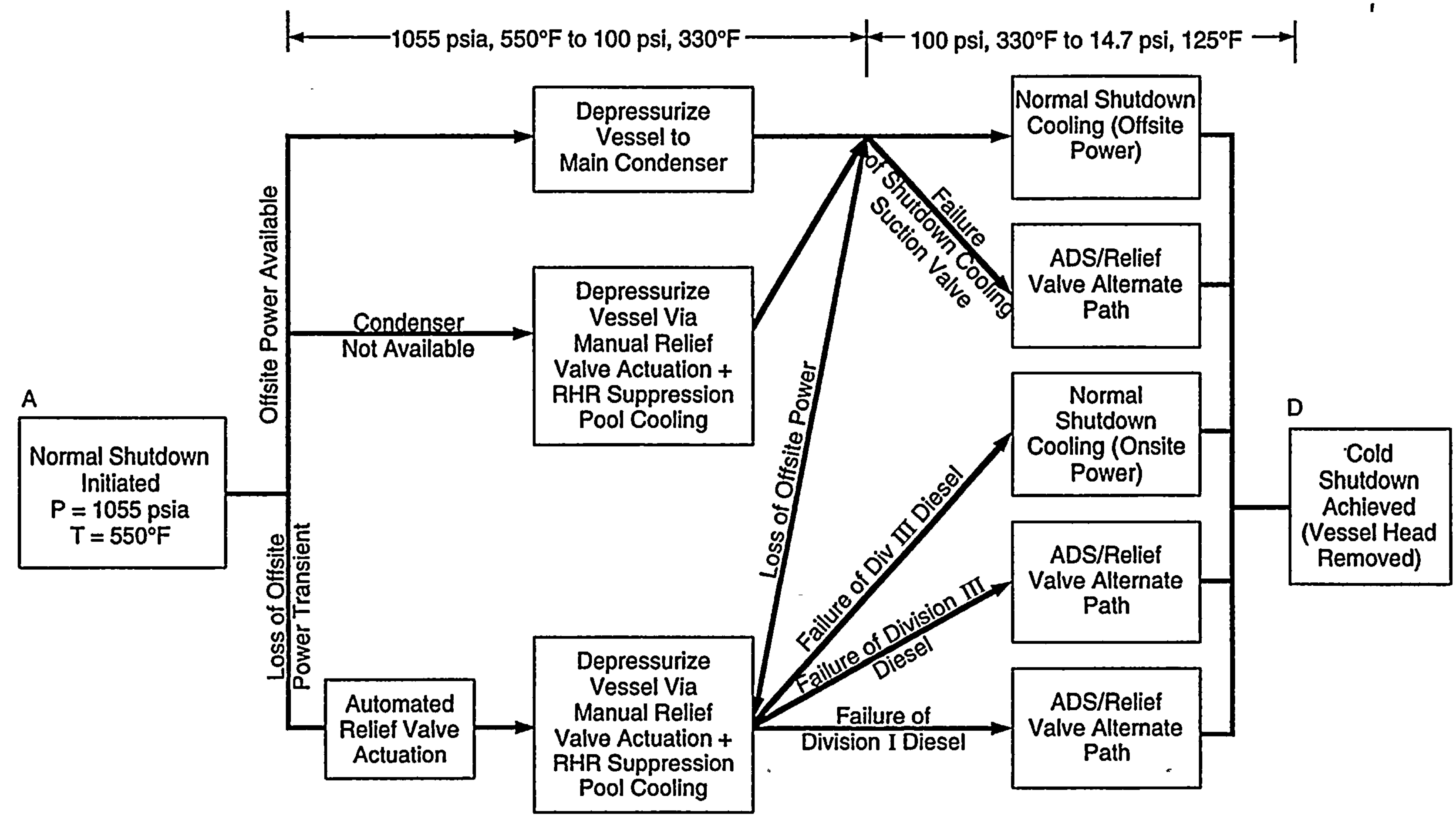

Summary of Paths Available to Achieve Cold Shutdown

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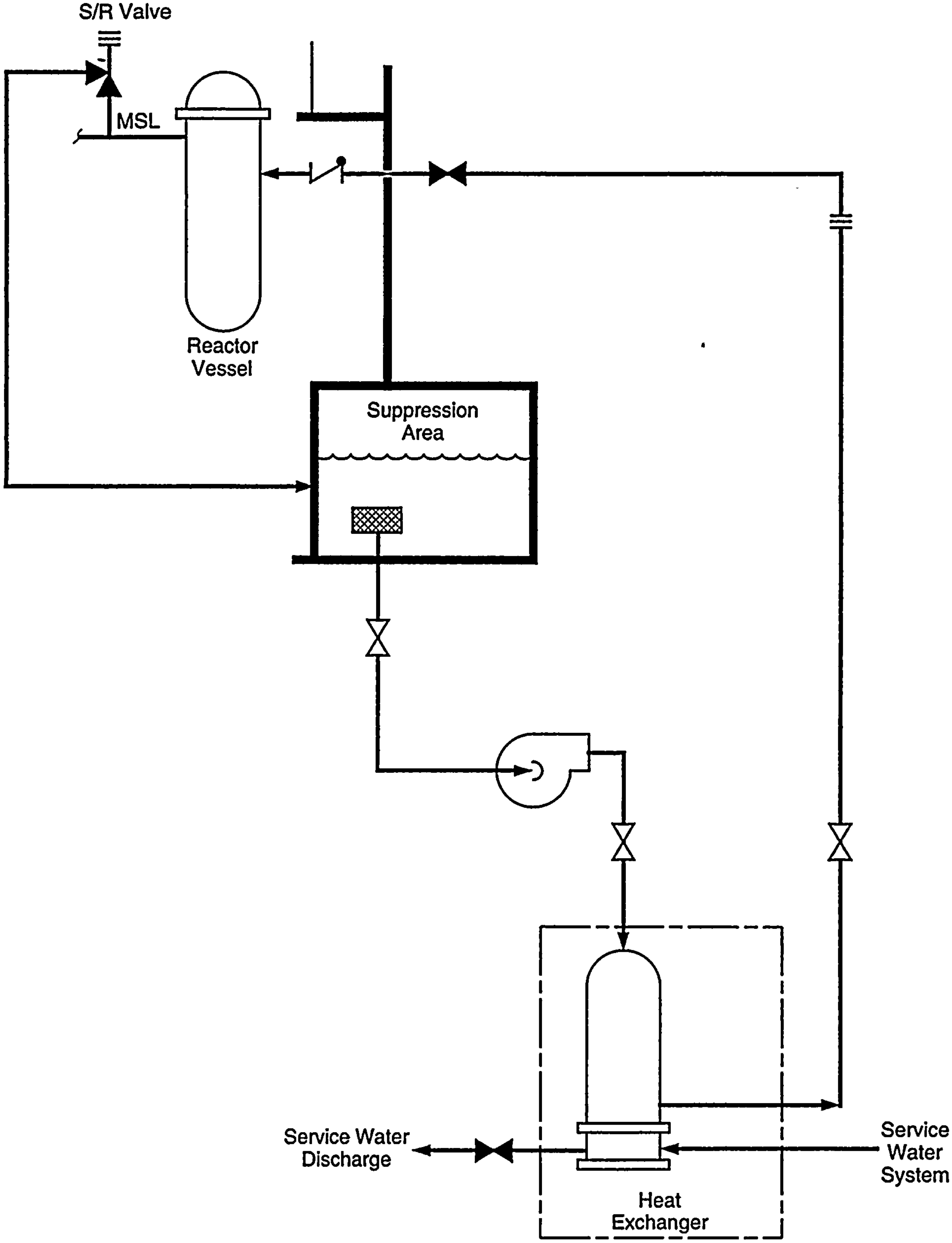
Rev.

Figure 15.2-11



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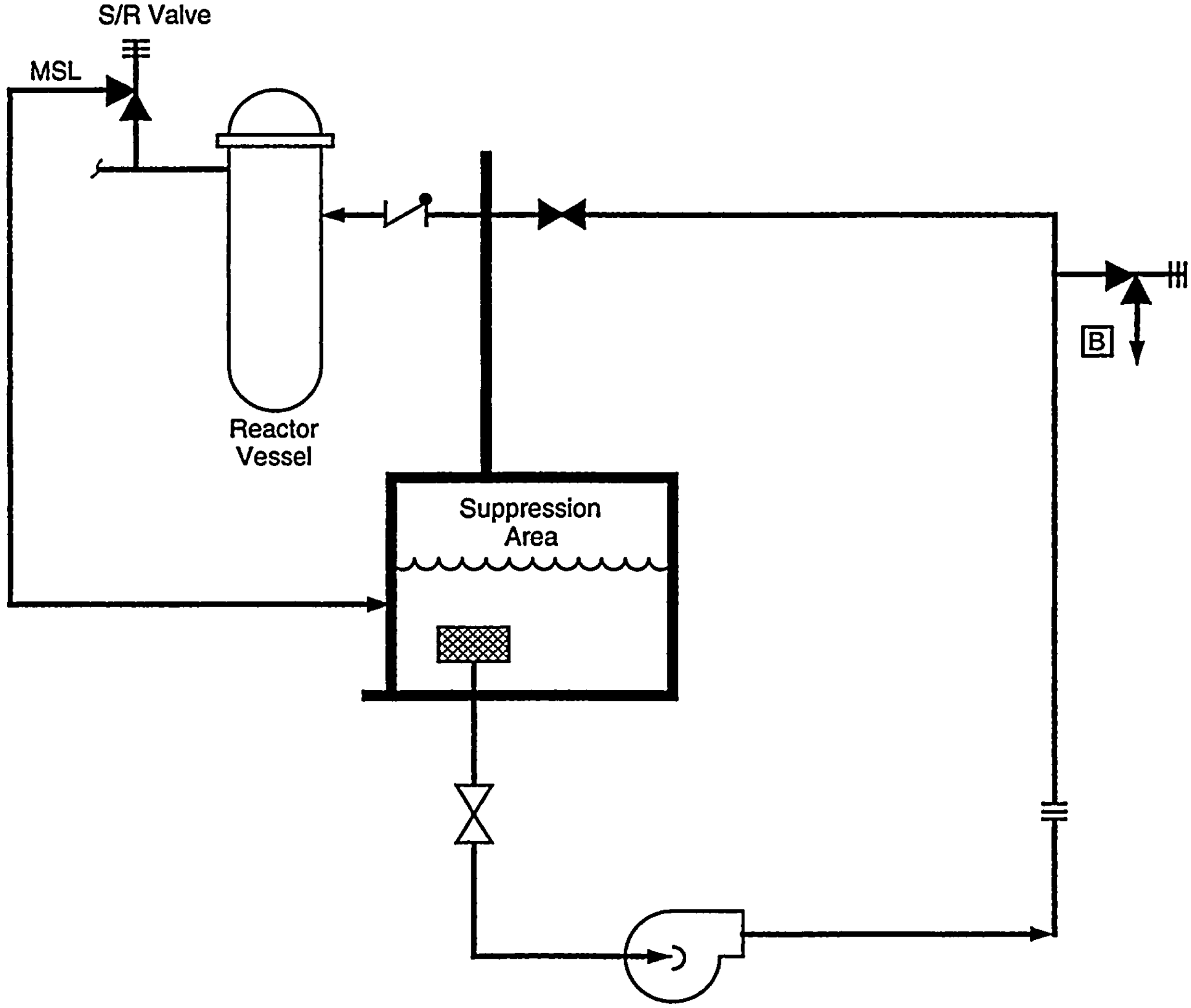
Activity C1 Alternate Shutdown Cooling Path Utilizing Residual Heat Removal Loop B

Draw. No. 900547.65	Rev.	Figure 15.2-12



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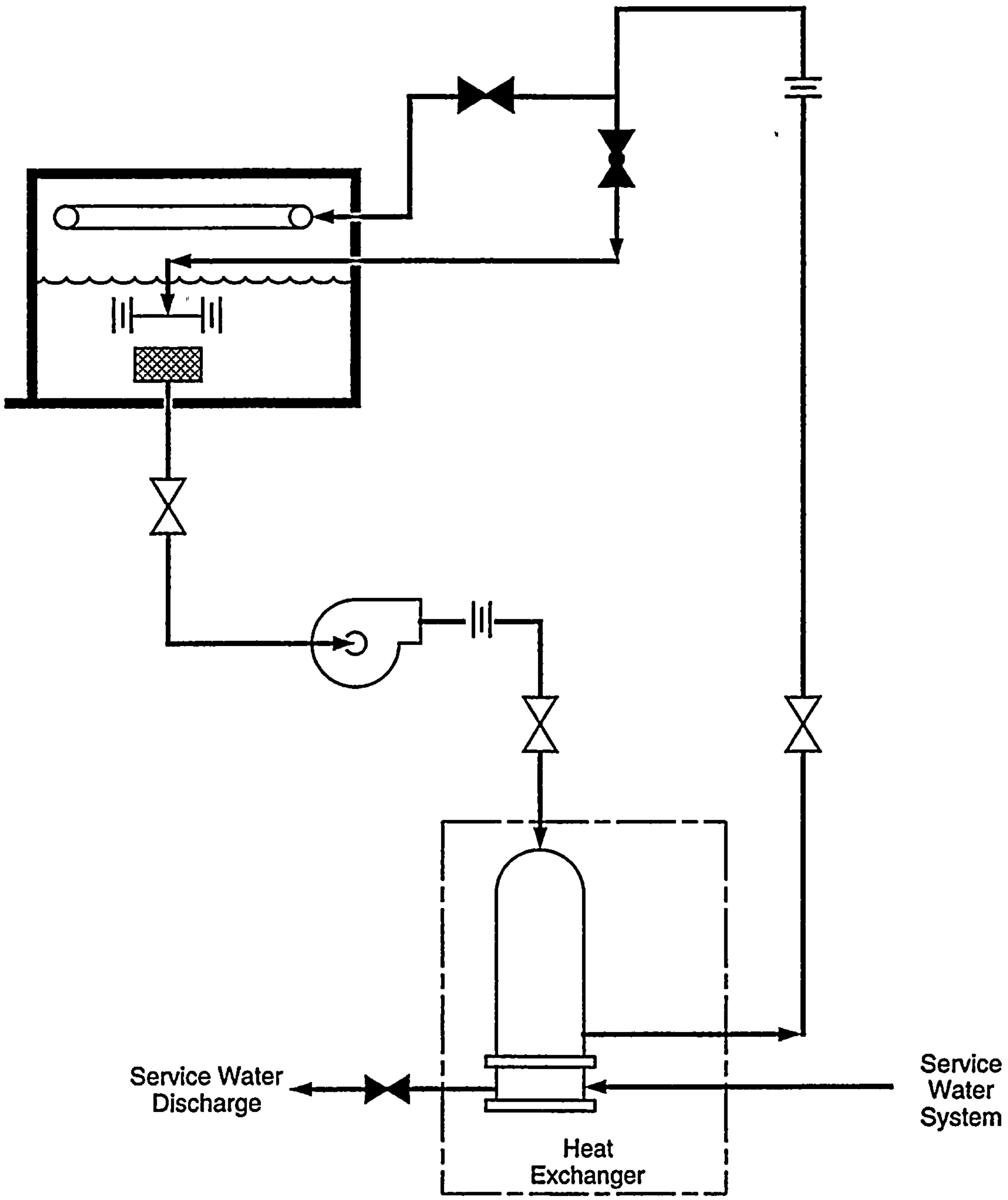
Residual Heat Removal Loop C

Draw. No. 900547.66 | Rev. | Figure 15.2-13



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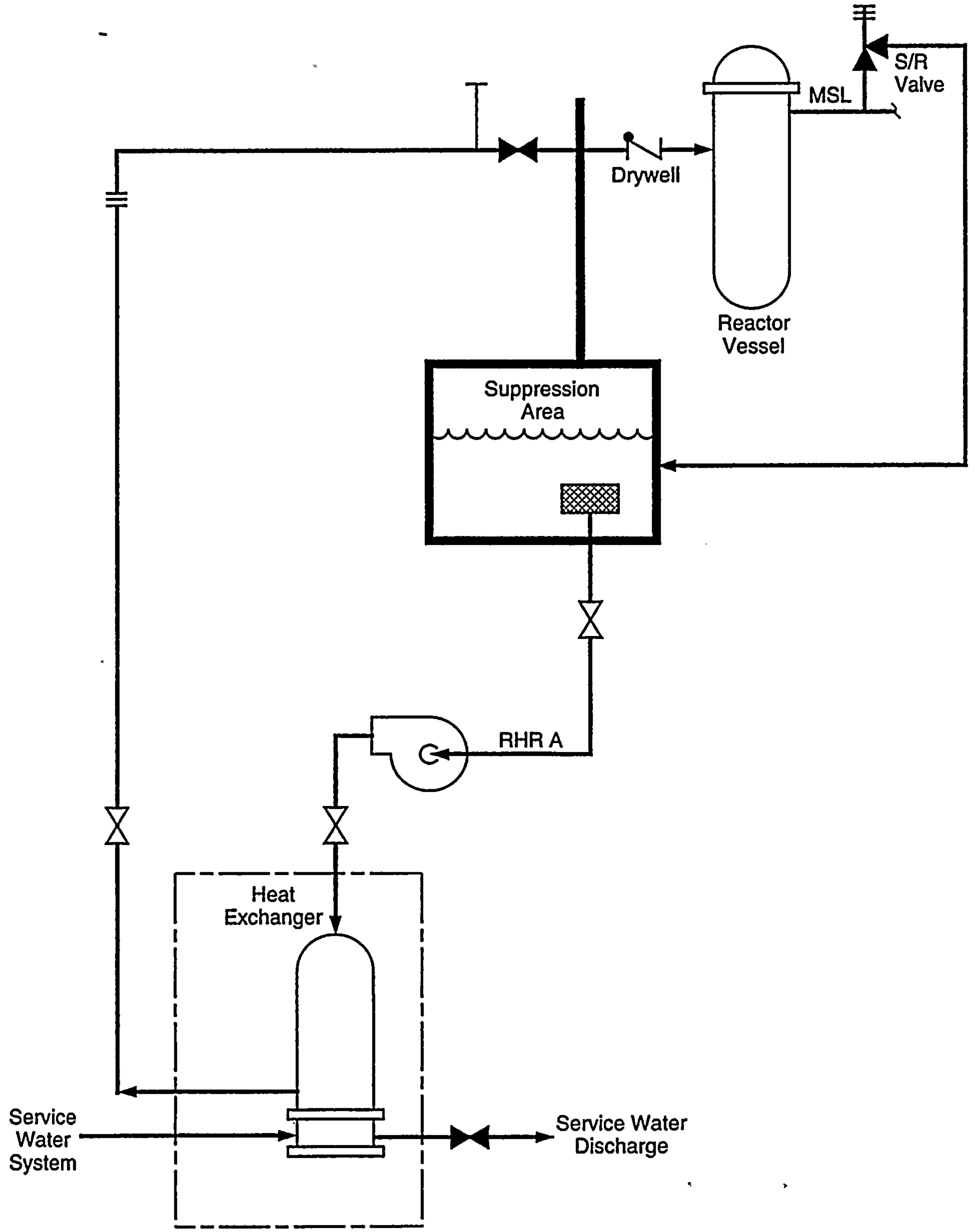
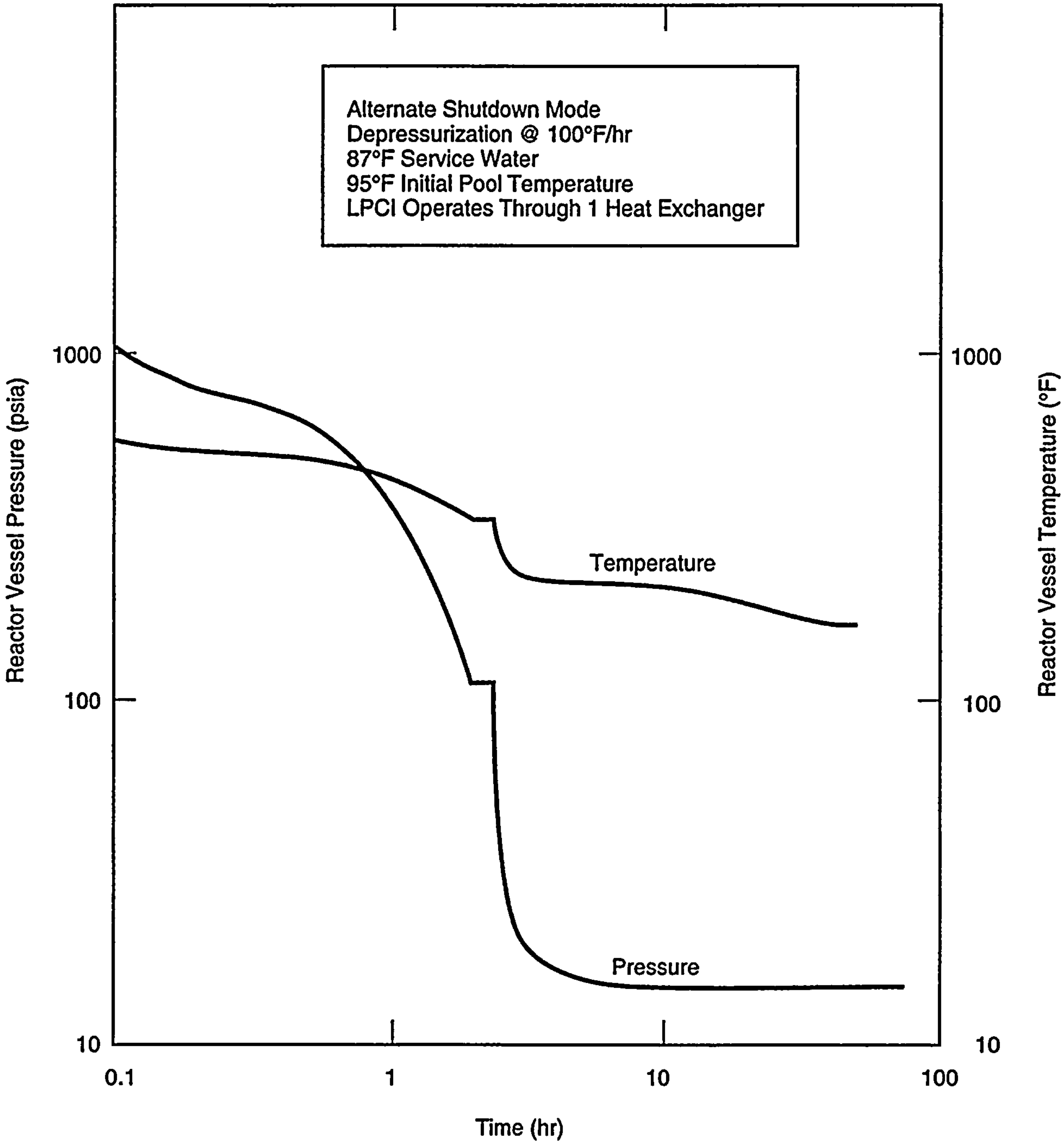
Residual Heat Removal Loop A(B) (Suppression Pool Cooling/ Rated Pump Flow Test Mode)

Draw. No. 900547.67 | Rev. | Figure 15.2-14



Activity C2 Alternate Shutdown Cooling Path Utilizing Residual Heat Removal Loop A



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Vessel Temperature and Pressure Versus Time
(Activity C1.b.1 or C2)

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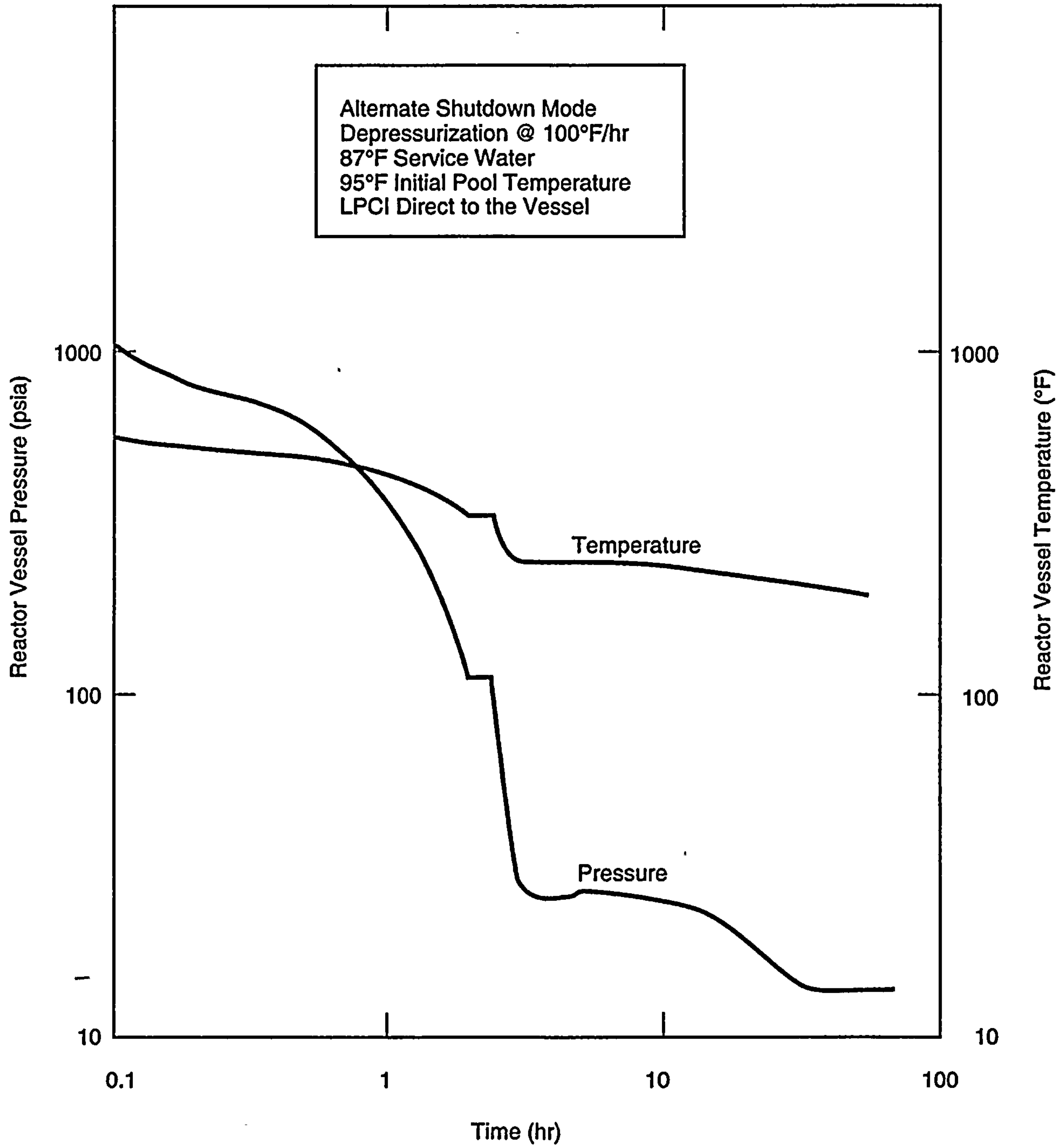

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Vessel Temperature and Pressure Versus Time (Activity C1.b.2)

Draw. No. 900547.70	Rev.	Figure 15.2-17

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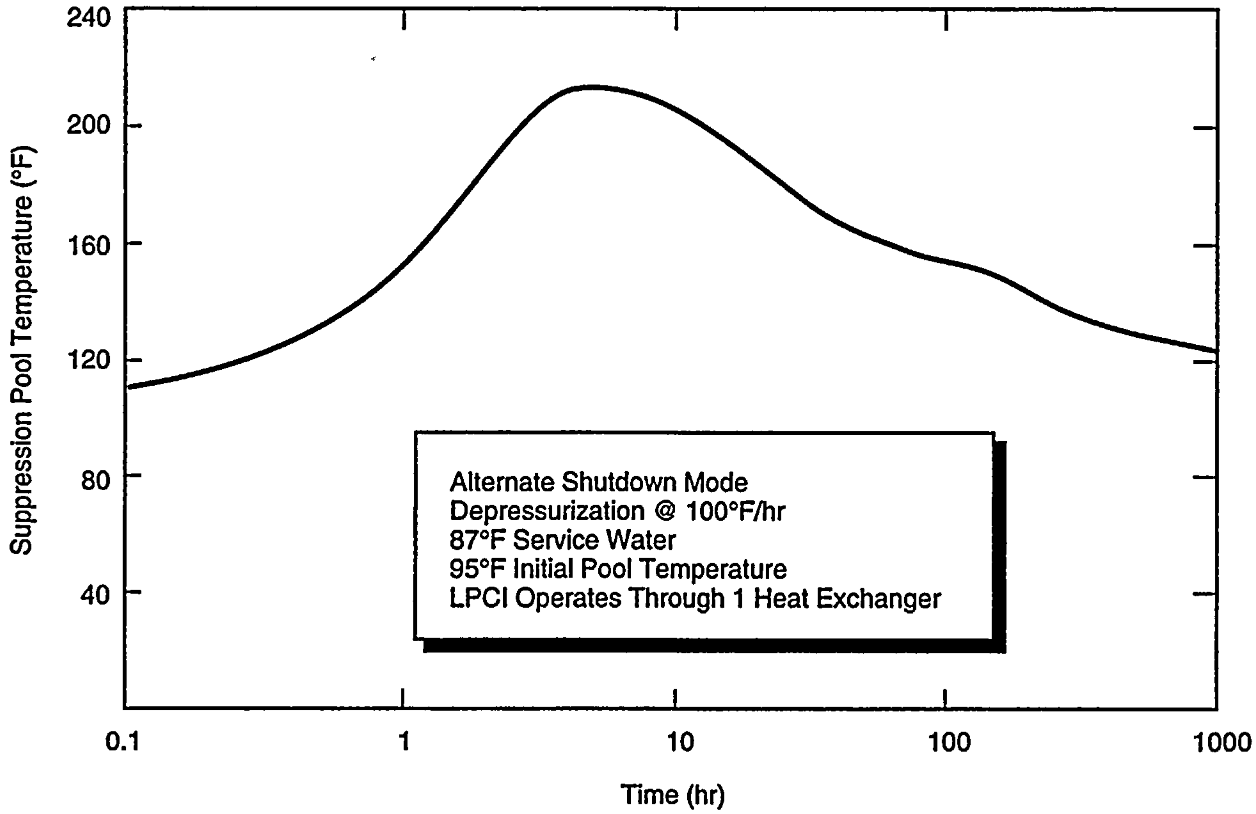

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Suppression Pool Temperature Versus Time (with 87°F Service Water Temperature) (Activity C1.b.1 or C2)

Draw. No. 900547.71 | Rev. | Figure 15.2-18

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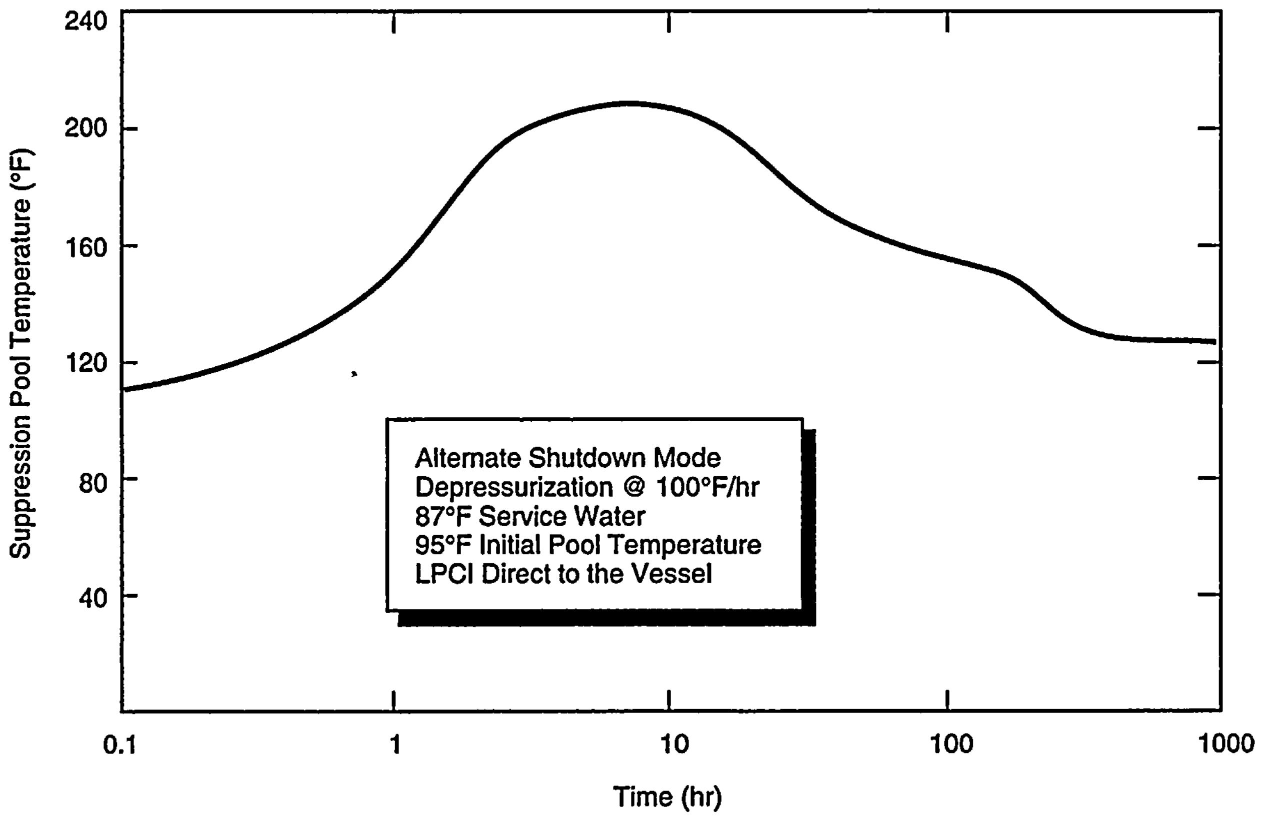


Suppression Pool Temperature Versus Time (with 87°F Service Water Temperature) (Activity C1.b.2)

15.3 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

15.3.1 RECIRCULATION PUMP TRIP

15.3.1.1 Identification of Causes and Frequency Classification

15.3.1.1.1 Identification of Causes

Recirculation pump motor operation can be tripped by design and by random operational failures. Design tripping will occur in response to:

a. Reactor vessel water level L2 setpoint trip,
b. Turbine control valve fast closure or stop valve closure,
c. Failure to scram high pressure setpoint trip,
d. Motor branch circuit over-current protection,
e. Motor overload protection, and
f. Suction block valve not fully open.

Random tripping will occur in response to:

a. Operator error,

b. Loss of electrical power source to the pumps, and

c. Equipment or sensor failures and malfunctions which initiate the above intended trip response.

15.3.1.1.2 Frequency Classification

15.3.1.1.2.1 Trip of One Recirculation Pump. This event is categorized as an incident of moderate frequency.

15.3.1.1.2.2 Trip of Two Recirculation Pumps. This event is categorized as an incident of moderate frequency.

15.3.1.2 Sequence of Events and Systems Operation

15.3.1.2.1 Sequence of Events

15.3.1.2.1.1 Trip of One Recirculation Pump. Table 15.3-1 lists the sequence of events for Figure 15.3-1.

15.3.1.2.1.2 Trip of Two Recirculation Pumps. Table 15.3-2 lists the sequence of events for Figure 15.3-2.

15.3.1.2.1.3 Identification of Operator Actions.

15.3.1.2.1.3.1 Trip of One Recirculation Pump. Since no scram occurs for trip of one recirculation pump no immediate operator action is required. The operator must verify that no operating limits are being exceeded and reduce flow of the operating pump to conform to the single pump flow criteria. Also, the operator must determine the cause of trip prior to returning the system to normal.

15.3.1.2.1.3.2 Trip of Two Recirculation Pumps. The operator must ascertain that the reactor scrams with the turbine trip resulting from reactor water level swell. The operator should regain control of reactor water level through high-pressure core spray (HPCS) and/or reactor core isolation cooling (RCIC) operation, monitoring reactor water level, and pressure control after shutdown. When both reactor pressure and level are under control, both HPCS and RCIC should be secured as necessary. The operator must also determine the cause of the trip prior to returning the system to normal.

15.3.1.2.2 Systems Operation

15.3.1.2.2.1 Trip of One Recirculation Pump. Tripping a single recirculation pump requires no protection system or safeguard system operation. This analysis assumes normal functioning of plant instrumentation and controls.

15.3.1.2.2.2 Trip of Two Recirculation Pumps. Analysis of this event assumes normal functioning of plant instrumentation and controls and plant and reactor protection systems.

Specifically, this transient takes credit for vessel level (L8) instrumentation to trip the turbine. Reactor shutdown relies on scram trips from the turbine stop valves. High system pressure is limited by the pressure relief valve system operation.

15.3.1.2.3 The Effect of Single Failures and Operator Errors

15.3.1.2.3.1 Trip of One Recirculation Pump. None

15.3.1.2.3.2 Trip of Two Recirculation Pumps. Table 15.3-2 lists the vessel level (L8) trip event as the first response to initiate corrective action in this transient and it is intended to prohibit moisture carryover to the main turbine. Multiple level sensors are used to sense and detect when the water level reaches the L8 setpoint. At this point, a single failure will neither initiate nor impede a turbine trip signal. Turbine trip signal transmission circuitry, however, is not built to single failure criterion. At this point the transient event is functionally over.

15.3.1.3 Core and System Performance

15.3.1.3.1 Mathematical Model

The dynamic model described in Reference 15.3-1 is used to simulate this event.

15.3.1.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions in Table 15.0-2.

Pump motors and pump rotors are simulated with minimum specified rotating inertias.

15.3.1.3.3 Results

15.3.1.3.3.1 Trip of One Recirculation Pump. Figure 15.3-1 shows the response of the reactor system following the trip of one recirculation pump motor. Initially a recirculation pump is tripped in one loop, causing the core inlet flow to decrease, while the other recirculation loop flow increases. Subsequently jet pump diffuser flow reverses in the tripped recirculation loop. At approximately 45 sec the reactor reaches a new equilibrium operating point, at approximately 75% power and 57% core flow. During the transient, level swell is not sufficient to cause turbine trip.

15.3.1.3.3.2 Trip of Two Recirculation Pumps. Figure 15.3-2 shows the response of the reactor system following the trip of both recirculation pump motors. Initially both recirculation pumps are tripped, causing the core inlet flow to decrease, while vessel level rises until both main and feedwater turbines trip on high level (L8). A reactor scram is subsequently initiated at 90% turbine stop valve position. Shortly after the scram is initiated the stop valves close and the bypass valves open to regulate pressure. At this point the transient event is functionally over.

15.3.1.3.4 Consideration of Uncertainties

Initial conditions chosen for these analyses are conservative and tend to force analytical results to be more severe than expected under actual plant conditions.

Actual pump and pump-motor drive line rotating inertias are expected to be somewhat greater than the minimum design values assumed in this simulation. Actual plant deviations regarding inertia are expected to lessen the severity as analyzed. Minimum design inertias were used as well as the least negative void coefficient since these maximize the flow reduction.

15.3.1.4 Barrier Performance

15.3.1.4.1 Trip of One Recirculation Pump

Figure 15.3-1 results indicate a basic reduction in system pressures from the initial conditions. Therefore, the reactor coolant pressure boundary (RCPB) barrier is not impacted.

15.3.1.4.2 Trip of Two Recirculation Pumps

The results shown in Figure 15.3-2 indicate peak pressures stay well below the limit allowed by the applicable American Society of Mechanical Engineers (ASME) code. Therefore, the RCPB barrier is not impacted.

15.3.1.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of safety/relief valve (SRV) operation. Since this activity is contained in the primary containment there will be no exposure to personnel. Since this event does not result in an uncontrolled release to the environment the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release will be in accordance with established requirements.

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment there are no radiological consequences associated with this event.

15.3.2 RECIRCULATION FLOW CONTROL FAILURE - DECREASING FLOW

15.3.2.1 Identification of Causes and Frequency Classification

15.3.2.1.1 Identification of Causes

A postulated failure of the input demand signal, which is used in both loops, can decrease core flow at the maximum ramp demand rate established by the adjustable speed drive (ASD) control. Failure within either loop controller can result in a maximum ramp demand rate as limited by the ASD control.

15.3.2.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.3.2.2 Sequence of Events and Systems Operation

15.3.2.2.1 Sequence of Events

15.3.2.2.1.1 Speed Decrease of One Recirculation Pump. Table 15.3-3 lists the sequence of events for Figure 15.3-3.

15.3.2.2.1.2 Speed Decrease of Two Recirculation Pumps. Table 15.3-4 lists the sequence of events for Figure 15.3-4.

15.3.2.2.2 Systems Operation

15.3.2.2.2.1 Speed Decrease of One Recirculation Pump. The most severe control system disturbance is a failure that causes the ASD internal controller to move at its maximum rate. Such transients may be obtained by instantaneous failure of a controller output into its upper or lower limits. Originally the recirculation flow was controlled by valve motion. For the current analysis the recirculation flow control valves have been locked at the full open position, and ASD units have been implemented to provide the necessary flow control.

15.3.2.2.2.2 Speed Decrease of Two Recirculation Pumps. The most severe control system disturbance is a failure that causes the ASD internal controller to move at its maximum rate. Such transients may be obtained by instantaneous failure of a controller output into its upper or lower limits. The independent and simultaneous failure of each individual loop controller would be highly improbable.

Thus, for the two loop controller failure event, the ASD internal controller is assumed to move at its maximum rate in both recirculation loops. Originally the recirculation flow was controlled by valve motion. For the current analysis the recirculation flow control valves have been locked at the full open position, and ASD units have been implemented to provide the necessary flow control.

15.3.2.2.3 The Effect of Single Failures and Operator Errors

The single failure and operator considerations for this event are essentially the same as in Section 15.3.1.2.3.2. The speed decrease of two instead of one recirculation pump would be the envelope case for the additional single component failure or operator error.

15.3.2.3 Core and System Performance

15.3.2.3.1 Mathematical Model

The dynamic model described in Reference 15.3-1 is used to simulate these transient events.

15.3.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions listed in Table 15.0-2.

15.3.2.3.2.1 Speed Decrease of One Recirculation Pump. For the simulation of this event, a controller malfunction causes a zero demand signal to be sent to one of the recirculation ASD units, while the plant is operating at 106% uprated power and 100% core flow. A control demand error (low) signal causes the ASD to adjust the recirculation pump speed demand rate limit downward at an assumed rate of 25%/sec for one loop failure. The ensuing transient is similar to a recirculation pump trip.

15.3.2.3.2.2 Speed Decrease of Two Recirculation Pumps. For the simulation of this event, a controller malfunction causes a zero demand signal to be sent to both of the recirculation ASD units, while the plant is operating at 106% uprated power and 100% core flow. A control demand error (low) can cause the ASD units to adjust the recirculation pump speed downward in both loops. The following analyses illustrate both the 5%/sec and 10%/sec pump speed rate limits.

15.3.2.3.3 Results

15.3.2.3.3.1 Speed Decrease of One Recirculation Pump. Figure 15.3-3 shows the response of the plant for this transient. Initially a negative recirculation pump speed demand is sent to the ASD due to a postulated controller failure. The negative pump speed demand causes the diffuser flow to decrease, and eventually reverse, in the failed loop. At the same time the active loop increases flow to compensate for the failed recirculation loop. At approximately 45 sec the reactor reaches a new equilibrium operating point, at approximately 74% and 57% core flow. During the transient, level swell is not sufficient to cause turbine trip which would result in a reactor scram.

15.3.2.3.3.2 Speed Decrease of Two Recirculation Pumps. Figure 15.3-4 shows the response of the plant to this transient using the 5%/sec pump speed demand rate limit. Initially, a negative recirculation pump speed demand is sent to both ASD units due to a postulated controller failure. The negative pump speed demand causes the diffuser flows to decrease in the failed loops. During the transient, level swell is not sufficient to cause turbine trip which would result in a reactor scram.

15.3.2.3.4 Consideration of Uncertainties

Initial conditions chosen for these analyses are conservative and tend to force analytical results to be more severe than expected under actual plant conditions.

These analyses are unaffected by deviations in pump/pump motor and driveline inertias since it is the ASD controller that causes rapid recirculation decreases.

15.3.2.4 Barrier Performance

15.3.2.4.1 Speed Decrease of One Recirculation Pump

The pressure in the vessel dome is well below the vessel pressure limit. The event does not result in a temperature or pressure transient in excess of the criteria for which the fuels pressure vessel or containment are designed. Therefore, barrier integrity and function is maintained.

15.3.2.4.2 Speed Decrease of Two Recirculation Pumps

The pressure in the vessel dome is well below the vessel pressure limit. The event does not result in a temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed and these barriers maintain their integrity and function as designed.

15.3.2.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment there are no radiological consequences associated with this event.

15.3.3 RECIRCULATION PUMP SEIZURE

15.3.3.1 Identification of Causes and Frequency Classification

The case of recirculation pump seizure represents the extremely unlikely event of instantaneous stoppage of the pump motor shaft of one recirculation pump. This event produces a very rapid decrease of core flow as a result of the large hydraulic resistance introduced by the stopped rotor. The sudden decrease in core coolant flow while the reactor is at full power results in a degradation of core heat transfer which could result in fuel damage.

15.3.3.1.1 Identification of Causes

For the simulation of this event, one recirculation pump was seized instantaneously (pump speed set to zero) while the plant is operating at 106% uprated power and 100% core flow.

15.3.3.1.2 Frequency Classification

The event is categorized as an incident of infrequent frequency.

15.3.3.2 Sequence of Events and Systems Operation

15.3.3.2.1 Sequence of Events

Table 15.3-5 lists the sequence of events for Figure 15.3-5.

15.3.3.2.1.1 Identification of Operator Actions. The operator must ascertain that the reactor scrams with the turbine trip resulting from reactor water level swell. The operator should regain control of reactor water level through HPCS and/or RCIC and he must monitor reactor water level and pressure control after shutdown.

15.3.3.2.2 Systems Operation

In order to properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems.

Operation of safe shutdown features, though not included in this simulation, is expected to be utilized in order to maintain adequate water level.

15.3.3.2.3 The Effect of Single Failures and Operator Errors

Single failures in the scram logic originating by means of the high vessel level (L8) trip are similar to the considerations in Section 15.3.1.2.3.2.

15.3.3.3 Core and System Performance

15.3.3.3.1 Mathematical Model

The dynamic model described in Reference 15.3-1 is used to simulate this event.

15.3.3.3.2 Input Parameters and Initial Conditions

This analysis has been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

15.3.3.3.3 Results

Figure 15.3-5 presents the results of the accident. Table 15.3-5 shows the sequence of events for this transient. Initially a recirculation pump is seized in one loop causing the flow in the seized loop to reverse and the flow in the active loop to increase. As the flow in the seized loop decreases, the vessel level rises until a turbine trip is initiated on high level, L8. Once L8

is reached, both feedwater pumps trip. A reactor scram is subsequently initiated due to 90% turbine stop valve position. Shortly after the turbine trip is initiated the stop valves close and the bypass valves open to regulate pressure. Simultaneously the active recirculation loop trips due to the turbine trip. The MCPR does not decrease significantly before fuel surface heat flux begins dropping enough to restore greater thermal margins. After the time at which MCPR occurs, heat flux decreases more rapidly than the rate at which heat is removed by the coolant. Table 15.0-1 shows the ΔCPR to be less than 0.01.

15.3.3.3.3.1 Considerations of Uncertainties. Considerations of uncertainties are included in the analysis.

15.3.3.4 Barrier Performance

The bypass valves open to limit the pressure well within the range allowed by the ASME vessel code. The RCPB is not impacted by overpressure. Therefore, barrier integrity and function is maintained.

15.3.3.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment there are no radiological consequences associated with this event.

15.3.4 RECIRCULATION PUMP SHAFT BREAK

15.3.4.1 Identification of Causes and Frequency Classification

The breaking of the shaft of a recirculation pump is considered a design basis accident event. It has been evaluated as a mild accident in relation to other design basis accidents such as the loss-of-coolant accident. The analysis has been conducted with consideration to a single or two loop operation. Two loop operation represents the worst case since single loop operation is limited to approximately 70% power.

This postulated event is bounded by the more limiting case of recirculation pump seizure.

15.3.4.1.1 Identification of Causes

The case of recirculation pump shaft breakage represents the unlikely event of rapid stoppage of the pump operation of one recirculation pump. This event produces a rapid decrease of core flow.

15.3.4.1.2 Frequency Classification

This event is categorized as an incident of infrequent frequency.

15.3.4.2 Sequence of Events and Systems Operation

15.3.4.2.1 Sequence of Events

A postulated instantaneous break of the pump motor shaft of one recirculation pump as discussed in Section 15.3.4.1.1 will cause the core flow to decrease rapidly resulting in water level swell in the reactor vessel. When the vessel water level reaches the high water level setpoint (Level 8), a main turbine trip and feedwater pump trip will be initiated.

A reactor scram and the remaining recirculation pump trip will be initiated due to the turbine trip. Eventually the vessel water level will be controlled by HPCS and/or RCIC flow.

15.3.4.2.1.1 Identification of Operator Actions. The operator must ascertain that the reactor scrams resulting from reactor water level swell. The operator should regain control of reactor water level through HPCS and/or RCIC operation and monitor reactor water level and pressure control after shutdown.

15.3.4.2.2 Systems Operation

Normal operation of plant instrumentation and control is assumed. This event takes credit for vessel water level (Level 8) instrumentation to scram the reactor and trip the main turbine and feedwater pumps. High system pressure is limited by the pressure relief system operation.

Operation of HPCS and/or RCIC is expected in order to maintain adequate water level control.

15.3.4.2.3 The Effect of Single Failures and Operator Errors

Effects of single failures in the high vessel level (L8) trip are similar to the considerations in Section 15.3.1.2.3.2.

Assumption of single component failure or operator error in other equipment has been examined and this has led to the conclusion that no other credible failure exists for this event. Therefore, the bounding case has been considered.

15.3.4.3 Core and System Performance

The pump shaft break event is bounded by the pump seizure event. Since this event is less limiting than that event, only qualitative evaluation is provided. Therefore, no discussion of mathematical model, input parameters, and consideration of uncertainties, etc., is necessary.

15.3.4.3.1 Qualitative Results

If this unlikely event occurs, core coolant flow will drop rapidly. The level swell produces a trip of the main and feedwater turbines. A scram is initiated due to turbine trip. Since heat flux decreases more rapidly than the rate at which heat is removed by the coolant, there is no impact on thermal limits. Additionally, the bypass valves and the potential for a momentary opening of some of the SRVs limit the pressure well within the range allowed by the ASME vessel code. Therefore, the RCPB is not impacted by overpressure.

The severity of this pump shaft break event is bounded by the pump seizure event. In either of these two events, the recirculation drive flow of the affected loop decreases rapidly.

In the case of the pump seizure event, the loop flow decreases faster than the normal flow coastdown as a result of the large hydraulic resistance introduced by the stopped rotor. For the pump shaft break event, the hydraulic resistance caused by the broken pump shaft is less than that of the stopped rotor for the pump seizure event. Therefore, the core flow decrease following a pump shaft break effect is slower than the pump seizure event. Thus, it can be concluded that the potential effects of the hypothetical pump shaft break accident are bounded by the effects of the pump seizure event.

15.3.4.4 Barrier Performance

The bypass valves and momentary opening of some of the SRVs limit the pressure well within the range allowed by the ASME vessel code. Therefore, the RCPB is not impacted by overpressure.

15.3.4.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment there are no radiological consequences associated with this event.

15.3.5 REFERENCES

15.4-1 General Electric Company, WNP-2 Power Uprate Transient Analysis Task Report, GE-NE-208-08-0393, September 1993.

TABLE 15.3-1

SEQUENCE OF EVENTS FOR FIGURE 15.3-1

Trip of One Recirculation Pump Motor
Uprated Power

Time (sec)	Event
0	Trip of one recirculation pump initiated.
9	Jet pump diffuser flow reverses in the tripped loop.
45[a]	Core flow and power level stabilize at new equilibrium conditions.

[a] Approximately.

TABLE 15.3-2

SEQUENCE OF EVENTS FOR FIGURE 15.3-2

Trip of Both Recirculation Pump Motors
Uprated Power

Time (sec)	Event
0	Trip of both recirculation pumps initiated.
5.66	Vessel water level (L8) trip initiates turbine trip.
5.66	Feedwater pumps are tripped off.
5.67	Main turbine stop valves reach 90% open position and initiate reactor scram trip.
5.76	Turbine bypass valves open.

TABLE 15.3-3

SEQUENCE OF EVENTS FOR FIGURE 15.3-3

Recirculation Flow Control Failure
Decreasing Flow in One Loop
Uprated Power

Time (sec)	Event
0	Initiate fast down scale of recirculation pump speed in one loop.
4[a]	Jet pump diffuser flow reverses in the affected loop.
45[a]	Core flow and power level stabilize at new equilibrium conditions.

[a] Approximately.

TABLE 15.3-4

SEQUENCE OF EVENTS FOR FIGURE 15.3-4

Recirculation Flow Control Failure
Decreasing Flow in Both Loops (5%/sec)
Uprated Power

Time (sec)	Event
0	Initiate 5%/sec down scale of recirculation pump speed in both loops.
85[a]	Core flow and power level stabilize at new equilibrium conditions.

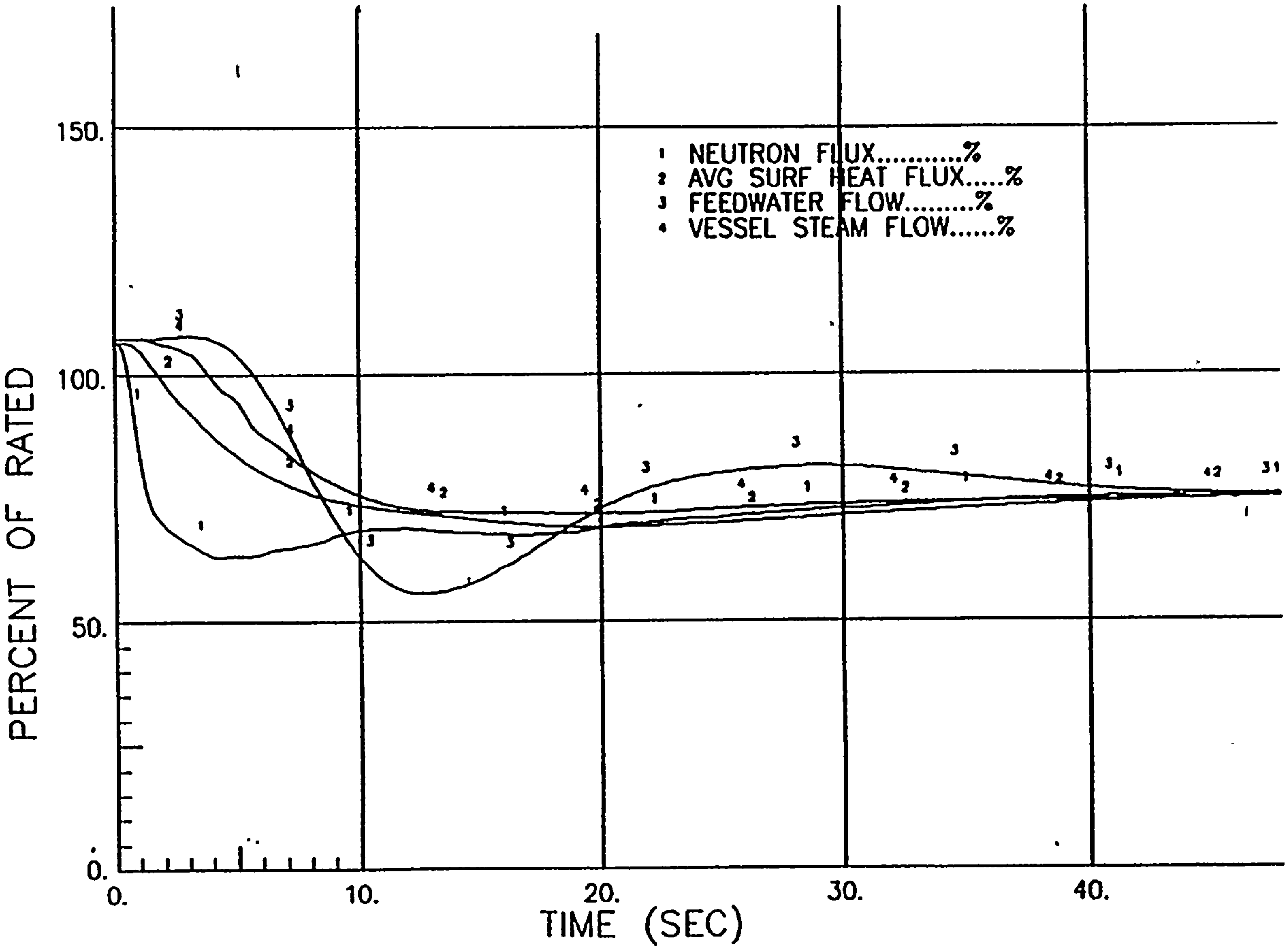
TABLE 15.3-5

SEQUENCE OF EVENTS FOR FIGURE 15.3-5

One Recirculation Pump Seizure
Uprated Power

Time (sec)	Event
0	Seizure of one recirculation pump initiated.
1[a]	Jet pump diffuser flow reverses in the seized loop.
4.40	Vessel water high level (L8) trip initiates a turbine trip.
4.40	Feedwater pumps are tripped off.
4.41	Main turbine stop valves reach 90% open position and initiate reactor scram.
4.59	Active recirculation loop trips due to previous turbine trip.

[a] Approximately.



Amendment 53
November 1998

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

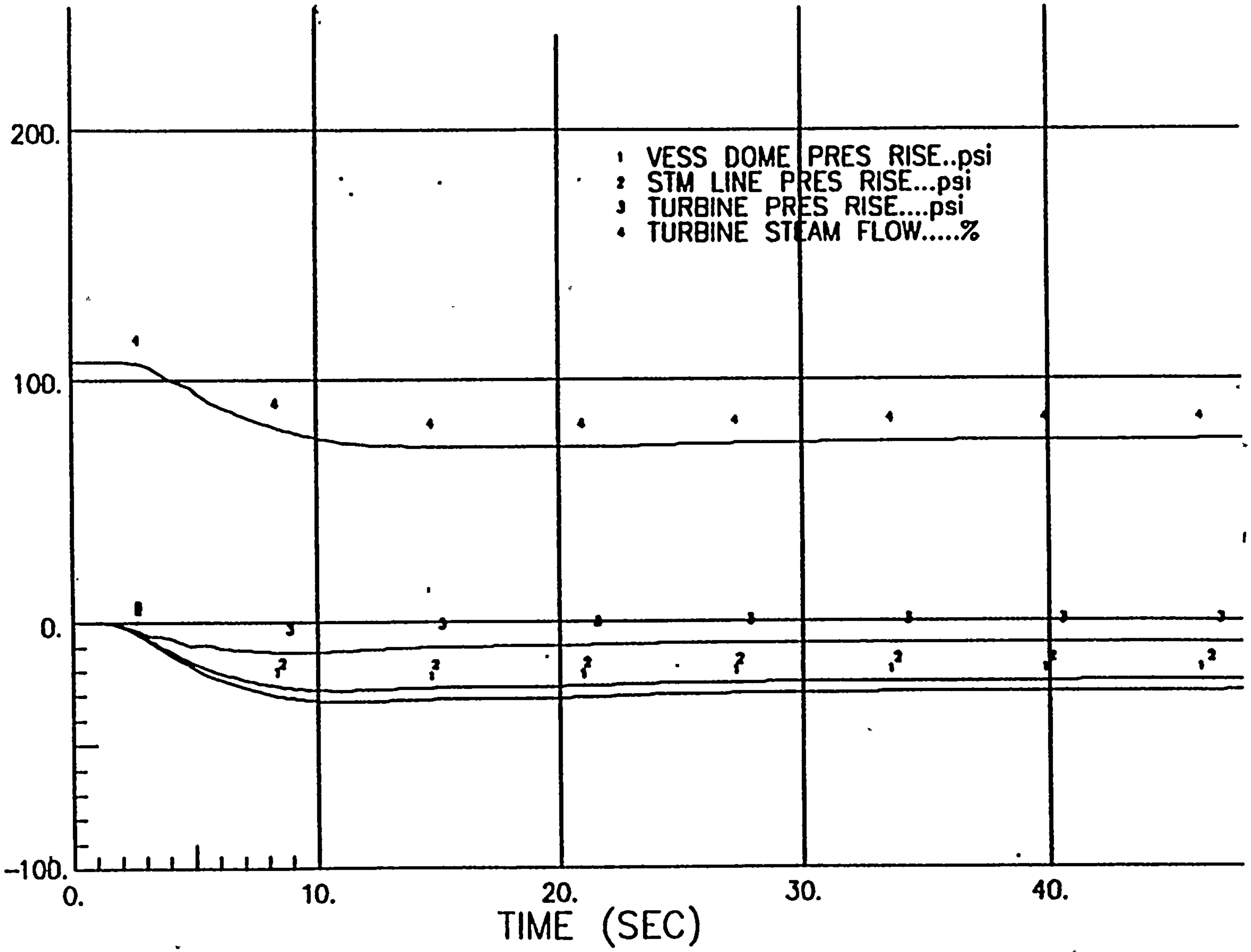
One Recirculation Pump Trip at 106.2%
Uprated Power, 100% Flow

Draw. No.

Rev.

Figure 15.3-1.1

Form No. 960690



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One Recirculation Pump Trip at 106.2%
Uprated Power, 100% Flow

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Figure 15.3-1.2

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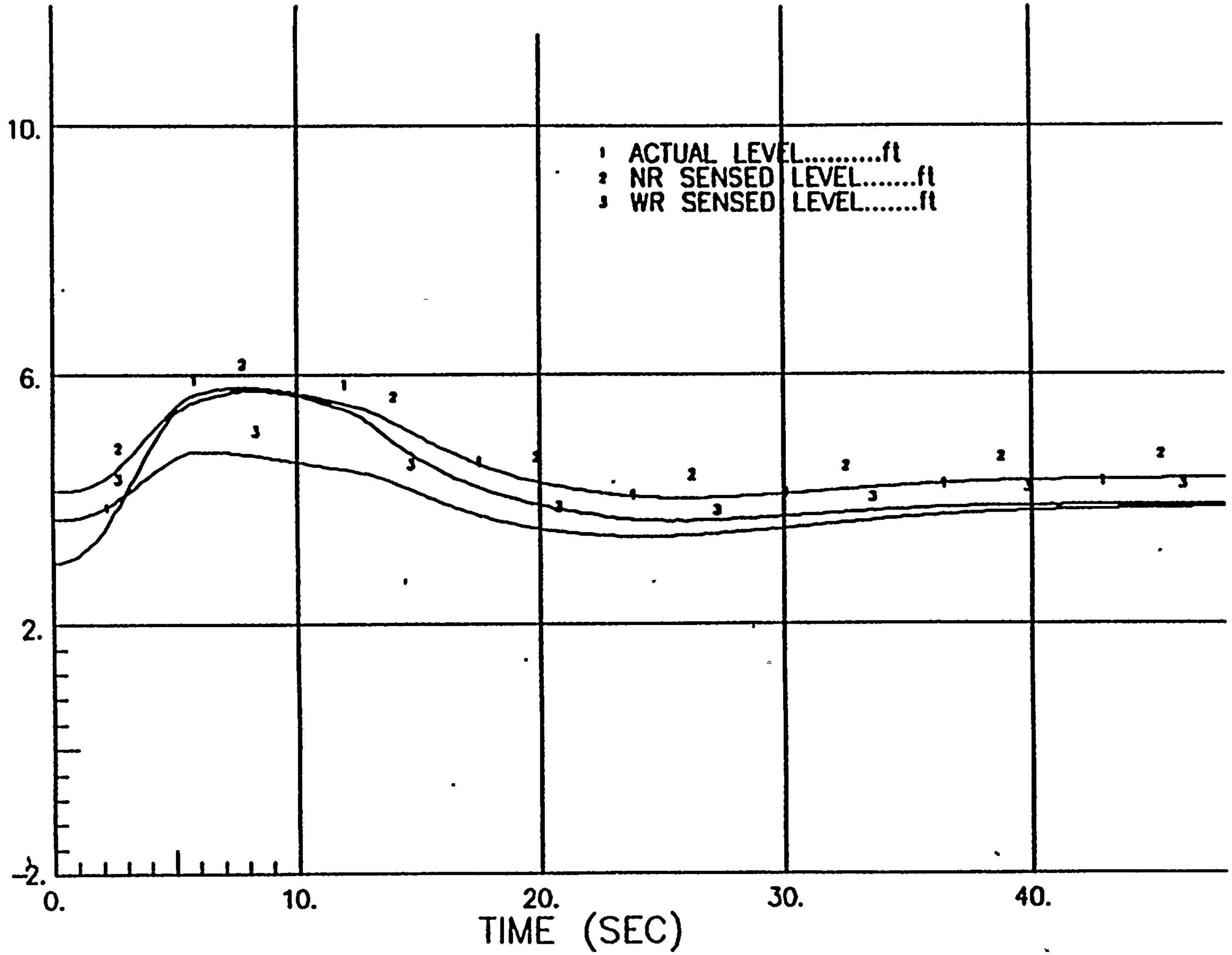

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One Recirculation Pump Trip at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-1.3

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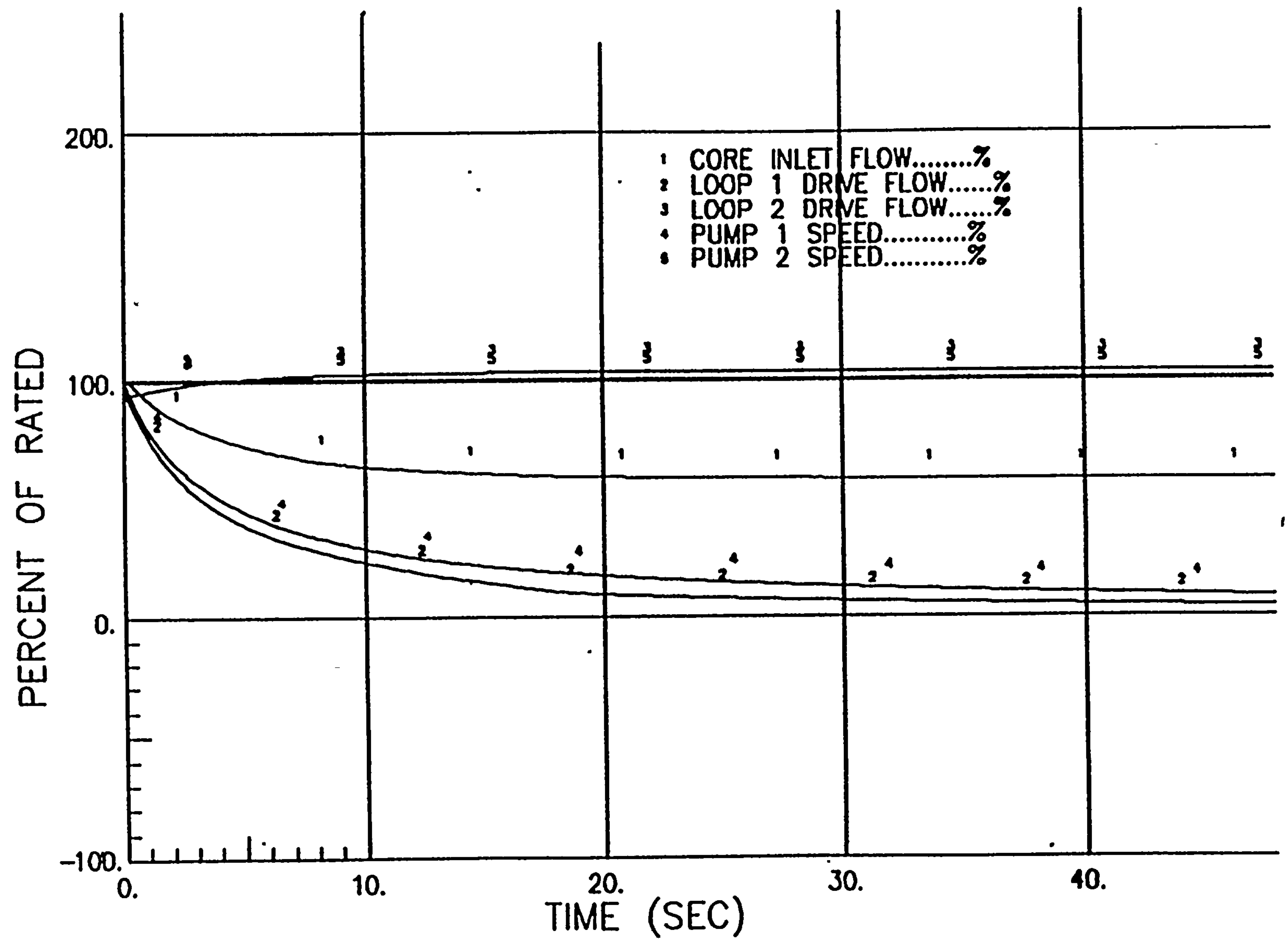

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One Recirculation Pump Trip at 106.2%
Uprated Power, 100% Flow

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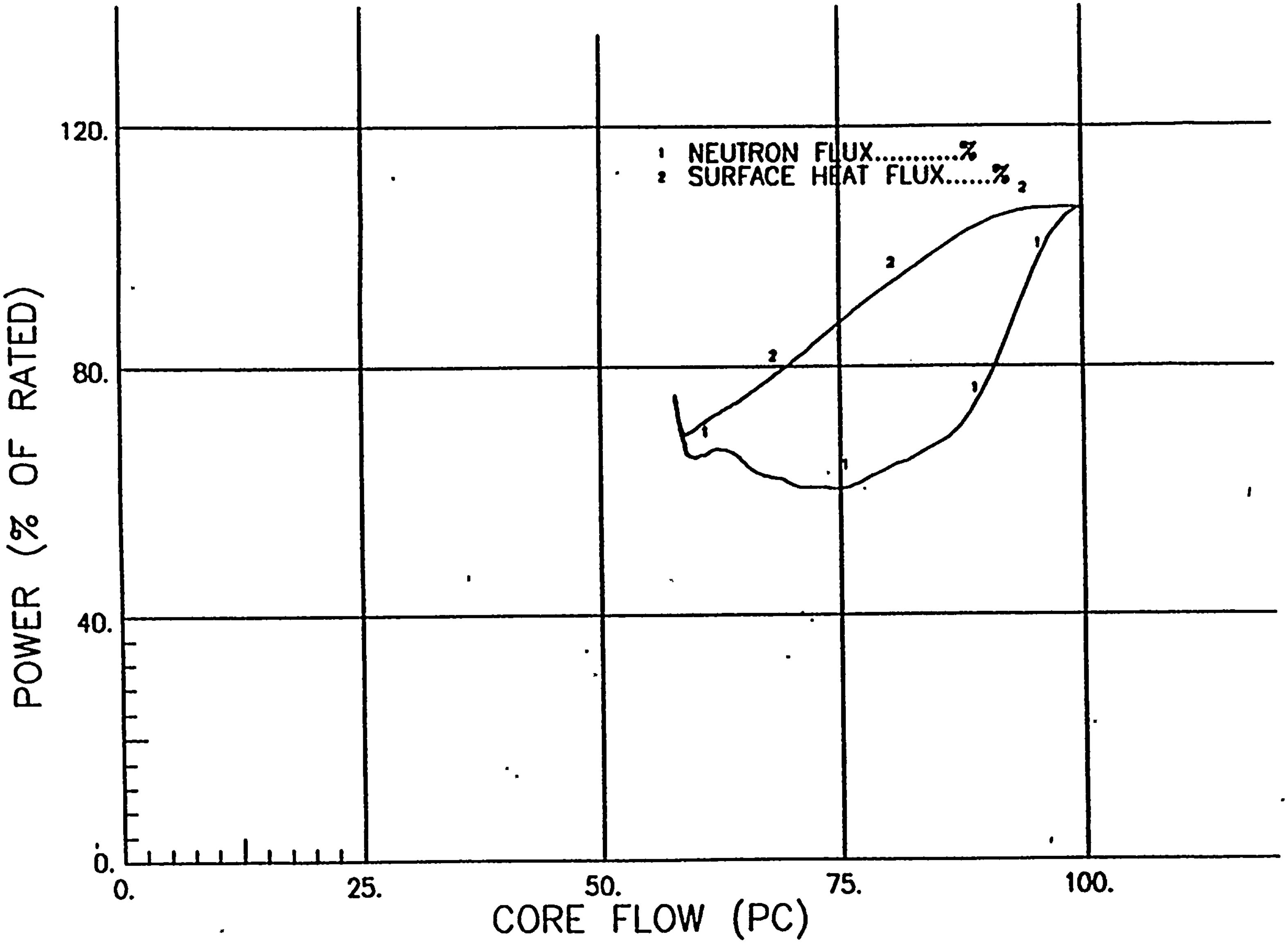
Figure 15.3-1.4



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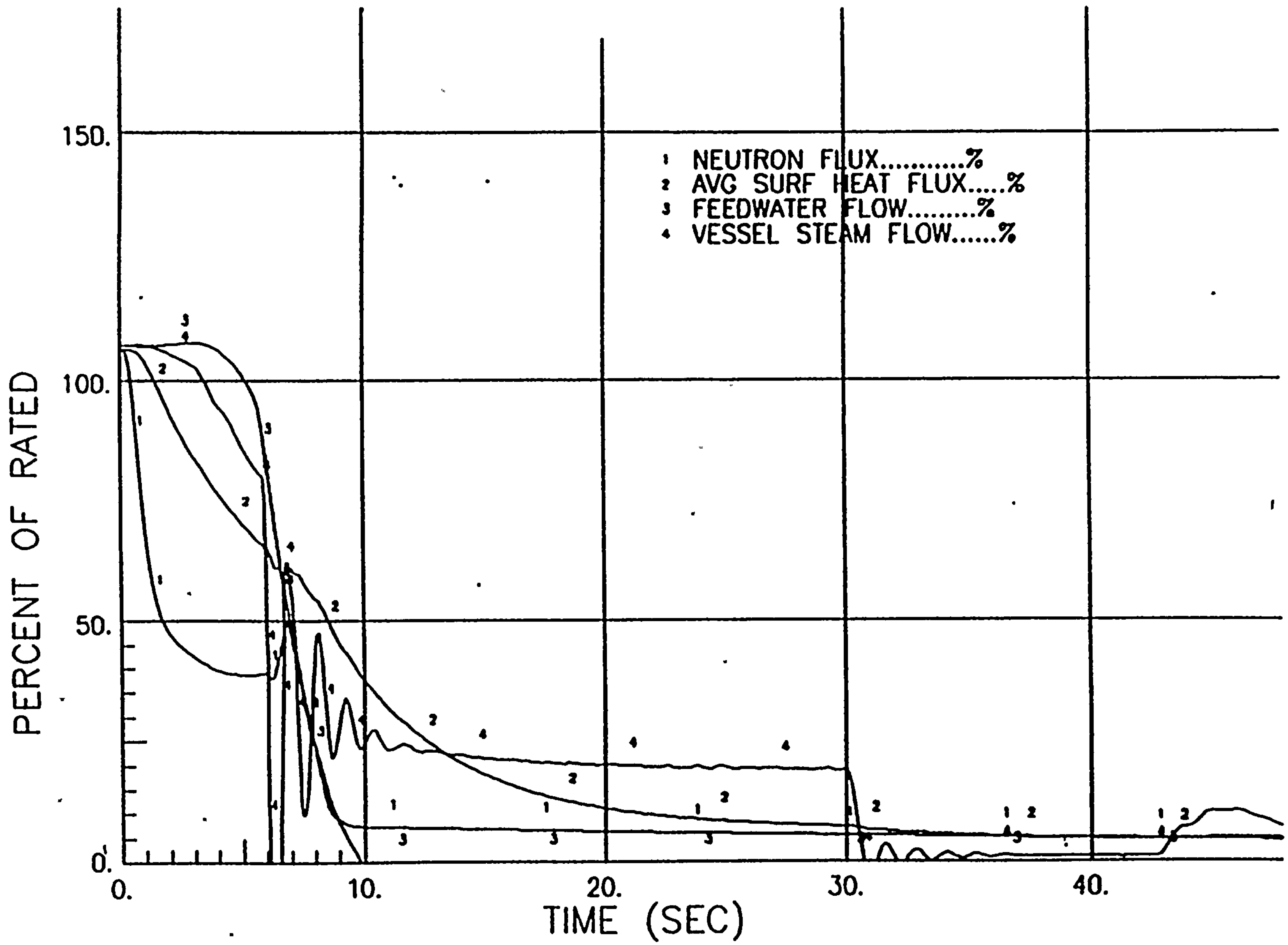
One Recirculation Pump Trip at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-1.5

Amendment 53
November 1998



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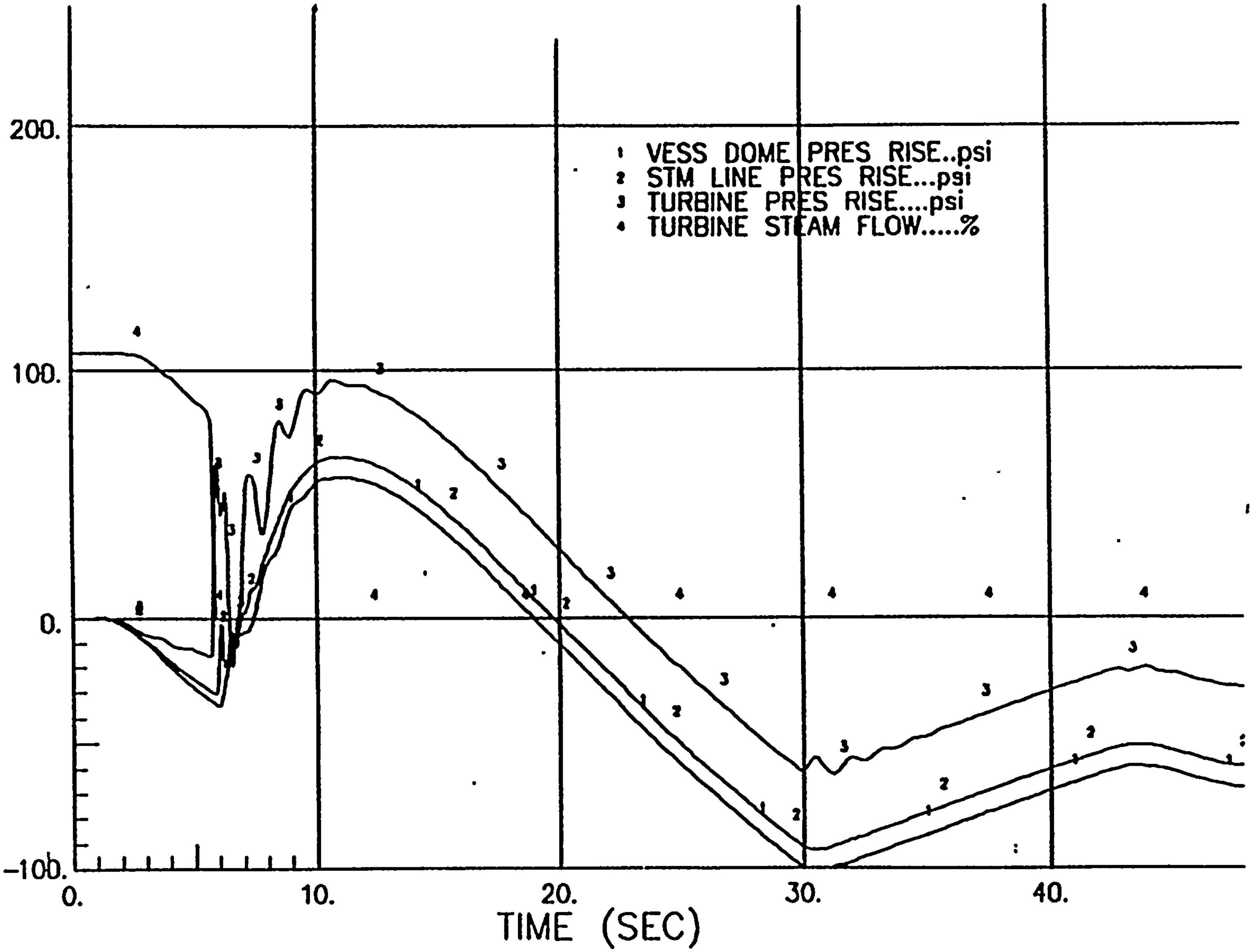
NUCLEAR PLANT 2 FSAR

Two Recirculation Pump Trip at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-2.1



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Two Recirculation Pump Trip at 106.2% Uprated Power, 100% Flow

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		15.3-2.2

Amendment 53
November 1998

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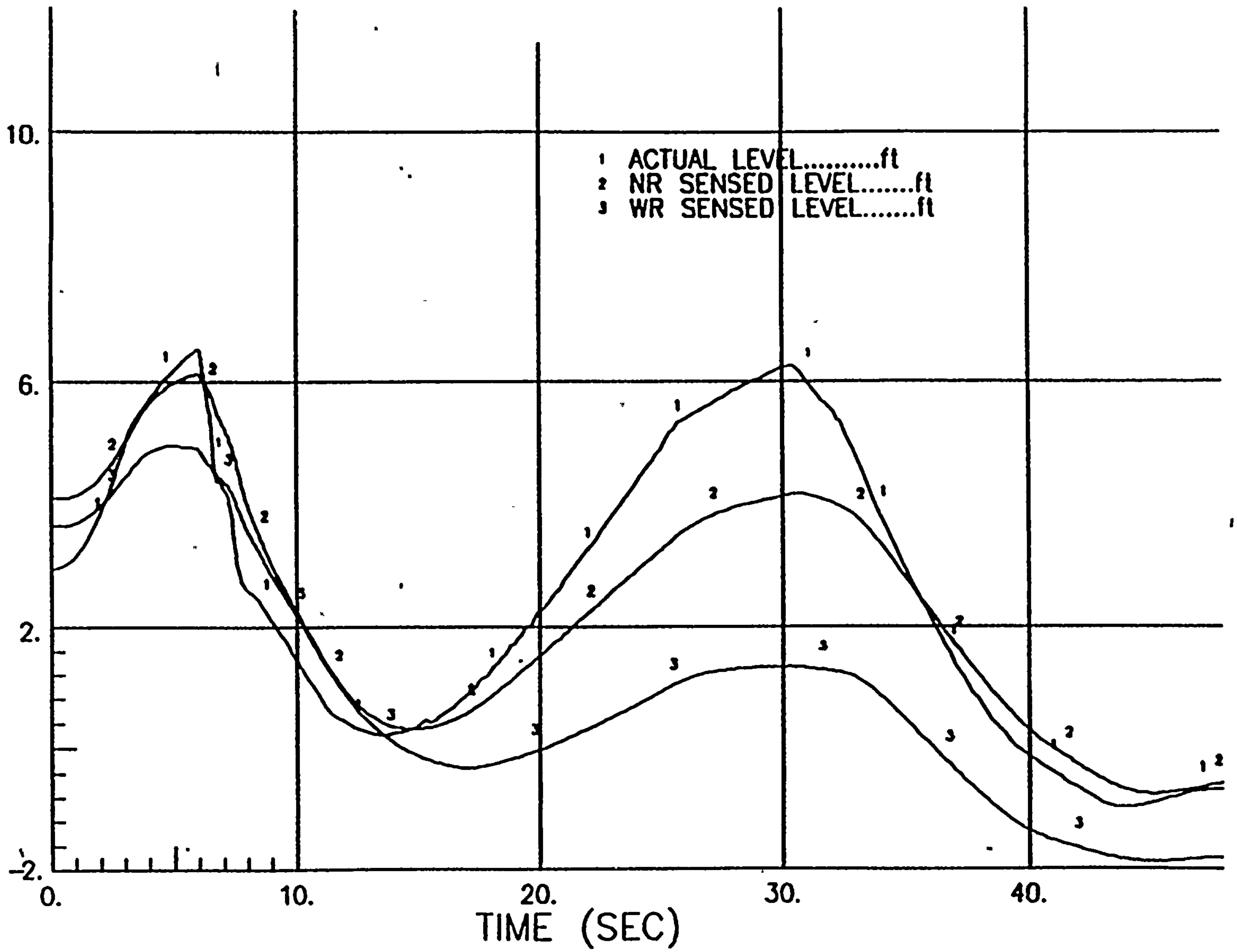

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Two Recirculation Pump Trip at 106.2%
Uprated Power, 100% Flow

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		15.3-2.3

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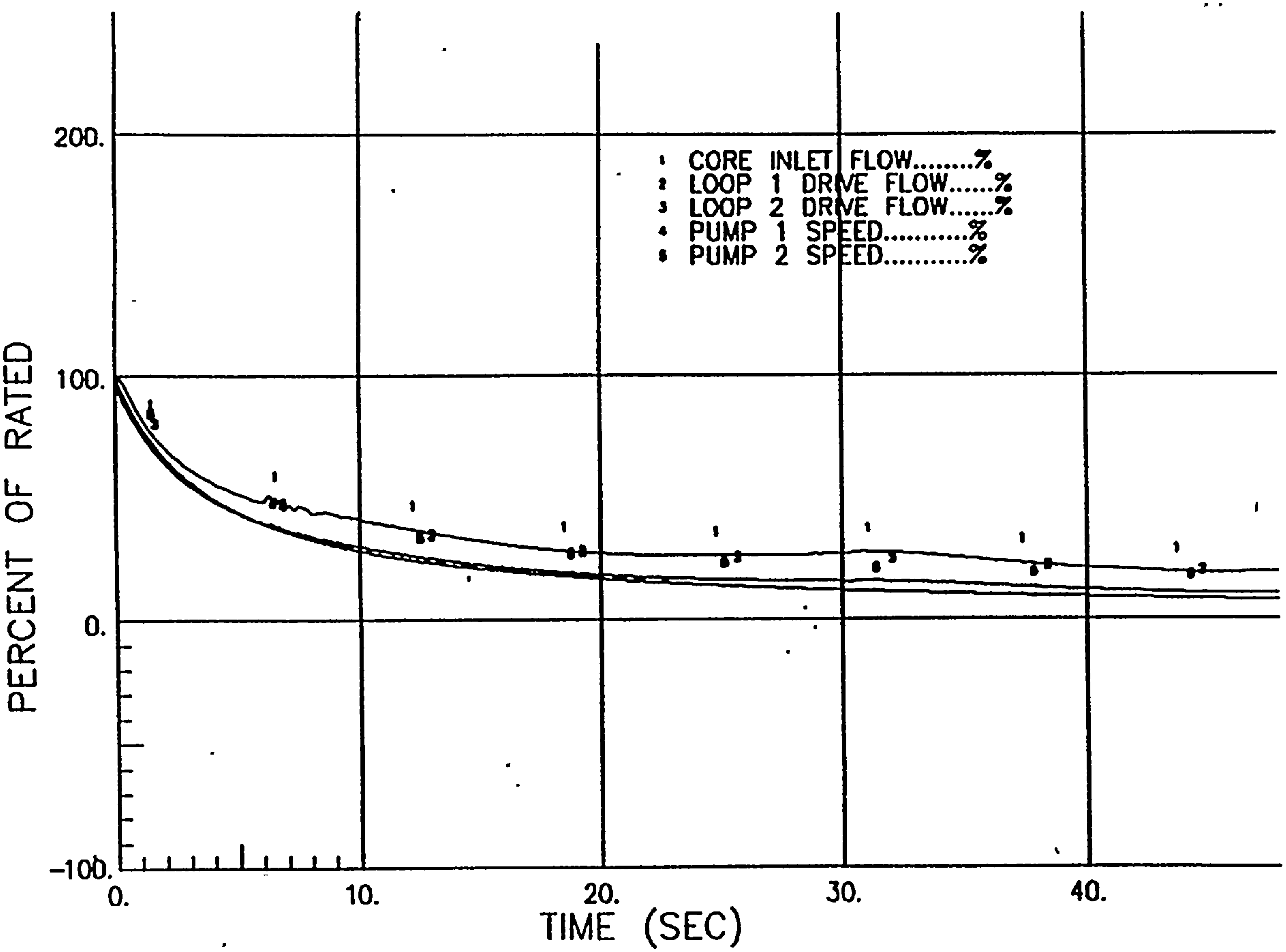

Two Recirculation Pump Trip at 106.2%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-2.4

Amendment 53
November 1998

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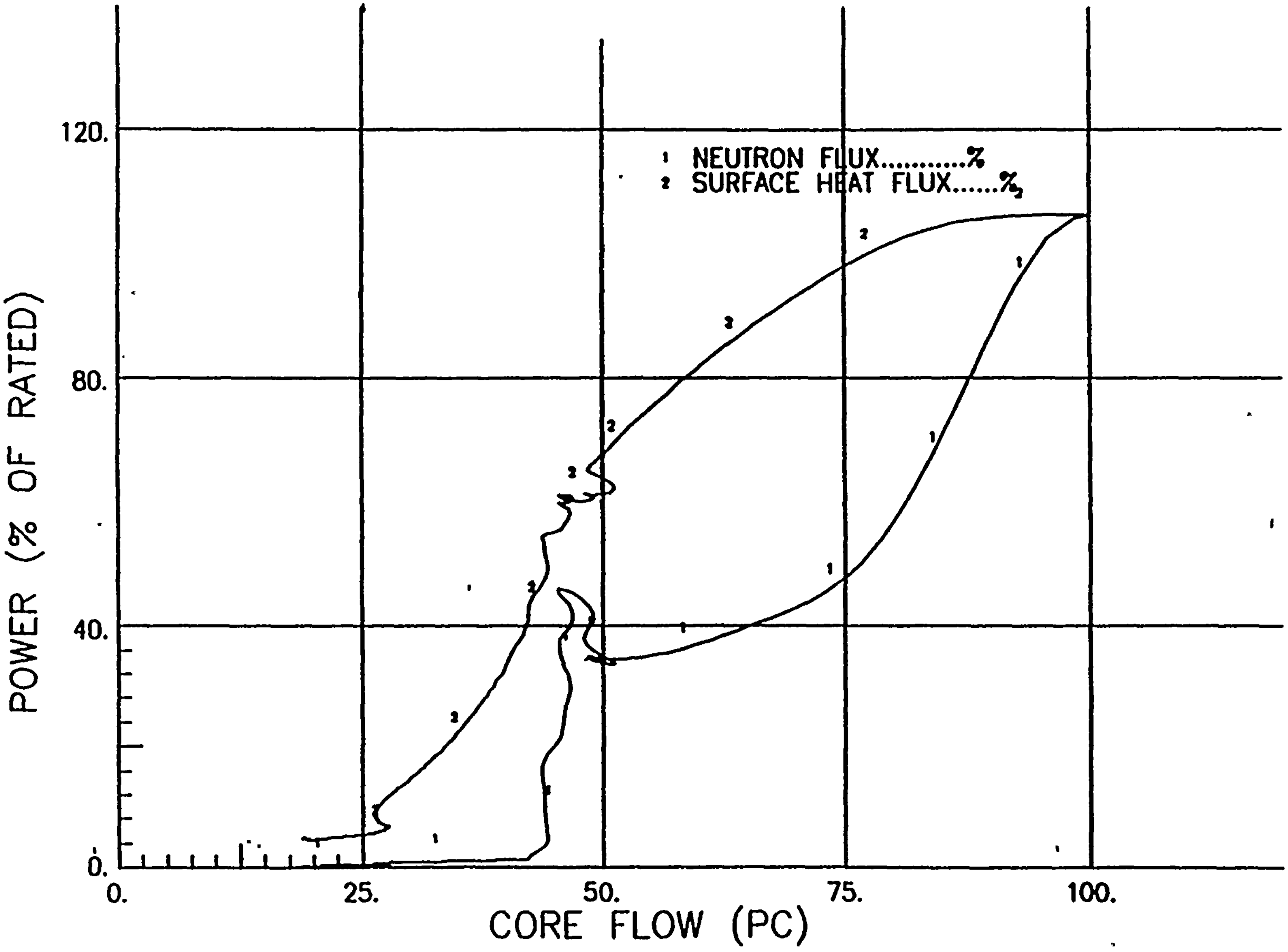

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Two Recirculation Pump Trip at 106.2% Uprated Power, 100% Flow

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Figure 15.3-2.5

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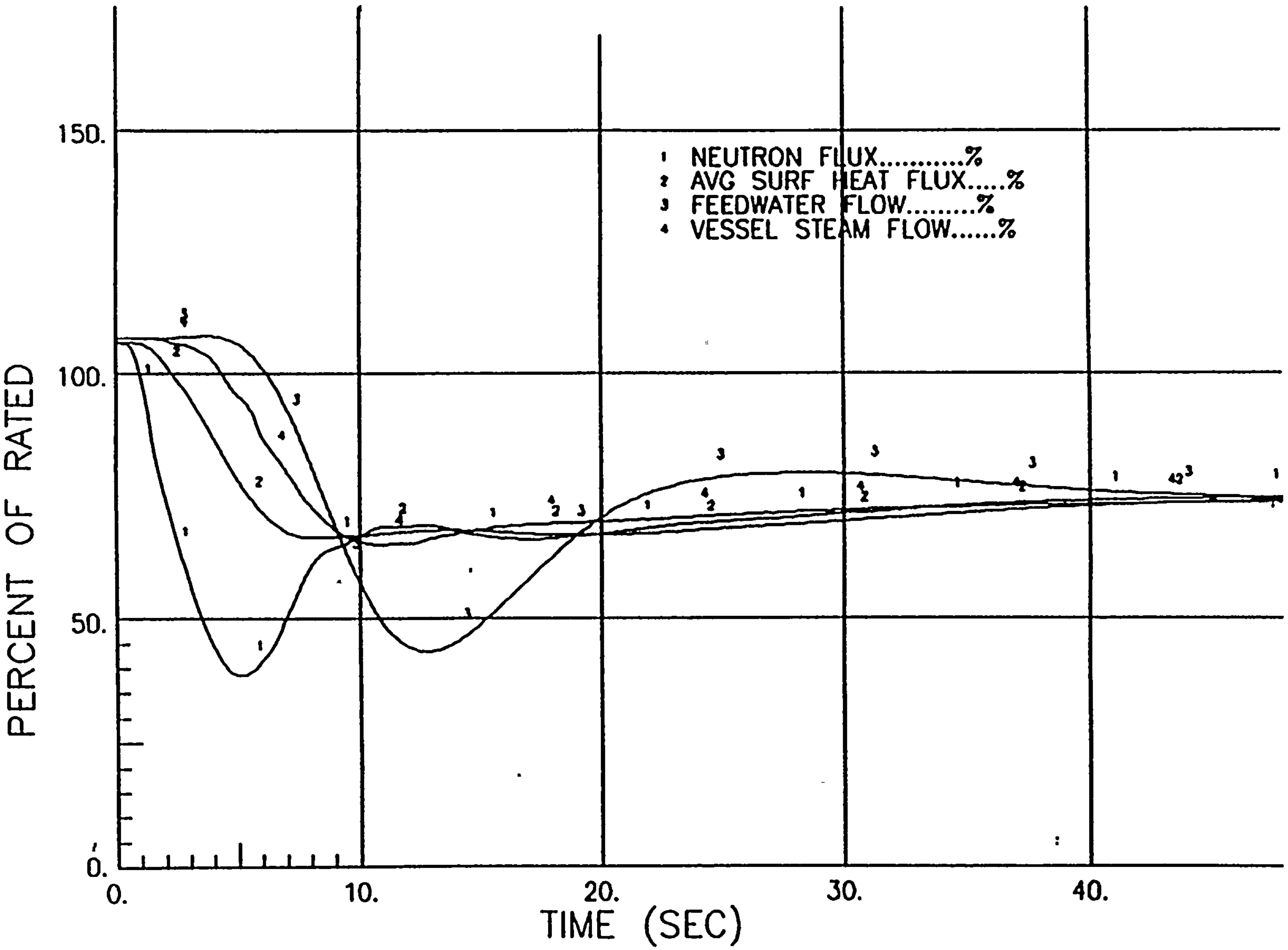

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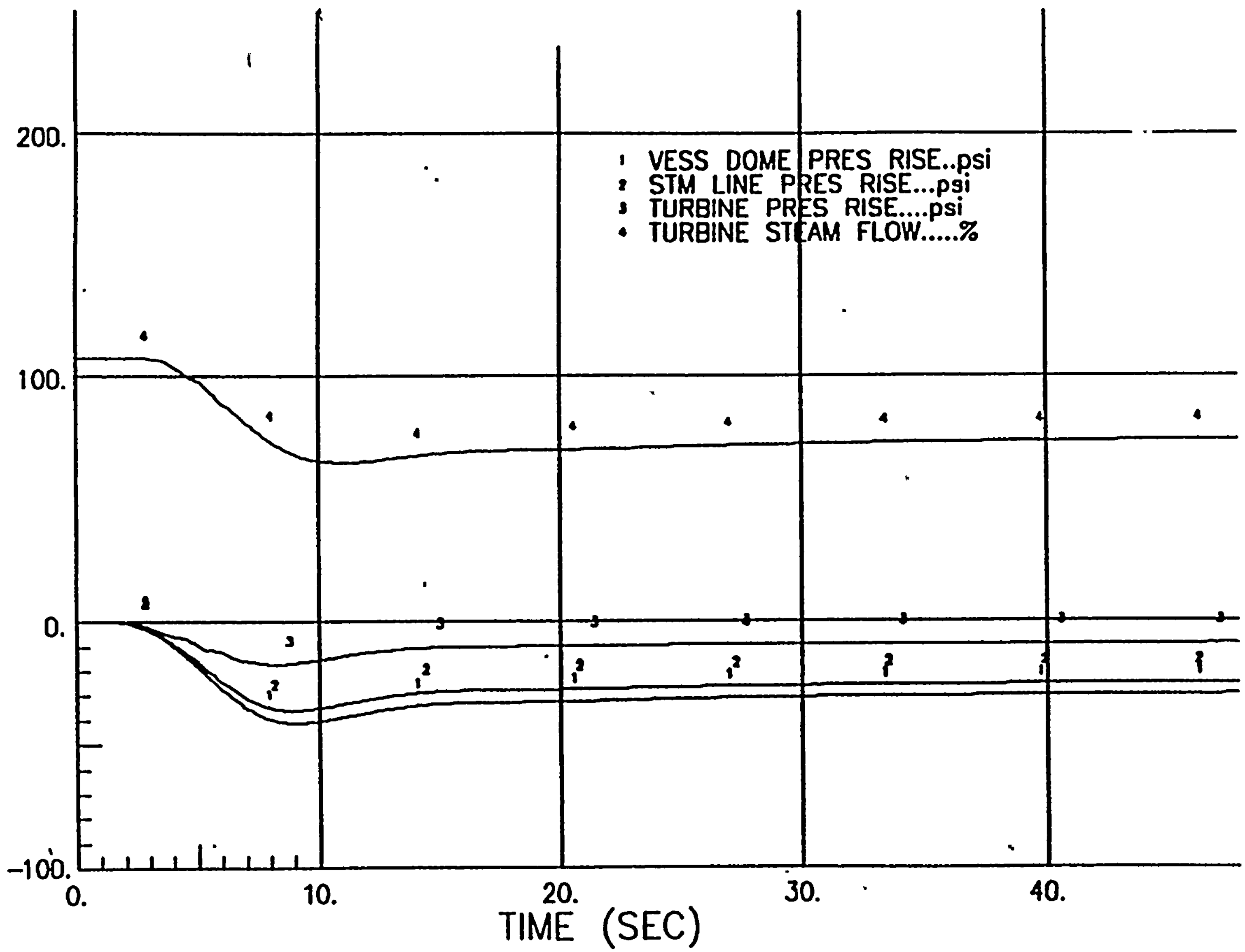
Recirculation Flow Control Failure - Decreasing Flow in One Loop at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-3.1

Amendment 53
November 1998



Recirculation Flow Control Failure - Decreasing Flow in One Loop at 106.2% Uprated Power, 100% Flow

Draw. No.

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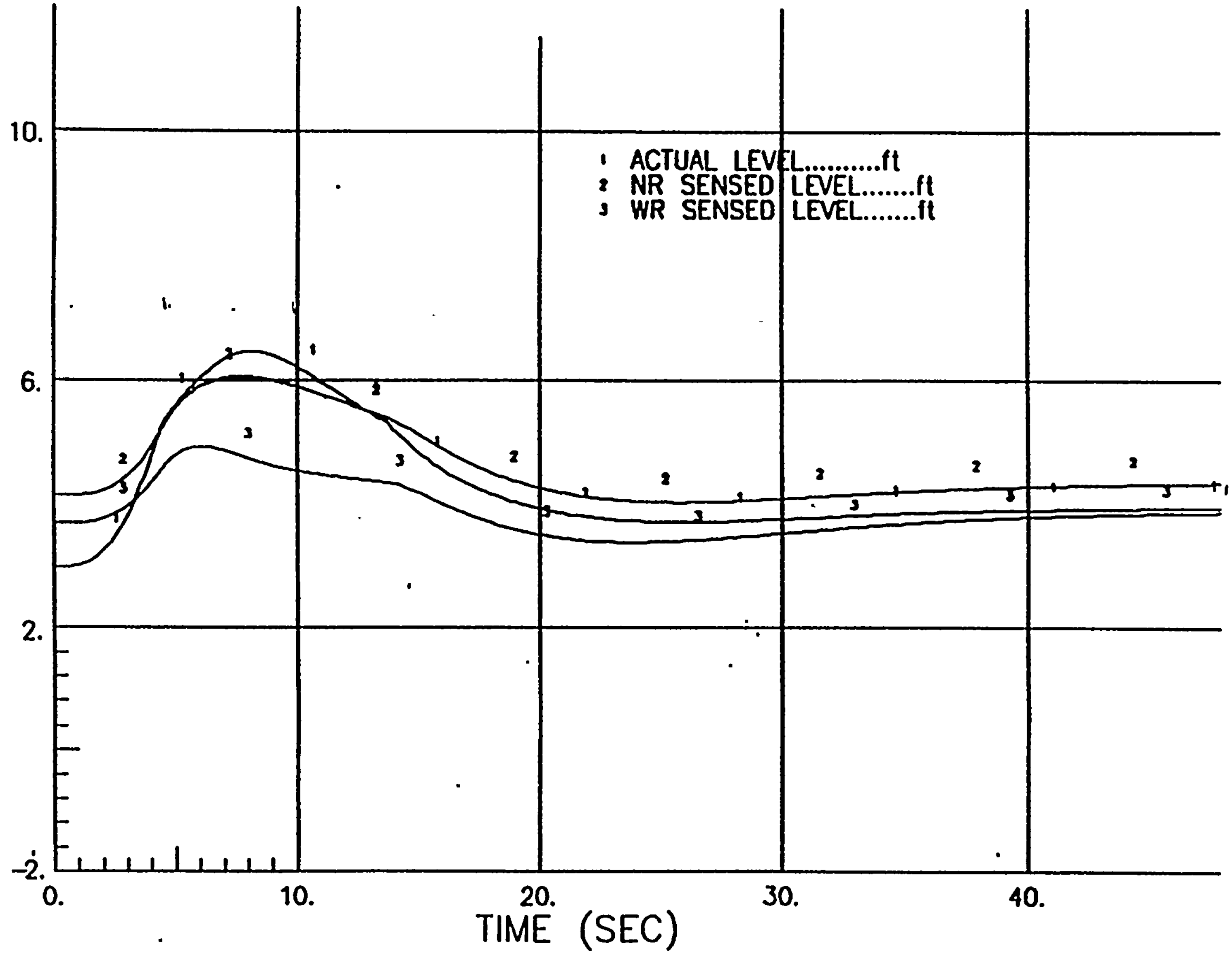
Figure 15.3-3.2



Recirculation Flow Control Failure - Decreasing Flow in One Loop at 106.2% Uprated Power, 100% Flow

Draw. No. | Rev. | Figure 15.3-3.3

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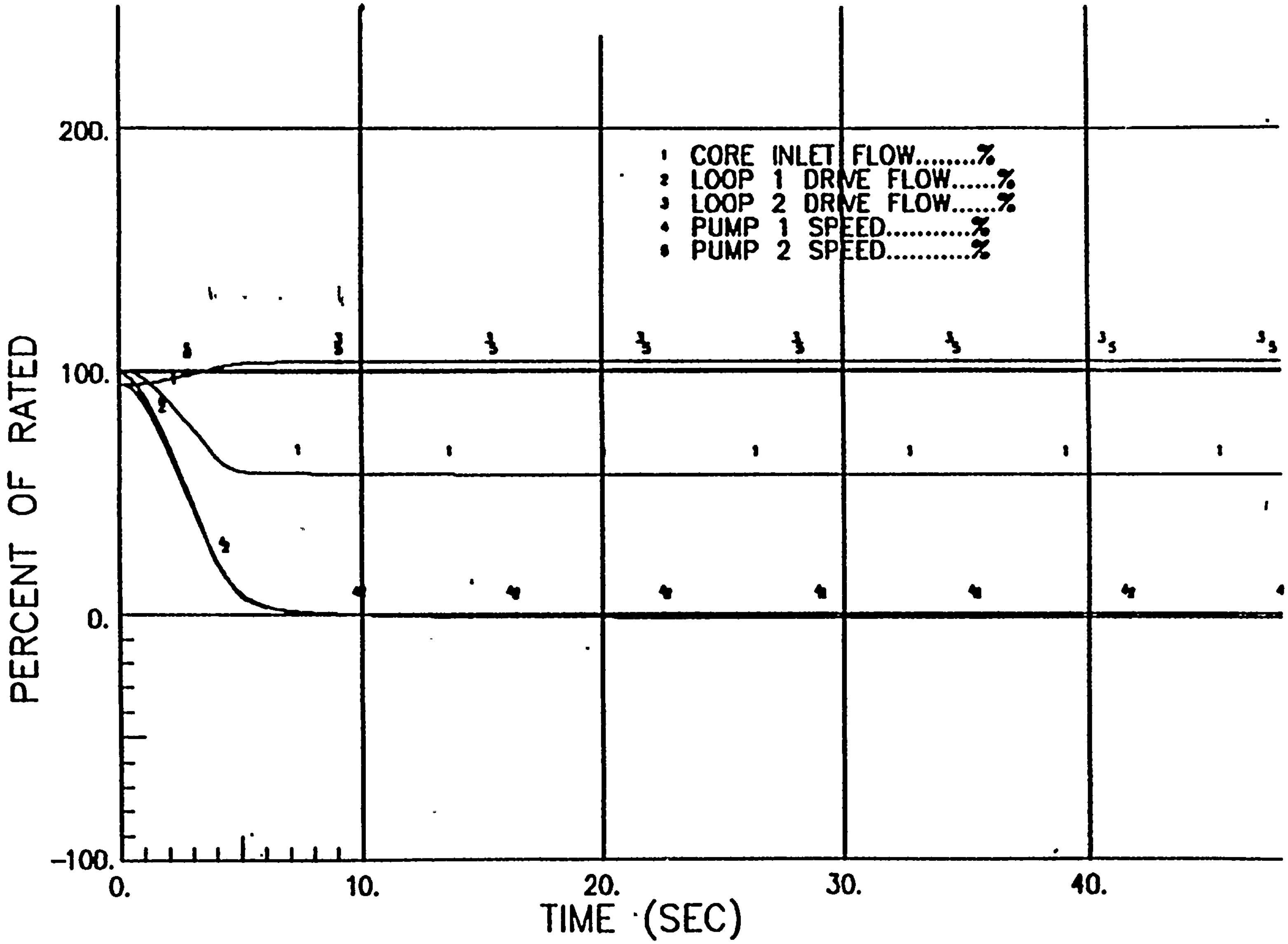

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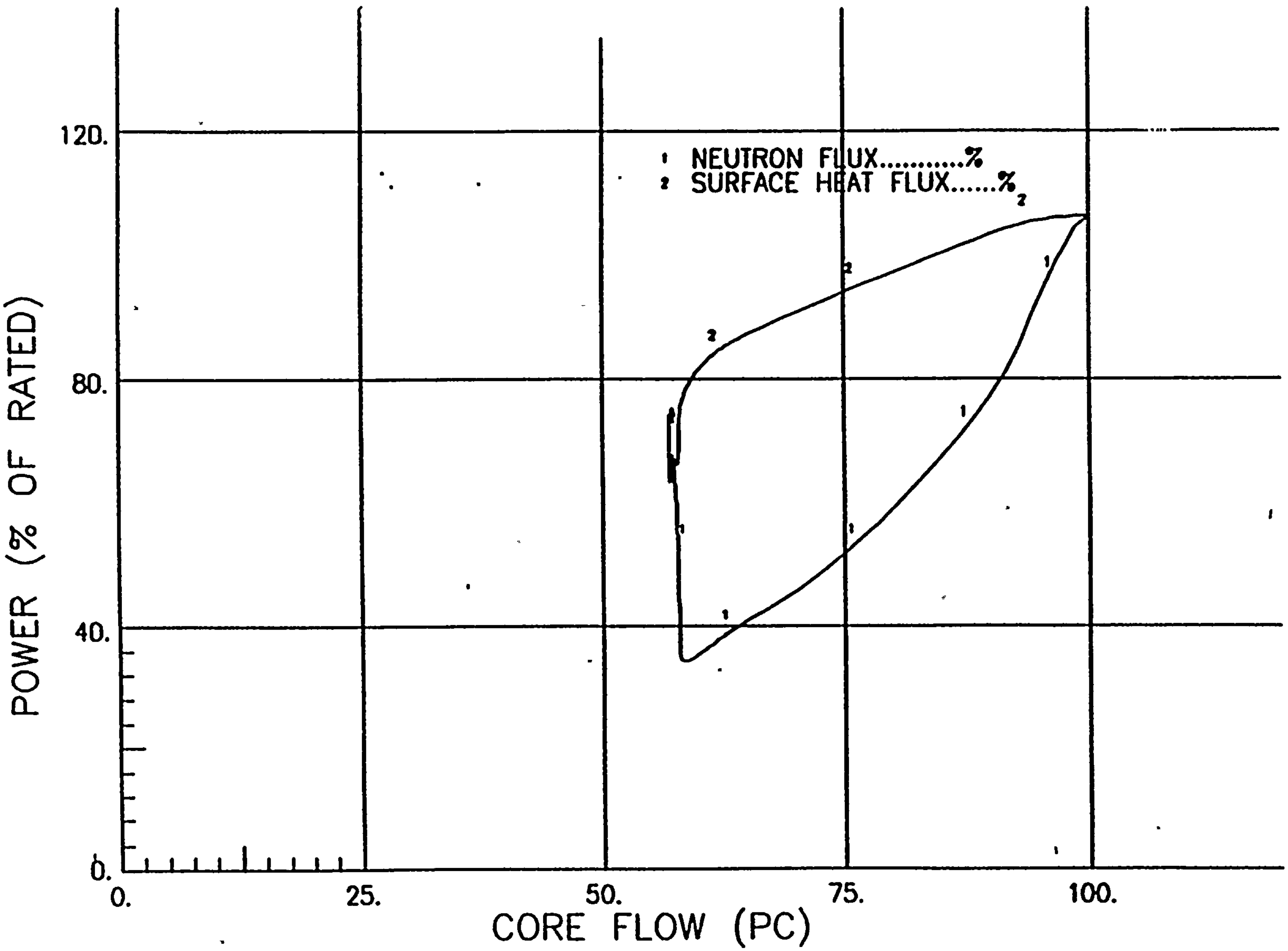
Recirculation Flow Control Failure - Decreasing Flow in One Loop at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-3.4

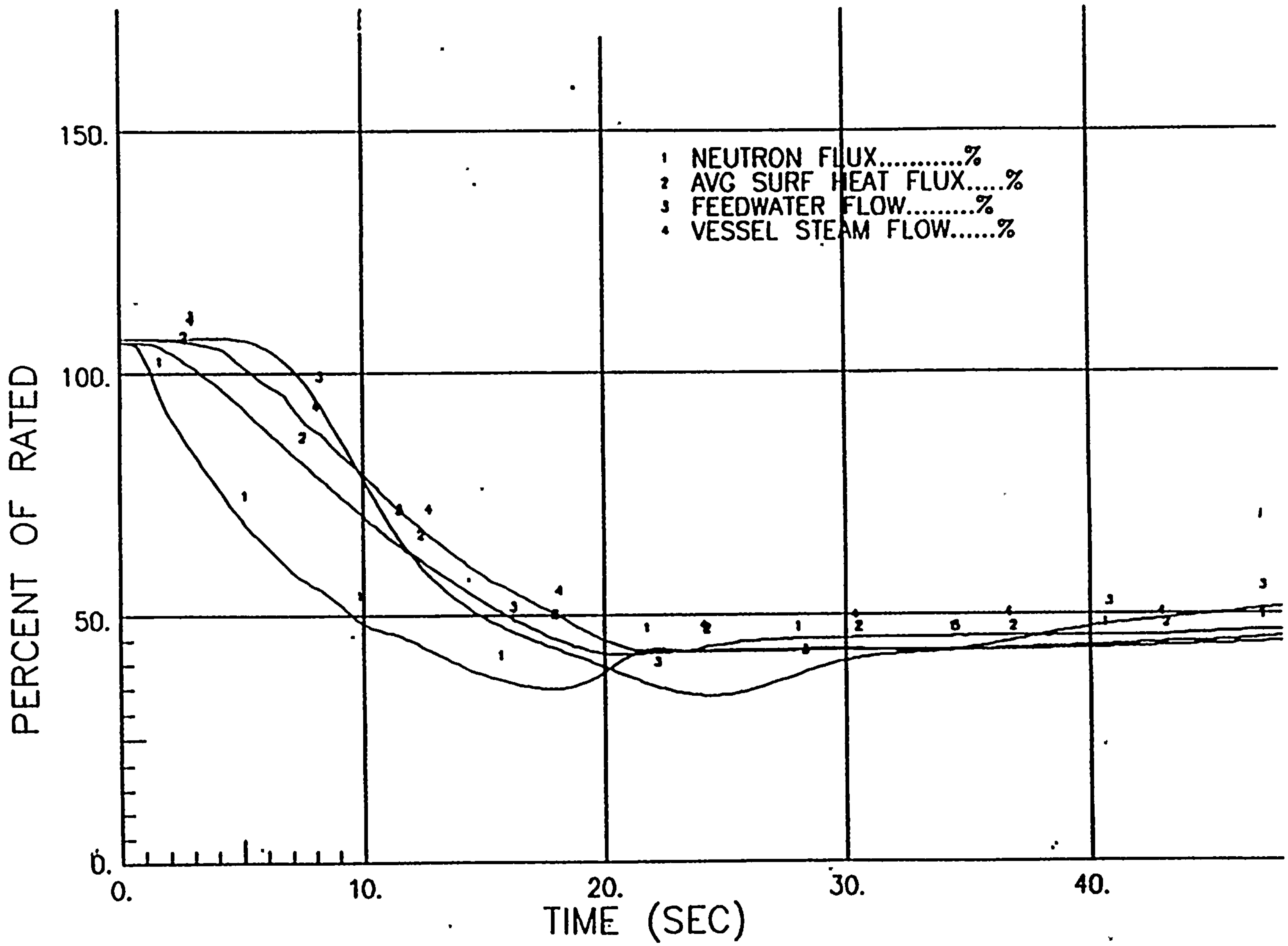


Recirculation Flow Control Failure - Decreasing Flow in One Loop at 106.2% Uprated Power, 100% Flow

Draw. No.

Rev.

Figure 15.3-3.5



Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-4.1

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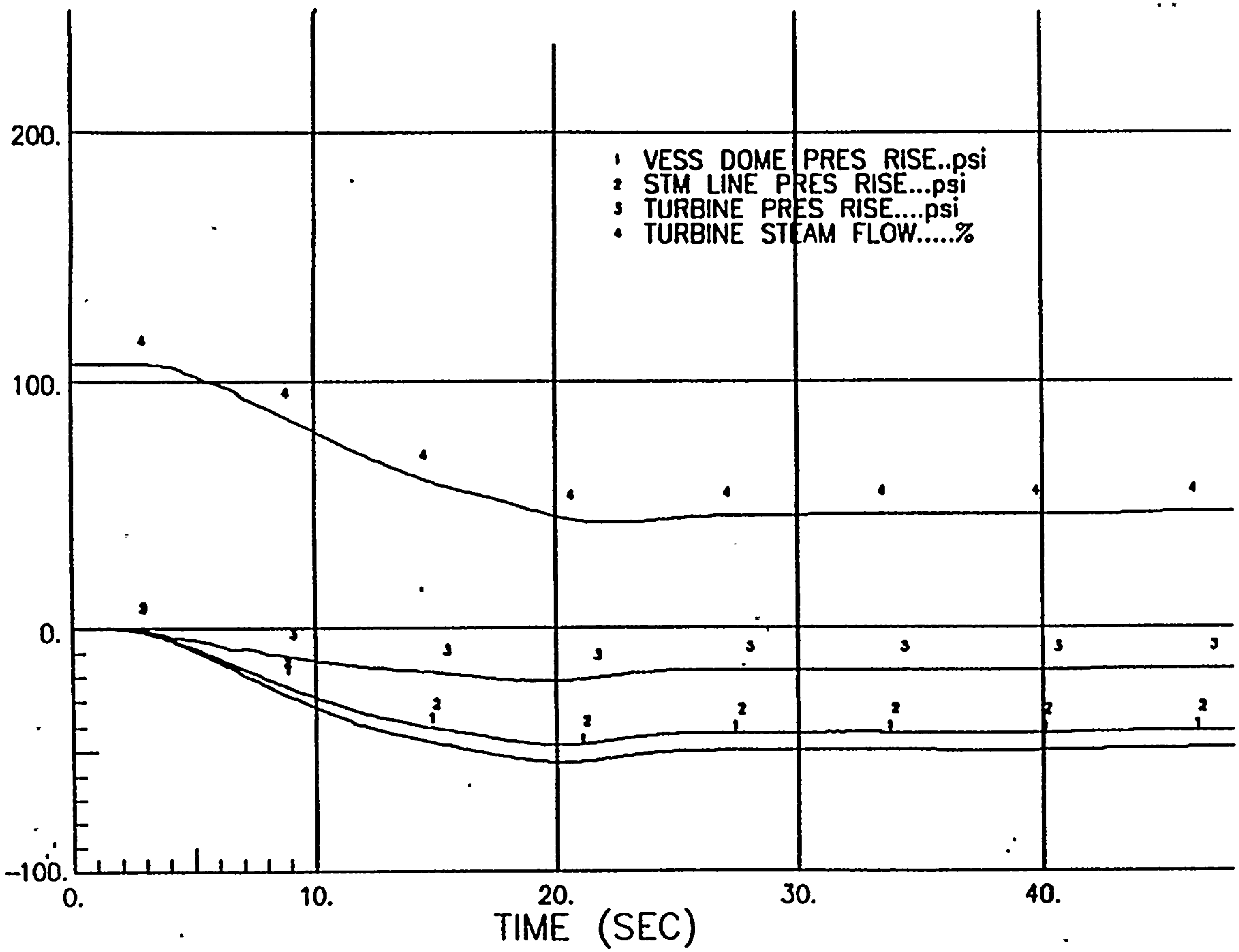

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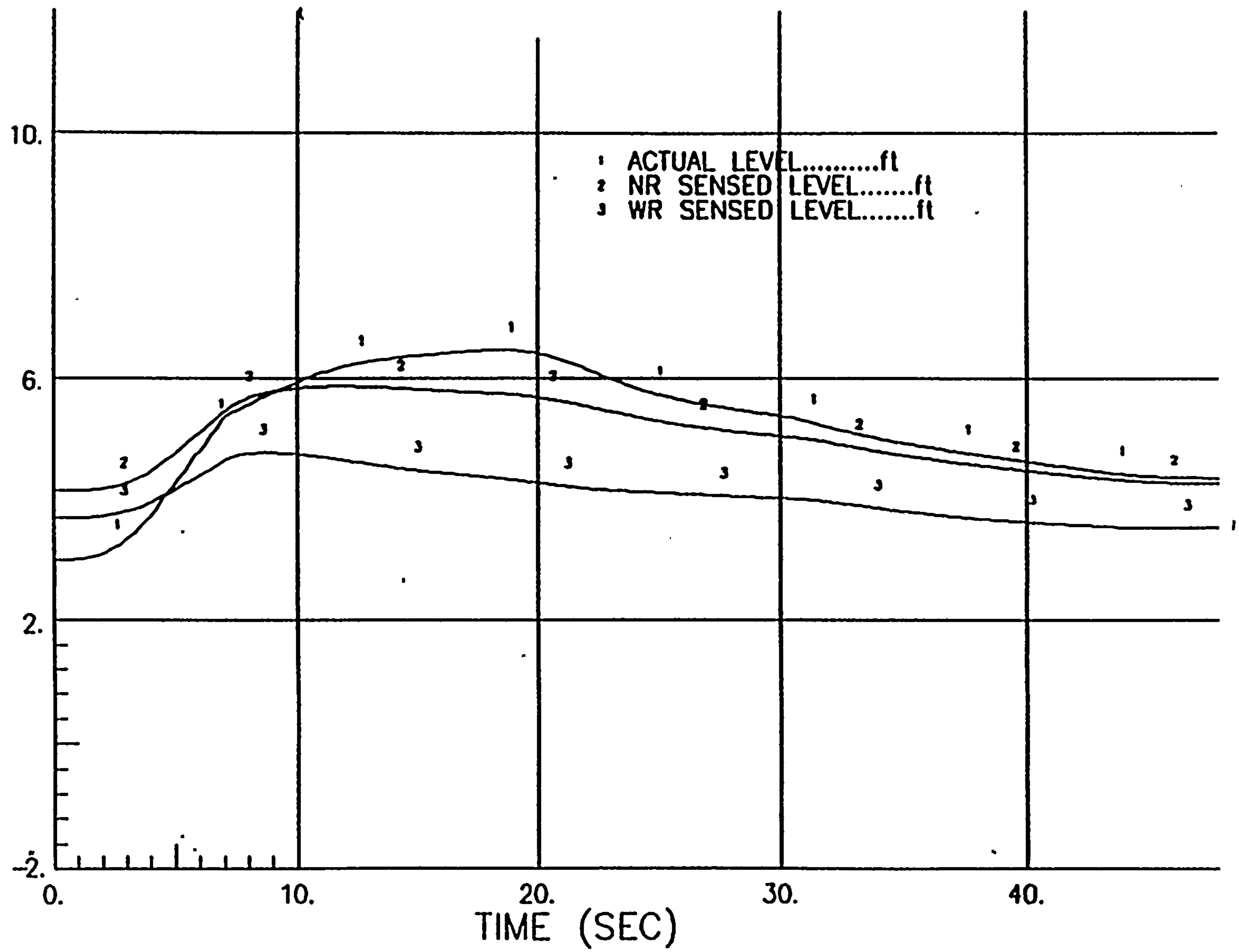
Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-4.2

Form No. 960690



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Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-4.3

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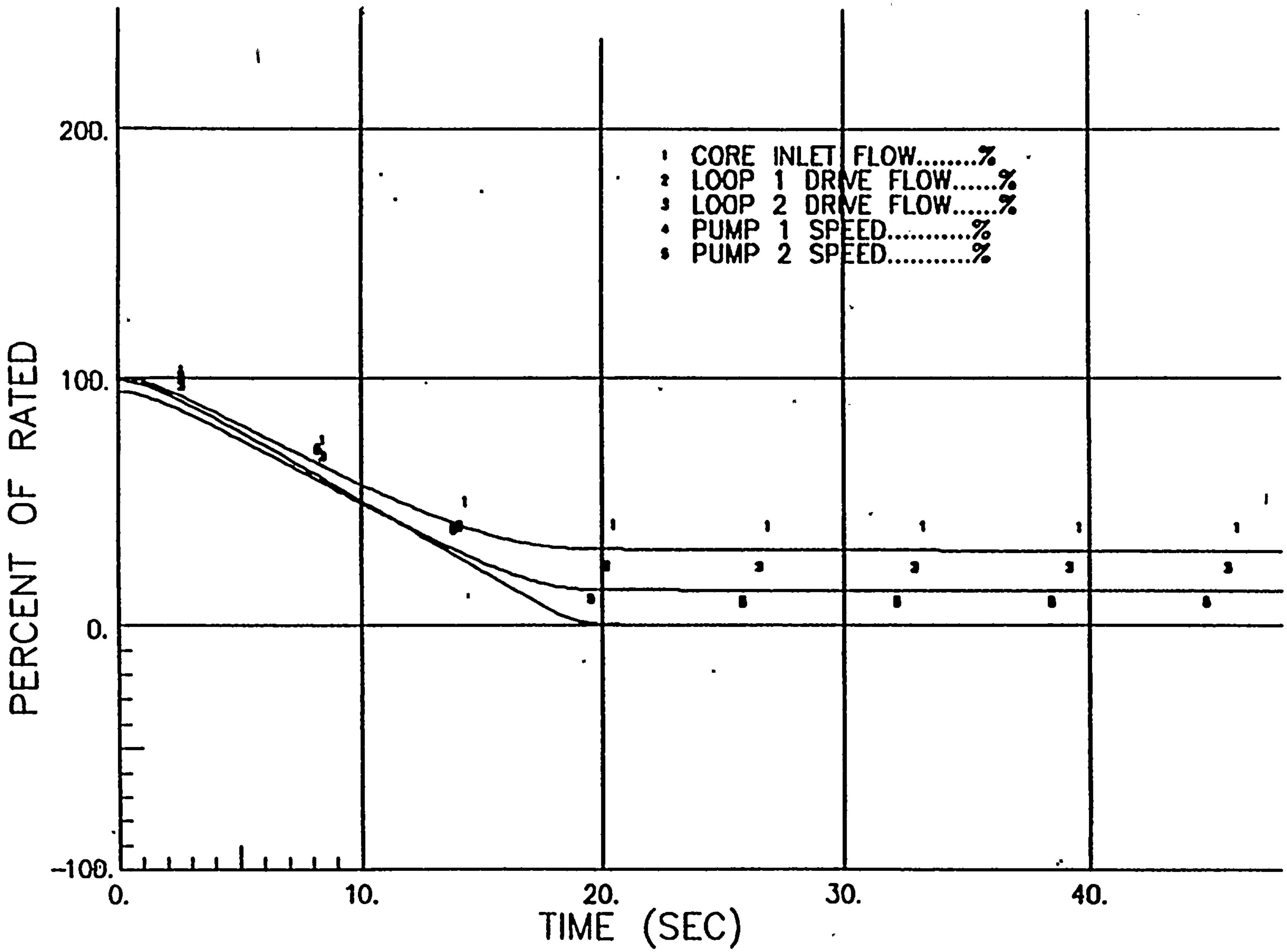
Form No. 960690



Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-4.4

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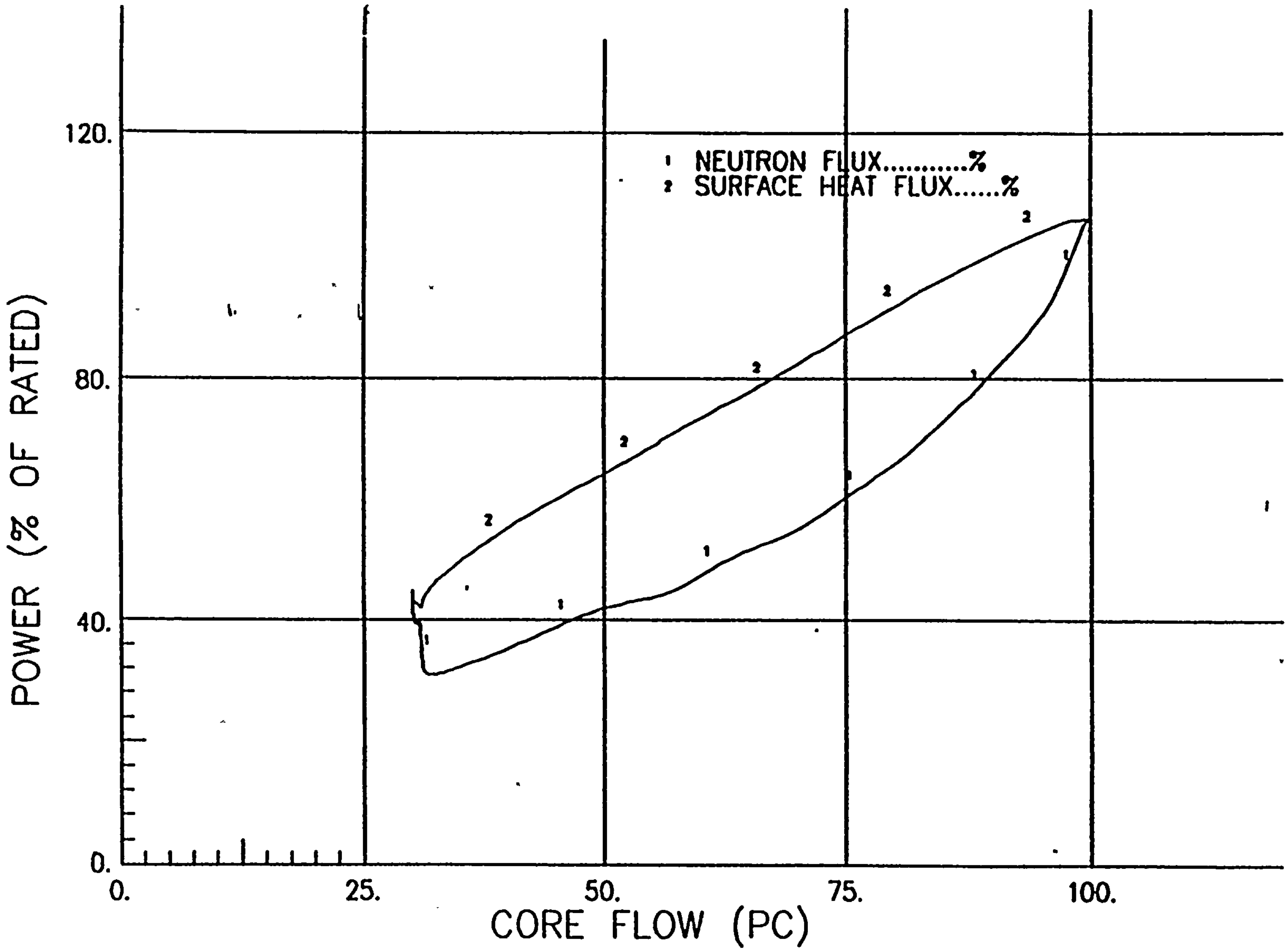
Form No. 960690



Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-4.5

Amendment 53
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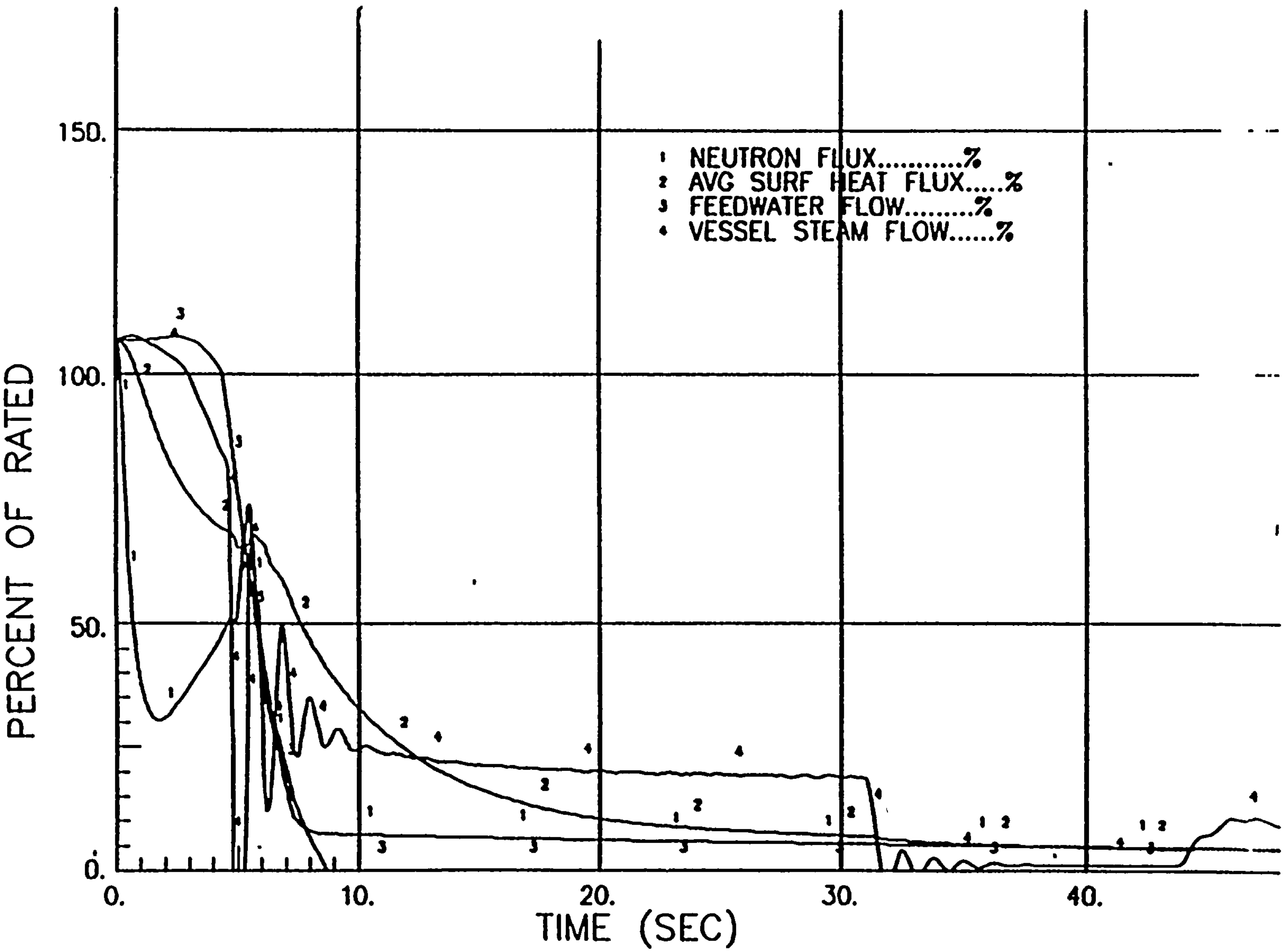

Recirculation Pump Seizure at 106% Uprated Power, 100% Flow

Draw. No.

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Figure 15.3-5.1

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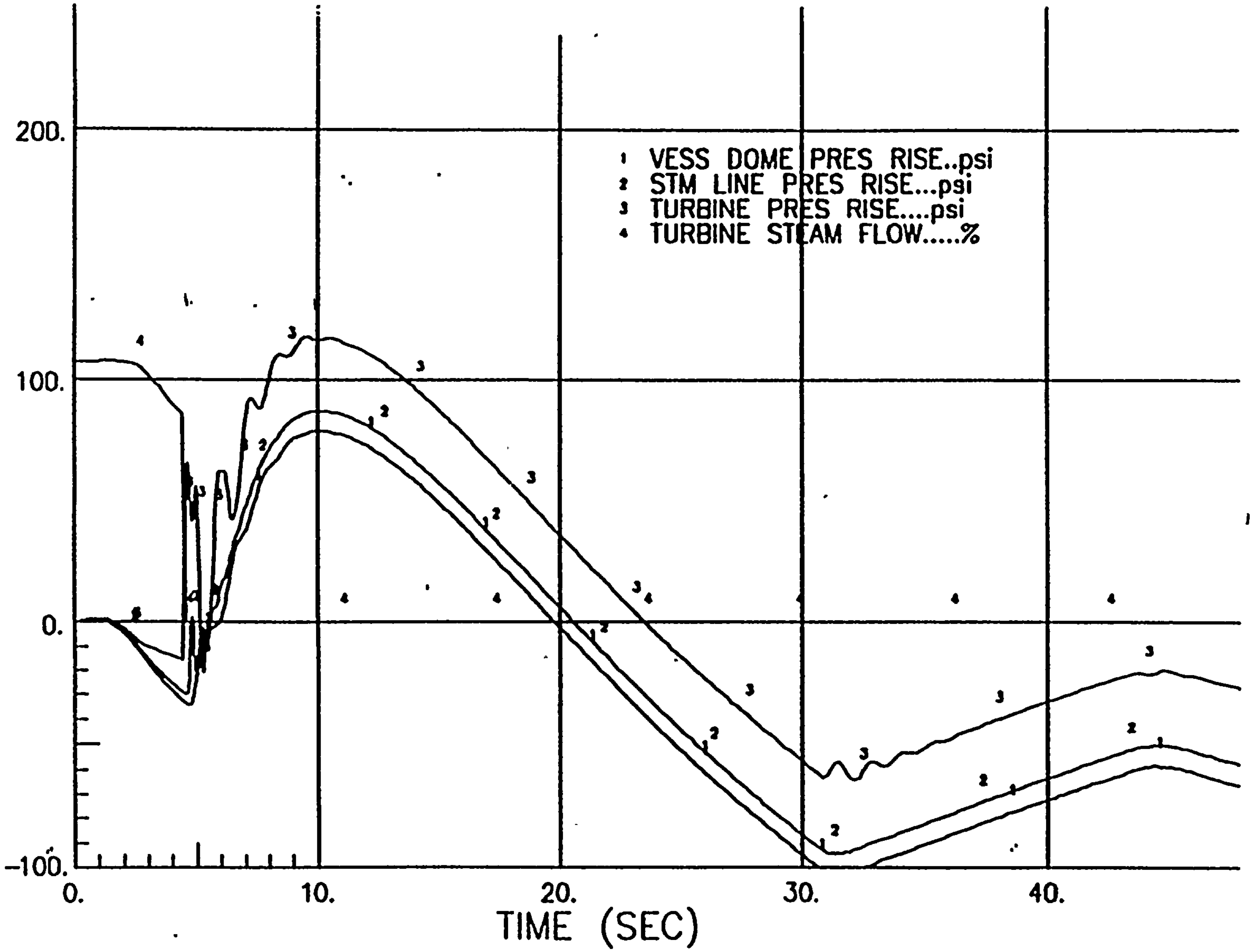

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Recirculation Pump Seizure at 106% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-5.2

Amendment 53
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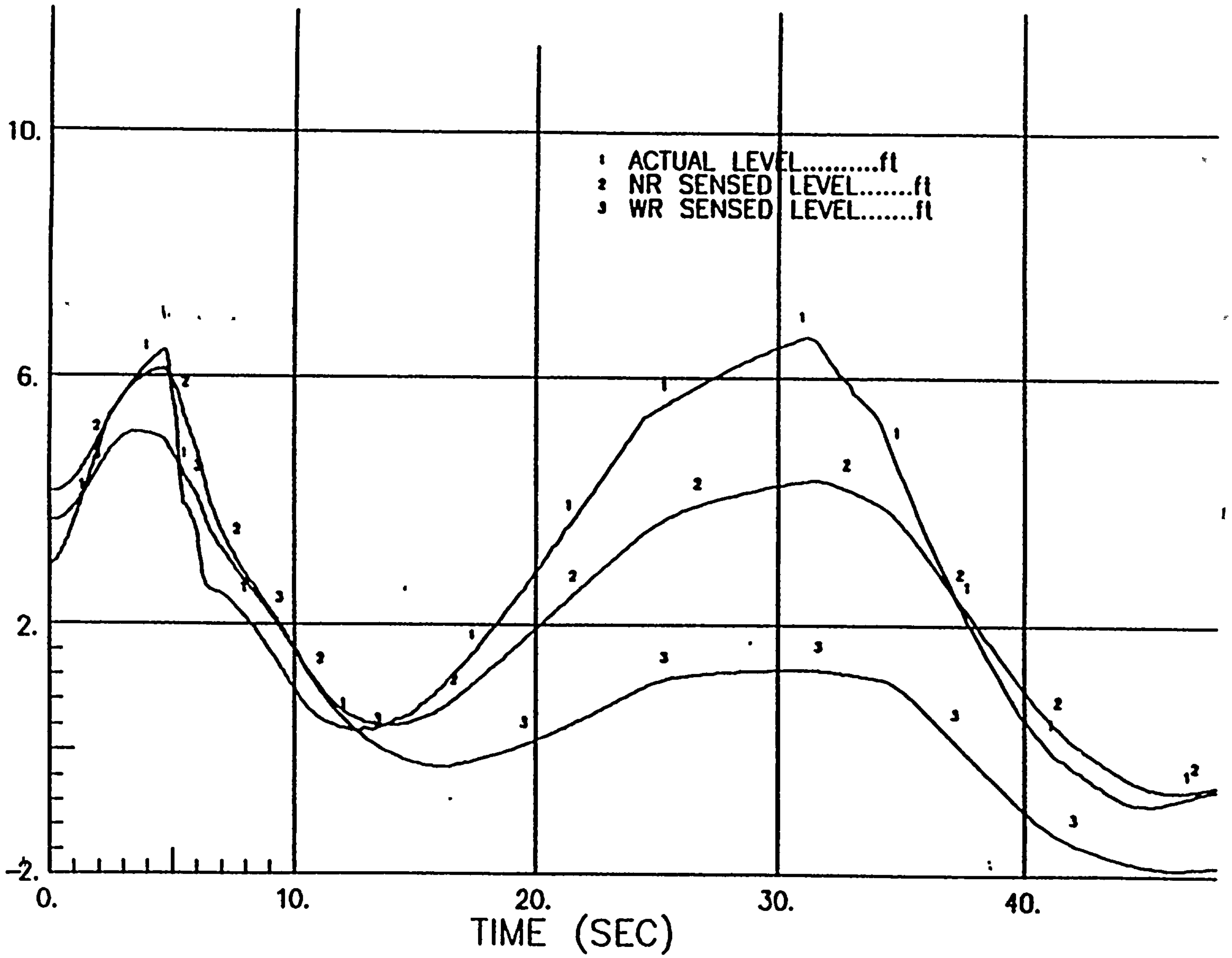

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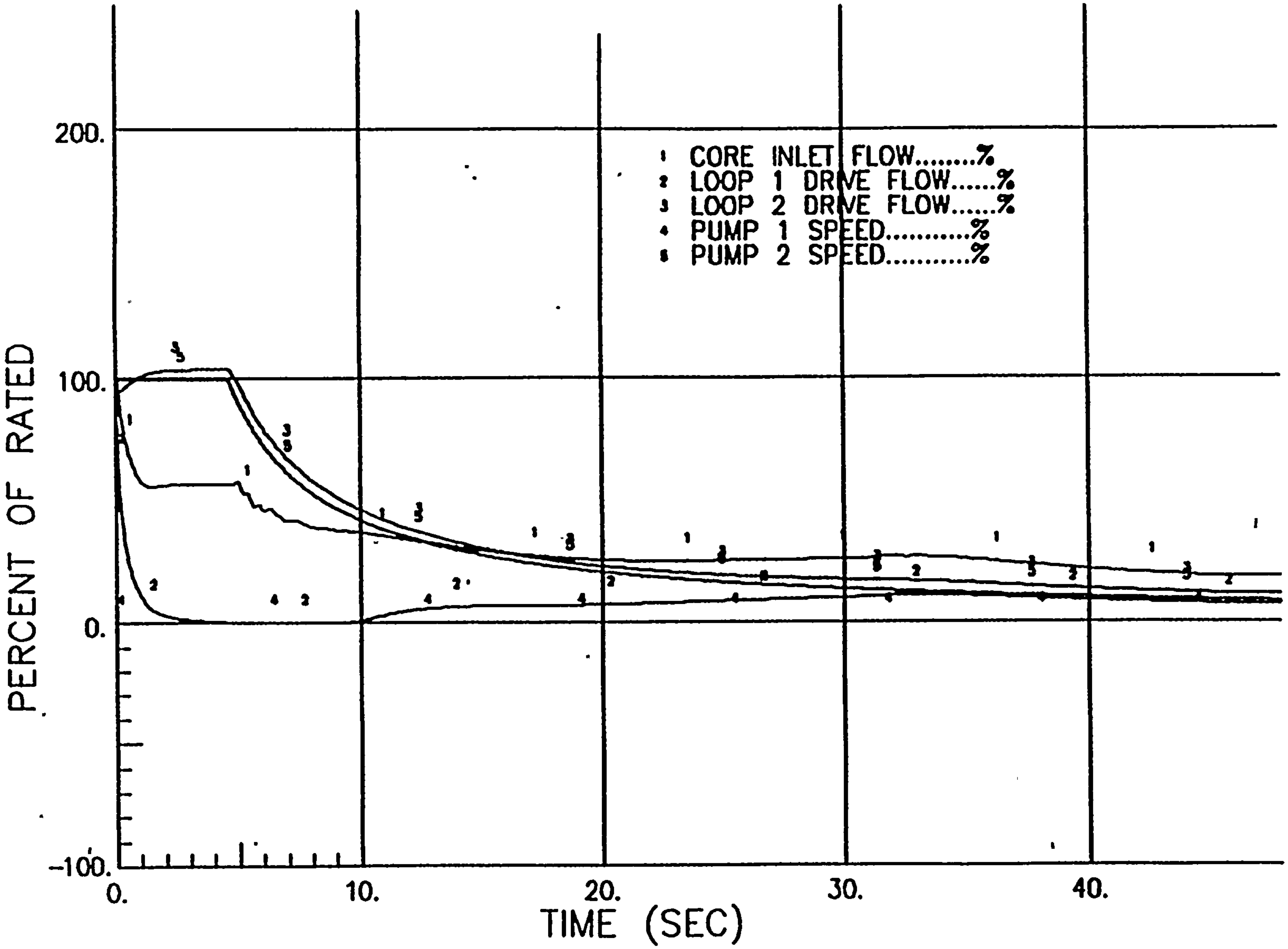
Recirculation Pump Seizure at 106%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-5.3

Form No. 960690



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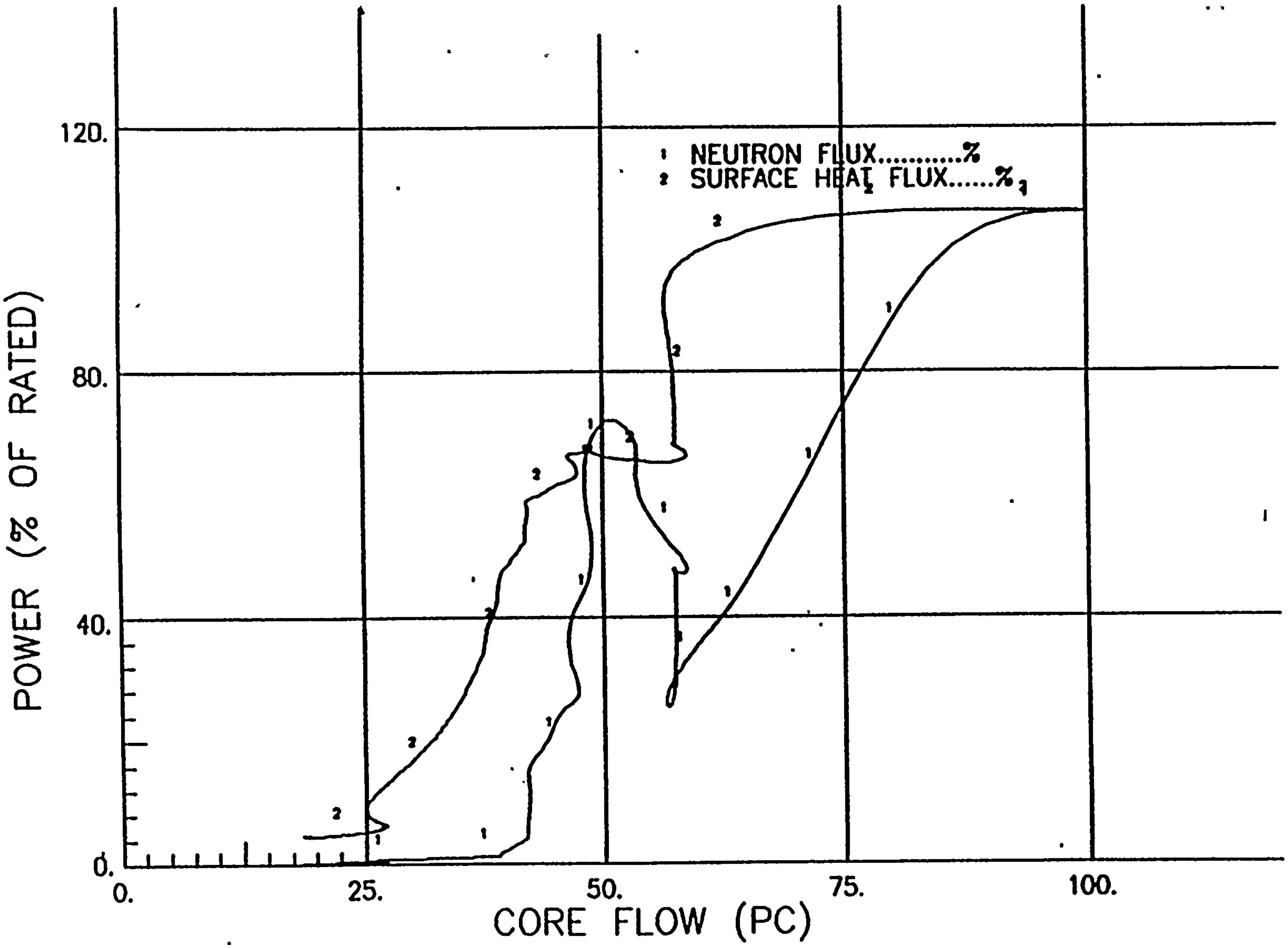
Recirculation Pump Seizure at 106% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-5.4



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Recirculation Pump Seizure at 106%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.3-5.5

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15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

15.4.1 ROD WITHDRAWAL ERROR - LOW POWER

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis was performed at the time of power uprate.

15.4.1.1 Control Rod Removal Error During Refueling

15.4.1.1.1 Identification of Causes and Frequency Classification

The event considered is inadvertent criticality due to the complete withdrawal or removal of the most reactive rod during refueling. The probability of the initial causes alone is considered low enough to warrant its being categorized as an infrequent incident since there is no postulated set of circumstances which results in an inadvertent rod withdrawal error (RWE) while in the refuel mode.

15.4.1.1.2 Sequence of Events and Systems Operation

15.4.1.1.2.1 Initial Control Rod Removal. During refueling operations, safety system interlocks provide assurance that inadvertent criticality does not occur because a control rod was removed or is withdrawn in coincidence with another control rod.

15.4.1.1.2.2 Fuel Insertion With Control Rod Removed. To minimize the possibility of loading fuel into a cell containing no control rod, it is required that all control rods are fully inserted when fuel is being loaded into the core. This requirement is backed up by refueling interlocks on rod withdrawal and movement of the refueling platform. When the mode switch is in the "REFUEL" position, the interlocks prevent the platform from being moved over the core if a control rod is withdrawn and fuel is on the hoist. Likewise, if the refueling platform is over the core and fuel is on the hoist, control rod motion is blocked by the interlocks.

15.4.1.1.2.3 Second Control Rod Removal. When the platform is not over the core (or fuel is not on the hoist) and the mode switch is in the "REFUEL" position, only one control rod can be withdrawn. Any attempt to withdraw a second rod results in a rod block by the refueling interlocks.

Since the core is designed to meet shutdown requirements with the highest worth rod withdrawn, the core remains subcritical even with one rod withdrawn.

15.4.1.1.2.4 Control Rod Removal Without Fuel Removal. The design of the control rod, incorporating the velocity limiter, does not physically permit the upward removal of the control rod without the simultaneous or prior removal of the four adjacent fuel bundles. This precludes any hazardous condition.

15.4.1.1.2.5 Identification of Operator Actions. No operator actions are required to preclude this event since the plant design prevents its occurrence.

15.4.1.1.2.6 Effect of Single Failure and Operator Errors. If any one of the operations involved in initial failure or error is followed by any other single equipment failure or single operator error, the necessary safety actions are taken (e.g., rod block or scram) automatically prior to violation of any limits.

15.4.1.1.3 Core and System Performances

Since the probability of inadvertent criticality during refueling is precluded, the core and system performances were not analyzed. The withdrawal of the highest worth control rod during refueling will not result in criticality. This is verified experimentally by performing shutdown margin checks. Additional reactivity insertion is precluded by interlocks. As a result, no radioactive material is released from the fuel, making it unnecessary to assess any radiological consequences.

No mathematic models are involved in this event. The need for input parameters or initial conditions is not required as there are no results to report. Consideration of uncertainties is not appropriate.

15.4.1.1.4 Barrier Performance

An evaluation of the barrier performance was not made for this event since it is a highly localized event and does not result in any change in the core pressure or temperature.

15.4.1.1.5 Radiological Consequences

An evaluation of the radiological consequences was not made for this event since no radioactive material is released from the fuel.

15.4.1.2 Continuous Rod Withdrawal During Reactor Startup

15.4.1.2.1 Identification of Causes and Frequency Classification

This event is categorized as an infrequent incident. The probability of further development of this event is low because it is contingent upon the failure of the rod worth minimizer (RWM) system or failure of a second licensed operator (or technically qualified member of the technical staff) observing the out-of-sequence rod selection concurrent with a high worth rod, out-of-sequence rod selection contrary to procedures, and operator disregard of continuous alarm annunciations prior to safety system actuation.

15.4.1.2.2 Sequence of Events and Systems Operation

15.4.1.2.2.1 Sequence of Events. Control RWEs are not considered credible in the startup and low power ranges. The RWM or second licensed operator (or other technically qualified member of the technical staff) prevents the operator from selecting and withdrawing an out-of-sequence control rod.

Continuous control RWEs during reactor startup are precluded by the RWM or second qualified person. The RWM or second qualified person prevents the withdrawal of an out-of-sequence control rod from 100% control rod density to 10% of rated thermal power.

15.4.1.2.2.2 Identification of Operator Actions. No operator actions are required to preclude this event since plant design prevents its occurrence.

15.4.1.2.2.3 Effects of Single Failure and Operator Errors. If any one of the operations involved in the initial failure or error is followed by another single component failure or single operator error, the necessary safety actions are automatically taken to preclude violation of any limits.

15.4.1.2.3 Core and System Performance

The performance of the RWM or second licensed operator (or technically qualified member of the technical staff) prevents erroneous selection and withdrawal of an out-of-sequence control rod. Thus, core and system performance is not affected by such a single operator error.

No mathematical models are involved in this event. The need for input parameters or initial conditions is not required as there are no results to report. Consideration of uncertainties is not applicable.

15.4.1.2.4 Barrier Performance

An evaluation of the barrier performance was not performed for this event since there is no postulated set of circumstances for which this error could occur.

15.4.1.2.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released.

15.4.2 ROD WITHDRAWAL ERROR - AT POWER

15.4.2.1 Identification of Causes and Frequency Classifications

15.4.2.1.1 Identification of Causes

While operating in the power range in a normal mode of operation, the reactor operator makes a procedural error and withdraws the maximum worth control rod until the rod block monitor (RBM) system inhibits further withdrawal.

15.4.2.1.2 Frequency Classification

The probability of this event is considered low enough to warrant its being categorized as an infrequent incident. However, because of the lack of sufficient frequency database, this event is considered an incident of moderate frequency.

15.4.2.2 Sequence of Events and Systems Operation

15.4.2.2.1 Sequence of Events

The sequence of events for this transient is presented in Table 15.4-1.

15.4.2.2.2 Systems Operations

The focal point of this event is localized to a small portion of the core; therefore, although reactor control and instrumentation is assumed to function normally, credit is taken only for the RBM system.

While operating in the power range in a normal operational mode, the reactor operator makes a procedural error and withdraws the maximum worth control rod until the RBM system inhibits further withdrawal.

Under most normal operating conditions no operator action is required. Should the peak linear power design limits be exceeded, the nearest local power range monitor (LPRM) would detect the condition and alarm. The operator would acknowledge the alarm and take appropriate action.

If the RWE is severe, the RBM system would alarm, at which time the operator would acknowledge the alarm and take corrective action. Even for conditions such as highly abnormal control rod patterns, operating conditions, operator disregard of all alarms and warnings, and continuous control rod withdrawal, the RBM system will block further withdrawal of the control rod before the fuel reaches the point of boiling transition or the 1% plastic strain limit imposed on the clad.

15.4.2.2.3 Effect of Single Failure and Operator Errors

Operator errors do not impact the consequences of this event due to the single failure proof design of the RBM system.

15.4.2.3 Core and System Performance

15.4.2.3.1 Mathematical Model

The mathematical model is referenced in the cycle-specific reload analysis. For this event the reactivity insertion rate is slow; therefore, it is adequate to assume that the core has time to equilibrate (i.e., that both the neutron flux and heat flux are in phase). Making use of the above assumption, this event is calculated using a steady-state three-dimensional coupled nuclear-thermal-hydraulics computer program. All spatial effects are included in the calculation. The program is described in Reference 4.3-1.

The primary output from this code, in addition to the basic nuclear parameters, is the variation of the linear heat generator rate (LHGR), the variation of the minimum critical power ratio (MCPR), the total reactor power, and the variation of the in-core instrument responses. These instrument responses are used to predict the RBM action under the specified condition for the RWE.

The analytical methods and assumptions which are used in evaluating the consequences of this accident are considered to provide a realistic, yet conservative assessment of the consequences.

15.4.2.3.2 Input Parameters and Initial Conditions

The number of possible RWE transients is large due to the number of control rods and the wide range of exposures and power levels. In order to encompass all of the possible RWEs which could conceivably occur, a limiting analysis is defined such that a conservative assessment of the consequences is provided.

a. The assumed error is a continuous withdrawal of the maximum worth rod at its maximum drive speed;

b. The core is assumed to be operating at rated conditions;

c. The reactor is presumed to be in its most reactive state and devoid of all xenon. This ensures that the amount of excess reactivity which must be controlled by the movable control rods is maximum;

d. It is assumed that the operator has fully inserted the maximum worth rod prior to its removal and selected the remaining control rod pattern in such a way as to approach thermal limits in the fuel bundles in the vicinity of the rod to be withdrawn. (This control rod configuration would only be achieved by deliberate operator action or by numerous operator errors.);

e. The operator is assumed to ignore all warnings during the transient;

f. Of the four LPRM strings nearest to the control rod being withdrawn, the two highest reading LPRMs during the transient are assumed to have failed; and

g. One of the two instrument channels is assumed to be bypassed and out-of-service. The A and C LPRM chambers input to one channel, while the B and D chambers input to the other. The channel with the greatest response is assumed to be bypassed.

15.4.2.3.2.1 Rod Block Monitor System Operation. The RBM system minimizes the consequences of a RWE by blocking motion of the control rod before the safety limits are exceeded.

The RBM has three trip levels (rod withdrawal permissive removed). The trip levels may be adjusted and are nominally 8% of reactor power apart. The highest trip level is set so that the safety limit is not exceeded. The lower two trip levels are intended to provide a warning to the operator. Settings are 106%, 98%, and 90% of initial, steady-state, operating power at 100% flow. The trip levels are automatically varied with reactor coolant flow to protect against fuel damage at lower flows. The variation is set to ensure that no fuel damage will occur at any indicated coolant flow. The operator may encounter any number (up to three) of trip points depending on the starting power of a given control rod withdrawal. The lower two points may be passed up (reset) by manual operation of a push button. The reset permissive is actuated (and indicated by a light) when the RBM reaches 2% power less than the trip point. The operator would then assess his local power and either reset or select a new rod. The highest (power) trip point may not be reset.

15.4.2.3.3 Results

The consequences of this transient are referenced in the cycle-specific reload analysis.

15.4.2.3.4 Considerations of Uncertainties

The conservative assumptions which ensure that this event has been conservatively analyzed have been previously discussed in Section 15.4.2.3.2.

15.4.2.4 Barrier Performance

An evaluation of the barrier performance was not made for this event since this is a localized event with very little change in the gross core characteristics. Typically, an increase in total core power is less than 5% and the changes in pressure are negligible.

15.4.2.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released from the fuel.

15.4.3 CONTROL ROD MALOPERATION (SYSTEM MALFUNCTION OR OPERATOR ERROR)

This event is covered with evaluation cited in Sections 15.4.1 and 15.4.2.

15.4.4 STARTUP OF IDLE RECIRCULATION PUMP

15.4.4.1 Identification of Causes and Frequency Classification

15.4.4.1.1 Identification of Causes

This action results directly from the operator's manual action to initiate pump operation. It assumes that the remaining loop is already operating.

15.4.4.1.2 Frequency Classification

15.4.4.1.2.1 Normal Restart of Recirculation Pump at Power. This event is categorized as an incident of moderate frequency.

15.4.4.1.2.2 Abnormal Startup of Idle Recirculation Pump. This event is categorized as an incident of moderate frequency.

15.4.4.2 Sequence of Events and Systems Operation

15.4.4.2.1 Sequence of Events

Table 15.4-2 lists the sequence of events for Figure 15.4-1.

15.4.4.2.1.1 Operator Actions. The normal sequence of operator actions expected in starting the idle loop is as follows:

a. Adjust rod pattern as necessary for new power level following idle loop start,

b. Determine that the idle recirculation pump suction and discharge block valves are open and, if not, place them in this configuration,

c. Readjust flow of the running loop downward to less than half of the rated flow,

d. Determine that the temperature difference between the two loops is no more than 50°F apart,

e. Start the idle loop pump and adjust flow to match the adjacent loop flow. Monitor reactor power, and

f. Readjust power as necessary.

NOTE: The time for the operator to perform the above work is approximately one-half hour.

15.4.4.2.2 Systems Operation

This event assumes and takes credit for normal functioning of plant instrumentation and controls. No protection systems action is anticipated. No engineered safety feature (ESF) action occurs as a result of the event.

15.4.4.2.3 The Effect of Single Failures and Operator Errors

Attempts by the operator to start the pump at higher power levels will result in a reactor scram on flux.

15.4.4.3 Core and System Performance

15.4.4.3.1 Mathematical Model

The nonlinear dynamic model described in Section 15.1.1.3.1 is used to simulate this event.

15.4.4.3.2 Input Parameters and Initial Conditions

This analysis has been performed unless otherwise noted with plant conditions in Table 15.0-2.

The active recirculation loop is operating with a pump speed that produces about 45% of normal rated jet pump diffuser flow in the active jet pumps. The inactive recirculation loop jet pumps are forward flowing at about 2% of normal jet pump diffuser flow because of natural circulation affects. The core is receiving about 34% of its normal rated flow.

The idle recirculation pump suction and discharge block valves are open. Normal procedure requires leaving an idle loop in this condition to maintain the loop temperature within the required limits for restart.

15.4.4.3.3 Results

The transient response to the incorrect startup of a cold idle recirculation loop is shown in Figure 15.4-1. Shortly after the pump begins to move, the flow from the started jet pump diffusers causes the core inlet flow to increase. The pump startup demand is conservatively assumed to ramp at a rate of 3.3% until maximum pump speed is achieved. The diffuser flows on the started side of the reactor increase ultimately to about 144% of rated while the flow rate of the opposite loop diffusers decreases and eventually reverses to about -8% of rated. As the inactive loop pump increases speed the cold fluid is pumped out of the recirculation loop piping and is mixed with hot downcomer fluid and the mixture flows to the core with a resulting increase of the core inlet subcooling.

A moderate-duration neutron flux peak to just above 124% of NB rated (NBR = 3486 MWt) is produced as the colder, increasing core flow reduces the void volume. Surface heat flux follows the slower response of the fuel and peaks at 110% of rated before decreasing after the cold water is washed out of the loop at about 30 sec. No damage occurs to the fuel barrier as the MCPR remains substantially above the safety limit.

15.4.4.3.4 Consideration of Uncertainties

This particular transient is analyzed for an initial power level that is higher than that expected for the actual event. The slower thermal response of the fuel mitigates the effects of the rather sharp neutron flux spike and even in this high range of power, no impact on thermal limits is possible.

15.4.4.4 Barrier Performance

No evaluation of barrier performance is required for this event since no significant pressure increases are incurred during this transient. See Figure 15.4-1.

15.4.4.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released.

15.4.5 RECIRCULATION FLOW CONTROL FAILURE WITH INCREASING FLOW

15.4.5.1 Identification of Causes and Frequency Classification

15.4.5.1.1 Identification of Causes

An upscale failure of the master manual setpoint station can cause an increase in the core coolant flow rate. Upscale failure of an individual remote manual setpoint station or manual demand loop can also cause an increase in core coolant flow rate.

15.4.5.1.2 Frequency Classification

This event is an incident of moderate frequency.

15.4.5.2 Sequence of Events and Systems Operation

15.4.5.2.1 Sequence of Events

15.4.5.2.1.1 Speed Increase of One Recirculation Pump. Table 15.4-3 lists the sequence of events for Figure 15.4-2.

15.4.5.2.1.2 Speed Increase of Two Recirculation Pumps. Table 15.4-4 lists the sequence of events for Figure 15.4-3.

15.4.5.2.1.3 Identification of Operator Actions.

a. Reduce flow to minimum, and
b. Identify cause of failure.

Reactor pressure will be controlled as required, depending on whether a restart or cooldown is planned. In general, the corrective action would be to hold reactor pressure and condenser vacuum for restart after the malfunction has been repaired. The following is the sequence of operator actions expected during the course of the event, assuming restart.

a. Observe that all rods are in,

b. Check reactor water level and maintain above low level (L2) trip to prevent main steam line isolation valves (MSIVs) from isolating,

c. Switch the reactor mode switch to the "startup" position,

d. Continue to maintain vacuum and turbine seals,

e. Reduce the setpoint to minimum,

f. Monitor the turbine coastdown and auxiliary systems, and

g. Restart the reactor as required.

NOTE: Time required from first trouble alarm to restart would be approximately 1 hr.

15.4.5.2.2 Systems Operation

The analysis of this event assumes and takes credit for normal functioning of plant instrumentation and controls, and the reactor protection system (RPS). Operation of ESF is not expected.

15.4.5.2.3 The Effect of Single Failures and Operator Errors

Both of these transients lead to a rise in reactor power level. Corrective action first occurs in the high flux trip which, being part of the RPS, is designed to single failure criteria. Operator errors are not of concern due to automatic shutdown features.

15.4.5.3 Core and System Performance

15.4.5.3.1 Mathematical Model

The nonlinear dynamic model described in Section 15.1.1.3.1 is used to simulate this event.

15.4.5.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

The input parameters and initial conditions are referenced in the cycle-specific reload analysis.

In each of these events the most severe transient results when initial conditions are established for operation at the lower end of the maximum allowed flow control rod line (i.e., high-power low-flow conditions). Specifically, this is 61% rated power (NBR = 3486 MWt) and 38% core flow. The initial operating MCPR is governed by the $MCPR_f$. The maximum ramp rate of the recirculation loop pumps for an upscale failure of the master manual setpoint station is limited by the adjustable speed drive system to approximately 10%/sec.

15.4.5.3.3 Results

15.4.5.3.3.1 Speed Increase of One Recirculation Pump. Figure 15.4-2 show the analysis of a failure where one recirculation pump speed is increased at a rate of 25%/sec. The rapid increase in core flow causes a sharp rise in neutron flux initiating a reactor scram at

approximately 2.5 sec. The peak neutron flux reached was 136% of NB rated value (NBR=3486 MWt), while the accompanying average fuel surface heat flux reaches 78% of NB rated (NBR=3486 MWt) at approximately 3.2 sec. The MCPR remains considerably above the safety limit and the fuel center temperature increases 233°F. Reactor pressure is discussed in Section 15.4.5.4.

15.4.5.3.3.2 Speed Increase of Two Recirculation Pumps. Figure 15.4-3 illustrates the failure where the speed of both recirculation loop pumps is increased at a ramp rate of approximately 10%/sec. It is very similar to the above transient. Flux scram occurs at approximately 4.3 sec, peaking at approximately 150% of NB rated (NBR=3486 MWt) while the average surface heat flux reaches 91% at approximately 5.5 sec. The MCPR remains considerably above the safety limit and fuel center temperature increases 550°F.

15.4.5.3.4 Considerations of Uncertainties

Some uncertainties in void reactivity characteristics, scram time and worth are expected to force analytical results to be more severe than under actual plant conditions.

15.4.5.4 Barrier Performance

15.4.5.4.1 Speed Increase of One Recirculation Pump

This event results in a slight increase in reactor vessel pressure, as shown in Figure 15.4-27, and does not impact the reactor coolant pressure boundary (RCPB).

15.4.5.4.2 Speed Increase of Two Recirculation Pumps

This event results in a slight increase in reactor vessel pressure as shown in Figure 15.4-3 and does not impact the RCPB.

15.4.5.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released.

15.4.6 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTIONS

This event is not applicable to boiling water reactor (BWR) plants.

15.4.7 MISPLACED BUNDLE ACCIDENT

15.4.7.1 Identification of Causes and Frequency Classification

15.4.7.1.1 Identification of Causes

The event discussed in this section is the improper loading of a fuel bundle and subsequent operation of the core. Three errors must occur for this event to take place in the initial core loading. First, a bundle must be misloaded into a wrong position in the core. Second, the bundle which was supposed to be loaded where the mislocation occurred would have to be placed in an incorrect location. Third, the misplaced bundles would have to be overlooked during the core verification performed following core loading.

15.4.7.1.2 Frequency of Occurrence

This event occurs when a fuel bundle is loaded into the wrong location in the core. It is assumed the bundle is misplaced to the worst possible location and the plant is operated with the mislocated bundle. This event is categorized as an infrequent incident based on the expected frequency of 0.004 events/operating cycle.

15.4.7.2 Sequence of Events and Systems Operation

The postulated sequence of events for the misplaced bundle accident (MBA) is presented in Table 15.4-5.

Fuel loading errors, undetected by in-core instrumentation following fueling operations, may result in undetected reductions in thermal margins during power operations. No detection is assumed, and therefore, no corrective operator action or automatic protection system functioning occurs.

15.4.7.2.1 Effect of Single Failure and Operator Errors

This analysis already represents the worst case (i.e., operation of a misplaced bundle with three single equipment failures or single operator errors).

15.4.7.3 Core and System Performance

15.4.7.3.1 Mathematical Model

A three-dimensional BWR simulator model is used to calculate the core performance resulting from this event. The results of cycle-specific analyses are shown in the cycle-specific reload reports.

15.4.7.3.2 Input Parameters and Initial Conditions

Initial input parameters and conditions are cycle specific and provided by the cycle-specific reload reports referenced in the Core Operating Limits Report (COLR). The fuel bundle loading error with the severest consequences occurs at "beginning of core" (BOC) when a low-enriched bundle (which should be loaded at the periphery) is interchanged with a high-enriched bundle (which should be loaded adjacent to a LPRM) predicted to have the highest LHGR and/or lowest CPR in the core. After the loading error is made and has gone undetected, it is assumed for purposes of conservatism that the operator uses a control rod pattern which places the limiting bundle in the four bundle array containing the misplaced bundle on design thermal limits, as recorded by LPRM.

As a result of loading the low-enriched bundle in an improper location, the reading of the adjacent LPRM decreases. Because there are no instruments in the three-mirror-images of the four-bundle-array, the operator incorrectly believes these arrays are operating at the same power as the instrumented one. As a result of placing the instrumented array on limits, the three-mirror-image arrays exceed the design limit. By replacing the high-enriched bundle with the greatest power peaking by the low-enriched bundle, it is assured that the difference in power peaking between the instrumented and the non-instrumented arrays is maximum (the ΔCPR and ΔLHGR are the upper bounds for this error).

Other input parameters assumed are given in the COLR.

15.4.7.3.3 Results

Results of analyzing the worst fuel bundle loading error are provided in the COLR. The MCPR remains well above the point where boiling transition would be expected to occur and the maximum linear heat generation rate does not exceed the 1% plastic strain limit for the clad. Therefore, no fuel damage occurs as a result of this event.

15.4.7.3.4 Considerations of Uncertainties

In order to ensure the conservatism of this analysis, major input parameters are taken as a worst case. The bundle is placed in location with the highest LHGR and/or the lowest CPR in the core and the bundle is operating on design thermal limits. This ensures that the ΔCPR and the ΔLHGR are the upper bounds for the error.

15.4.7.4 <u>Barrier Performance</u>

An evaluation of the barrier performance was not made for this event since it is a mild and highly localized event. No perceptible change in the core pressure would be observed.

15.4.7.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released.

15.4.8 SPECTRUM OF ROD EJECTION ASSEMBLIES

This event is not applicable to BWR plants.

15.4.9 CONTROL ROD DROP ACCIDENT

15.4.9.1 Identification of Causes and Frequency Classification

15.4.9.1.1 Identification of Causes

The control rod drop accident (CRDA) is the result of a postulated event in which a high worth control rod is inserted out-of-sequence into the core. Subsequently, it becomes decoupled from its drive mechanism. The mechanism is withdrawn, but the decoupled control rod is assumed to be stuck in place. At a later optimum moment, the control rod suddenly falls free and drops out of the core. This results in the removal of large negative reactivity from the core and a localized power excursion.

A more detailed discussion is given in Reference 15.4-1.

15.4.9.1.2 Frequency Classification

The CRDA is categorized as a limiting fault because it is not expected to occur during the lifetime of the plant. However, if postulated to occur, it has consequences that include the potential for the release of radioactive material.

For radiological release, this event is the limiting incident for any cycle.

15.4.9.2 Sequence of Events and Systems Operation

15.4.9.2.1 Sequence of Events

Before the CRDA is possible, the sequence of events presented in Table 15.4-6 must occur. No operator actions are required to terminate this event. Subsequent to reactor scram which terminates the event, normal vessel inventory makeup systems will be used as available including reactor core isolation cooling and/or high-pressure core spray (not simulated).

15.4.9.2.2 Systems Operation

An unlikely set of circumstances makes possible the rapid removal of a control rod. The dropping of the rod results in high reactivity in a small region of the core. For large, loosely coupled cores, this would result in a highly peaked power distribution and subsequent operation of shutdown mechanisms. Significant shifts in the spatial power generation would occur during the course of the excursion.

The RWM system limits the worth of any control rod which could be dropped by regulating the withdrawal sequence. This prevents the movement of an out-of-sequence rod in accordance to the prescribed banked position withdrawal sequence (BPWS) from 100% control rod density to 10% of rated thermal power (the low power setpoint). The BPWS requirements are described in Reference 15.4-2.

The BPWS is assumed to be adhered to throughout the event. The RWM would enforce adherence to the prescribed BPWS.

The termination of this excursion is accomplished by automatic safety feature shutdown mechanisms. Therefore, no operator action during the event is required. Although other normal plant instrumentation and controls are assumed to function, no credit for their operation is taken in the analysis of this event.

15.4.9.2.3 Effect of Single Failures and Operator Errors

Systems mitigating the consequences of this event are the RWM and the APRM scram systems. The APRM scram system is designed to single failure criteria. Failure of the RWM concurrent with an operator error of withdrawing an out-of-sequence rod contrary to procedures would be required (in addition to the initial event) to result in a potentially more limiting event. Therefore, sufficient redundancy exists such that termination of this transient within the limiting results discussed below is assured.

No operator error (in addition to the one that initiates this event) can result in a more limiting case since the RPS will automatically terminate the transient.

15.4.9.3 <u>Core and System Performance</u>

15.4.9.3.1 Mathematical Model

The mathematical model is referenced in the COLR. The analytical methods, assumptions, and conditions for evaluating the excursion aspects of the CRDA are described in detail in References 15.4-1, 15.4-3, and 15.4-4. They are considered to provide a realistic, yet conservative assessment of the associated consequences. The data presented in

Reference 15.4-2 shows that the BPWS requirements reduce the control rod worths to an acceptable value.

This accident is analyzed each cycle and the results are shown in Section 15.F.4.3.

15.4.9.3.2 Input Parameters and Initial Conditions

The core at the time of rod drop accident is assumed to be at the point in cycle which results in the highest control rod worth (contains no xenon) to be in a hot-startup condition, and to have the control rod drive mechanisms moved in accordance to BPWS requirements. Removing xenon, which competes well for neutron absorptions, increases the fractional absorptions, or worth, of the control rods.

Since the maximum incremental rod worth is maintained at very low values, the postulated CRDA cannot result in peak enthalpies in excess of 280 cal/gm for any plant condition.

15.4.9.3.3 Results

Radiological evaluations are based on the assumed failure of 850 fuel rods. The number of rods which exceed the damage threshold is less than 850 for all plant operating conditions or core exposure provided the peak enthalpy is less than the 280 cal/gm design limit.

The results of the compliance-check calculation, indicate that the maximum incremental rod worth is below the worth required to cause a CRDA which would result in 280 cal/gm peak fuel enthalpy. The conclusion is that the 280 cal/gm design limit is not exceeded and the assumed failure of 850 fuel rods for the radiological evaluation is conservative.

15.4.9.4 Barrier Performance

An evaluation of the barrier performance was not made for this accident since this is a localized event with no significant change in the gross core temperature or pressure.

15.4.9.5 Radiological Consequences

The radiological analysis is based on Reference 15.4-5. Specific models, assumptions, and the program used for computer evaluation are described in Reference 15.4-6. Specific parametric values used in the evaluation are presented in Table 15.4-7.

15.4.9.5.1 Fission Product Release from Fuel

The failure of 850 fuel rods is used for this analysis. The mass fraction of the fuel in the damaged rods which reaches or exceeds the initiation temperature of fuel melting (taken as 2804°C) is estimated to be 0.0077.

Fuel reaching melt condition is assumed to release 100% of the noble gas inventory and 50% of the iodine inventory. The remaining fuel in the damaged rods is assumed to release 10% of both the noble gas and iodine inventories.

A maximum equilibrium inventory of fission products in the core is based on 1000 days of continuous operation at 3556 MWt. No delay time is considered between departure from that power condition and the initiation of the accident.

15.4.9.5.2 Fission Product Transport to the Environment

The transport pathway is shown in Figure 15.4-4 and consists of carryover with steam to the turbine condenser prior to MSIV closure, and leakage from the condenser to the environment. No credit is taken for the turbine building. Of the activity released from the fuel, 100% of the noble gases and 10% of the iodines are assumed to be carried to the condenser before MSIV closure is complete.

Of the activity reaching the condenser, 100% of the noble gases and 10% of the iodines (due to partitioning and plate-out) remain airborne. The activity airborne in the condenser is assumed to leak directly to the environment a rate of 1% per day. Radioactive decay is accounted for during residence in the condenser, however, it is neglected after release to the environment.

The activity airborne in the condenser is presented in Table 15.4-8. The cumulative release of activity to the environment is presented in Table 15.4-9.

15.4.9.5.3 Results

The calculated exposures from the design basis analysis are presented in Table 15.4-10 and are within the guidelines of 10 CFR 100.

15.4.10 REFERENCES

15.4-1 Stirn, R. G. et al., "Rod Drop Accident Analysis for Large BWRs," (NEDO-10527).

15.4-2 Paone, C. J., "Bank Position Withdrawal Sequence," (NEDO-21231).

15.4-3 Stirn, R. G. et al., "Rod Drop Accident Analysis for Large BWRs," (NEDO-10527, Supplement 1).

15.4-4 Stirn, R. G. et al., "Rod Drop Accident Analysis for Large BWRs," (NEDO-10527, Supplement 2).

15.4-5 NRC Standard Review Plan, NUREG-75/037.

15.4-6 Careway, H. A., V. D. Nguyen, P. P. Stancavage, "Radiological Accident Evaluation - The CONAC03 Code," (NEDO-21143-1).

TABLE 15.4-1

SEQUENCE OF EVENTS - ROD WITHDRAWAL ERROR IN POWER RANGE

Time (sec)[a]	Event
0	Core is assumed to be operating at rated conditions.
0	Operator selects and withdraws the maximum worth control rod.
1	The total core power and the local power in the vicinity of the control rod increase.
5	The LPRM system indicates excessive localized peaking.
5	The operator ignores warning and continues withdrawal.
15	The RBM system indicates excessive localized peaking.
15	The operator ignores warning and continues withdrawal.
20	The RBM system initiates a rod block inhibiting further withdrawal.
40	Reactor core stabilizes at higher core power level.
60	Operator re-inserts control rod to reduce core power level.
80	Core stabilizes at rated conditions.

[a] Approximately.

TABLE 15.4-2

SEQUENCE OF EVENTS FOR AN ABNORMAL STARTUP
OF AN IDLE RECIRCULATION LOOP

Time (sec)	Event
0.00	Plant operating with one recirculation loop only.
5.00	Start idle recirculation loop pump motor.
29.6	Peak value of core inlet subcooling.
29.6	Peak thermal power. Estimated APRM thermal power approximately 1% below APRM thermal power setpoint.
45.7	Pump motor at full speed.
80+	Reactor reaches new equilibrium condition.

TABLE 15.4-3

SEQUENCE OF EVENTS FOR RECIRCULATION FLOW CONTROL FAILURE
INCREASING FLOW IN ONE LOOP

Time (sec)	Event
0.00	Initiate fast increase of recirculation pump speed in one loop.
2.49	Reactor high flux scram trip initiated.
48.73	Vessel water level (L8) trip initiates turbine trip.
48.73	Feedwater pumps trip on high water level (L8).
48.92	Recirculation pumps trip due to turbine trip.

TABLE 15.4-4

SEQUENCE OF EVENTS FOR RECIRCULATION FLOW CONTROL FAILURE
INCREASING FLOW IN TWO LOOPS AT 10%/SEC
PUMP SPEED RAMP RATE LIMIT

Time (sec)	Event
0.00	Initiate fast increase of recirculation pump speed in both loops.
4.29	Reactor APRM high flux scram trip initiated.
6[a]	Turbine control valves start to close on failing turbine pressure.
14[a]	Turbine control valves closed.
48.81	Vessel high water level (L8) trip initiates main turbine and feedwater turbine trips.
48.82	Main turbine stop valve reaches 90% open position and initiates recirculation pump trip.
49.00	Recirculation pumps trip due to turbine trip.

[a] Approximately.

TABLE 15.4-5

SEQUENCE OF EVENTS FOR MISPLACED BUNDLE ACCIDENT

(1)	During core loading operation, bundle is placed in the wrong position.
(2)	Subsequently, the bundle intended for this position is placed in the position of the previous bundle.
(3)	During core verification procedure, error is not observed.
(4)	Plant is brought to full power operation without detecting misplaced bundle.
(5)	Plant continues to operate.

TABLE 15.4-6

SEQUENCE OF EVENTS FOR ROD DROP ACCIDENT

Time[a]	Event
	Reactor is operating with the limiting rod configuration within BPWS.
	Rod worth minimizer is not functioning.
	Maximum worth control rod blade becomes decoupled from the CRD.
	Operator selects and withdraws the CRD of the decoupled rod along with the other control rods assigned to the RWM group.
	Decoupled control rod sticks in the fully inserted or an intermediate bank position.
0	Control rod becomes unstuck and drops to the drive position at the nominal measured velocity plus three standard deviations.
<1 sec	Reactor goes on a positive period and initial power increase is terminated by the doppler coefficient.
<1 sec	Average power range monitor 120% power signal scrams reactor.
<5 sec	Scram terminates accident.

[a] Approximately.

TABLE 15.4-7

CONTROL ROD DROP ACCIDENT EVALUATION PARAMETERS

I.	Data and assumptions used to estimate radioactive source from postulated accidents.		
	A.	Power level	Section 15.4.9.5.1
	B.	Burnup	Section 15.4.9.5.1
	C.	Fuel damaged	850 rods
	D.	Release of activity by nuclide	Table 15.4-9
	E.	Iodine fractions	
		(1) Organic	0
		(2) Elemental	1
		(3) Particulate	0
	F.	Reactor coolant activity before the accident.	N/A
II.	Data and assumptions used to estimate activity released.		
	A.	Condenser leak rate (%/day)	1.0
	B.	Turbine building leak rate (%/day)	N/A
	C.	Valve closure time (sec)	N/A
	D.	Adsorption and filtration efficiencies	
		(1) Organic iodine	N/A
		(2) Elemental iodine	N/A
		(3) Particulate iodine	N/A
		(4) Particulate fission products	N/A
	E.	Recirculation system parameters	
		(1) Flow rate	N/A
		(2) Mixing efficiency	N/A
		(3) Filter efficiency	N/A
	F.	Containment spray parameters (flow rate, drop size, etc.)	

TABLE 15.4-7

CONTROL ROD DROP ACCIDENT EVALUATION PARAMETERS (Continued)

II.	Data and assumptions used to estimate activity released. (Continued)			
	G.	Containment volumes		N/A
	H.	All other pertinent data and assumptions		None
III.	Dispersion data			
	A.	Boundary and LPZ distances (m)		1950/4827
	B.	χ/Qs for time intervals of		
		(1)	0-2 hr - SB	2.62×10^{-4}
			-LPZ	1.06×10^{-4}
		(2)	2-8 hr - LPZ	4.47×10^{-5}
		(3)	8-24 hr - LPZ	2.91×10^{-5}
		(4)	1-4 days - LPZ	1.14×10^{-5}
		(5)	4-30 day - LPZ	2.97×10^{-6}
IV.	Dose data			
	A.	Method of dose calculation		Reference 15.4-6
	B.	Dose conversion assumptions		Reference 15.4-6
	C.	Peak activity concentrations in condenser		Table 15.4-8
	D.	Doses		Table 15.4-10

TABLE 15.4-8

CONTROL ROD DROP ACCIDENT
ACTIVITY AIRBORNE IN THE CONDENSER (CURIES)

Uprated Power

Isotope	1 Minute	30 Minutes	1 Hr	2 Hr	8 Hr	12 Hr	1 Day	3 Days	4 Days	30 Days
^{131}I	2.63E 03	2.62E 03	2.62E 03	2.61E 03	2.54E 03	2.50E 03	2.39E 03	1.97E 03	1.79E 03	1.47E 02
^{133}I	5.34E 03	5.25E 03	5.17E 03	4.99E 03	4.08E 03	3.56E 03	2.38E 03	4.72E 02	2.09E 02	1.53E-07
^{134}I	5.78E 03	3.94E 03	2.66E 03	1.20E 03	1.05E 01	4.42E-01	3.34E-05	0.00E+00	0.00E+00	0.00E+00
^{135}I	4.99E 03	4.74E 03	4.50E 03	4.05E 03	2.15E 03	1.41E 03	3.99E 02	2.56E 00	2.01E-01	0.00E+00
Total iodine	2.25E 04	1.98E 04	1.77E 04	1.49E 04	9.12E 03	7.58E 03	5.17E 03	2.44E 03	2.00E 03	1.47E 02
^{83m}Kr	3.33E 04	2.77E 04	2.29E 04	1.57E 04	1.61E 03	3.54E 02	3.75E 00	4.78E-08	5.01E-12	0.00E+00
^{85m}Kr	7.07E 04	6.56E 04	6.07E 04	5.20E 04	2.05E 04	1.10E 04	1.71E 03	1.01E 00	2.37E-02	0.00E+00
^{85}Kr	2.41E 03	2.41E 03	2.41E 03	2.41E 03	2.41E 03	2.40E 03	2.39E 03	2.34E 03	2.32E 03	1.78E 03
^{87}Kr	1.34E 05	1.03E 05	7.87E 04	4.56E 04	1.73E 03	1.95E 02	2.80E-01	1.23E-12	0.00E+00	0.00E+00
^{88}Kr	1.90E 05	1.69E 05	1.50E 05	1.17E 05	2.70E 04	1.02E 04	5.41E 02	4.38E-03	1.19E-05	0.00E+00
^{89}Kr	1.87E 05	3.30E 02	4.67E-01	9.38E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
^{131m}Xe	2.79E 03	2.79E 03	2.78E 03	2.78E 03	2.73E 03	2.70E 03	2.61E 03	2.28E 03	2.12E 03	3.61E 02
^{133m}Xe	1.74E 04	1.72E 04	1.71E 04	1.69E 04	1.56E 04	1.47E 04	1.25E 04	6.52E 03	4.69E 03	9.65E-01
^{133}Xe	5.54E 05	5.53E 05	5.51E 05	5.48E 05	5.29E 05	5.16E 05	4.81E 05	3.62E 05	3.14E 05	7.81E 03
^{135m}Xe	1.05E 05	2.90E 04	7.68E 03	5.38E 02	6.38E-05	1.54E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00
^{135}Xe	1.28E 05	1.23E 05	1.19E 05	1.10E 05	6.94E 04	5.11E 04	2.03E 04	5.13E 02	8.04E 01	0.00E+00
^{137}Xe	4.03E 05	2.12E 03	9.30E 00	1.79E-04	0.00E+00	0.00E+00	0.00E+00	0 00E+00	0.00E+00	0.00E+00
^{138}Xe	4.34E 05	1.05E 05	2.42E 04	1.28E 03	2.88E-05	2.29E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total noble gases	2.26E 06	1.20E 06	1.04E 06	9.12E 05	6.70E 05	6.09E 05	5.21E 05	3.74E 05	3.23E 05	9.95E 03

TABLE 15.4-9

CONTROL ROD DROP ACCIDENT
ACTIVITY AIRBORNE TO THE ENVIRONMENT (CURIES)

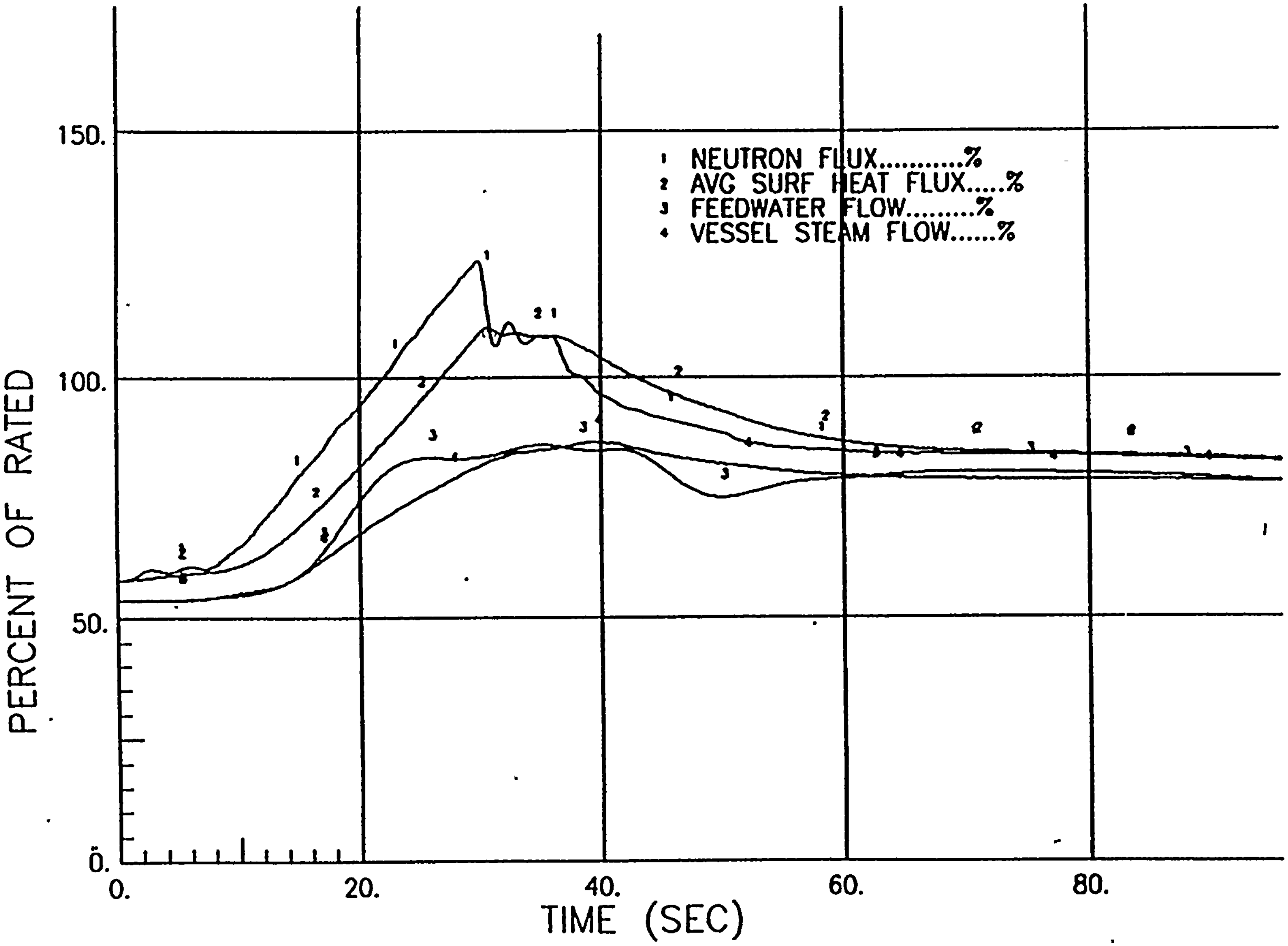
Uprated Power

Isotope	1 Minute	30 Minutes	1 Hr	2 Hr	8 Hr	12 Hr	1 Day	3 Days	4 Days	30 Days
^{131}I	1.82E-02	5.47E-01	1.09E 00	2.18E 00	8.62E 00	1.28E 01	2.50E 01	6.84E 01	8.73E 01	2.58E 02
^{132}I	2.62E-02	7.33E-01	1.36E 00	2.37E 00	4.76E 00	5.09E 00	5.23E 00	5.23E 00	5.23E 00	5.23E 00
^{133}I	3.71E-02	1.10E 00	2.19E 00	4.31E 00	1.56E 01	2.20E 01	3.66E 01	6.02E 01	6.34E 01	6.60E 01
^{134}I	4.04E-02	1.01E 00	1.69E 00	2.45E 00	3.08E 00	3.09E 00	3.09E 00	3.09E 00	3.09E 00	3.09E 00
^{135}I	3.47E-02	1.01E 00	1.98E 00	3.75E 00	1.13E 01	1.42E 01	1.82E 01	1.98E 01	1.98E 01	1.98E 01
Total iodine	1.57E-01	4.40E 00	8.31E 00	1.51E 01	4.33E 01	5.72E 01	8.82E 01	1.57E 02	1.79E 02	3.52E 02
^{83m}Kr	2.32E-01	6.36E 00	1.16E 01	1.96E 01	3.51E 01	3.64E 01	3.68E 01	3.68E 01	3.68E 01	3.68E 01
^{85m}Kr	4.92E-01	1.42E 01	2.74E 01	5.08E 01	1.35E 02	1.61E 02	1.86E 02	1.90E 02	1.90E 02	1.90E 02
^{85}Kr	1.68E-02	5.03E-01	1.01E 00	2.01E 00	8.03E 00	1.20E 01	2.40E 01	7.13E 01	9.47E 01	6.24E 02
^{87}Kr	9.38E-01	2.47E 01	4.36E 01	6.88E 01	1.02E 02	1.04E 02	1.04E 02	1.04E 02	1.04E 02	1.04E 02
^{88}Kr	1.32E 00	3.75E 01	7.06E 01	1.26E 02	2.80E 02	3.08E 02	3.25E 02	3.26E 02	3.26E 02	3.26E 02
^{89}Kr	1.45E 00	7.39E 00	7.40E 00	7.40E 00	7.40E 00	7.40E 00	7.40E 00	7.40E 00	7.40E 00	7.40E 00
^{131m}Xe	1.94E-02	5.81E-01	1.16E 00	2.32E 00	9.20E 00	1.37E 01	2.70E 01	7.57E 01	9.78E 01	3.56E 02
^{133m}Xe	1.21E-01	3.60E 00	7.18E 00	1.43E 01	5.48E 01	8.01E 01	1.48E 02	3.32E 02	3.88E 02	5.31E 02
^{133}Xe	3.85E 00	1.15E 02	2.30E 02	4.59E 02	1.80E 03	2.68E 03	5.17E 03	1.35E 04	1.69E 04	3.84E 04
^{135m}Xe	7.44E-01	1.26E 01	1.60E 01	1.71E 01	1.72E 01	1.72E 01	1.72E 01	1.72E 01	1.72E 01	1.72E 01
^{135}Xe	8.90E-01	2.62E 01	5.14E 01	9.91E 01	3.19E 02	4.19E 02	5.86E 02	6.94E 02	6.96E 02	6.96E 02
^{137}Xe	3.07E 00	1.85E 01	1.85E 01	1.85E 01	1.85E 01	1.85E 01	1.85E 01	1.85E 01	1.85E 01	1.85E 01
^{138}Xe	3.09E 00	4.97E 01	6.12E 01	6.44E 01	6.46E 01	6.46E 01	6.46E 01	6.46E 01	6.46E 01	6.46E 01
Total noble gases	1.62E 01	3.17E 02	5.47E 02	9.50E 02	2.86E 03	3.92E 03	6.71E 03	1.55E 04	1.90E 04	4.14E 04

TABLE 15.4-10

CONTROL ROD DROP ACCIDENT
RADIOLOGICAL EFFECTS (rem)

Area	Time	Thyroid Dose	Whole Body Dose
Exclusion area (1950 m)	2 hr	0.3	0.03
Low population zone (4830 m)	30 days	0.7	0.02

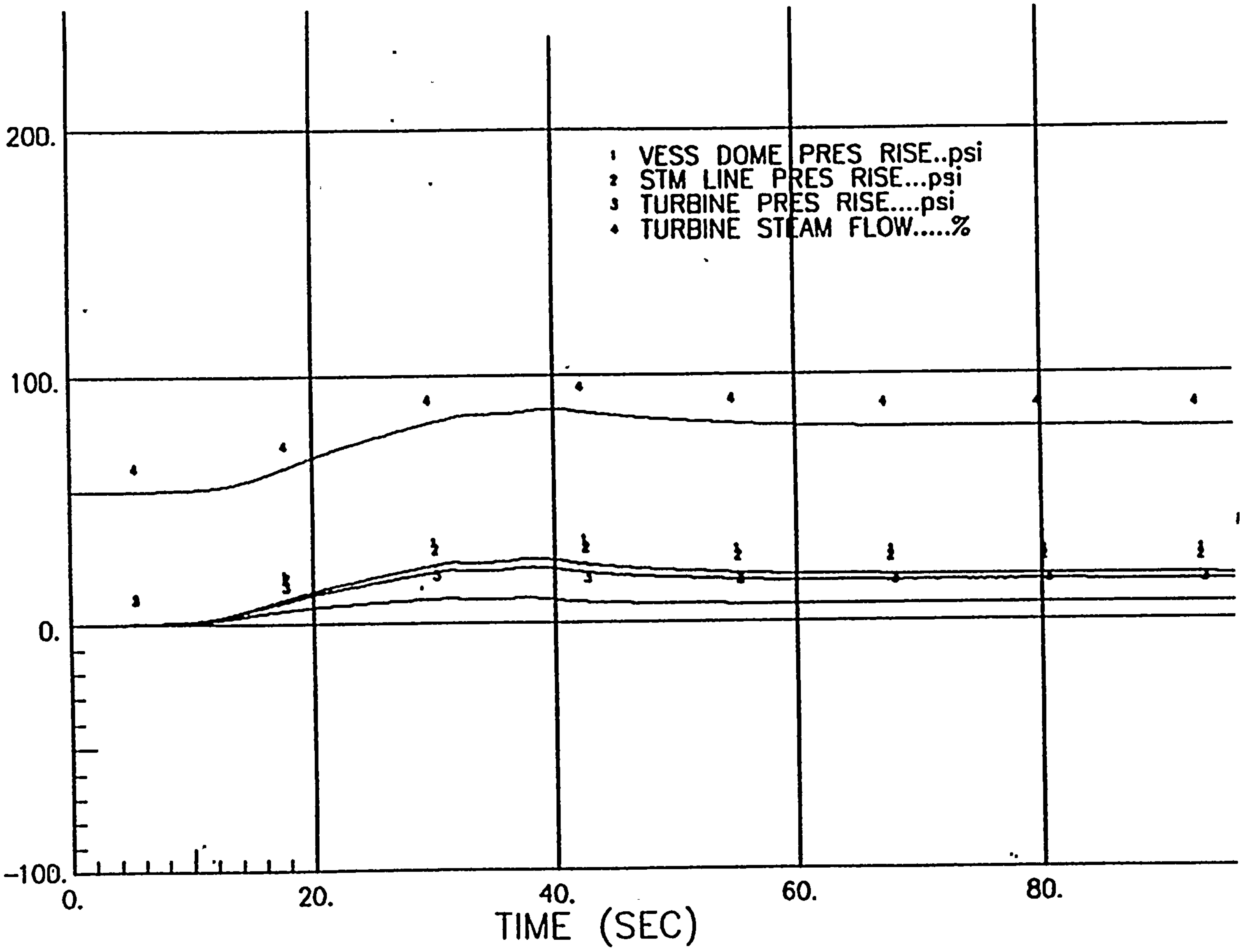


Abnormal Startup of an Idle Recirculation Loop at 57.9% Uprated Power, 34.1% Flow

Draw. No.

Rev.

Figure 15.4-1.1



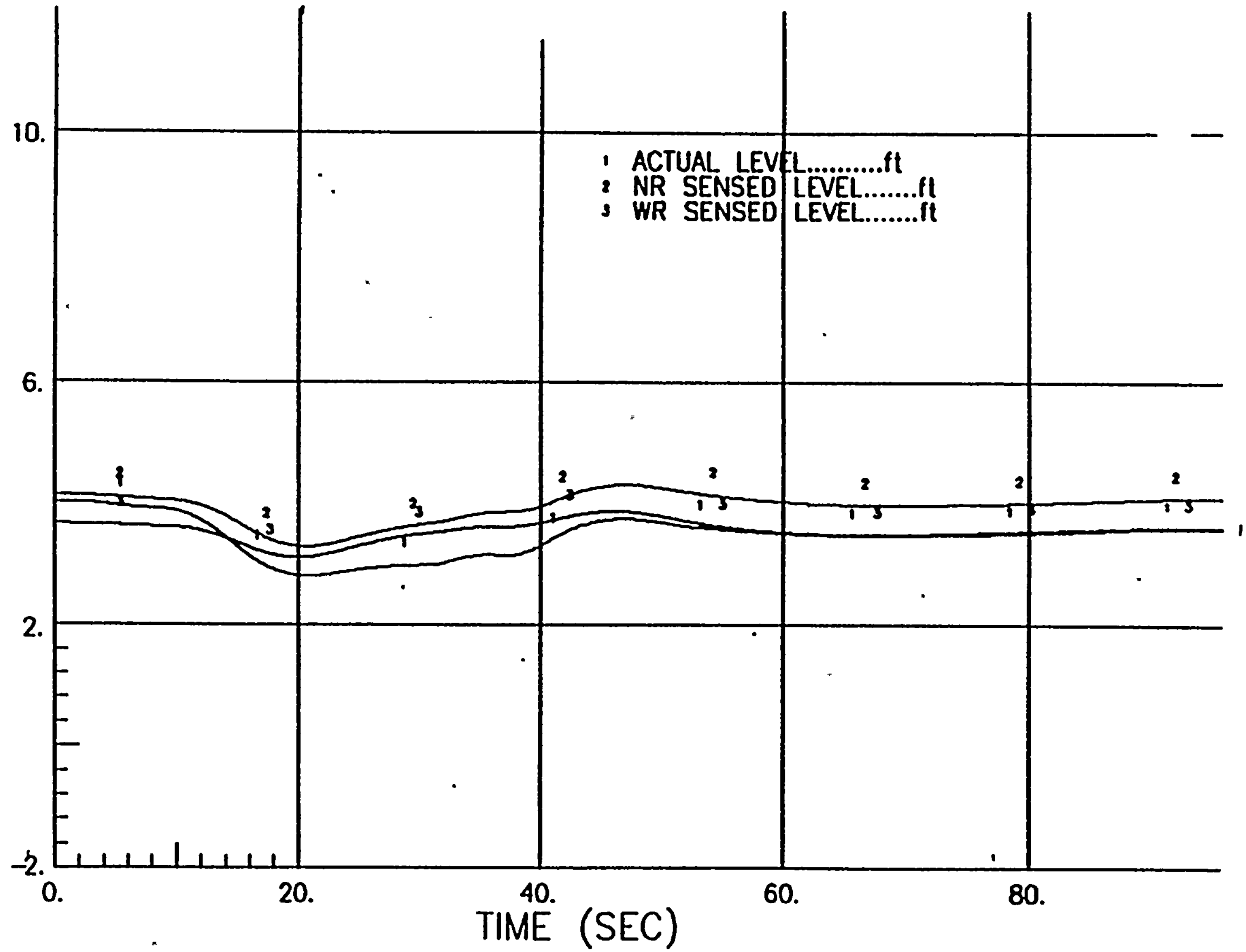
Amendment 53
November 1998

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Abnormal Startup of an Idle Recirculation Loop at 57.9% Uprated Power, 34.1% Flow

Draw. No.	Rev.	Figure
		15.4-1.2

Form No. 960690



Amendment 53
November 1998

WASHINGTON PUBLIC POWER
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NUCLEAR PLANT 2 FSAR

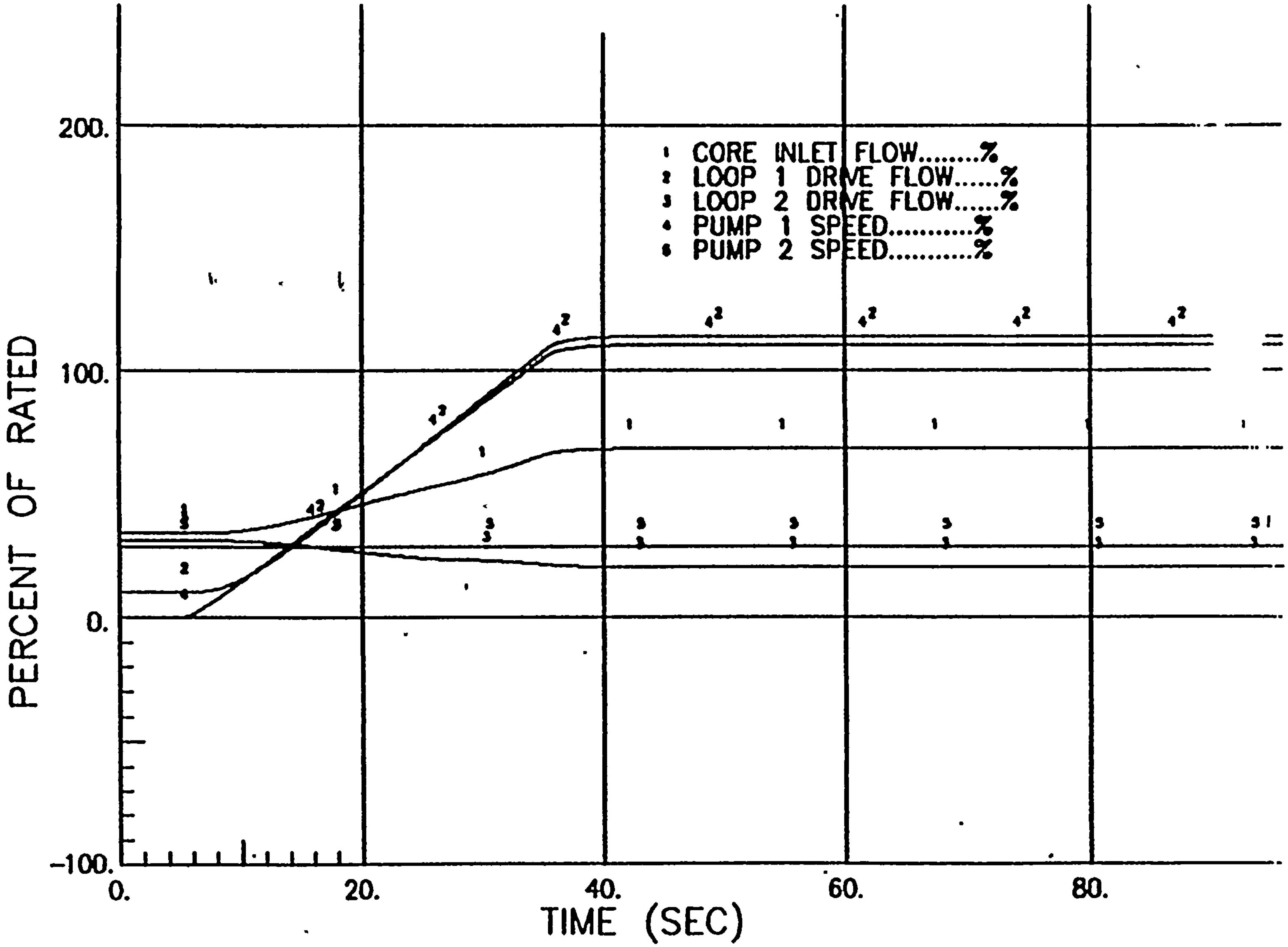
Abnormal Startup of an Idle Recirculation Loop at 57.9% Uprated Power, 34.1% Flow

Draw. No.

Rev.

Figure 15.4-1.3

Form No. 960690



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November 1998

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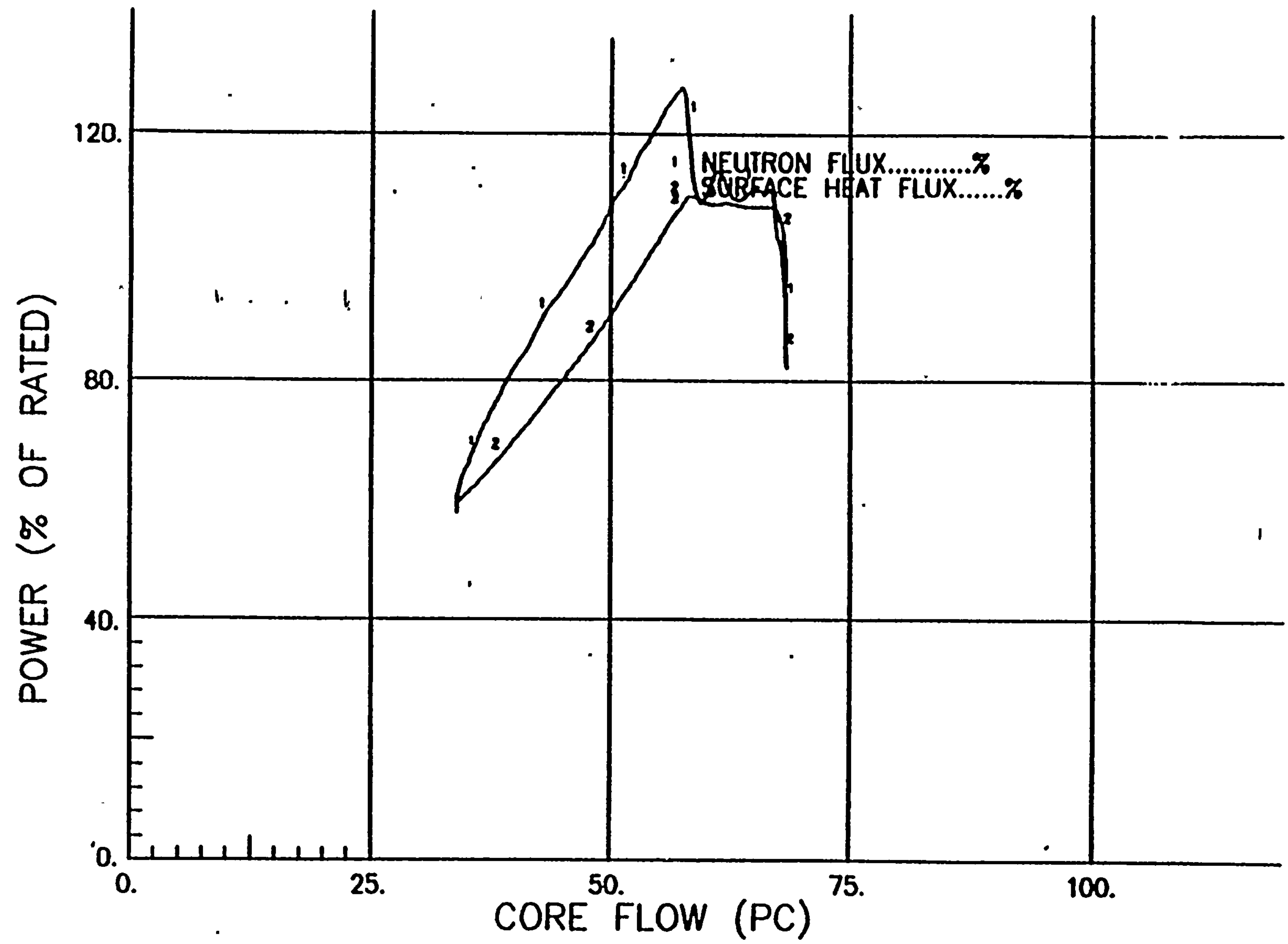
Abnormal Startup of an Idle Recirculation Loop at 57.9% Uprated Power, 34.1% Flow

Draw. No.	Rev.	Figure
		15.4-1.4

Form No. 960690



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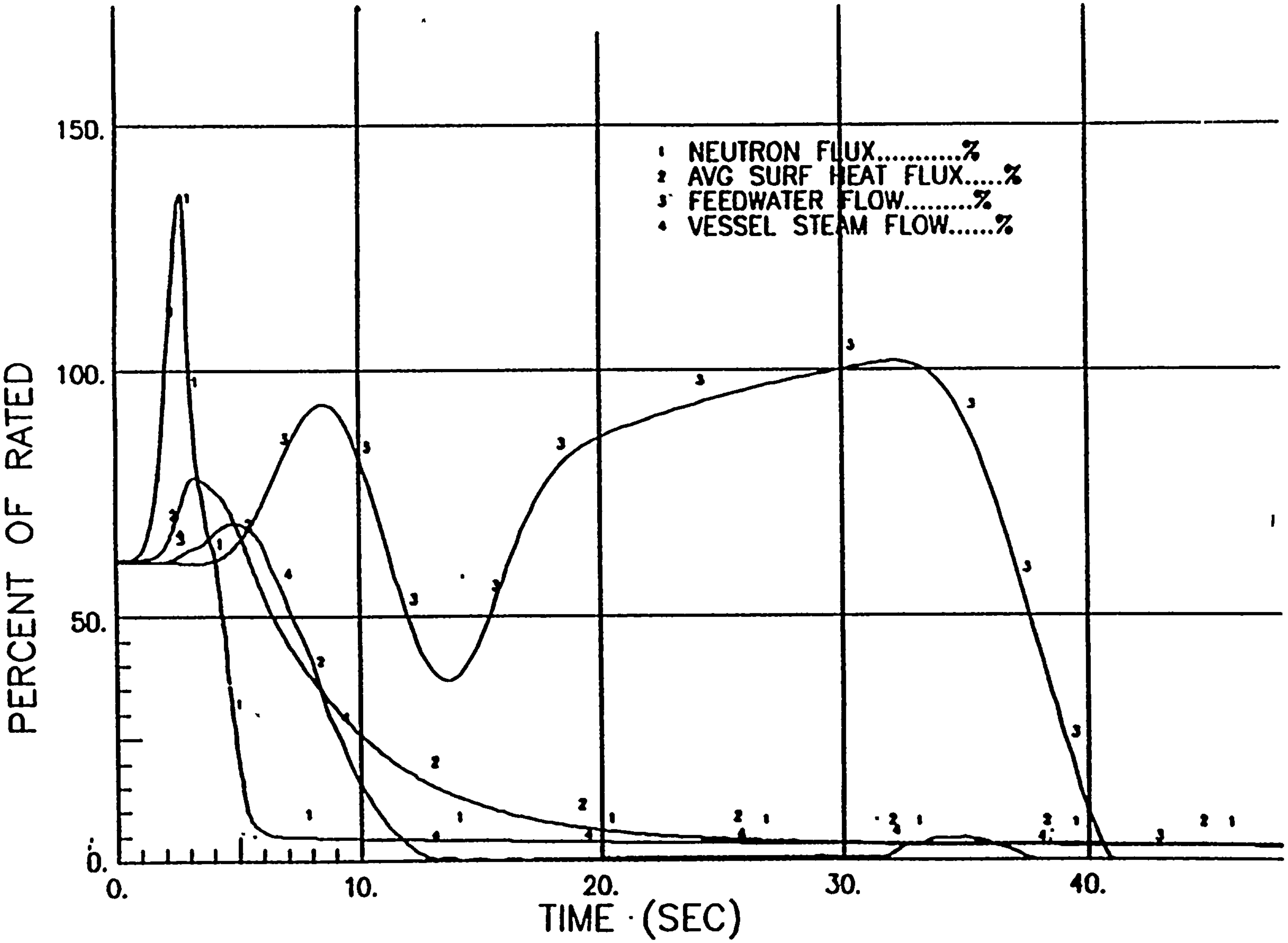
Abnormal Startup of an Idle Recirculation Loop at 57.9% Uprated Power, 34.1% Flow

Draw. No.	Rev.	Figure
		15.4-1.5

Form No. 960690



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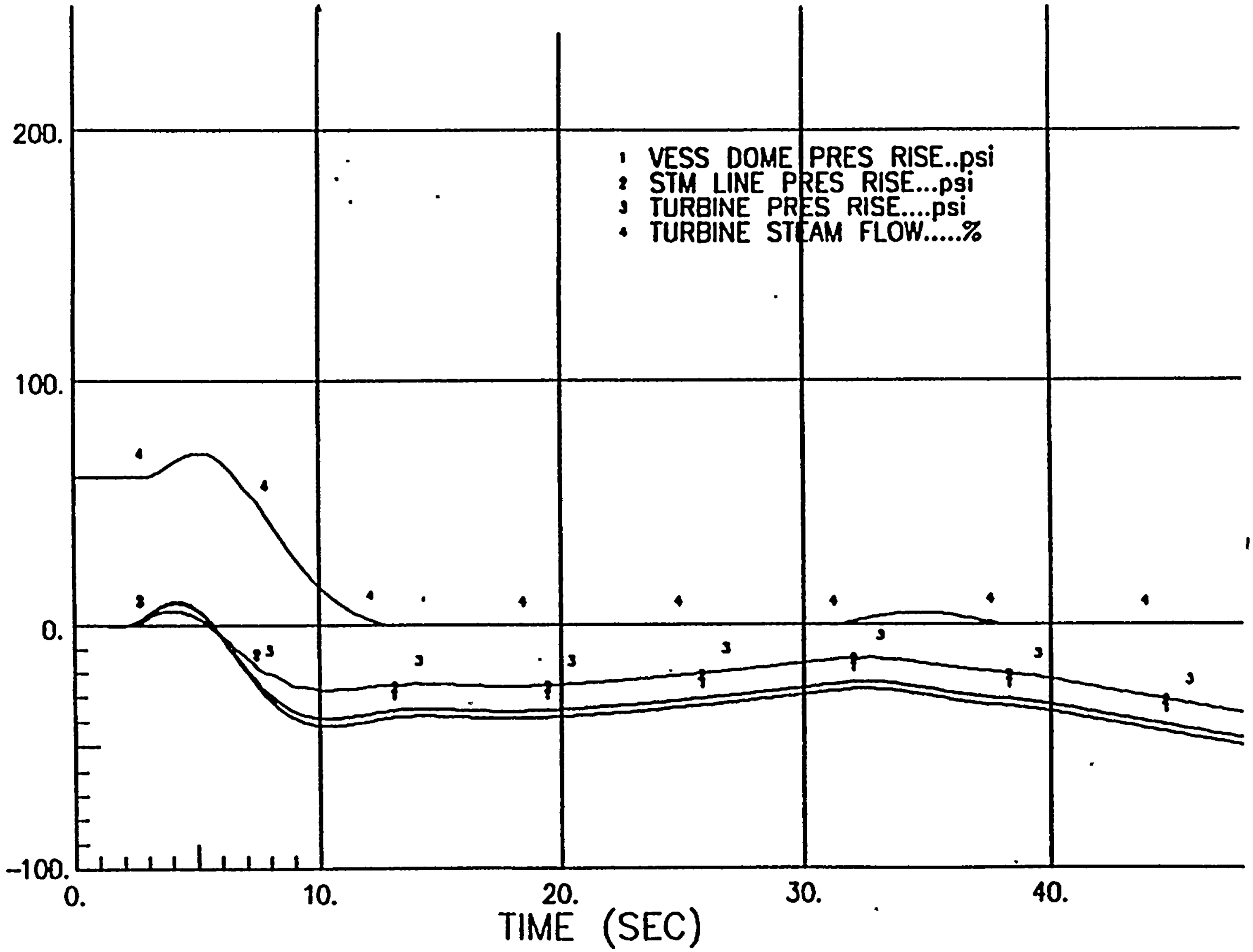
Recirculation Flow Control Failure - Increasing Flow in One Loop, (25%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.	Rev.	Figure
		15.4-2.1

Form No. 960690



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Recirculation Flow Control Failure - Increasing Flow in One Loop, (25%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.

Rev.

Figure 15.4-2.2

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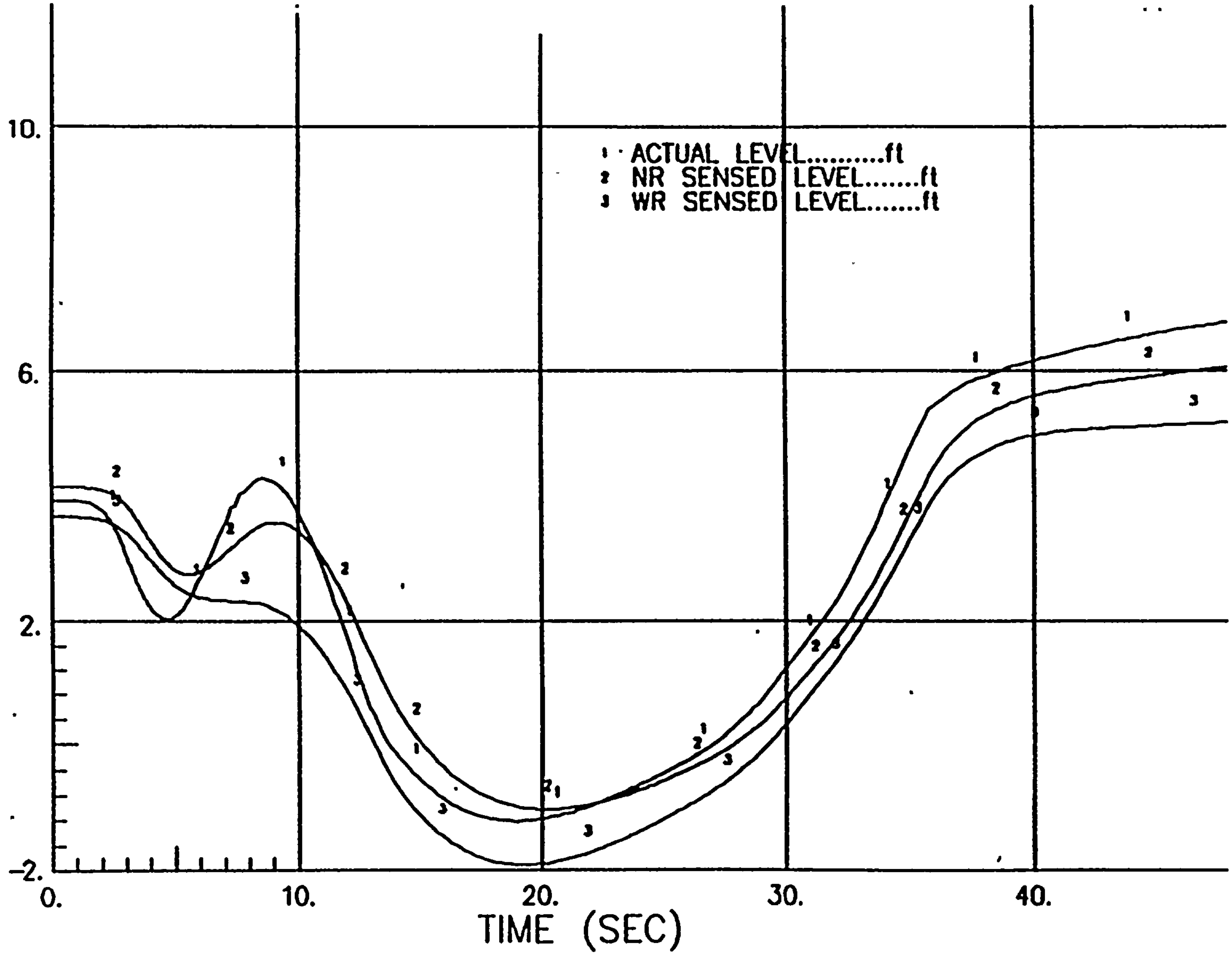

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NUCLEAR PLANT 2 FSAR

Recirculation Flow Control Failure - Increasing Flow in One Loop, (25%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.	Rev.	Figure
		15.4-2.3

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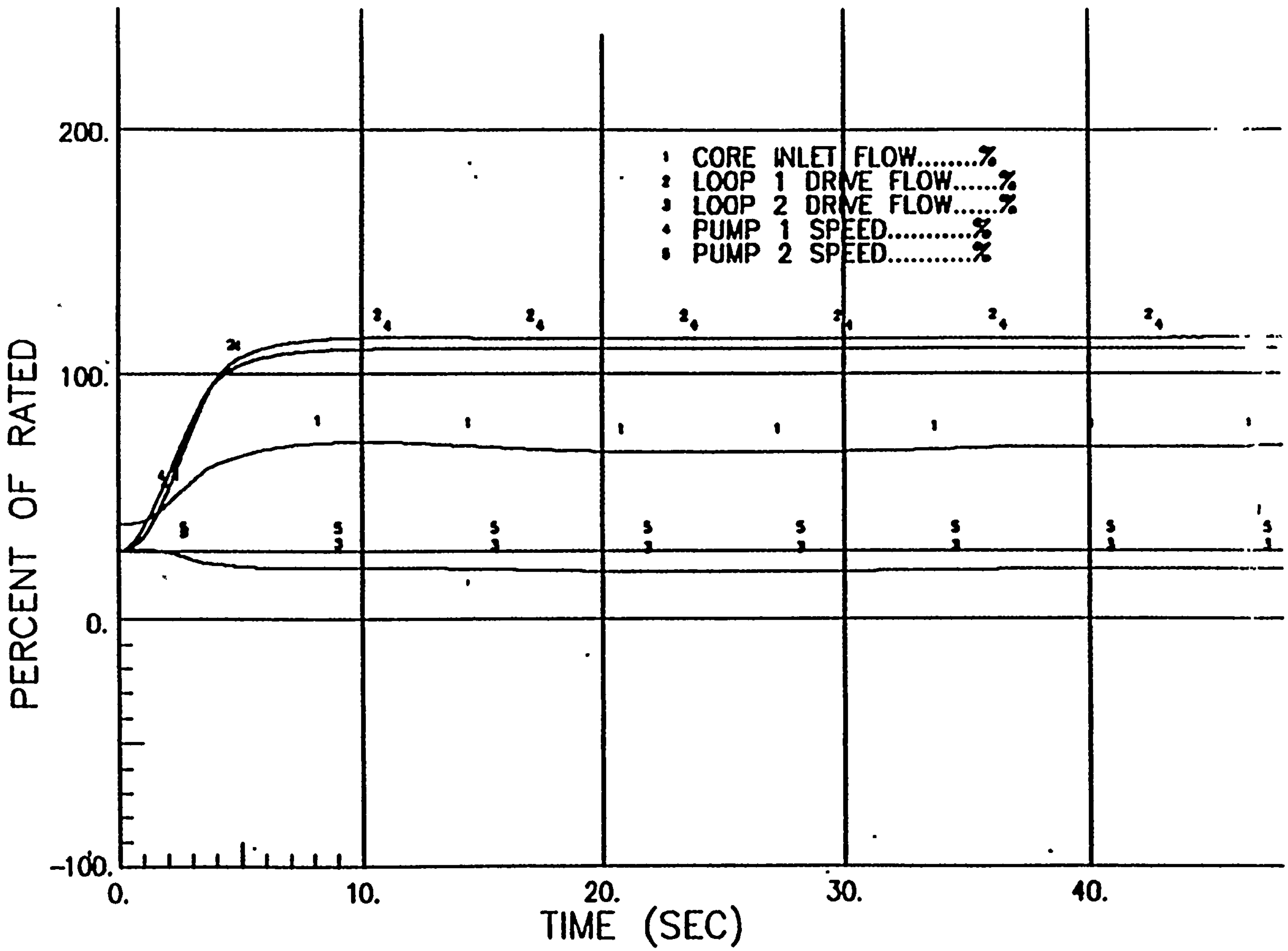
Form No. 960690



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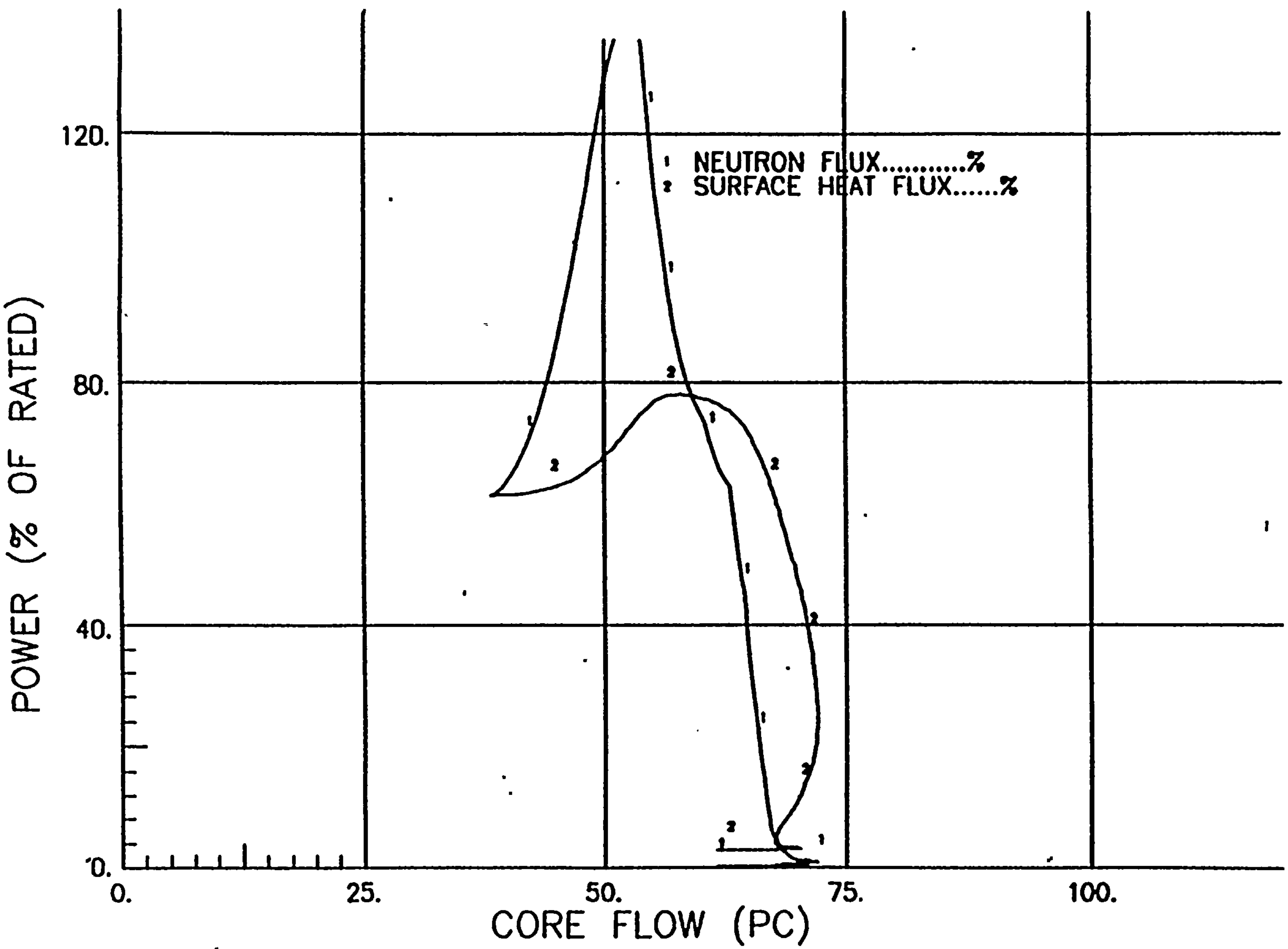
Recirculation Flow Control Failure - Increasing Flow in One Loop, (25%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.	Rev.	Figure
		15.4-2.4



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Recirculation Flow Control Failure - Increasing Flow in One Loop, (25%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.	Rev.	Figure
		15.4-2.5

Amendment 53
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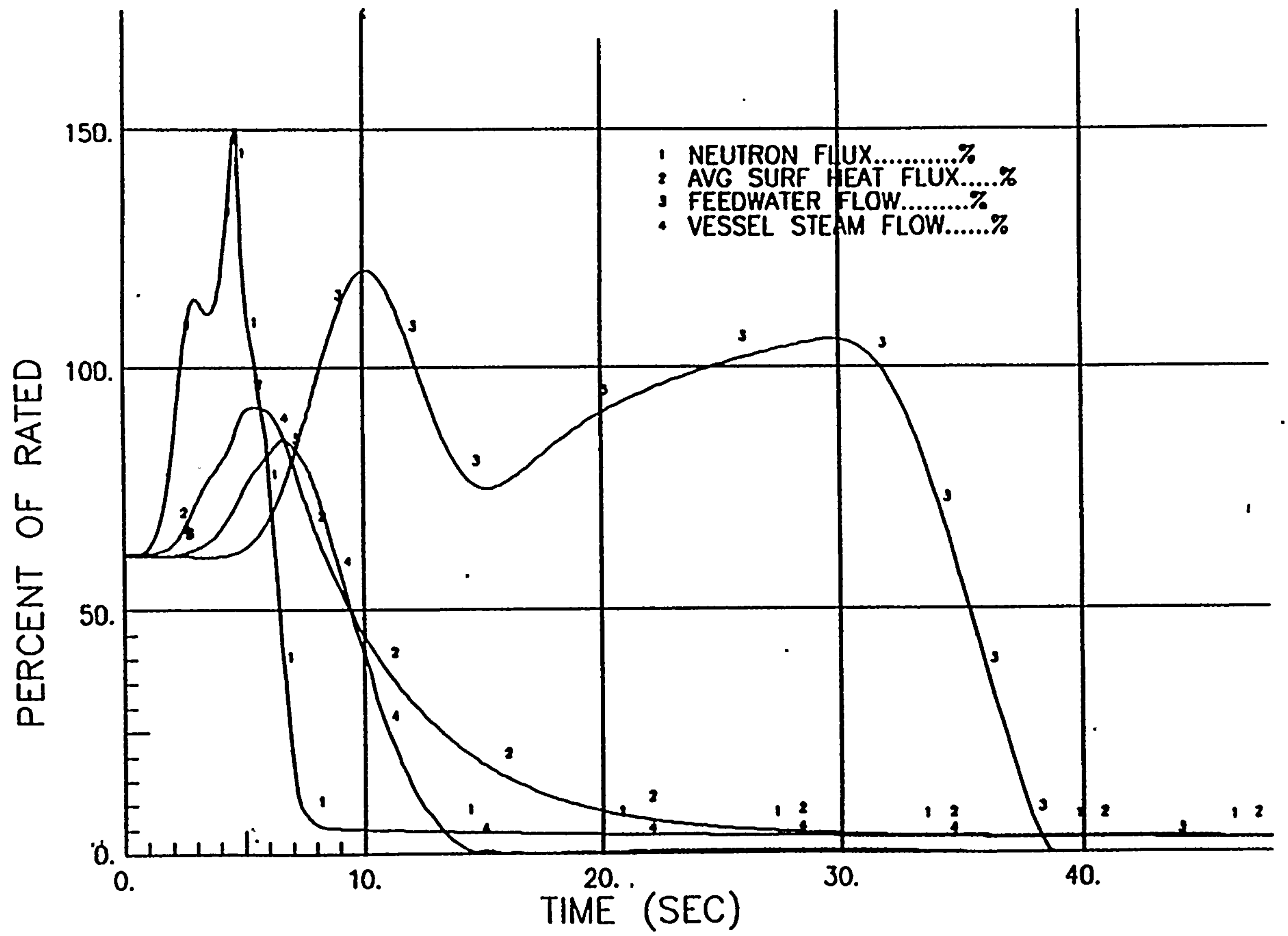

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Recirculation Flow Control Failure - Increasing Flow in Two Loops, (10%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.	Rev.	Figure
		15.4-3.1

Amendment 53
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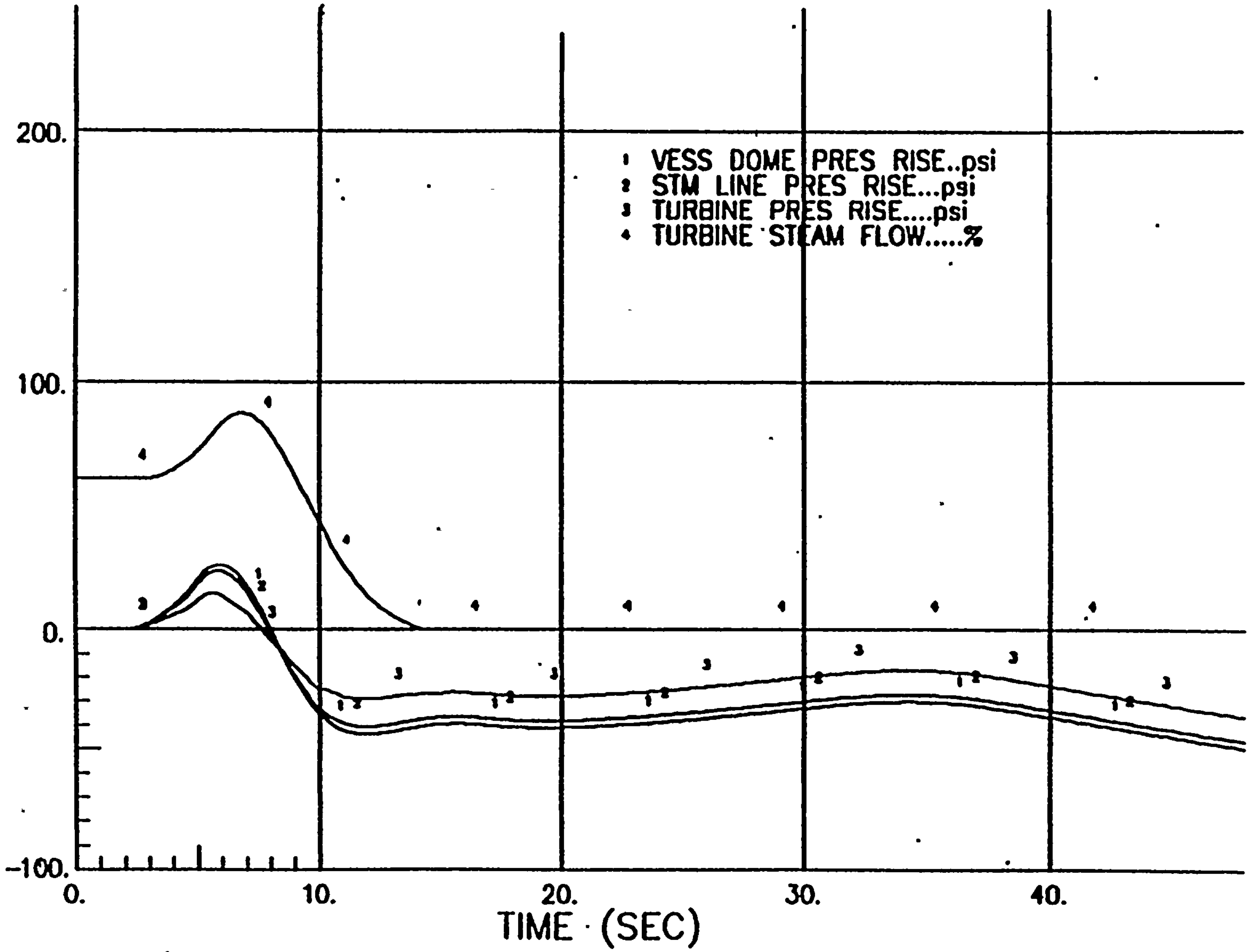
Form No. 96690

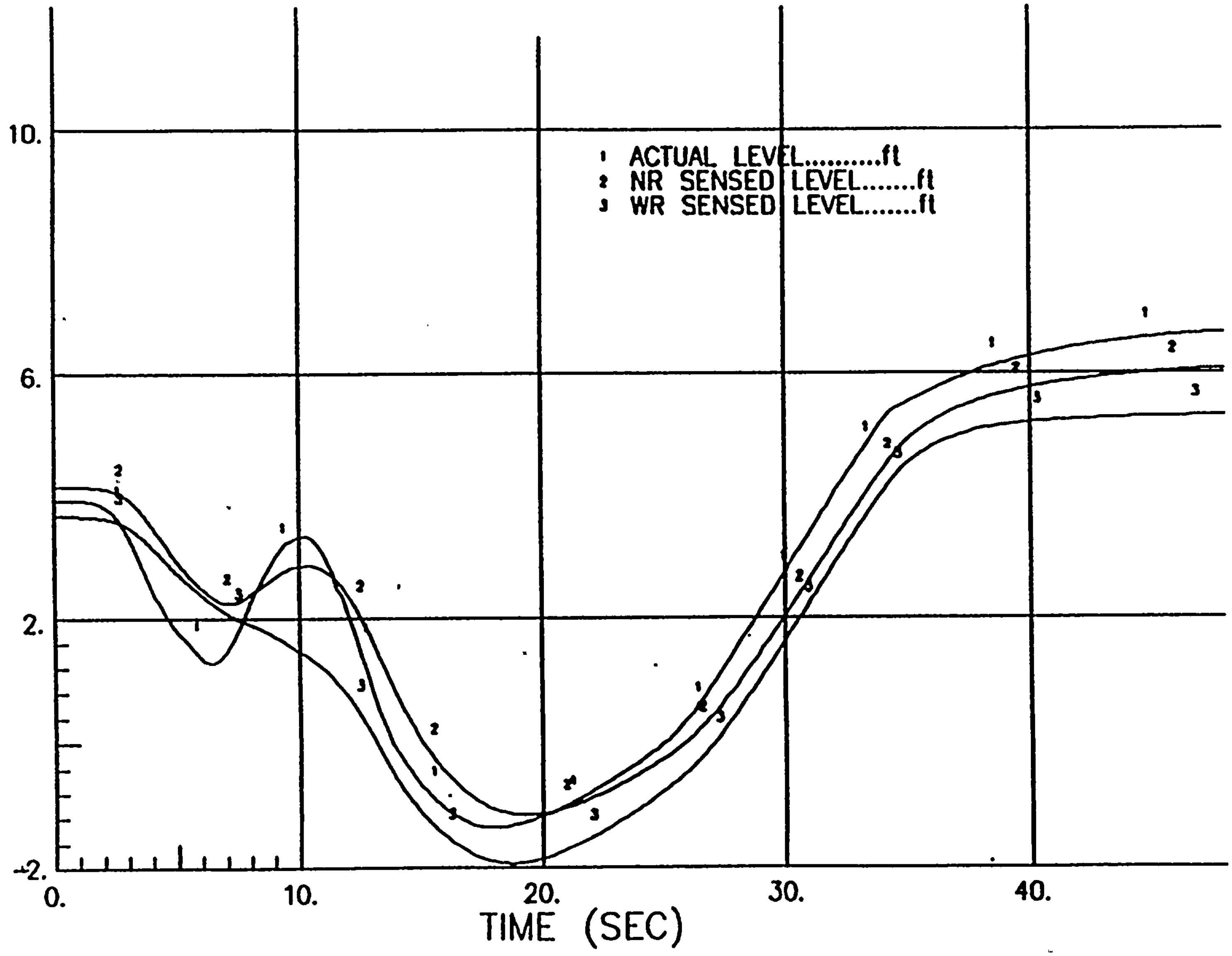


Recirculation Flow Control Failure - Increasing Flow in Two Loops, (10%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.

Rev.

Figure 15.4-3.2



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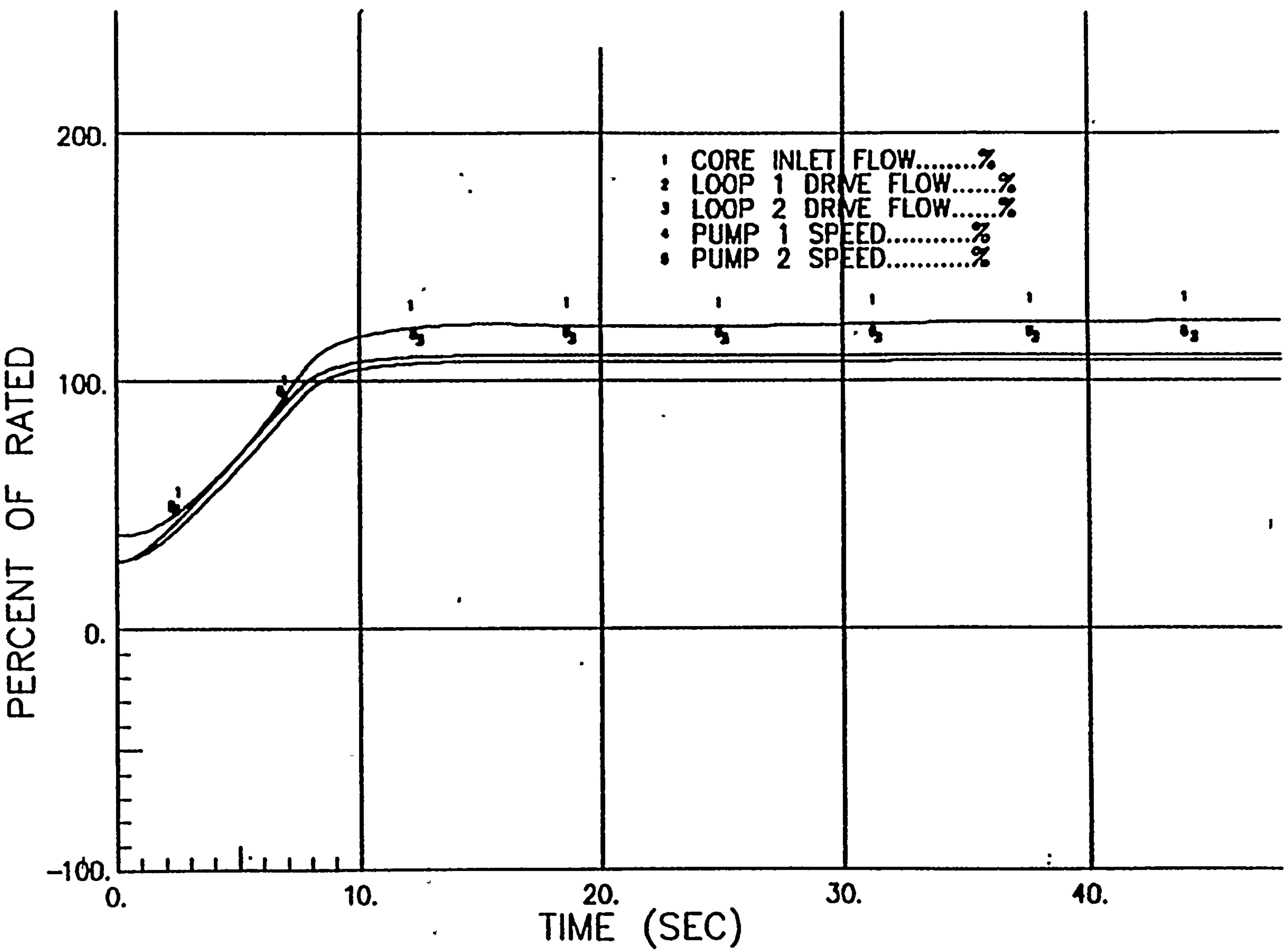
Recirculation Flow Control Failure - Increasing Flow in Two Loops, (10%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.	Rev.	Figure
		15.4-3.3

Form No. 960690



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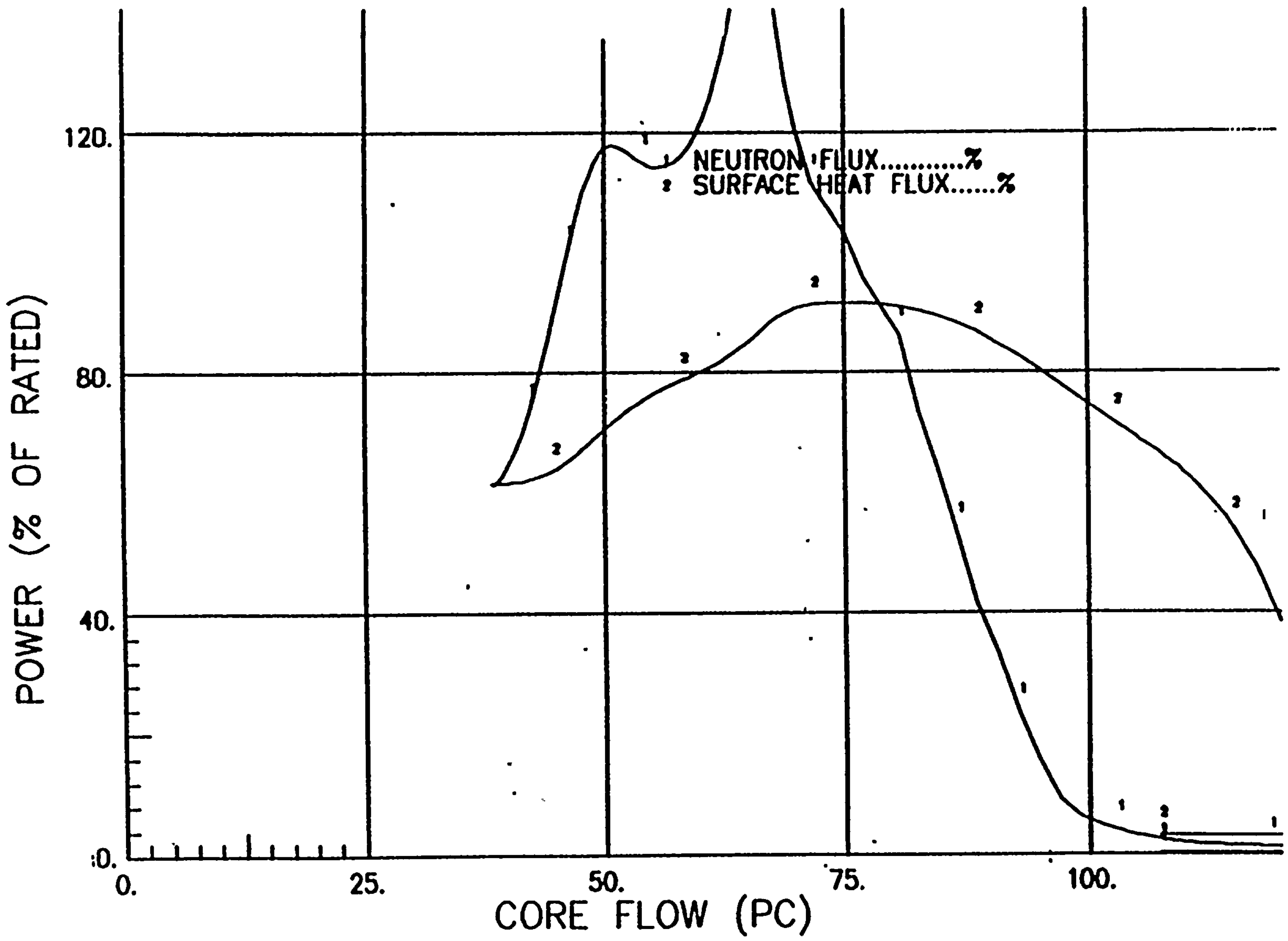
Recirculation Flow Control Failure - Increasing Flow in Two Loops, (10%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

Draw. No.	Rev.	Figure
		15.4-3.4

Form No. 960690



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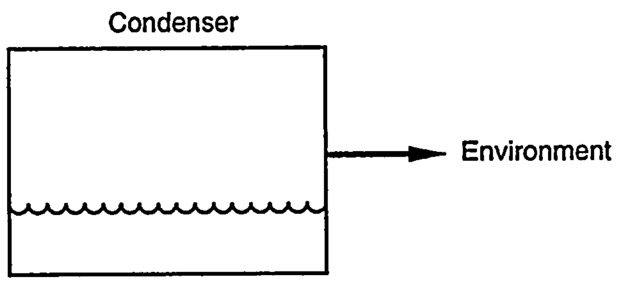
Recirculation Flow Control Failure - Increasing Flow in Two Loops, (10%/Sec Ramp) at 61.4% Uprated Power, 38.3% Flow

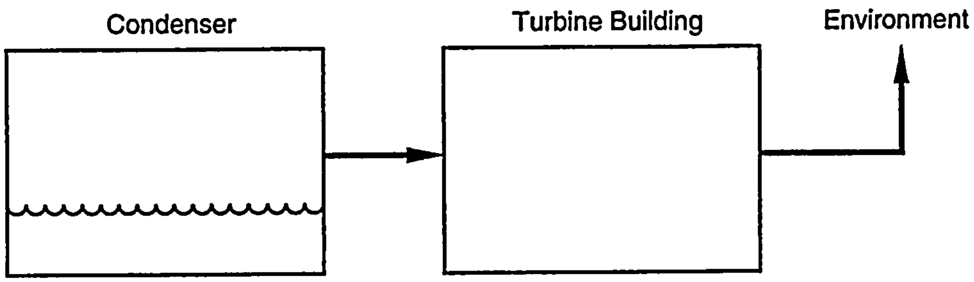
Draw. No.	Rev.	Figure
		15.4-3.5

Form No. 960690

1. Design Basis Evaluation



2. Realistic Basis Evaluation



Leakage Path Model for Rod Drop Accident
(Original Rated Power)

15.5 INCREASE IN REACTOR COOLANT INVENTORY

15.5.1 INADVERTENT HIGH-PRESSURE CORE SPRAY STARTUP

This transient is classified as a nonlimiting event for both original and uprated power conditions. Inadvertent startup of the high-pressure core spray (HPCS) system was chosen to be analyzed since it provides the greatest auxiliary source of cold water into the vessel.

15.5.1.1 Identification of Causes and Frequency Classification

15.5.1.1.1 Identification of Causes

Manual startup (i.e., operator error) of the HPCS system is postulated for this analysis.

15.5.1.1.2 Frequency Classification

This transient disturbance is categorized as an incident of moderate frequency.

15.5.1.2 Sequence of Events and Systems Operation

15.5.1.2.1 Sequence of Events

Table 15.5-1 lists the sequence of events for Figure 15.5-1.

15.5.1.2.1.1 Identification of Operator Actions. With the recirculation system in the manual mode, relatively small changes would be experienced in plant conditions. Following HPCS initiation, the operator should check reactor water level and drywell pressure and take any necessary follow-up actions.

15.5.1.2.2 Systems Operation

In order to properly simulate the expected sequence of events, the analysis assumes normal functioning of plant instrumentation and controls, such as the pressure regulator and the vessel level control.

Required operation of engineered safety features (ESF) other than what is described is not expected for this transient event.

15.5.1.2.3 The Effect of Single Failures and Operator Errors

Inadvertent operation of the HPCS system results in a mild pressurization. Pressure regulator actuation and/or level control is expected to establish a new stable operating state. The effect

of a single failure in the pressure regulator will aggravate the transient depending upon the nature of the failure.

The effect of a single failure in the level control system has rather straightforward consequences including level rise or fall by improper control of the feedwater system. Increasing level will trip the turbine and automatically trip the HPCS system. Decreasing level will automatically initiate a scram at the L3 level trip.

15.5.1.3 Core and System Performance

15.5.1.3.1 Mathematical Model

The detailed nonlinear dynamic model described in Section 15.2.2.3.1 is used to simulate this transient.

15.5.1.3.2 Input Parameter and Initial Conditions

This analysis has been performed, unless otherwise noted, with plant conditions in Table 15.0-2.

The water temperature of the HPCS system was assumed to be 40°F with an enthalpy of 11 Btu/lb.

15.5.1.3.3 Results

Table 15.5-1 shows the sequence of events for this transient. Initially the HPCS pump is started. Within 1 sec the full HPCS flow is established at approximately 7.8% of rated feedwater flow rate. The addition of cooler water to the upper plenum causes a reduction in steam, which results in some depressurization as the pressure regulator responds to the event. As the steam flow decreases, the feedwater system tries to respond by decreasing flow. At approximately 45 sec the reactor reaches a new equilibrium condition at approximately 102% power and 100% core flow.

The calculated uncorrected ΔCPR for the simulated 8 x 8 and 9 x 9 bundles is less than 0.01. A summary of transient key peak values is found in Table 15.0-1.

15.5.1.3.3.1 Consideration of Uncertainties. Important analytical factors including reactivity coefficient and feedwater temperature change have been assumed to be at the worst conditions so that any deviations in the actual plant parameters will produce a less severe transient.

15.5.1.4 Barrier Performance

Figure 15.5-1 indicates only a slight pressure reduction from initial conditions; therefore, reactor coolant pressure boundary pressure margins are not impacted.

15.5.1.5 Radiological Consequences

Since no radioactivity is released during this event, a detailed evaluation is not required.

15.5.2 CHEMICAL VOLUME CONTROL SYSTEM MALFUNCTION (OR OPERATOR ERROR)

This event is not applicable to boiling water reactor plants.

15.5.3 BOILING WATER REACTOR TRANSIENTS WHICH INCREASE REACTOR COOLANT INVENTORY

These events are discussed in Sections 15.1 and 15.2.

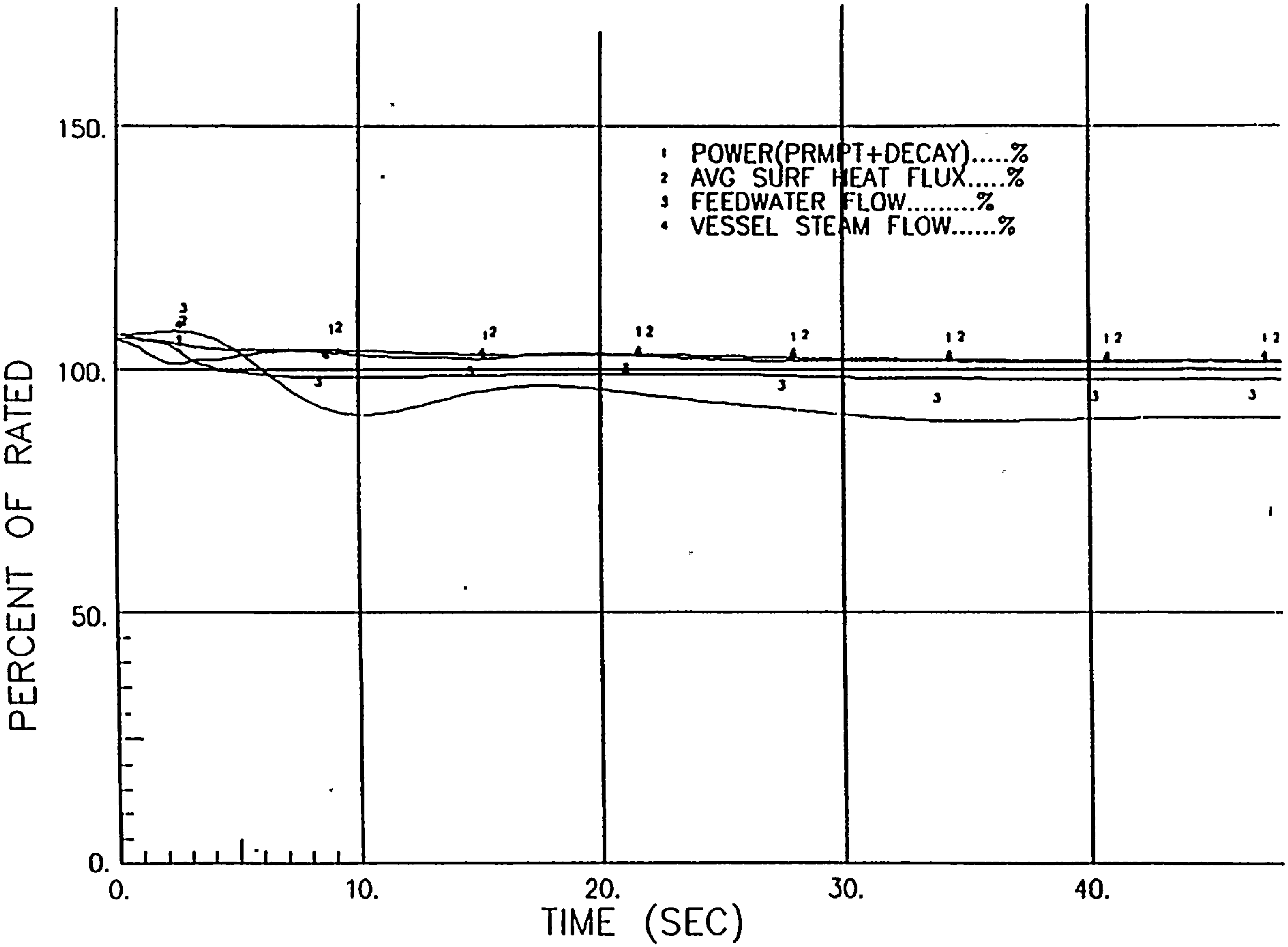
TABLE 15.5-1

SEQUENCE OF EVENTS FOR FIGURE 15.5-1

Inadvertent High-Pressure Core Spray Pump Start
Uprated Power

Time (sec)	Event
0	Simulate HPCS cold water injection
1	Full flow established for HPCS
45[a]	Depressurization effect stabilized

[a] Approximately.



Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No. | Rev. | Figure 15.5-1.1

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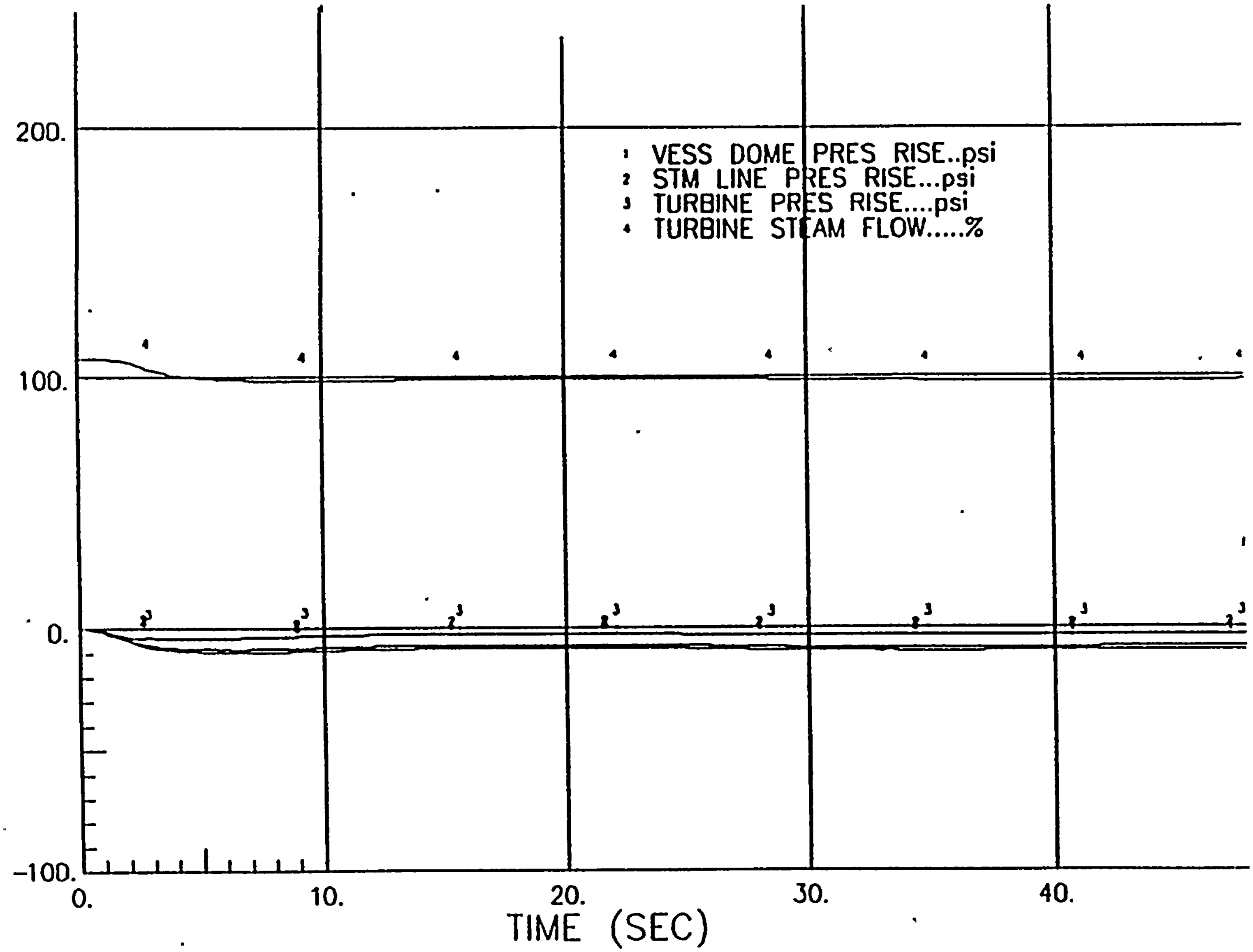

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Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.5-1.2

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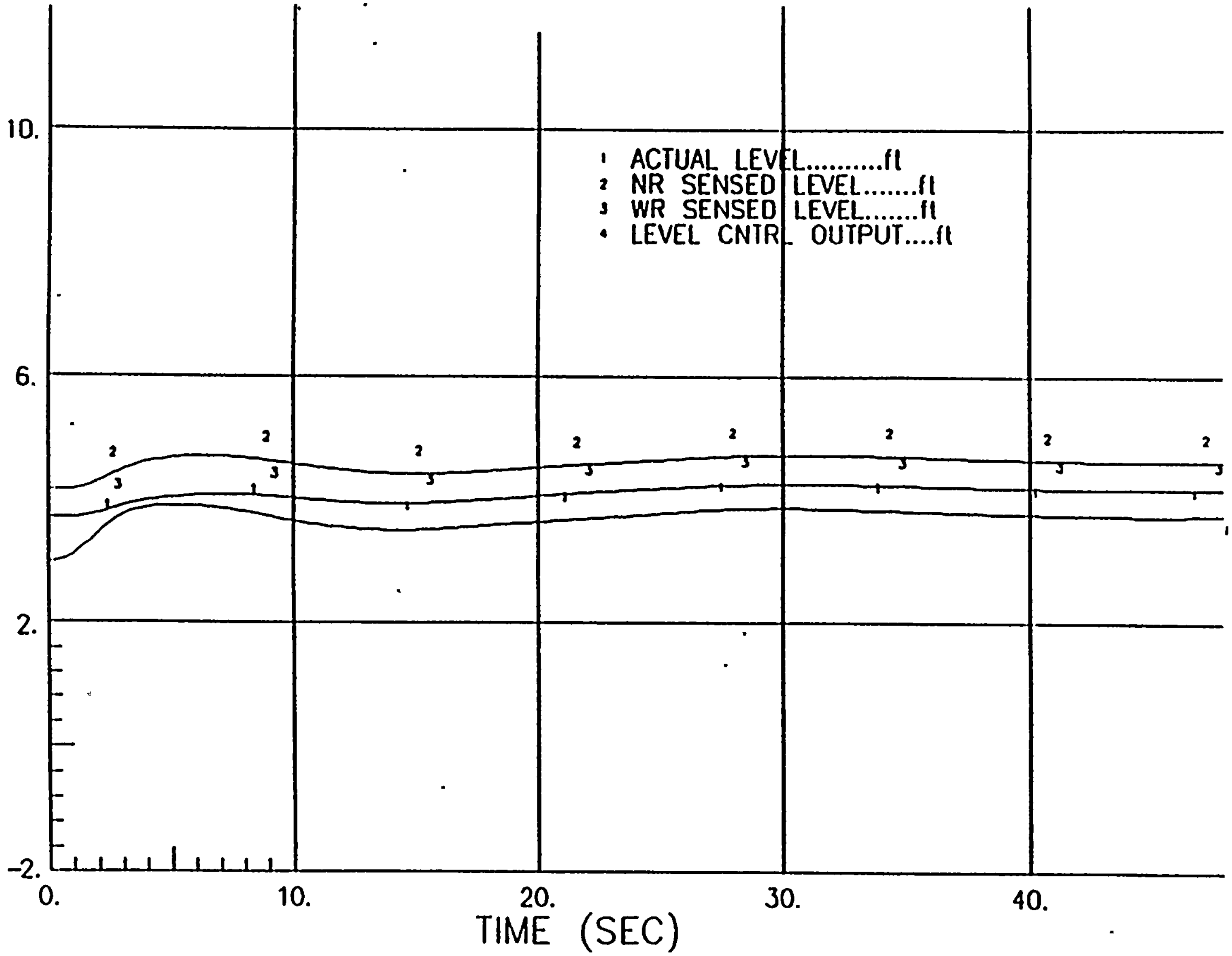

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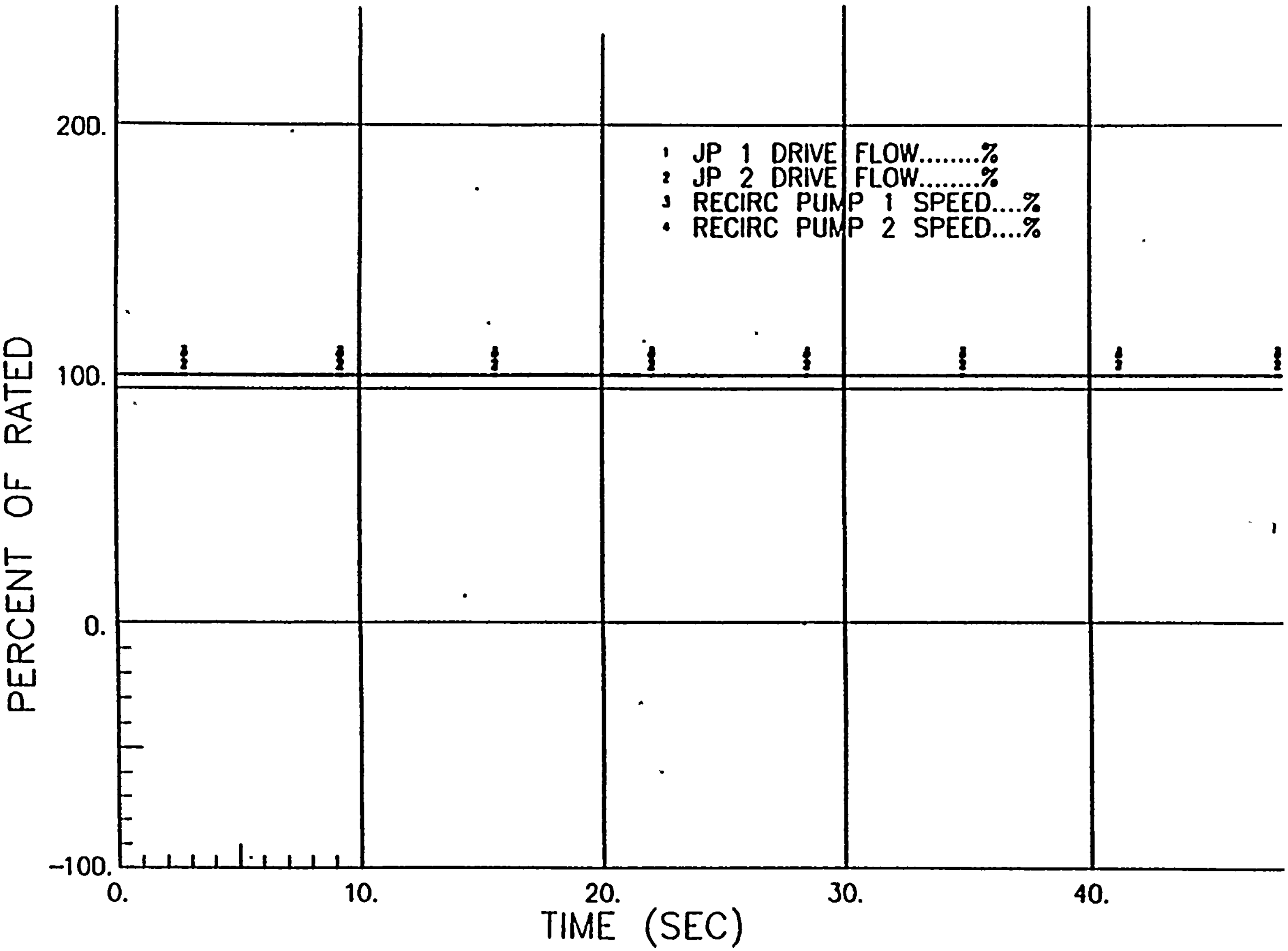
Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.5-1.3



Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No. | Rev. | Figure 15.5-1.4

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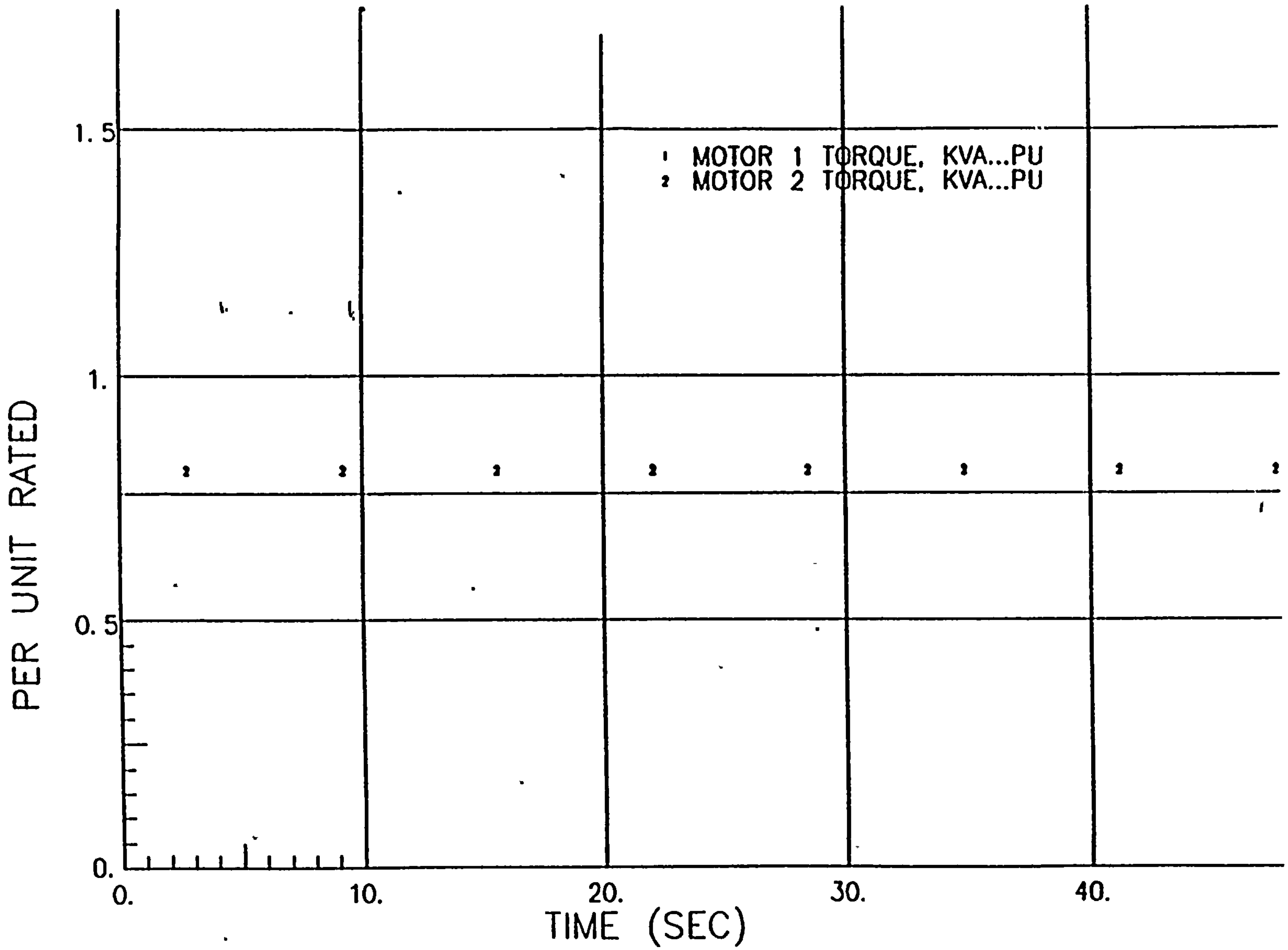

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Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.5-1.5

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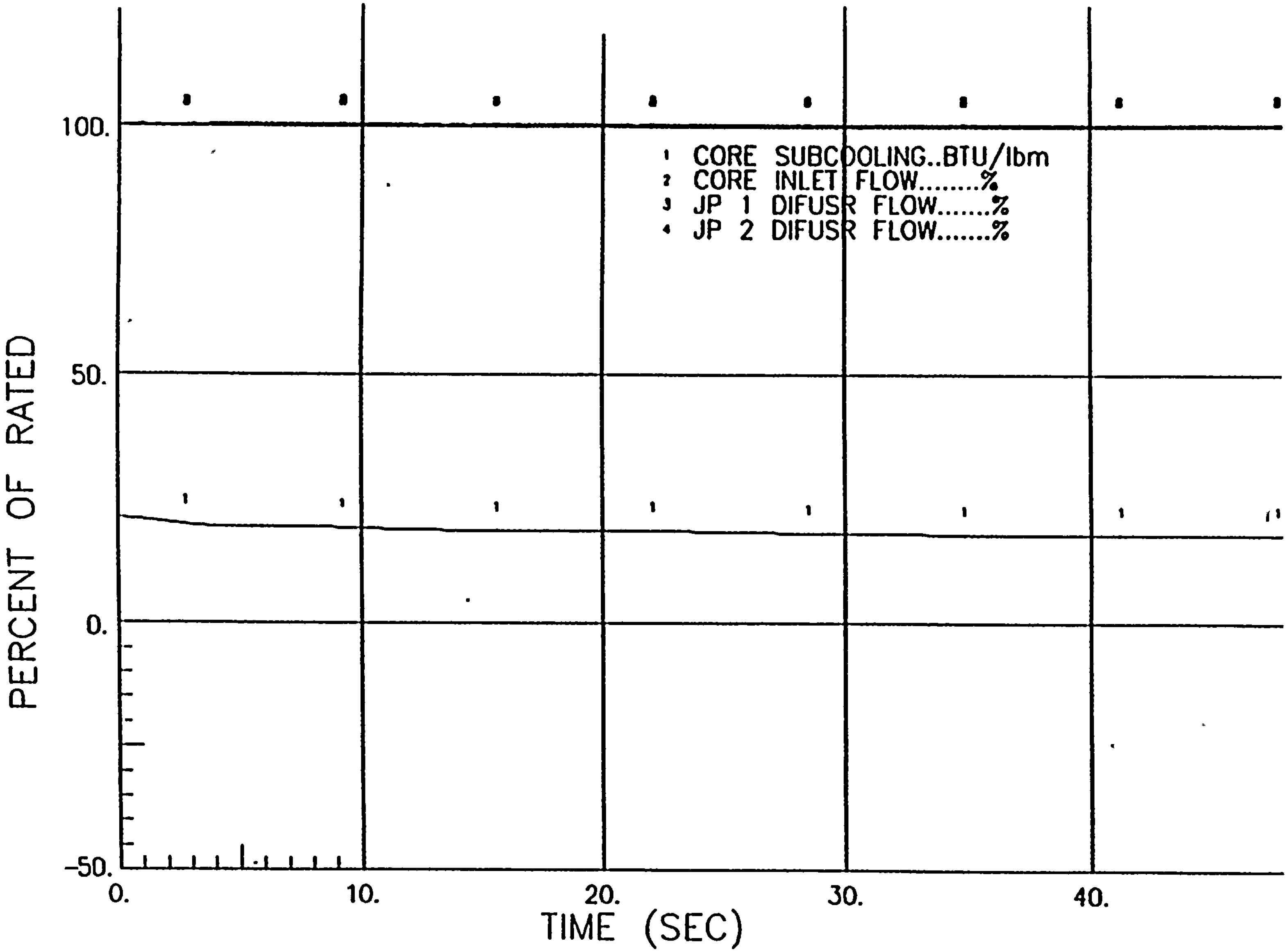

Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.

Rev.

Figure 15.5-1.6

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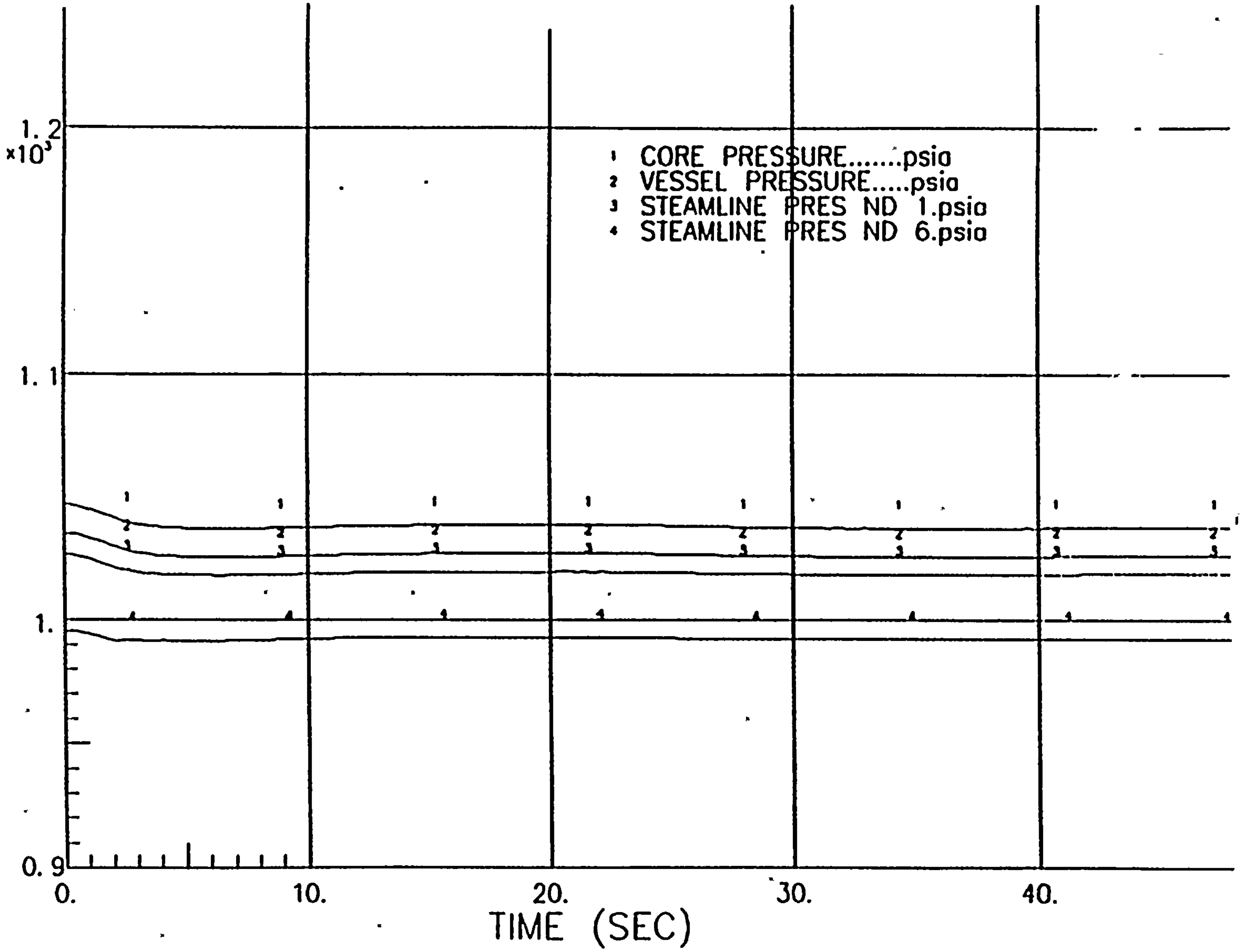

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Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.5-17

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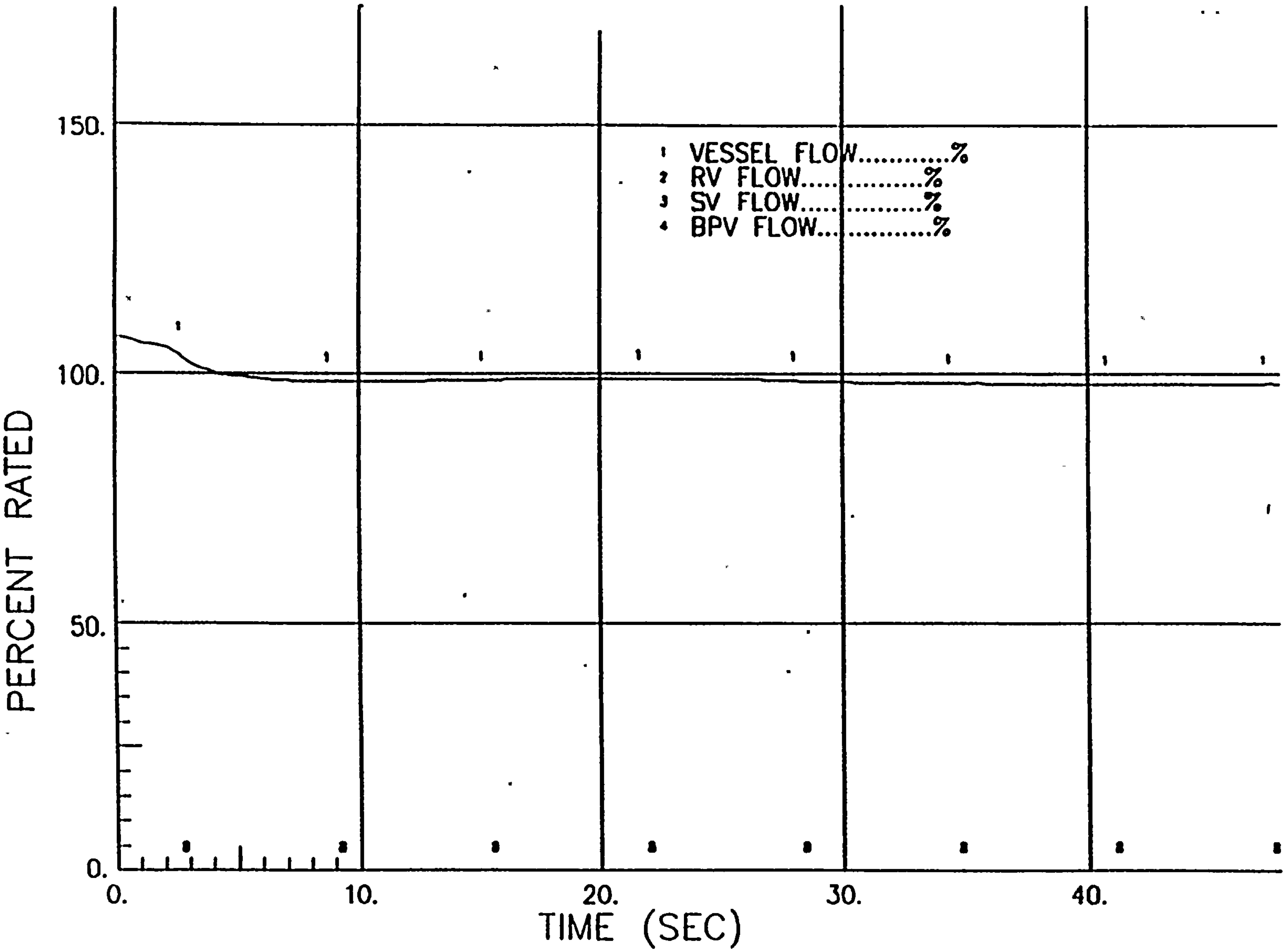
Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.5-1.8



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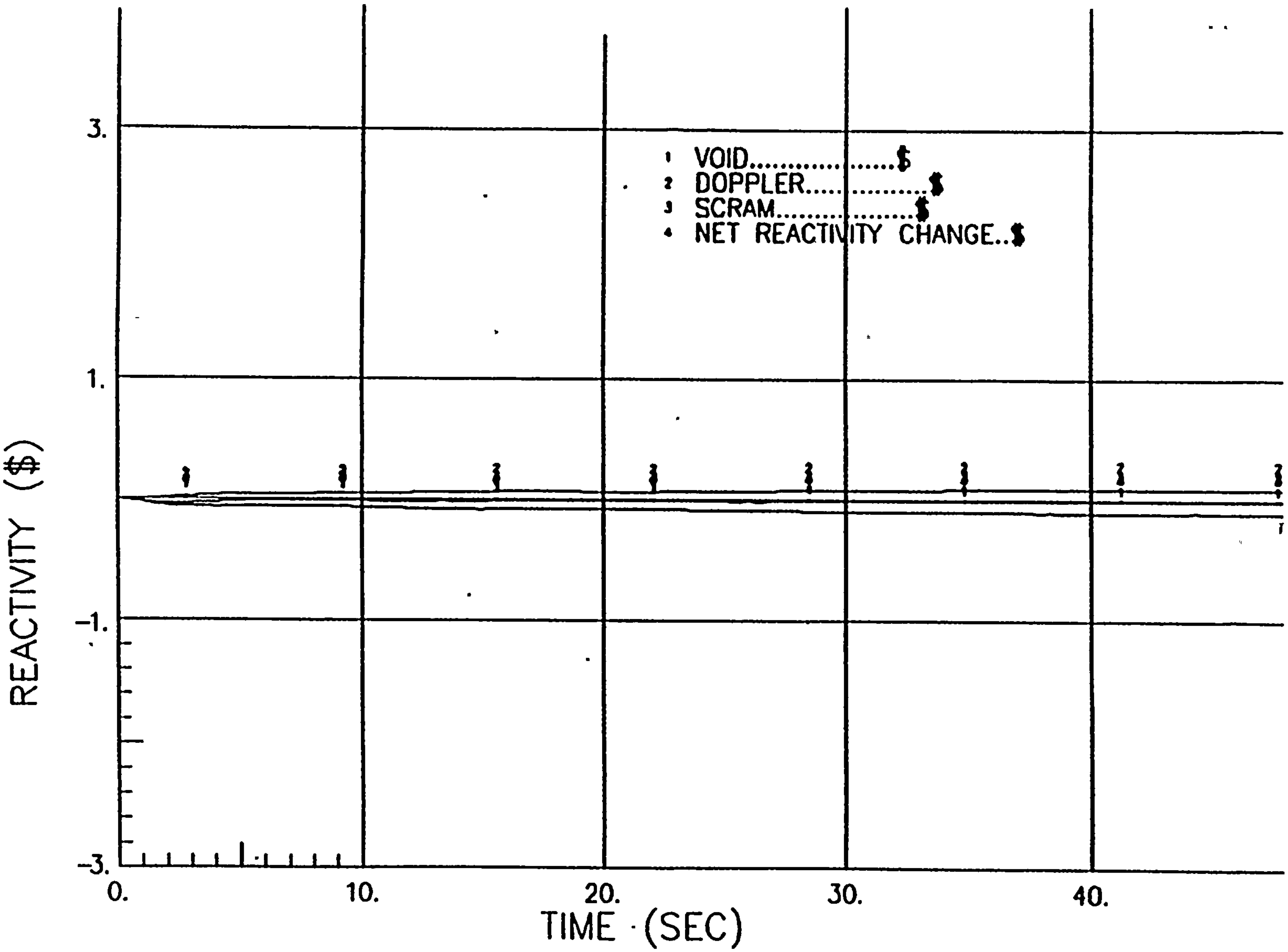

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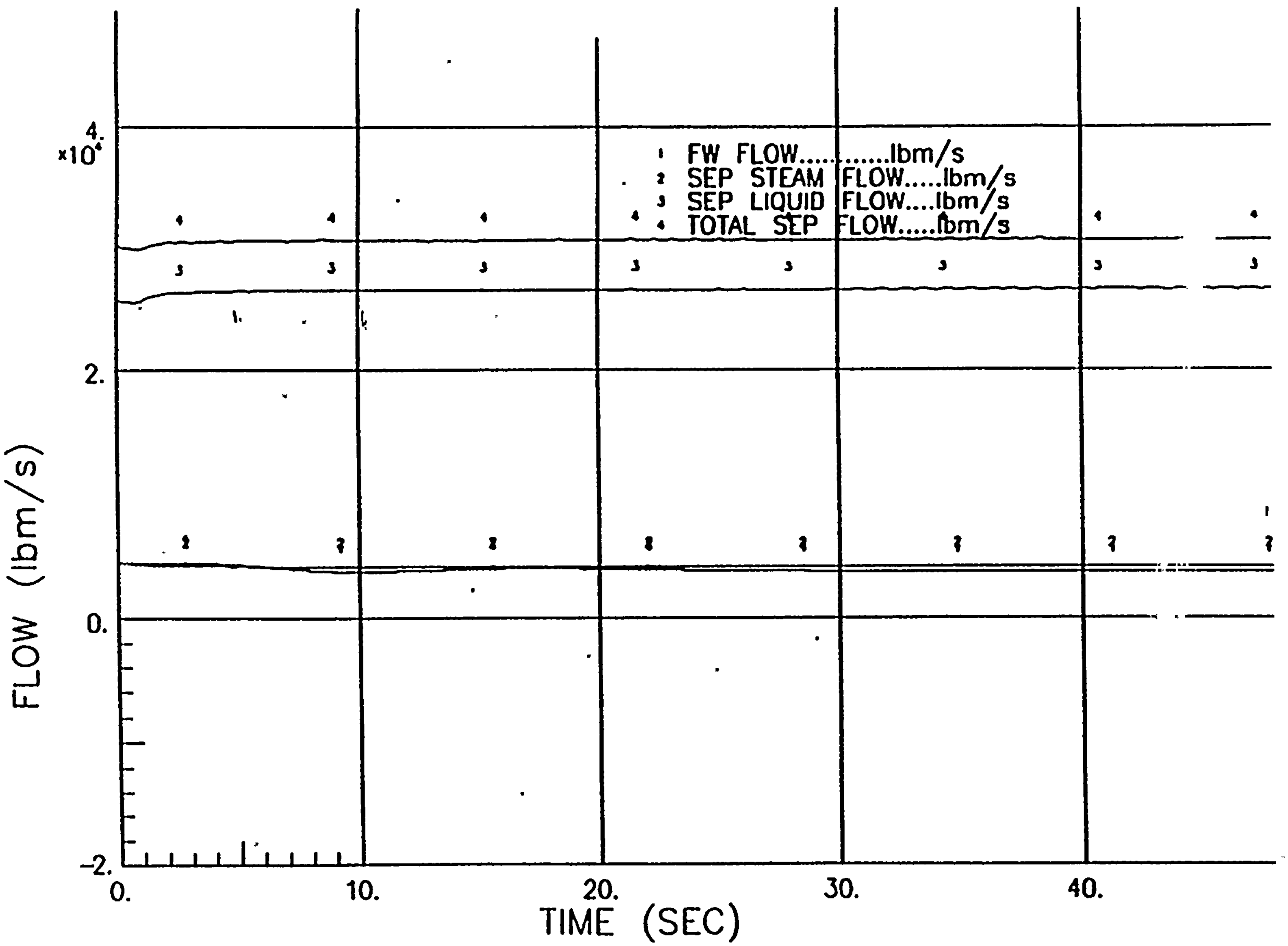
Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.5-1.9



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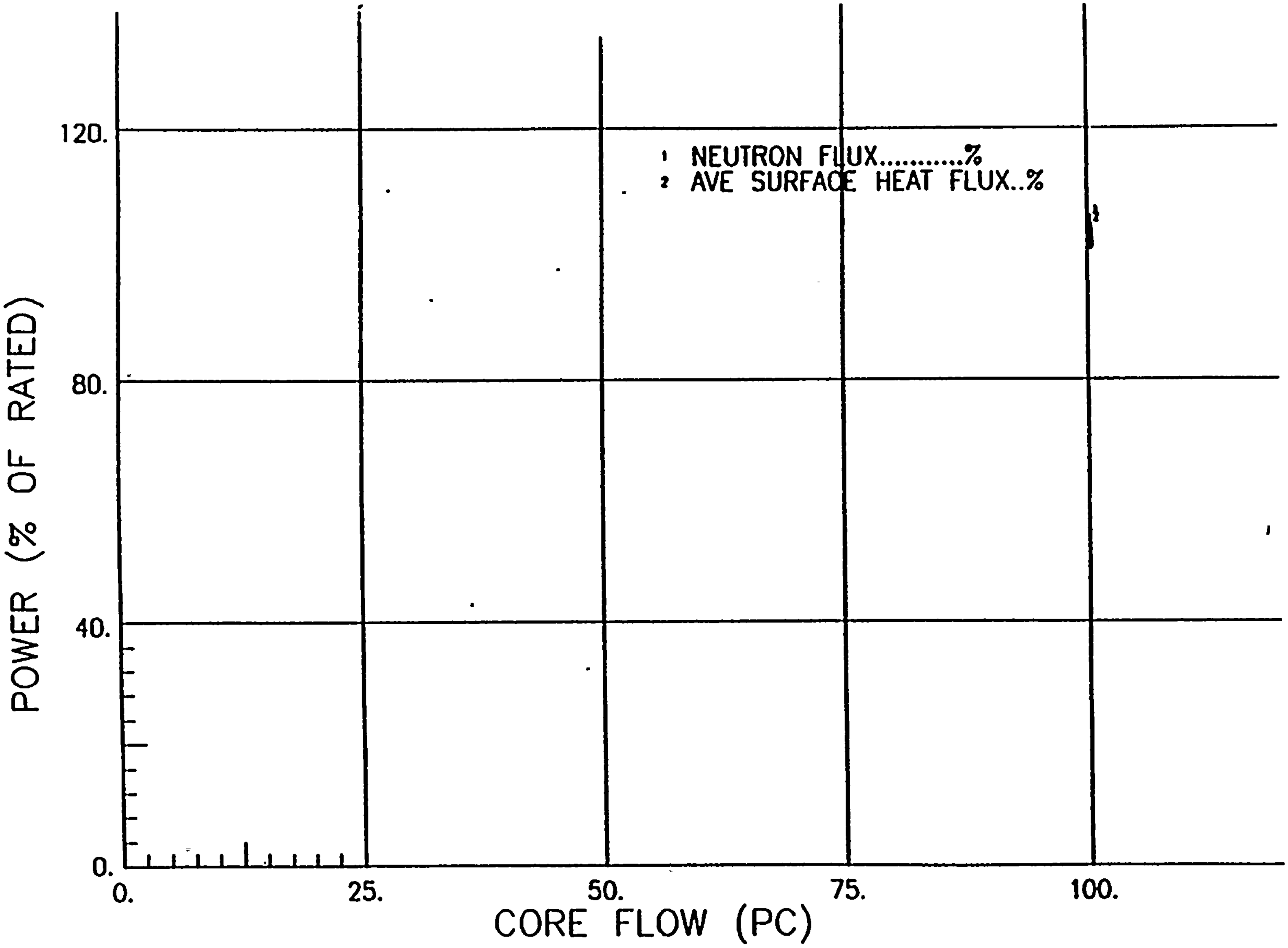
Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.5-1.10

Form No. 960690



Inadvertent Start of Auxiliary High Pressure Core Spray Pump at 106.2% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
		15.5-1.11

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15.6 DECREASE IN REACTOR COOLANT INVENTORY

15.6.1 INADVERTENT SAFETY/RELIEF VALVE OPENING

This event is discussed in Section 15.1.4.

15.6.2 INSTRUMENT LINE PIPE BREAK

This faulted condition is not a limiting event for either original or uprated power conditions. Therefore, no further analysis has been performed.

This event involves the postulated small steam or liquid line pipe break inside or outside containment, but within a controlled release structure. In order to bound the event, it is assumed that a small instrument line, instantaneously and circumferentially, breaks at a location where it may not be able to be isolated and where immediate detection is not automatic or apparent.

This analysis assumes that the line is not isolated and a plant shutdown is performed.

15.6.2.1 Identification of Causes and Frequency Classification

15.6.2.1.1 Identification of Causes

There is no specific event or circumstance identified which results in the failure of an instrument line. These lines are designed to specific engineering specifications and standards, and seismic and environmental requirements. However, for the purpose of evaluating the consequences of this event, the failure of an instrument line is assumed to occur.

15.6.2.1.1.1 Event Description. A circumferential rupture of an instrument line which is connected to the primary coolant system is postulated to occur outside the drywell but inside the secondary containment structure. This failure results in the release of primary system coolant into secondary containment until the reactor is depressurized. This event could conceivably also occur in the drywell. However, the associated effects would not be as significant as those from a line rupture in the secondary containment.

15.6.2.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.2.2 Sequence of Events and Systems Operation

15.6.2.2.1 Sequence of Events

The sequence of events for this accident is shown in Table 15.6-1.

15.6.2.2.1.1 Identification of Operator Actions. The operator should, if possible, isolate the affected instrument line. Assuming the line is isolated and depending on which line is broken, the operator should proceed with plant shutdown.

As a result of increased radiation, temperature, humidity, and fluid levels, operator action to evaluate risk to the public and shut down the plant can be initiated by any one or any combination of the following:

a. Comparing readings with several instruments monitoring the same process variable such as reactor level, jet pump flow, steam flow, and steam pressure,

b. Annunciation of the control function, either high or low in the main control room,

c. A half-channel scram if rupture occurred on a reactor protection system (RPS) instrument line,

d. A general increase in the area radiation monitor readings,

e. An increase in the ventilation process radiation monitor readings,

f. Increases in area temperature monitor readings in the containment, and

g. Leak detection system actuations.

This analysis assumes the line is not isolated and a shutdown is performed.

15.6.2.2.2 Systems Operation

Normal plant instrumentation and controls are assumed to be fully operational during the entire plant transient to ensure positive identification of the break and safe shutdown of the plant. Minimum reactor and plant protection system operations such as emergency core cooling system (ECCS) flow and suppression pool cooling are assumed for the analysis. As a consequence of the accident, the reactor is scrammed, and the reactor vessel cooled and depressurized over a 5 hr period.

15.6.2.2.3 The Effect of Single Failures and Operator Errors

The initiating event is handled by a protection sequence which can accommodate additional single equipment failure or single operator error occurrences.

15.6.2.3 Core and System Performance

15.6.2.3.1 Qualitative Summary - Results

Instrument line breaks, because of their small size, are less limiting from a core and systems performance standpoint. Instrument line breaks are bounded by the steam line break. Instrument line breaks are also considered within the spectrum considered in ECCS performance calculations.

Since instrument line breaks result in a slower rate of coolant loss and are bounded, the results are qualitative rather than quantitative. Since the rate of coolant loss is slow, an orderly reactor system depressurization follows reactor scram and the primary system is cooled down and maintained without ECCS actuation. No fuel damage or core uncovery occurs as a result of this event.

15.6.2.3.2 Considerations of Uncertainties

The approach toward conservatively analyzing this event is discussed in Section 6.3 for a more limiting case.

15.6.2.4 Barrier Performance

15.6.2.4.1 General

The release of primary coolant through the orificed instrument line would not result in an increase in secondary containment pressure.

The following assumptions and conditions are the basis for the mass loss during the 5 hr reactor shutdown period of this event:

a. Shutdown and depressurization initiated at 10 minutes after break occurs,

b. Normal depressurization and cooldown of reactor pressure vessel (RPV),

c. Line contains a 0.5-in. diameter flow restricting orifice inside the drywell, and

d. Flow is critical at the orifice and is determined using the GOTHIC computer program which employs the Henry model for subcooled liquid and the Moody model for saturated and superheated vapors (Reference 15.6-1).

The total integrated mass of fluid released by means of the break during the blowdown is 121,000 lb. Of this total, 29,800 lb flash to steam. Release of this mass of coolant in the drywell would result in a containment pressure which is below the design pressure.

15.6.2.4.2 Secondary Containment Effects

If the airborne activity is above the setpoint of the radiation monitor in the reactor building exhaust air plenum, the ventilation system will be automatically isolated and standby gas treatment system (SGTS) initiated. Otherwise, the operator upon detecting the leak will initiate the above action from the control room.

The SGTS can maintain the secondary containment at -0.25 in. water gauge, with respect to the atmosphere, ensuring no direct leakage to the environment.

15.6.2.5 Radiological Consequences

15.6.2.5.1 Design Basis Analysis

The specific models, assumptions and the program used for computer evaluation are based on those described in Reference 15.6-2. Specific values of parameters used in the evaluation are presented in Table 15.6-2. The leakage path used in these calculations is shown in Figure 15.6-1.

15.6.2.5.1.1 Fission Product Release from Fuel. The quantity of activity released as a consequence of reactor scram and vessel depressurization is based in part on measurements during plant shutdowns (Reference 15.6-3). These measurements have been used to develop an empirical model which predicts, during the depressurization transient, ^{131}I releases of 0.42 Ci/bundle for a 50% probability value, to 2.14 Ci/bundle for the 95% probability value. For the purpose of this evaluation, the 95th percentile values are used.

The release of other iodine isotopes is considered to be inversely proportional to the fission yields. The activity released to the environment is presented in Table 15.6-3.

15.6.2.5.1.2 Fission Product Release to the Environment. The activity released from the instrument line break is assumed not to mix within the secondary containment and is released instantly to the environment for the first 10 minutes. After 10 minutes operator action is taken to initiate SGTS and credit is taken for filtration. After initiation of the SGTS (at 10 minutes) flow to the environment is at a rate of 100% for 5 hr.

15.6.2.5.1.3 Results. The calculated exposures for the realistic analysis are presented in Table 15.6-4.

15.6.3 STEAM GENERATOR TUBE FAILURE

This event is not applicable to boiling water reactor (BWR) plants.

15.6.4 STEAM SYSTEM PIPING BREAK OUTSIDE CONTAINMENT

This event involves the postulation of a large steam line pipe break outside the primary containment. It is assumed that the largest steam line instantaneously and circumferentially breaks at a location downstream of the outermost isolation valve. The plant is designed to immediately detect such an occurrence, initiate isolation of the broken line, and actuate the necessary protective features. This postulated event represents the envelope evaluation of steam line failures outside containment.

15.6.4.1 Identification of Causes and Frequency Classification

15.6.4.1.1 Identification of Causes

A main steam line break is postulated without the cause being identified. These lines are designed to specific engineering codes and standards, and seismic and environmental requirements. However, for the purpose of evaluating the consequences of a postulated large steam line rupture, the failure of a main steam line is assumed to occur.

15.6.4.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.4.2 Sequence of Events and Systems Operation

15.6.4.2.1 Sequence of Events

Accidents that result in the release of radioactive materials directly outside the containment are the results of postulated breaches in the RCPB or the steam power conversion system boundary. A break spectrum analysis for the complete range of reactor conditions indicates that the limiting fault event for breaks outside the containment is a complete severance of one of the four main steam lines. The sequence of events and approximate time required to reach the event is given in Table 15.6-5.

15.6.4.2.1.1 Identification of Operator Actions. The reactor operator will maintain reactor vessel water inventory and core cooling with the high-pressure core spray (HPCS) system and the reactor core isolation cooling (RCIC) system if available. Without operator action, HPCS

would initiate automatically on low water level following isolation of the main steam supply system [i.e., main steam line isolation valve (MSIV) closure]. The core would be covered throughout the accident and there would be no fuel damage. Assuming HPCS failure and not crediting RCIC operation since it is not an ECCS nor required for this event, automatic depressurization system (ADS) in combination with low pressure injection ECCS ensure conformance with the acceptance criteria of 10 CFR 50.46 as discussed in Section 6.3.1.

15.6.4.2.2 Systems Operation

A postulated guillotine break of one of the four main steam lines outside the containment results in mass loss from both ends of the break. The flow from the upstream side is initially limited by the flow restrictor upstream of the inboard isolation valve. Flow from the downstream side is initially limited by the total area of the flow restrictors in the three unbroken lines. Subsequent closure of the MSIVs further limits the flow when the valve area becomes less than the limiter area and finally terminates the mass loss when the full closure is reached.

15.6.4.2.3 The Effect of Single Failures and Operator Errors

The effect of single failures has been considered in analyzing this event. All of the protective sequences for this event are capable of single equipment failure or single operator error accommodation and yet still complete the necessary safety action.

15.6.4.3 Core and System Performance

The temperature and pressure transients resulting as a consequence of this accident are insufficient to cause fuel damage.

15.6.4.3.1 Input Parameters and Initial Conditions

See Section 6.3 for initial conditions.

15.6.4.3.2 Results

There is no fuel damage as a consequence of this accident.

See Section 6.3 for ECCS analysis.

15.6.4.3.3 Considerations of Uncertainties

Discussions of the uncertainties associated with the ECCS performance and the containment isolation systems are discussed in Sections 6.3 and 7.3, respectively.

15.6.4.4 Barrier Performance

Since this break occurs outside the primary containment, barrier performance within the containment envelope is not applicable. There are sufficient vent openings in the steam tunnel to ensure that the secondary containment structure will not be damaged.

The following assumptions and conditions are used in determining the mass loss from the primary system from the inception of the break to full closure of the MSIVs:

a. The reactor is operating at the power level associated with maximum mass release,

b. Nuclear system pressure is 1060 psia and remains constant during closure,

c. An instantaneous circumferential break of the main steam line occurs,

d. Isolation valves start to close at 0.5 sec on high flow signal and are fully closed at 6 sec,

e. The Moody critical flow model (Reference 15.6-4) is applicable, and

f. Level rise time is conservatively assumed to be one second. Mixture quality is conservatively taken to be a constant 7% (steam weight percentage) during mixture flow.

Initially, only steam will issue from the broken end of the steam line. The flow in each line is limited by critical flow at the limiter to a maximum of 200% of rated flow for each line. Rapid depressurization of the RPV causes the water level to rise resulting in a steam-water mixture flowing from the break until the valves are closed. The total integrated mass leaving the RPV through the steam line break is 130,000 lb of which 105,000 lb is liquid and 25,000 lb is steam.

15.6.4.5 Radiological Consequences

The radiological analysis is based on NRC Standard Review Plan 15.6.4 and NRC Regulatory Guide 1.5.

The specific models, assumptions, and the program used for computer evaluation are described in Reference 15.6-5. Specific values of parameters used in the evaluation are presented in Table 15.6-6.

15.6.4.5.1 Fission Product Release from Fuel

There is no fuel damage as a result of this accident. The only activity available for release from the break is that which is present in the reactor coolant and steam lines prior to the break. This level of activity is consistent with the Technical Specifications and translates to the following isotopic coolant concentrations in μci/gm:

^{131}I	8.0 x 10-2
^{132}I	7.4 x 10-1
^{133}I	5.5 x 10-1
^{134}I	1.5 x 10-0
^{135}I	8.0 x 10-1

Because of its short half-life, ^{16}N is not considered in the analysis.

15.6.4.5.2 Fission Product Transport to the Environment

The transport pathway is a direct unfiltered release to the environment as presented in Figure 15.6-2. The MSIV detection and closure time of 6 sec results in a discharge of 25,000 lb of steam and 105,000 lb of liquid from the break. Assuming all the activity in this discharge becomes airborne, the release of activity to the environment is presented in Table 15.6-7.

15.6.4.5.3 Results

The calculated exposures for the design basis analysis are presented in Table 15.6-8 and are a small fraction of the guidelines of 10 CFR 100.

15.6.5 LOSS-OF-COOLANT ACCIDENTS (RESULTING FROM SPECTRUM OF POSTULATED PIPING BREAKS WITHIN THE REACTOR COOLANT PRESSURE BOUNDARY) - INSIDE CONTAINMENT

This event involves the postulation of a spectrum of piping breaks inside containment varying in size, type, and location. The break type includes steam and/or liquid process system lines. This event is coincident with a safe shutdown earthquake (SSE).

The postulated event represents the envelope evaluation for liquid or steam line failures inside containment.

15.6.5.1 Identification of Causes and Frequency Classification

15.6.5.1.1 Identification of Causes

There are no realistic, identifiable events which would result in a pipe break inside the containment of the magnitude required to cause a loss-of-coolant accident (LOCA) coincident with SSE plus single active component failure (SACF) criteria requirements. The piping is designed to specific engineering codes and standards and for severe seismic and environmental conditions. However, since such an accident provides an upper limit estimate to the resultant effects for this category of pipe breaks, it is evaluated without the causes being identified.

15.6.5.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.5.2 Sequence of Events and Systems Operation

15.6.5.2.1 Sequence of Events

The sequence of events associated with this accident is shown in Reference 6.3-1 for core system performance and Table 6.2-8 for barrier (containment) performance.

15.6.5.2.1.1 Identification of Operator Actions. Since automatic actuation and operation of the ECCS is a system design basis, no immediate operator actions are required for the accident. The operator will perform the following described actions.

The operator will, after checking that all rods are inserted at time zero plus approximately 10 sec, determine plant condition by observing the annunciators. After observing that the ECCS flows are initiated on low water level, the operator will check that the diesel generators have started and are on standby condition. The operator initiates at 10 minutes the operation of the residual heat removal (RHR) system heat exchangers in the suppression pool cooling mode. After the RHR system and other auxiliary systems are in proper operation, the operator will monitor the hydrogen concentration in the drywell for proper activation of the recombiner, if necessary.

15.6.5.2.2 Systems Operation

Accidents that could result in the release of radioactive fission products directly into the containment are the results of postulated nuclear system primary coolant pressure boundary pipe breaks. The most severe nuclear system effects and the greatest release of radioactive material to the containment result from a complete circumferential break of one of the two recirculation loops. The minimum required functions of the reactor and plant protection system are discussed in Sections 6.2, 6.3, 7.3, 7.6, and 8.3. The capabilities of the SGTS to

maintain the secondary containment at 0.25-in. water gauge following a LOCA is discussed in Section 6.2.3.

15.6.5.2.3 The Effect of Single Failures and Operator Errors

Single failures and operator errors have been considered in the analysis of the entire spectrum of primary system breaks. The consequences of a LOCA with considerations for single equipment failure or single operator error are shown to be fully accommodated without the loss of any required safety function.

15.6.5.3 Core and System Performance

15.6.5.3.1 Mathematical Model

The analytical methods and associated assumptions which are used in evaluating the consequences of this accident are considered to provide an ultra-conservative assessment of the expected consequences of this improbable event.

The details of these calculations, their justification, and bases for the models are developed in Sections 6.2, 6.3, 7.3, 7.6, and 8.3.

15.6.5.3.2 Input Parameters and Initial Conditions

Input parameters and initial conditions used for the analysis of this event are given in Table 6.3-2.

15.6.5.3.3 Results

Results of this event are given in detail in Sections 6.2 and 6.3. The temperature and pressure transients resulting as a consequence of this accident are insufficient to cause perforation of the fuel cladding. Therefore, no fuel damage results from this accident. The containment integrity is maintained. Continued long-term core and containment cooling is demonstrated. Radiological input is minimized and within limits.

15.6.5.3.4 Consideration of Uncertainties

This event was conservatively analyzed: see Sections 6.2, 6.3, 7.3, 7.6, and 8.3.

15.6.5.4 Barrier Performance

The design basis for the containment is to maintain its integrity after the instantaneous rupture of the largest single primary system piping within the structure accommodating the dynamic effects of the pipe break and an SSE all acting concurrently. Therefore, any postulated LOCA

does not result in exceeding the containment design limit. For details and results of the analysis, see Sections 3.8, 3.9, and 6.2.

15.6.5.5 Radiological Consequences

The radiological consequences are based on conservative assumptions considered to be acceptable to the NRC for the purpose of determining adequacy of the plant design to meet 10 CFR Part 100 guidelines.

A schematic of the transport pathway is shown in Figure 15.6-3.

15.6.5.5.1 Design Basis Analysis

The specific models, assumptions, and computer code used to evaluate this event based on the above criteria are presented in Reference 15.6-5. Specific values of parameters used in this evaluation are presented in Table 15.6-9.

15.6.5.5.1.1 Fission Product Release from Fuel. It is assumed that 100% of the noble gases and 50% of the iodine are released from an equilibrium core operating at a power level of 3556 MWt for 1000 days prior to the accident. Of this release, 100% of the noble gases and 50% of the iodine become airborne. The remaining 50% of the iodine is removed by plateout and condensation; therefore, it is not available for airborne release to the environment. The activity airborne in the containment is presented in Table 15.6-10.

15.6.5.5.1.2 Fission Product Transport to the Environment. The fission product transport to the environment consists of two basic pathways. One transport pathway consists of leakage from the containment to the secondary containment by several different mechanisms and is discharged to the environment through the SGTS at an elevated location. The SGTS filter efficiency for iodine removal is assessed at 99%. The second transport pathway consists of leakage from the containment directly to the environment through piping systems which originate in containment and terminate outside the reactor building. This pathway is called "bypass leakage". The individual mechanisms for leakage from the primary containment are specifically discussed as follows:

a. Containment leakage - The design basis leak rate of the containment and its penetrations including MSIV leakage is 0.5 weight percent per day for the duration of the accident. This leakage is to the secondary containment and from there to the environment by means of the SGTS. No credit is taken for forced mixing and holdup within the secondary containment.

b. Leakage from engineered safety feature (ESF) components outside the primary containment (all ESF equipment which circulates primary coolant or suppression pool water during the course of the postulated accident) is located within the

secondary containment so that any leakage from the pressure barriers for these systems goes into the secondary containment atmosphere and is, therefore, processed by the SGTS prior to release to the environment. Some of the ESF systems connect to other systems that terminate outside secondary containment. These potential bypass leakage paths have been evaluated and are discussed in Section 6.2.3.2.

c. Hydrogen purge - Since the hydrogen recombining system consists of two 100% redundant recombiners, no hydrogen purge is required nor assumed throughout the postaccident period.

d. Leakage from the main steam isolation valve leakage control system (MSIV-LCS). The MSIV-LCS routes any leakage through the MSIVs to an area serviced by the SGTS. This leakage is assumed to be included into the 0.5% containment leakage.

e. Bypass leakage - Primary containment leakage of 0.74 scfh is assumed to bypass the secondary containment and leak directly to the environment.

Fission product release to the environment based on the above assumptions is given in Tables 15.6-11 and 15.6-12.

15.6.5.5.1.3 Results. The calculated exposures for the design basis analysis are presented in Table 15.6-13 and are within the guidelines of 10 CFR 100.

The calculated exposures to control room personnel are described in Section 6.4.4.1.

15.6.6 FEEDWATER LINE BREAK - OUTSIDE CONTAINMENT

In order to evaluate large liquid process line pipe breaks outside containment, the failure of a feedwater line is assumed to evaluate the response of the plant design to this postulated event. The postulated break of the feedwater line, representing the largest liquid line outside the containment, provides the envelope evaluation relative to this type of occurrence. The break is assumed to be instantaneous, circumferential, and outboard of the outermost isolation valve.

15.6.6.1 Identification of Causes and Frequency Classification.

15.6.6.1.1 Identification of Causes

A feedwater line break is assumed without the cause being identified. The subject piping is designed to specific engineering codes and standards.

15.6.6.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.6.2 Sequence of Events and Systems Operation

15.6.6.2.1 Sequence of Events

The sequence of events is shown in Table 15.6-14.

15.6.6.2.1.1 Identification of Operator Actions. Since automatic actuation and operation of the ECCS is a system design basis, no immediate operator actions are required for this accident. The operator is not required to take any action to prevent primary reactor system mass loss, but should ensure that the reactor is shut down and that HPCS is operating normally.

15.6.6.2.2 Systems Operation

It is assumed that the normally operating plant instrument and controls are functioning. Credit is taken for the actuation of the reactor isolation system and ECCS system. The RPS (SRVs, ECCS, and control rod drives) and plant protection system (RHR heat exchanger) are assumed to function. The ESF system is assumed to operate normally. Although not an ECCS and not credited nor required for mitigation of this event, RCIC will also be used if available for maintaining vessel level as it initiates at approximately the same low reactor vessel as HPCS.

15.6.6.2.3 The Effect of Single Failures and Operator Errors

The feedwater line outside the containment is a special case of the general LOCA break spectrum considered in Section 6.3. The general single-failure analysis for LOCAs is discussed in Section 6.3.3.3. For the feedwater line break outside the containment, since the break is isolable, the HPCS can provide adequate flow to the vessel to maintain core cooling and prevent fuel rod cladding failure. A single failure of the HPCS would require actuation of ADS and the low-pressure core cooling systems to keep the core covered with water.

15.6.6.3 Core and System Performance

15.6.6.3.1 Qualitative Summary

The accident evaluation qualitatively considered in this section is considered to be a conservative and envelope assessment of the consequences of the postulated failure of one of the feedwater piping lines external to the containment. The accident is postulated to occur at the input parameters and initial conditions are given in Table 6.3-2.

15.6.6.3.2 Qualitative Results

The feedwater line break outside the containment is less limiting than the steam line break outside the containment or the LOCAs inside the containment.

The reactor vessel is isolated on low-low water level and the HPCS would restore the reactor water level to the normal elevation. The fuel is covered throughout the event and there are no pressure or temperature transients sufficient to cause fuel damage.

15.6.6.3.3 Consideration of Uncertainties

This event was conservatively analyzed and uncertainties were adequately considered (see Section 6.3 for details).

15.6.6.4 Barrier Performance

A break spectrum analysis for the complete range of reactor conditions indicates that the limiting fault event for breaks outside the containment is a complete severance of one of the main steam lines. The feedwater system piping break is less severe than the main steam line break.

15.6.6.5 Radiological Consequences

The specific models, assumptions, and the program used for computer evaluation are described in Reference 15.6-2. Specific values of parameters used in the evaluation are presented in Table 15.6-15. A diagram of the leakage path for this accident is shown in Figure 15.6-4.

15.6.6.5.1 Fission Product Release

Fission product release is assumed to occur from two pathways: activity being pumped from the condenser hotwell and activity returning to the feedwater system from the reactor water cleanup (RWCU) system. The activity in both of these sources is based on the Technical Specification coolant limit.

Noble gas activity in the condensate is negligible since the air ejectors remove most of the noble gas from the condenser.

15.6.6.5.2 Fission Product Transport to the Environment

The transport pathway consists of liquid release from the break, carryover to the turbine building atmosphere due to flashing and partitioning and unfiltered release to the environment through the turbine building ventilation system.

Of the 860,000 lb of condensate released from the break, 86,000 lb flashes to steam with assumed iodine carryover of 100%. Of the activity remaining in the unflashed liquid, 5% is assumed to become airborne. Normally, all feedwater reaching the break location will have passed through condensate demineralizers which have a 90% iodine removal efficiency. However, as a result of the increased feedwater flow caused by the break, differential pressure across the demineralizers is assumed to initiate flow through the demineralizer bypass line. This bypass line then carries 15% of the total flow resulting in an effective iodine removal efficiency for all flow of 76.5%. In addition, it is also assumed that 2771 lb of liquid returning from the RWCU are released prior to isolation of the RWCU. The activity concentration in this return steam is 1% of the RPV coolant concentration.

Taking no credit for holdup, decay, or plate-out during transport through the turbine building, the release of activity to the environment is presented in Table 15.6-16. The release is assumed to take place within 2 hr of the occurrence of the break.

15.6.6.5.3 Results

The calculated exposures for the realistic analysis are presented in Table 15.6-17 and are a small fraction of 10 CFR 100 guidelines.

15.6.7 REFERENCES

15.6-1 GOTHIC Containment Analysis Package, Technical Manual, Version 4.0, Numerical Applications, Inc., NA18907-06, Revision 3.

15.6-2 Nguyen, D., "Realistic Accident Analysis for General Electric Boiling Water Reactor - The RELAP Code and User's Guide," (NEDO-21142).

15.6-3 Brutshcy, F. J., Hills, C. R., Horton, H. R., Levin, A. J., "Behavior of Iodine in Reactor Water During Plant Shutdown and Startup," (NEDO-10585).

15.6-4 Moody, F. J, "Maximum Two-Phase Vessel Blowdown from Pipes," ASME Paper Number 65-WA/HT-1, March 15, 1965.

15.6-5 Careway, H. A, V. D. Nguyen, and P. P. Stancavage, "Radiological Accident Evaluation - The CONAC03 Code," (NEDO-21143-1).

15.6-6 Regulatory Guide 1.109, Revision 1.

15.6-7 ICRP (International Commission on Radiological Protection), Publication 30.

TABLE 15.6-1

SEQUENCE OF EVENTS FOR INSTRUMENT LINE BREAK

Time	Event
0	Instrument line fails.
0-10 minutes	Identification of break.
10 minutes	Activation of SGTS; initiation of an orderly shutdown.
5 hr	Reactor vessel depressurized and break flow terminated.

TABLE 15.6-2

INSTRUMENT LINE BREAK ACCIDENT - PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSES

				Design Basis Assumptions
	Parameters			
I.	Data and assumptions used to estimate radioactive source from postulated accidents			
	A.	Power level		3629
	B.	Burnup		N/A
	C.	Fuel damaged		None
	D.	Release of activity by nuclide		Table 15.6-3
	E.	Iodine fractions		
		(1)	Organic	0
		(2)	Elemental	1%
		(3)	Particulate	0
	F.	Reactor coolant activity before the accident		Section 15.6.4.5.2.2
II.	Data and assumptions used to estimate activity released			
	A.	Primary containment leak rate (%/day)		N/A
	B.	Secondary containment leak rate (%/5 hrs)		100[a]
	C.	Valve movement times		N/A
	D.	Adsorption and filtration efficiencies		
		(1)	Organic iodine	N/A
		(2)	Elemental iodine	99%
		(3)	Particulate iodine	N/A
		(4)	Particulate fission products	N/A
	E.	Recirculation system parameters		
		(1)	Flow rate	N/A
		(2)	Mixing efficiency	N/A
		(3)	Filter efficiency	N/A
	F.	Containment spray parameters (flow rate, drop size, etc.)		N/A
	G.	Containment volumes		N/A
	H.	All other pertinent data and assumptions		None

TABLE 15.6-2

INSTRUMENT LINE BREAK ACCIDENT - PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSES (Continued)

				Design Basis Assumptions
			Parameters	
III.	Dispersion data			
	A.	Boundary and LPZ distance (m)		1950/4827
	B.	χ/Qs for time intervals of		
		(1)	0-2 hr - EAB/LPZ	$2.62 \times 10^{-4}/1.06 \times 10^{-4}$
		(2)	2-8 hr - LPZ	4.47×10^{-5}
		(3)	8-24 hr - LPZ	2.91×10^{-5}
		(4)	1-4 days - LPZ	1.14×10^{-5}
		(5)	4-30 days - LPZ	2.97×10^{-6}
IV.	Dose data			
	A.	Method of dose calculation		Reference 15.6-2
	B.	Dose conversion assumptions		References 15.6-6/ 15.6-7
	C.	Peak activity released from secondary containment		Table 15.6-3
	D.	Doses		Table 15.6-4

[a] No forced mixing in secondary containment is considered.

TABLE 15.6-3

INSTRUMENT LINE FAILURE
ACTIVITY AIRBORNE IN SECONDARY
CONTAINMENT STRUCTURE (CURIES)

Isotope	10 Minutes	1 Hr	2 Hr	8 Hr	1 Day	4 Days	30 Days
^{131}I	1.45E-01	1.58E-0	2.45E-0	3.25E-0	1.58E-00	6.03E-02	3.37E-14
^{132}I	2.12E-01	2.09E-0	2.70E-0	8.13E-1	3.25E-03	5.04E-14	0
^{133}I	3.39E-01	3.67E-0	5.58E-0	6.36E-0	1.92E-0	8.58E-03	0
^{134}I	3.44E-01	2.91E-0	2.92E-0	9.60E-0	1.55E-07	0	0
^{135}I	3.21E-01	3.39E-0	4.93E-0	3.92E-0	3.74E-01	9.46E-06	0
Total	1.36E-0	1.36E-1	1.86E-1	1.44E-1	3.87E-0	6.89E-02	3.37E-14

TABLE 15.6-4

INSTRUMENT LINE FAILURE
RADIOLOGICAL EFFECTS

Area	Whole Body Dose (rem)	Thyroid Dose (rem)
Exclusion area (1950 m) (2 hr)	4.3×10^{-5}	3.0×10^{-2}
Low population zone (4827 m) (30 days)	2.3×10^{-5}	1.6×10^{-2}

Note: This case reflects the original reactor power level of 3323 MWt. It is not a limiting case and, therefore, was not reanalyzed for reactor power uprate.

TABLE 15.6-5

SEQUENCE OF EVENTS FOR STEAM LINE BREAK
OUTSIDE CONTAINMENT

Time	Event
0	Guillotine break of one main steam line outside primary containment.
0.5[a]	High steam line flow signal initiates closure of MSIV.
<1.0	Reactor begins to scram.
$\geq$6.0	Main steam line isolation valves fully closed.
10	Safety/relief valves open on high vessel pressure. The valves open and close to maintain vessel pressure at approximately 1100 psi.
600	Operator initiates ADS or manually controls relief valves. Vessel depressurizes rapidly.
750	High-pressure core spray initiates on low water level.
1270	Core effectively reflooded. No fuel rod failure.

[a] Approximately.

TABLE 15.6-6

STEAM LINE BREAK ACCIDENT - PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSES

			Parameters	Design Basis Assumptions
I.	Data and assumptions used to estimate radioactive source from postulated accidents.			
	A.	Power level		N/A
	B.	Burnup		N/A
	C.	Fuel damaged		None
	D.	Release of activity by nuclide		Table 15.6-7
	E.	Iodine fractions		
		(1)	Organic	0
		(2)	Elemental	1%
		(3)	Particulate	0
	F.	Reactor coolant activity before the accident		Section 15.6.4.5.1.1
II.	Data and assumptions used to estimate activity released.			
	A.	Primary containment leak rate (%/day)		N/A
	B.	Secondary containment leak rate (%/day)		N/A
	C.	Isolation valve closure time (sec)		5.5
	D.	Adsorption and filtration efficiencies		
		(1)	Organic iodine	N/A
		(2)	Elemental iodine	N/A
		(3)	Particulate iodine	N/A
		(4)	Particulate fission products	N/A
	E.	Recirculation system parameters		N/A
		(1)	Flow rate	N/A
		(2)	Mixing efficiency	N/A
		(3)	Filter efficiency	N/A
	F.	Containment spray parameters (flow rate, drop size, etc.)		N/A
	G.	Containment volumes		N/A
	H.	All other pertinent data and assumptions		None

TABLE 15.6-6

STEAM LINE BREAK ACCIDENT - PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSES (Continued)

		Parameters	Design Basis Assumptions
III.	Dispersion data		
	A.	Boundary and LPZ distance (m)	1950/4827
	B.	χ/Qs for total dose - EAB/LPZ	$2.62 \times 10^{-4}/1.06 \times 10^{-4}$
IV.	Dose data		
	A.	Method of dose calculation	Reference 15.6-5
	B.	Dose conversion assumptions	Reference 15.6-5
	C.	Peak activity concentrations in containment	N/A
	D.	Doses	Table 15.6-8

TABLE 15.6-7

STEAM LINE BREAK ACCIDENT
ACTIVITY RELEASE TO ENVIRONMENT (CURIES)

Isotope	Activity Released
^{131}I	3.90 x 10
^{132}I	3.60×10^{-1}
^{133}I	2.67×10^{-1}
^{134}I	7.17×10^{-1}
^{135}I	3.90×10^{-1}
Total iodine	1.77×10^{-2}
^{83m}Kr	8.85E-02
^{85m}Kr	1.55E-01
^{85}Kr	6.05E-04
^{87}Kr	4.83E-01
^{88}Kr	4.95E-01
^{89}Kr	2.06E-00
^{131m}Xe	4.94E-04
^{133m}Xe	7.39E-03
^{133}Xe	2.07E-01
^{135m}Xe	6.06E-01
^{135}Xe	5.59E-01
^{137}Xe	2.72E-00
^{138}Xe	2.06E-00
Total noble gases	9.4E-00

TABLE 15.6-8

STEAM LINE BREAK ACCIDENT
RADIOLOGICAL EFFECTS OF A PUFF RELEASE

Area	Whole Body Dose (rem)	Thyroid Dose (rem)
Exclusion area (1950 m)	2.30×10^{-2}	9.59×10^{-1}
Low population zone (4827 m)	9.32×10^{-3}	3.88×10^{-1}

TABLE 15.6-9

LOSS-OF-COOLANT ACCIDENT - PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSIS

		Parameters	Design Basis Assumptions
I.		Data and assumptions used to estimate radioactive source from postulated accidents	
	A.	Power level	3556
	B.	Burnup	N/A
	C.	Fuel damaged	100%
	D.	Release of activity by nuclide	Table 15.6-11 and 15.6-12
	E.	Iodine fractions	
		(1) Organic	4%
		(2) Elemental	91%
		(3) Particulate	5%
	F.	Reactor coolant activity before the accident	N/A
II.		Data and assumptions used to estimate activity released	
	A.	Primary containment leak rate includes MSIV leakage (%/day)	0.5
	B.	Secondary containment leak rate (%/day)	N/A
	C.	Drawdown period (sec)	150
	D.	Adsorption and filtration efficiencies (%)	
		(1) Organic iodine	99%
		(2) Elemental iodine	99%
		(3) Particulate iodine	99%
		(4) Particulate fission products	N/A
	E.	Secondary containment bypass leakage	0.74 scfh

TABLE 15.6-9

LOSS-OF-COOLANT ACCIDENT - PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSIS (Continued)

Parameters				Design Basis Assumptions
	F.	Recirculation system parameters		
		(1)	Flow rate (cfm)	N/A
		(2)	Mixing efficiency	N/A
		(3)	Filter efficiency	N/A
	G.	Containment spray parameters (flow rate, drop size, etc.)		N/A
	H.	Containment volumes		N/A
	I.	All other pertinent data and assumptions		None
III.	Dispersion data			
	A.	Boundary/LPZ distance (m)		1950/4827
	B.	χ/Qs for time intervals of		
		(1)	0-2 hr - SB/LPZ	2.62×10^{-4}/1.06×10^{-4}
		(2)	2-8 hr - LPZ	4.47×10^{-5}
		(3)	8-24 hr - LPZ	2.91×10^{-5}
		(4)	1-4 days - LPZ	1.14×10^{-5}
		(5)	4-30 days - LPZ	2.97×10^{-6}
IV.	Dose data			
	A.	Method of dose calculation		Reference 15.6-5
	B.	Dose conversion assumptions		Reference 15.6-5
	C.	Peak activity concentrations in containment		Table 15.6-10
	D.	Doses		Table 15.6-13

TABLE 15.6-10

LOSS-OF-COOLANT ACCIDENT
PRIMARY CONTAINMENT ACTIVITY (CURIES)

Isotope	1 Minute	10 Minutes	30 Minutes	1 Hr	2 Hr	8 Hr	1 Day	2 Days	4 Days	30 Days
^{131}I	2.37E 07	2.37E 07	2.36E 07	2.36E 07	2.35E 07	2.30E 07	2.16E 07	1.97E 07	1.64E 07	1.53E 06
^{132}I	3.40E 07	3.25E 07	2.94E 07	2.53E 07	1.87E 07	3.06E 06	2.45E 04	1.77E 01	9.13E-06	1.00E-20
^{133}I	4.81E 07	4.79E 07	4.73E 07	4.66E 07	4.50E 07	3.68E 07	2.15E 07	9.63E 06	1.93E 06	1.57E-03
^{134}I	5.21E 07	4.63E 07	3.55E 07	2.39E 07	1.09E 07	9.44E 04	3.02E-01	1.73E-09	1.00E-20	1.00E-20
^{135}I	4.49E 07	4.42E 07	4.27E 07	4.05E 07	3.65E 07	1.94E 07	3.62E 06	2.90E 05	1.87E 03	1.00E-20
Total iodine	2.03E 08	1.95E 08	1.79E 08	1.60E 08	1.35E 08	8.24E 07	4.68E 07	2.96E 07	1.84E 07	1.53E 06
^{83m}Kr	1.16E 07	1.09E 07	9.64E 06	7.97E 06	5.46E 06	5.62E 05	1.31E 03	1.47E-01	1.85E-09	1.00E 20
^{85m}Kr	2.46E 07	2.40E 07	2.28E 07	2.11E 07	1.81E 07	7.13E 06	5.98E 05	1.45E 04	8.55E 00	1.00E-20
^{85}Kr	8.39E 05	8.38E 05	8.38E 05	8.38E 05	8.38E 05	8.37E 05	8.34E 05	8.30E 05	8.21E 05	7.18E 05
^{87}Kr	4.67E 07	4.31E 07	3.59E 07	2.73E 07	1.58E 07	6.01E 05	9.78E 01	2.03E-04	1.00E-20	1.00E-20
^{88}Kr	6.61E 07	6.37E 07	5.88E 07	5.20E 07	4.07E 07	9.41E 06	1.89E 05	5.37E 02	4.34E-03	1.00E-20
^{89}Kr	6.50E 07	9.09E 06	1.15E 05	1.62E 02	3.26E-04	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{131m}Xe	9.70E 05	9.70E 05	9.69E 05	9.68E 05	9.65E 05	9.50E 05	9.11E 05	8.55E 05	7.53E 05	1.45E 05
^{133m}Xe	6.03E 06	6.02E 06	5.99E 06	5.95E 06	5.87E 06	5.42E 06	4.37E 06	3.17E 06	1.66E 06	3.87E 02
^{133}Xe	1.93E 08	1.92E 08	1.92E 08	1.91E 08	1.90E 08	1.84E 08	1.68E 08	1.46E 08	1.11E 08	3.14E 06
^{135m}Xe	3.64E 07	2.44E 07	1.01E 07	2.67E 06	1.87E 05	2.22E-02	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{135}Xe	4.45E 07	4.40E 07	4.29E 07	4.13E 07	3.82E 07	2.42E 07	7.10E 06	1.13E 06	2.87E 04	1.00E-20
^{137}Xe	1.40E 08	2.75E 07	7.37E 05	3.23E 03	6.22E-02	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{138}Xe	1.51E 08	9.70E 07	3.65E 07	8.40E 06	4.46E 05	1.00E-02	1.00E-20	1.00E-20	1.00E-20	1.00E-20
Total noble gases	7.86E 08	5.44E 08	4.17E 08	3.60E 08	3.17E 08	2.33E 08	1.82E 08	1.52E 08	1.15E 08	4.01E 06

TABLE 15.6-11

LOSS-OF-COOLANT ACCIDENT
SECONDARY CONTAINMENT ACTIVITY (CURIES) - 5 MINUTE DRAWDOWN CASE

Isotope	1 Minute	5 Minutes	30 Minutes	1 Hr	2 Hr	8 Hr	1 Day	2 Days	4 Days	30 Days
^{131}I	0.00E+00	0.00E+00	1.17E-03	1.17E-03	1.16E-03	1.14E-03	1.07E-03	9.76E-04	8.13E-04	7.59E-05
^{132}I	0.00E+00	0.00E+00	1.45E-03	1.25E-03	9.24E-04	1.51E-04	1.21E-06	8.73E-10	4.52E-16	1.00E-20
^{133}I	0.00E+00	0.00E+00	2.34E-03	2.30E-03	2.23E-03	1.82E-03	1.07E-03	4.76E-04	9.53E-05	7.79E-14
^{134}I	0.00E+00	0.00E+00	1.76E-03	1.18E-03	5.37E-04	4.67E-06	1.50E-11	8.56E-20	0.00E+00	0.00E+00
^{135}I	0.00E+00	0.00E+00	2.11E-03	2.01E-03	1.81E-03	9.61E-04	1.79E-04	1.44E-05	9.27E-08	0.00E+00
Total iodine	0.00E+00	0.00E+00	8.84E-03	7.91E-03	6.66E-03	4.08E-03	2.31E-03	1.47E-03	9.09E-04	7.59E-05
^{83m}Kr	0.00E+00	0.00E+00	4.77E-04	3.95E-04	2.70E-04	2.78E-05	6.47E-08	7.27E-12	9.17E-20	0.00E+00
^{85m}Kr	0.00E+00	0.00E+00	1.13E-03	1.04E-03	8.94E-04	3.53E-04	2.96E-05	7.18E-07	4.23E-10	0.00E˜00
^{85}Kr	0.00E+00	0.00E+00	4.15E-05	4.15E-05	4.15E-05	4.14E-05	4.13E-05	4.11E-05	4.06E-05	3.55E-05
^{87}Kr	0.00E+00	0.00E+00	1.78E-03	1.35E-03	7.84E-04	2.98E-05	4.84E-09	1.00E-14	1.00E-20	0.00E+00
^{88}Kr	0.00E+00	0.00E+00	2.91E-03	2.57E-03	2.02E-03	4.65E-04	9.34E-06	2.66E-08	2.15E-13	0.00E+00
^{89}Kr	0.00E+00	0.00E+00	5.67E-06	8.04E-09	1.61E-14	1.00E-20	1.00E-20	1.00E-20	1.00E-20	0.00E+00
^{131m}Xe	0.00E+00	0.00E+00	4.79E-05	4.79E-05	4.78E-05	4.70E-05	4.51E-05	4.23E-05	3.73E-05	7.20E-06
^{133m}Xe	0.00E+00	0.00E+00	2.96E-04	2.94E-04	2.91E-04	2.68E-04	2.16E-04	1.57E-04	8.24E-05	1.91E-08
^{133}Xe	0.00E+00	0.00E+00	9.50E-03	9.48E-03	9.42E-03	9.10E-03	8.31E-03	7.24E-03	5.51E-03	1.55E-04
^{135m}Xe	0.00E+00	0.00E+00	4.99E-04	1.32E-04	9.25E-06	1.10E-12	0.00E+00	0.00E+00	0.00E+00	0.00E+00
^{135}Xe	0.00E+00	0.00E+00	2.12E-03	2.04E-03	1.89E-03	1.20E-03	3.51E-04	5.60E-05	1.42E-06	0.00E+00
^{137}Xe	0.00E+00	0.00E+00	3.65E-05	1.60E-07	3.08E-12	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
^{138}Xe	0.00E+00	0.00E+00	1.80E-03	4.16E-04	2.21E-05	4.96E-13	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total noble gases	0.00E+00	0.00E+00	2.06E-02	1.78E-02	1.57E-02	1.15E-02	9.00E-03	7.54E-03	5.67E-03	1.98E-04

TABLE 15.6-12

LOSS-OF-COOLANT ACCIDENT
ACTIVITY RELEASED TO THE ENVIRONMENT (CURIES) - 5 MINUTE DRAWDOWN CASE

Isotope	1 Minute	5 Minutes	30 Minutes	1 Hr	2 Hr	8 Hr	1 Day	2 Days	4 Days	30 Days
^{131}I	8.22E 01	4.11E 02	4.59E 02	5.15E 02	6.29E 02	1.30E 03	3.02E 03	5.42E 03	9.59E 03	2.85E 04
^{132}I	1.18E 02	5.85E 02	6.48E 02	7.14E 02	8.19E 02	1.07E 03	1.12E 03	1.12E 03	1.12E 03	1.12E 03
^{133}I	1.67E 02	8.35E 02	9.31E 02	1.04E 03	1.26E 03	2.45E 03	4.65E 03	6.36E 03	7.47E 03	7.75E 03
^{134}I	1.82E 02	8.87E 02	9.71E 02	1.04E 03	1.12E 03	1.19E 03	1.19E 03	1.19E 03	1.19E 03	1.19E 03
^{135}I	1.56E 02	7.78E 02	8.66E 02	9.66E 02	1.15E 03	1.94E 03	2.66E 03	2.81E 03	2.83E 03	2.83E 03
Total iodine	7.06E 02	3.50E 03	3.87E 03	4.28E 03	4.99E 03	7.94E 03	1.26E 04	1.69E 04	2.22E 04	4.14E 04
^{83m}Kr	4.03E 01	1.99E 02	1.11E 03	2.02E 03	3.40E 03	6.09E 03	6.40E 03	6.40E 03	6.40E 03	6.40E 03
^{85m}Kr	8.54E 01	4.25E 02	2.47E 03	4.75E 03	8.82E 03	2.35E 04	3.23E 04	3.31E 04	3.31E 04	3.31E 04
^{85}Kr	2.91E 00	1.46E 01	8.73E 01	1.75E 02	3.49E 02	1.40E 03	4.18E 03	8.34E 03	1.66E 04	1.16E 05
^{87}Kr	1.63E 02	8.00E 02	4.30E 03	7.57E 03	1.20E 04	1.78E 04	1.80E 04	1.80E 04	1.80E 04	1.80E 04
^{88}Kr	2.30E 02	1.14E 03	6.51E 03	1.23E 04	2.19E 04	4.86E 04	5.65E 04	5.66E 04	5.66E 04	5.66E 04
^{89}Kr	2.52E 02	8.54E 02	1.28E 03	1.28E 03	1.28E 03	1.28E 03	1.28E 03	1.28E 03	1.28E 03	1.28E 03
^{131m}Xe	2.09E 01	1.05E 02	6.26E 02	1.25E 03	2.48E 03	9.53E 03	2.58E 04	4.45E 04	6.78E 04	9.37E 04
^{133}Xe	6.69E 02	3.34E 03	2.00E 04	4.00E 04	7.98E 04	3.14E 05	9.00E 05	1.68E 06	2.96E 06	6.90E 06
^{135m}Xe	1.29E 02	5.93E 02	2.19E 03	2.77E 03	2.97E 03	2.98E 03	2.98E 03	2.98E 03	2.98E 03	2.98E 03
^{135}Xe	5.33E 02	1.92E 03	3.21E 03	3.22E 03	3.22E 03	3.22E 03	3.22E 03	3.22E 03	3.22E 03	3.22E 03
^{138}Xe	5.36E 02	2.44E 03	8.64E 03	1.06E 04	1.12E 04	1.12E 04	1.12E 04	1.12E 04	1.12E 04	1.12E 04
Total noble gases	2.82E 03	1.26E 04	5.51E 04	9.51E 04	1.65E 05	4.97E 05	1.17E 06	2.00E 06	3.32E 06	7.43E 06

TABLE 15.6-13

LOSS-OF-COOLANT ACCIDENT
(DESIGN BASIS ANALYSIS)
RADIOLOGICAL EFFECTS

Total Effect (Including MSIV-LCS leakage)	Whole Body Dose (rem)	Thyroid Dose (rem)
Exclusion area (1950 m) (2 hr)	5.7	86.3
Low population zone (4827 m) (30 days)	4.1	95.8

TABLE 15.6-14

SEQUENCE OF EVENTS FOR FEEDWATER LINE BREAK
OUTSIDE CONTAINMENT

Time	Event
0	One feedwater line breaks.
0+	Feedwater line check valves isolate the reactor from the break.
<30 sec	At low-low water reactor level HPCS, MSIV closure and reactor scram would initiate and recirculation pumps would trip.
2 minutes[a]	The SRVs open and close and maintain the reactor vessel pressure at approximately 1100 psig.
1 to 2 hr	Normal reactor cooldown established.

[a] Approximately.

TABLE 15.6-15

FEEDWATER LINE BREAK ACCIDENT - PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSIS

Parameter			Value
I.	Data and assumptions used to estimate radioactive source from postulated accidents		
	A.	Power level	N/A
	B.	Burnup	N/A
	C.	Fuel damaged	None
	D.	Release of activity by nuclide	Table 15.6-16
	E.	Iodine fractions	
		(1) Organic	0
		(2) Elemental	1%
		(3) Particulate	0
		(4) Reactor coolant activity before the accident	Section 15.6.6.5.1
II.	Data and assumptions used to estimate activity released		
	A.	Primary containment leak rate (%/day)	N/A
	B.	Secondary containment leak rate (%/day)	N/A
	C.	RWCU total isolation valve closure time (sec)	75
	D.	Adsorption and filtration efficiencies	
		(1) Organic iodine	N/A
		(2) Elemental iodine	N/A
		(3) Particulate iodine	N/A
		(4) Particulate fission products	N/A
	E.	Recirculation system parameters	N/A
		(1) Flow rate	N/A
		(2) Mixing efficiency	N/A
		(3) Filter efficiency	N/A
	F.	Containment spray parameters (flow rate, drop size, etc.)	N/A
	G.	Containment volumes	N/A
	H.	All other pertinent data and assumptions	None

TABLE 15.6-15

FEEDWATER LINE BREAK ACCIDENT - PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSIS (Continued)

		Parameter	Value
III.	Dispersion data		
	A.	Boundary and LPZ distance (m)	1950/4827
	B.	χ/Qs for time intervals of 0-2 hr - EAB/LPZ	$2.62 \times 10^{-4}/1.06 \times 10^{-4}$
IV.	Dose data		
	A.	Method of dose calculation	Reference 15.6-2
	B.	Dose conversion assumptions	Reference 15.6-2
	C.	Peak activity concentrations in containment	N/A
	D.	Doses	Table 15.6-17

TABLE 15.6-16

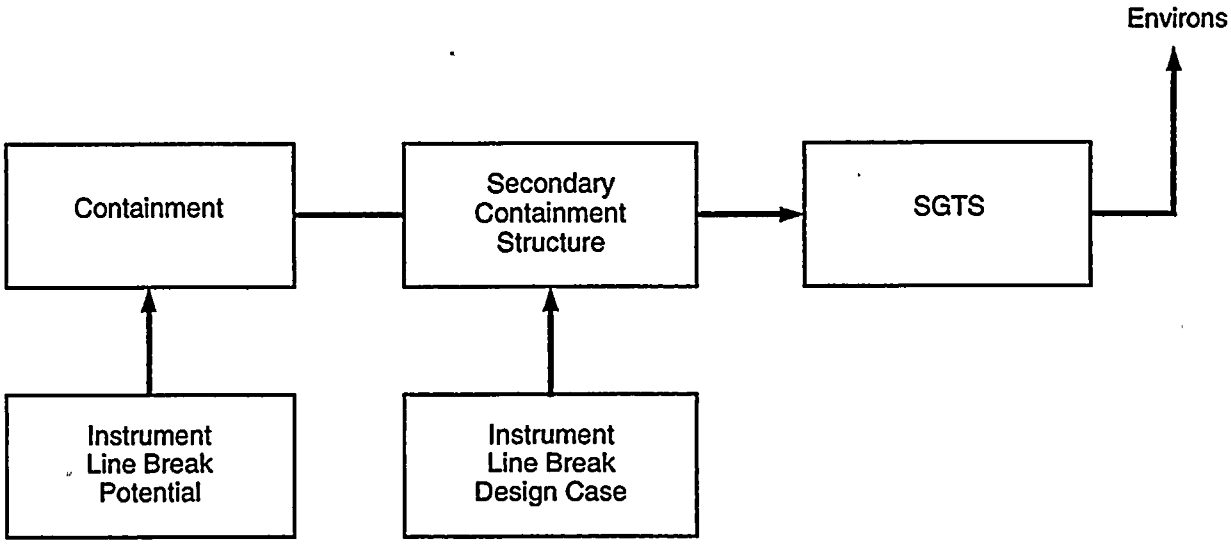
FEEDWATER LINE BREAK ACCIDENT
ACTIVITY RELEASE TO ENVIRONMENT (CURIES)

Isotope	Activity
^{131}I	2.22×10^{-2}
^{132}I	2.05×10^{-1}
^{133}I	1.52×10^{-1}
^{134}I	4.45×10^{-1}
^{135}I	2.22×10^{-1}
Total	1.04×10

TABLE 15.6-17

FEEDWATER LINE BREAK ACCIDENT
BIOLOGICAL EFFECTS OF A PUFF RELEASE

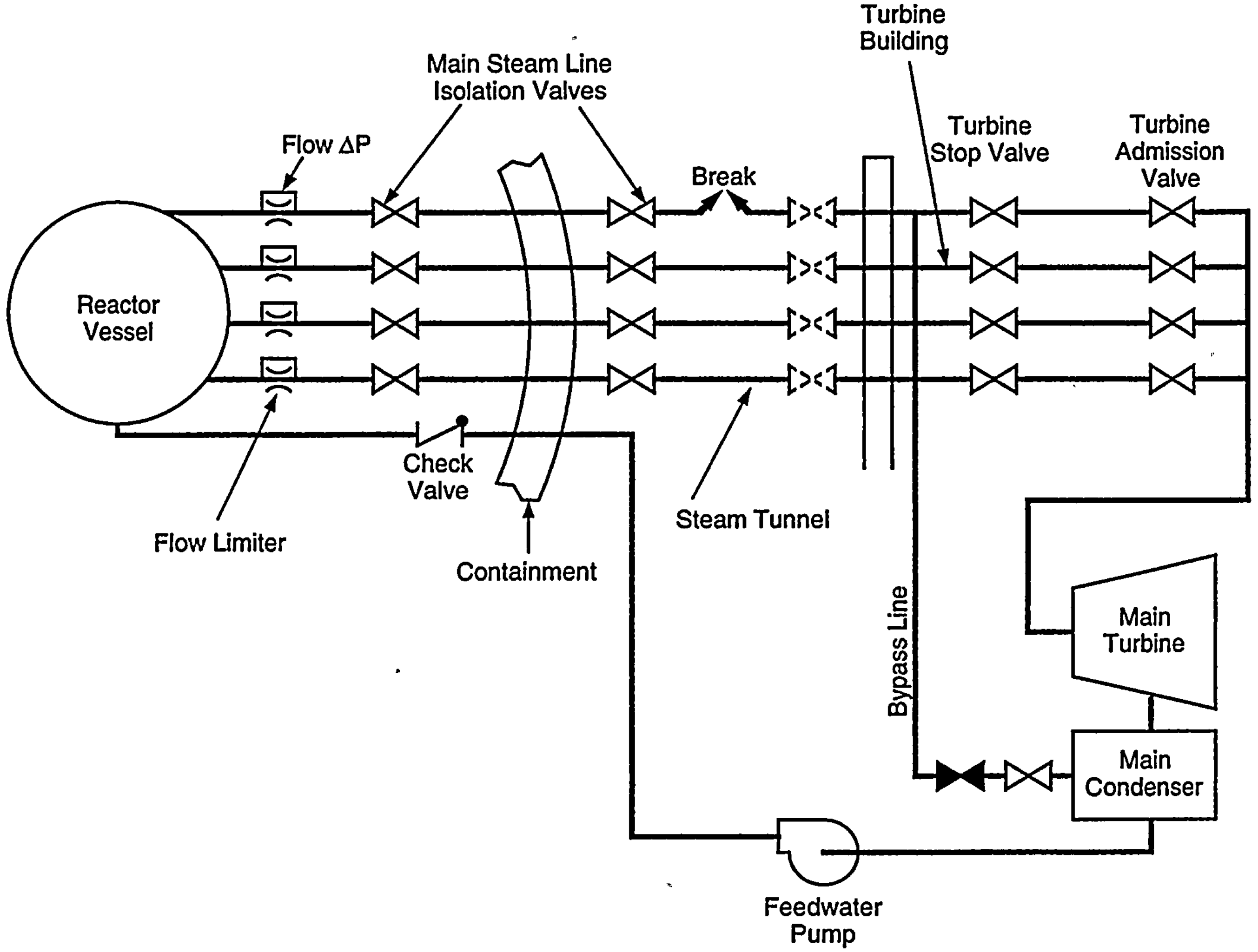
Area	Whole Body Dose (rem)	Thyroid Dose (rem)
Exclusion area (1950 m)	1.37×10^{-4}	5.47×10^{-3}
Low population zone (4827 m)	5.53×10^{-5}	2.21×10^{-3}



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Leakage Path for Instrument Line Break

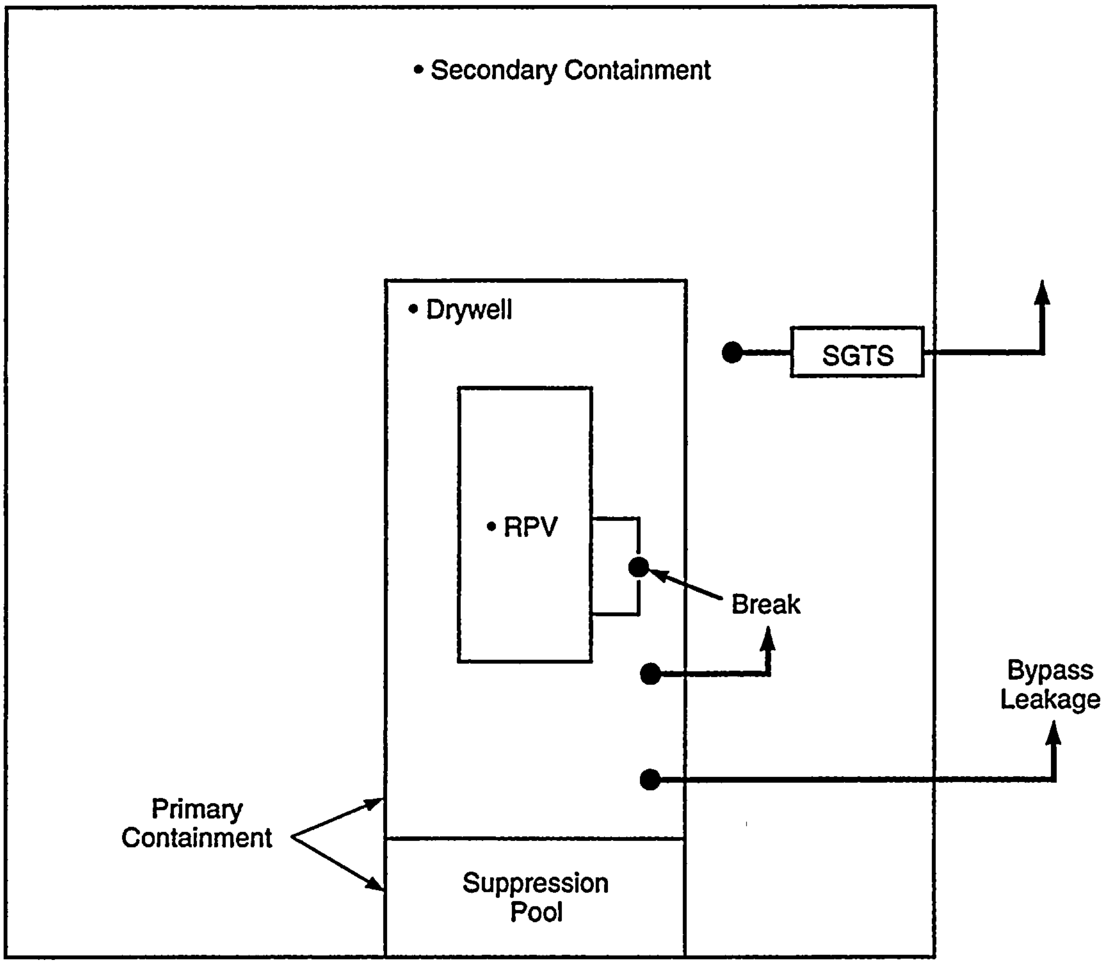
Draw. No. 900547.73 | Rev. | Figure 15.6-1



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

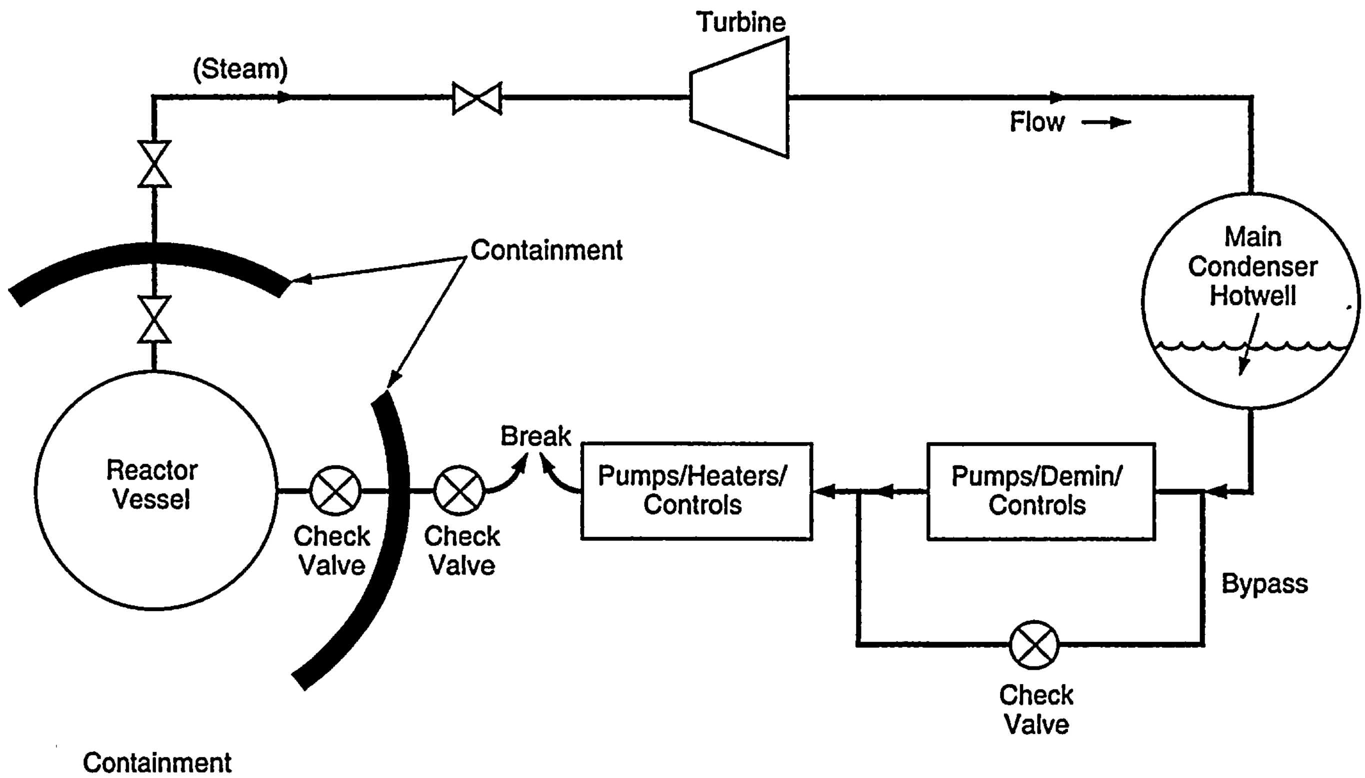
Steam Flow Schematic for Steam Break Outside Containment

Draw. No. 900547.74	Rev.	Figure 15.6-2



Leakage Path for LOCA

Draw. No. 900547.75	Rev.	Figure 15.6-3



Leakage Path for Feedwater Line Break Outside Containment

Draw. No. 900547.76 | Rev. | Figure 15.6-4

15.7 RADIOACTIVE RELEASE FROM SUBSYSTEMS AND COMPONENTS

These events are classified as nonlimiting events for both original and uprated power conditions. Therefore, no further analysis has been performed.

15.7.1 RADIOACTIVE GAS WASTE SYSTEM LEAK OR FAILURE

Not applicable.

15.7.2 LIQUID RADIOACTIVE SYSTEM FAILURE

Not applicable.

15.7.3 POSTULATED RADIOACTIVE RELEASES DUE TO LIQUID RADWASTE TANK FAILURE

15.7.3.1 Identification of Causes and Frequency Classification

15.7.3.1.1 Identification of Causes

The liquid radwaste tanks are constructed to specific engineering codes and standards and to the uniform building code seismic requirements. These tanks operate at atmosphere pressure and low temperatures. A positive action interlock system is provided to prevent inadvertent opening of a drain valve because of operator error. Accordingly, the possibility of a complete tank failure or drainage is considered small.

An unspecified event is postulated to cause the complete release of the average radioactivity inventory in the tank containing the largest quantities of significant radionuclides in the liquid radwaste system. The tank postulated to rupture is one of the two decontamination solution concentrated waste tanks (see Figure 11.2-1).

15.7.3.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.7.3.2 Sequence of Events and Systems Operation

15.7.3.2.1 Sequence of Events

The sequence of events expected to occur is as follows.

Sequence of Events - Liquid Radwaste Tank Failure

Events	Time
Event begins-failure occurs	0
Area radiation alarms alert plant personnel	~ 1 minute
Operator action begins	~ 10 minute

15.7.3.2.2 Identification of Operator Actions

The operator would, upon receiving the alarms, alert personnel to evacuate affected areas of the radwaste building and isolate the radwaste building ventilation system.

15.7.3.2.3 Systems Operation

Failure of a concentrated waste tank does not require a shutdown nor does it impair a safe shutdown. It will lead to limited operation of the concentrated waste system using the remaining tank.

The liquid contents of this tank will also be contained by the building walls and an unlined, 18-in. high concrete dike around the radwaste tank area. Floor drain sump pumps would receive a high water level alarm, activate automatically, and remove the spilled liquid.

15.7.3.2.4 The Effects of Single Failures and Operator Errors

This event has been analyzed without taking credit for any expected operator action or system operation; therefore, a discussion of single equipment failure or single operator error is not applicable.

15.7.3.3 <u>Core and System Performance</u>

The failure of this liquid radwaste system component does not directly affect the nuclear steam supply system (NSSS). It will lead to decoupling of NSSS with the subject system.

This failure has no applicable effect on the reactor core or the NSSS safety performance. Specific assumptions and parameters are presented in Table 15.7-1.

15.7.3.4 <u>Barrier Performance</u>

This event does not involve any containment barrier integrity except the tank itself and the radwaste building. The dike and walls of the radwaste building surrounding the tanks are built

to Seismic Category I criteria. In the analysis of spill consequences, no credit is taken for the dike or radwaste building in recontaining the spilled liquid.

15.7.3.5 Radiological Consequences

The entire volume (700 gal) of concentrator waste tank assumed to spill with isotope inventory given in Table 11.2-1. Tritium concentration is assumed to be 0.01 µCi/ml (WNP ER OL Section 3.5.1).

The hypothetical radwaste tank failure was evaluated using conservative assumptions such as no containment in the radwaste building and unimpeded flow vertically through 50-60 ft of sand and gravel.

The following offsite concentration data for the radionuclides of interest are provided for the WNP-1/4 wells and at the Columbia River:

Radionuclide	Concentration at WNP-1/4 Wells (µCi/ml)	Concentration at Columbia River (µCi/ml)	Concentration Limit (µCi/ml)
^{3}H	1.0×10^{-7}	1.3×10^{-8}	1×10^{-3}
^{90}Sr	1.7×10^{-4}	4.2×10^{-7}	5×10^{-7}
^{137}Cs	2.2×10^{-10}	1.4×10^{-27}	1×10^{-6}

The calculations show the strontium concentration exceeding the unrestricted area limitation at the WNP-1/4 wells. These wells are a temporary water supply and are under the control of the Supply System. Should a spill occur at WNP-2 there will be ample time to assess the severity and extent of contamination.

Concentration at the river bank will be diluted by the river flow. The nearest surface water users are several miles downstream.

15.7.4 FUEL HANDLING ACCIDENT

15.7.4.1 Identification of Causes and Frequency Classification

15.7.4.1.1 Identification of Causes

The fuel handling accident is assumed to occur as a consequence of a failure of the fuel assembly lifting mechanism resulting in the dropping of a raised fuel assembly onto other fuel bundles. A variety of events which qualify for the class of accidents termed "fuel handling accidents" has been investigated. The accident which produces the largest number of failed spent fuel rods is the drop of a spent fuel bundle into the reactor core when the reactor vessel head is off.

15.7.4.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.7.4.2 Sequence of Events and Systems Operation

15.7.4.2.1 Sequence of Events

The most severe fuel handling accident from a radiological viewpoint is dropping a fuel assembly onto the top of the core. The sequence of events is expected to occur as follows:

Sequence of Events - Dropped Fuel Assembly

Event	Time
Fuel assembly is being handled by refueling equipment. The assembly drops onto the top of the core. Some of the fuel rods in both the dropped assembly and the reactor core are damaged, resulting in the release of gaseous fission products to the reactor coolant and eventually to the reactor building atmosphere. The air is drawn in by the ventilation exhaust ducts.	≤ 0
Airborne activity reaches the ventilation system exhaust air plenum where the radiation monitoring instrumentation is located.	0
Radiation monitoring instrumentation alarms to alert plant personnel, isolate the ventilation system, and start operation of the standby gas treatment system (SGTS).	≤ 3 sec
Reactor building ventilation exhaust isolation valves fully close.	≤ 15 sec
Standby gas treatment system on line	34 sec
Operator action begins	≤ 5 minutes

The isolation valves will fully close in 15.0 sec after the postulated accident occurs. It takes 3 sec for the airborne activity to reach the radiation monitors in the exhaust air ductwork. There will be a 4 sec instrument response time before the isolation valves receive the signal to isolate. It will take 8 sec closing time for the exhaust isolation valves to fully close. Release of the postulated airborne activity to the atmosphere will begin 8.5 sec after the postulated accident occurs due to the transport time through the exhaust air ductwork. Thus, there will be an interval of 6.5 sec where airborne halogens will be released to the atmosphere without processing by the SGTS.

15.7.4.2.2 Identification of Operator Actions

a. The individual in charge of fuel handling will inform the control room and direct affected personnel to the personnel decontamination area,

b. Control room personnel will verify that the normal ventilation system has isolated and the SGTS is in operation and performing as designed,

c. The operator will initiate the evacuation of the reactor building and the locking of the reactor building doors,

d. Operations personnel will initiate action to determine the extent of potential radiation doses by measuring the radiation levels in the vicinity of or close to the reactor building, and

e. Operations personnel will initiate action to post the appropriate radiological control signs at the entrance of the reactor building.

Entry to the reactor building will not be allowed until conditions permit.

15.7.4.2.3 Systems Operation

Normally operating plant instrumentation and controls are assumed to function, although credit is only taken for isolation of the normal ventilation system and operation of the SGTS. Operation of other plant or reactor protection systems or engineered safety feature systems is not expected.

Four radiation monitoring channels of the reactor building ventilation exhaust plenum subsystem are provided for detection of radioactivity releases from a fuel handling accident. This subsystem is designed to Seismic Category I Class 1E requirements. Two of the channels are physically and electrically separated from the other two channels. Channel response time is less than 3 sec for response to 90% of a step change input.

15.7.4.2.4 The Effects of Single Failures and Operator Errors

The automatic ventilation isolation system, which includes the radiation monitoring detectors, isolation valves, and the SGTS, are designed to single failure criteria and safety requirements.

15.7.4.3 Core and System Performance

15.7.4.3.1 Mathematical Model

The analytical methods and associated assumptions used to evaluate the consequences of this accident are considered to provide a realistic, yet conservative assessment of the consequences.

The kinetic energy acquired by a falling fuel assembly may be dissipated in one or more impacts. To estimate the expected number of failed fuel rods in each impact, an energy approach is used. The energy absorption on successive impacts is estimated by considering a plastic impact.

The fuel assembly is expected to impact on the reactor core at a small angle from the vertical, possibly inducing a bending mode of failure on the fuel rods of the dropped assembly. It is assumed that each fuel rod resists the imposed bending load by a couple consisting of two equal, opposite concentrated forces. Therefore, fuel rods are expected to absorb little energy prior to failure as a result of bending. Actual bending tests with concentrated point-loads show that each fuel rod absorbs approximately 1 ft/lb prior to cladding failure. Each rod that fails as a result of gross compression distortion is expected to absorb approximately 250 ft/lb before cladding failure (based on 1% uniform plastic deformation of the rods). The energy of the dropped assembly is conservatively assumed to be absorbed by only the cladding and other core structures. Because a fuel assembly consists of 72% fuel, 11% cladding, and 17% other structural material by weight, the assumption that no energy is absorbed by the fuel material results in considerable conservatism in the mass-energy calculations.

15.7.4.3.2 Input Parameters and Initial Conditions

The assumptions used in the analysis of this accident are listed below:

a. The fuel assembly is dropped from a height of 34 ft. The maximum height allowed by the fuel handling equipment is less than 34 ft;

b. The entire amount of potential energy, referenced to the top of the reactor core, is available for application to the fuel assemblies involved in the accident. This assumption neglects the dissipation of some of the mechanical energy of the falling fuel assembly in the water above the core and requires the complete detachment of the assembly from the fuel hoisting equipment. This is only possible if the fuel assembly handle, the fuel grapple, or the grapple cable breaks;

c. None of the energy associated with the dropped fuel assembly is absorbed by the fuel material; and

d. All fuel rods in the dropped bundle, including tie rods, were assumed to fail by 1% strain in compression. For the fuel designs considered here, there is no propensity for preferential failure of tie rods. The struck bundle(s) are assumed to experience fuel rod failure by 1% strain in compression. The number of fuel rods that fail in the struck bundle(s) is a function of the energy dissipated on impact.

15.7.4.3.3 Results

Because of the complex nature of the impact and the resulting damage to fuel assembly components, a rigorous prediction of the number of failed rods is not possible. For this reason, a simplified energy approach was taken and numerous conservative assumptions were made to ensure a conservative estimate of the number of failed rods.

15.7.4.3.3.1 Energy Available. The potential energy of the dropped assembly consists of two components. The primary component of the potential energy is determined by the vertical distance between the bottom of the lifted assembly and the top of the reactor core and is fully dissipated during the initial impact of the dropped assembly on the reactor core. The secondary component is determined by the elevation of the center of mass of the dropped assembly above the reactor core following the initial impact. The secondary component is assumed to be fully dissipated during the secondary impact of the dropped assembly on the reactor core.

15.7.4.3.3.2 Energy Loss Per Impact. The wet weight of the dropped bundle (W_B) is 617 lb and the wet weight of the grapple component (W_G) is 350 lb. The drop distance is 34 ft. The total energy to be dissipated by the initial impact is 32,878 ft-lb.

Following the initial impact, the assembly was assumed to tip over and impact horizontally on the top of the core. The remaining available energy was used to predict the number of additional rod failures. The 8780 ft-lb available energy for the secondary impact was calculated by assuming a linear weight distribution in the assembly with a point load at the top of the assembly to represent the fuel grapple weight.

15.7.4.3.3.3 Fuel Rod Failures. The number of failed fuel rods was determined by balancing the energy of the dropped assemblage against the energy required to fail a rod. One-half of the energy was considered to be absorbed by the falling assembly and one-half by the four impacted assemblies.

No energy was considered to be absorbed by the fuel pellets (i.e., the energy was absorbed entirely by the non-fuel components of the assemblies). The energy available for cladding deformation was considered to be proportional to the mass ratio and is equal to a maximum of 0.519.

15.7.4.3.3.3.1 First Impact Failure. The dropped assembly was considered to impact at a small angle, subjecting all of the fuel rods in the dropped assembly to bending moments. The fuel rods are expected to absorb little energy prior to failure as a result of bending. For this reason, it is assumed that all of the rods in the dropped assembly fail. The energy absorbed by the cladding of the four impacted assemblies is 8532 ft-lb.

Each rod that fails is expected to absorb approximately 250 ft-lb before cladding failure, based on uniform 1% plastic deformation of the cladding. The number of rods failed in the impacted assemblies is 96 on initial impact.

15.7.4.3.3.3.2 Second Impact Failures. As with the initial impact, the energy was considered to be absorbed equally by the falling assembly and the impacted assemblies and the fraction available for cladding deformation was 0.519. The energy available to deform cladding in the impacted assemblies was 2278 ft-lb and the number of failures in the impacted assemblies was nine rods.

Since the rods in the dropped assembly were considered to have failed in the initial impact, no additional failures are predicted for the dropped assembly.

15.7.4.3.3.3.3 Total Failures. The total rods failed in both impacts is 105. The radiological consequences are determined from a conservatively-assumed 124 failed fuel rods during the event.

To provide an upper limit bounding analysis, it is conservatively assumed that 250 fuel rods experience cladding damage.

15.7.4.4 Barrier Performance

The reactor coolant pressure boundary and primary containment are assumed to be open.

15.7.4.5 Radiological Consequences

The fission product inventory in the fuel rods assumed to be damaged is based on 1000 days of continuous operation at 3556 MWt. A 24-hr period for decay from the power condition is assumed because it is not expected that fuel handling can begin within 24 hr following initiation of reactor shutdown. Figure 15.7-1 indicates the leakage flow path for this accident.

15.7.4.5.1 Design Basis Analysis

Specific values of parameters used in evaluation are presented in Table 15.7-2.

15.7.4.5.1.1 Fission Product Release From Fuel. The fission product inventory of a core average exposure fuel rod is adjusted by a peaking factor of 1.5 to establish the inventory of

each damaged rod. Ten percent of the noble gases inventory (30% for ^{85}Kr) and 10% of the iodine inventory are assumed to be released to the fuel pool. The activity airborne in the secondary containment is presented in Table 15.7-3.

15.7.4.5.1.2 <u>Fission Product Transport to the Environment</u>. The transport pathway consists of mixing in the fuel pool, migration from the pool to the secondary containment atmosphere and release to the environment through the reactor building ventilation exhaust system (REA) and the SGTS. All of the noble gas and 1% (Reference 15.7-1) of the iodines in the fuel pool are assumed to become airborne in the secondary containment.

Release by means of the REA system will occur for a maximum of 6.5 sec. Continued airborne activity release to the environment over a 2-hr period will be after filtration by the SGTS (99% removal efficiency for iodine).

The release of activity to the environment is presented in Table 15.7-4.

15.7.4.5.1.3 <u>Results</u>. The calculated exposures for the design basis analysis are presented in Table 15.7-5 and are within the guidelines of 10 CFR 100.

15.7.5 SPENT FUEL CASK DROP ACCIDENT

The spent fuel cask is equipped with redundant sets of lifting lugs and yolks compatible with the reactor building crane main hook. The reactor building crane is provided with sufficient redundancy such that no credible postulated failure of any crane component required to lift, hold, and move loads, will result in the dropping of the fuel cask. Therefore, an analysis of the spent fuel cask drop is not required.

15.7.6 REFERENCES

15.7-1 "Decontamination Factor For Fuel Handling Accident," NE-02-96-0011, August 1996.

TABLE 15.7-1

LIQUID RADWASTE TANKS FAILURE - PARAMETERS
AND CONCENTRATIONS

	Parameter	Value
I.	Data and assumptions used to estimate radioactive source	Entire volume (700 gal) of concentrator waste tank assumed to spill with isotope inventory given in Table 11.2-1. Tritium concentration assumed to be 0.01 mCi/ml from the WNP-2 ER-OL.
II.	Data and assumptions used to estimate activity released	
	A. Containment leak rate (%/day)	N/A
	B. Secondary containment leak rate (%/day)	N/A
	C. Valve movement times	N/A
	D. Absorption and filtration efficiencies	N/A
	(1) Organic iodine	N/A
	(2) Elemental iodine	N/A
	(3) Particulate iodine	N/A
	(4) Particulate fission products	N/A
	E. Recirculation system parameters	N/A
	(1) Flow rate	N/A
	(2) Mixing efficiency	N/A
	(3) Filter efficiency	N/A
	F. Containment spray parameters (flow rate, drop size, etc.)	N/A
	G. Containment volumes	N/A
	H. Other pertinent data and assumptions	See Section 2.4.13.3
III.	Concentration data	

@ WNP-1/4 Wells		Conc. Limit[a]	
Radionuclide	@ Col. R (µCi/ml)	(µCi/ml)	(µCi/ml)
^{3}H	1.0×10^{-7}	1.3×10^{-8}	1×10^{-3}
^{90}Sr	1.7×10^{-4}	4.2×10^{-7}	5×10^{-7}
^{137}Cs	2.2×10^{-10}	1.4×10^{-27}	1×10^{-6}

[a] From 10 CFR Part 20.

TABLE 15.7-2

FUEL HANDLING ACCIDENT PARAMETERS TABULATED
FOR POSTULATED ACCIDENT ANALYSIS

Parameters	Design Basis Assumptions
I. Data and assumptions used to estimate radioactive source from postulated accidents	
A. Power level	3556
B. Radial peaking factor	1.5
C. Assumed fuel damaged	250 rods
D. Release of activity by nuclide	10% noble gas 10% iodine 30% ^{85}Kr
E. Iodine fractions	
(1) Organic	0
(2) Elemental	1
(3) Particulate	0
F. Reactor coolant activity before the accident	N/A
II. Data and assumptions used to estimate activity released	
A. Primary containment leak rate (%/day)	N/A
B. Secondary containment leak rate	100%/2 hr
C. Valve movement times	N/A
D. Absorption and filtration	
(1) Organic iodine	99%
(2) Elemental iodine	99%
(3) Particulate iodine	99%
(4) Particulate fission products	99%
E. Recirculation system parameters	
(1) Flow rate	N/A
(2) Mixing efficiency	N/A
(3) Filter efficiency	N/A
F. Containment spray parameters (flow rate, drop size, etc.)	N/A
G. Containment volumes	N/A
H. All other pertinent data and assumptions	None

TABLE 15.7-2

FUEL HANDLING ACCIDENT PARAMETERS TABULATED
FOR POSTULATED ACCIDENT ANALYSIS (Continued)

Parameters	Design Basis Assumptions
III. Dispersion data	
A. Boundary/LPZ distances (m)	950/4827
B. χ/Qs for time intervals of	
(1) 0-2 hr - SB/LPZ	$2.62 \times 10^{-4}/1.06 \times 10^{-4}$
(2) 2-8 hr - LPZ	4.47×10^{-5}
(3) 8-24 hr - LPZ	2.91×10^{-5}
(4) 1-4 days - LPZ	1.14×10^{-5}
(5) 4-30 days - LPZ	2.97×10^{-6}
IV. Dose data	
A. Method of dose calculation	Regulatory Guide 1.25
B. Dose conversion assumptions	Regulatory Guide 1.25
C. Peak activity concentrations in containment	N/A
D. Doses	Table 15.7-5

TABLE 15.7-3

FUEL HANDLING ACCIDENT
ACTIVITY AIRBORNE IN SECONDARY CONTAINMENT (CURIES)

Isotope	6.5 Sec	5 Minutes	30 Minutes	1 Hr	2 Hr	8 Hr	1 Day	2 Days	4 Days	30 Days
^{131}I	6.91E 02	4.75E 02	6.96E 01	6.95E 00	6.92E-02	6.78E-14	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{132}I	8.80E 02	5.90E 02	7.64E 01	6.57E 00	4.86E-02	7.98E-15	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{133}I	6.96E 02	4.77E 02	6.90E 01	6.79E 00	6.57E-02	5.38E-14	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{134}I	3.69E-05	2.37E-05	2.51E-06	1.69E-07	7.66E-10	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{135}I	1.14E 02	7.78E 01	1.09E 01	1.04E 00	9.34E-03	4.98E-15	1.00E-20	1.00E-20	1.00E-20	1.00E-20
Total iodine	2.38E 03	1.62E 03	2.26E 02	2.13E 01	1.93E-01	1.35E-13	5.00E-20	5.00E-20	5.00E-20	5.00E-20
^{83m}Kr	4.13E 01	2.75E 01	3.45E 00	2.85E-01	1.95E-03	2.02E-16	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{85m}Kr	4.78E 02	3.24E 02	4.46E 01	4.13E 00	3.54E-02	1.40E-14	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{85}Kr	1.97E 03	1.36E 03	1.99E 02	1.99E 01	1.99E-01	1.99E-13	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{87}Kr	7.79E-02	5.12E-02	5.99E-03	4.56E-04	2.64E-06	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{88}Kr	1.49E 02	1.00E 02	1.33E 01	1.18E 00	9.21E-03	2.13E-15	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{89}Kr	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{131m}Xe	7.64E 02	5.24E 02	7.69E 01	7.68E 00	7.66E-02	7.56E-14	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{133m}Xe	4.27E 03	2.93E 03	4.27E 02	4.25E 01	4.19E-01	3.88E-13	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{133}Xe	1.46E 05	1.00E 05	1.47E 04	1.46E 03	1.45E 01	1.41E-11	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{135m}Xe	1.82E 03	1.01E 03	4.88E 01	1.29E 00	9.07E-04	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{135}Xe	3.58E 04	2.44E 04	3.47E 03	3.34E 02	3.10E 00	1.96E-12	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{137}Xe	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20
^{138}Xe	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20	1.00E-20
Total noble gases	1.91E 05	1.31E 05	1.89E 04	1.87E 03	1.84E 01	1.67E-11	1.30E-19	1.30E-19	1.30E-19	1.30E-19

TABLE 15.7-4

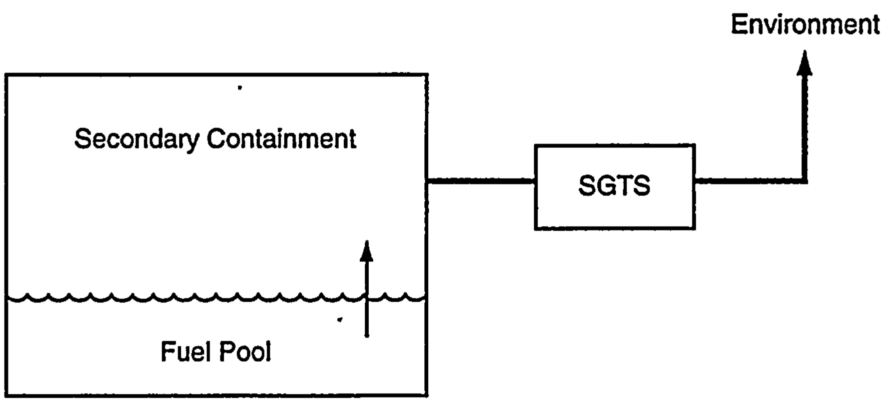
FUEL HANDLING ACCIDENT
ACTIVITY RELEASED TO THE ENVIRONMENT (CURIES)

Isotope	6.5 Sec	5 Minutes	30 Minutes	1 Hr	2 Hr	8 Hr	1 Day	2 Days	4 Days	30 Days
^{131}I	5.77 E 00	7.93E 00	1.20E 01	1.26E 01	1.27E 01	1.27E 01	1.27E 01	1.27E 01	1.27E 01	1.27E 01
^{132}I	7.35 E 00	1.01E 01	1.49E 01	1.55E 01	1.56E 01	1.56E 01	1.56E 01	1.56E 01	1.56E 01	1.56E 01
^{133}I	5.81 E 00	7.98E 00	1.20E 01	1.26E 01	1.27E 01	1.27E 01	1.27E 01	1.27E 01	1.27E 01	1.27E 01
^{134}I	3.08 E-07	4.20E-07	6.01E-07	6.21E-07	6.22E-07	6.22E-07	6.22E-07	6.22E-07	6.22E-07	6.22E-07
^{135}I	9.54 E-01	1.31E 00	1.96E 00	2.06E 00	2.07E 00	2.07E 00	2.07E 00	2.07E 00	2.07E 00	2.07E 00
Total iodine	1.99 E 01	2.73E 01	4.09E 01	4.29E 01	4.31E 01	4.31E 01	4.31E 01	4.31E 01	4.31E 01	4.31E 01
^{83m}Kr	3.45 E-01	1.31E 01	3.53E 01	3.82E 01	3.85E 01	3.85E 01	3.85E 01	3.85E 01	3.85E 01	3.85E 01
^{85m}Kr	3.99 E 00	1.53E 02	4.23E 02	4.62E 02	4.66E 02	4.66E 02	4.66E 02	4.66E 02	4.66E 02	4.66E 02
^{85}Kr	1.65 E 01	6.35E 02	1.79E 03	1.97E 03	1.99E 03	1.99E 03	1.99E 03	1.99E 03	1.99E 03	1.99E 03
^{87}Kr	6.50 E-04	2.45E-02	6.49E-02	6.99E-02	7.03E-02	7.03E-02	7.03E-02	7.03E-02	7.03E-02	7.03E-02
^{88}Kr	1.24 E 00	4.74E 01	1.30E 02	1.41E 02	1.42E 02	1.42E 02	1.42E 02	1.42E 02	1.42E 02	1.42E 02
^{89}Kr	1.00 E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20
^{131m}Xe	6.38 E 00	2.45E 02	6.93E 02	7.62E 02	7.69E 02	7.70E 02	7.70E 02	7.70E 02	7.70E 02	7.70E 02
^{133m}Xe	3.56 E 01	1.37E 03	3.86E 03	4.25E 03	4.29E 03	4.29E 03	4.29E 03	4.29E 03	4.29E 03	4.29E 03
^{133}Xe	1.22 E 03	4.68E 04	1.32E 05	1.45E 05	1.47E 05	1.47E 05	1.47E 05	1.47E 05	1.47E 05	1.47E 05
^{135m}Xe	1.52 E 01	5.31E 02	1.14E 03	1.17E 03	1.17E 03	1.17E 03	1.17E 03	1.17E 03	1.17E 03	1.17E 03
^{135}Xe	2.99E 02	1.15E 04	3.21E 04	3.52E 04	3.55E 04	3.55E 04	3.55E 04	3.55E 04	3.55E 04	3.55E 04
^{137}Xe	1.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E 20	2.00E-20	2.00E-20	2.00E-20
^{138}Xe	1.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20	2.00E-20
Total noble gases	1.59E 03	6.13E 04	1.72E 05	1.89E 05	1.91E 05	1.91E 05	1.91E 05	1.91E 05	1.91E 05	1.91E 05

TABLE 15.7-5

FUEL HANDLING ACCIDENT (DESIGN BASIS ANALYSIS)
RADIOLOGICAL EFFECTS

Area	Whole Body Dose (rem)	Thyroid Dose (rem)
Exclusion area (1950 m)	1.1	1.5
Low population zone (4827 m)	0.4	0.6



Leakage Path for Fuel Handling Accident

15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

15.8.0 CAPABILITIES OF PRESENT DESIGN TO ACCOMMODATE ANTICIPATED TRANSIENTS WITHOUT SCRAM

The anticipated transients without scram (ATWS) events described in this section are not design basis events for WNP-2. A proposed method for minimizing the effects of failure-to-scram is described in References 15.8-1 and 15.8-2.

The recirculation pump trip (RPT), alternate rod insertion (ARI), and two pump standby liquid control (SLC) system operation features are utilized at WNP-2 to provide protection against failure to scram. Due to the WNP-2 design feature utilizing SLC system injection through the high-pressure core spray (HPCS) header, a plant-unique analysis was performed to demonstrate ATWS protection and mitigation at pre-power uprate conditions.

The ATWS acceptance criteria are established in Reference 15.8-3 as:

a. The reactor coolant pressure boundary (RCPB) remains below emergency pressure limits,

b. The containment pressure remains below design limits. The suppression pool temperature remains below local saturation temperature limits as defined in Reference 15.8-3,

c. A coolable geometry is maintained,

d. Radiological releases are maintained within 10 CFR 100 allowable limits, and

e. Equipment necessary to mitigate the postulated ATWS event are evaluated to provide a high degree of assurance (assurance of function) that it will function in the environment (pressure, temperature, humidity, and radiation) predicated to occur as a result of the ATWS event.

Subsequent to the completion of the ATWS analyses at prepower uprate condition, it was recognized that analyses did not account for the time for the SLC storage tank outlet valves to stroke open. This delay of approximately 35 sec is bounded by a sensitivity study (Reference 15.8-4) that showed a 5 minute delay in SLC injection would not prevent safe shutdown. The limiting ATWS event for peak suppression pool temperature was analyzed with the 35 sec delay in SLC system injection time.

Section 15.8.9 shows that for the ATWS event with the most severe heat flux transient, fuel related applicable limits were met with considerable margins. In addition, Reference 15.8-3 concludes that maximum peak cladding temperature will not exceed 2200°F and the maximum

local oxidation will be much less than 17%. Thus, criteria 3 and 4 are shown to be satisfied by the plant specific and generic analyses. Sections 15.8.7 and 15.8.9 show that resulting primary system pressures will be less than emergency pressure limit and that suppression pool temperature increase and peak pressure are within design limits. Reference 15.8-3 concludes that the safety/relief valve (SRV) air clearing loads will be bounded by the design loads. Thus criteria 1 and 2 are satisfied. In Reference 15.8-5, the Supply System concluded that ATWS equipment had been determined to be qualified by (a) materials analysis of agreeable components including test reports when available, (b) existing qualification to other accident profiles (LOCA, HELB) that encompass the ATWS profile, or (c) location in a mild environment that is not affected by the ATWS accident environment. This satisfies criterion 5.

Power Uprate Evaluation

The ATWS events were analyzed at power uprate operating conditions to demonstrate protection and mitigation of the consequences of these events. These analyses were performed at 3629 MWt power level and bound operation at uprate power level of 3486 MWt. The selection of critical events which were analyzed were guided by Reference 15.8-3.

For power uprate evaluation, it was conservatively assumed that ARI has failed, thus, requiring SLC system injection to achieve reactor shutdown.

The analysis presented herein are applicable to application of flow control valve (FCV) or adjustable speed drive to reactor recirculation system (RRC). A summary of ATWS results are shown in Table 15.8-1.

15.8.1 INADVERTENT CONTROL ROD WITHDRAWAL

This transient is bounded by assumptions in the GE licensing topical reports and the other transients analyzed in this section.

15.8.2 LOSS OF FEEDWATER

15.8.2.1 Identification of Causes and Frequency Classification

15.8.2.1.1 Identification of Causes

Section 15.2.7 provides identification of causes for loss of feedwater event. The loss of feedwater event with failure to scram will initiate an ATWS event.

15.8.2.1.2 Frequency Classification

This event is of extremely low probability and is categorized as a limiting fault.

15.8.2.2 Sequence of Events and System Operation

15.8.2.2.1 Sequence of Events

Table 15.8-2 lists the sequence of events for Figure 15.8-1.

15.8.2.2.1.1 Identification of Operator Actions. For the simulation purpose, the following operator actions have been assumed.

a. Allow automatic operation of the HPCS and reactor core isolation cooling (RCIC),

b. Begin boron injection at two minutes following ATWS high-pressure trip or at boron injection initiation temperature (BIIT), whichever is later, and

c. Switch residual heat removal (RHR) to suppression pool cooling mode 11 minutes following initiation of the transient.

The emergency operating procedures provide operator actions for an ATWS event.

15.8.2.2.2 System Operation

For the loss of feedwater ATWS event, a complete failure to scram is postulated to occur for all reactor protection system (RPS) scram signals. All other plant control systems maintain normal operation. The relief valves are all assumed to function at the specified setpoints. Loss of feedwater flow results in a proportional reduction of vessel inventory causing the vessel water level to drop. The first corrective action is the initiation of HPCS and RCIC on Level 2. For this event, a complete failure of ARI is postulated. The operator must manually initiate SLC system to inject boron into the reactor vessel for reactor shutdown.

15.8.2.2.3 The Effect of Single Failure and Operator Errors

This ATWS event is based on the assumed complete failure of all control rods to scram. This is a multiple equipment failure. For the conservative assumption of failure of the ARI system, the ATWS event is terminated by boron injection through operator activation of the SLC system. This event is less limiting compared with other ATWS events analyzed at power uprate condition.

15.8.2.3 Core and System Performance

15.8.2.3.1 Mathematical Model

The computer model described in Section 15.1.1 and those identified in Reference 15.8-3 were used to simulate this event.

15.8.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless noted otherwise, with plant conditions in Tables 15.8-3 and 15.8-4.

15.8.2.3.3 Results

The results of this ATWS event simulation are shown in Figure 15.8-1. Feedwater pump trip is assumed to occur at the onset of the event. Upon the loss of the feedwater flow, reactor pressure, water level, and neutron flux begin to fall. Once reactor water level reaches low water level (L2), the protection system trips the recirculation pumps, initiates HPCS and RCIC and signals closure of main steam line isolation valves (MSIVs). Reactor pressure begins to rise due to closure of MSIVs. The relief valves begin to open due to reactor pressure increase. It is conservatively assumed the operator manually initiates SLC system 2 minutes after the ATWS setpoint has been reached.

15.8.2.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system setpoints, system capacities, and system response times. For ATWS transient analyses, best estimated values are used when possible. Examples of conservative bounding values which were used to cover uncertainties are as follows:

a. For conservatism, the analysis assumed the highest probable ATWS high-pressure trip setpoint, and

b. Boron injection is the later time of BIIT or 2 minutes following ATWS high-pressure trip.

15.8.2.4 Barrier Performance

The calculated peak vessel bottom head pressure is 1202 psig, which is below the American Society of Mechanical Engineers (ASME) Code Limit of 1375 psig for the RCPB and well below the ASME service level C of 1500 psig. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.8.2.5 Radiological Consequences

While this event does not result in fuel failure it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no uncontrolled release to the environment.

15.8.3 LOSS OF ALTERNATE CURRENT POWER

This transient is bounded by the other transients analyzed in this section.

15.8.4 LOSS OF ELECTRICAL LOAD

This transient is bounded by assumptions in the GE licensing topical reports and the other transients analyzed in this section.

15.8.5 LOSS OF CONDENSER VACUUM

This transient is bounded by assumptions in the GE licensing topical reports and the other transients analyzed in this section.

15.8.6 TURBINE TRIP

This event was analyzed at pre-power uprate condition for low power and full power (corresponding to 3323 MWt) operation. At uprated conditions, the event is bounded by the other transients analyzed in this section. The selection of critical events were guided by Reference 15.8-3.

15.8.7 CLOSURE OF MAIN STEAM LINE ISOLATION VALVES

15.8.7.1 Identification of Causes and Frequency Classification

15.8.7.1.1 Identification of Causes

Various steam line and nuclear system malfunctions, or operator actions, can initiate MSIV closure. These are detailed in Section 15.2.4. The MSIV closure event with failure to scram will initiate an ATWS event.

15.8.7.1.2 Frequency Classification

This event is of extremely low probability and is categorized as a limiting fault.

15.8.7.2 Sequence of Events and System Operation

15.8.7.2.1 Sequence of Events

Table 15.8-5 lists the sequence of events for Figure 15.8-2.

15.8.7.2.1.1 Identification of Operator Actions. For the simulation purpose, the following operator actions have been assumed:

a. Allow automatic operation of the HPCS and RCIC,

b. Begin boron injection at 2 minutes following ATWS high-pressure trip or at BIIT, whichever is later, and

c. Switch RHR to suppression pool cooling mode 11 minutes following initiation of the transient.

Emergency Operating Procedures provide operator actions for an ATWS event.

15.8.7.2.2 System Operation

For the MSIV closure ATWS event, a complete failure to scram is postulated to occur for all RPS scram signals. All other plant control systems maintain normal operation. The relief valves are all assumed to function at the specified setpoints. The RPT occurs at the ATWS high pressure trip setpoint. For this event, a complete failure of ARI is postulated. The operator must manually initiate SLC system to inject boron into the reactor vessel for reactor shutdown.

15.8.7.2.3 The Effect of Single Failures and Operator Errors

For the conservative assumption of failure of ARI system, the ATWS event is terminated by boron injection through operator activation of the SLC system. Relief valves operate to limit system pressure. All of these aspects are designed to single failure criterion. Two sensitivity analysis were performed. One to determine the impact of four SRVs inoperable and the other to determine the impact of delay in SLC system injection time.

15.8.7.3 Core and System Performance

15.8.7.3.1 Mathematical Model

The computer model described in Section 15.1.1 and those identified in Reference 15.8-3 were used to simulate this event.

15.8.7.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless noted otherwise, with plant conditions tabulated in Tables 15.8-3 and 15.8-4.

15.8.7.3.3 Results

The results of this ATWS event simulation are shown in Figure 15.8-2. The MSIVs close within a nominal 4 sec stroke time. Once the MSIVs reach the 85% open position, a reactor scram is initiated. The scram was assumed to fail to insert any control rods. The rapid increase in reactor pressure generates rapid increase in reactor core power due to collapsing core voids. The relief valves begin to open responding to reactor pressure rise. Upon reaching the ATWS high-pressure setpoint, the RPT occurs and reduces core power. It is conservatively assumed the operator manually initiates SLC system 2 minutes after the ATWS setpoint has been reached.

The results of an ATWS event simulation with four SRVs inoperable are shown in Figure 15.8-3. The sequence of events for this event are shown in Table 15.8-6. The peak calculated vessel bottom head pressure is 1467 psig, which is below the ASME Service Level C limit of 1500 psig.

The calculated peak suppression pool temperature of the event with delayed SLC system injection time is less than 175°F, which is below the containment design limit. The calculated peak containment pressure for this event is 8.46 psig, which is also below the containment design limit.

15.8.7.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system setpoints, system capacities, and system response times. For ATWS transient analyses, best estimated values are used when possible. Examples of conservative bounding values which were used to cover uncertainties are as follows:

a. For conservatism, the analyses assumed the highest probable ATWS high-pressure trip setpoint, and

b. Boron injection is the later time of BIIT or 2 minutes following ATWS high-pressure trip.

15.8.7.4 <u>Barrier Performance</u>

The calculated peak vessel bottom head pressure is 1310 psig and 1467 psig for MSIV with full complement of SRVs and with four SRVs inoperable respectively. The calculated peak

vessel bottom head pressure are below the ASME Service Level C of 1500 psig, thus, meeting criterion 1. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containments are designed. Therefore, these barrier integrity and function is maintained.

15.8.7.5 Radiological Consequences

While this event does not result in fuel failure it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no uncontrolled release to the environment.

15.8.8 INADVERTENT OPENING OF RELIEF VALVE

15.8.8.1 Identification of Causes and Frequency Classification

15.8.8.1.1 Identification of Causes

This event assumes that a SRV may "open" and stick in the "open" position. These events are detailed in Section 15.2.4. The inadvertent opening of relief valve (IORV) event with failure to scram will initiate an ATWS event.

15.8.8.1.2 Frequency Classification

This event is of extremely low probability and is categorized as a limiting fault.

15.8.8.2 Sequence of Events and System Operation

15.8.8.2.1 Sequence of Events

Table 15.8-7 lists the sequence of events for Figure 15.8-4.

15.8.8.2.1.1 Identification of Operator Actions. For the simulation purpose, the following operator actions have been assumed:

a. Initiate boron injection 2 minutes after BIIT,
b. Disable HPCS, RCIC, and low level MSIV closure,
c. Use feedwater to manually control the water level at the top of active fuel, and
d. Manually trip the recirculation pumps.

15.8.8.2.1.2 System Operation. For the IORV ATWS event, a complete failure to scram is postulated to occur for all RPS scram signals. All other plant control systems maintain normal operation. For this event, a complete failure of ARI is also postulated. The operator must manually initiate SLC system to inject boron into the reactor vessel for reactor shutdown.

15.8.8.2.2 The Effect of Single Failures and Operator Errors

For the conservative assumption of failure of ARI system, the ATWS event is terminated by boron injection through operator activation of the SLC system. This is a multiple equipment failure event. All of these aspects are designed to single failure criterion.

The instrumentation, which detects and audibly alarms the resulting suppression pool temperature rise, and the RHR containment heat removal system are designed to meet the single failure criteria. The operator must, however, manually initiate suppression pool cooling.

15.8.8.3 Core and System Performance

15.8.8.3.1 Mathematical Model

The computer model described in Section 15.1.1 and those identified in Reference 15.8-3 were used to simulate this event.

15.8.8.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless noted otherwise, with plant conditions in Tables 15.8-3 and 15.8-4.

15.8.8.3.3 Results

The results of this ATWS event simulation are shown in Figure 15.8-4. The opening of a SRV allow steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a mild depressurization transient.

Discharge of steam into the suppression pool increases the suppression pool temperature. The operator initiates SLC system 2 minutes after the suppression pool temperature reaches 110°F, trips the recirculation pumps, and initiates feedwater runback to lower the reactor water level to top of active fuel (TAF). Suppression pool cooling begins 11 minutes after the initiation of the event. The operator disables HPCS and RCIC level 2 initiation. The MSIV Level 2 closure is also disabled. Turbine steam flow is terminated upon closure of the MSIVs due to low steam line pressure.

15.8.8.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system setpoints, system capacities, and system response times. For ATWS transient analyses, best estimated values are used when

possible. Examples of conservative bounding values which were used to cover uncertainties are as follows:

a. For conservatism, the analysis assumed the highest probable ATWS high-pressure trip setpoint, and

b. Boron injection is the later time of BIIT or 2 minutes following ATWS high-pressure trip.

15.8.8.4 Barrier Performance

The IORV ATWS event is a mild depressurization which has no significant effect on RCPB. During the event, the suppression pool is continually heated due to SRV discharge. The peak suppression pool temperature and pressure are within the design criteria of the containment.

15.8.8.5 Radiological Consequences

While this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no uncontrolled release to the environment.

15.8.9 PRESSURE REGULATOR FAILURE - OPEN (PREGO)

15.8.9.1 Identification of Causes and Frequency Classification

15.8.9.1.1 Identification of Causes

The causes for this event is detailed in Section 15.1.3. The PREGO event with failure to scram will initiate an ATWS event.

15.8.9.1.2 Frequency Classification

This event is of extremely low probability and is categorized as a limiting fault.

15.8.9.2 Sequence of Events and System Operation

15.8.9.2.1 Sequence of Events

Table 15.8-8 lists the sequence of events for Figure 15.8-5.

15.8.9.2.1.1 Identification of Operator Actions. For the simulation purpose, the following operator actions have been assumed.

a. Allow automatic operation of the HPCS and RCIC,

b. Begin boron injection at 2 minutes following ATWS high-pressure trip or at BIIT, whichever is later, and

c. Switch RHR to suppression pool cooling mode 11 minutes following initiation of the transient.

The emergency operating procedures provide operator actions for an ATWS event.

15.8.9.2.1.2 System Operation. For the PREGO ATWS event, a complete failure to scram is postulated to occur for all RPS scram signals. All other plant control systems maintain normal operation. For this event, a complete failure of ARI is also postulated. The operator must manually initiate SLC system to inject boron into the reactor vessel for reactor shutdown.

15.8.9.2.3 The Effect of Single Failures and Operator Errors

For the conservative assumption of failure of ARI system, the ATWS event is terminated by boron injection through operator activation of the SLC system. This is a multiple equipment failure event. All of these aspects are designed to single failure criterion.

The instrumentation, which detects and audibly alarms the resulting suppression pool temperature rise, and the RHR containment heat removal system are designed to meet the single failure criteria.

15.8.9.3 Core and System Performance

15.8.9.3.1 Mathematical Model

The computer model described in Section 15.1.1 and those identified in Reference 15.8-3 were used to simulate this event.

15.8.9.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless noted otherwise, with plant conditions tabulated in Tables 15.8-3 and 15.8-4.

15.8.9.3.3 Results

The results of this ATWS event simulation are shown in Figure 15.8-5. The pressure regulator failure with 130% steam flow demand signal is assumed to occur. Ensuring reactor depressurization results in formation of voids in the reactor coolant and causes a decrease in reactor power almost immediately. The MSIV closure occurs due to trip signal from low

steam line pressure. Reactor pressure rises to the relief setpoints and the recirculation pumps trip on the high pressure ATWS setpoint.

Discharge of steam into the suppression pool increases the suppression pool temperature. The operator initiates feedwater runback to lower the reactor water level to TAF after the suppression pool temperature reaches 110°F. The HPCS and RCIC systems are initiated at low reactor water level. The SLC system is manually initiated 2 minutes after the ATWS high pressure setpoint was reached.

15.8.9.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system setpoints, system capacities, and system response times. For ATWS transient analyses, best estimated values are used when possible. Examples of conservative bounding values which were used to cover uncertainties are as follows:

a. For conservatism, the analysis assumed the highest probable ATWS high-pressure trip setpoint, and

b. Boron injection is the later time of BIIT or 2 minutes following ATWS high-pressure trip.

15.8.9.4 Barrier Performance

The calculated peak vessel bottom head pressure is 1306.5 psig, which is below ASME Code limit of 1375 psig for the RCPB and well below the ASME Service Level C of 1500 psig. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel pressure vessel or containment are designed. Therefore, barrier integrity and function is maintained.

The calculated peak suppression pool temperature for this event is less than 173°F, which is below the containment design limit. The calculated peak containment pressure for this event is 8.10 psig, which is also below the containment design limit.

15.8.9.5 Radiological Consequences

While this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no uncontrolled release to the environment.

15.8.10 SINGLE REACTOR RECIRCULATION SYSTEM PUMP OPERATION

The following discussion is based on pre-uprate power level of 3323 MWt. Thus, the 100% rod line corresponds to 3323 MWt power at rated core flow.

For pre-uprate condition, it was shown that operation of the plant with only a single RRC pump and the resulting transient conditions which could occur while in this mode are bounded by the other transients analyzed in this section, and the parametric studies performed in Reference 15.8-4. This conclusion was based on evaluating the effects of power, void reactivity worth and doppler worth at both 100% conditions, and at conditions present under single RRC pump operation.

Sensitivity studies presented in Reference 15.8-4 compare the turbine trip at 100% power condition with the turbine trip at lower power conditions, such as one would have under single RRC pump.

The rod line for single RRC pump operation for pre-uprate condition was normally maintained between 100% and 104.25% power level. At less than 100% power the average void in the core was slightly higher for operation on the 104.25% rod line than for operation on the 100% rod line. In addition, the doppler worth at lower power conditions is higher than at 100% power. The presence of higher voids and the increased doppler worth when operating at the 104.15% rod line is bounded by the parametric analyses in Reference 15.8-4. These parametric analyses determined the sensitivity of plant response between the MSIV closure at 100% power and the MSIV closure with higher reactivity coefficients at 100% power. The void worth assumed in the higher reactivity coefficient case gives a much higher effect than the increased average void present in the single RRC pump operation mode at the 104.25% rod line, which bounds this case. The doppler reactivity worth used in the MSIV closure with higher reactivity coefficients is representative of the doppler reactivity worth found at lower power conditions such as those present in the single RRC pump operation mode.

15.8.11 EXTENDED LOAD LINE LIMIT ANALYSIS OPERATION

Power uprate ATWS analysis were performed with Extended Load Line Limit Analysis (ELLLA) operating conditions. These analyses show that performance at the power uprate condition is within vessel maximum pressure, fuel temperature, and containment pressure limit for the most severe ATWS transients (Reference 15.8-6).

15.8.12 REFERENCES

15.8-1 Hatch Unit 1 FSAR. Amendment 10, Appendix L, "Failure-to-Scram Analysis," October 27, 1971.

15.8-2 Michelotti, L. A., "Analysis of Anticipated Transients Without Scram," NEDO-10349.

15.8-3 NEDE-24222, "Assessment of BWR Mitigation of ATWS, Volume II (NUREG-0460 Alternate No. 3)."

15.8-4 EI International, Inc., "Final Report, Anticipated Transients Without Scram Analysis for the WNP-2 Nuclear Power Plant," SA-JAD-087-90, December 1989.

15.8-5 Supply System Letter G02-90-116, G. C. Sorensen (Supply System) to NRC, "Nuclear Plant No. 2. Operating License (NPF-21 Resolution of Anticipated Transient Without Scram (ATWS) for WNP- 2," dated June 29, 1990.

15.8-6 GE Nuclear Energy, "Power Uprate with Extended Load Line Limit Safety Analysis for WNP-2," NEDC-32141P, Class III (Proprietary).

TABLE 15.8-1

ANTICIPATED TRANSIENTS WITHOUT SCRAM ANALYSIS
INITIAL CONDITIONS

Parameters	Value
Reactor dome pressure (psig)	1020
Vessel core flow (Mlb/hr)	108.5
Vessel steam flow (Mlb/hr)	15.728
Reactor thermal power (MWt)	3629
Initial vessel and recirculation piping inventory (lbm)	609,600
Narrow range sensed initial water level (ft above separator skirt)	4.13
Initial core average void fraction (%)	41.8
Void reactivity coefficient (¢%)	-12.937
Doppler coefficient (%F)	-0.31087
Feedwater enthalpy (Btu/lb)	403.1
Sodium penetaborate solution (% by weight)	13.6
Concentration	
Suppression pool liquid volume (ft^3)	112,197
Suppression pool temperature (°F)	90
Service water temperature (°F)	90

TABLE 15.8-2

ANTICIPATED TRANSIENTS WITHOUT SCRAM ANALYSIS
EQUIPMENT PERFORMANCE CHARACTERISTICS

Parameter	Value
Main steam line isolation valve nominal closure time (sec)	4
Relief valve system capacity (% of current NBR steam flow at 1144 psia)	100.18
Number of SRVs	18
Relief valve and sensor time delay (sec)	0.4
Relief valve opening time (sec)	0.15
Relief valve closure time delay (sec)	0.3
Standby liquid control system injection rate (gpm)	86.0
High-pressure core spray/RCIC low water level initiation nominal setpoint (ft above separator skirt)	-3.04 (L2)
High-pressure core spray/RCIC high water level shutoff setpoint (ft above separator skirt)	5.667 (L8)
High-pressure core spray flow rate (gpm at 1035 psia)	3875
Reactor core isolation cooling flow rate (gpm)	600
Anticipated transients without scram high pressure UAL setpoint (psia)	1186
Anticipated transients without scram dome pressure sensor and logic time delay (sec)	0.53
Total bypass capacity (Mlb/hr)	35.5
Total bypass capacity (% of uprate steam flow)	22.7
Pump inertia constant (sec)	5.4729
Residual heat removal pool cooling capacity (Btu/sec-°F)	578

TABLE 15.8-3

SUMMARY OF WNP-2
ANTICIPATED TRANSIENTS WITHOUT SCRAM RESULTS

Parameter	ATWS Event			
	PREGO	MSIVC	LOFW	IORV
Maximum neutron flux (%)	421.22	683.2	282.07	116.6
Time (sec)	22.59	4.02	22.36	7.96
Maximum average fuel heat flux (%)	170.99	151.83	102.9	103.14
Time (sec)	4.41	5.11	0.49	0.69
Maximum bottom pressure (psig)	1306.5	1310.1	1202.2	1061.4
Time (sec)	27.62	8.28	23.62	0.19
Peak suppression pool temperature (°F)	172.79	173.40	161.06	165.29
Peak containment pressure (psig)	8.10	8.20	5.97	6.87
Time (sec)	4600	4500	8400	6600
Peak cladding temperature (°F)	1473.67	N/A	N/A	N/A
Time (sec)	83.5			
Minimum water level (ft above separator)	-10.47	-10.27	-11.24	-10.66
Skirt time (sec)	211.18	197.29	197.29	975.4
Time of hot shutdown[a] (sec)	948.6	962.6	977.0	1524.6
Time of reaching ATWS setpoint (sec)	24.09	4.73	17.5	N/A
Time of BIIT (sec)	67.9	54.6	170.0	554.0

[a] Hot shutdown is defined as generated power remaining below 1% NBR.

TABLE 15.8-4

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER

Time	Event
0 sec	Feedwater pump trip.
17.5 sec	High-pressure core spray and RCIC initiated on Level 2.
17.5 sec	Main steam line isolation valve closure on Level 2 - scram fails.
17.5 sec	Recirculation pump tripped on Level 2 (ATWS setpoint reached, ARI fails).
22.9 sec	Relief valves lift.
23.6 sec	Vessel pressure peaks.
2 minutes 18 sec	Operator initiates SLCS (2 minutes after ATWS setpoint reached).
3 minutes 3 sec	Liquid control flow enters the core.
16 minutes	Hot shutdown achieved.
140 minutes	Suppression pool temperature and containment pressure peak.

TABLE 15.8-5

SEQUENCE OF EVENTS FOR MAIN STEAM LINE
ISOLATION VALVE CLOSURE
(LONG TERM TRANSIENT)

Time	Event
0 sec	Nominal 4-sec MSIV closure - scram fails.
4.37 sec	Relief valves lift.
4.37 sec	Recirculation pump trip on high pressure (ATWS setpoint reached, ARI fails).
8.28 sec	Vessel pressure peaks.
54.60 sec	Operator initiates feedwater runback (suppression pool at 110°F).
1 minute 15 sec	High-pressure core spray and RCIC initiated on Level 2.
2 minutes 4 sec	Operator initiates SLC system 2 minutes after ATWS setpoint reached.
2 minutes 51 sec	Liquid control flow enters the core.
11 minutes	Suppression pool cooling begins.
16 minutes	Hot shutdown achieved.
75 minutes	Suppression pool temperature and containment pressure peak.

TABLE 15.8-6

SEQUENCE OF EVENTS FOR MAIN STEAM LINE ISOLATION VALVE CLOSURE WITH FOUR SAFETY/RELIEF VALVES OUT-OF-SERVICE

Time (sec)	Event
0	Nominal 4-sec MSIV closure - scram fails.
4.47	Relief valves lift.
4.73	Recirculation pump trip on high pressure (ATWS setpoint reached).
12.30	Vessel pressure peaks.

TABLE 15.8-7

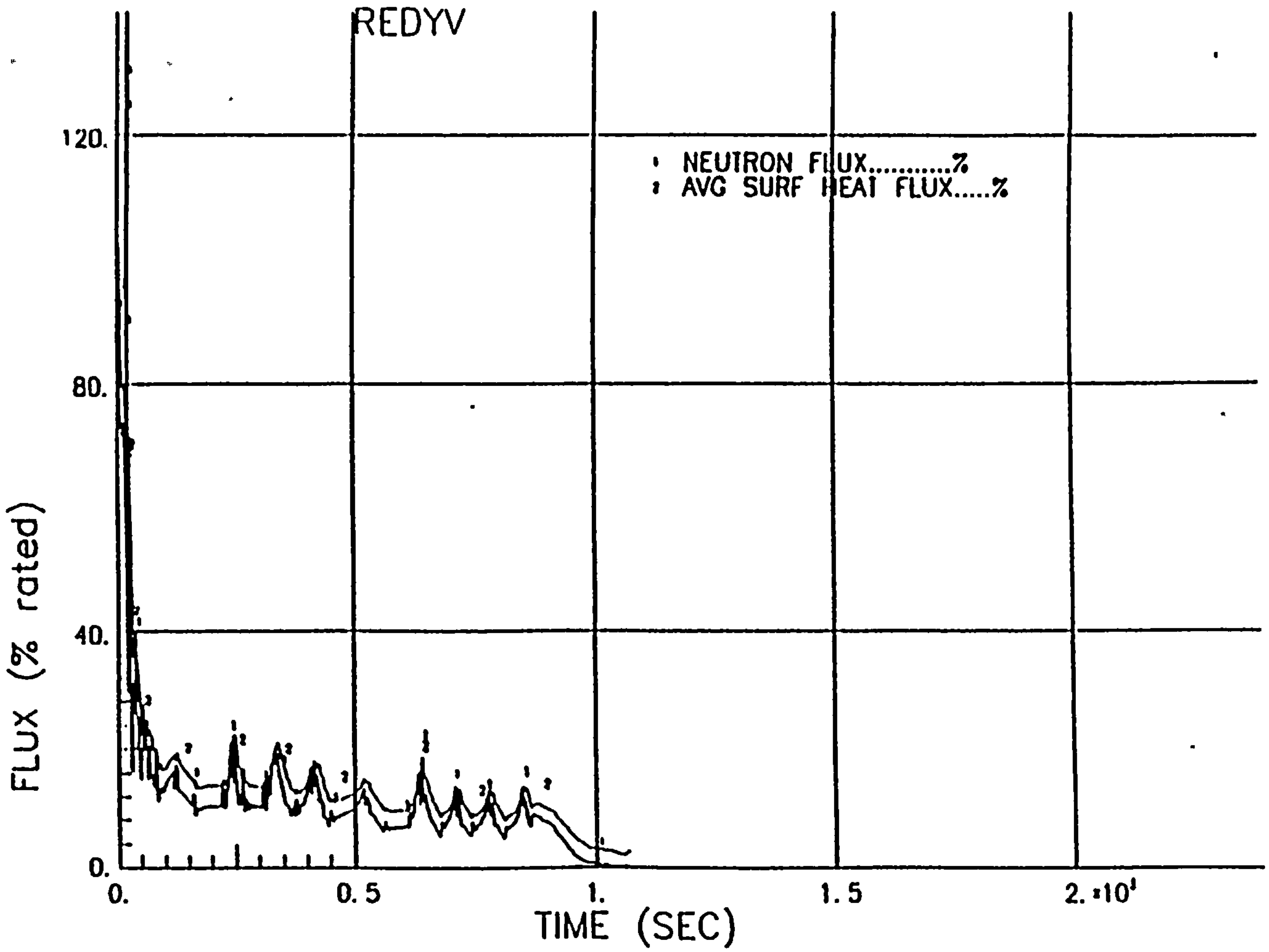
SEQUENCE OF EVENTS FOR INADVERTENT OPEN RELIEF VALVE

Time	Event
0 sec	Relief valve with the lowest opening setpoint opens.
9 minutes 14 sec	Operator initiates SLCS 2 minutes after suppression pool temperature = 110°F (scram and ARI fail).
9 minutes 14 sec	Operator trips recirculation pumps.
9 minutes 14 sec	Operator initiates feedwater runback to bring level to TAF.
11 minutes	Suppression pool cooling begins.
13 minutes	Operator disables HPCS, RCIC Level 2 initiation and MSIV Level 2 closure.
14 minutes	Liquid control flow enters the core.
25 minutes	Hot shutdown achieved.
29 minutes	Main steam line isolation valve closure on low pressure.
110 minutes	Suppression pool temperature and containment pressure peak.

TABLE 15.8-8

SEQUENCE OF EVENTS FOR PRESSURE REGULATOR FAILURE OPEN (LONG TERM TRANSIENT)

Time	Event
0 sec	Pressure regulator fails to maximum demand.
15.3 sec	Main steam line isolation valve closure on low steam line pressure - scram fails.
23.7 sec	Relief valves lift.
24.1 sec	Recirculation pump trip on high pressure (ATWS setpoint reached, ARI fails).
27.6 sec	Vessel pressure peaks.
1 minute 8 sec	Operator initiates feedwater runback (Suppression pool at 110°F).
1 minute 30 sec	High-pressure core spray and RCIC initiated on Level 2.
2 minutes 24 sec	Operator initiates SLC system 2 minutes after ATWS setpoint is reached.
3 minutes 9 sec	Liquid control flow enters the core.
11 minutes	Suppression pool cooling begins.
16 minutes	Hot shutdown achieved.
77 minutes	Suppression pool temperature and containment pressure peak.



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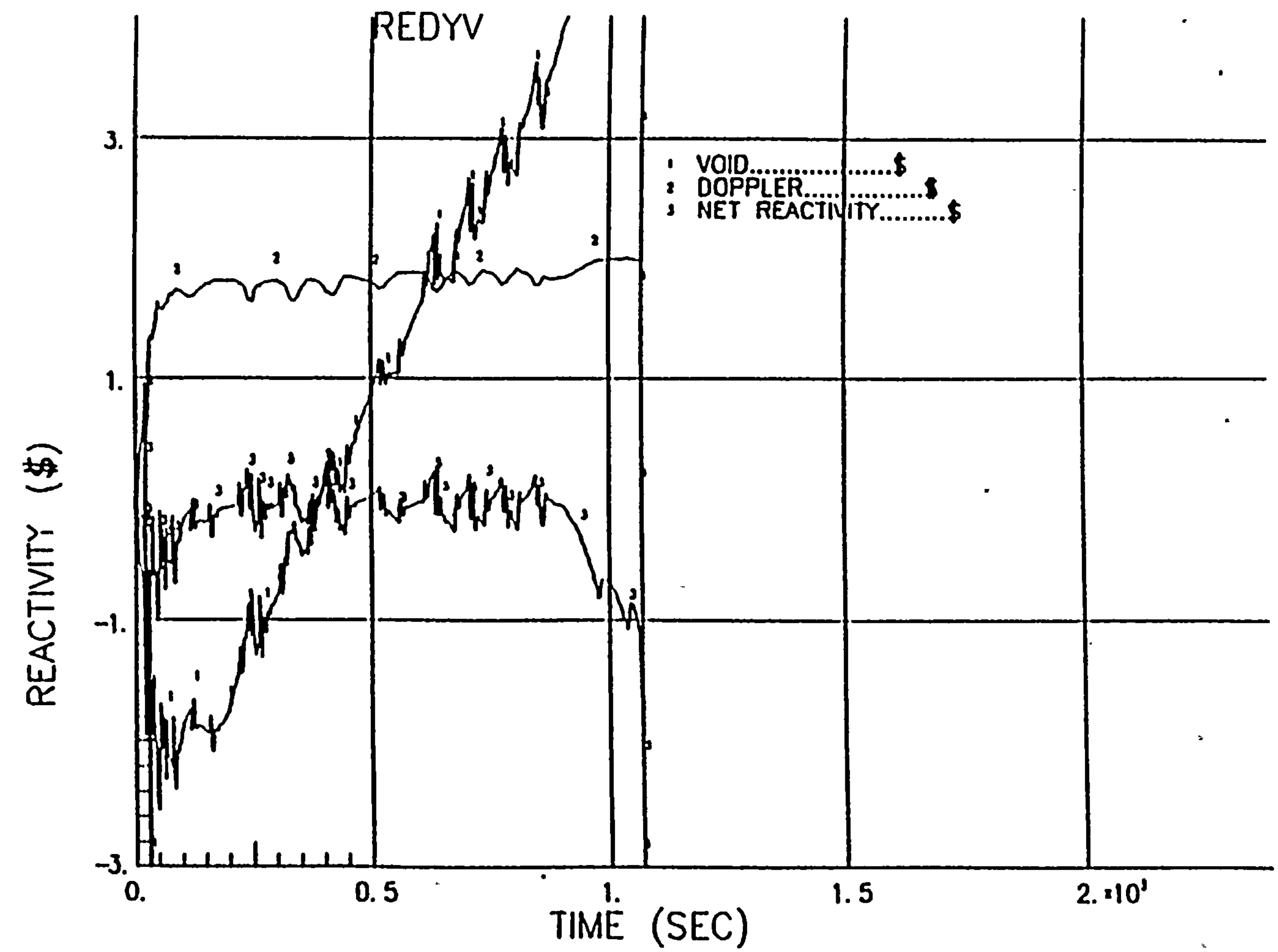
WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Loss of Feedwater Event

Draw. No.	Rev.	Figure
		15.8-1.1

Form No. 960690



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November 1998

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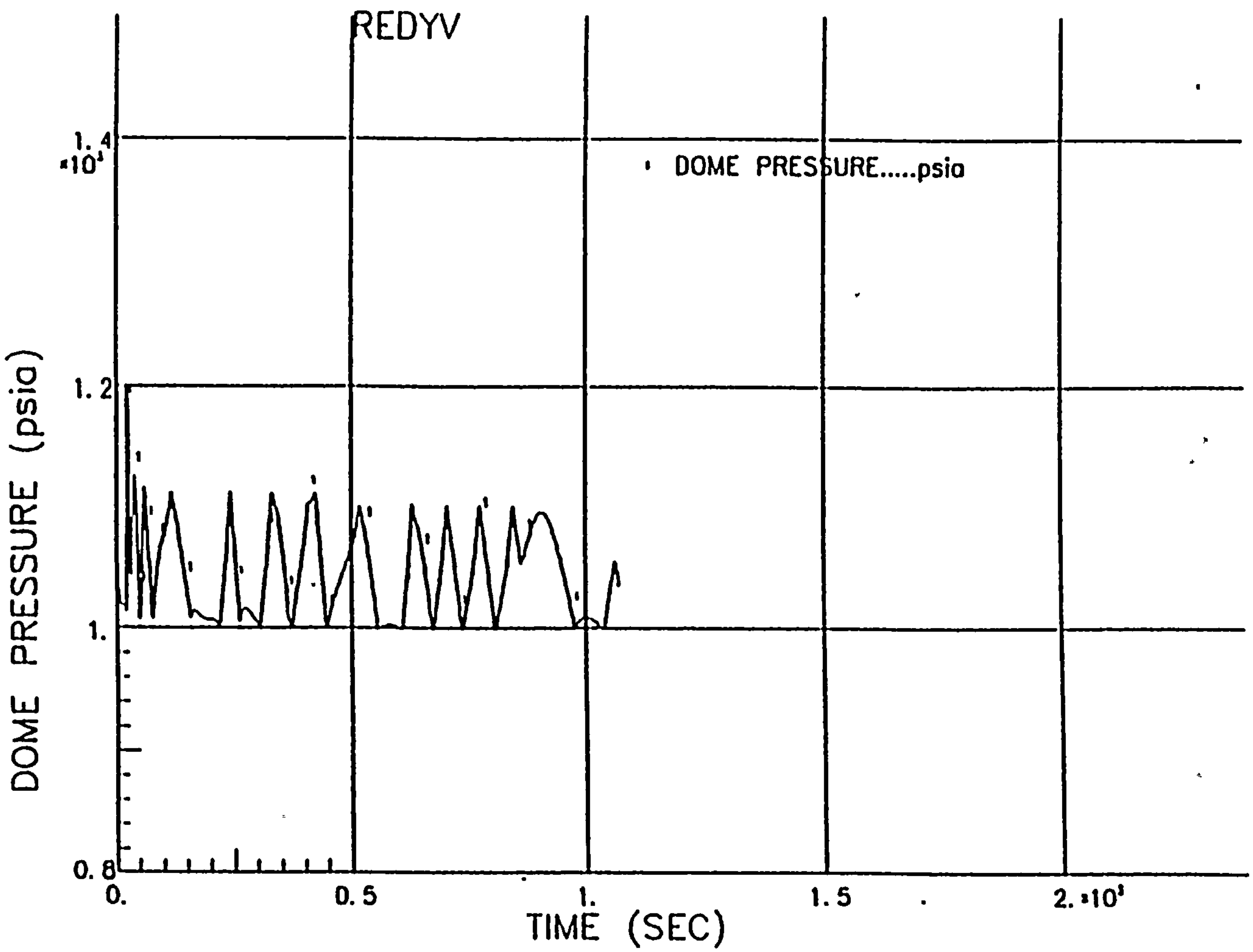
Loss of Feedwater Event

Draw. No.	Rev.	Figure
		15.8-1.2



Loss of Feedwater Event

Draw. No.	Rev.	Figure
		15.8-13

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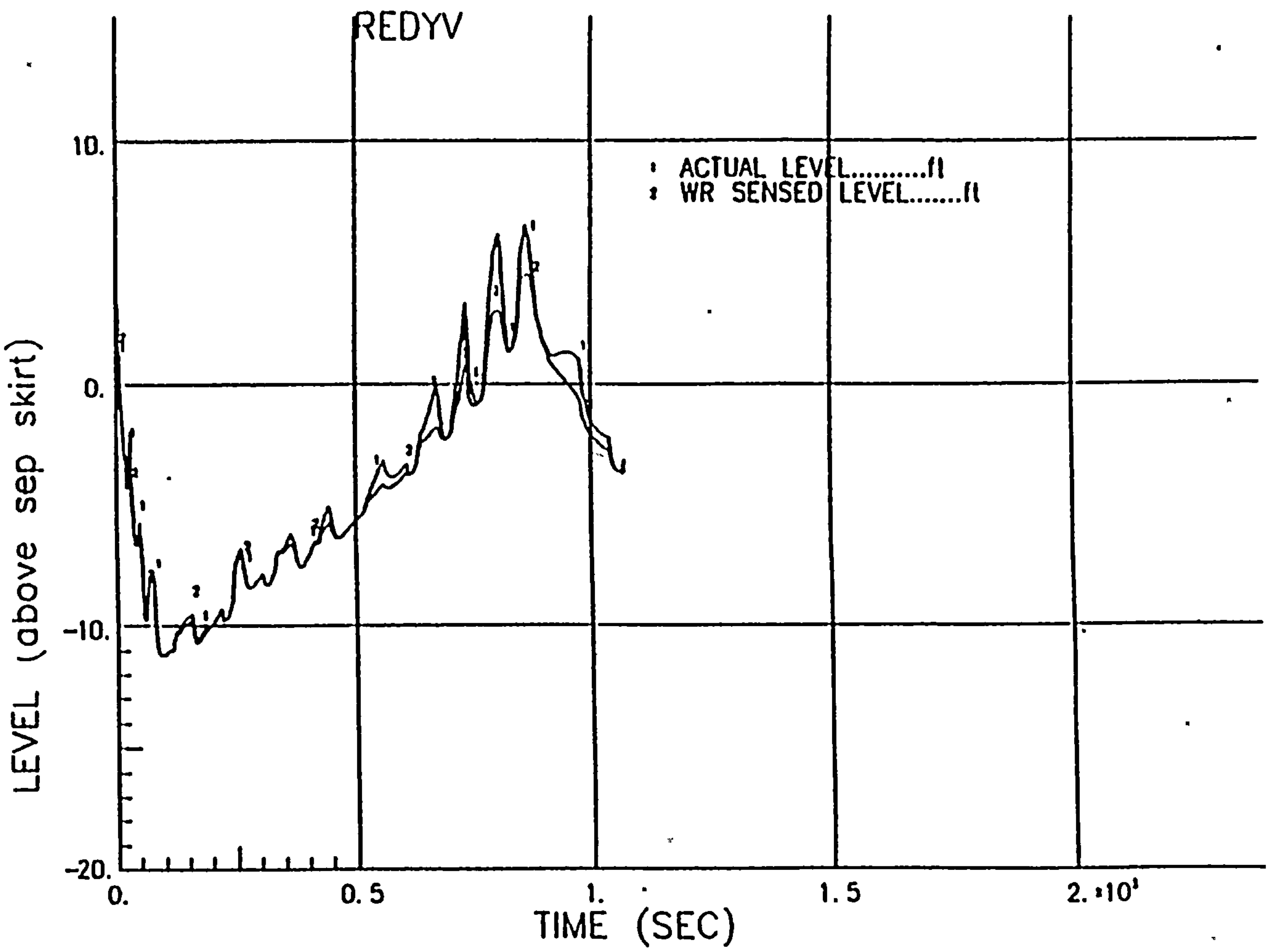
November 1998



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Loss of Feedwater Event

Draw. No.	Rov.	Figure
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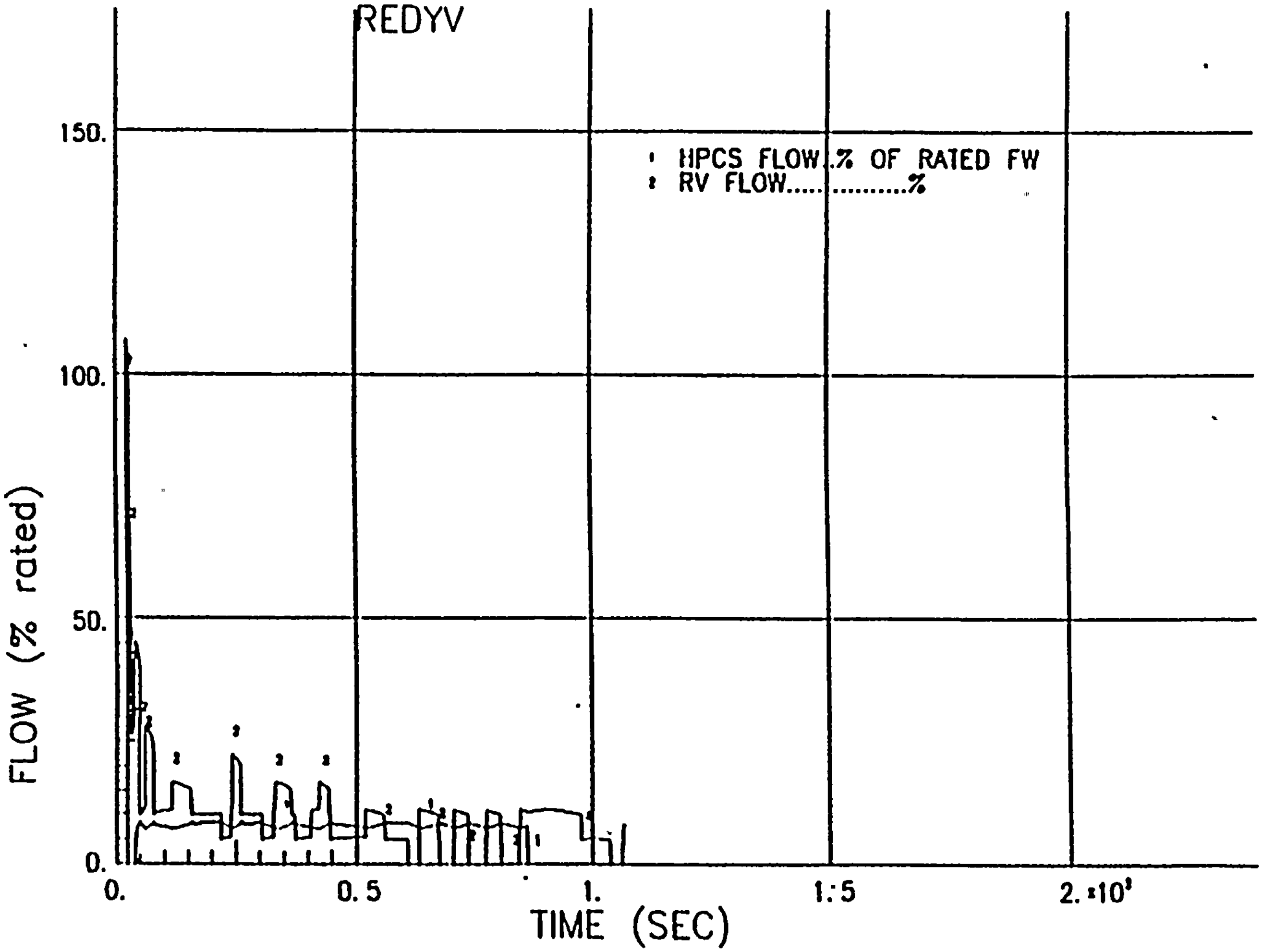
Amendment 53
November 1998

Form No. 960690



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November 1998

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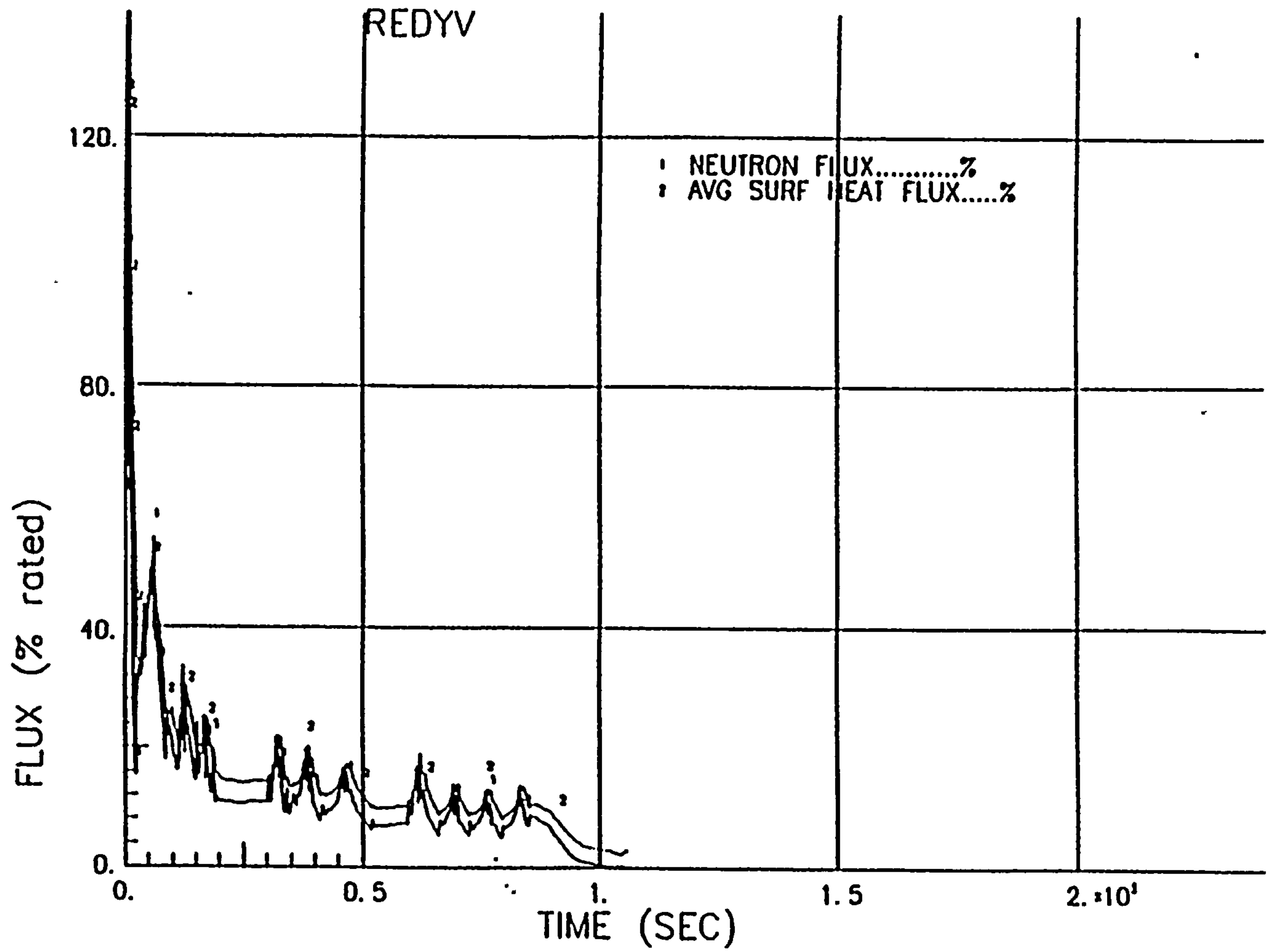
NUCLEAR PLANT 2 FSAR

Loss of Feedwater Event

Draw. No.	Rev.	Figure
		15.8-1.5

Form No. 960690



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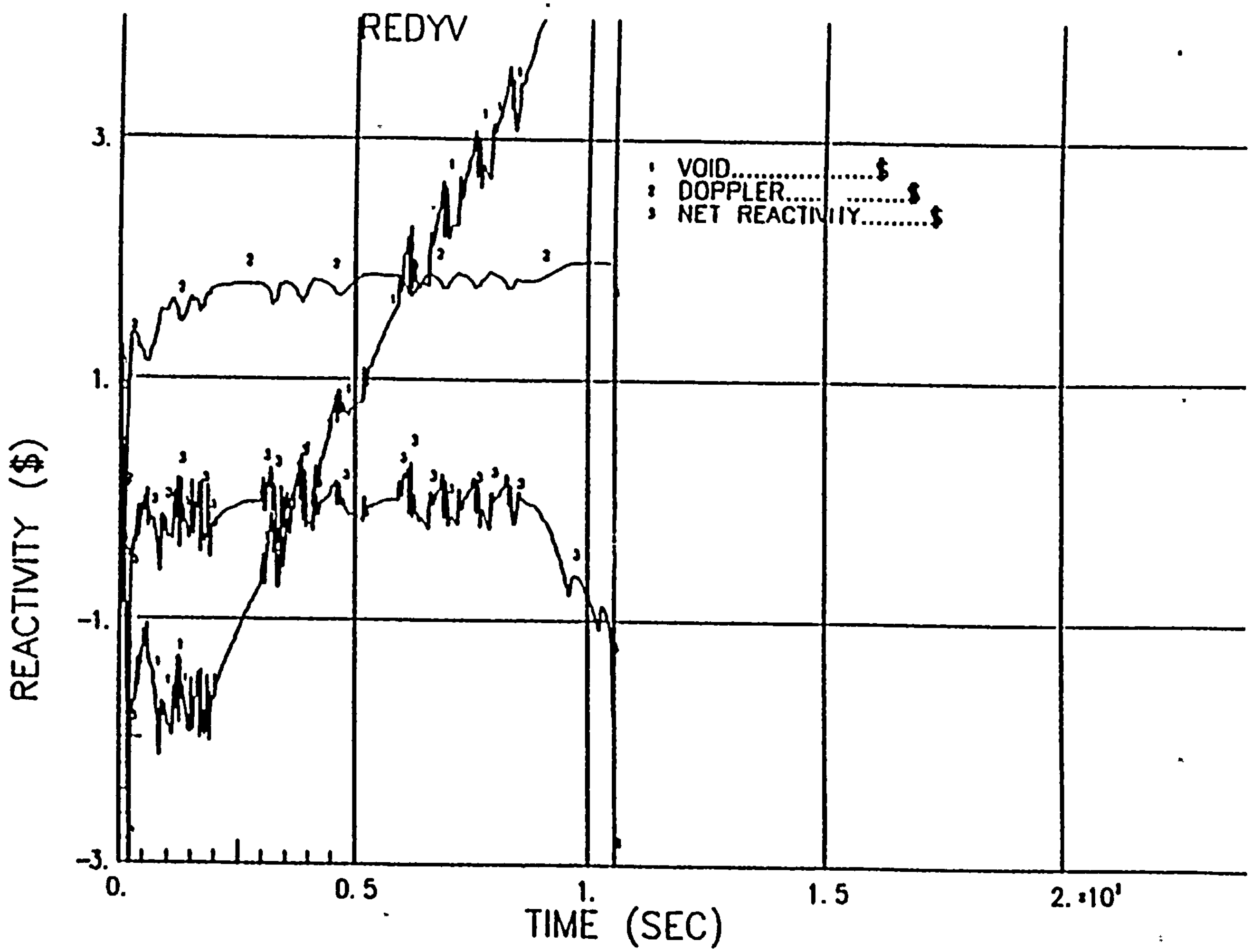
Main Steam Isolation Valve Closure Event

Draw. No.	Rev.	Figure
		15.8-2.1



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NUCLEAR PLANT 2 FSAR

Main Steam Isolation Valve Closure Event

Draw. No.	Rev.	Figure
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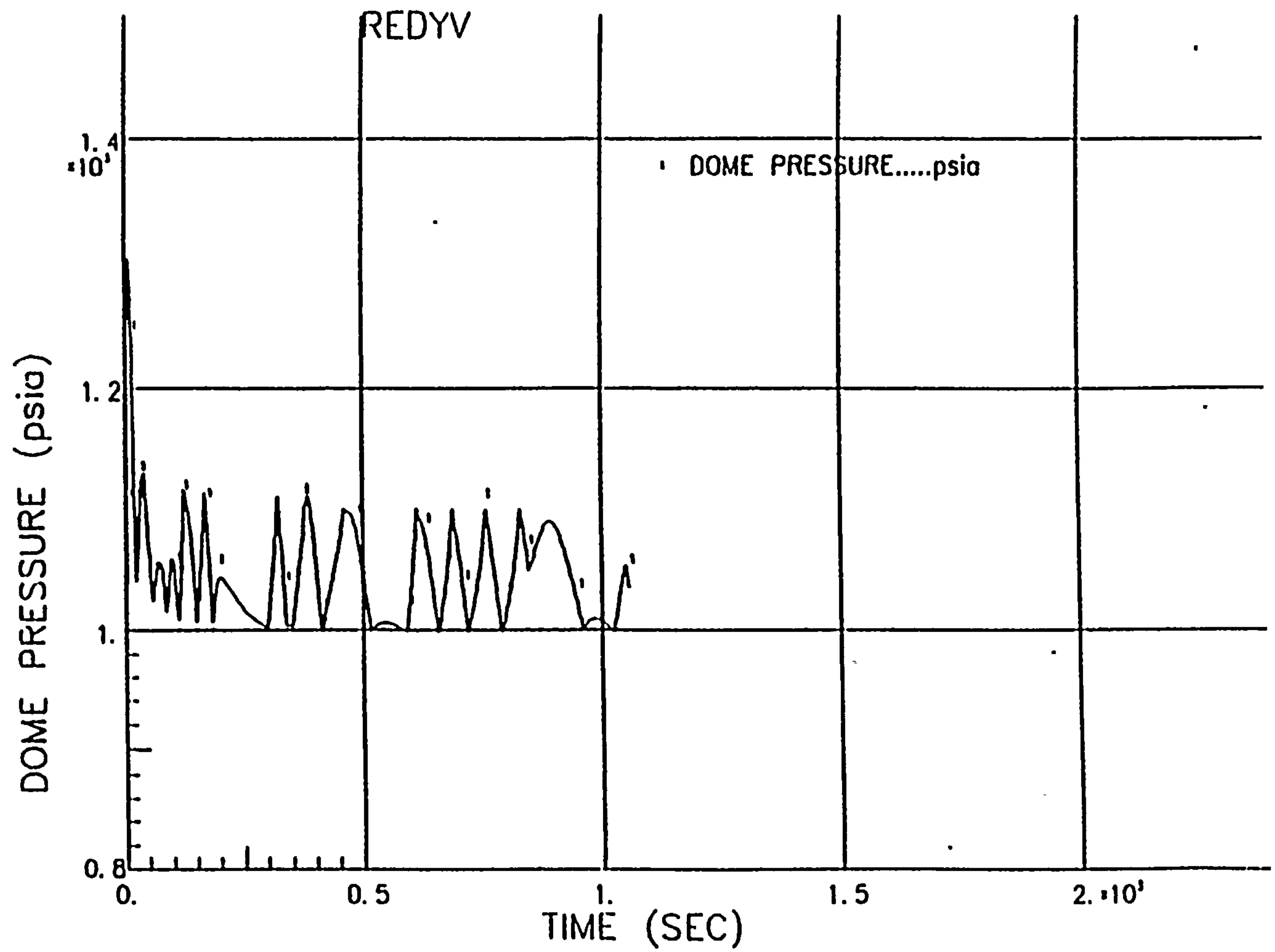
Form No. 960690



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Main Steam Isolation Valve Closure Event

Draw. No.	Rev.	Figure
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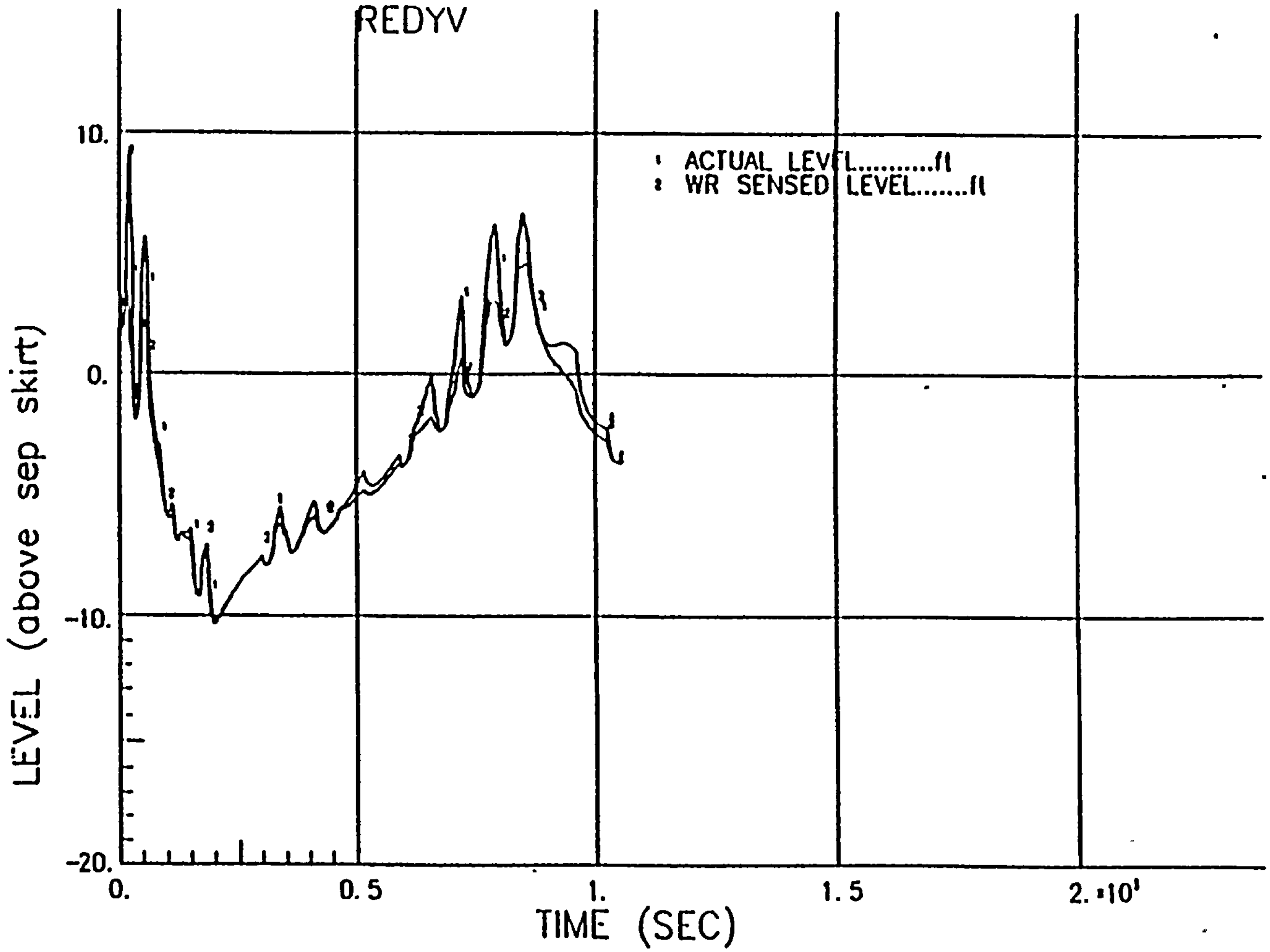

Main Steam Isolation Valve Closure Event

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Draw. No.	Rev.	Figure
		15.8-2.4

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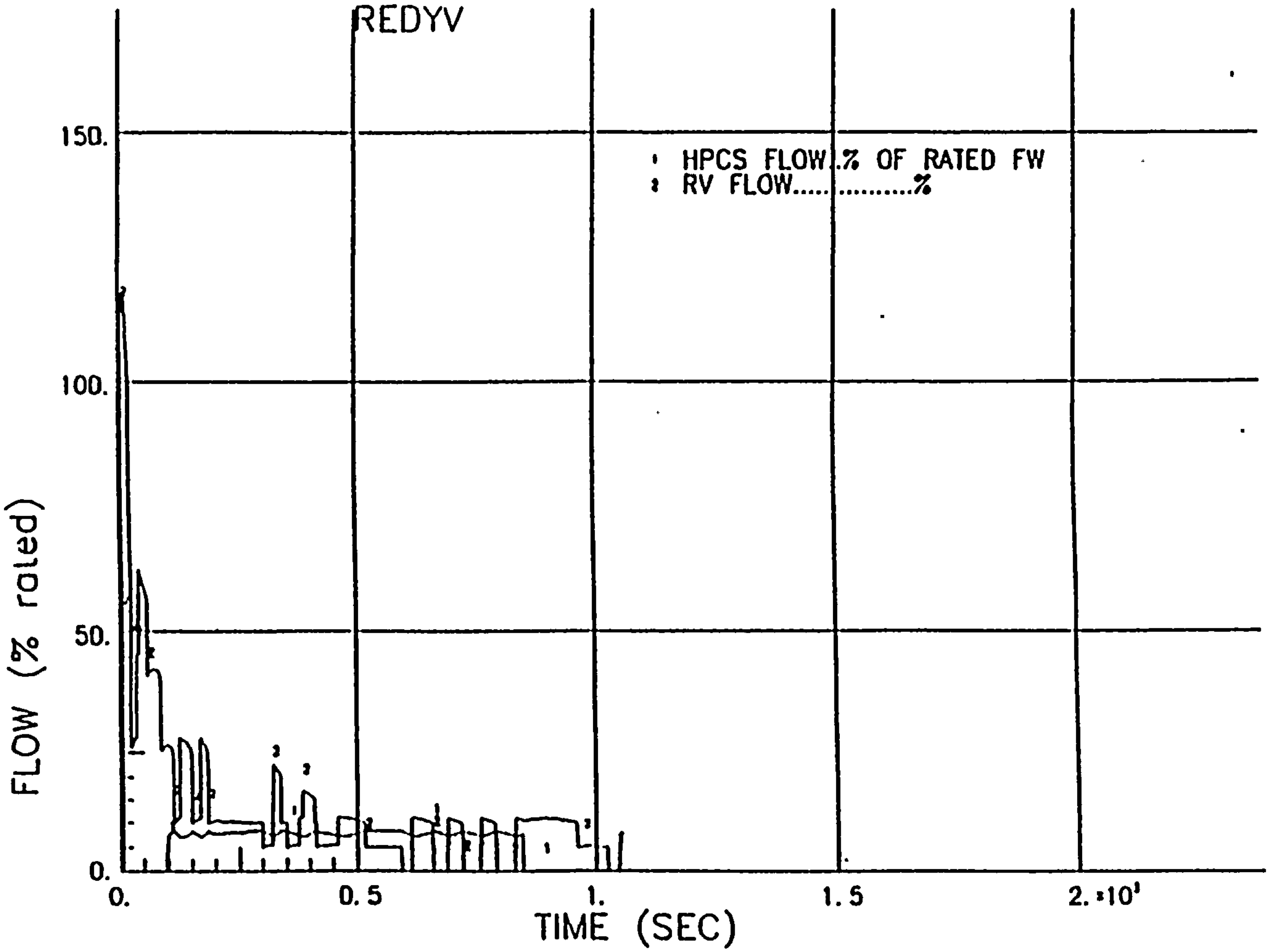


WASHINGTON PUBLIC POWER SUPPLY SYSTEM

NUCLEAR PLANT 2 FSAR

Main Steam Isolation Valve Closure Event

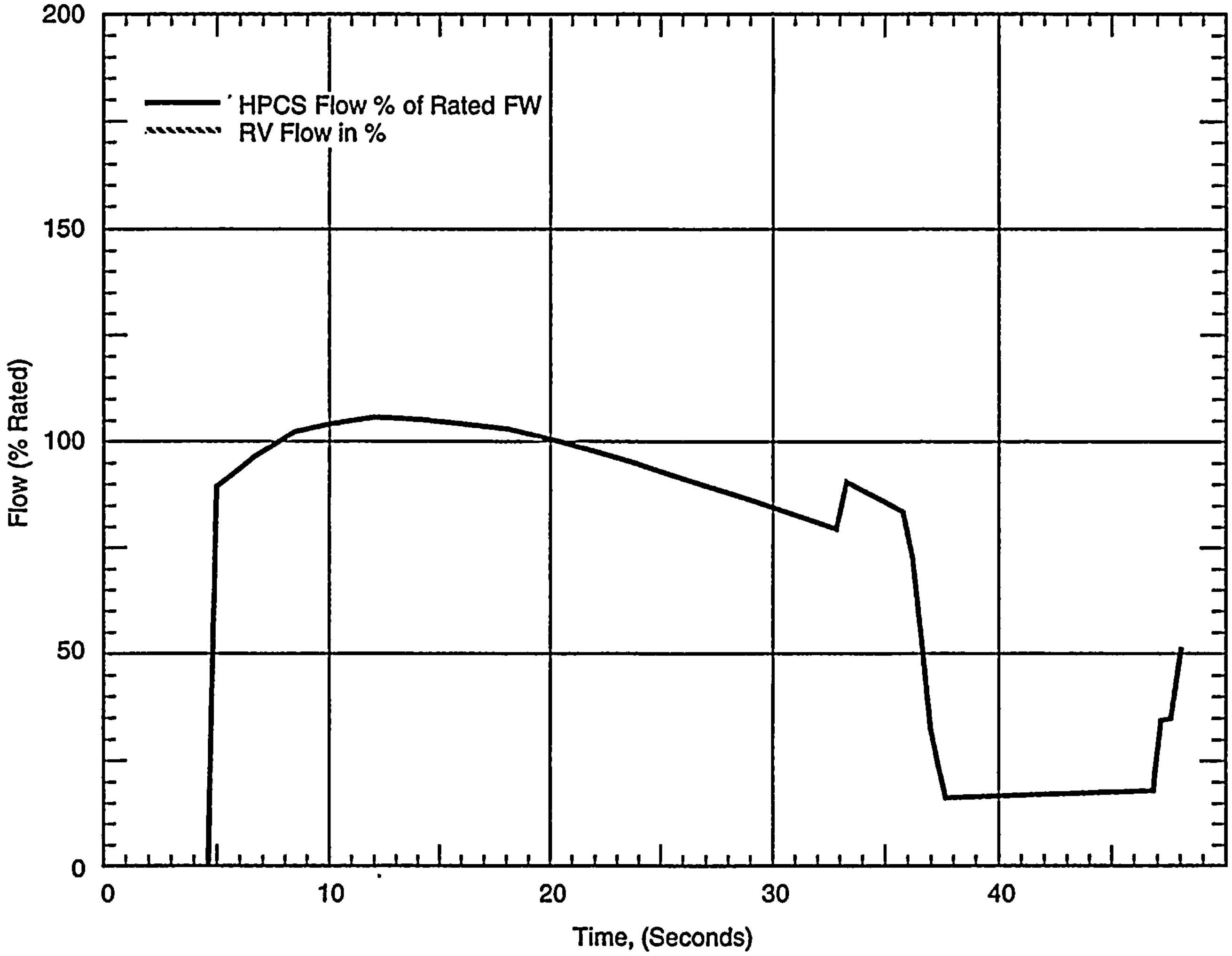
Draw. No.

Rev.

Figure 15.8-2.5

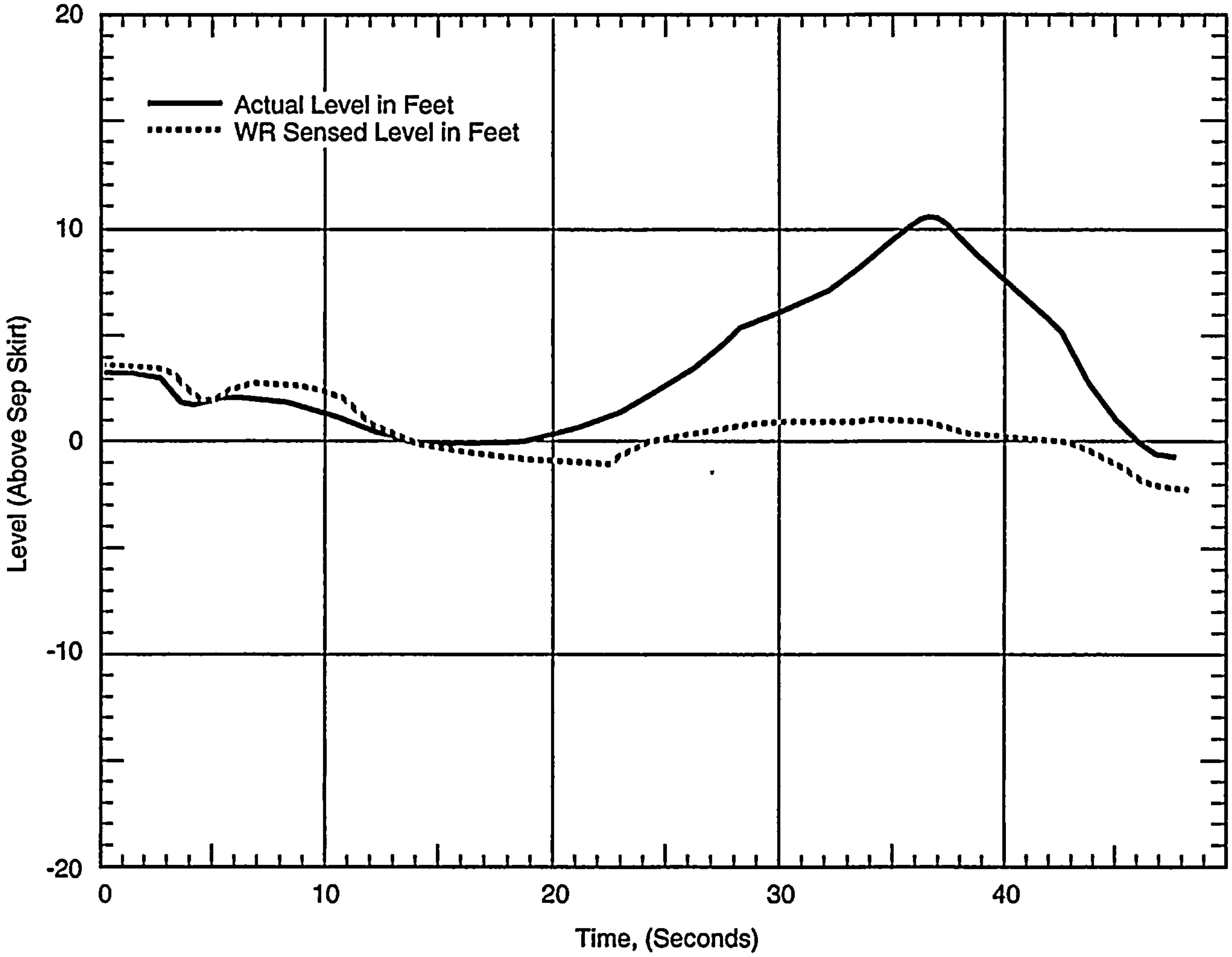
Amendment 53
November 1998

Form No. 960690



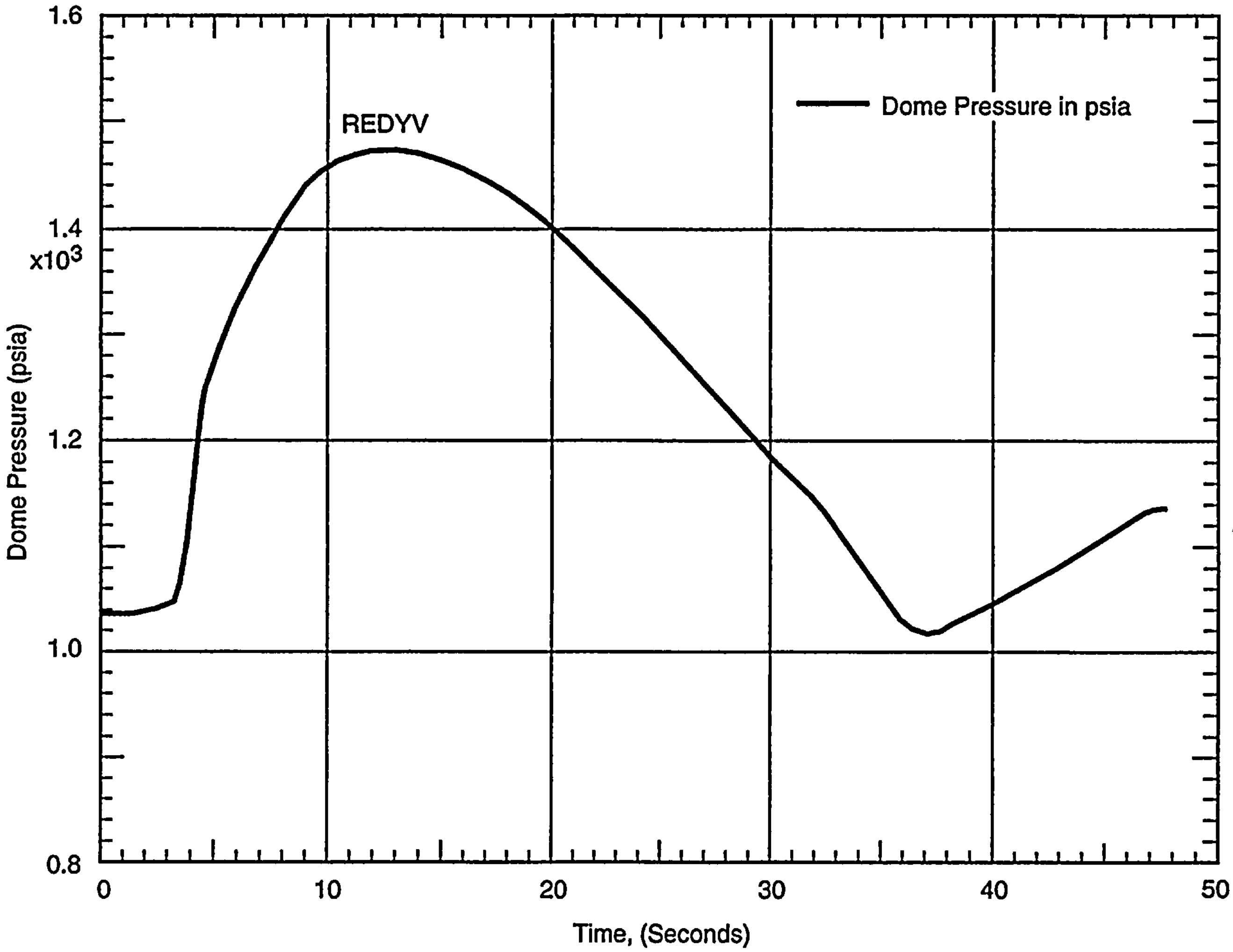
Main Steam Isolation Valve Closure Event with 4 SRVs Out-of-Service

Draw. No. 960222.40	Rev.	Figure 15.8-3.1



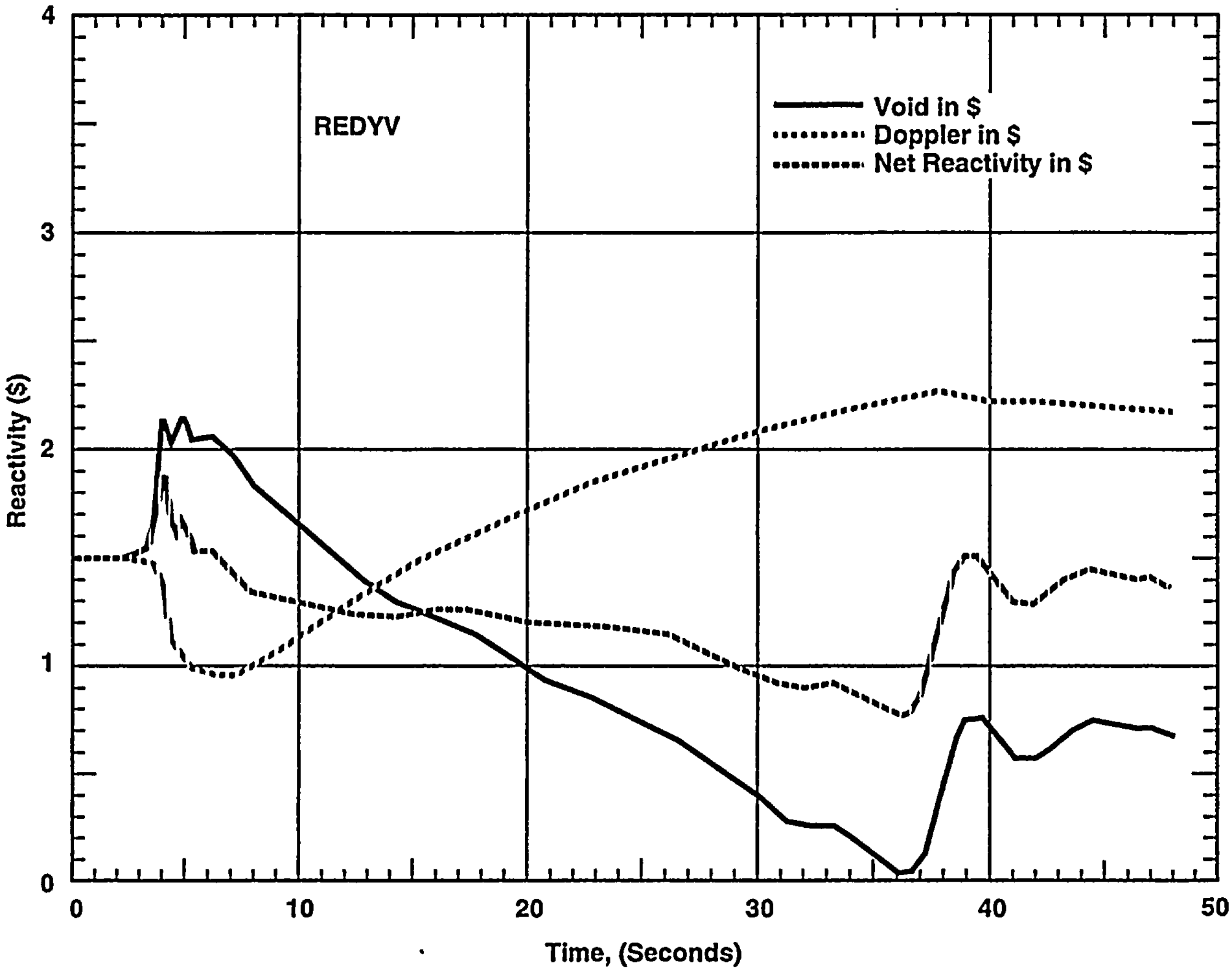
Main Steam Isolation Valve Closure Event with 4 SRVs Out-of-Service

Draw. No. 960222.41	Rev.	Figure 15.8-3.2



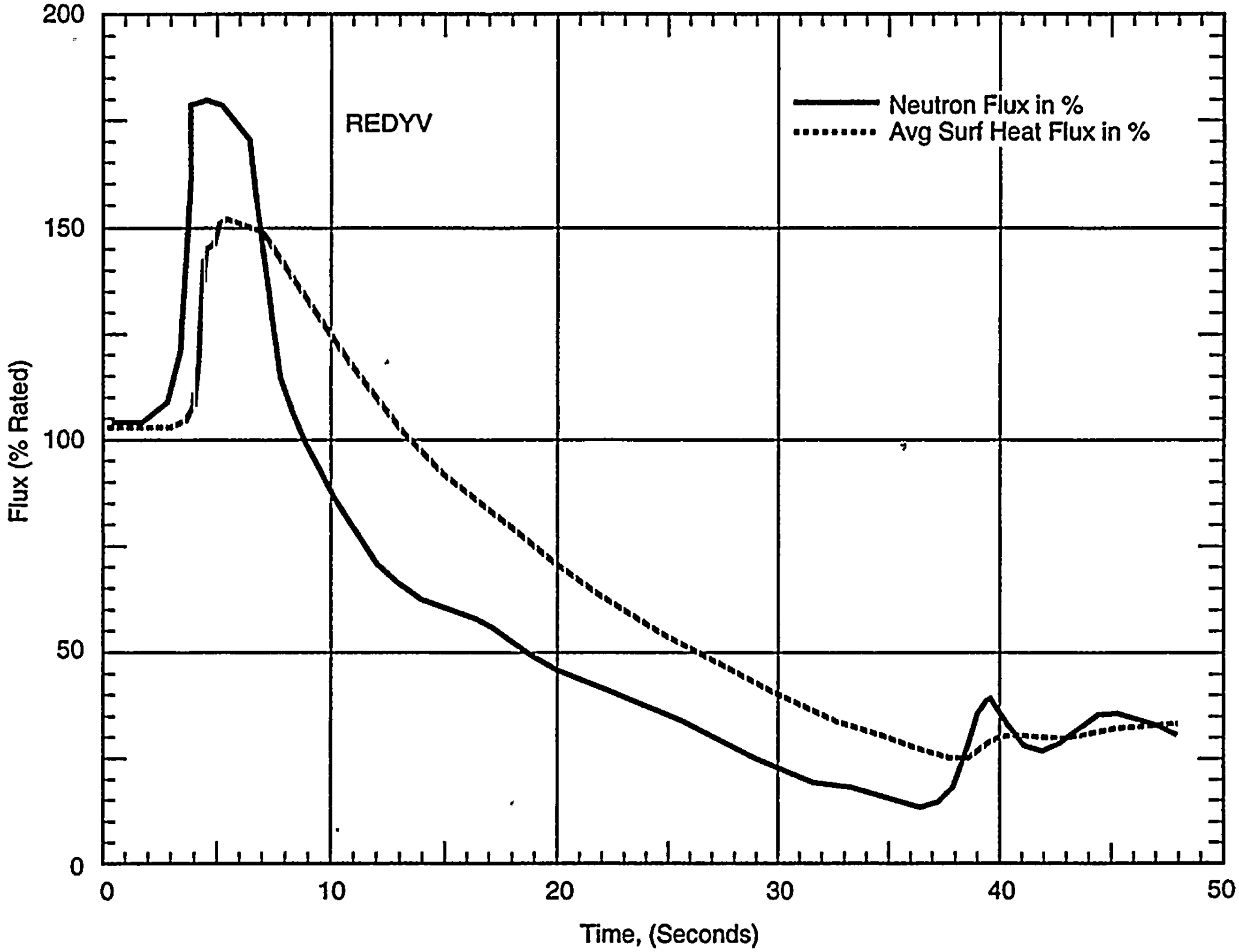
Main Steam Isolation Valve Closure Event with 4 SRVs Out-of-Service

Draw. No. 960222.42 | Rev. | Figure 15.8-3.3

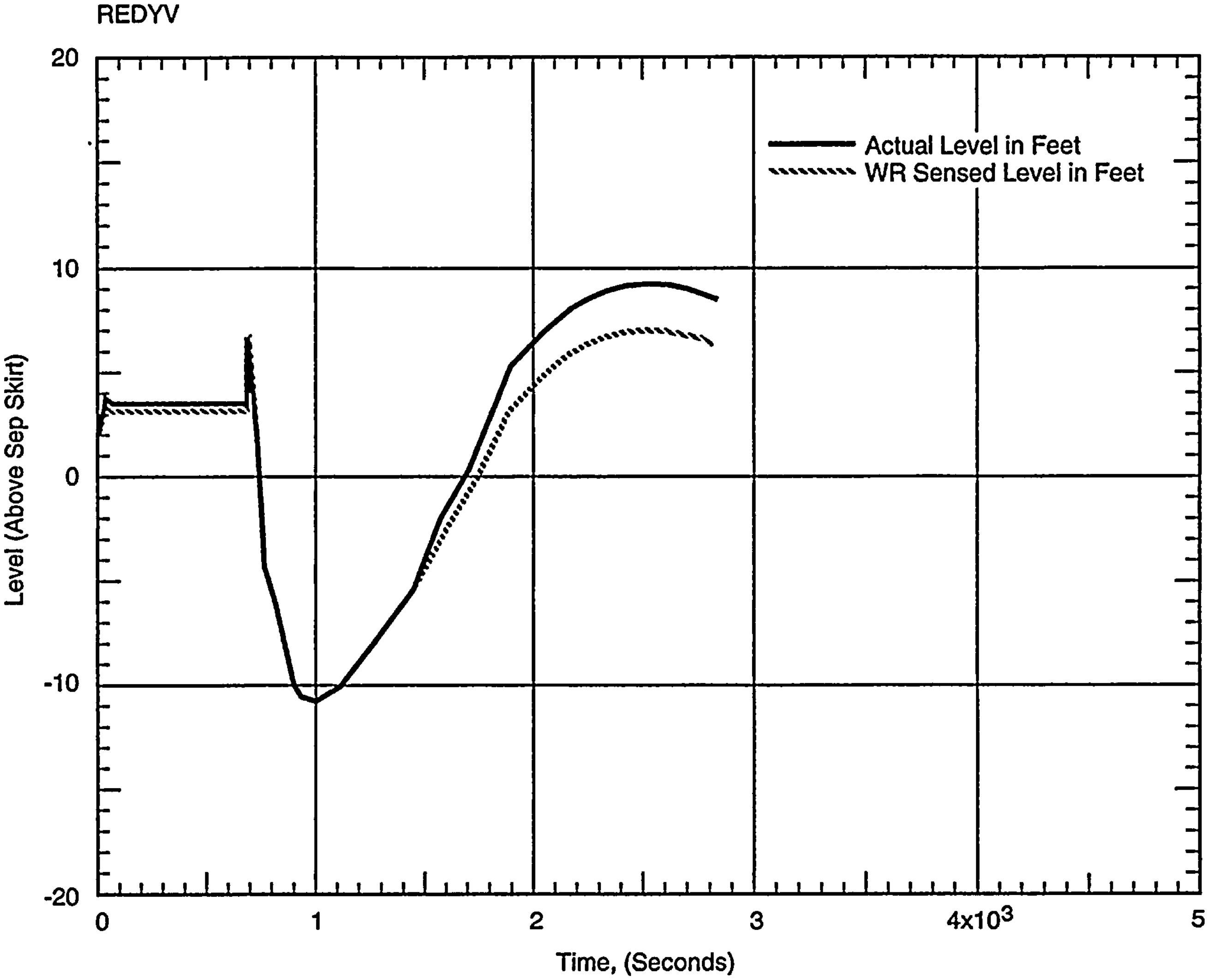


Main Steam Isolation Valve Closure Event with 4 SRVs Out-of-Service

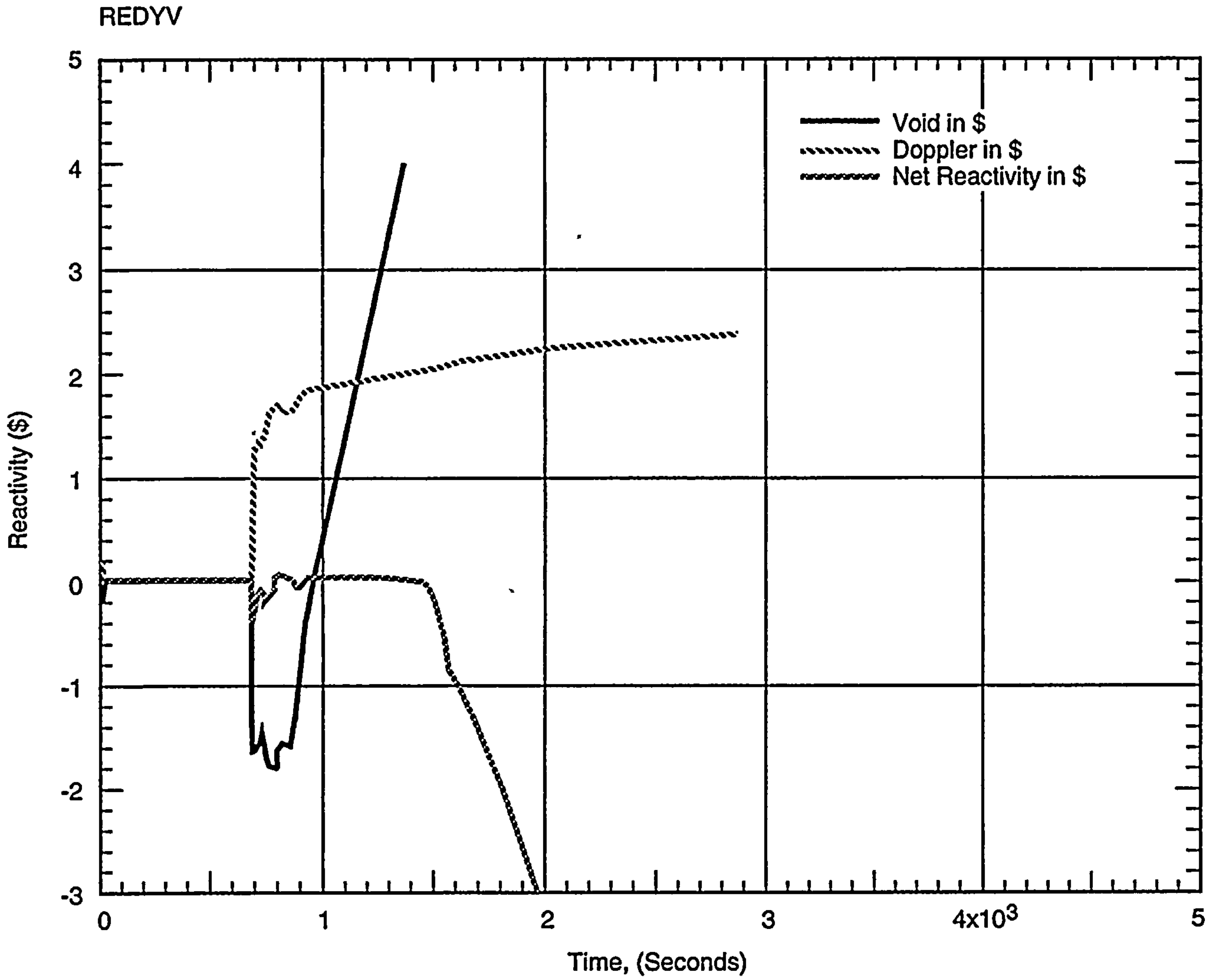
Draw. No. 960222.43 | Rev. | Figure 15.8-3.4

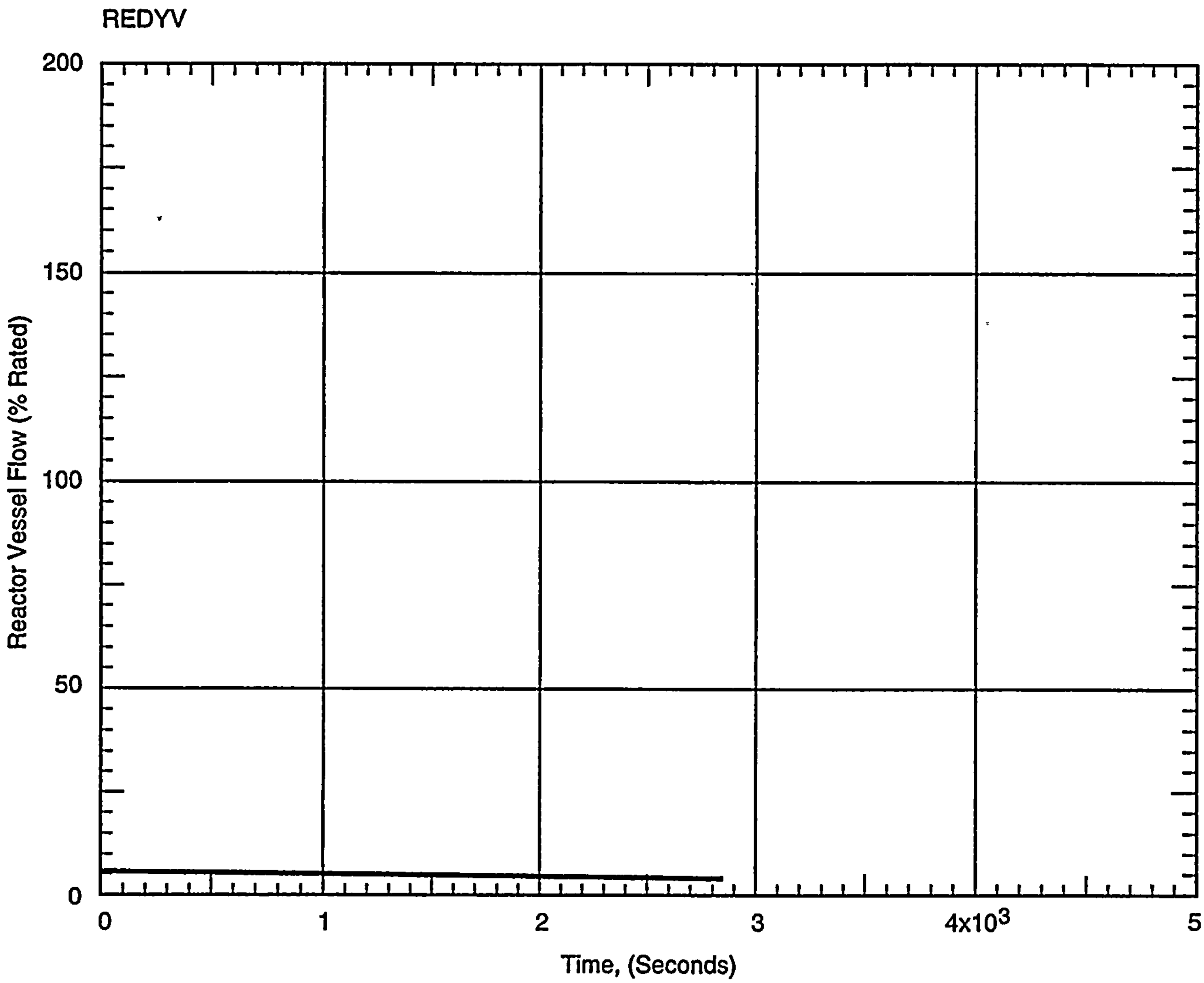


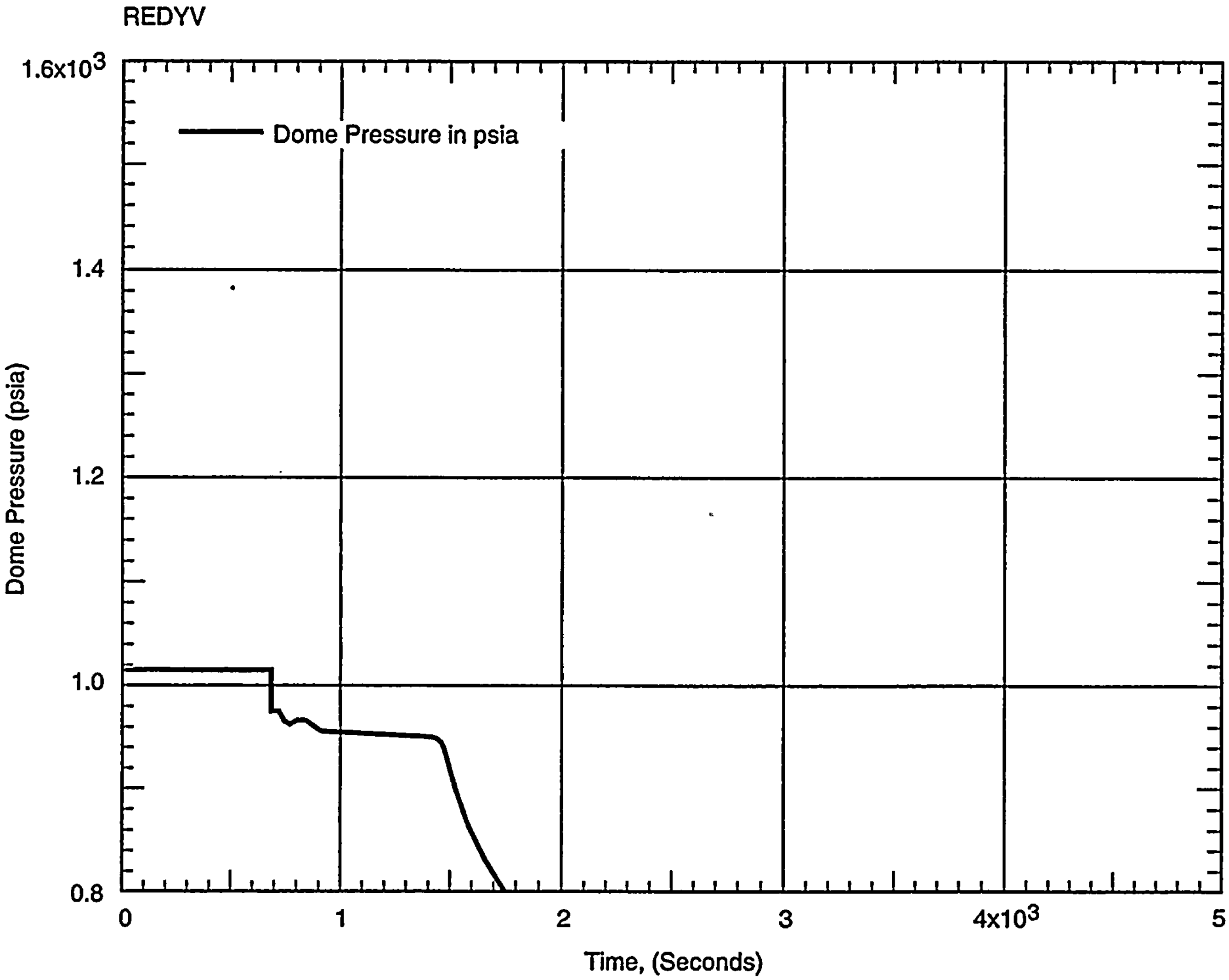
Main Steam Isolation Valve Closure Event with 4 SRVs Out-of-Service



Inadvertent Opening of Relief Valve Event

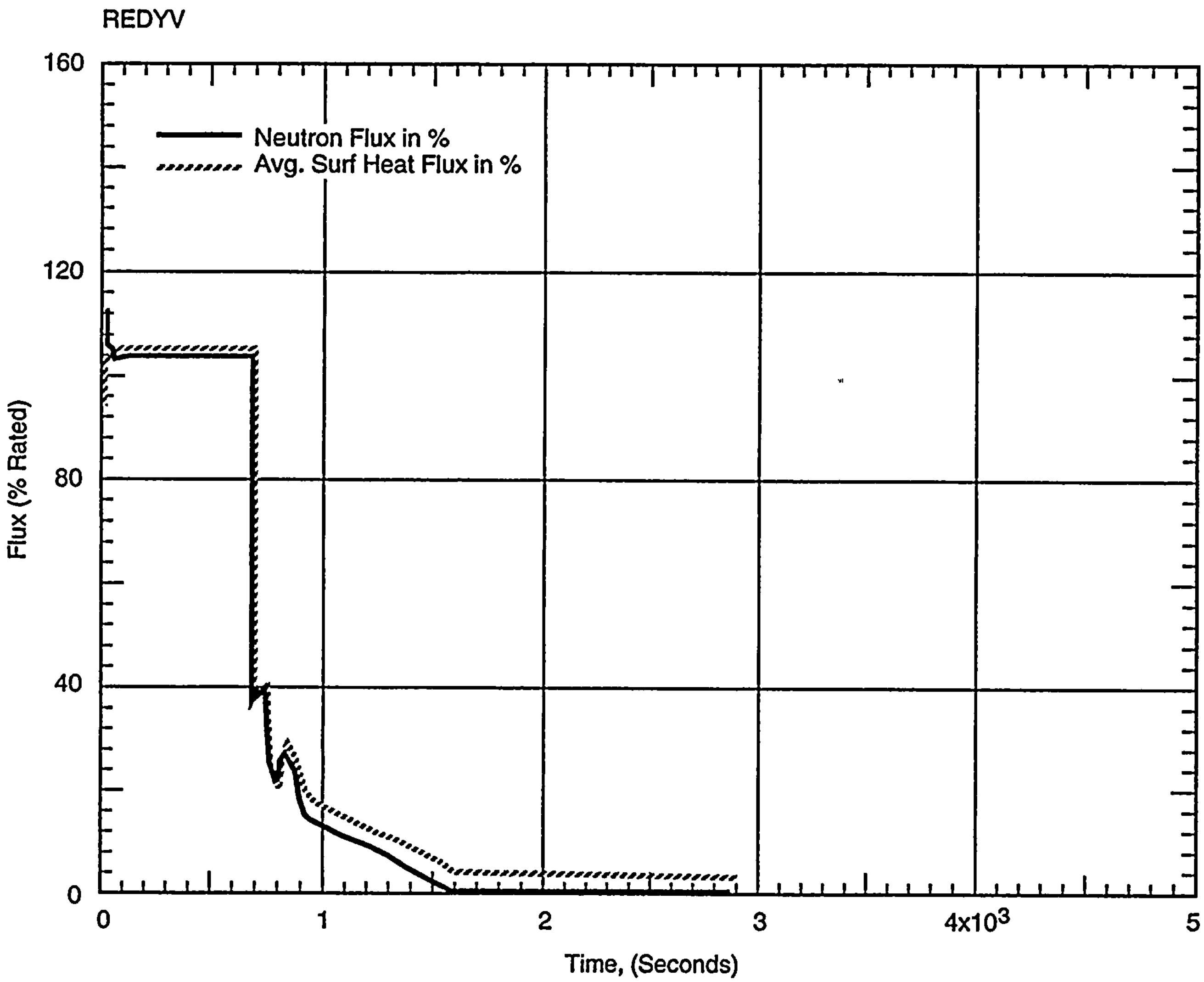

REDYV
Void in $
Doppler in $
Net Reactivity in $
Reactivity ($)
5
4
3
2
1
0
-1
-2
-3
0
1
2
3
4x10^3
5
Time, (Seconds)


REDYV
Reactor Vessel Flow (% Rated)
200
150
100
50
0
0
1
2
3
4x10^3
5
Time, (Seconds)



Inadvertent Opening of Relief Valve Event

Draw. No. 960222.47	Rev.	Figure 15.8-4.4



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Inadvertent Opening of Relief Valve Event

Draw. No. 960222.49	Rev.	Figure 15.8-4.5

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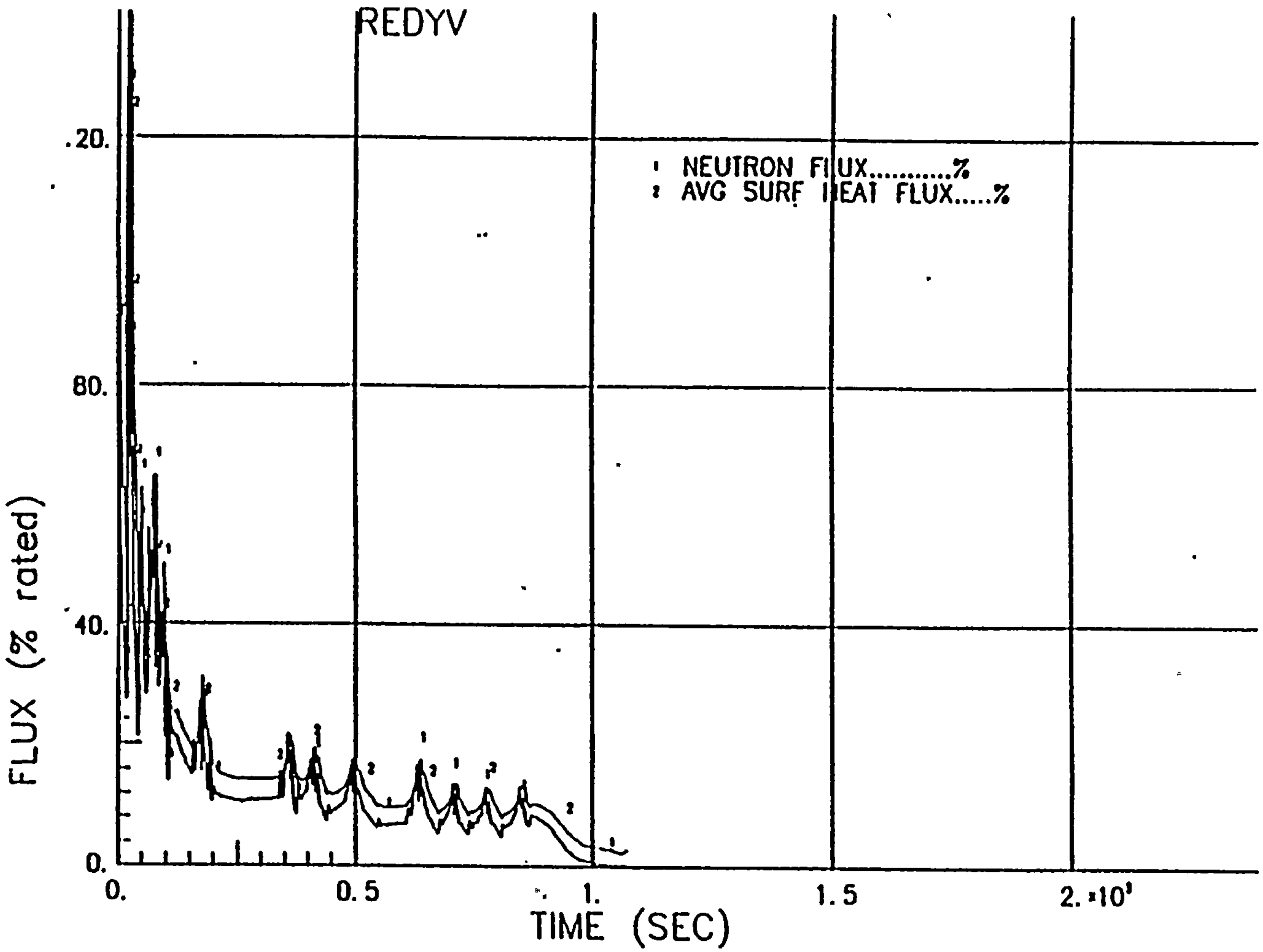

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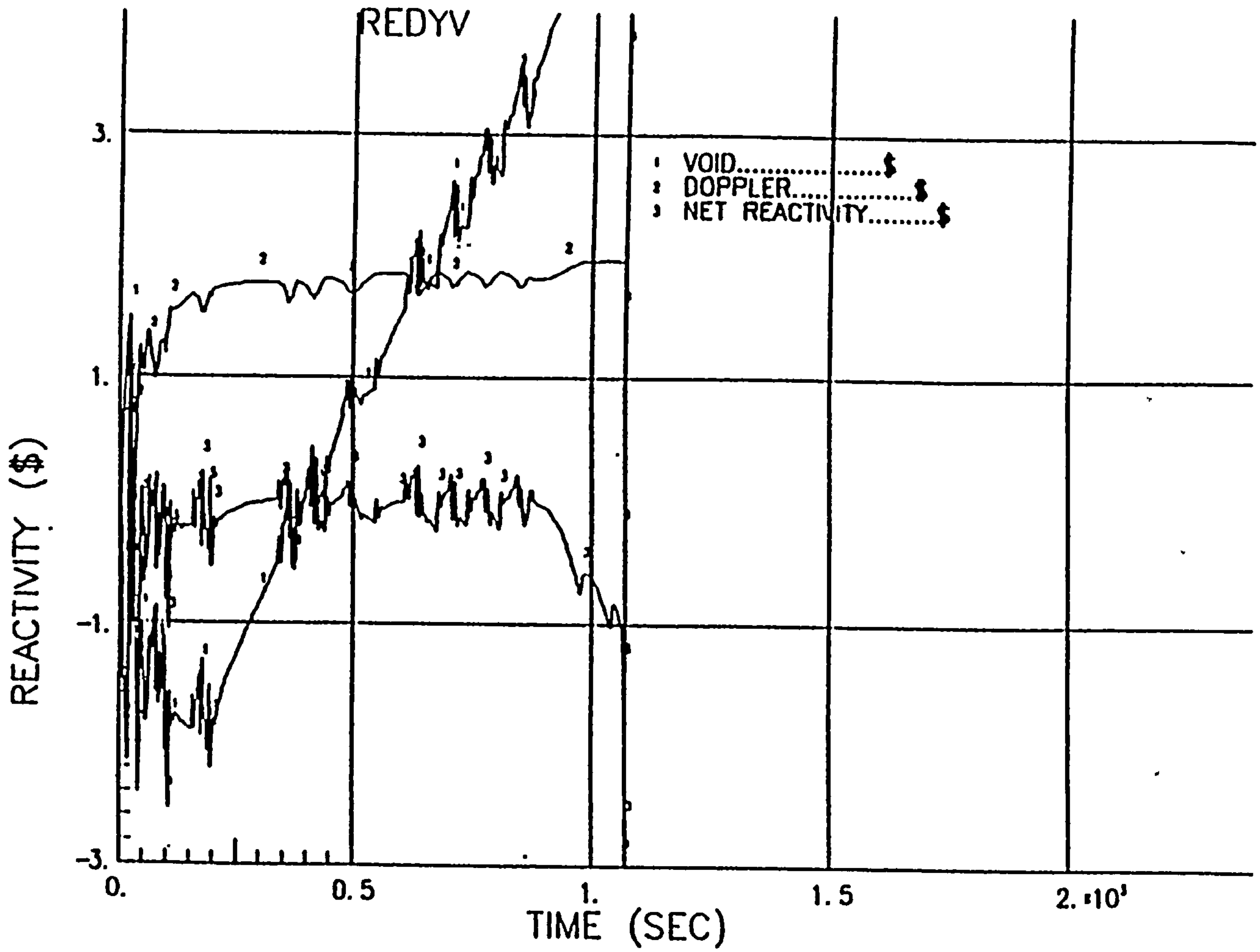
Pressure Regulator Failure - Open Event

Draw. No.	Rev.	Figure
		15.8-5.1



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NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open Event

Draw. No.	Rev.	Figure
		15.8-5.2

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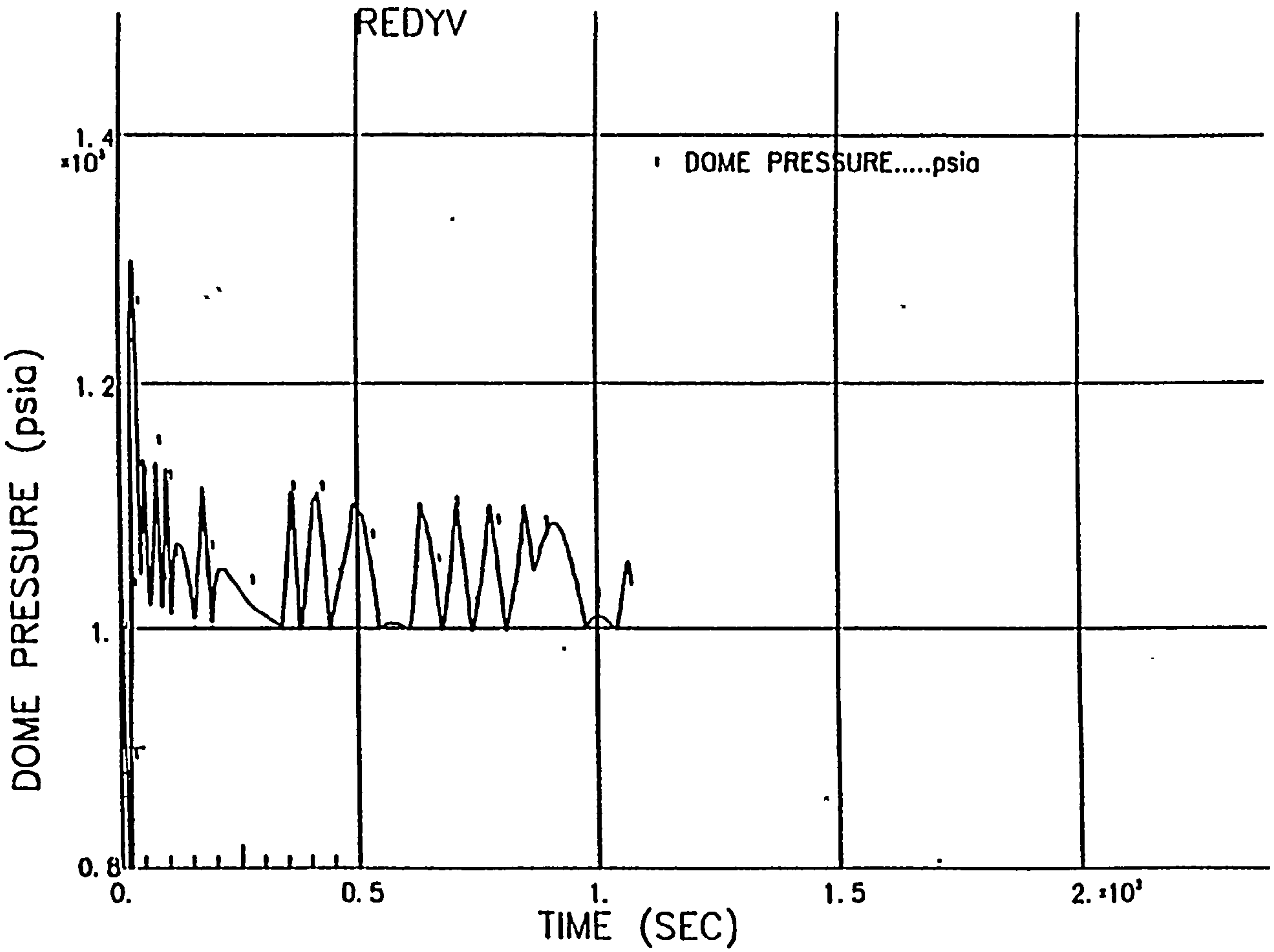
Form No. 96090



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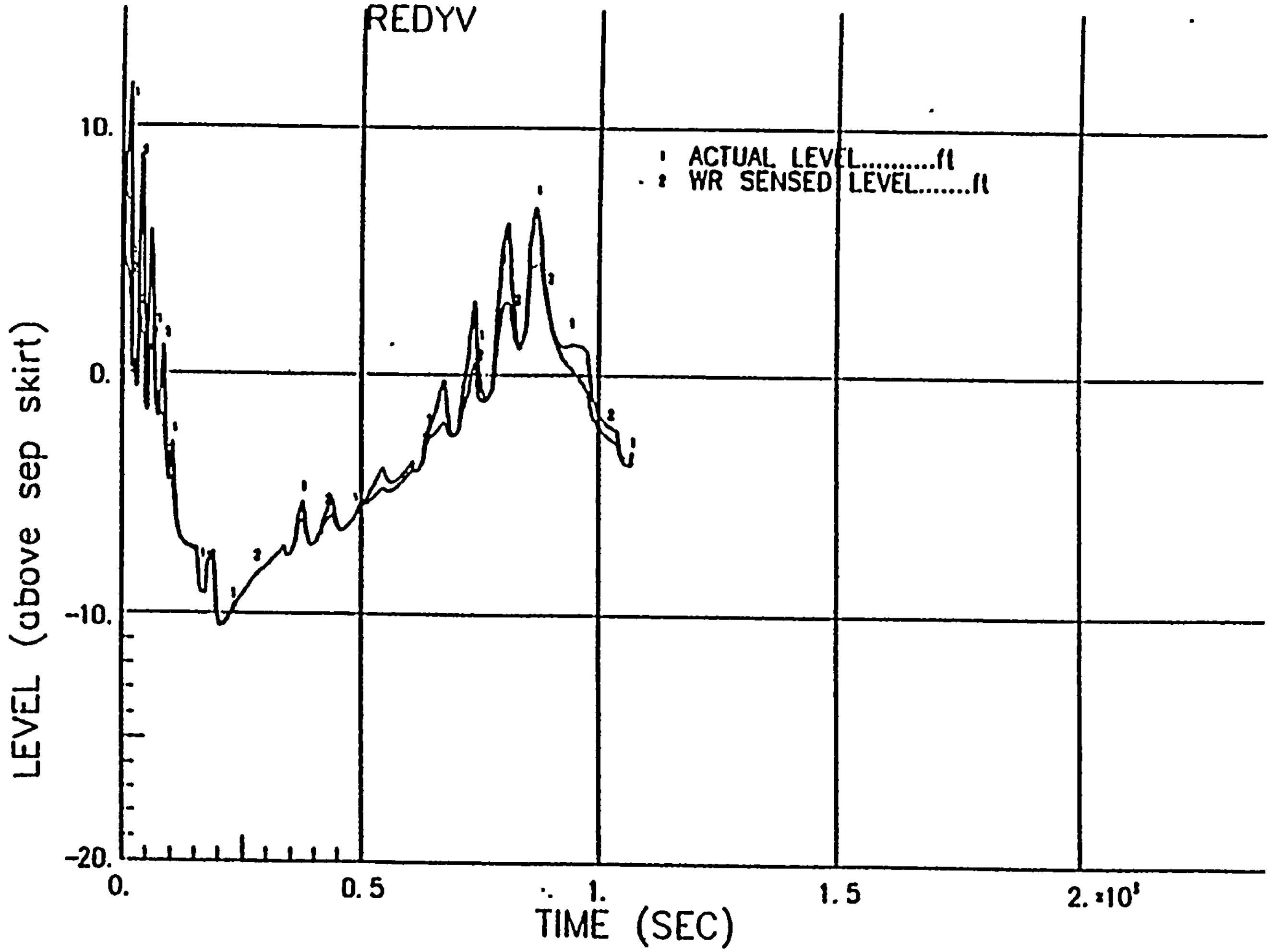
NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open Event

Draw. No.	Rev.	Figure
		15.8-5.3

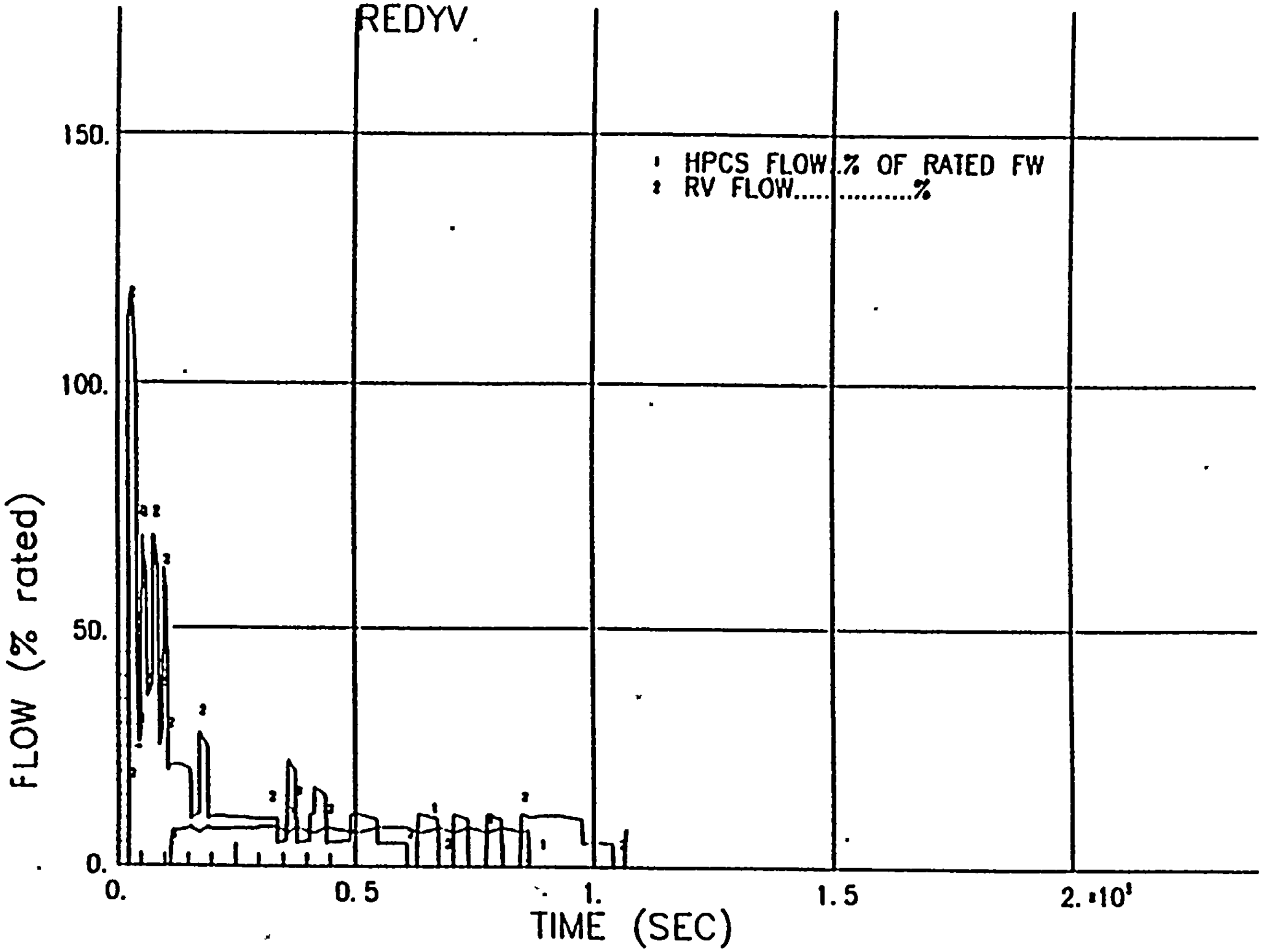
Form No. 960690



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open Event

Draw. No.	Rev.	Figure
		15.8-5.4



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Pressure Regulator Failure - Open Event

Draw. No.	Rev.	Figure
		15.8-5.5

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Appendix 15F

RELOAD ANALYSIS

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Appendix 15F

RELOAD ANALYSIS

15F.0 GENERAL

The scope of the Chapter 15 accident analyses includes categorization of events by transient type and expected frequency of occurrence, and evaluation against unacceptable results criteria based upon event frequency. Each event is evaluated to ensure the resulting transient does not exceed the applicable unacceptable results criteria for fuel, system, and containment performance and for radiological consequences. The analyses cover SPC 9 x 9 reload fuel and SVEA-96 reload fuel.

The scope of work performed by the current fuel vendor in performing the reload analysis in support of the current operating cycle is limited to analyzing the class of anticipated operational transients expected to be limiting with regard to core performance. Thus, only a subset of the analyses performed by the original nuclear steam supply system (NSSS) vendor are performed in the reload analysis. In addition, in the reload analysis, the transients are evaluated against the applicable unacceptable results criteria for fuel performance only. The Chapter 15 analyses continue to be relied upon for evaluation of containment and system performance and radiological consequences. These evaluations continue to provide the bases for Technical Specification requirements for instrument setpoints and system operability and performance. Also, the Chapter 15 analyses as a whole provide a complete and consistent envelope of expected plant response to postulated transients and design basis accidents. For these reasons, the Chapter 15 analyses are maintained intact, and the reload analysis for the current cycle of operation is described separately in this appendix. This format not only preserves the Chapter 15 analyses, it also eliminates potential confusion due to different fuel vendor methodology, and facilitates a cycle-specific) update of the reload analysis in a straightforward manner.

15F.0.1 CORE AND SYSTEM PERFORMANCE

The exceeding of unacceptable results criteria for anticipated operational transients is avoided by meeting the following criteria (Reference 15F.0.4-1):

a. The expected number of fuel rods in boiling transition should not exceed 0.1% of the fuel rods in the core. This criterion is met by ensuring that the minimum critical power ratio (MCPR) for any anticipated operational transient is not calculated to be less than the safety limit MCPR values given in the cycle-specific Core Operating Limits Report (COLR).

b. No fuel centerline melting nor uniform total cladding strain in excess of 1% will occur. This criterion is met by compliance with the operating limits for linear heat generation rate (LHGR) given in the cycle-specific COLR.

The operating limit for MCPR is developed as follows:

The MCPR calculated during the transient is compared to the safety limit. The MCPR safety limit is established using the critical power evaluation methods and includes consideration of the operating domain and manufacturing uncertainties and a conservative core power distribution as inputs. The operating limit MCPR is established such that the transient ΔCPR for the dynamic anticipated operational occurrences, quasi steady-state anticipated operational occurrences, and the fuel loading errors are included in the evaluation. Thus, the operating limit MCPR is specified to maintain an adequate margin to boiling transition.

The MCPR operating limit is the maximum of (a) the applicable exposure dependent, full power and full flow MCPR limit, (b) the applicable exposure and power dependent MCPR limit, and (c) the flow dependent MCPR limit as specified in the cycle-specific COLR. This stipulation ensures that the safety limit MCPR will not be violated throughout the WNP-2 operating regime. Full power MCPR limits are specified to define operating limits at rated power and a range of flow conditions which support extended load line operation. Power dependent MCPR limits are specified to define operating limits at other than rated power conditions. A flow dependent MCPR is specified to define operating limits at other than rated flow conditions.

Extended load line limit analysis (ELLLA) operation extends the power and flow operating regime for WNP-2 above the rated rod line. The COLR defines the maximum allowable rod line for ELLLA operation. References 15F.0.4-1 and 15F.0.4-2 document the reload analyses in support of ELLLA operation.

15F.0.2 INPUT PARAMETERS AND INITIAL CONDITIONS FOR ANALYZED EVENTS

In general the events analyzed within this section have values for input parameters and initial conditions as specified in Table 15F.0-1 (Reference 15F.0.4-1 and Reference 15F.0.4-2) and the WNP-2 Design Specifications, Division 60. When different input parameters or initial conditions are assumed, they are specified in the appropriate event discussion.

15F.0.3 EVENT DISCUSSION AND RESULTS

The information presented in this appendix, except where specifically referenced, is taken from References 15F.0.4-1 and 15F.0.4-2. The analyses were based on the design and operational assumption in effect for WNP-2 during the previous cycle of operation.

15F.0.4 REFERENCES

15F.0.4-1 "WNP-2 Cycle 14 Reload Report," CE NPSD-826-P, ABB/Combustion Engineering, Revision 1, March 1998.

15F.0.4-2 "WNP-2 Cycle 14 Transient Analysis Report," CE NPSD-825-P, ABB/Combustion Engineering, March 1998.

TABLE 15F.0-1

INPUT PARAMETERS AND INITIAL CONDITIONS FOR
WNP-2 RELOAD TRANSIENT ANALYSIS

Parameter	Value
Reactor thermal power (100%)[a]	3486 MWt
Total recirculating flow (106%)	115.0 Mlb/hr
Core active flow	99.4 Mlb/hr
Core bypass flow	15.6 Mlb/hr
Core inlet enthalpy	530 Btu/lbm
Vessel pressures	
Steam dome	1035 psia[b]
Upper plenum	1048 psia
Core mid-plane	1056 psia
Lower plenum	1074 psia
Turbine inlet pressure	1000 psia
Feedwater/steam flow	15.0 Mlb/hr
Feedwater enthalpy	395 Btu/lbm
Recirculating pump flow (per pump)	16.9 Mlb/hr
High neutron flux trip	128.7%
Time from deenergize pilot scram solenoid valves to start of drive motion	200 msec
Time to sense fast turbine control valve closure	80 msec
Time to sense high neutron flux	90 msec
Scram insertion times	Technical Specifications[c]

TABLE 15F.0-1

INPUT PARAMETERS AND INITIAL CONDITIONS FOR
WNP-2 RELOAD TRANSIENT ANALYSIS (Continued)

Parameter	Value
Turbine throttle valve stroke time	100 msec
Turbine throttle valve position trip	90% open
Turbine governor valve stroke time (total)	150 msec
Safety/relief valve performance settings	Technical Specifications
Group 1	
Safety valve capacity	250 lbm/sec (1236 psig)
Safety valve opening delay/stroke	0.0/300 msec

[a] A power level of 104.6% was also analyzed and the most conservative results were used.

[b] The higher pressure level of 1050 psia was also analyzed and resulted in the same thermal limit.

[c] Normal scram insertion times are specified in the cycle specific COLR.

Note: WNP-2 Design Specifications, Division 60, specifies the reactor core and system analysis parameters in addition to the above.

15F.1 DECREASE IN REACTOR COOLANT TEMPERATURE

15F.1.1 LOSS OF FEEDWATER HEATING

15F.1.1.1 Sequence of Events

The loss of feedwater heating leads to a gradual increase in the subcooling of the water in the reactor lower plenum. Reactor power slowly rises to the average power range monitor (APRM) simulated thermal power trip setpoint. The gradual power change allows fuel thermal response to maintain pace with the increase in neutron flux. For this analysis, it was assumed that the initial feedwater temperature dropped 100°F.

15F.1.1.2 Core and System Performance

15F.1.1.2.1 Mathematical Model

Loss of feedwater heating (LOFH) events were evaluated with the ABB core simulator model POLCA (Reference 15F.1.3-1) by representing the reactor in equilibrium before and after the event. Actual and projected operating setpoints were used as initial conditions. Final conditions were determined by reducing the feedwater temperature by 100°F and increasing core power such that the calculated eigenvalue remains unchanged.

15F.1.1.2.2 Input Parameters and Initial Conditions

This analysis has been performed, unless otherwise noted, with plant conditions as specified in Section 15F.0.2.

A matrix of initial power/flow conditions is used with a maximum initial power level of 100%.

15F.1.1.2.3 Results

The MCPR operating limit bounds the loss of feedwater heating event. The MCPR operating limit is given in the cycle-specific COLR.

15F.1.2 FEEDWATER CONTROLLER FAILURE

15F.1.2.1 Sequence of Events

Failure of the feedwater control system is postulated to lead to a maximum increase in feedwater flow into the vessel. As the excessive feedwater flow subcools the recirculating water returning to the reactor core, the core power will rise and attain a new equilibrium if no other action is taken. Eventually, the inventory of water in the downcomer will rise until the

high vessel level (L8) setpoint is exceeded. To protect against wet steam entering the turbine, the turbine trips upon reaching the high level (L8) setpoint, closing the turbine throttle valves. The compression wave that is created, though mitigated by bypass flow, pressurizes the core and causes a power excursion. The power increase is terminated by reactor scram, recirculation pump trip (RPT), and pressure relief from the bypass valves opening.

15F.1.2.2 Core and System Performance

15F.1.2.2.1 Mathematical Model

The predicted dynamic behavior has been determined using BISON and BISON SLAVE, plant transient simulator codes developed for modeling jet pump BWRs. The computer code models are described in detail in Reference 15F.1.3-1. Some significant features of the model are:

a. The axial neutron flux profile and power density are calculated using a one-dimensional nodal solution of the two-group, space and time dependent neutron diffusion equation. The transient decay heat contribution from fission products is modeled;

b. The radial heat transfer model calculates the temperature distribution in the fuel and the heat transfer to the coolant;

c. The core hydraulic model solves mass, energy, and momentum balance equations to determine core flow rate and enthalpy;

d. The recirculation loops, jet pumps, and steam lines are modeled by nodalization. Solutions to mass, energy, momentum, and state equations are found for each node;

e. Feedwater flow, system pressure, and recirculation flow control systems are modeled; and

f. Trip system modeling includes simulated delays for instrument response and/or mechanical delays.

15F.1.2.2.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions as specified in Section 15F.0.2.

Analysis assumptions are:

a. Control rod insertion time based on WNP-2 measured data, and

b. Feedwater flow rate increased to the maximum feedwater flow based on a first order response following a step change to maximum demand.

15F.1.2.2.3 Results

The transient is terminated by reactor scram, RPT actuation, and pressure relief from bypass valves opening. The response of key parameters is given in Reference 15F.1.3-2.

Because the total change in feedwater flow is greatest from reduced power conditions, the feedwater controller failure (FWCF) transient was analyzed for several reduced power states. The power dependent MCPR limits which protect against the FWCF event are given in the cycle-specific Core Operating Limits Report.

15F.1.3 REFERENCES

15F.1.3-1 "Referenced Safety Report for Boiling Water Reactor Reload Fuel," CE NPD-300-P-A, July 1996.

15F.1.3-2 "WNP-2 Cycle 14 Transient Analysis Report," CE NPSD-825-P, Revision 0, ABB/Combustion Engineering, March 1998.

15F.2 INCREASE IN REACTOR PRESSURE

15F.2.1 GENERATOR LOAD REJECTION WITHOUT BYPASS

15F.2.1.1 Sequence of Events

This event is the most limiting (with respect to thermal margin) of the class of transients characterized by rapid vessel pressurization. The generator load rejection causes a turbine governor valve fast closure, which initiates a reactor scram and a recirculation pump trip (RPT). The compression wave produced by the governor valve fast closure travels through the steam lines into the vessel and pressurizes the reactor vessel and core. Bypass flow to the condenser, which would mitigate the pressurization effect, is conservatively not allowed. The excursion of core power due to void collapse is primarily terminated by reactor scram and void growth due to RPT.

15F.2.1.2 Core and System Performance

15F.2.1.2.1 Mathematical Model

The predicted dynamic behavior has been determined using the plant transient simulator codes BISON and BISON SLAVE. See Section 15F.1.2.2.1 for a description of the model.

15F.2.1.2.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions as specified in Section 15F.0.2.

Analysis assumptions are:

a. Control rod insertion time based on WNP-2 measured data, and
b. Turbine control valves in full arc mode.

15F.2.1.2.3 Results

Analyses were performed to analyze combinations of RPT operable/inoperable and normal/Technical Specification scram speeds (Reference 15F.2.2-1). The excursion of core power due to void collapse is primarily terminated by reactor scram and void growth due to RPT. The cycle-specific COLR shows the CPR results for the generator load rejection without bypass events where they are limiting. The time variance of critical reactor and plant parameters from the design basis analysis are given in Reference 15F.2.2-1.

15F.2.2 REFERENCES

15F.2.2-1 "WNP-2 Cycle 14 Transient Analysis Report," CE NPSD-825-P, March 1998.

15F.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

15F.4.1 ROD WITHDRAWAL ERROR - AT POWER

15F.4.1.1 Sequence of Events and System Operation

This is the analysis of the transient resulting from the withdrawal of a fully inserted control rod until the motion is stopped by a rod block. It is assumed that the reactor is operating at power, that the maximum reactivity rod is being withdrawn and the operator ignores the local power range monitor (LPRM) alarm.

15F.4.1.2 Core and System Performance

15F.4.1.2.1 Mathematical Model

The analysis is performed with the POLCA codes as a series of steady-state calculations.

A detailed discussion of the code is presented in Reference 15F.4.5-1.

The control rod withdrawal error analysis has been performed to estimate the minimum critical power ratio (MCPR) and maximum linear heat generation rate (LHGR) in such a transient. A starting control rod pattern is established for the typical BWR reactor and a central control rod is withdrawn from the fully inserted position. Rod withdrawal results in an increase of the LHGR and decrease of the critical power ratio (CPR). The computed maximum linear heat generation rate (MLHGR) and MCPR are compared to values of other transients to establish operating limits for the reactor. The analysis determines the transient MCPR as a function of the rod block monitor setpoint.

15F.4.1.2.2 Input Parameters and Initial Conditions

The generic input parameters, mathematical assumptions, and initial conditions utilized in this analysis are presented in Reference 15F.4.5-1. Input parameters specific to the WNP-2 rod withdrawal error analysis are found in Reference 15F.4.5-2.

15F.4.1.2.3 Results

The cycle-specific Core Operating Limits Report (COLR) provides CPR limits which bound the limiting transient. At certain core exposures and power/flow conditions this limiting transient may be control rod withdrawal error (CRWE).

15F.4.2 MISPLACED BUNDLE ACCIDENT

15F.4.2.1 Sequence of Events and System Operation

The fuel loading error considers the consequences of either of two possible events: misorientation or mislocation of a fuel assembly. Further, the assumption is made that the error is not discovered during core verification. The purpose of the analysis is to determine the change in the minimum CPR between the correctly loaded core and the misloaded core. A combination of the misorientation and mislocation is not considered because of the very low probability of occurrence.

15F.4.2.2 Core and System Performance

15F.4.2.2.1 Mathematical Model

One possible fuel loading error is to misorient a fuel assembly so it is rotated 90° or 180° from its correct orientation. The consequence of misorienting an assembly in WNP-2 is reduced because the core is designed with equal water gaps and the fuel is designed with diagonal symmetry.

Another possible fuel loading error is to load a fuel assembly in an incorrect location in the core. A high reactivity fuel assembly is assumed to be loaded in place of a low reactivity fuel assembly, which will result in higher local power. The MCPR is computed by direct CPR comparison of misloaded and normal assemblies. First it is assumed that the control rod and loading patterns have been developed using the POLCA code. The next step is to identify candidate mislocation assemblies, i.e., those which involve a high reactivity assembly in a low reactivity location. Each such location is then burned through the cycle to determine the MCPR for the misloaded assembly under normal loading conditions. The MCPR is then obtained by direct CPR comparison.

Detailed descriptions of POLCA are presented in Reference 15F.4.5-1.

15F.4.2.2.2 Input Parameters and Initial Conditions

The assumptions and initial conditions utilized in this analysis are described in Reference 15F.4.5-1. The neutronic design parameters are given in Tables 15F.4-1 and 15F.4-2. The core loading pattern is given in Figure 15F.4-1.

15F.4.2.2.3 Results

The fuel bundle loading error event results in a change in critical power ratio (ΔCPR) which is bounded by the MCPR operating limit specified in the cycle-specific COLR. There is no fuel damage which occurs as a result of this event.

15F.4.3 CONTROL ROD DROP ACCIDENT

15F.4.3.1 Sequence of Events and System Operation

The control rod drop accident (CRDA) assumes that a central control rod becomes uncoupled from the drive and remains stuck fully inserted in the reactor core as the control rod drive is withdrawn. The uncoupled control rod is then assumed to drop out of the core. The reactor is assumed to be at a hot zero power condition.

15F.4.3.2 Core and System Performance

15F.4.3.2.1 Mathematical Model

A complete cycle-specific analysis of this accident is fundamentally a two-step approach. The first step involves determination of possible candidates for the control rod which would cause the most severe consequences resulting from a CRDA. The evaluation of dropped control rod worth is performed within the constraints of permissible control blade withdrawal sequencing and assuming the same limiting selection error by the operator previously established for licensing basis calculations for that unit. The three-dimensional static core simulator POLCA, in conjunction with the cross section generator code PHOENIX are utilized for this evaluation.

The second step is simulation of the dynamic response to the identified worst dropped control rod(s) and the subsequent consequences to the fuel. This evaluation is performed with the three dimensional systems transient code RAMONA-3B. The candidates for the worst-case condition established in the first step are simulated in the RAMONA-3B core model for the dynamic evaluation. The RAMONA-3B methodology utilizes state-of-the-art phenomenological models including moderator feedback to describe the overall transient response of the plant and core in conjunction with the local thermal behavior of the fuel.

The limiting criteria for the CRDA are: (a) maximum deposited enthalpy no greater than 280 cal/gm of fuel, and (b) maximum reactor pressure vessel stresses not to exceed the "Service Limit C" as defined in the ASME Code (Section III). The neutronic parameters which affect the rod drop analysis are: (a) the doppler coefficient, (b) the maximum rod worth, (c) the power peaking, and (d) the delayed neutron fraction.

15F.4.3.2.2 Input Parameters and Initial Conditions

The important parameters in the analysis of a rod drop accident include: rod worth, the doppler coefficient, the delayed neutron fraction, and power distribution. Values for these parameters are provided in References 15F.4.5-2, 15F.4.5-3, and 15F.4.5-4.

The variables are chosen to envelope anticipated reactor operating conditions for WNP-2.

15F.4.3.2.3 Results

The control rod drop transient analysis demonstrates that the maximum deposited fuel rod enthalpy is 67 cal/g or less. The limit on deposited enthalpy is not exceeded by this event.

15F.4.4 RECIRCULATION FLOW RUN-UP

15F.4.4.1 Sequence of Events

The reduced flow MCPR operating limit is determined by evaluating the bounding slow flow increase event. In the calculations the event is initiated from several power/flow points and terminates at 123% power, 108.5% flow. It is conservatively assumed that the event is quasi-steady state and a flow biased scram does not occur.

15F.4.4.2 Core and System Performance

15F.4.4.2.1 Mathematical Model

The predicted dynamic behavior has been determined using the plant simulator code POLCA. See Reference 15F.4.5-1 for a description of the POLCA model.

15F.4.4.2.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions as specified in Section 15F.0.2.

Analysis assumptions are

a. Flow increase is initiated from several power/flow points and terminates at 123% power, 108.5% flow,

b. Quasi-steady-state conditions exist,

c. No flow biased scram, and

d. The power distribution was chosen such that the MCPR equals the safety limit at the final power/flow condition.

15F.4.4.2.3 Results

The reduced flow MCPR was calculated at discrete flow points. The reduced flow MCPR operating limit curve is shown in the cycle specific COLR for all cycle exposures, including FFTR operation.

15F.4.5 REFERENCES

15F.4.5-1 "Reference Safety Report For Boiling Water Reactor Reload Fuel," CE NPD-300-P-A, July 1997.

15F.4.5-2 "WNP-2 Cycle 14 Reload Report," CE NPSD-826-P., Revision 1, March 1998.

15F.4.5-3 "WNP-2 Cycle 14 Transient Analysis Report," CE NPSD-825-P, March 1998.

15F.4.5-4 "Control Rod Drop Accident Analysis Methodology for Boiling Water Reactors: Summary and Qualification," CE NPD-284-P-A, July 1996.

TABLE 15F.4-1

RELOAD FUEL NEUTRONIC DESIGN VALUES

	SPC 9 x 9-9X	SVEA-96
Fuel pellet		
Fuel material	UO_2 sintered pellets	UO_2 sintered pellets
Density, g/cm^3	10.36	10.5
% of T.D.	94.5	95.8
Diameter		
Enriched fuel	0.3655	0.3224
Natural fuel	0.3655	0.3224
Fuel rod		
Fuel length, in.	150	150
Cladding material	Zircaloy-2	Zircaloy-2
Clad I.D., in.	0.374	0.3291
Clad O.D., in.	0.433	0.3787
Fuel assembly		
Number of fuel rods	72	96
Number of inert water rods	1 central water channel	central water cross
Fuel rod enrichments	Reference 4.3-2	Reference 15F.4.5-2
Fuel rod pitch, in.	0.569	0.488
Fuel assembly loading, kg uranium	167.6	175.7

TABLE 15F.4-2

NEUTRONIC DESIGN VALUES

Parameter	Value
Core data	
Number of fuel assemblies	764
Rated power, MWt	3486
Rated core flow, Mlbm/hr	108.5
Core inlet enthalpy, Btu/lbm	528.7
Reactor pressure, psia	1035
Fuel assembly pitch, in.	6.00
Water gap thickness (symmetric), in.	0.522
Control rod data[a]	
Absorber material	B_4C
Total blade span, in.	9.75
Total blade support span, in.	1.58
Blade thickness	0.260
Blade face-to-face internal dimension, in.	0.200
Absorber rods per blade	76
Absorber rods outside diameter, in.	0.188
Absorber rods inside diameter, in.	0.138
Absorber density, % of theoretical	70.0

[a] Original equipment control rods. Some of the control blades are replaced with Duralife 215 control blades. The two designs are treated as equivalent (Reference 15F.4.5-2).

16	AC 11	AC 10	SA 12	AC 11	AC 11	SB 14	AC 10	AC 11	AC 11	SB 14	AC 10	AC 11	AC 11	SA 13	AC C9
17	AC 10	SB 14	SA 13	AC 10	SA 13	A7 C9	SA 13	SA 12	SA 13	AC 11	SA 13	AC 10	SA 14	SA 12	A7 C9
18	SA 12	SA 13	AC 10	SB 14	SA 12	SB 14	AC 11	SB 14	AC 10	SB 14	SA 12	SB 14	SA 12	SA 13	A7 C9
19	AC 11	AC 10	SB 14	AC 10	AC 11	AC 10	SA 13	AC 11	SA 12	A7 C9	SA 13	AC 10	SA 13	AC 11	A7 C9
20	AC 11	SA 13	SA 12	AC 11	AC 11	SA 14	SA 12	AC 11	AC 11	SB 14	SA 12	SB 14	AC 11	AC 10	A7 C9
21	SB 14	A7 C9	SB 14	AC 10	SA 14	AC 10	AC 11	AC 10	SA 13	AC 10	SB 14	SA 13	SA 12	AC 11	A7 C9
22	AC 10	SA 13	AC 11	SA 13	SA 12	AC 11	SA 12	SB 14	SA 12	SB 14	AC 10	SB 14	AC 10	AC 10	A7 C8
23	AC 11	SA 12	SB 14	AC 11	AC 11	AC 10	SB 14	AC 11	AC 11	SA 12	SA 13	SA 13	AC 10	A7 C9	
24	AC 11	SA 13	AC 10	SA 12	AC 11	SA 13	SA 12	AC 11	AC 11	SA 14	AC 10	AC 10	A7 C9		
25	SB 14	AC 11	SB 14	A7 C9	SB 14	AC 10	SB 14	SA 12	SA 14	SA 12	AC 10	A7 C8	A7 C8		
26	AC 10	SA 13	SA 12	SA 13	SA 12	SB 14	AC 10	SA 13	AC 10	AC 10	A7 C9				
27	AC 11	AC 10	SB 14	AC 10	SB 14	SA 13	SB 14	SA 13	AC 10	A7 C8					
28	AC 11	SA 14	SA 12	SA 13	AC 11	SA 12	AC 10	AC 10	A7 C9	A7 C9					
29	SA 13	SA 12	SA 13	AC 11	AC 10	AC 11	AC 10	A7 C9							
30	A7 C9	A7 C9	A7 C9	A7 C9	A7 C9	A7 C9	A7 C9								

Assembly Type	Cycle Loaded	Number Assemblies	Description
A7C8	8	16	9x9-9X 2.92 w/o U-235
A7C9	9	92	9x9-9X 2.92 w/o U-235
AC10	10	156	9x9-9X 2.92 w/o U-235
AC11	11	152	9x9-9X 2.92 w/o U-235
SA12	12	104	SVEA-96 3.33 w/o U-235
SA13	13	112	SVEA-96 3.33 w/o U-235
SA14	14	24	SVEA-96 3.33 w/o U-235
SB14	14	108	SVEA-96 3.14 w/o U-235

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SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

WNP-2 Loading Pattern by Fuel Type (One-Quarter of Symmetrical Core Loading)

Draw. No. 960690.24 | Rev. | Figure 15F.4-1

Form No. 960690

15F.6 DECREASE IN REACTOR COOLANT INVENTORY

15F.6.1 INTRODUCTION

A break spectrum analysis has been performed to establish the limiting break for the WNP-2 boiling water reactor (BWR) 5 reactor system (Reference 15F.6.3-1). Previous analyses by the nuclear steam supply system (NSSS) vendor have shown that a large pipe break in the recirculation line on the suction side of the recirculation pump is the most limiting break for a BWR 5. To ensure that the limiting break has been identified with the ABB/CE loss-of-coolant accident (LOCA) BWR evaluation model (Reference 15F.6.3-2), ABB/CE performed calculations of various possible locations, sizes, and configurations. The limiting break is used in the emergency core cooling system (ECCS) heatup analyses to determine the maximum average planar linear heat generation rate (MAPLHGR) limits for ABB/CE fuel. The break spectrum analysis was performed at a point on the power/flow map to support the plant rated thermal power operation with increased core flow.

The break location analysis included breaks in the recirculation suction and in the sprayline piping with a double-ended guillotine (DEG) break configuration. The break configuration and size spectrum included the DEG break coefficients of 1.0, 0.8, and 0.6. A split break configuration of the pump suction piping was calculated with a break area equal to .09 ft^2.

The break spectrum results show very little dependence of the peak cladding temperature (PCT) on break location, size, or configuration, and confirm that considerable margin exists in a BWR 5 to the acceptance criteria of 10 CFR 50.46. The limiting break location for the WNP-2 plant was confirmed to be in the recirculation suction piping consistent with the NSSS vendor analysis results. The limiting break configuration and size were determined to be an 80% recirculation suction line break along with failure of the low-pressure core spray (LPCS) diesel generator.

15F.6.2 LOSS-OF-COOLANT ACCIDENTS (RESULTING FROM SPECTRUM OF POSTULATED PIPING BREAKS WITHIN THE REACTOR COOLANT PRESSURE BOUNDARY) - INSIDE CONTAINMENT

15F.6.2.1 Sequence of Events

The sequence of events associated with this accident is shown in Table 15F.6-1.

15F.6.2.2 System Operation

An ECCS analysis calculation of the limiting break has been performed for the WNP-2 plant. The break spectrum calculations for WNP-2 have been previously performed and reported in Section 15F.6.1.1. The limiting break was found to be a split break on the suction side of the recirculation pump with a break area equal to 80% of the DEG break flow area.

The limiting calculation for WNP-2 has been performed for 106.6% power and 106% core flow to support operation within the WNP-2 power/flow map. The 106% core flow represents the maximum core flow at which the plant can operate while maintaining 100% power. The performance of the ECCS analysis at the maximum core flow results in the highest radial peaking factor given that the calculations are initialized at the same MAPLHGR and minimum critical power ratio (MCPR) limits. Therefore, this analysis envelopes lower flow conditions at rated core power because the calculations would be initialized with a lower radial peaking factor while maintaining the same initial MAPLHGR and MCPR values.

The LOCA system behavior is determined by the system geometry and break size. Core parameters have only a secondary effect on system event times. For these reasons, this analysis is applicable to future cycles of WNP-2 unless system modifications or revised operating conditions negate the plant conditions assumed herein.

15F.6.2.3 Core and System Performance

15F.6.2.3.1 Mathematical Model

A LOCA is defined as a hypothetical rupture of the reactor coolant system piping, up to and including the double-ended rupture of the largest pipe in the reactor coolant system or of any line connected to that system up to the first closed valve. In the unlikely event a LOCA occurs in the WNP-2 plant, reactor system coolant inventory loss would result in a high containment drywell pressure concurrent with low reactor water level. These two events would provide a safety signal which would bring ECCS into operation to limit the accident consequences.

During the early phase of a LOCA depressurization transient, core cooling is provided by the existing coolant inventory. During the reactor system depressurization, the high-pressure core spray (HPCS) provides additional core heat removal. In the latter stage of system depressurization and as well as after depressurization has been achieved, the HPCS provides core cooling and the low-pressure coolant injection (LPCI) supplies additional liquid to rapidly refill the bypass region of the reactor vessel and reflood the core. The liquid which fills the bypass can flow into the lower plenum through the core support structure paths and the bypass holes in the inlet orifices of the fuel. During the core reflood process, cooling is provided above the mixture level by entrained reflood liquid and below the mixture level by pool boiling processes. These reflood processes provide heat removal at all core elevations to terminate the core temperature transient rise.

The GOBLIN, DRAGON, and CHACHA-3 codes were used for the LOCA-ECCS analysis for ABB/CE fuel in the WNP-2 Reactor (Reference 15F.6.3-1).

The overall ABB LOCA-ECCS licensing evaluation methodology is described in Reference 15F.6.3-2.

The GOBLIN system of computer codes uses one-dimensional assumptions and solution techniques to calculate the BWR transient response to both large and small break LOCAs. The code system is composed of three major computer programs - GOBLIN, DRAGON, and CHACHA-3. The functions of the individual codes are

a. GOBLIN performs the thermal-hydraulic calculations for the entire reactor primary system including interactions with various safety systems;

b. DRAGON performs the thermal-hydraulic calculations for a specified fuel assembly in the reactor core. The GOBLIN code provides DRAGON with the necessary boundary conditions; and

c. CHACHA-3 calculates the detailed temperature distribution and cladding oxidation at a given axial cross section of the assembly analyzed by DRAGON. Its input boundary conditions are supplied by GOBLIN and DRAGON.

The NRC approved GOBLIN/DRAGON/CHACHA-3 evaluation model is designated "USA2".

The process of performing the LOCA-ECCS analysis using the ABB methodology for a specific plant application consists of the following steps.

a. The LOCA-ECCS licensing bases for the plant is defined,

b. Plant-specific GOBLIN, DRAGON, and CHACHA-3 code models are developed,

c. A confirmatory break spectrum evaluation is performed to identify the "limiting break" from the potentially limiting breaks defined in the plant licensing bases,

d. A set of conservative initial reactor core conditions are defined that bound the expected conditions for each reload cycle that the fuel design in question shall be in the reactor,

e. For the limiting break and conservative initial conditions, the MAPLHGR operating limit as a function of exposure is determined for the reload fuel design, and

f. The total hydrogen generation for a core of SVEA-96 fuel is evaluated and confirmed to be in compliance with the acceptance limit.

The ABB LOCA evaluation model was developed for the WNP-2 plant. The GOBLIN system model consists of a total of 60 control volumes with 13 axial core nodes, representing a full core of SVEA-96 fuel. The two recirculation lines are explicitly modeled including dynamic simulation of the adjustable speed drive recirculation pumps installed prior to the start of

Cycle 12. Structural heat transfer is modeled with 71 conduction plates. The model includes downcomer level calculation, steam and feedwater boundary flow conditions, point reactor kinetics, emergency core cooling injection, and safety/ADS valve functions. The model includes a WNP-2 specific representation of the core average neutron kinetics.

The peak power fuel assembly is modeled with the DRAGON code. The model consists of 41 control volumes including explicit modeling of the SVEA-96 watercross channel and interassembly bypass. The fuel rods are modeled by four separate groups representing the different rod radiative characteristics. Radiative and conductive heat transfer with fuel channel and watercross is modeled with 32 structural plates. The initial channel power is specified to yield a minimum critical power ratio of 1.20 in normal operation (and 1.35 in single loop operation).

The CHACHA-3 heat-up model is a peak plane mode of the SVEA-96 fuel assembly subbundle with explicit representation of each fuel rod and channel wall. The model includes a WNP-2 specific representation of local pin power peaking and pellet-clad gap gas compositions.

15F.6.2.3.2 Input Parameters and Initial Conditions

Input parameters and initial conditions used for the analysis of this event are given in Table 15F.6-2.

15F.6.2.3.3 Results

The results of the LOCA ECCS analysis for ABB SVEA-96 reload fuel in the Supply System WNP-2 reactor are presented in terms of the MAPLHGR limit as a function of fuel average planar exposure. These calculations were performed with the NRC approved GOBLIN, DRAGON, and CHACHA-3 Evaluation Models. These models are in compliance with the requirements of Title 10 CFR 50, Appendix K, and are used to show compliance with the acceptance criteria of Title 10 CFR 50.46.

A LOCA break spectrum analysis was performed for WNP-2 licensing uprated conditions. Specifically, the ABB LOCA analysis supports plant operation at 104.5% power, 106% core flow, with conservative ECCS and safety valve performance requirements. The ABB analysis shows that the limiting break for WNP-2 is a double-ended guillotine break on the suction side of the recirculation pump with an area equal to 80% of the area of the largest double-ended recirculation pipe break. This limiting break was confirmed applicable for two loop and single loop operation. For the limiting break, MAPLHGR operating limits were calculated as a function of exposure.

Operation of the WNP-2 reactor with SVEA-96 reload fuel, designated "SA" and/or "SB" within the limit of the MAPLHGR ensures that the ECCS for the WNP-2 reactor will meet the NRC acceptance criteria for breaks up to and including the double-ended guillotine severance

of a reactor coolant pipe. The MAPLHGR limits apply to the initial and subsequent reloads incorporating the SVEA-96 "SA", and/or "SB" bundle design for the WNP-2 reactor core.

15F.6.3 REFERENCES

15F.6.3-1 "WNP-2 LOCA Analysis Report," CE NPSD-801-P, Revision 2, March 1998.

15F.6.3-2 "Reference Safety Report for Boiling Water Reactor Reload Fuel," CE NPD-300-P-A, July 1996.

TABLE 15F.6-1

LOSS-OF-COOLANT ACCIDENT SEQUENCE OF EVENTS
FOR LIMITING BREAK

Time (sec)	Event
0.0	Break initiation
0.0	Loss of offsite power (LOOP)
0.0	Loss of reactor recirculation coolant pumps - start pump coastdown
1.0	Main steam line isolation valves begin to close on LOOP
2.5	Reactor scram signal on low level
4.0	Main steam line isolation valves closed
6.0	High-pressure core spray injection signal on low level
7.0	Jet pumps uncover
7.3	Jet pump flashing
10.7	Low-pressure coolant injection signal on low level
11.1	Start lower plenum flashing
30.7	Peak assembly peak plane uncovery
43.0	Start HPCS flow
66.5	Start LPCI flow
177.0	Peak cladding temperature reached
177.0	Peak plane reflood

TABLE 15F.6-2

INPUT PARAMETERS AND INITIAL CONDITIONS

Parameter	Value
Rated core thermal power	3486 MWt
Core thermal power (includes 2% power uncertainty)	3716 MWt (106.6% of rated)
Total core flow rate	115.0 Mlb/hr (106% of rated)
Steam flow rate	16.1 Mlb/hr (107.3% of rated)
Feedwater temperature	425°F
Steam dome pressure	1055 psia
Upper plenum (core exit) pressure	1063 psia
Lower plenum (core inlet) pressure	1087 psia
Core inlet temperature	536°F
Maximum recirculation line inside diameter	21.564 in.
Fuel design	SVEA-96, 4 (5x5-1) lattice
Initial minimum critical power ratio	1.20 (two loop operation) 1.35 (single loop operation)
Recirculation pump moment of inertia (pump, motor, and drive line)	21,800 lbm-ft
Recirculation pumps	Adjustable speed drive with locked open flow control valves

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FIRE PROTECTION EVALUATION

F.1 INTRODUCTION

The Fire Protection Evaluation summarizes the overall fire protection program at WNP-2. The plant fire protection program provides a defense-in-depth approach to fire protection to:

a. Prevent fires from starting,
b. Promptly detect and extinguish a fire should it occur,
c. Limit potential fire damage, and
d. Maintain the capability to safely shut down the plant following a fire.

The Fire Protection Evaluation describes those fire protection related organizational responsibilities, administrative and technical controls, fire suppression and detection systems, fire hazards analyses, and the post-fire safe shutdown methods, which comprise the fire protection program.

The Fire Protection Evaluation also includes the fire protection operational conditions, compensatory measures, and testing requirements which were removed from the Technical Specifications in Operating License (OL) Amendment 67, dated May 25, 1989. Operating License Amendment 67 also modified License Condition 2.c.14 such that the approved fire protection program may be altered without prior NRC approval when the changes do not

a. Otherwise involve a change in a license condition or Technical Specifications or result in an unreviewed safety question (10 CFR 50.59), and

b. Adversely impact the capability to safely shut down in the event of fire.

The scope of WNP-2 structures that must satisfy the fire protection program are those buildings designated as fire areas in Section F.4, plus the buildings containing fire pumps shown in Figure F.6-11.

F.1.1 FIRE PROTECTION PROGRAM

The approved fire protection program and the changes thereto are contained in this Appendix of the FSAR except for certain other sections of the FSAR included in the Fire Protection Program by Reference F.7.1.

Appendix F is divided into seven sections. This first section contains background information on the development of the fire protection program.

Section F.2 contains a description of the plant fire protection systems. The codes and standards considered and used in the design of the systems are listed. Deviations from code design requirements are identified.

Section F.3 presents point-by-point comparisons of the plant fire protection program to the guidelines of Branch Technical Position (BTP) APCSB 9.5-1, Appendix A, and with the specific requirements of 10 CFR 50 Appendix R, Section III.

Section F.4 describes the methods used to implement the required post-fire safe shutdown protection requirements of 10 CFR 50, Appendix R. The selection of the post-fire shutdown equipment and the circuit analysis methods are also described in Section F.4. The fire hazards analysis for each fire area describes the respective area, combustible loading, fire protection features which may be used to mitigate the consequences of a potential fire, and the methods used to ensure post-fire safe shutdown capability.

Section F.5 describes the fire protection system operational conditions, compensatory measures, and testing requirements for the essential portions of the fire protection systems (those portions of the fire protection systems formerly contained in the Technical Specifications).

Section F.6 contains the fire protection arrangement drawings and Section F.7 lists the references.

F.1.2 BACKGROUND

On September 30, 1976, Washington Public Power Supply System was requested by the NRC to conduct an evaluation of the fire protection program at WNP-2. The evaluation consisted of a comparison of the fire protection provisions of WNP-2 with the guidelines in BTP APCSB 9.5-1, Appendix A. The performance of the evaluation required that a fire hazards analysis be performed to define plant fire areas, determine the potential sources of combustion and design fire loading, describe the fire detection and extinguishing capabilities, identify the safety-related equipment within the area, and determine the potential consequences of a design-basis fire.

10 CFR 50 Appendix R added new requirements for the fire protection of safe shutdown capability, emergency lighting, and lubricating oil collection systems for noninerted containment reactor coolant pumps. By letter dated October 15, 1981 (D. G. Eisenhut, NRC, to R. L. Ferguson, Supply System), the NRC indicated that the requirements of Appendix R would be used for review of fire protection requirements for the WNP-2 OL.

10 CFR 50, Appendix R, Section III.G, imposed specific requirements for post-fire safe shutdown. The approved WNP-2 methodology used is a transition directly to cold shutdown

using standby service water, residual heat removal, and the automatic depressurization system (see Reference F.7.4.i).

Section F.7.4 lists the NUREG-0892 NRC Safety Evaluation Reports (SER) for the WNP-2 fire protection program. In the SERs, the NRC compared WNP-2 to the Standard Review Plan BTP CMEB 9.5.1 (which includes the combined guidelines of BTP 9.5-1, Appendix A, and 10 CFR 50, Appendix R). WNP-2 received its operating license on December 12, 1983. Therefore, WNP-2 is an Appendix A plant, also committed to certain sections of Appendix R (as defined in Table F.3-2).

Generic Letter 88-12 guidance resulted in Amendment 41 incorporating the fire protection Technical Specifications into the FSAR.

Fire protection measures are established according to the function(s) of the structure, system, or component.

a. Fire protection for those portions of plant systems which are required for post-fire safe shutdown is provided in accordance with 10 CFR 50, Appendix R, Section III.G (see Sections F.3 and F.4),

b. Fire protection for safety-related equipment which is not required for post-fire safe shutdown is provided to minimize the risk from a single fire hazard, in accordance with the plant response to Appendix A to BTP 9.5-1 (see Section F.3);

c. Fire protection measures, such as fire brigade activities, manual actions, and dispatch of health physics personnel and an environmental field team (in the case of an alert condition) will aid in the monitoring and control of potential radioactive release to the environment; and

d. Fire protection for plant structures, systems, or components to reduce commercial fire risk.

F.2 FIRE PROTECTION SYSTEMS

Fire protection is provided through a combination of active and passive features which function to detect, contain, and suppress potential fires. These features include:

a. Fire resistive construction

b. Fire detection and alarm systems

c. Fire suppression systems

    1. Fire water supply system
    2. Deluge water spray systems
    3. Wet pipe sprinkler systems
    4. Preaction sprinkler systems
    5. Carbon dioxide systems
    6. Halon 1301 systems
    7. Dry chemical suppression systems
    8. Manual fire fighting equipment

d. Manual fire fighting equipment

    1. Protective clothing and self-contained breathing apparatus (SCBA)
    2. Yard fire hydrants
    3. Standpipes, hose, and foam carts
    4. Portable extinguishers
    5. Smoke removal

e. Operator action equipment

   1. Emergency lighting

   2. Emergency communications

The design of the plant fire protection features is described below.

F.2.1 APPLICABLE INDUSTRY STANDARDS

The following industry standards are used, where applicable, in the design of the fire protection systems serving the reactor building, radwaste/control building, diesel generator building, turbine generator building, circulating water pump house, water filtration building 33, and transformer yard. Differences between the installed plant configuration and the design requirements of the industry standards are listed in Table F.2-1.

a. NFPA 10 - 1975, Standard for Portable Fire Extinguishers;

b. NFPA 12 - 1973, Standard on Carbon Dioxide Extinguishing Systems;

c. NFPA 12A - 1973, Standard on Halogenated Fire Extinguishing Agent-Halon 1301;

d. NFPA 13 - 1975, Standard for the Installation of Sprinkler Systems;

e. NFPA 14 - 1974, Standard for the Installation of Standpipe and Hose Systems;

f. NFPA 15 - 1973, Standard for Water Spray Fixed Systems for Fire Protection;

g. NFPA 20 - 1974, Standard for the Installation of Centrifugal Fire Pumps;

h. NFPA 24 - 1973, Standard for Outside Protection;

i. NFPA 30 - 1973, Standard for Flammable and Combustible Liquids Code. See Table F.3-1 paragraph D.2.d for applicability;

j. NFPA 50A - 1973, Standard for Gaseous Hydrogen Systems at Consumer Sites. See Table F.3-1 paragraph D.2.b for applicability;

k. NFPA 70 - 1975, National Electric Code. Used for the design of electrical equipment and wiring for the main control room cabinet Halon 1301 systems and for wiring of the fire detection and alarm initiating devices;

l. NFPA 72A - 1975, Standard for the Installation, Maintenance and Use of Local Protective Signaling Systems for Watchman, Fire Alarm and Supervisory Service;

m. NFPA 72D - 1975, Standard for the Installation, Maintenance and Use of Proprietary Protective Signaling Systems for Guard, Fire Alarm, and Supervisory Service;

n. NFPA 72E - 1974, Standard for Automatic Fire Detectors;

o. NFPA 78 - 1975, Lightning Protection Code. See Table F.3-1 paragraph A.4 for applicability;

p. NFPA 80 - 1974, Standard for Fire Doors and Windows;

q. NEDO-10466-A, Power Generation Control Complex Design Criteria and Safety Evaluation. See Table F.3-1 paragraph E.4.a for applicability;

r. IEEE 383-1974, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations. Where cable does not meet IEEE 383, NFPA 262-1990 or UL 910-1985 may be used. See Table F.3-1 paragraph D.3.f for further clarification;

s. Regulatory Guide 1.52, Revision 1, Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants. See Table F.3-1 paragraph D.4.d for applicability; and

t. ANSI A21.4,-1974. See Table F.3-1 paragraph E.2.a for applicability.

Current editions of the above codes are used for modifications and additions to the plant fire protection systems when new facilities or systems are constructed or enhanced and defense-in-depth is warranted. In some cases, the guidance of more recent code editions may be followed which deviates from designs of the above code of record, without a corresponding Table F.2-1 discussion (when managed through administrative controls and maintained as a plant record).

F.2.2 FIRE RESISTIVE CONSTRUCTION

Fire barriers and fire resistive construction prevent the spread of fire from one location to another. Fire resistance is provided in building construction through the use of noncombustible structural materials. Rated fire barriers further isolate certain high hazard areas and provide additional separation for those systems needed for post-fire safe shutdown.

Essential fire rated assemblies are those fire area boundary features which separate fire areas with redundant post-fire safe shutdown equipment/cables or those fire areas containing redundant post-fire safe shutdown cables where one division is protected by raceway fire barriers. The overall category of fire rated assemblies (see Section F.5.7) can be broken into subcategories of fire area boundary features, raceway fire barriers, and fireproof coatings.

Figures F.6-1 through F.6-5 show the fire area boundaries, barrier hourly fire ratings, and barrier classifications. Reference F.7.7.o is the raceway fire barrier drawings.

F.2.2.1 Fire Area Boundary Features

Structural fire barriers may be provided by wall, floor, or ceiling assemblies. The fire rating of structural fire barriers is described in Section F.4 fire hazards analysis. A concrete wall with a thickness of 6 in. or greater provides a 3-hr rating. Based on the construction of masonry fire barriers, the fire rating may vary from 2 to 3 hr. The fire resistance rating for structures is determined using information from the NFPA Fire Protection Handbook, vendor data, industry fire resistance directories, and/or engineering evaluation. The containment fire barrier is not a standard 3-hr rated assembly but is adequate to prevent fire propagation.

Fire doors, fire dampers, and fire rated penetration seals are typically designed with a fire rating equivalent to that of the structural barrier in which they are installed. The 2-hr barriers may have 1.5-hr rated doors and dampers.

Fire doors are installed to the guidelines of NFPA 80 - 1974, with exceptions contained in Table F.2-1. Non-fire rated specialty doors (air lock, watertight, radiation shield, and blast doors) located in fire barriers are installed based on equivalent door construction, as approved in Reference F.7.4.c.

Penetrations for ventilation systems through fire rated barriers are protected by fire dampers. Some plant areas have 1.5-hr rated fire dampers in 3-hr barriers, as approved by Reference F.7.4.a. Certain fire damper assemblies consist of a 3-hr listed fire door as the guillotine or trap door, installed in unlisted frames or supports. The construction and installation of the frames and supports is similar to listed assemblies. Although the design has not been fire tested and listed as a fire damper assembly, it was approved by Reference F.7.4.f. As approved in Reference F.7.4.1, fire dampers are not drop tested under air flow conditions since administrative controls are present to shut down ventilation on confirmation of a fire. All fire dampers in rooms containing safety-related equipment are qualified to Seismic Category I.

Conduit, piping, and cable penetrations are sealed where they pass through the barrier, except for some internal conduit seals where evaluation has shown no seal is required. Penetration seals provide a fire resistance equal to that of the barrier unless a fire protection evaluation has

justified a lesser fire rating. Grouted penetrations are sealed with grout to the same thickness of the wall and are assumed not to degrade the rating of the penetrated fire barrier. The fire rating of nongrouted penetration seal designs is established by tests performed in accordance with Reference F.7.6.b. Qualification of fire-rated and pressure-rated penetration seals is contained in Reference F.7.6.a. Configuration control of penetration seals is maintained by Reference F.7.5.q.

The containment barrier and penetrations are nonstandard fire barriers not qualified by representative fire testing. See Section F.2.2.5 for more details.

F.2.2.2 Raceway Fire Barriers

Fire barriers are also used to prevent damage to designated components within a fire area in the event other equipment in the area is damaged by fire. Raceway fire barriers are constructed of Thermo-Lag 330-1 or 3M Interam E-50D. Raceway fire barriers are installed at a thickness recommended by the vendors, based on fire tests to ANI guidelines. Structural steel supports and intervening steel members are wrapped to the minimum distance recommended by the vendors or as determined by heat flow calculations. Reference F.7.4.f approved that unprotected commodities can be present above raceway fire barriers.

F.2.2.3 Fireproof Coatings

Thermo-Lag 330-1 is also installed to create a 20-ft zone of no intervening combustibles in the cable spreading room. This will prevent a fire from propagating between redundant divisions along the intervening trays and was approved by Reference F.7.4.j.

Thermo-Lag 330-1 is used as a fire resistive coating on certain reactor building structural steel members supporting post-fire safe shutdown credited instrument tubing.

F.2.2.4 Electrical Separation Barriers

Electrical separation barriers are present throughout the plant to limit internally generated fire damage to nearby redundant safety-related systems. See Section 8.3.1.4 for more detail.

Plant building construction is further described below. The Section F.4.4.4 fire hazards analysis for each fire area has additional building construction and fire rating details.

F.2.2.5 Reactor Building

Exterior walls, floors, and ceilings are reinforced concrete from the top of the foundation mat to the refueling floor level. The minimum thickness of reinforced-concrete walls is 1 ft. From the refueling level to the top of the roof, the exterior walls are framed with structural steel and are enclosed with insulated metal wall panels. The reactor building is separated from

other plant buildings by 3-hr fire rated reinforced-concrete walls and nonrated steel airtight doors. The building roof is a Factory Mutual Class I insulated steel roof deck.

Within the reactor building, Class 1E motor control centers are enclosed to provide separation from the general area hazards. Partial height concrete walls on the 471 ft, 501 ft, and 522 ft el. protect four Division 2 instrument racks. Fire barriers with nonrated watertight steel doors separate the safety-related pump rooms below grade.

Primary containment is inerted during operation. There is no permanently installed fire protection equipment inside containment. Portable extinguishers and manual hoses are available for fire suppression when containment is deinerted for maintenance during plant outages.

The annular gap constructed between the metal shell and the primary containment vessel and the concrete biological shield wall, above 446 ft, is filled with a compressible insulating spacer system consisting of polyurethane flexible foam sheets butted at the joints and cemented directly to the primary containment shell, a jacket of premolded fiberglass reinforced polyester jacket panels, and epoxy flashing. The foam spacer is in a confined space, exposed to a minimal quantity of air through clearance around pipe penetrations. There is adequate spatial separation from the foam to the nearest combustible (electrical cable insulation) to reduce the possibility of a fire spreading into the foam liner. Mechanical penetrations within a 20-ft surface radius of Appendix R protected containment penetrations in Division 1 fire areas are 3-hr fire rated to ensure the combustible spacer/liner material does not ignite. Other containment mechanical penetrations have nonrated radiant energy Kaowool seals. Fire spread in the annular gap would be very slow due to the limited space and oxygen deficient atmosphere. The metal vessel liner and the concrete bioshield wall would act as large heat sinks and further slow fire propagation. The use of Kaowool seals was approved by Reference F.7.4.1.

Stairs and elevator shafts in the reactor building are constructed of noncombustible reinforced concrete. Air locks are constructed of reinforced concrete with steel airtight doors.

F.2.2.6 Radwaste/Control Building

The vital island section of the building consists of reinforced-concrete walls, floors, and ceilings from the top of the foundation mat up to and including the roof slab. The radwaste sections of the building are constructed of reinforced-concrete walls, floors, and ceilings at the lower levels and structural steel framing with reinforced-concrete floors and enclosure walls on insulated metal wall panels at the upper levels. The building roof is Factory Mutual Class I insulated steel roof deck.

The main control room walls are 3-hr rated reinforced concrete.

The main control room contains steel enclosed power generation control complex (PGCC) units which are divisionally separated. Each unit consists of a 1 ft false floor assembly, a vertical panel and/or benchboard panel, and a termination cabinet. All cables entering through the floor cable penetrations are sealed. The cables enter either directly into the false floor assembly to the control panels and terminate there or into an enclosed steel trough which extends to the termination cabinets. The remaining cables penetrating the control room floor behind the termination cabinets are compatible divisional cables routed in flexible metal conduit. Penetrations into the back of the panel assembly are fire stopped or sealed.

The remote shutdown room, the vital switchgear rooms and battery rooms, the reactor protection system rooms, and their respective mechanical equipment rooms are divisionally separated by 3-hr rated enclosures.

Stairs constructed of noncombustible material are enclosed in 2-hr minimum fire rated walls. The elevator is enclosed in a reinforced-concrete shaft.

From grade level 441 ft to 460 ft, the west wall facing the alternate health physics building is 3-hr rated.

F.2.2.7 Turbine Generator Building

The turbine building is separated from all other areas of the plant by noncombustible reinforced masonry block and/or concrete construction with hollow metal or steel doors. The building roof is a Factory Mutual Class I insulated steel roof deck.

The exterior walls of the turbine building are reinforced concrete or structural steel covered by insulated metal panels. Within the area, reinforced-concrete walls contain the turbine, feedwater heaters, and condenser. At the operating floor level, the reinforced-concrete walls isolating the turbine continue for a height of 23 ft 6 in. From the top of this wall, the structure changes to structural steel covered with insulated metal panels up to the roof level. A section of the exterior north wall is also structural steel covered with insulated metal panels. Equipment access areas at the grade, mezzanine, and operating levels are contained with reinforced-concrete masonry units and insulated metal panels.

Rated fire barriers are provided to isolate high hazard areas:

a. The turbine generator lube oil conditioning system room (containing reservoir, separator, transfer pump, etc.) is located within 3-hr fire rated reinforced-concrete and masonry block walls. The oil cooler heads are open to the 501 ft floor level but is protected by deluge system 55;

b. The turbine generator lube oil storage tanks are located within 3-hr fire rated reinforced-concrete and masonry block walls and fire doors;

c. The auxiliary boiler room is separated from adjacent areas by 3-hr fire rated reinforced-concrete and masonry block walls;

d. The hydrogen seal oil room is separated from adjacent areas by 3-hr fire rated reinforced-concrete and masonry block walls;

e. The makeup water pump house transformer vaults are separated from adjacent areas by 3-hr fire rated reinforced-concrete and masonry block walls;

f. See Figures F.6-1 and F.6-2 for turbine building north wall facing transformer yard fire rating; and

g. From grade level 441 ft to 501 ft, the west wall facing the adjustable speed drive (ASD) building (Column D.3-H) is 3-hr fire rated.

Stairs of noncombustible material are enclosed in walls of 2-hr minimum rated construction. The elevator is enclosed in a reinforced-concrete shaft.

F.2.2.8 Diesel Generator Building

Exterior walls, floors, and ceilings are reinforced concrete of varying thicknesses from the top of the foundation mat to the roof. The building is divided into separate compartments by reinforced-concrete walls. The walls separating the diesel compartments and the walls separating the diesel generator building from adjacent plant buildings are 3-hr fire rated. The exterior walls of the building are nonrated.

F.2.2.9 Standby Service Water Pump Houses No. 1A and 1B

Exterior walls and roof are of nonrated reinforced-concrete construction. Floors are metal grating or reinforced concrete.

F.2.2.10 Service Building

The service building is separated from the turbine building and the reactor building by 3-hr rated reinforced-concrete walls.

F.2.2.11 Circulating Water Pump House and Chlorination Building

The building has a reinforced-concrete floor, insulated metal wall panels, and a metal roof deck over structural steel framing. The circulating water pump house and the chlorination sections of the building are separated by a reinforced-concrete masonry wall. The diesel fire pump fuel storage tank room is isolated by 3-hr rated walls.

F.2.2.12 Cooling Towers

The cooling towers are of noncombustible construction (except for fan shrouds, fan blades, fill material, and drift eliminators).

F.2.2.13 Water Filtration Building 33

The building has a reinforced-concrete floor, insulated metal wall panels, and metal roof deck over structural steel framing. All barriers are nonrated.

F.2.2.14 North Yard Transformers

The yard transformers are separated from the turbine building by 2-hr rated barriers and spatial separation. The transformers are not separated by fire barriers.

F.2.2.15 Technical Support Center

The technical support center is separated from the radwaste building by 3-hr rated barriers.

F.2.2.16 Alternate Health Physics Building

The alternate health physics building is separated from the radwaste building and turbine building by 3-hr rated barriers.

F.2.2.17 Reactor Recirculation Pump Adjustable Speed Drive Building

The reactor recirculation (RRC) pump ASD building has a reinforced-concrete floor, insulated wall panels, and a metal roof deck over structural steel framing. The building walls on the west and north side are 2-hr rated. The adjacent turbine building wall is 3-hr rated. The concrete barriers separating and to the north of the ASD transformers are 2-hr fire rated.

F.2.3 FIRE DETECTION AND ALARM SYSTEMS

The fire detection and alarm systems are designed to rapidly identify developing fire conditions. Signals from plant fire detection instruments and fire suppression system alarms are transmitted via a proprietary fire alarm system to a fire alarm panel in the main control room.

Standard and functional zone annunciation indicator lights are located on the fire control panel in the main control room. Standard zone annunciation results from the installed fire detection instruments. Functional zone annunciation derives from the activation of individual devices such as deluge system flow devices, wet pipe sprinkler system flow devices, preaction system

flow devices and low pressure sensors, carbon dioxide flow devices, and fire pump status. Most systems have individual bells on the fire control panel sound automatically whenever their associated alarm devices are activated. There are no devices to automatically record incoming signals to the main control room. See Table F.2-1 for alternate recording methods.

Ionization, photoelectric, air duct ionization, thermal, or ultraviolet fire detectors are installed in hazard areas of the plant. Smoke detectors are generally installed in areas containing moderate amounts of combustibles with no large combustible oil or gas hazards. Ionization detectors are not located in areas where the background radiation exceeds the manufacturer's rating. The sensitivity of thermal detectors is based on the normal average air temperature in the area where they are located.

Manual fire alarm pull stations are generally located near exterior doorways and at each elevation of the main plant buildings in close proximity to the stairwells. Manual fire alarms are wired with other detection and alarm devices in appropriate fire detection zones.

Standard and functional alarms in the main control room do not initiate a plant-wide alarm signal. Depending on the fire condition, voice announcements over the public address system or emergency evacuation alarms may be used to warn plant personnel. A manual push button in the control room initiates a coded fire alarm radio signal to the DOE fire department dispatch center.

The fire protection system wiring for alarm initiation, alarm signaling, and control room annunciation at the fire control panel is electrically supervised to prevent false fire alarms due to open or grounded wiring. The supervisory circuitry sounds a trouble alarm using a single buzzer on the fire control panel on detection of open circuits, short circuits, closed valves, low water pressure, low air pressure, or other trouble condition.

Fire detection systems which actuate suppression systems in safety-related areas have Class A circuitry (as defined in NFPA 72D - 1975). Other fire detection system wiring is Class B.

The plant fire detection system is powered from a local power panel which is normally supplied from uninterruptible power. Backup power is supplied from onsite emergency diesel generators.

The fire control panel mounted in the main control room is designated Seismic Category I; all panel mounted equipment in this room is designated Sèismic Category II. Other fire detection equipment, components, and accessories are designated Seismic Category II.

Portable detection systems may be used as a backup to fixed plant fire detection systems or as additional compensatory measures.

The fire detection system is designed in accordance with the guidelines of NFPA 72D - 1975 and NFPA 72E - 1974. Differences between the installed plant configuration and the NFPA code sections are documented in Table F.2-1. Reference F.7.4.f approved deletion of fire detection in various plant areas.

F.2.4 FIRE SUPPRESSION SYSTEMS

Automatic and manual suppression systems and manual fire fighting equipment are located within the plant as described below. The type of fire suppression provided for a particular plant area is based on consideration of the nature of the fire hazard in the area, the type of equipment protected, and the physical arrangement of the area. Fixed automatic suppression systems are installed to protect areas or equipment containing large quantities of combustibles, oils, or gases. Reference F.7.4.c approved the lack of fire suppression in various plant areas. Plant areas with fire suppression coverage and type of suppressant are shown in Figures F.6-7 through F.6-11.

The fire protection system is designed such that inadvertent operation or failure of any component of the system will not impair the ability of engineered safety features to safely shut down or isolate the reactor, or to limit the release of radioactivity to the environment in the event of an accident.

Fire protection system piping in Seismic Category I areas of the reactor building, the diesel generator building, the radwaste control building, and the reactor/radwaste corridors, required to be seismically supported/mounted, are designed to Seismic Category IM and Quality Assurance Class II+. Fire protection system piping not required to be seismically supported/mounted are designed to Seismic Category II and Quality Assurance Class II.

F.2.4.1 Fire Protection Water Supplies

The fire protection water supply system consists of a primary fire water supply, a secondary fire water supply, and yard mains to distribute water to the yard hydrant isolation valves and building standpipes. The fire protection water supply system is shown schematically in Reference F.7.7.1.

The primary fire protection water supply consists of three fire pumps: two electric (FP-P-2A and FP-P-2B) and one diesel driven (FP-P-1), each of which have a design capacity of 2000 gpm at a total dynamic head of 289 ft. The primary fire pump discharge lines are piped so that each electric motor-driven pump discharges to the underground fire main loop.

Each of the three primary fire pumps is furnished with an automatic air release valve. In addition, the primary diesel-driven pump is furnished with a pressure relief valve and an open discharge cone back to the circulating water basin. Each electric motor-driven pump is furnished with a circulation relief valve. Three 10-in. fire protection branch lines have been

provided (one for each fire pump) to a flow element, six-headed test header for fire pump testing. Fire protection water to the plant underground fire protection loop is supplied by two 12-in. fire protection main feed lines from the fire pump discharge.

The secondary water supply is drawn from a 400,000-gal embankment supported bladder tank (FP-TK-110) with a dedicated water supply of 284,640 gal. The water supply is delivered to the fire main loop by diesel-driven fire pump (FP-P-110) located in the water filtration building. The diesel fire pump is rated at 2500 gpm at a total dynamic head of 323 ft. The secondary water supply connects to the fire loop through a 12-in. branch line.

During maintenance drawdown of the circulating water basin, the fire loop system pressure is maintained between 115 psig and 125 psig by a pressure maintenance jockey pump (FP-P-111) also located in the water filtration building.

The primary water supply jockey pump (FP-P-3) is normally running to maintain closed system pressure. Pressure control valves installed on the jockey pump discharge limit system pressure to below 175 psig. A drop in system pressure below 120 psig will cause the first motor-driven fire pump to automatically start. The second motor-driven pump will start if pressure drops to 110 psi. The start of the primary diesel-driven pump is controlled by a drop in pressure to 110 psi and a time delay relay. The sequential starting of the secondary diesel-driven fire pump is controlled by a drop in pressure to 100 psi. One or multiple pumps will start if the first motor-driven pump cannot maintain system pressure.

The capacity of the fire water pumps is based on a maximum probable water system demand (1872 gpm in the cable spreading room), 500 gpm for a hose stream, and standby pump capacity available. Each motor-driven fire pump controller and each diesel-driven fire pump controller contains automatic start controls and manual start/stop controls. Any fire pump can be started either locally or from the main control room. After a start, a fire pump can be stopped only locally at the pump controller. Fire pump start, failure to start, and loss of current to the motor-driven pumps is indicated in the control room. Diesel-driven fire pump alarms include fire pump start, fire pump failure to start, high jacket water temperature, low oil pressure, and engine overspeed.

In the event of electrical power failure to a diesel-driven fire pump controller, the associated diesel-driven fire pump will start automatically. Both motor-driven fire pumps are inoperative during loss of offsite power.

Since either water supply can provide the necessary water demand and the circulating water basin is not considered a tank, the primary and secondary water supplies need not be interconnected.

A 1.5-in. line takes water from the discharge side of the fire protection jockey pump (FP-P-3) to provide an emergency source of pump bearing lubricating water to the plant service water

pumps (TSW). The design of the backup bearing lubricating line limits the fire protection water flow rate to approximately 20 gpm. Under normal conditions, a pressure regulating valve ensures that no water comes from the fire protection system. A sight glass is provided for verification.

Fire protection water is distributed through a 12-in. underground fire main to supply station hydrants, fire hose stations, and suppression systems. The looped arrangement of the fire protection system ensures continued flow to the remainder of the system when sections of the system are isolated for tests or repairs. Post indicator valves sectionalize the yard loop to increase the reliability of fire protection water supply in case of a fire main break.

A series of 12-in. and one 8-in. branch lines lead from the underground fire main loop to various building standpipes. Each line contains an outside post indicator isolation valve. See Reference F.7.7.1 for more detail.

A fire main is routed under the diesel generator building. This was approved according to Reference F.7.4.k.

A connection from the drain valve outlet from standpipe TGB-4 provides the capability to connect a hose to provide emergency cooling to the control and service air compressors in the event both TSW pumps or both compressor cooling loop pumps are out of service.

Leakage in the fire protection underground is monitored by a flow totalizer on the bypass line of the detector check valve on the discharge line of the jockey pump in the circulating water pump house. Serious leaks or a rupture of the fire protection system piping could also be indicated by fire pump running alarms in the main control room with no concurrent fixed automatic or preaction fire protection system operating alarms, no detector fire alarms, and no report of any fire or use of fire hose.

The location of a fire main leak may be determined by visual observation. If no visual indications are present, the location of the leak could be determined by using the sectionalizing valves to isolate a section of the system and observing the flow meter gauge on the detector check valve. The leak would be indicated by a decrease in flow as the section is isolated.

The fire pump installation is designed in accordance with the guidelines of NFPA 20 - 1975. Differences between the fire pump installation and the NFPA code sections are listed in Table F.2-1. The installation of the underground fire main is designed in accordance with the guidelines of NFPA 24 - 1973. Differences between the underground fire main installation and the NFPA code sections are listed in Table F.2-1.

F.2.4.2 Wet Pipe Sprinkler Systems

Wet pipe sprinkler systems are installed to provide automatic fire suppression of general area hazards. Wet pipe sprinklers consist of closed sprinklers attached to piping which contains water under pressure at all times. System operation is initiated when the local temperature rise from a fire reaches the operating temperature of fusible link sprinkler heads. Water discharge allows the hinged clapper in the alarm check valve to open. Valve operation provides remote alarm/indication in the main control room.

Temperature ratings for automatic sprinkler heads are selected based on normal area temperatures and proximity to heat generating components.

Sprinkler system piping may be designed using pipe schedules or hydraulically calculated to provide a minimum design density according to the nature of the hazard protected. See Figures F.6-7 through F.6-11 for locations of wet pipe sprinkler systems.

The wet pipe sprinkler system installation in the main control room is designed in accordance with the guidelines of NFPA 13 - 1975. This is the only wet pipe sprinkler system which protects a safety-related area. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.4.3 Preaction Sprinkler Systems

Preaction systems are used in areas where inadvertent operation of the sprinklers could damage or cause outages of vital electrical equipment. Preaction systems are installed in the cable spreading room and cable chase in the radwaste building, the reactor/radwaste corridor, the diesel generator building, and the RRC pump ASD building.

The preaction systems have closed fusible link sprinkler heads. Downstream of the control valve, the preaction sprinkler piping is normally dry and pressurized with air to supervise piping system integrity. Low air system pressure, which could indicate damaged piping or sprinkler heads, is alarmed in the control room. Fire detectors located in the protected area activate a solenoid valve to open the deluge valve, supplying water to fill and pressurize the sprinkler system piping. Pull stations are also provided to allow manual operation of the preaction system. Sprinkler flow is not initiated until the local temperature increases to the operating temperature of the closed fusible link sprinkler heads.

In the cable spreading room, cable chase, ASD building, and reactor/radwaste corridor ionization detectors are used to trip the preaction system. The diesel generator preaction systems are actuated by thermal detectors. Detector operation and preaction system flow devices alarm in the main control room.

The preaction sprinkler systems installed in safety-related areas are designed in accordance with the guidelines of NFPA 15 - 1975. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.4.4 Deluge Water Spray Systems

Deluge water spray systems are used where fast response may be required to control or extinguish a fire. A deluge system employs open nozzles attached to a normally dry piping system. Fire detectors located in the hazard area activate a solenoid valve to open the deluge valve and initiate water flow. Electric heat actuating devices (HAD) indicate fire conditions by sensing an abnormally high temperature or an unusually rapid rise in temperature. Detector operation and deluge system waterflow devices alarm in the main control room.

Deluge water spray systems provide automatic fire protection for various locations in the turbine generator building where oil is stored or piped, for yard transformers, and for the reactor feed pump rooms in the turbine generator building. Spray nozzles near the transformer bushings are carefully placed to avoid flashovers at the bushings or to the piping.

Manually actuated deluge water spray systems are installed to protect charcoal filters in certain HVAC filter units. High temperature signals are used to alarm control room operators to potential fire conditions.

Deluge water spray systems installed in safety-related plant areas are designed in accordance with the guidelines of NFPA 13 - 1975 and NFPA 15 - 1973. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.4.5 Carbon Dioxide Fire Suppression Systems

The low pressure carbon dioxide system automatically provides fire protection for the turbine generator exciter housing. A 1-in. manual carbon dioxide hose station, with reel and 100 ft of hose, is also provided for exciter housing protection on the turbine operating floor (501 ft). The carbon dioxide storage tank also provides carbon dioxide for generator purging during startup and shutdown conditions. The capacity of the carbon dioxide unit is 6 tons. Interlocks are provided such that the generator purge system cannot draw down tank level below that needed for automatic fire protection of the exciter housing.

The carbon dioxide unit is located in the northwest corner of the 441 ft level of the turbine generator building. The low pressure carbon dioxide storage tank maintains liquid carbon dioxide at approximately 300 psig and 0°F by refrigeration. The refrigeration is accomplished by a compressor and refrigeration coil within the vessel. The carbon dioxide storage unit is electrically powered and automatically controlled and monitored by means of pressure switches. High or low carbon dioxide pressure causes a remote alarm and indication in the main control room.

Thermal detectors located in the generator exciter housing provide early warning alarm in the main control room allowing the operator to review and evaluate the problem prior to manual or automatic actuation of the system. Automatic operation of the carbon dioxide system is initiated when the temperature increases to the setpoint of the high temperature detector. However, if a fire is noticed before the temperature detector actuates the system, the system can be manually actuated by a break glass station located near the carbon dioxide protected area. An automatic timer regulates the carbon dioxide discharge for both automatic and manual electric operation to provide even distribution of the discharge.

Actuation of the system alarms locally and remotely in the main control room. The local alarms consist of two separate alarm devices located near the protected area. One device sounds 20 sec before its associated carbon dioxide system is released and the other device sounds continuously during the duration of such release.

The carbon dioxide system is designed in accordance with the guidelines of NFPA 12 - 1973. The carbon dioxide distribution system is shown schematically in Reference F.7.7.n.

F.2.4.6 Halon 1301 Fire Suppression Systems

Halon 1301 suppression systems are installed in normally occupied areas where the application of water would be inappropriate. Halon 1301 provides automatic fire protection for the main control room PGCC under floor areas.

Eighteen Halon 1301 systems are installed in the various main control room PGCC subfloor duct sections to discharge on activation of their associated thermal detector units. Each system is sized to provide a 20% Halon concentration for a minimum duration of 20 minutes. Cable penetrations into the PGCC are sealed to contain Halon discharge. Thermal detector operation also causes a local alarm and indication on the main control room fire control panel. Ionization detectors are located in each PGCC section to provide early warning alarm. Each system includes supervision features which actuate a trouble alarm and indication on the main control room fire control panel in case of a wiring or component failure.

The PGCC Halon suppression system is designed in accordance with the guidelines of NFPA 12A - 1973 and Reference F.7.5.j. See Section 8.3.1.4.3.6.2 and Figure 8.3-36 for more detail. The Halon system was approved according to Reference F.7.4.a.

F.2.4.7 Dry Chemical Fire Suppression Systems

Dry chemical suppression systems may be found installed in approved portable hazardous material storage buildings within the plant. These systems automatically actuate by melting of the fusible link(s) or manually by a local pull station. WNP-2 is not committed to NFPA 17 compliance.

F.2.5 MANUAL FIRE FIGHTING EQUIPMENT

Manual fire fighting equipment includes protective clothing, SCBA, fire hydrants, standpipe and fire hose stations, AFFF foam carts, portable fire extinguishers, and smoke removal equipment.

F.2.5.1 Protective Clothing and Self-Contained Breathing Apparatus

Protective clothing and SCBAs are provided in designated locations for use by the plant fire brigade. The SCBA positive pressure masks are National Institute for Occupational Safety and Health (NIOSH) approved. At least a 1-hr supply of breathing air in extra bottles is located onsite for each required SCBA. See Table F.3-2 III.2.H for more details.

F.2.5.2 Yard Fire Hydrants

Fire hydrants are provided at approximately 300 ft intervals along the fire main loop around the main plant buildings and at each standby service water pump house. Hydrant hose houses containing approximately 200 ft of 2.5-in. hose and accessories are located adjacent to each hydrant. Fire hydrants adjacent to the transformers and the diesel generator building are strategically located as backup protection in the event of a large scale fire in these areas. Fire mains and hydrants are designed in accordance with NFPA 24 - 1973. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.5.3 Standpipes, Hose, and Foam Carts

Standpipe and hose connections provide a second line of defense for fires which may get beyond the extinguishing capabilities of hand fire extinguishers. Standpipes and hose racks are installed so that all safety-related areas are within 30 ft of the nozzle when 100 ft of 1.5-in. hose is attached to the connection. The reactor building has 150 ft of 1.5-in. hose to reach all areas as approved in Reference F.7.4.d. Most standpipes are located in protected stairways. Each standpipe contains an isolation valve, hose racks on each landing, takeoffs to sprinkler or other water fire protection systems where applicable, and a pressure gauge at the top of each standpipe. To ensure the availability of primary and secondary fire protection, the following standpipes have been interconnected: TGB-1 and TGB-2; TGB-3, TGB-5, and RWB-1; and DG-1 and the 12-in. branch line to RWB-1. Hose station locations are shown on Figures F.6-7 through F.6-11. Where large combustible liquid fire hazards exist, AFFF foam eductors/carts are present. Standpipes and hose are designed in accordance with NFPA 14 - 1974. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.5.4 Portable Extinguishers

Portable extinguishers are strategically located within the plant to provide plant personnel with a readily available means to extinguish a fire in its early stages. Halon 1211, dry chemical, and wheeled dry chemical extinguishers are used. Portable fire extinguishers are installed in accordance with NFPA 10 - 1975 based on the class and quantity of combustibles in that location.

F.2.5.5 Smoke Removal

Portable fans are available for smoke removal. Fixed smoke removal fans consist of WEA-FN-52 which purges the cable spreading room, cable chase, and remote shutdown room. WEA-FN-7 is located on the radwaste building 507-ft roof and is used primarily for purging the main control room. Large portable fan REA-FN-16 can be connected to the reactor building HVAC exhaust at 471 ft and 572 ft. See Section 6.4 for control room actions and habitability during onsite and offsite fires. Smoke purging activities include monitoring to prevent an uncontrolled release.

F.2.6 OPERATOR ACTION EQUIPMENT

Equipment for credited operator actions consists of emergency lighting and communication equipment.

F.2.6.1 Emergency Lighting

Fire protection credited emergency lighting falls into two categories: (a) 1.5-hr life safety and (b) 8-hr Appendix R. See Section 9.5.3 for more detail.

F.2.6.2 Emergency Communications

Fire protection credited communication equipment falls into two categories: (a) sound powered phone system and (b) two-way hand held radios. See Section 9.5.2 for more detail.

F.2.7 INSPECTION AND TESTING

The fire protection system and equipment is tested periodically in accordance with the requirements of Section F.5, NFPA, or insurer requirements. Periodic testing is performed within the specified intervals with a maximum allowable extension not to exceed 25% of the interval. Periodic tests need not be performed on inoperable equipment. Testing which would require entry into high radiation areas is performed when radiation levels allow. However, there are some areas of WNP-2 that remain high radiation areas at all times which will require an ALARA evaluation to determine the respective testing interval.

Inspections of the fire pump diesel engines will be conducted periodically in accordance with plant procedures prepared in conjunction with the manufacturer's recommendations.

TABLE F.2-1

CODE DEVIATIONS

CODE SECTION		POSITION	
	NFPA 13-1975		
3-9.3	Protection of Piping Against Damage Where Subject to Earthquakes	3-9.3	Protection of Piping Against Damage Where Subject to Earthquakes
3-9.3.3	Sleeves shall be provided around all piping extending through the walls, floors, platforms, and foundations. (a) Minimum clearance between the pipe and sleeve shall not be less than 1 in. for pipes 1 in. through 3.5 in. and 2 in. for pipe sizes 4 in. and larger. (b) The clearance between pipe and sleeve shall be filled with noncombustible flexible material such as mineral wool, fiberglass, or equivalent.	3-9.3.3	No design limitations exist to ensure annular gap is greater than 1 or 2 in. Where piping penetrates a fire-rated barrier, penetration seals are installed in which the seal design accounts for pipe movement. Piping in safety-related areas is seismically qualified.
3-11	Joining of Pipes and Fittings	3-11	Joining of Pipes and Fittings
3-11.2.2	Sections of welded piping shall be joined by means of screwed flanged or flexible gasketed joints or other approved fittings.	3-11.2.2	The control room sprinkler system as installed used other design criteria (seismic and flooding concerns) which required welding as the method of installation.
3-13	Valves	3-13	Valves
3-13.2.3	Valves controlling sprinkler systems, except underground gate valves with roadway boxes, shall be supervised open by one of the following methods: (a) Central station, proprietary or remote station alarm service, (b) Local alarm service which will cause the sounding of an audible alarm at a constantly attended point, (c) Locking valves open, (d) Sealing of valves and approved weekly recorded inspection when valves are located within fenced enclosures under the control of the owner.	3-13.2.3	Control valves are locked or sealed open and inspected quarterly.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
3-14	Hangers	3-14	Hangers
3-14.1.5	The components of hanger assemblies which attach directly to building structure, except for mild steel hangers formed from rod, shall be listed.	3-14.1.5	Not all hangers are listed. For hangers with special seismic requirements the hanger design is certified by a registered professional engineer in accordance with Section 3-14.1.2.
4-4	Locations or Conditions Involving Special Consideration	4-4	Locations or Conditions Involving Special Consideration
4-4.20	Small Rooms. In small rooms such as rest rooms, toilets, closets, and offices with smooth ceilings, sprinklers may be located a maximum distance of 7 ft 6 in. from any two walls of this room providing the total area of the room divided by the number of sprinklers does not exceed the limitation of 4-2.2.1 and 4-2.2.2. The maximum area of such a room is defined as 800 ft^2 for Light Hazard and 520 ft^2 for Ordinary Hazard occupancies.	4-4.20	Small Rooms. Sprinkler heads are located a maximum distance of 7 ft 6 in. from two walls as required by code. In the control room shift manager's office, there are two sprinklers in an area of approximately 250 ft^2. Later revisions of this code (1985) allow sprinkler heads in small rooms to be located up to 9 ft from one wall. The exception has been used in this room. The sprinklers are below the maximum spacing of 130 ft^2 for ordinary hazard occupancy.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
	NFPA 14-1974		
CHAPTER 3 - NUMBER AND LOCATION OF STANDPIPES		CHAPTER 3 - NUMBER AND LOCATION OF STANDPIPES	
32	Number of Standpipes	32	Number of Standpipes
321	The number of hose stations for Class I and Class III services in each building and in each section of a building divided by fire walls shall be such that all portions of each story of the building are within 30 ft of a nozzle attached to not more than 100 ft of hose.	321	The reactor building requires 150 ft long hoses to reach all areas. This was approved per Reference F.7.4.d. The radwaste building room C405 requires 200 ft of hose. This is not a safety-related area of the plant.
CHAPTER 4 - HOSE OUTLETS		CHAPTER 4 - HOSE OUTLETS	
41	Location of Hose	41	Location of Hose
412	Hose outlets for Class I service should be located in a stairway enclosure, and for Class II service in the corridor or space adjacent to the stairway enclosure and connected through the wall to the standpipe. For Class III service, the outlets for large hose should be located in a stairway enclosure, and for small hose located in the corridor or space adjacent to the stairway enclosure.	412	Hose stations are installed for Class III service. Building standpipes were originally provided with large hose outlets located in the stairways.. Fire tactics have changed to prefer smaller hose lines for plant fire suppression activities. Smaller hose lines are currently provided.
413	Valves of approved indicating type shall be provided at the main riser for controlling branch lines to hose outlets so that in the event that the branch is broken during the fire, the fire department may shut off this branch, conserving the water for their use.	413	Valves are not provided at the branch lines to hose outlets at the main risers. The standpipe system is welded to increase its reliability under normal and fire conditions.
44	Hose Valves	44	Hose Valves
442	Where the static pressure at any standpipe outlet exceeds 100 lb/in.^{2}, an approved device shall be installed at the outlet to reduce the pressure with required flow at the outlet to 100 lb/in.^{2}	442	At certain hose stations, the static pressure at the hose outlet could exceed 100 psi. Hose stations are provided for use only by the plant fire brigade. The fire brigade is hands-on trained and drilled on the use of high pressure hose lines. Pressure reducing valves are not required.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
	NFPA 15-1973		
CHAPTER 2 - SYSTEM COMPONENTS		CHAPTER 2 - SYSTEM COMPONENTS	
2030	Spray Nozzles	2030	Spray Nozzles
2031	Care shall be taken in the application of nozzle types. Distance of "throw" or location of nozzle from surface shall be limited by the nozzle's discharge characteristics (see 4070). Care shall also be taken in the selection of nozzles to obtain waterways which are not easily obstructed by debris, sediment, sand, etc., in the water. Requirements for strainers and their placement are described in 2110 and 4110.	2031	Nozzles were selected based on protection requirements. Strainers are not provided for all small orifice nozzle systems.
2040	Piping	2040	Piping
2042	Galvanized pipe shall be used except that; where corrosion of galvanized pipe may be caused by corrosive atmospheres or the water, or by additives to the water, other suitable coatings shall be provided.	2042	Exterior surface of piping is galvanized.
2050	Fittings	2050	Fittings
2052	Rubber gasketed fittings subject to direct fire exposure are generally not suitable. Where necessary for piping flexibility, or for locations subject to earthquake, explosion, or similar hazards, such installations are acceptable. In such cases, special hanging or bracing may be necessary.	2052	Rubber gaskets are used for flange connections at preaction system valves in the area protected by the preaction system. The remainder of the piping joints are threaded connections. Pipe supports for these preaction systems are designed and installed to Seismic Category I requirements.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
CHAPTER 4 - SYSTEM DESIGN AND INSTALLATION		CHAPTER 4 - SYSTEM DESIGN AND INSTALLATION	
4020	Design Guides	4020	Design Guides
4021	Water spray systems shall conform to the applicable requirements of the following Standards of the National Fire Protection Association, except where otherwise specified herein: - Installation of Sprinkler Systems (NFPA No 13 - 1973) - Installation of Standpipe and Hose Systems (NFPA 14 - 1973) - Wetting Agents (NFPA 18 - 1973) - Installation of Centrifugal Fire Pump (NFPA 20 - 1972) - Water Tanks for Private Fire Protection (NFPA 22 - 1971) - Outside Protection (NFPA 24 - 1973) - Supervision of Valves (NFPA 26 - 1958) - National Electric Code (NFPA 70 - 1971) - Central Station Protective Signaling Systems (NFPA 71 - 1972) - Local Protective Signaling Systems (NFPA 72A - 1972) - Auxiliary Protective Signaling Systems (NFPA 72B - 1972) - Remote Station Protective Signaling Systems (NFPA 72C - 1972) - Proprietary Protective Signaling Systems (NFPA 72D - 1973) - Protection from Exposure Fires (NFPA 80A - 1970) - Indoor General Storage (NFPA 231C - 1972) - Rack Storage of Materials (NFPA 231C - 1973) Note: Components of the electrical portions of these protective systems, where installed in locations subject to hazardous vapors or dusts, shall be of types approved for use therein.	4021	The design of the systems has been reviewed by the authority having jurisdiction and approved for insurance purposes. WNP-2 is not committed to meet all of the specified NFPA codes.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
4030	Density and Application	4030	Density and Application
4032	(b) Nozzles shall be installed to impinge on the areas of the source of the fire, and where spills may travel or accumulate. The water application rate on the provable surface of the spill shall be at the rate of not less than 0.50 gpm/ft^2.	4032	(b) A water spray density of 0.30 gpm/ft^2 is provided in areas of potential spill in the diesel generator rooms. The diesel fuel piping and storage tanks are welded, Seismic Category I systems; thus a line break and resulting fuel spill are unlikely. The day tanks are in separate rooms which have an average density of approximately 0.90 gpm/ft^2.
4052	Area Drainage	4052	Area Drainage
	(a) Adequate provisions shall be made to promptly and effectively dispose of all liquids from the fire area during operation of all systems in the fire area. Such provisions shall be adequate for: (1) Water discharged from fixed fire protection systems at maximum flow (2) Water likely to be discharged by hose streams (3) Surface water (4) Cooling water normally discharged to the system		(a) The RRC ASD transformer sumps are not sized to contain the total contents of 10 minutes of deluge actuation, manual hose stream, and the contents of the transformer oil. The ASD transformers are not safety related. Fire-rated barriers separate the two transformers, the transformers from the ASD building, and the transformers from the turbine building. The grade slopes away from the transformers to a yard french drain.
4063	Drain Valves. Readily accessible drains shall be provided for low points in underground and aboveground piping.	4063	Drains are provided; however, not all drains are readily accessible.
4100	Hangers	4100	Hangers
4101	System piping shall be adequately supported. All supports in the fire area should be protected by the system. In any area where possibility of explosion may be recognized, special care shall be taken to support the piping from portions of the structure least liable to disruption.	4101	Not all supports are protected by the spray patterns. Failure of unprotected supports is unlikely as the systems are supported to Seismic Category IM requirements.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
4110	Strainers	4110	Strainers
4111	Main pipeline cleaners shall be provided for all systems using nozzles with waterways less than 3/8 in. and for any system where the water is likely to contain obstructive material.	4111	The manually actuated deluge systems which protect the SGTs and control room HVAC charcoal filter units have nozzles less than 3/8 in. but are not provided with strainers. These interior systems are periodically tested with air to verify the nozzles are not obstructed.
CHAPTER 8 - AUTOMATIC DETECTION EQUIPMENT		CHAPTER 8 - AUTOMATIC FIRE DETECTORS	
8050	RESPONSE TIME	8050	RESPONSE TIME
8051	The heat detection system shall be designed to cause actuation of the special system water control valve within 20 sec under expected fire conditions. Under test conditions when exposed to a standard heart source, the system shall operate within 40 sec. These are to be considered as maximum response times subject to the considerations described in 8011 and 8031.	8051	Response time of detectors is not checked by plant procedures. Detectors are checked for operation only. The heat detection system does not have any artificial delays that would prevent the immediate activation of the system. Later editions of this code have removed the time limit and replaced it with this intent only.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
	NFPA 20-1974		
CHAPTER 2 - GENERAL		CHAPTER 2 - GENERAL	
2-8	Equipment Protection	2-8	Equipment Protection
2-8.6	Floors shall be pitched for adequate draining of escaping water or fuel away from critical equipment such as the pump, driver, controller, fuel tank, etc.	2-8.6	The equipment is installed on concrete pedestals.
2-9	Discharge Pipe and Fittings	2.9	Discharge Pipe and Fittings
2-9.7	Protection of Piping Against Damage Due to Movement	2-9.7	Protection of Piping Against Damage Due to Movement
2-9.7.1	A clearance of not less than 1 in. (25.4 mm) shall be provided around pipes which pass through walls or floors.	2-9.7.1	Not all penetrations are provided with a 1-in. annular clearance. Fire pump discharge piping is designed to Seismic Category II requirements.
CHAPTER 8 - DIESEL ENGINE DRIVE		CHAPTER 8 - DIESEL ENGINE DRIVE	
8-2.6	Storage Battery	8-2.6	Storage Battery
8-2.6.5	Battery Location. Storage batteries shall be substantially supported, secured against displacement, and located where they will not be subject to excessive temperature, vibration, mechanical injury, or flooding with water. They shall be readily accessible for servicing.	8-2.6.5	Battery Location. Batteries are located where they are not subject to excessive temperatures, vibration, mechanical injury, or flooding. Batteries are substantially supported, but are not secured against displacement.
CHAPTER 9 - ENGINE DRIVE CONTROLLERS		CHAPTER 9 - ENGINE DRIVE CONTROLLERS	
9-1.3	Construction	9-1.3	Construction
9-1.3.4	Locked Cabinet. All switches required to keep the controller in the "automatic" position shall be within locked cabinets having break glass panels.	9-1.3.4	Locked Cabinet. Pump controller cabinets are not locked. Controllers are supervised; "non-auto" alarms are monitored in the main control room.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
	NFPA 24-1973		
CHAPTER 3 - VALVES		CHAPTER 3 - VALVES	
36	Identifying and Securing	36	Identifying and Securing
3601	All control valves shall be plainly marked indicating the section or portion controlled. To ensure that valves are kept open, it is essential to provide central station proprietary valve supervisory service and/or to secure the valves in the open position using an acceptable type of seal which must be destroyed before the valve can be closed. Weekly recorded inspections shall be made.	3601	Yard control valves are labeled in accordance with the plant tagging procedures. Valves are locked in position and inspected quarterly.
CHAPTER 5 - HOSE HOUSES AND EQUIPMENT		CHAPTER 5 - HOSE HOUSES AND EQUIPMENT	
52	Location	52	Location
5201	When hose houses are used, they should be located over the hydrant and arranged so that the hydrant will be as close to the front of the house as possible and still allow sufficient room back of the doors for the hose gates and the attached hose.	5201	Hose houses are installed adjacent to the hydrant (as recommended by the 1977 edition of this code).
56	Equipment - General	56	Equipment - General
5601	Depending on local conditions and subject to approval of the authority having jurisdiction, each hose house should be equipped with: 2 - Underwriters' play pipes 1 - pair play pipe brackets 1 - fire axe 1 - fire axe brackets 1 - crowbar 1 - extra hydrant wrench (in addition to wrench on hydrant) 4 - coupling spanners 2 - hose and ladder straps 1 - Underwriter's play pipe holder 2 - 2.5-in. hose washers (spares)	5601	Hydrant hose houses are not equipped with play pipes, axes, crowbars, and hose and ladder straps.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
58	Nozzles	58	Nozzles
5801	Nozzles shall be approved type. <u>Note</u>: Standard play pipes are smooth tapering tubes 30 in. long wound and painted, with 1-1/8 in. smooth bore nozzle. For use of other types of approved nozzles consult the authority having jurisdiction.	5801	Nozzles are FM approved. Smooth bore 1-1/8 in. nozzles are considered to be a safety hazard and are no longer used.
59	Domestic Service Use Prohibited	59	Domestic Service Use Prohibited
5901	The use of hydrants and hose for purposes other than fire or fire drills shall be prohibited.	5901	The use of hydrants for nonfire-related activities is controlled by plant procedures under controlled conditions only.
CHAPTER 8 - UNDERGROUND PIPE AND FITTINGS		CHAPTER 8 - UNDERGROUND PIPE AND FITTINGS	
81	Selection of Pipe	81	Selection of Pipe
8101	Piping shall be approved asbestos cement, cast iron, ductile iron, reinforced concrete, steel, or other approved pipe. Steel pipe shall have minimum thickness of 0.250 in., and be coated and lined. See paragraph 8301 for required coating and lining.	8101	WNP-2 has ductile iron, cast iron, and steel pipe installed in the fire protection underground loop. The ductile and cast iron piping is cement lined per ANSI A21.4. The steel pipe installed in the fire protection underground loop system is not cement lined. Later editions of this code required only that steel pipe be coated (not lined).
83	Coating and Lining	83	Coating and Lining
8301	Where coating or lining or both are required for pipe or fitting, the coating or lining or both shall be approved. Coating and Lining Standards. The following apply to the application of coating and linings:	8301	The exterior of underground fire protection piping is coated with bitumastic enamel and coal tar. See paragraph 8101 above for discussion of interior coating.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
	- American Standard for Cement Mortar Lining for Cast-Iron Pipe and Fittings for Water, ANSI A21.4-1974, AWWA C104-71. - AWWA Standard for Coal-Tar Enamel. Protective Coatings for Steel Water Pipe, AWWA C203-66. - AWWA Standard for Cement-Mortar Protective Lining and Coating for Steel Water Pipe, AWWA C205-71. - AWWA Standard for Cement-Mortar Lining of Water Pipe Lines in Place, Sizes 16 in. and Over, AWWA C602-67.		
CHAPTER 9 - RULES FOR LAYING PIPE		CHAPTER 9 - RULES FOR LAYING PIPE	
91	Depth of Cover	91	Depth of Cover
9101	The depth of cover over water pipes should be determined by the maximum depth of frost penetration in the locality where the pipe is laid, and in those locations where frost is not a factor, the depth of cover shall be not less than 2.5 ft to prevent mechanical injury. Pipe under driveways shall be buried a minimum of 3 ft and under railroad tracks a minimum 4 ft. Recommended depth of cover above the top of underground yard mains is indicated in Figure 91.	9101	Certain piping in the warehouse area does not have the required depth of cover. However, it was verified that the depth of bury is adequate for this locality (Reference F.7.3.w).
93	Protection Against Damage	93	Protection Against Damage
9301	Pipe should not be run under buildings or under heavy piles or iron, coal, etc. Where piping necessarily passes under a building, the foundation walls shall be arched over the pipe. (See paragraph 3502.) [Paragraph 3502 ... It is also recommended that valves be installed to shut off sections of pipe under buildings.]	9301	The routing of a fire main under the diesel generator building was approved by the NRC in Reference F.7.4.k.

TABLE F.2-1

CODE DEVIATIONS (Continued)

	CODE SECTION		POSITION
9302	Where riser is close to building foundations, underground fittings of proper design and type shall be used to avoid pipe joints being located in or under the foundations.	9302	See paragraph 9301 above.
9303	Special care is necessary in running pipes under railroad tracks, under roads carrying heavy trucking, under large piles of iron, under building having heavy machinery liable to fall and under buildings containing hammers or other machinery or having heavy trucking which will subject the buried piping to shock or vibration. Where subject to such breakage, pipes should be run in a covered pipe trench or otherwise be properly guarded.	9303	See paragraph 9301 above.
96	Anchoring Fire Mains	96	Anchoring Fire Mains
9605	Thrust blocks are satisfactory where soil is suitable. Table 9605 gives bearing areas against undisturbed vertical well of a trench in soil equivalent to sand and gravel cemented with clay. For other soils, the values in the table should be multiplied by an appropriate factor.	9605	Thrust blocks were not installed against undisturbed soil. Design drawings specified a minimum area requirement in square feet of thrust block to be in contact with the trench wall. Compression of soil behind the thrust blocks was used to obtain a high density equivalent to undisturbed soil.

TABLE 9605
AREA OF BEARING FACE OF
CONCRETE THRUST BLOCKS

Pipe Size (in.)	1/4 bend (ft^2)	1/8 bend (ft^2)	Tees, Plugs, Caps, Hydrants (ft^2)
4	2	2	2
6	5	3	4
8	8	5	6
10	13	7	9
12	18	10	13
14	25	14	18
16	32	18	23

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
	NFPA 30-1973		
2343	Flammable or combustible liquid storage tanks located inside of buildings shall be provided with an automatic-closing heat actuated valve.	2343	Diesel generator and HPCS day tanks are not equipped with an automatic-closing heat actuated shutoff valve. The day tank rooms are equipped with preaction sprinkler systems and are 3-hr rated. Piping from day tanks to diesels are routed primarily in floor trenches and have substantial construction (Reference F.7.6.h).

TABLE F.2-1

CODE DEVIATIONS (Continued)

NFPA 72D-1975

CODE SECTION	POSITION
CHAPTER 1 - GENERAL	CHAPTER 1 - GENERAL
ARTICLE 120 - SYSTEM FACILITIES	ARTICLE 120 - SYSTEM FACILITIES
1210 System Operation	1210 System Operation
1211 The proprietary system shall be arranged to receive and record all signals received at its central supervising station and to transmit to the fire department, or other location acceptable to the authority having jurisdiction, indication of the building or group of buildings from which an alarm has been received. The transmitting means shall be reliable and use supervised circuits. Where permissible and deemed necessary, the means shall consist of a direct supervised circuit to the fire department or a municipal fire, alarm box, either ordinary or auxiliary type, within 50 ft of the central supervising station.	1211 The system receives but does not automatically record all signals at the fire control panel in the main control room. The circuits are supervised. Fire alarms are manually logged. Logs are retained as plant records. A manual push button on the fire control panel is used to transmit a radio fire alarm for outside fire department assistance.
1212 Recording devices shall be designed and arranged to automatically provide a permanent record of the incoming signal and date and time of receipt.	1212 See paragraph 1211 above.
ARTICLE 210 - WIRING	ARTICLE 210 - WIRING
2110 The installation of wiring and equipment shall be in accordance with Article 760, Fire Protective Signaling Systems of the National Electrical Code, NFPA No. 70 - 1975.	2110 Article 760 of the 1978 edition of the National Electric Code was used for the installation of wiring and equipment for the protective signaling system.
ARTICLE 220 - POWER SUPPLY SOURCES	ARTICLE 220 - POWER SUPPLY SOURCES
2224 A separate power supply, independent of the main power supply, shall be provided for the operation of trouble signals. The secondary power supply may be used for this purpose.	2224 The plant fire alarm panels do not annunciate loss of ac power. Loss of ac power to the fire alarm equipment is annunciated on other panels located in the main control room.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
2230	Power Supply for Remotely Located Control Equipment	2230	Power Supply for Remotely Located Control Equipment
2231	Additional power supplies when provided for control units, transmitters, or other equipment, essential to system operation, located remote from the central supervising station, shall comprise a primary (main), secondary (standby), and a trouble power supply which shall meet the same requirements as for the central supervising station power supplies. See Paragraphs 2220 through 2224.	2231	Each local fire control panel is provided with a single power supply.
2240	Light and Power Services	2240	Light and Power Services
2243	An overcurrent protective device of suitable current-carrying capacity and capable of interrupting the maximum short-circuit current to which it may be subjected shall be provided in each ungrounded conductor. The overcurrent protective device shall be enclosed in a locked or sealed cabinet located immediately adjacent to the point of connection to the light and power conductors.	2243	Cabinets are not locked or sealed but are located in access controlled areas.
CHAPTER 3 - TYPES OF SIGNALING SERVICES		CHAPTER 3 - TYPES OF SIGNALING SERVICES	
ARTICLE 340 - SPRINKLER SYSTEM WATERFLOW ALARM AND SUPERVISORY SIGNAL SERVICE		ARTICLE 340 - SPRINKLER SYSTEM WATERFLOW ALARM AND SUPERVISORY SIGNAL SERVICE	
3444	Water storage containers shall be supervised to obtain two separate and distinctive signals, one indicating that the required water level has been lowered or increased and the other indicating restoration to the normal level. a. A pressure tank supervisory attachment shall indicate both high and low level conditions. A signal shall be obtained when the water level is lowered or raised 3 in. from the required level.	3444	Fire water is supplied from the circulating water basin or the 400,000 gal bladder tank. The levels are checked manually by equipment operators once per shift.

TABLE F.2-1

CODE DEVIATIONS (Continued)

	CODE SECTION		POSITION
	b. A supervisory attachment for other than pressure tanks shall indicate a low level condition. A signal shall be obtained when the water level is lowered 12 in. from the required level.		
3445	Water storage containers shall be supervised to obtain two separate and distinctive signals, one indicating that the temperature of the water has been lowered to 40°F, and the other indicating restoration to proper temperature.	3445	Fire water is supplied from the circulating water basin or the 400,000 gal bladder tank. The water temperature is not supervised or alarmed. The circulating water system is continuously recirculated. The bladder tank is provided with a manually initiated recirculation pump to prevent freezing.
ARTICLE 350 - AUTOMATIC SMOKE ALARM SERVICE		ARTICLE 350 - AUTOMATIC SMOKE ALARM SERVICE	
3540	Circuit Arrangement	3540	Circuit Arrangement
3541	A smoke detecting combination of a Class A Proprietary System shall be capable of operating for a smoke alarm signal during a single break or a single ground fault condition of the circuit wiring conductors (a) between the central supervising station and the smoke alarm signal transmitter and (b) between the smoke alarm signal transmitter and the smoke detector control unit, except as indicated in Paragraph 3542.	3541	Class A wiring is used only on detection wiring activating suppression systems in safety-related areas. All other circuits are Class B wiring including connections from local suppression panels to the fire control panel in the main control room. The Class A wiring, where provided, meets the requirements of this code section.
3542	The requirement of Paragraph 3541 does not apply to the circuits between the smoke alarm signal transmitter and the smoke detector control unit if both of these units are located in a common enclosure, or in adjacent enclosures not more than 3 ft apart and having the circuits between the enclosures run in conduit.	3542	Class A wiring is used only on detection wiring activating suppression systems in safety-related areas. All other circuits are Class B wiring including connections from local suppression panels to the fire control panel in the main control room. The Class A wiring, where provided, meets the requirements of this code section.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
NFPA 72E-1974			
CHAPTER 4 - SMOKE DETECTORS		CHAPTER 4 - SMOKE DETECTORS	
4-4	Spacing	4-4	Spacing
4-4.5	High Ceilings	4-4.5	High Ceilings
4-4.5.2	For proper protection for buildings with high ceilings, detectors shall be installed alternately at two levels; one half at ceiling level, and the other held at least 3 ft below the ceiling. (See Figure A-4.5.4 of Appendix.)	4-4.5.2	Smoke detectors are not installed at alternating levels on the ceilings. Intermediate level detectors are installed in the cable chase (radwaste control building).
4-4.6	Beam Construction. Beams 8 in. or less in depth can be considered equivalent to a smooth ceiling in view of the "spill over" effect of smoke. In beam construction over 8 in. in depth, movement of heated air and smoke may be slowed by the pocket or bay formed by the beams. In this case, spacing shall be reduced. If the beams exceed 18 in. in depth and are more than 8 ft on centers, each bay shall be treated as a separate area requiring at least one detector.	4-4.6	Beam Construction. The location and spacing of smoke detectors in the vicinity of beams and similar projections were evaluated by field inspection and data from fire detector response from Reference F.7.2.u. These evaluations indicate that the smoke detector locations near the beam construction will not impede proper detector function.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
	NFPA 80-1974		
1-5	Classifications and Types of Doors	1-5	Classification and Types of Doors
1-5.1.1	Only labeled doors shall be used.	1-5.1.1	WNP-2 has various specialty doors in fire barriers which are not labeled for fire. These doors are required to meet other design considerations associated with a nuclear facility. Specialty doors include watertight, airtight, radiation shielding, low- and high-range blast and bullet resistance. These nonlabeled door types have been previously approved by the NRC (Reference F.7.4.c).
2-1	Swinging Doors with Builders Hardware	2-1	Swinging Doors with Builders Hardware
2-1.5.1	Only labeled steel door frames shall be used. (The requirements to be a labeled door implies that there are no untested frame modifications, such as frame holes, which void the label.)	2-1.5.1	Only labeled hollow metal steel door frames are used; however, where nonfactory frame holes are present, grout may be installed inside the frame at the area of the frame defect. Grouted frames do not void the frame laboratory label.
2-1.5.4	The clearance between the door and the frame and between meeting edges of doors swinging in pairs shall not exceed 1/8 in. The clearance between the bottom of the door and the floor surface shall not exceed 0.75 in. regardless of the existence of a raised sill or threshold.	2-1.5.4	The clearance between the door and frame and between double doors may exceed NFPA 80 dimensions by 0.0125 in. Door bottom clearance can exceed NFPA 80 dimensions by 0.25 in. Industry fire testing has shown that similar construction fire doors meet a 3-hr fire rating with the above clearances. See Reference F.7.5.r.
2-1.7.4.5	A closing device shall be installed on every fire door except elevator and power-operated dumbwaiter doors.	2-1.7.4.5	Various specialty fire doors are not equipped with automatic closing devices. The presence and design of specialty doors has been previously approved by the NRC and ANI. See above. Note: the complete list of NFPA 80-1974 deviations for specialty doors in fire barriers is not further listed here.

TABLE F.2-1

CODE DEVIATIONS (Continued)

CODE SECTION		POSITION	
2-9	Access Doors	2-9	Access Doors
2-9.2.2	When installed in a vertical surface, access doors shall be self-closing. This shall be accomplished by use of a closer or by top hinging to provide gravity closing.	2-9.2.2	Fire doors R413 and R610 are elevated equipment access doors that are only used for large equipment removal and are normally locked. Thus, periodic verification of self-closing is not performed.
4-1	General Care and Maintenance	4-1	General Care and Maintenance
4-1-3	Doors, shutters, and windows shall be operable at all times. They shall be kept closed and latched or arranged for automatic closing.	4-1.3	Fire doors D104, D105, and D107 may not always self-close due to differential pressure. These doors are equipped with strobe lights and are monitored by security.

F.3 COMPLIANCE WITH FIRE PROTECTION REGULATORY DOCUMENTS

Branch Technical Position (BTP) APCSB 9.5-1, Appendix A, Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976, provides guidance on the preferred alternatives for fire protection design for nuclear power plants for which applications for construction permits were docketed prior to July 1, 1976.

Table F.3-1 provides a comparison of the WNP-2 fire protection program to BTP APCSB 9.5-1 Appendix A. The comparison describes how the WNP-2 fire protection program implements the BTP recommendations.

Although WNP-2 is not an "Appendix R" plant, Appendix R commitments were part of the original basis for safe plant operation and are therefore part of the WNP-2 license basis, Appendix R Sections III.G/L, III.J, and III.O are NRC requirements and any deviations require licensing action. The responses to the other Appendix R sections are commitments that can be revised under license condition 2.c(14) without prior NRC approval. The comparison of the WNP-2 fire protection program to the full content of Appendix R is included in Table F.3-2.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
A. OVERALL REQUIREMENTS FOR NUCLEAR PLANT FIRE PROTECTION PROGRAM	A. OVERALL REQUIREMENTS FOR NUCLEAR PLANT FIRE PROTECTION PROGRAM
A.1 Personnel	A.1 Personnel
Responsibility for the overall fire protection program should be assigned to a designated person in the upper level of management. This person should retain ultimate responsibility even though formulation and assurance of program implementation is delegated. Such delegation of authority should be to staff personnel prepared by training and experience in fire protection and nuclear plant safety to provide a balanced approach in directing the fire protection programs for nuclear power plants. The qualification requirements for the fire protection engineer or consultant who will assist in the design and selection of equipment, inspect and test the completed physical aspects of the system, develop the fire protection program, and assist in the fire-fighting training for the operating plant should be stated. Subsequently, the FSAR should discuss the training and the updating provisions such as fire drills provided for maintaining the competence of the station fire-fighting and operating crew, including personnel responsible for maintaining and inspecting the fire protection equipment. The fire protection staff should be responsible for a. coordination of building layout and systems design with fire area requirements, including consideration of potential hazards associated with postulated design basis fires. b. design and maintenance of fire detection, suppression, and extinguishing systems. c. fire prevention activities. d. training and manual fire-fighting activities of plant personnel and the fire brigade. Note: NFPA 6 - Recommendations for Organization of Industrial Fire Loss Prevention, contains useful guidance for organization and operation of the entire fire loss prevention program.)	The Vice President, Nuclear Operations, is the management official responsible for the fire protection program and systems. The Plant General Manager has the responsibility for the adequacy of implementation and effectiveness of the fire protection program at the facility. The Plant Fire Marshal serves as the principal point of contact for the plant fire protection program. The position responsibilities include ensuring that the fire protection administrative controls for fire protection system/component testing, maintenance, and remedial actions are adequately implemented, monitoring plant activities and plant condition for fire prevention and combustible controls, and ensuring the plant fire brigade is adequately trained, staffed, and equipped. The Supply System staff includes an engineer meeting the qualifications listed in Section 13.1.3.1.3. The qualified Fire Protection Engineer is delegated the responsibility for ensuring the technical adequacy of elements of the fire protection program. This responsibility is implemented through the review of proposed fire protection program changes, design changes, and procedure changes. The qualified fire protection engineer is also responsible for the assessment of the effectiveness of the fire protection programs in support of the Plant General Manager.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
A.2 Design Basis	A.2 Design Basis
The overall fire protection program should be based upon evaluation of potential fire hazards throughout the plant and the effect of postulated design basis fires related to maintaining ability to perform safety shutdown functions and minimize radioactive releases to the environment.	The overall fire protection program is based on evaluation of potential fire hazards throughout the plant relative to maintaining the ability to safely shut down the plant and minimize the releases of radioactivity to the environment. See Section F.4 for the WNP-2 fire hazards analysis.
A.3 Backup	A.3 Backup
Total reliance should not be placed on a single automatic fire suppression system. Appropriate backup fire suppression capability should be provided.	Automatic fire suppression systems have been installed in areas where there are significant fire hazards. Automatic suppression systems are backed up by hose stations and portable fire extinguishers distributed throughout the plant.
A.4 Single Failure Criterion	A.4 Single Failure Criterion
A single failure in the fire suppression system shall not impair both the primary and backup fire suppression capability. For example, redundant fire water pumps with independent power supplies and controls should be provided. Postulated fires or fire protection system failures need not be considered concurrent with other plant accidents or the most severe natural phenomena. The effects of lightning strikes should be included in the overall plant fire protection program.	A combination of design features provides fire protection in the event of fire protection system component failures.

Malfunction	Consequences
Electric fire pump motor failure	Second electric fire pump on separate power supply
Electric fire pumps fail due to loss of offsite power.	Two diesel fire pumps available - one 2000 gpm and one 2500 gpm
Water source low water level (no makeup)	Primary fire pumps are supplied from the circ water pump house, second diesel fire pump is supplied from separate water supply.
Yard pipe rupture	Isolate portion of main loop header using sectionalizing valves.
System pipe rupture	Isolate using system isolation valve. Use backup hose from standpipe and/or hydrants.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM	
	System alarm check valve fails to open	Use manual fire fighting equipment (hoses and portable extinguishers)
	Detection system wire short	Trouble alarm in control room
	Loss of offsite power to detection system	Detection system is provided with backup power from an uninterruptible power supply.
	Fire dampers	All fire dampers serving rooms containing safety-related equipment are qualified to Seismic Category I.

The plant is provided with redundant fire pumps which supply water to the fire water supply loop from two separate water supplies. (See paragraph E.2.c.).

The fixed water suppression system and the backup fire hose station are connected to the same riser in the following safety-related areas:

a. Main control room emergency filter units (with standpipe cross-connection),

b. Standby gas treatment filter units, and

c. Reactor building sump vent filter units

These combination systems are permitted under NFPA 14-1974. A pipe rupture coincident with a fire is not, however, considered credible as the pipe is a passive component.

Lightning rods and steel towers are used to minimize the potential for lightning-caused fires. The reactor building and stacks are equipped with a lightning protection system. Air terminals are installed and spaced along the roof in accordance with NFPA 78-1975. The vent stack lightning protection

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
	mast, the communications and fire protection masts, and the air terminals are bonded to structural steel and/or heavy copper conductors which connect directly to the plant ground grid. The height of the reactor building and its installed air terminals provide zones of protection for the diesel generator building and the safety-related portions of the radwaste/control building. The metal wall panels of the turbine building are grounded directly to the structural steel, which in turn is bonded to the plant ground grid.
A.5 Fire Suppression Systems	A.5 Fire Suppression Systems
Failure or inadvertent operation of the fire suppression system should not incapacitate safety-related systems or components. Fire suppression systems that are pressurized during normal plant operation should meet the guidelines specified in APCSB Branch Technical Position 3-1, "Protection Against Postulated Piping Failures in Fluid Systems Outside Containment."	The safety-related areas which have fixed fire suppression systems include the following: a. The standby gas treatment (SGT) filter units in the reactor building are provided with manually activated water spray that is operated from the main control room. b. The cable spreading room in the radwaste control building has an automatic preaction system. c. The diesel generator building has an automatic preaction system installed to protect each diesel generator, day tank, and oil transfer pump room. d. The main control room emergency filter units in the radwaste control building have manually actuated water spray systems within the units. e. The radwaste control building cable chase and portions of the diesel generator corridor and the radwaste-reactor building corridor have an automatic preaction system. f. The control room power generation control complex (PGCC) subfloor sections longitudinal cable ducts have automatic Halon 1301 systems.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
	g. The control room office areas have automatic sprinkler protection. The deluge spray systems for the SGT filter units and the control room emergency filter units are actuated by remote manual action to prevent inadvertent wetting. The redundant units are physically separated and would remain operable. A failure or inadvertent operation of a preaction sprinkler system in the cable spreading room, cable chase, or in the diesel generator building would not incapacitate the safety-related systems as two actions would be required for water to be released: the feed mains and lines must be flooded and the sprinkler heads must be fused. Failure or inadvertent operation of the PGCC Halon 1301 system does not incapacitate safety-related systems. Fire suppression systems that are pressurized during normal plant operation meet the guidelines specified in APCSB BTP 3-1. Potential flooding due to failure of the fire protection system piping has been included in plant flooding analyses.
A.6 Fuel Storage Areas The fire protection program (plans, personnel, and equipment) for buildings storing new reactor fuel and for adjacent fire zones which could affect the fuel storage zone should be fully operational before fuel is received on the site. Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	A.6 Fuel Storage Areas The fire protection program for all fuel storage areas was fully operational when fuel was received at the site.
A.7 Fuel Loading The fire protection program for an entire reactor unit should be fully operational prior to initial fuel loading in that reactor unit. Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	A.7 Fuel Loading The fire protection programs for the entire power unit were fully operational prior to initial fuel loading.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
A.8 Multiple-Reactor Sites	A.8 Multiple-Reactor Sites
On multiple-reactor sites where there are operating reactors and construction of remaining units is being completed, the fire protection program should provide continuing evaluation and include additional fire barriers, fire protection capability, and administrative controls necessary to protect the operating units from construction fire hazard. The superintendent of the operating plant should have the lead responsibility for site fire protection.	WNP-2 is not a multiple-reactor site.
A.9 Simultaneous Fires	A.9 Simultaneous Fires
Simultaneous fires in more than one reactor need not be postulated, where separation requirements are met. A fire involving more than one reactor unit need not be postulated except for facilities shared between units.	WNP-2 is not a multiple reactor site.
B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE	B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE
B.1 Administrative procedures consistent with the need for maintaining the performance of the fire protection system and personnel in nuclear power plants should be provided.	B.1 Administrative procedures for maintaining performance of fire protection systems and personnel are provided.
Guidance is contained in the following publications: NFPA 4 - Organization for Fire Services NFPA 4A - Organization for Fire Department NFPA 6 - Industrial Fire Loss Prevention NFPA 7 - Management of Fire Emergencies NFPA 8 - Management Responsibility for Effects of Fire on Operations NFPA 27 - Private Fire Brigades	The listed NFPA codes have been superseded. The current equivalent NFPA codes may be used as guidance.
B.2 Effective administrative measures should be implemented to prohibit bulk storage of combustible materials inside or adjacent to safety-related buildings or systems during	B.2 Administrative procedures for housekeeping and fire protection control the introduction of combustible materials into the plant.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
	operation or maintenance periods. Regulatory Guide 1.39, "Housekeeping Requirements for Water-Cooled Nuclear Power Plants," provides guidance of housekeeping, including the disposal of combustible materials.		
B.3	Normal and abnormal conditions or other anticipated operations such as modifications (e.g., breaking fire stops, impairment of fire detection and suppression systems) and refueling activities should be reviewed by appropriate levels of management for appropriate special actions and procedures such as fire watches or temporary fire barriers implemented to assure adequate fire protection and reactor safety. In particular:	B.3	Normal and abnormal conditions and other anticipated operations and refueling activities are reviewed by management for appropriate special actions. Primary implementing procedures are listed in Section F.7.8. In particular:
	a. Work involving ignition sources such as welding and flame cutting should be done under closely controlled conditions. Procedures governing such work should be reviewed and approved by persons trained and experienced in fire protection. Persons performing and directly assisting in such work should be trained and equipped to prevent and combat fires. If this is not possible, a person qualified in fire protection should directly monitor the work and function as a fire watch.		a. Work involving ignition sources is done under controlled conditions and procedures governing such work will be reviewed and approved by persons trained and experienced in fire protection. Persons performing and assisting in such work are trained and equipped to prevent and control fires. Qualified personnel monitor the work and act as fire watch.
	b. Leak testing and similar procedures such as air flow determinations should use one of the commercially available aerosol techniques. Open flames or combustion generated smoke should not be permitted.		b. Leak testing uses instrumentation or soapy water. Smoke detector testing may use aerosol cans. Open flames or combustion generated smoke are not permitted.
	c. Use of combustible material, e.g., HEPA and charcoal filters, dry ion exchange resins or other combustible supplies, in safety-related areas should be controlled. Use of wood inside buildings containing safety-related systems or equipment should be permitted only when suitable		c. Provisions have been made for controlling the use of combustible materials in safety-related areas. Use of wood in the permanent structure of buildings containing safety-related systems or equipment is not permitted except when suitable non-combustible substitutes are not available. If wood is used only pressure impregnated fire retardant or fire retardant coated wood is permitted. The use of minor amounts of transient untreated wood is not considered a significant hazard. For more than minor amounts in safety-related areas, additional

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

	BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
	non-combustible substitutes are not available. If wood must be used, only fire retardant treated wood (scaffolding, lay down blocks) should be permitted. Such materials should be allowed into safety-related areas only when they are to be used immediately. Their possible and probable use should be considered in the fire hazard analysis to determine the adequacy of the installed fire protection systems.		compensating measures are implemented as necessary. d. Equipment or supplies shipped in untreated combustible packaging containers may be unpacked in safety-related areas if required for operating reasons. All combustible packing materials are removed from the area as soon as practicable after the unpacking.
B.4	Nuclear power plants are frequently located in remote areas, at some distance from public fire departments. Also, first response fire departments are often volunteer. Public fire department response should be considered in the overall fire protection program. However, the plant should be designed to be self-sufficient with respect to fire fighting activities and rely on the public response only for supplemental or backup capability.	B.4	The plant is designed to be self-sufficient with respect to fire-fighting activities. The plant fire brigade is trained in fire-fighting procedures. Supplemental fire-fighting capability is available from the local fire department. Interagency agreements delineate the responsibilities and duties of the local fire department during a coordinated response.
B.5	The need for good organization, training and equipping of fire brigades at nuclear power plant sites requires effective measures be implemented to assure proper discharge of these functions. The guidance in Regulatory Guide 1.101, "Emergency Planning of Nuclear Power Plants," should be followed as applicable.	B.5	Current requirements are contained in the WNP-2 Emergency Plan.
	a. Successful fire-fighting requires testing and maintenance of the fire protection equipment, emergency lighting, and communication, as well as practice as brigades for the people who must utilize the equipment. A test plan that lists the individuals and their responsibilities in connection with routine tests and inspections of the fire detection and protection systems should be developed. The test plan should contain the types, frequency and detailed procedures for testing. Procedures should also contain instructions on maintaining fire		Procedures have been prepared for the testing and maintenance of the fire protection equipment, emergency lighting, and communication equipment. Procedures list responsibilities in connection with routine tests and inspections of the fire detection and protection systems. Procedures for compensatory measures are implemented when fire systems are impaired. The plant fire brigade composition is described in Section 13.1.2.3.4. The fire brigade training requirements are described in Section 13.2.2.5.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
protection during those periods when the fire protection system is impaired or during periods of plant maintenance, e.g., fire watches or temporary hose connections to water systems.	
b. Basic training is a necessary element in effective fire fighting operation. In order for a fire brigade to operate effectively, it must operate as a team. All members must know what their individual duties are. They must be familiar with the layout of the plant and equipment location and operation in order to permit effective firefighting operations during times when a particular area is filled with smoke or is insufficiently lighted. Such training can only be accomplished by conducting drills several times a year (at least quarterly) so that all members of the fire brigade have had the opportunity to train as a team, testing itself in the major areas of the plant.	
The drills should include the simulated use of equipment in each area and should be preplanned and post-critiqued to establish the training objective of the drills and determine how well these objectives have been met. These drills should periodically (at least annually) include local fire department participation where possible. Such drills also permit supervising personnel to evaluate the effectiveness of communications within the fire brigade and with the on-scene fire team leader, the reactor operator in the control room, and the offsite command post.	
c. To have proper coverage during all phases of operation, members of each shift crew should be trained in fire protection. Training of the plant fire brigade should be coordinated with the local fire department so that	

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
responsibilities and duties are delineated in advance. This coordination should be part of the training course and implemented into the training of the local fire department staff. Local fire departments should be educated in the operational precautions when fighting fires on nuclear power plant sites. Local fire departments should be made aware of the need for radioactive protection of personnel and the special hazards associated with a nuclear power plant site.	
d. NFPA 27, "Private Fire Brigade," should be followed in organization, training, and fire drills. This standard also is applicable for the inspection and maintenance of fire fighting equipment. Among the standards referenced in this document, the following should be utilized: NFPA 194, "Standard for Screw Threads and Gaskets for Fire Hose Couplings," NFPA 196, "Standards for Fire Hose," NFPA 197, "Training Standard on Initial Fire Attacks," NFPA 601, "Recommended Manual of Instructions and Duties for the Plant Watchman on Guard." NFPA booklets and pamphlets listed on page 27-11 of Volume 8, 1971-72, are also applicable for good training references. In addition, courses in fire prevention and fire suppression which are recognized and/or sponsored by the fire protection industry should be utilized.	
C. QUALITY ASSURANCE PROGRAM	C. QUALITY ASSURANCE PROGRAM
C.1 Design Control and Procurement Document Control	C.1 Design Control and Procurement Document Control
Measures should be established to assure that all design-related guidelines of the Branch Technical Position are included in design and procurement	At the time BTP APCSB 9.5-1 was issued, the basic design of all fire protection equipment and systems had been completed. The established engineering

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
documents and that deviations therefrom are controlled.	procedures require the design and design changes to be reviewed by cognizant personnel to ensure material, parts, and equipment specified will meet or exceed the design criteria. Design and design changes are incorporated into design and/or procurement documents which contain requirements that deviations be documented and controlled. Design and procurement activities are audited and reviewed on a scheduled and surveilled basis.
C.2 Instructions, Procedures, and Drawings	C.2 Instructions, Procedures, and Drawings
Inspections, tests, administrative controls, fire drills, and training that govern the fire protection program should be prescribed by documented instructions, procedures, or drawings and should be accomplished in accordance with these documents.	Specifications are prepared, when required, to define design requirements. Instructions, procedures, and drawings additionally define and implement fire protection requirements. Contractors/suppliers are requested to provide instructions, procedures, or drawings as stipulated by contract/procurement documents. During plant operation, the fire protection program and those portions of the fire protection systems which are designated as essential fire protection systems (see Appendix F.5) are subject to the applicable portions of the WNP-2 Operational Quality Assurance Program Description (OQAPD).
C.3 Control of Purchased Material, Equipment, and Services	C.3 Control of Purchased Material, Equipment, and Services
Measures should be established to assure that purchased material, equipment, and services conform to the procurement documents.	Contractors/suppliers are required to provide inspection and/or test documentation as stipulated by contract/procurement documents. Identification and traceability requirements are included in procurement documents as required. Source surveillance and/or receiving inspection will depend on the degree of design control applied.
C.4 Inspection	C.4 Inspection
A program for independent inspection of activities affecting fire protection should be established and executed by, or for, the organization performing the activity to verify conformance with documented installation drawings and test procedures for accomplishing the activities.	Purchase orders/contracts are reviewed to provide applicable quality assurance requirements. Source surveillance and/or receiving inspections are performed depending on the degree of design control applied. Plant quality control or cognizant field engineering performs inspection/surveillance, as required, to ensure compliance with fire protection requirements.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
C.5 Test and Test Control	C.5 Test and Test Control
A test program should be established and implemented to assure that testing is performed and verified by inspection and audit to demonstrate conformance with design and system readiness requirements. The tests should be performed in accordance with written test procedures; test results should be properly evaluated and acted on.	During construction, contractors performing installation and tests were required to perform inspections which ensured system readiness were performed in accordance with approved procedures. Additionally, these contractors were subject to surveillance and/or audit for compliance to fire protection requirements. Modifications to installations are required to be tested to ensure system readiness using approved procedures.
C.6 Inspection, Test, and Operating Status	C.6 Inspection, Test, and Operating Status
Measures should be established to provide for the identification of items that have satisfactorily passed required tests and inspections.	All items received are identified to ensure proper traceability and status. This traceability is sufficiently ensured during installation and test. A system of tagging is used during operations to establish operating status or to prevent inadvertent operation.
C.7 Non-Conforming Items	C.7 Non-Conforming Items
Measures should be established to control items that do not conform to specified requirements to prevent inadvertent use or installation.	Inspection procedures require that items that do not conform to specified requirements be tagged and segregated to prevent inadvertent installation.
C.8 Corrective Action	C.8 Corrective Action
Measures should be established to assure that conditions adverse to fire protection, such as failures, malfunctions, deficiencies, deviations, defective components, uncontrolled combustible material and non-conformances are promptly identified, reported, and corrected.	Those portions of the fire protection system which are designated as essential fire protection systems (see Section F.5) are subject to the applicable portions of the WNP-2 OQAPD. Plant procedures require that conditions adverse to fire protection, such as failures, malfunctions, deficiencies, deviations, defective components, uncontrolled combustible material, and nonconformances are promptly identified, reported, and corrected.
C.9 Records	C.9 Records
Records should be prepared and maintained to furnish evidence that the criteria enumerated above are being met for activities affecting the fire protection program.	During design and construction, the quality assurance program required vendors and contractors to prepare and maintain documents indicating compliance with quality assurance requirements. During operations, documents indicating compliance with quality assurance requirements are prepared in accordance with the applicable portions of the WNP-2 OQAPD.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
C.10 Audits	C.10 Audits
Audits should be conducted and documented to verify compliance with the fire protection program including design and procurement documents; instructions; procedures and drawings; and inspection and test activities.	During design and construction, a surveillance/audit program was implemented to include design and procurement documents, instructions, procedures, and drawings; inspection, and test activities. Procurement documents were reviewed for application of source surveillance requirements. Site contractors were subject to surveillance/audit to ensure compliance to fire protection requirements. Audits are performed in accordance with NRC Generic Letter No. 82-21.
D. GENERAL GUIDELINES FOR PLANT PROTECTION	D. GENERAL GUIDELINES FOR PLANT PROTECTION
D.1 Building Design	D.1 Building Design
D.1.a Plant layouts should be arranged to: a. Isolate safety-related systems from unacceptable fire hazards, and b. Alternatives: 1. redundant safety-related systems that are subject to damage from a single fire hazard should be protected by a combination of fire retardant coatings and fire detection and suppression systems, or 2. a separate system to perform the safety function should be provided.	D.1.a Those portions of redundant systems which are required for post-fire safe shutdown are protected in accordance with 10 CFR 50 Appendix R, Section III.G, as detailed in Section F.4. Safety-related equipment which is not required for post-fire safe shutdown is generally separated to minimize potential risk from a single fire hazard. Cabling for the safety-related equipment which is not required for post-fire safe shutdown is routed in accordance with divisional electrical separation requirements (Section 8.3), not in accordance with Appendix R requirements, and could be subject to damage from a single exposure fire. Fire area boundaries serve to separate fire hazards from safety-related systems.
D.1.b In order to accomplish 1.(a) above, safety-related systems and fire hazards should be identified throughout the plant. Therefore, a detailed fire hazard analysis should be made. The fire hazards analysis should be reviewed and updated as necessary.	D.1.b In designing the plant, careful consideration has been given to equipment location, fire walls, barriers, material selection, and fire protection system design. A fire hazards analysis is included in Section F.4. Proposed plant modifications are evaluated for impact on the validity of the fire hazards analysis.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

	BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
	Additional fire hazards analysis should be done after any plant modification.		Revisions to the fire hazards analyses are performed as required.
D.1.c	For multiple reactor sites, cable spreading rooms should not be shared between reactors. Each cable spreading room should be separated from other areas of the plant by barriers (walls and floors) having a minimum fire resistance of three hr. Cabling for redundant safety divisions should be separated by walls having three hour fire barriers.	D.1.c	WNP-2 is not a multiple reactor site. The cable spreading room is separated from other fire areas by 3-hr barriers.
D.1.d	Interior wall and structural components, thermal insulation materials and radiation shielding materials and sound-proofing should be non-combustible. Interior finishes should be non-combustible or listed by a nationally recognized testing laboratory, such as Factory Mutual or Underwriters' Laboratory, Inc. for flame spread, smoke and fuel contribution of 25 of less in its use configuration (ASTM E-84 Test, "Surface Burning Characteristics of Building Materials"). Alternative guidance for constructed plants is shown in Section E.3 "Cable Spreading Room".	D.1.d	Interior wall and structural components, thermal insulation materials, and radiation shielding materials are noncombustible. Decontaminable coatings have flame spreads less than 25. Paint on concrete or masonry block is not considered a fire hazard. Auxiliary rooms within the main control room and the north wall of the radwaste control room have plastic laminate faced wall panels. The plastic laminate faced wall panels are UL listed for a flame spread of 25 and a smoke developed rating of 40. The materials in these rooms are not, however, considered to present a significant fire hazard. The combustibility of Thermo-Lag 330-1 has been considered in the fire hazards analysis. The combustible containment barrier spacer material is shielded from fire exposure by ceramic fiber in the annular gap of mechanical containment penetrations. See Section F.2.2.5 for more details. Shielding material installed within access doors at certain penetrations in the primary containment sacrificial shield wall is under the trade name of "Permali." Flame spread and smoke contribution are both under 25.
D.1.e	Metal deck roof construction should be noncombustible (see the building materials directory of the Underwriters' Laboratory, Inc.) or listed as Class I by Factory Manual System Approval Guide.	D.1.e	All metal deck roof systems meet the requirements of Factory Mutual Class I insulated steel roof decks.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

	BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
	Where combustible material is used in metal deck roofing design, acceptable alternatives are (i) replace combustibles with non-combustible materials, (ii) provide an automatic sprinkler system, or (iii) provide ability to cover roof exterior and interior with adequate water volume and pressure.		
D.1.f	Suspended ceilings and their supports non-combustible construction. Concealed spaces should be devoid of combustibles. Adequate fire detection and suppression systems should be provided where full implementation is not practicable.	D.1.f	Suspended ceilings and their supports are of noncombustible construction. Within the control room, there are no exposed combustibles in concealed spaces above the suspended ceilings. All electrical cable above the suspended ceiling is routed in conduit. Cable trays are routed above the suspended ceilings of the 487-ft radwaste chemistry laboratory.
D.1.g	High voltage - high amperage transformers installed inside buildings containing safety related systems should be of the dry type or insulated and cooled with non-combustible liquid. Safety related systems that are exposed to flammable oil filled transformers should be protected from the effects of a fire by: (i) replacing with dry transformers or transformers that are insulated and cooled with non-combustible liquid; or (ii) enclosing the transformer with a three-hour fire barrier and installing automatic water spray protection.	D.1.g	All high voltage transformers installed inside safety-related building areas are cooled with high flash point insulating fluid. The indoor river makeup transformers are enclosed in 3-hr barriers without automatic suppression. Fire Areas RC-8 and RC-14, containing the radwaste building 467-ft switchgear room transformers, are enclosed in 3-hr barriers without automatic suppression.
D.1.h	Buildings containing safety related systems, having openings in exterior walls closer than 50 ft to flammable oil filled transformers should be protected from the effects of a fire by:	D.1.h	There are no oil-filled transformers located within 50 ft of the exterior wall of a safety-related building. The main step-up transformers, the normal auxiliary transformers, the startup auxiliary power transformers, and the backup auxiliary

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
(i) closing of the opening to have fire resistance equal to three hr (ii) constructing a three-hour barrier between the transformers and the wall openings; or (iii) closing the openings and providing the capability to maintain a water curtain in case of fire.	power transformers are oil filled and located within 50 ft north of the turbine generator building. They are protected by deluge sprinklers. The turbine generator building wall is 2-hr rated reinforced concrete and insulated metal panel with 1.5-hr fire-rated doors. There are no barriers between transformers. Four additional oil-filled transformers are located in the cooling tower area. The RRC pump ASD transformers are protected by deluge systems. The adjacent RRC pump ASD building wall is 2-hr rated and turbine building wall is 3-hr rated. A 2-hr barrier separates the divisional transformers.
D.1.i Floor drains, sized to remove expected fire fighting water flow, should be provided in those areas where fixed water fire suppression systems are installed. Drains should also be provided in other areas where hand hose lines may be used if such fire fighting water could cause unacceptable damage to equipment in the area. Equipment should be installed on pedestals, or curbs should be provided as required to contain water and direct it to floor drains. (See NFPA 92M, "Waterproofing and Draining of Floors.") Drains in areas containing combustible liquids should have provisions for preventing the spread of the fire throughout the drain system. Water drainage from areas which may contain radioactivity should be sampled and analyzed before discharge to the environment. In operating plants or plants under construction, if accumulation of water from the operation of new fire suppression systems does not create unacceptable consequences, drains need not be installed.	D.1.i Floor drains for the turbine oil reservoir, turbine lube oil storage, and hydrogen seal oil rooms discharge into sumps. There are no floor drains in the diesel generator day tank rooms. The floor drain systems in areas where fixed fire protection systems are located are not sized adequately to accept the large quantity of water which could be discharged over a long period of time. Flooding may be relieved through open doorways. Potential actuation of fire protection systems has been evaluated to ensure that it would not adversely affect any safety-related equipment by flooding. Most equipment has been installed on raised concrete pads or pedestals. Water flowing down stairwells or into elevator shafts will not degrade safety-related equipment. All drains empty into sumps which are divided into radioactive and nonradioactive sumps according to the areas served.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
		a. Turbine generator building nonradioactive sumps discharge into the roof drain system which empties into the yard. b. Radioactive sumps in all buildings discharge into the floor drain collection tank and waste collection tank in the radwaste building to be processed prior to being discharged. In all buildings where fixed fire suppression systems or hand hose stations are actuated and flooding does occur, water could ultimately flow into the basement area and cover the sumps and floor. a. Areas where no or little radiation is present, the excessive quantity of water will dilute any possible contamination. This water could be pumped into the yard by portable equipment after the fire is suppressed. b. Areas where contaminated particles are prevalent, which have had flooding, must have the floor area monitored. 1. Non-contaminated water could be pumped into the yard. 2. Contaminated water would be left in the basement until the sump can be reactivated to discharge the water to the radwaste floor drain collection tank. As indicated above, temporary flooding beyond the drainage system provided is possible if water is discharged for extended periods.
D.1.j Doors, walls, and ceilings enclosing separate fire areas should have minimum fire rating of 3 hr. Penetrations in these fire barriers, including conduits and piping,	D.1.j	See Sections F.2.2 and F.5.7 for a description of building construction and fire rated assemblies.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
should be sealed or closed to provide a fire resistance rating at least equal to that of the fire barrier itself. Door openings should be protected with equivalent rated doors, frames and hardware that have been tested and approved by a nationally recognized laboratory. Such doors should be normally closed and locked or alarmed with alarm and annunciation in the control room. Penetrations for ventilation system should be protected by a standard "fire door damper" where required. (Refer to NFPA 80, "Fire Doors and Windows.") The fire hazard in each area should be evaluated to determine barrier requirements. If barrier fire resistance cannot be made adequate, fire detection and suppression should be provided, such as: (i) water curtain in case of fire (ii) flame retardant coatings (iii) additional fire barriers	
D.2 Control of Combustibles	D.2 Control of Combustibles
D.2.a Safety-related systems should be isolated or separated from combustible materials. When this is not possible because of the nature of the safety system or the combustible material, special protection should be provided to prevent a fire from defeating the safety system function. Such protection may involve a combination of automatic fire suppression, and construction capable of withstanding and containing a fire that consumes all combustibles present. Examples of such combustible materials that may not be separable from the remainder of its system are: (1) Emergency diesel generator fuel oil day tanks (2) Turbine-generator oil and hydraulic control fluid systems (3) Reactor coolant pump lube oil system.	D.2.a Safety-related systems have been isolated or separated from combustible materials to the extent possible. The emergency diesel generator fuel oil day tanks are located in separate rooms with 3-hr fire-rated walls and 3-hr fire-rated door assemblies. The turbine generator oil reservoir and coolers and hydraulic control reservoir and coolers are separated from each other by fire-rated walls and are protected by deluge sprinkler system. The turbine-generator oil reservoir coolers are open to the turbine-generator operating floor but the opening is protected by a deluge sprinkler system. The feedwater pump rooms are not separated by fire barriers but are protected by deluge systems. The reactor recirculation pumps are not protected by an automatic fire suppression system since the containment is inerted. Reactor recirculation, pump bearing temperature and

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
	oil level and containment temperature and pressure are monitored.
D.2.b Bulk gas storage (either compressed or cryogenic), should not be permitted inside structures housing safety-related equipment. Storage of flammable gas such as hydrogen, should be located outdoors or in separate detached buildings so that a fire or explosion will not adversely affect any safety related systems or equipment. (Refer to NFPA 50A, "Gaseous Hydrogen Systems.") Care should be taken to locate high pressure gas storage containers with the long axis parallel to building walls. This will minimize the possibility of wall penetration in the event of a container failure. Use of compressed gases (especially flammable and fuel gases) inside buildings should be controlled. (Refer to NFPA 5, "Industrial Fire Loss Prevention.")	D.2.b A separate building, remote from the main buildings of the plant, is provided for bulk storage of hydrogen bottles. The location is north of the turbine generator building such that a fire or explosion would not affect safety-related buildings or equipment. The building is of noncombustible construction and complies with NFPA Standard 50A (1973). The storage facility consists of a three-sided elevated building with louvers to ensure proper ventilation. All bottles are stored in a vertical position. The hydrogen supply piping is installed inside a culvert to ensure proper protection of the hydrogen line. All electrical equipment within the hydrogen storage facility is rated for installation in a hazardous area Class I, Division II, Group B. The hydrogen storage facility has an elaborate grounding system. These precautions minimize the occurrence of fires and explosions. The hydrogen gas supply system is shown in Figures 1.2-5 and 10.2-4. Minimum amounts of compressed gases are permanently stored in safety-related buildings where the gases are required for system functioning. These are limited to the following: - Nitrogen - 2% hydrogen in argon - 2% hydrogen in nitrogen - 6% hydrogen in argon - 2% oxygen in argon - 6% oxygen in argon - Freon - 10% methane in argon - Propane - Helium - Scott air pack bottles

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
			With the exception of the air pack bottles, the compressed gases are stored in a vertical position and are seismically restrained. The air pack bottles are stored horizontally, but do not present a hazard to any safety-related equipment. The propane is used in a laboratory and does not present a hazard to any safety-related equipment. The other types of compressed gas bottles do not present explosive hazards. Temporary use of flammable and fuel compressed gases is controlled by plant procedures.
D.2.c	The use of plastic materials should be minimized. In particular, halogenated plastics such as polyvinyl chloride (PVC) and neoprene should be used only when substitute non-combustible materials are not available. All plastic materials, including flame and fire retardant materials, will burn with an intensity and BTU production in a range similar to that of ordinary hydrocarbons. When burning, they produce heavy smoke that obscures visibility and can plug air filters, especially charcoal and HEPA. The halogenated plastics also release free chlorine and hydrogen chloride when burning, which are toxic to humans and corrosive to equipment.	D.2.c	The use of plastic materials, in particular halogenated plastics, are minimized to the extent practical. See response to paragraph D.3.f.
D.2.d	Storage of flammable liquids should, as a minimum, comply with the requirements of NFPA 30, "Flammable and Combustible Liquids Code."	D.2.d	Flammable liquids, as defined in NFPA 30-1973, are not used in plant systems. The storage of combustible liquids in plant systems conforms to the requirements of NFPA 30-1973. See Table F.2-1 and item F.9 for approved NFPA 30 deviations. Flammable/combustible liquids for incidental used in maintenance and operations are normally stored in accordance with NFPA 30. Exceptions may be authorized by special handling permits in accordance with plant procedures. Note that the storage

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
			restrictions within a fire area are implemented using the NFPA 30 definition of fire area(s) - not the fire area boundaries as defined for the purpose of post-fire safe shutdown analysis.
D.3	Electric Cable Construction, Cable Trays, and Cable Penetrations	D.3	Electric Cable Construction, Cable Trays, and Cable Penetrations
D.3.a	Only non-combustible material should be used for cable tray construction.	D.3.a	All cable trays, covers, their supports, and hardware are constructed of non-combustible material.
D.3.b	See section E3 for fire protection guidelines for cable spreading rooms.	D.3.b	See paragraph E.3 below.
D.3.c	Automatic water sprinkler systems should be provided for cable trays outside the cable spreading room. Cables should be designed to allow wetting down with deluge water without electrical faulting. Manual hose stations and portable hand extinguishers should be provided as backup. Safety-related equipment in the vicinity of such cable trays, that does not itself require water fire protection, but is subject to unacceptable damage from sprinkler water discharge, should be protected from sprinkler system operation or malfunction. When safety-related cables do not satisfy the provisions of Regulatory Guide 1.75, all exposed cables should be covered with an approved fire retardant coating and a fixed automatic water fire suppression system should be provided.	D.3.c	Spacial separation or electrical separation barriers have been provided between redundant safety-related cable trays as described in Section 8.3. Fixed water suppression systems for all such cable trays outside the cable spreading room are, therefore, considered unnecessary. The cable spreading room and the cable chase in the radwaste/control building and the radwaste-reactor building corridor, however, contain redundant safety-related cables in trays and are located such that the heat resulting from a fire could not be dissipated. Therefore, these areas are provided with automatic water sprinkler systems even where the WNP-2 divisional separation guidelines are met. Manual hose stations and portable extinguishers are available for backup. All hose stations are equipped with fog nozzles. Use of these fog nozzles is not likely to cause unacceptable damage to any safety-related equipment when used by trained personnel in the prescribed manner.
D.3.d	Cable and cable tray penetration of fire barriers (vertical and horizontal) should be sealed to give protection at least equivalent to that fire barrier. The design of fire barriers for horizontal and vertical cable	D.3.d	Cable and cable tray penetrations in fire barriers are sealed with a fire rating equivalent to that of the penetrated area unless fire protection evaluation has justified a lesser fire rating.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

	BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
	trays should, as a minimum, meet the requirements of ASTM E-119, "Fire Test of Building Construction and Materials," including the hose stream test. Where installed penetration seals are deficient with respect to fire resistance, these seals may be protected by covering both sides with an approved fire retardant material. The adequacy of using such material should be demonstrated by suitable testing.		Nongrouted electrical penetration seals designs through fire rated barriers are fire rated based on the criteria established in Reference F.7.6.b (which uses the ASTM E-119 time temperature curve).
D.3.e	Fire breaks should be provided as deemed necessary by the fire hazards analysis. Flame of flame retardant coatings may be used as a fire break for grouped electrical cables to limit spread of fire in cable ventings. (Possible cable derating owing to use of such coating materials must be considered during design.)	D.3.e	Thermo-Lag and Flamemastic coated cable tray fire breaks have been abandoned in place (Reference F.7.6.e). Where long vertical run trays breach nonrated barriers, silicone foam seals which fill the entire blockout are maintained as fire breaks. Within the cable spreading room, Thermo-Lag is applied as a fire proof coating to cable trays to prevent the spread of fire along the intervening trays between redundant post-fire safe shutdown divisional fire zones. Where coating materials are used on cables, derating of cables is considered in the design.
D.3.f	Electric cable constructions should as a minimum pass the current IEEE No. 383 flame test. (This does not imply that cables passing this test will not require additional fire protection). For cable installation in operating plants and plants under construction that do not meet the IEEE No. 383 flame test requirements, all cables must be covered with an approved flame retardant coating and properly derated.	D.3.f	All safety-related cabling meets the IEEE 383-1974 flame test requirements. Generally, cabling within plant cable trays, cable penetrations, and enclosures meets IEEE 383-1974 flame test requirements. Certain lighting circuits and low energy wiring within plant control panels, racks, and other electrical enclosures do not meet the IEEE 383-1974 requirements. The use of polyvinyl chloride (PVC) cabling is minimized. Where IEEE 383 rated cable is not available for a particular application, cable procured to meet National Electric Code guidelines for fire resistance for plenum rated cabling using

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
			NFPA 262-1990, UL 910-985, or equivalent may be used.
D.3.g	To the extent practical, cable construction that does not give off corrosive gases while burning should be used. Applicable to new cable installations.	D.3.g	Cables are generally jacketed with a cross-linked polyolephin (XLPE) material which gives off as little corrosive gas as practical. The use of polyvinyl chloride (PVC) cabling is minimized.
D.3.h	Cable trays, raceways, conduit, trenches, or culverts should be used only for cables. Miscellaneous storage should not be permitted, nor should piping for flammable or combustible liquids or gases be installed in these areas. Installed equipment in cable tunnels or culverts need not be removed if they present no hazard to the cable runs as determined by the fire hazards analysis.	D.3.h	Cable trays, raceways, and conduits are used only for cables. There are no cable tunnels or culverts in the plant. There are no provisions for miscellaneous storage in cable areas, nor are flammable or combustible liquids or gases installed in these areas.
D.3.i	The design of cable tunnels, culverts and spreading rooms should provide for automatic or manual smoke venting as required to facilitate manual fire fighting capability.	D.3.i	There are no cable tunnels or culverts in the plant. Air from the cable spreading room normally passes into the cable chase through openings protected by 3-hr fire-rated dampers and then back to an air conditioning unit. Ionization detectors spaced through both areas and a smoke detector, mounted in the ductwork, monitor the return air. On actuation of the detector, an alarm sounds in the control room. The control room operator can then shut down the air conditioning unit. As the cable spreading room and cable chase are each protected by an automatic preaction sprinkler system designed for cable tray fire extinguishment, a fire would be of limited duration. Smoke from a fire would be purged through the actuation of a fixed exhaust fan and ductwork and discharged directly to the atmosphere. The use of fans and ducting to discharge smoke to the atmosphere would help maintain visibility in both the cable chase and the cable spreading room.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
D.3.j	Cables in the control room should be kept to the minimum necessary for operation of the control room. All cables entering the control room should terminate there. Cables should not be installed in floor trenches or culverts in the control room. Existing cabling installed in concealed floor and ceiling spaces should be protected with an automatic total flooding Halon system.	D.3.j	The main control room is composed mainly of a "panel assembly" system. Each "panel assembly" consists of a termination cabinet, a subfloor section (with enclosed, segregated ducts for cable routing), and a vertical panel and/or benchboard assembly. A 1-ft deep raised floor is provided for the entire room. The "panel assembly" subfloor sections comprise a major portion of this false floor. Panel assembly ducts, termination cabinet cable entrance/exit areas, and vertical panel and benchboard assembly cable entrance/exit areas are located beneath the false floor. Most cables entering the room enter the termination cabinets directly. They are either terminated there or route directly to vertical panels or benchboards for termination. Some cables enter the false floor outside the "panel assemblies." They then route either into the panel assemblies, or to other control room equipment not a part of the "panel assembly" system (lighting panels, relay panels, etc.). A Halon extinguishing system is provided for the subfloor sections longitudinal cable ducts. Seals for Halon containment are provided at the entrance and exit points to the ducts. All penetrations into the main control room are provided with fire-rated seals. Cables entering the false floor outside the "panel assemblies" are enclosed in metallic flexible conduit, covered metal troughs, Haveg Siltemp tape, or suitable fire resistive cable as identified in NFPA 70 for under raised floors. All cables in the suspended ceiling area (lighting, communication, fire detector, etc.) are non-safety-related and enclosed in conduit. For this reason, an automatic flooding system is not deemed necessary.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
D.4 Ventilation	D.4 Ventilation
D.4.a The products of combustion that need to be removed from a specific fire area should be evaluated to determine how they will be controlled. Smoke and corrosive gases should generally be automatically discharged directly outside to a safe location. Smoke and gases containing radioactive materials should be monitored in the fire area to determine if release to the environment is within the permissible limits of the plant Technical Specifications. The products of combustion which need to be removed from a specific fire area should be evaluated to determine how they will be controlled.	D.4.a Products of combustion are removed from specific areas by two methods, as follows: a. Areas with direct duct connections to the exhaust system discharge directly to the atmosphere. These areas are: 1. Turbine generator building a) Reactor feed pump rooms b) Mechanical vacuum pump rooms c) Auxiliary boiler room 2. Reactor building a) LPCS pump room b) RHR pump rooms c) RCIC pump room d) HPCS pump room e) CRD pump room 3. Diesel generator building a) Diesel oil day tank rooms b) Diesel generator rooms c) Diesel oil transfer pump rooms d) Air compressors and electrical equipment rooms 4. Circulation water pump house b. Areas of the plant to which air is supplied and return air is routed to other areas of higher potential radioactivity prior to final exhaust are: 1. Turbine generator building (a) Turbine oil reservoir and conditioner room (b) H_2 seal oil unit room (c) Turbine lube oil storage room (d) General area containing (1) Service and instrument air compressors (2) Condensate pumps (3) Condensate booster pumps (4) Turbine oil transfer lines (5) Cables

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
	2. Reactor building general area containing (a) SLC pumps (b) Cables (c) Standby gas treatment units (d) Sump vent filter units 3. Radwaste building general area containing (a) Exhaust air filter units (b) Cables Exhaust air from the reactor, radwaste, and turbine generator buildings is monitored to determine the quantity of radioactive material being released to the environment. Smoke removal equipment, such as a fixed and a portable fan and flexible ducting are available in the radwaste/control and reactor buildings to aid in smoke removal. The basic air flow patterns were established by exhausting directly from potentially contaminated areas, as well as indirectly by inducing air from nonpotentially contaminated areas into shielded areas before discharging to the atmosphere. See Section F.2.5.5 for more details on smoke removal. Fire dampers were provided in ducting and wall penetrations to protect areas containing large quantities of combustibles or redundant safety-related systems against the postulated fires according to the severity of the fire as determined by the fire loading in the hazards analysis. The portable fan and ducting provide the latitude of allowing the existing fire barrier dampers to remain in a closed position while exhausting the impeding smoke from the fire area.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
D.4.b	Any ventilation system designed to exhaust smoke or corrosive gases should be evaluated to ensure that inadvertent operation or single failures will not violate the controlled areas of the plant design. This requirement includes containment functions for protection of the public and maintaining habitability for operations personnel.	D.4.b	All ventilation systems designed to exhaust smoke and corrosive gases are functioning during normal plant operation with the exception of the SGT units and the portable smoke removal units. Standby fans are available for backup operation of the ventilation systems in the reactor, radwaste, and turbine generator buildings. Inadvertent operation or single failures of these units will not violate safety requirements for the plant personnel or the public.
D.4.c	The power supply and controls for mechanical ventilation systems should be run outside the fire area served by the system.	D.4.c	The power supply and controls for mechanical ventilation systems have not always been run outside the fire areas served by the system. The fire hazards analysis demonstrates that post-fire safe shutdown capability is not jeopardized by this cable routing.
D.4.d	Fire suppression systems should be installed to protect charcoal filters in accordance with Regulatory Guide 1.52, "Design Testing and Maintenance Criteria for Atmospheric Cleanup Air Filtration."	D.4.d	Fire suppression systems have been installed in the safety-related standby gas treatment filter unit, control room emergency filter unit, and the reactor sump vent filter unit in accordance with Regulatory Guide 1.52. The offgas system charcoal units are contained in eight ASME, Section III, Class 3 coded vessels in the radwaste building. They are not protected by a fire suppression system. Valving, however, breaks the tanks down into groups that can be closed off to eliminate oxygen thereby extinguishing a fire. The probability of flame spread from the units is considered small and they are well separated from safety-related circuits and components.
D.4.e	The fresh air supply intakes to areas containing safety related equipment or systems should be located remote from the exhaust air outlets and smoke vents of other fire areas to minimize the possibility of contaminating the intake air with the products of combustion.	D.4.e	The fresh air supply intakes to areas containing safety-related equipment or systems are located with sufficient separation from exhaust air outlets and smoke vents to minimize the possibility of contaminating the intake air with products of combustion.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
D.4.f Stairwells should be designed to minimize smoke infiltration during a fire. Staircases should serve as escape routes and access routes for fire fighting. Fire exit routes should be clearly marked. Stairwells, elevators and chutes should be enclosed in masonry towers with minimum fire rating of three hr and automatic fire doors at least equal to the enclosure construction, at each opening into the building. Elevators should not be used during fire emergencies.	D.4.f Enclosed fire rated stairwells and elevators provide either a 2-hr or 3-hr fire rating, with 1.5 hr minimum fire doors. See Figures F.6-1 through F.6-5. Door T207 to the service building roof is nonrated. Enclosed fire rated stairwells are not equipped with ventilation and would effectively limit smoke infiltration. Elevators are not typically used for egress during fire emergencies.
D.4.g Smoke and heat vents may be useful in specific areas such as cable spreading rooms and diesel fuel oil storage areas and switchgear rooms. When natural-convection ventilation is used, a minimum ratio of 1 sq. ft of venting area per 200 sq. ft of floor area should be provided. If forced-convection ventilation is used, 300 CFM should be provided for every 200 sq. ft of floor area. See NFPA No. 204 for additional guidance on smoke control.	D.4.g Provisions for smoke and heat relief are discussed in paragraphs D.3.i and D.4.a above. In areas where smoke and heat are removed by the normal ventilation systems, a minimum of 300 cfm is provided for every 200 ft^2 of floor area except in the following areas:

Area	Ventilation per 200 ft^2	Supplementary Ventilation Equipment
Safety-Related Areas		
HPCS pump room	251 cfm	Portable fan flex duct
RHR-2A pump room	148 cfm	Portable fan-flex-duct
RHR-2B pump room	127 cfm	Portable fan-flex-duct
SGT-general area	207 cfm	Portable fan-flex-duct
D.O. transfer pump room	278 cfm	Portable fan-flex-duct
Cable spreading rooms	24 cfm[a]	Fixed fan-flex-duct
Control room	0 cfm	Fixed fan-flex duct
Control bldg. mech. duct equipment room	0 cfm	Fixed fan-flex duct
Cable chase	205 cfm	Fixed fan-flex duct

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
			Non-Safety-Related Areas Turbine L.O. storage room — 277 cfm — Portable fan-flex duct TG operating floor[b] — 274 cfm — Portable fan-flex duct [a] 1000 cfm purge air. [b] Roof vents are not provided.
			Portable and fixed fans with flexible ducting are provided to allow smoke removal from rooms in which additional ventilation is required.
D.4.h	Self-contained breathing apparatus, using full face positive pressure masks, approved by NIOSH (National Institute of Occupational Safety and Health - approval formerly given by the US Bureau of Mines) should be provided for fire brigade, damage control, and control room personnel. Control room personnel may be furnished breathing air by a manifold.	D.4.h	Provisions have been made to ensure that adequate self-contained breathing apparatus (SCBA) are available for fire fighting, damage control personnel, and control room operating personnel. These units are independent of respiratory protective equipment provided for general plant activities. See Table F.3-2 of Section III.H for more SCBA requirements.
D.4.i	Where total flooding gas extinguishing systems are used, area intake and exhaust ventilation dampers should close upon initiation of gas flow to maintain necessary gas concentration. (See NFPA 12, "Carbon Dioxide Systems," and 12A, "Halon 1301 Systems.")	D.4.i	The total flooding Halon 1301 system for the main control room PGCC ducts does not require closure of any ventilation dampers to maintain necessary gas concentration.
D.5	Lighting and Communication	D.5	Lighting and Communication
D.5.a	Fixed emergency lighting should consist of sealed beam units with individual 8-hour minimum battery power supplies.	D.5.a	Fixed emergency lighting for egress consists of 1.5-hr Life Safety and Appendix R 8-hr emergency lights. In critical areas, emergency lighting is installed and powered from the emergency buses which are supplied by the diesel generators. All plant areas, which must be manned for post-fire safe shutdown and all associated

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
	access/egress routes, have been provided with adequate lighting such that any required operator actions can be accomplished. The plant emergency lighting systems are further described in Section 9.5.3.
D.5.b Suitable sealed-beam battery powered portable hand lights should be provided for emergency use.	D.5.b Suitable sealed-beam, battery-powered portable hand lights have been provided.
D.5.c Voice powered head sets are provided throughout the plant at preset locations.	D.5.c Fixed emergency communication use voice powered head sets at preselected locations.
D.5.d Fixed repeaters installed to permit use of portable radio communication units should be protected from exposure fire damage.	D.5.d There are two remote fixed repeaters installed for radio communication which would not be subject to plant exposure fires due to their offsite locations. The repeaters will not permit communication from portable radios from all areas of the plant because of shielding from structural steel and other metallic structures. However, portable radios can communicate via either of two base stations. During normal operations with both stations operating, portable radios can be used for fire protection communication via the Operations and Maintenance (O&M) station located in the communications equipment room on the 525-ft elevation of the radwaste/control building. In the event the O&M radio is not operable, radio communication can be transmitted over the security system radio under administrative control. The security radio base station is located in the central alarm station.
E. FIRE DETECTION AND SUPPRESSION	E. FIRE DETECTION AND SUPPRESSION
E.1 <u>Fire Detection</u>	E.1 <u>Fire Detection</u>
E.1.a Fire detection systems should as a minimum comply with NFPA 72D, "Standard for Installation, Maintenance and Use of	E.1.a The fire detection system conforms to NFPA 72D for a Class B designation with the following exceptions: detection circuits

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

	BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
	Proprietary Protective Signaling Systems." Deviations from the requirements of NFPA 72D should be identified and justified.		that actuate fire suppression systems in safety-related areas are Class A. Incoming signals to the control room fire panel are manually recorded. WNP-2 employs a pre-alarm detection system which sounds an alarm signal in the control room only. The control room operator manually sounds a building wide alarm over the public address system. All signals to the control room are identified by zones which designate the building, floor, and cause of alarm. A manual push button radio fire alarm reporter is used to transmit an alarm to the offsite fire department. Pre-alarm detectors are installed according to UL recommendations and are spaced to provide the following coverage in the main plant: a. Ionization detector................. 520 ft^2 b. Photoelectric smoke detector.... 1200 ft^2 c. Combination rate of rise and fixed temperature detector........ 500 ft^2 Certain testing which would require entry into high radiation areas may not be performed during power operation. See Section F.2 for further discussion of the fire detection system.
	Fire detection system should give audible and visual alarm and annunciation in the control room. Local audible alarms should also sound at the location of the fire.		Fire detection systems provide audible and visual alarms in the control room. Plant-wide alarms and public address announcements are initiated by the main control room operator in accordance with emergency procedures.
E.1.c	Fire alarms should be distinctive and unique. They should not be capable of being confused with any other plant system alarms.	E.1.c	Fire alarms are distinctive and unique from all other plant system alarms.
E.1.d	Fire detection and actuation systems should be connected to the plant emergency power supply.	E.1.d	Fire detection and actuation systems are connected to power panels which are supplied by uninterruptible power supplies.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
E.2 Fire Protection Water Supply System	E.2 Fire Protection Water Supply System
E.2.a An underground yard fire main loop should be installed to furnish anticipated fire water requirements, NFPA 24 - Standard for Outside Protection - gives necessary guidance for such installation. It references other design codes and standards developed by such organizations as the American National Standards Institute (ANSI) and the American Water Works Association (AWWA). Lined steel or cast iron pipe should be used to reduce internal tuberculation. Such tuberculation deposits in an unlined pipe over a period of years can significantly reduce water flow through the combination of increased friction and reduced pipe diameter. Means for treating and flushing the systems should be provided. Approved visually indicating sectional control valves, such as post indicator valves, should be provided to isolate portions of the main for maintenance or repair without shutting off the entire system. The fire main system piping should be separate from service or sanitary water system piping. Visible location marking signs for underground valves is acceptable. Alternative valve position indicators should also be provided. For operating plants, fire main system piping that can be isolated from service or sanitary water system piping is acceptable.	E.2.a The underground yard fire main circles the plant. NFPA 24-1973 was used as the design code. The fire main is constructed of 12-in. ductile iron, cast iron, and steel pipe. The underground pipe, valves, and fittings have an applied coating of bituminous material with a minimum thickness of 1 mil. The interior coating on ductile iron and cast iron piping conforms to the requirements of ANSI A21.4. All underground valves in the fire main loop have post indicators for visual indication and to isolate portions of the fire main. The underground fire main is periodically flushed. The fire protection water system is independent of the domestic system. The fire water system does interface with a. CW and TMU system for makeup water, b. TSW system for temporary lubrication, c. CAS system for backup station air compressor cooling, and d. COND system as one of the alternate injection methods.
E.2.b A common yard fire main loop may serve multi-unit nuclear power plant sites if cross-connected between units. Sectional control valves should permit maintaining independence of the individual loop around each unit. For such installations, common water supplies may also be utilized. The water supply should be sized for the largest	E.2.b WNP-2 is not a multiple reactor site.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
	single expected flow. For multiple reactor sites with widely separated plants (approaching 1 mile or more), separate yard fire main loops should be used. Sectionalized systems are acceptable.		
E.2.c	If pumps are required to meet system pressure or flow requirements, a sufficient number of pumps should be provided so that 100% capacity will be available with one pump inactive (e.g., three 50% pumps or two 100% pumps). The connection to the yard fire main loop from each fire pump should be widely separated, preferably located on opposite sides of the plant. Each pump should have its own driver with independent power supplies and control. At least one pump (if not powered from the emergency diesels) should be driven by nonelectrical means, preferably diesel engine. Pumps and drivers should be located in rooms separated from the remaining pumps and equipment by a minimum 3-hr fire wall. Alarms indicating pump running, driver availability, or failure to start should be provided in the control room. Details of the fire pump installation should as a minimum conform to NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps."	E.2.c	Fire pumps are required to meet the fire protection system pressure and flow requirements. This system design has been accepted by the insuring authority. Three fire pumps, each with a flow rate of 2000 gpm, are located in the circulating water pump house and draw water from the circulating water pump house basin. This is the primary source of water for fire protection. Two of the pumps are electrically driven and powered from separate electrical buses. The third pump is powered by its own diesel engine. The three pumps are spatially separated with approximately 23 ft between electric pumps and 30 ft between the nearest electric driven pump and the diesel driven pump. The pump house hall is protected by a fixed sprinkler system. The pumps and drivers are elevated above the floor by concrete pedestals thus floor drainage is not a concern. Each pump is capable of supplying 100% of the fire water flow rate except under the following conditions: a. Due to the complexity of cable tray routing in the cable chase and cable spreading rooms, two pumps are required to meet the fire water system design requirements, and b. The 100% pump flow rate capacity would be limited to the fixed system and two interior hoses. If exterior hoses are used, there would be a slight reduction in system and hose densities.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM	
			Two supply lines run parallel to each other from the circulating water pump house fire pumps to the south side of the plant fire water supply loop where they connect to the loop with a 10-ft separation. A back up diesel-driven fire pump rated at 2500 gpm is provided and located in the filtration building. The pump draws water from a 400,000 gal bladder tank. It discharges into the north side of the plant fire water supply loop. NFPA 20-1974 was used for design guidance in the fire pump installation. The fire pumps are UL listed and Factory Mutual approved. Alarms indicating pump running and power failure malfunction are provided for each pump in the main control room.
E.2.d	Two separate reliable water supplies should be provided. If tanks are used, two 100% (minimum of 300,000 gal each) system capacity tanks should be installed. They should be so interconnected that pumps can take suction from either or both. However, a leak in one tank or its piping should not cause both tanks to drain. The main plant fire water supply capacity should be capable of refilling either tank in a minimum of 8 hr. Common tanks are permitted for fire and sanitary or service water storage. When this is done, however, minimum fire water storage requirements should be dedicated by means of a vertical standpipe for other water services.	E.2.d	Two separate reliable water supplies are provided. The primary water supply is the circulating water pump house basin. The water level in the basin is monitored and it provides 100% of the fire water supply as defined in paragraph E.2.e. Should the quantity of water drop to a low level an alarm signals the Control Room operator to initiate the makeup water pumps. An inexhaustible quantity of makeup water can be supplied to the basin at the rate of 12,500 to 25,000 gpm from the cooling tower makeup water system from the Columbia River. Water is returned to the basin from the cooling towers by gravity feed. At the low level, the total water available to the fire pumps in the basin and its gravity fed tributary piping is 370,000 gal. A backup water supply is provided by a 400,000 gal bladder tank which provides 100% of the fire water supply as defined in paragraph E.2.e. It has a dedicated water supply of 284,640 gal. The bladder tank can be refilled in approximately 8 hr.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

	BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
			The circulating water pump house basin is not considered a tank with a limited capacity. Therefore, the separate water supplies need not be interconnected.
E.2.e	The fire water supply (total capacity and flow rate) should be calculated on the basis of the largest expected flow rate for a period of two hr, but not less than 300,000 gallons. This flow rate should be based (conservatively) on 1000 gpm for manual hose stream plus the greater of: a. all sprinkler heads opened and flowing in the largest designed fire area; or b. the largest open head deluge system(s) operating.	E.2.e	The requirement of 1000 gpm for manual hose streams has been reduced to 500 gpm by BTP CMEB 9.5.1 (NUREG-0800). The fire protection system water supply is designed to meet the water flow demand assuming the shortest leg of the fire main loop is inoperable. The required water supply of 284,640 gal is based on a 2-hr flow period for the largest demand of a sprinkler system in a safety-related area of 2372 gpm (sprinkler demand for the cable spread room which includes 500 gpm for hose streams). See also paragraph E.2.d.
E.2.f	Lakes or fresh water ponds of sufficient size may qualify as sole source of water for fire protection, but require at least two intakes to the pump supply. When a common water supply is permitted for fire protection and the ultimate heat sink, the following should also be satisfied: a. The additional fire protection water requirements are designed into the total storage capacity; and b. Failure of the fire protection system should not degrade the function of the ultimate heat sink.	E.2.f	Two sources of water are provided for fire protection. See paragraph E.2.d above. The fire water supply is independent of the ultimate heat sink.
E.2.g	Outside manual hose installation should be sufficient to reach any location with an effective hose stream. To accomplish this, hydrants should be installed approximately every 250 feed on the yard main system. The lateral to each hydrant from the yard main should be controlled by a visually indicating or key operated (curb) valve. A hose house, equipped with hose and combination nozzle, and other auxiliary	E.2.g	The yard fire main loop includes hydrants installed approximately every 300 ft. Each hydrant has a post indicating control valve. A hose cabinet equipped with 200 ft of 2.5 in. hose and other auxiliary equipment is provided at each hydrant. By joining sufficient hose sections together, all plant locations can be reached by an effective hose stream. A combination fog shut-off type hose nozzle is provided at each hose house.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

	BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
	equipment recommended in NFPA 24, "Outside Protection," should be provided as needed but at least every 1000 ft.		Threads are compatible with those used by the local fire department.
	Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings and standpipe risers.		
E.3.a	Each automatic sprinkler system and manual hose station standpipe should have an independent connection to the plant underground water main. Headers fed from each end are permitted inside buildings to supply multiple sprinkler and standpipe systems. When provided, such headers are considered an extension of the yard main system. The header arrangement should be such that no single failure can impair both the primary and backup fire protection systems.	E.3.a	Each automatic sprinkler system does not have an independent connection to the fire main loop. Sectionalizing valves have been installed in the yard loop to isolate impairments. Standpipes in the radwaste/control and diesel generator buildings have been interconnected with other standpipes so that a single failure would not impair systems protecting safety-related equipment. (See paragraph A.4 above for further discussion of the single failure criterion).
	Each sprinkler and standpipe system should be equipped with OS&Y (outside screw and yoke) gate valve, or other approved shut off valve, and water flow alarm. Safety related equipment that does not itself require sprinkler water fire protection, but is subject to unacceptable damage if wetted by sprinkler water discharge, should be protected by water shields or baffles.		Each sprinkler and standpipe system within the permanent plant island is controlled by an OS&Y gate valve or other approved shut-off valve. Alarm type check or deluge valves are installed as required in each sprinkler system and cause an alarm in the control room on water flow. There are no flow alarms on hose station standpipes but the control room operator would be aware of a flow by the main fire pumps operating annunciators. There is no safety-related equipment that is subject to unacceptable damage if wetted by sprinkler water discharge. Buildings in the WNP-2 industrial area with installed sprinkler systems are isolated from the yard main by post indicating valves. These systems are alarmed to the Protected Area Access Security Control Center (SCC).
E.3.b	All valves in the fire water systems should be electrically supervised. The electrical supervision signal should indicate in the	E.3.b	Water supply control valves in the fire water system are either locked open or have valve tamper switches which alarm in the control

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

	BTP 9.5-1 APPENDIX A		WNP-2 FIRE PROTECTION PROGRAM
	control room and other appropriate command locations in the plant (See NFPA 26, "Supervision at Valves.") When electrical supervision of fire protection valves is not practicable, an adequate management supervision program should be provided. Such a program should include locking valves open with strict key control; tamper proof seals; and periodic visual check of all valves.		room. Outside valves are provided with post indicators. Valves FP-V-16A and FP-V-16B have valve tamper switches which alarm in the control room. Valves that control water to the fire protection system are controlled as follows: a. Valves larger than 2-in. are locked in the wide open position with non-breakable shackle locks, b. Valves 2-in. and smaller controlling water supplies are sealed in the full open position, c. Valves to sprinkler or deluge alarm lines are sealed in the open position, and d. Valves that control water flow are checked quarterly.
E.3.c	Automatic sprinkler systems should as a minimum conform to requirements of appropriate standards such as NFPA 13, "Standard for the Installation of Sprinkler Systems", and NFPA 15, "Standard for Water Spray Fixed Systems."	E.3.c	Installed sprinkler systems were designed using NFPA 13-1975 and NFPA 15-1973. Fire protection systems installed in safety-related areas have been specifically reviewed to identify deviations from the code requirements. (See Section F.2).
E.3.d	Interior manual hose installation should be able to reach any location with at least one effective hose stream. To accomplish this, standpipes with hose connections equipped with a maximum of 75 ft of 1.5 in. woven jacket lined fire hose and suitable nozzles should be provided in all buildings, including containment, on all floors and should be spaced at not more than 100-ft intervals. Individual standpipes should be of at least 4-in. diameter for multiple hose connections and 2.5-in. diameter for single hose connections. These systems should follow the requirements of NFPA No. 14 for sizing, spacing and pipe support requirements of NFPA No. 14 for sizing, spacing and pipe support requirements (NELPIA).	E.3.d	Standpipes and manual hose stations were designed using NFPA 14-1974. Hose stations are presently provided with 150 ft of 1.5-in. rubber lined fire hose with shutoff type fog nozzle and are capable of reaching any location with at least one effective hose stream in all building fire areas. The interior manual hose installations provide hose connections equipped with a maximum of 100 ft of 1.5-in. fire hose in most safety-related areas. The reactor building requires 150-ft hose lengths. The modified arrangement allows any location that contains, or could present a fire exposure hazard, to safety-related equipment to be reached with at least one effective hose stream as defined in NFPA 14.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
Hose stations should be located outside entrances to normally unoccupied areas and inside normally occupied areas. Standpipes serving hose stations in areas housing safety-related equipment should have shut off valves and pressure reducing devices (if applicable) outside the area.	Hose stations are presently located inside enclosed stairways to the various fire areas of all buildings. All hose stations and their shutoff valves serving areas housing safety-related equipment are located outside of the area.
E.3.e The proper type of hose nozzles to be supplied to each area should be based on the fire hazard analysis. The usual combination spray/straight stream nozzle may cause unacceptable mechanical damage (for example, the delicate electronic equipment in the control room) and be unsuitable. Electrically safe nozzles should be provided at locations where electrical equipment or cabling is located.	E.3.e Manual hose stations are equipped with all fog nozzles for use with Class A, B, and C fires. The nozzle control goes from shutoff directly to 30° fog with adjustments to 90°.
E.3.f Certain fires such as those involving flammable liquids respond well to foam suppression. Consideration should be given to use of any of the available foams for such specialized protection application. These include the more common chemical and mechanical low expansion foams, high expansion foam and the relatively new aqueous film forming foam (AFFF).	E.3.f Portable AFFF foam units are staged in designated areas for fighting combustible liquid fires. There is no bulk storage of flammable liquids included in the plant design.
E.4 Halon Suppression Systems	E.4 Halon Suppression Systems
The use of Halon fire extinguishing agents should as a minimum comply with the requirements of NFPA 12A and 12B, "Halogenated Fire Extinguishing Agent Systems - Halon 1301 and Halon 1211." Only UL of FM approved agents should be used. In addition to the guidelines of NFPA 12A and 12B, preventative maintenance and testing of the systems, including check weighing of the Halon cylinders should be done at least quarterly. Particular consideration should also be given to: a. minimum required Halon concentration and soak time	Halon 1301 extinguishing systems are installed in the control room PGCC subfloor sections longitudinal cable ducts. The systems comply with the requirements of NFPA Standard 12A and GE Topical Report NEDO 10466-A. The Halon system for the control room PGCC subfloor sections longitudinal cable ducts in Area 1 consist of high pressure cylinders and necessary piping, nozzles, valves and detectors for suppressing fires in each of the sections. The Halon system will provide 20% concentration by volume for a 20-minute duration in the subfloor section ducts.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
b. toxicity of Halon c. toxicity and corrosive characteristics of thermal decomposition products of Halon	The Halon 1301 agent is considered noninjurious to room occupants when the design concentration of the gas for total flooding does not exceed 7% of room volume. Halon discharges in the PGCC subfloor only, not in the occupied areas of the control room. A local alarm is installed to alert personnel prior to any discharge. It is considered that there will be no immediate adverse effects to sensitive electronic equipment due to thermal decomposition products of Halon 1301 under fire and nonfire conditions.
E.5 Carbon Dioxide Suppression Systems	E.5 Carbon Dioxide Suppression Systems
The use of carbon dioxide extinguishing systems should as a minimum comply with the requirements of NFPA 12, "Carbon Dioxide Extinguishing Systems." Particular consideration should be given to a. Minimum required CO_2 concentration and soak time: b. Toxicity of CO_2; c. Possibility of secondary thermal shock (cooling damage); d. Offsetting requirements for venting during CO_2 injection to prevent overpressurization versus sealing to prevent loss of agent; e. Design requirements from overpressurization; and f. Possibility and probability of CO_2 systems being out-of-service because of personnel safety consideration. CO_2 systems are disarmed whenever people are present in an area so protected. Areas entered frequently (even though duration time for any visit is short) have often been found with CO_2 systems shut off.	A low-pressure carbon dioxide extinguishing system is installed in the exciter housing of the turbine generator. During outages when the exciter housing is accessible, the CO_2 system is disarmed. The system was designed using NFPA 12-1973 where applicable.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
E.6 Portable Extinguishers	E.6 Portable Extinguishers
Fire extinguishers should be provided in accordance with guidelines of NFPA 10 and 10A, "Portable Fire Extinguishers, Installation, Maintenance and Use." Dry chemical extinguishers should be installed with due consideration given to cleanup problems after use and possible adverse effects on equipment installed in the area.	Dry chemical portable fire extinguishers are located throughout WNP-2. Halon 1211 portable extinguishers are also present in electronic equipment areas. Portable extinguishers were selected using NFPA 10-1975.
F. GUIDELINES FOR SPECIFIC PLANT AREAS	F. GUIDELINES FOR SPECIFIC PLANT AREAS
F.1 Primary and Secondary Containment	F.1 Primary and Secondary Containment
F.1.a Normal Operation	F.1.a Normal Operation
Fire protection requirements for the primary and secondary containment areas should be provided on the basis of specific identified hazards. For example: a. Lubricating oil or hydraulic fluid system for the primary coolant pumps b. Cable tray arrangements and cable penetrations c. Charcoal filters Fire suppression systems should be provided based on the fire hazards analysis. Fixed fire suppression capability should be provided for hazards that could jeopardize safe plant shutdown. Automatic sprinklers are preferred. An acceptable alternate is automatic gas (Halon or CO_2) for hazards identified as requiring fixed suppression protection. An enclosure may be required to confine the agent if a gas system is used. Such enclosures should not adversely affect safe shutdown, or other operating equipment in containment.	The primary containment is inerted with nitrogen. In the secondary containment, manually actuated fire suppression systems have been provided for each charcoal filter bed and roughing filter in the standby gas treatment unit and each charcoal filter bed in the sump vent filter unit. Operation of these systems will not compromise the operation of safety-related systems. Automatic fire detection is provided throughout the secondary containment with annunciation in the control room. Detectors were selected and located after evaluating the hazards involved.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
Automatic fire suppression capability need not be provided in the primary containment atmospheres that are inerted during normal operation. However, special fire protection requirements during refueling and maintenance operations should be satisfied as provided below.	
F.1.b Refueling and Maintenance	F.1.b Refueling and Maintenance
Refueling and maintenance operations in containment may introduce additional hazards such as contamination control materials, decontamination supplies, wood planking, temporary wiring, welding and flame cutting (with portable compressed fuel gas supply). Possible fires would not necessarily be in the vicinity of fixed detection and suppression systems. Management procedures and controls necessary to assure adequate fire protection are discussed in Section B.3.a. In addition, manual fire fighting capability should be permanently installed in containment. Standpipes with hose stations, and portable fire extinguishers, should be installed at strategic locations throughout containment for any required manual fire fighting operations. Equivalent protection from portable systems should be provided if it is impractical to install standpipes with hose stations. Adequate self-contained breathing apparatus should be provided near the containment entrances for fire fighting and damage control personnel. These units should he independent of any breathing apparatus or air supply systems provided for genelant activities.	Plant procedures establish fire protection controls during refueling and maintenance operations. Manual fire fighting capability is provided in secondary containment by standpipes with hose stations and portable fire extinguishers Adequate self-contained breathing apparatus is available for fire fighting. See Table F.3-2, paragraph III-H.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
F.2 Control Room	F.2 Control Room
The control room is essential to safe reactor operation. It must be protected against disabling fire damage and should be separated from other areas of the plant by floors, walls and roofs having minimum fire resistance ratings of 3 hr. Control room cabinets and consoles are subject to damage from two distinct fire hazards: a. Fire originating within a cabinet or console, and b. Exposure fire involving combustibles in the general room area. Manual fire fighting capability should be provided for both hazards. Hose stations and portable water and Halon extinguishers should be located in the control room to eliminate the need for operators to leave the control room. An additional hose piping shut off valve and pressure reducing device should be installed outside the control room. Hose stations adjacent to the control room with portable extinguishers in the control room are acceptable. Nozzles that are compatible with the hazards and equipment in the control room should be provided for the manual hose station. The nozzles chosen should satisfy actual fire fighting needs, satisfy electrical safety and minimize physical damage to electrical equipment from hose stream impingement. Fire detection in the control room cabinets, and consoles should be provided by smoke and heat detectors in each fire area. Alarm and annunciation should be provided in the control room. Fire alarms in other parts of the plant should also be alarmed and annunciated in the control room. Breathing apparatus for control room operators should be readily available. Control room floors, ceiling, supporting structures, and walls, including penetrations and doors, should be designed to a minimum fire rating of three hr. All penetration seals should be air tight.	The control room is separated from other areas of the plant by floor, walls, and ceiling having a minimum fire resistance rating of 3 hr. Access to the control room is gained by passing through low range blast doors with construction equivalent to that of a 3-hr fire-rated door. The exit from the control room consists of a door from the airlock to the stairwell which has a construction equivalent to that of a 1.5-hr fire-rated door, and a 1.5 hr rated doors from the stairwell to adjacent areas. The control room PGCC subfloor sections longitudinal cable ducts are protected from fire by a total flooding Halon 1301 system. Portable Halon and dry chemical extinguishers are located inside the control room and a standby hose station is provided adjacent to the control room for manual fighting of fires in cabinets, consoles, and involving combustibles in the general room area. Fire detection in the PGCC cabinets and consoles is provided by ionization detectors. Fire detection in the PGCC subfloor sections longitudinal cable ducts is provided by ionization and thermal detectors. Alarm and annunciation are provided in the control room. Fire alarms in other parts of the plant are alarmed and annunciated in the control room. Adequate numbers of SCBA are provided for fire fighting and damage control personnel. All penetration seals to the control room are pressure resistant. All ventilation penetrations into the control room are protected by 3-hr fire-rated dampers. The control room ventilation intake is provided with smoke detection to automatically alarm and isolate the control room ventilation system. The control room is also monitored by area ionization detectors. Smoke is prevented from entering the control room from other areas due to the pressurization of the room by the air conditioning system. Makeup air for the control room air conditioning system is drawn through the outside air intake which is located approximately 87 ft above the ground. If smoke is observed entering the intake, the control room operator has the option of

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
The control room ventilation intake should be provided with smoke detection capability to automatically alarm locally and isolate the control room ventilation system to protect operators by preventing smoke from entering the control room.	drawing the makeup air through alternate intakes remote from the main plant buildings.
Manually operated venting of the control room should be available so that operators have the option of venting for visibility. Manually operated ventilation systems are acceptable.	If it is necessary to exhaust smoke from the room, then fixed fan and flexible ducting would be used.
Cables should not be located in concealed floor and ceiling spaces. All cables that enter the control room should terminate in the control room. That is, no cabling should be simply routed through the control room from one area to another. If such concealed spaces are used, however, they should have fixed automatic total flooding Halon protection.	All cables in the suspended ceiling of the control room are in electric metallic tubing (EMT) type conduit. All cables in the raised floor extending beyond the PGCC cabinets are either in covered metal troughs, flexible metal conduit, Haveg Siltemp tape, or suitable fire resistive cable as identified in NFPA 70 for under raised floors. There are no automatic fixed Halon systems other than those protecting the PGCC subfloor sections longitudinal cable ducts.
F.3.a Cable Spreading Room	F.3.a Cable Spreading Room
The preferred acceptable methods (for fire suppression) are: a. Automatic water system such as closed head sprinklers, open head deluge, or open directional spray nozzles. Deluge and open spray systems should have provisions for manual operation at a remote station; however, there should also be provisions to preclude inadvertent operation. Location of sprinkler heads of spray nozzles should consider cable tray sizing and arrangements to assure adequate water coverage. Cables should be designed to allow wetting down with deluge water without electrical faulting. Open head deluge and open directional spray systems should be zoned so that a single failure will not deprive the entire area of automatic fire suppression capability. The use of foam is acceptable, provided it is of a type capable of being delivered by a sprinkler or deluge system, such as an aqueous film forming foam (AFFF).	The cable spreading room is protected by a closed head preaction sprinkler system designed to protect the overhead and to protect alternate open cable trays horizontally every 10 ft of the cable tray. A large number of ionization detectors are installed to reduce detection time. Cables have been designed to allow wetting without electrical fault. Inadvertent operation is prevented by the preaction system because either a manual trip from a local manual pull station or an automatic trip from the ceiling mounted ionization detectors is required to actuate the deluge valve and flood the system with water. In addition sprinkler heads must be heat actuated before water will flow from the system. The system has been designed taking into consideration cable tray sizing and arrangements such that there is adequate water coverage. Dry chemical portable extinguishers are available inside and outside the cable spreading room. A manual hose station is located immediately outside one of the entrances. An additional hose can be extended from the next lower floor at the other entrance.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
b. Manual hoses and portable extinguishers should be provided as backup. c. Each cable spreading room of each unit should have divisional cable separation, and be separated from the other and the rest of the plant by a minimum 3-hr rated fire wall (See NFPA 251 or ASTM E-119 for fire test resistance rating). d. At least two remote and separate entrances are provided to the room for access by fire brigade personnel; and e. Aisle separation provided between tray stacks should be at least 3 ft wide and 8 ft high.	The cable spreading room is separated from other areas of the plant by walls having a minimum fire resistance of 3 hr. There are two remote and separate entrances to the room having doors with a 3-hr rating. Generally, tray stacks are separated by 3-ft aisles and aisle headroom is typically 8 ft; however, there are some tray crossover and support obstructions which hamper but do not preclude access. Cables have been arranged to provide divisional separation in accordance with WNP-2 electrical separation guidelines as described in Section 8.3.1.4. A 20-ft noncombustible zone divides the cable spreading room. The intervening zone runs the entire length of the room (east-west) and is formed by providing a Thermo-Lag coating over all cables in trays to prevent fire propagation. The intervening zone is also protected by the cable spreading room preaction sprinkler system.
F.3.b Cable Spreading Room	F.3.b Cable Spreading Room
For cable spreading rooms that do not provide divisional cable separation of c, in addition to meeting a, b, d, and e (of paragraph F.3.a) above, the following should also be provided: a. Divisional cable separation should meet the guidelines of Regulatory Guide 1.75, "Physical Independence of Electric Systems." b. All cabling should be covered with a suitable fire retardant coating. c. As an alternate to a above, automatically initiated gas systems (Halon or CO_2) may be used for primary fire suppression, provided a fixed water system is used as a backup. d. Plants that cannot meet the guidelines of Regulatory Guide 1.75, in addition to meeting a, b, d and e above, an auxiliary shutdown system with all	The cable spreading room is designed to provide divisional separation as stated in paragraph F.3.a .

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
cabling independent of the cable spreading room should be provided.	
F.4 Plant Computer Room	F.4 Plant Computer Room
Safety-related computers should be separated from other areas of the plant by barriers having a minimum three-hour fire resistant rating. Automatic fire detection should be provided to alarm and annunciate in the control room and alarm locally. Manual hose stations and portable water and Halon fire extinguishers should be provided.	The plant computers are not safety related.
F.5 Switchgear Rooms	F.5 Switchgear Rooms
Switchgear rooms should be separated from the remainder of the plant by minimum three-hour rated fire barriers to the extent practicable. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Fire hose stations and portable extinguishers should be readily available.	Switchgear rooms have been separated from the remainder of the plant by 3-hr rated barriers. Duct penetrations serving the switchgear rooms are provided with 3-hr rated fire dampers. Cable penetrations are sealed. Automatic ionization detectors are provided to alarm in the control room. Manual hose stations and dry chemical portable extinguishers are available.
Acceptable protection for cables that pass through the switchgear room is automatic water or gas agent suppression. Such automatic suppression must consider preventing unacceptable damage to electrical equipment and possible necessary containment of agent following discharge.	Cable routing has been designed such that cables either originate or terminate at the switchgear cabinets and do not just "pass through" the room.
F.6 Remote Safety-Related Panels	F.6 Remote Safety-Related Panels
The general area housing remote safety-related panels should be provided with automatic fire detectors that alarm locally and alarm and annunciate in the control room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be provided.	All areas housing remote safety-related panels are provided with ionization detectors which alarm and annunciate in the control room. Local alarms can be initiated from the control room. Dry chemical portable extinguishers and hose stations are available. Combustible materials are controlled and limited to those required for operation.
F.7 Station Battery Rooms	F.7 Station Battery Rooms
Battery rooms should be protected against fire explosions. Battery rooms should be separated from each other and other areas of the plant by barriers having a minimum fire rating of 3-hr inclusive of all penetrations and openings. (See NFPA 69, "Standard on Explosion Prevention Systems.") Ventilation systems in the battery rooms should be capable of	Battery rooms are separated from each other and other areas of the plant by walls with a minimum fire rating of 3 hr. Door assemblies are also 3-hr rated. Ventilation penetrations serving the battery rooms are protected by 1.5-hr fire rated dampers. This is in excess of that required by the fire loading. Other penetrations serving the battery rooms are sealed.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
maintaining the hydrogen concentration well below 2 vol. % hydrogen concentration. Standpipe and hose and portable extinguishers should be provided. Alternatives: a. Provide a total fire rated barrier enclosure of the battery room complex that exceeds the fire load contained in the room. b. Reduce the fire load to be within the fire barrier capability of 1.5 hr. or c. Provide a remote manual actuated sprinkler system in each room and provide the 1.5-hr fire barrier separation.	The ventilation systems serving the battery room will maintain the hydrogen concentration below 2%. Dry chemical portable extinguishers and hose stations are available to the battery rooms.
F.8 Turbine Lubrication and Control Oil Storage and Use Areas	F.8 Turbine Lubrication and Control Oil Storage and Use Areas
A blank fire wall having a minimum resistance rating of 3 hr should separate all areas containing safety-related systems and equipment from the turbine oil system. When a blank wall is not present, open head deluge protection should be provided for the turbine oil hazards and automatic open head water curtain protection should be provided for wall openings.	The turbine oil system is located in the turbine generator building, separate from all safety-related equipment by a minimum 3-hr fire-rated barrier and/or by spatial separation of at least 50 ft. Components of the turbine oil system are protected by deluge spray or wet sprinkler systems. The ceiling opening in the turbine oil reservoir room is protected by a deluge system.
F.9 Diesel Generator Areas	F.9 Diesel Generator Areas
Diesel generators should be separated from each other and other areas of the plant by fire barriers having a minimum fire resistance rating of three hr. Automatic fire suppression such as AFFF foam, or sprinklers should be installed to combat any diesel generator or lubricating oil fires. Automatic fire detection should be provided to alarm and annunciate in the control room and alarm locally. Drainage for fire fighting water and means for local manual venting of smoke should be provided. Day tanks with total capacity up to 1100 gal are permitted in the diesel generator area under the following conditions:	The diesel generators are separated from each other and other areas of the plant by walls and doors having a minimum fire resistance rating of 3 hr, except at 472 ft 9 in. (see FHA for Fire Areas TG-2 or TG-3). Each diesel generator and day tank is protected by a preaction sprinkler system. Fire detectors are provided for the diesel generator and day tanks which alarm and annunciate in the control room. Means for automatic smoke venting in the diesel generator rooms is accomplished through actuation of the mechanical exhaust air system.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
a. The day tank is located in a separate enclosure, with a minimum fire resistance rating of three hr, including doors or penetrations. These enclosures should be capable of containing the entire contents of the day tanks. The enclosure should be ventilated to avoid accumulation of oil fumes. b. The enclosure should be protected by automatic fire suppression systems such as AFFF or sprinklers. When day tanks cannot be separated from the diesel generator one of the following should be provided for the diesel generator area: a. Automatic open head deluge or open head spray nozzle system(s) , b. Automatic closed head sprinklers, c. Automatic AFFF that is delivered by a sprinkler deluge or spray system, d. Automatic gas system (Halon or CO_2) may be used in lieu of foam or sprinklers to combat diesel generator and/or lubricating oil fires.	Water which would be emitted from the preaction or manual hose systems would be carried away by the floor drain system and through the exterior hinged door flap to the yard. Day tanks, each having a 3000-gal capacity, are provided in separate enclosed areas. One tank is provided for each diesel generator. The day tank enclosures have a minimum fire resistance, including doors, of 3 hr. Enclosure penetrations are sealed. The day tank areas are vented to avoid the accumulation of oil fumes. The enclosures are capable of containing the entire contents of the day tanks. No floor drains are provided in the day tank rooms. Although the total gallon capacity of the day tank exceeds 1100 gal (based on the hourly consumption of the tandem diesels), adequate structural, ventilation, and fire extinguishment features are provided.
F.10 Diesel Fuel Oil Storage Areas Diesel fuel oil tanks with a capacity greater than 1100 gal should not be located inside the buildings containing safety-related equipment. They should be located at least 50 ft from any building containing safety-related equipment, or if located within 50 ft, they should be housed in a separate building with construction having a minimum fire resistance rating of 3 hr. Buried tanks are considered as meeting the 3-hr fire resistance requirements. See NFPA 30, "Flammable and Combustible Liquids Code," for additional guidance. When located in a separate building, the tank should be protected by an automatic fire suppression system such as AFFF or sprinklers.	F.10 Diesel Fuel Oil Storage Areas The diesel oil storage tanks are buried in the yard except for the end portion of each tank containing the transfer pump which extends under the diesel generator building. Each transfer pump is housed in its own room and is separated from other parts of the plant by a fire barrier with a minimum rating of 3 hr. Each pump room is vented mechanically to avoid accumulation of oil fumes. Automatic fire detection is provided in each room to alarm and annunciate in the control room. Each room is protected by a preaction sprinkler system.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
Tanks, unless buried, should not be located directly above or below safety-related systems or equipment regardless of the fire rating of separating floors or ceilings. In operating plants where tanks are located directly above or below the diesel generators and cannot reasonably be moved, separating floor, and main structural members should, as a minimum, have fire resistance rating of three hr. Floors should be liquid tight to prevent leaking of possible oil spills from one level to another. Drains should be provided to remove possible oil spills and fire fighting water to a safe location. One of the following acceptable methods of fire protection should also be provided: a. Automatic open head deluge or open head spray nozzle system(s); b. Automatic closed head sprinklers; or c. Automatic AFFF that is delivered by a sprinkler system or spray system.	
F.11 Safety-Related Pumps Pump houses and rooms housing safety-related pumps should be protected by automatic sprinkler protection unless a fire hazards analysis can demonstrate that a fire will not endanger other safety-related equipment required for safe plant shutdown. Early warning fire detection should be installed with alarm and annunciation locally and in the Control Room. Local hose stations and portable extinguishers should also be provided.	F.11 Safety-Related Pumps Safety-related pumps in the reactor building and in the standby service water pump houses are not protected by sprinklers. Early warning fire detection which alarms and annunciates in the main control room is installed in these areas. Portable fire extinguishers and local hose stations are available. The fire hazards analysis for these areas indicates that a fire will not endanger post-fire safe shutdown capability. The non-safety-related circulating water pumps and fire pumps in the circulating water pump house and the secondary diesel fire pump in the water filtration building are protected by automatic sprinkler systems.
F.12 New Fuel Area Hand portable extinguishers should be located within this area. Also, local hose stations should be located outside but within hose reach of this area. Automatic	F.12 New Fuel Area New fuel is temporarily stored in a storage rack on the 606-ft elevation of the reactor building. Manual hose stations and dry chemical fire extinguishers are

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
fire detection should alarm and annunciate in the control room and alarm locally. Combustibles should be limited to a minimum in the new fuel area. The storage area should be provided with a drainage system to preclude accumulation of water. The storage configuration of new fuel should always be so maintained as to preclude criticality for any water density that might occur during fire water application.	provided in the vicinity. Control room alarms are initiated by the automatic fire detection system. Local audible alarms can be manually sounded from the control room.
F.13 Spent Fuel Pool Area Protection for the spent fuel pool area should be provided by local hose stations and portable extinguishers. Automatic fire detection should be provided to alarm and annunciate in the Control Room and to alarm locally.	F.13 Spent Fuel Pool Area Manual hose stations and dry chemical fire extinguishers are provided in the vicinity of the spent fuel pool. Automatic fire detectors are provided which alarm and annunciate in the control room. Local audible alarms can be manually sounded from the control room.
F.14 Radwaste Building The radwaste building should be separated from other areas of the plant by fire barriers having at least three-hour ratings. Automatic sprinklers should be used in all areas where combustible materials are located. Automatic fire detection should be provided to annunciate the alarm in the control room and alarm locally. During a fire, the ventilation systems in these areas should be capable of being isolated. Water should drain to liquid radwaste building sumps. Acceptable alternative fire protection is automatic fire detection to alarm and annunciate in the control room, in addition to manual hose stations and portable extinguishers consisting of hand held and large wheeled units.	F.14 Radwaste Building The radwaste building is separated from other areas of the plant by fire barrier walls and door assemblies which have fire ratings adequate for the fire loadings. All penetrations in the fire barrier walls are sealed. Automatic sprinkler systems have been provided to protect the prefiltration in the radwaste building exhaust filter systems. In addition, automatic sprinkler protection has been provided over the combustible storage on the 467-ft and 487-ft elevations of the building, and in the solid waste processing area on the 437-ft elevation. Fire detectors are installed in hazard areas to alarm and annunciate in the main control room. Manual hose stations and portable extinguishers are also provided. Water from the fire suppression systems would be drained into the floor drain system which is then pumped into the floor drain collection tank.
F.15 Decontamination Areas The decontamination areas should be protected by automatic sprinklers if flammable liquids are stored. Automatic fire detection should be provided to annunciate and alarm in the control room and alarm	F.15 Decontamination Areas The principal decontamination area is located on the 467-ft level of the radwaste building. A personnel decontamination area is located on the 487-ft level of the radwaste building.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
locally. The ventilation system should be capable of being isolated. Local hose stations and hand portable extinguishers should be provided as backup to the sprinkler system.	The decontamination areas are monitored by automatic fire detectors. The decontamination area on the 467-ft elevation is protected by an automatic sprinkler system. Each area has dry chemical portable extinguishers and manual hose stations provided. Flammable liquids are not stored in decontamination areas. Capability for isolation of the ventilation system is not considered necessary for fire control due to the nature of the combustible loading in the area.
F.16 Safety-Related Water Tanks	F.16 Safety-Related Water Tanks
Storage tanks that supply water for safe shutdown should be protected from the effects of fire. Local hose stations and portable extinguishers should be provided. Portable extinguishers should be located in nearby hose houses. Combustible materials should not be stored next to outdoor tanks. A minimum of 50 ft of separation should be provided between outdoor tanks and combustible materials where feasible.	Water for shutdown is supplied from the condensate storage tanks which are located in the transformer yard on the north side of the turbine generator building. The tanks are separated from the yard area by a wall approximately 18 ft high. Portable extinguishers are provided in the turbine generator building. Manual hose stations are available from the yard hydrants or the turbine generator building. The suppression pool in the reactor building supplies water for post-fire safe shutdown. Manual hose stations and portable extinguishers are provided in the building.
F.17 Cooling Towers	F.17 Cooling Towers
Cooling towers should be of non-combustible construction or so located that a fire will not adversely affect any safety-related systems or equipment. Cooling towers should be of non-combustible construction when the basins are used for the ultimate heat sink or for the fire. Cooling towers of combustible construction, so located that a fire in them could adversely affect safety-related systems or equipment should be protected with an open head deluge system installation with hydrants and hose houses strategically located.	The cooling towers are constructed of non-combustible materials (except for fan shrouds, fan blades, fill material, and drift eliminators). The cooling towers are located remote from any safety-related buildings or equipment. The cooling tower basins are not used for the ultimate heat sink. There is a separate reliable fire protection water supply provided by a bladder tank remotely located away from the cooling towers.
F.18 Miscellaneous Areas	F.18 Miscellaneous Areas
Miscellaneous areas such as records storage areas, shops, warehouses, and auxiliary boiler rooms should be so located that a fire or effects of a fire,	Miscellaneous areas such as records storage areas, shops, warehouses, and auxiliary boiler rooms are located such that a fire or the effects of a fire,

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
including smoke, will not adversely affect any safety-related systems or equipment. Fuel oil tanks for auxiliary boilers should be buried or provided with dikes to contain the entire tank contents.	including smoke, will not adversely affect any safety-related systems or equipment. The auxiliary boiler fuel oil tank is buried in the yard.
G. SPECIAL PROTECTION GUIDELINES	G. SPECIAL PROTECTION GUIDELINES
G.1 Welding and Cutting, Acetylene - Oxygen Fuel Gas Systems	G.1 Welding and Cutting, Acetylene - Oxygen Fuel Gas Systems
This equipment is used in various areas throughout the plant. Storage locations should be chosen to permit fire protection by automatic sprinkler systems. Local hose stations and portable equipment should be provided as backup. The requirements of NFPA 51 and 51B are applicable to these hazards. A permit system should be required to utilize this equipment. (Also refer to 2f herein.)	Bulk storage of flammable gases is in a special structure well separated from plant structures. When not in use (to support of ongoing maintenance activities), flammable gas welding equipment is stored in designated areas which do not contain safe post-fire shutdown systems. A permit system is used for welding control and/or temporary storage of welding gases in all areas except for those specifically designated. Plant procedures call for protection or removal of combustibles, protection of equipment/cabling, and fire watch during and after the welding operation. During normal plant operation, ordinary welding and cutting is done in designated welding areas, which may not have automatic suppression. However, manual suppression equipment is available.
G.2 Storage Areas for Dry Ion Exchange Resins	G.2 Storage Areas for Dry Ion Exchange Resins
Dry ion exchange resins should not be stored near essential safety-related systems. Dry unused resins should be protected by automatic wet pipe sprinkler installations. Detection by smoke and heat detectors should alarm and annunciate in the control room and alarm locally. Local hose stations and portable extinguishers should provide backup for these areas. Storage areas of dry resin should have curbs and drains. (Refer to NFPA 92M, "Waterproofing and Draining of Floors.")	Bulk storage of dry ion exchange resins is located on 467 ft elevation of the radwaste building. There are no safety-related systems or equipment located in this area. Ionization detectors and automatic sprinkler protection is provided. Portable extinguishers and hose stations are available. Floor drains are provided for removal of fire fighting water.
G.3 Hazardous Chemicals	G.3 Hazardous Chemicals
Hazardous chemicals should be stored and protected in accordance with the recommendations of NFPA 49, "Hazardous Chemicals Data." Chemicals	Hazardous chemicals are controlled in accordance with plant procedures.

TABLE F.3-1

COMPARISON WITH BTP 9.5-1 APPENDIX A (Continued)

BTP 9.5-1 APPENDIX A	WNP-2 FIRE PROTECTION PROGRAM
storage areas should be well ventilated and protected against flooding conditions since some chemicals may react with water to produce ignition.	
G.4 Materials Containing Radioactivity	G.4 Materials Containing Radioactivity
Materials that collect and contain radioactivity such as spent ion exchange resins, charcoal filters, and HEPA filters should be stored in closed metal tanks or containers that are located in areas free from ignition sources of combustibles. These materials should be protected from exposure to fires in adjacent areas as well. Consideration should be given to requirements for removal of isotopic decay heat from entrained radioactive materials.	Spent resins are contained in metal vessels or containers. HEPA and charcoal filters are disposed of on a routine basis such that no large accumulation exists. After removal, the interior storage is in a controlled area where hose stations and fire extinguishers are readily available.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
I. INTRODUCTION AND SCOPE	I. INTRODUCTION AND SCOPE
This appendix applies to licensed nuclear power electric generating stations that were operating prior to January 1, 1979, except to the extent set forth in § 50.48(b) of this part. With respect to certain generic issues for such facilities it sets forth fire protection features required to satisfy Criterion 3 of Appendix A to this part.[1] A Fire Protection Safety Evaluation Report that has been issued for each operating plant states how these guidelines were applied to each facility and identifies open fire protection issues that will be resolved when the facility satisfies the appropriate requirements of Appendix R to Part 50. Criterion 3 of Appendix A to this part specifies that "Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions." When considering the effects of fire, those systems associated with achieving and maintaining safe shutdown conditions assume major importance to safety because damage to them can lead to core damage resulting from loss of coolant through boiloff. The phrases "important to safety" or "safety-related" will be used throughout this Appendix R as applying to all safety functions. The phrase "safe shutdown" will be used throughout this appendix as applying to both hot and cold shutdown functions.	Although the WNP-2 plant was licensed to operate after January 1, 1979, the guidelines of this appendix were used in the development of the WNP-2 Fire Protection Program. A comparison of the current WNP-2 Fire Protection Program to Appendix R, Section II, General Requirements, and against Section III, Specific Requirements, has been included in the Fire Protection Evaluation since 1981. Appendix R, Section I, is provided here for information only.

[1] Clarification and guidance with respect to permissible alternatives to satisfy Appendix A to BTP 9.5-1 has been provided in four other NRC documents:

"Supplementary Guidance on Information Needed for Fire Protection Evaluation," dated October 21, 1976;
"Sample Technical Specifications," dated May 12, 1977;
"Nuclear Plant Fire Protection Functional Responsibilities, Administrative Control and Quality Assurance," dated June 14, 1977;
"Manpower Requirements for Operating Reactors," dated May 11, 1978.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
Because fire may affect safe shutdown systems and because the loss of function of systems used to mitigate the consequences of design basis accidents under post-fire conditions dose not per se impact public safety, the need to limit fire damage to systems desired to achieve and maintain safe shutdown conditions is greater than the need to limit fire damage to those systems required to mitigate the consequences of design basis accidents. Three levels of fire damage limits are established according to the safety functions of the structure, system, or component.	

Safety Function	Fire damage limits
Hot shutdown	One train of equipment necessary to achieve hot shutdown from either the control room or emergency control station(s) must be maintained free of fire damage by a single fire, including an exposure fire.[2]
Cold shutdown	Both trains of equipment necessary to achieve cold shutdown may be damaged by a single fire, but damage must be limited so that at least one train can be repaired or made operable within 72 hr using onsite capability.
Design basis accidents	Both trains of equipment necessary for mitigation of consequences following design basis accidents may be damaged by a single exposure fire.

[2]Exposure fire - An exposure fire is a fire in a given area that involves either in situ or transient combustibles and is external to any structures, systems, or components located in or adjacent to that same area. The effects of such fire (e.g. smoke, heat, or ignition) can adversely affect those structures, systems, or components important to safety. Thus, a fire involving one train of safe shutdown equipment may constitute an exposure fire for the redundant train located in the same area and a fire involving combustibles other tan either redundant train may constitute an exposure fire to both redundant trains located in the same area.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
The most stringent fire damage limit shall apply for those systems that fall into more than one category. Redundant systems used to mitigate the consequences of other design basis accidents but not necessary for safe shutdown may be lost to a single exposure fire. However, protection shall be provided so that a fire within only one such system will not damage the redundant system.	
II. GENERAL REQUIREMENTS	II. GENERAL REQUIREMENTS
A. Fire Protection Program	A. Fire Protection Program
A fire protection program shall be established at each nuclear power plant. The program shall establish the fire protection of structures, systems, and components important to safety at each plant and the procedures, equipment, and personnel required to implement the program at the plant site.	The WNP-2 fire protection program establishes the fire protection policy for the protection of structures, systems, and components important to safety and describes the plant procedures, equipment, and personnel required to implement the program at the plant site.
The fire protection program shall be under the direction of an individual who has been delegated authority commensurate with the responsibilities of the position and who has available staff personnel knowledgeable in both fire protection and nuclear safety.	The personnel assigned responsibilities for the fire protection program are described in Table F.3-1, Section A.1.
The fire protection program shall extend the concept of defense-in-depth to fire protection in fire areas important to safety, with the following objectives: - to prevent fires from starting; - to detect rapidly, control, and extinguish promptly those fires that do occur; and - to provide protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant.	The fire protection program shall extend the concept of defense-in-depth to fire protection in fire areas important to safety, with the following objectives: - to prevent fires from starting; - to detect rapidly, control, and extinguish promptly those fires that do occur; and - to provide protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant in the event of fire.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
B. Fire Hazards Analysis	B. Fire Hazards Analysis
A fire hazards analysis shall be performed by qualified fire protection and reactor systems engineers to (1) consider potential in situ and transient fire hazards; (2) determine the consequences of fire in any location in the plant on the ability to safely shutdown the reactor or on the ability to minimize and control the release of radioactivity to the environment; and (3) specify measures for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability as required for each fire area containing structures, systems, and components important to safety in accordance with NRC guidelines and regulations.	The WNP-2 fire hazards analysis is provided in Section F.4.
C. Fire Prevention Features	C. Fire Prevention Features
Fire protection features shall meet the following general requirements for all areas that contain or present a fire hazard to structures, systems, or components important to safety.	Fire prevention features have been established at WNP-2 as listed below:
1. In situ fire hazards shall be identified and suitable protection provided.	1. The combustible loading calculation (Reference F.7.3.b) identifies the in-situ and the maximum expected transient fire loading in each plant fire area. The combustible loading calculation results are an input to the fire hazards analysis.
2. Transient fire hazards associated with normal operation, maintenance, repair, or modification activities shall be identified and eliminated where possible. Those transient fire hazards that can not be eliminated shall be controlled and suitable protection provided.	2. Plant procedures control the introduction of combustible materials into the safety-related areas of the plant.
3. Fire detection systems, portable extinguishers, and standpipe and hose stations shall be installed.	3. Fire detection systems, portable fire extinguishers, and standpipe and hose connections are installed.
4. Fire barriers or automatic suppression systems or both shall be installed as necessary to protect redundant systems or components necessary for safe shutdown.	4. Fire barriers or automatic suppression systems or both are installed for the protection of redundant post-fire safe shutdown equipment as detailed in the fire hazards analysis.
5. A site fire brigade shall be established, trained, and equipped and shall be on site at all times.	5. The plant fire brigade has been established, trained, and equipped. The fire brigade is maintained onsite at all times. The fire brigade composition may be less than the minimum requirements for a period of time
6. Fire detection and suppression systems shall be designed, installed, maintained, and tested by	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
personnel properly qualified by experience and training in fire protection systems.	not to exceed 2 hr in order to accommodate unexpected absence provided immediate action is taken to fill the required position.
7. Surveillance procedures shall be established to ensure that fire barriers are in place and that fire suppression systems and components are operable.	6. Fire detection and suppression systems are designed by qualified engineering personnel. Maintenance and testing is performed by qualified plant maintenance and operations personnel in accordance with plant procedures. 7. Periodic testing procedures have been established to ensure that essential fire barriers are in place and that fire detection and suppression systems are operable.
D. Alternative or Dedicated Shutdown Capability	D. Alternative or Dedicated Shutdown Capability
In areas where the fire protection features cannot ensure safe shutdown capability in the event of a fire in that area, alternative or dedicated shutdown capability shall be provided.	Alternative shutdown capability is provided for use in the event of a fire in the main control room.
III. SPECIFIC REQUIREMENTS	III. SPECIFIC REQUIREMENTS
A. Water Supplies for Fire Suppression Systems	A. Water Supplies for Fire Suppression Systems
Two separate water supplies shall be provided to furnish necessary water volume and pressure to the fire main loop. Each supply shall consist of a storage tank, pump, piping, and appropriate isolation and control valves. Two separate redundant suctions in one or more intake structures from a large body or water (river, lake, etc.) will satisfy the requirement for two separated water storage tanks. These supplies shall be separated so that a failure of one supply will not result in a failure of the other supply. Each supply of the fire water distribution system shall be capable of providing for a period of 2 hr the maximum expected water demands as determined by the fire hazards analysis for safety-related fire areas or other areas that present a fire exposure hazard to safety-related areas.	See Section F.2.4.1 and Table F.3-1 (paragraphs E.2.a through E.2.g) for a description of the fire protection system water supplies.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
When storage tanks are used for combined service water/fire water use the minimum volume for fire uses shall be ensured by means of dedicated tanks or by some physical means such as a vertical standpipe for other water service. Administrative controls including locks for tank outlet valves, are unacceptable as the only means to ensure minimum water volume.	
Other water systems used as one of the two fire water supplies shall be permanently connected to the fire main system and shall be capable of automatic alignment to the fire main system. Pumps, controls, and power supplies in these systems shall satisfy the requirements for the main fire pumps. The use of other water systems for fire protection shall not be incompatible with their functions required for safe plant shutdown. Failure of the other system shall not degrade the fire main system.	
B. Sectional Isolation Valves	B. Sectional Isolation Valves
Sectional valves or key operated valves shall be installed in the fire main loop to permit isolation of portions of the fire main loop for maintenance or repair without interrupting the entire water supply.	See Section F.2.4.1 and Table F.3-1, paragraph E.2.a. for a description of the fire protection system sectional isolation valves.
C. Hydrant Isolation Valves	C. Hydrant Isolation Valves
Valves shall be installed to permit isolation of outside hydrants from the fire main for maintenance or repair without interrupting the water supply to automatic or manual fire suppression systems in any area containing or presenting a fire hazard to safety-related or safe shutdown equipment.	See Section F.2.4.1 and Table F.3-1, paragraph E.2.a. for a description of the fire protection system hydrant isolation valves.
D. Manual Fire Suppression	D. Manual Fire Suppression
Standpipe and hose systems shall be installed so that at least one effective hose stream will be able to reach any location that contains or presents an exposure fire hazard to structures, systems, or components important to safety.	See Section F.2.5.3 and Table F.3-1, paragraph E.2.g and E.3.d for a description of the hose standpipe system. Fire hose stations in the reactor building are adequate to reach drywell fire hazards.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
Access to permit effective functioning of the fire brigade shall be provided to all areas that contain or present an exposure fire hazard to structures, systems, or components important to safety.	
Standpipe and hose stations shall be inside PWR containments and BWR containments that are not inerted. Standpipe and hose stations inside containment may be connected to a high quality water supply of sufficient quantity and pressure other than the fire main loop if plant specific features prevent extending the fire main supply inside containment. For BWR drywells, standpipe and hose stations shall be placed outside the dry well with adequate lengths of hose to reach any location inside the dry well with an effective hose stream.	
E. Hydrostatic Hose Tests	E. Hydrostatic Hose Tests
Fire hose shall be hydrostatically tested at a pressure of 150 psi or 50 psi above maximum fire main pressure, whichever is greater. Hose stored in outside hose houses shall be tested annually. Interior standpipe hose shall be tested every 3 years.	See Section F.5.5 for a description of fire system hose hydrostatic testing.
F. Automatic Fire Detection	F. Automatic Fire Detection
Automatic fire detection systems shall be installed in all areas of the plant that contain or present a hazard to safe shutdown or safety-related systems or components. These fire detection systems shall be capable of operating with or without offsite power.	See Section F.2.3 and Table F.3-1, paragraphs E.1.a through E.1.d for a description of the fire detection system.
G. Fire Protection of Safe Shutdown Capability	G. Fire Protection of Safe Shutdown Capability
1. Fire protection features shall be provided for structures, systems, and components important to safe shutdown. These features shall be capable of limiting fire damage so that:	Fire protection of post-fire safe shutdown capability is provided as detailed in the fire hazards analysis, Section F.4.
a. One train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station(s) is free of fire damage; and	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
b. Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) can be repaired within 72 hr.	
2. Except as provided for in paragraph G.3 of this section, where cables or equipment, including associated non-safety circuits that could prevent operation or cause maloperation due to hot shorts, open circuits, or shorts to ground of redundant trains of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area outside of primary containment, one of the following means of ensuring that one of the redundant trains is free of fire damage shall be provided.	
a. Separation of cables and equipment and associated non-safety circuits of redundant trains by a fire barrier having a 3-hr rating. Structural steel forming a part of or supporting such fire barriers shall be protected to provide fire resistance equivalent to that required of the barrier.	
b. Separation of cables and equipment and associated non-safety circuits of redundant trains by a horizontal distance of more than 20 ft with no intervening fire hazards. In addition, fire detectors and an automatic fire suppression system shall be installed in the fire area.	
c. Enclosure of cable and equipment and associated non-safety circuits of one redundant train in a fire barrier having a 1-hr fire rating. In addition, fire detectors and an automatic fire suppression system shall be installed in the fire area.	
Inside noninerted containments one of the following fire protection means shall be provided:	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
d. Separation of cables and equipment and associated non-safety circuits of redundant trains by a horizontal distance of more than 20 ft with no intervening combustibles or fire hazards;	
e. Installation of fire detectors and an automatic fire suppression system in the fire area; or	
f. Separation of cables and equipment and associated non-safety circuits of redundant trains by a noncombustible radiant energy shield.	
3. Alternative or dedicated shutdown capability and its associated circuits[3] independent of cables, systems, or components in the area, room, or zone under consideration shall be provided:	
a. Where the protection of system whose function is required for hot shutdown does not satisfy the requirement of paragraph G.2 of this section; or	
b. Where redundant trains of system required for hot shutdown located in the same fire area may be subject to damage from fire suppression activities or from the rupture or inadvertent operation of the fire suppression systems.	
In addition, fire detection and a fixed fire suppression system shall be installed in the area, room, or zone under consideration.	

[3] Alternative shutdown capability is provided by rerouting, relocating, or modification of existing systems; dedicated shutdown capability is provided by installed new structures and systems for the function of post-fire shutdown.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
H. Fire Brigade	H. Fire Brigade
A site fire brigade trained and equipped for fire fighting shall be established to ensure adequate manual fire fighting capability for all areas of the plant containing structures, systems, or components important to safety. The fire brigade shall be at least five members on each shift. The brigade leader and at least two brigade members shall have sufficient training in or knowledge of plant safety-related systems to understand the effects of fire and fire suppressants on safe shutdown capability. The qualification of fire brigade members shall determine their ability to perform strenuous fire fighting activities. The shift supervisor shall not be a member of the fire brigade. The brigade leader shall be competent to assess the potential safety consequences of a fire and advise control room personnel. Such competence by the brigade leader may be evidenced by possession of an operator's license or equivalent knowledge of plant safety-related systems.	The WNP-2 plant complies with these requirements related to post-fire safe shutdown plant equipment. The fire brigade composition is specified in Section 13.1.2.3.4. See paragraph II.C.5 above and Table F.3-1, paragraphs B.2 through B.5.
The minimum equipment provided for the brigade shall consist of personal protective equipment such as turnout coats, boots, gloves, hard hats, emergency communication equipment, portable lights, portable ventilation equipment, and portable extinguishers. Self-contained breathing apparatus using full-face positive pressure masks approved by National Institute for Occupational Safety and Health (NIOSH) - approval formerly given by the U.S. Bureau of Mines) shall be provided for fire brigade damage control and control room personnel. At least 10 masks shall be available for fire brigade personnel. Control room personnel may be furnished breathing air by a manifold system piped from a storage reservoir if practical. Service or rated operating life shall be a minimum of 0.5 hr for the self-contained units.	
At least a 1-hr supply of breathing air in extra bottles shall be located on the plant site for each unit of self-contained breathing apparatus. In addition, an onsite 6-hr supply of reserve air shall be provided and arranged to permit quick and complete replenishment	For each of the 10 required SCBA units, there is a 1-hr reserve supply of SCBA bottles located onsite. The 6-hr supply is provided by compressor recharging of SCBA bottles.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
of exhausted air supply bottles as they are returned. If compressors are used as a source of breathing air, only units approved for breathing air shall be used and the compressors shall be operable assuming a loss of offsite power. Special care must be taken to locate the compressor in areas free of dust and contaminants.	
I. Fire Brigade Training	I. Fire Brigade Training
The fire brigade training program shall ensure that the capability to fight potential fires is established and maintained. The program shall consist of an initial classroom instruction program followed by periodic classroom instruction, fire fighting practice, and fire drills.	The WNP-2 plant fire brigade training program is described in Section 13.2.2.5. The requirements of this section were used as guidance in the development of this program. See Table F.3-1, paragraph B.5.
1. Instruction	
a. The initial classroom instruction shall include:	
(1) Indoctrination of the plant fire fighting plan with specific identification of each individual's responsibilities.	
(2) Identification of the type and location of fire hazards and associated types of fires that could occur in the plant.	
(3) The toxic and corrosive characteristics of expected products of combustion.	
(4) Identification of the location of fire fighting equipment for each fire area and familiarization with the layout of the plant including access and egress routes to each area.	
(5) The proper use of available fire fighting equipment and the correct method of fighting each type of fire. The types of fires covered should include fires in energized electrical equipment, fires in cables and cable trays, hydrogen fires, fires involving flammable and	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
combustible liquids or hazardous process chemicals, fires resulting from construction or modifications (welding), and record file fires.	
(6) The proper use of communication, lighting, ventilation, and emergency breathing equipment.	
(7) The proper method for fighting fires inside buildings and confined spaces.	
(8) The direction and coordination of the fire fighting activities (fire brigade leaders only).	
(9) Detailed review of fire fighting strategies and procedures.	
(10) Review of latest plant modifications and corresponding changes in fire fighting plans.	
NOTE: Items (9) and (10) may be deleted from the training of no more than two of the non-operations personnel who may be assigned to the fire brigade.	
b. The instruction shall be provided by qualified individuals who are knowledgeable, experienced, and suitable trained in fighting the types of fires that could occur in the plant and in using the types of equipment available in the nuclear power plant.	
c. Instruction shall be provided to all fire brigade members and fire brigade leaders.	
d. Regular planned meetings shall be held at least every 3 months for all brigade members to review changes in the fire protection program and other subjects as necessary.	
e. Periodic refresher training sessions shall be held to repeat the classroom instruction program for all brigade members over a	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
2-year period. These sessions may be concurrent with the regular planned meetings.	
2. Practice	
Practice sessions shall be held for each shift fire brigade on the proper method of fighting the various types of fires that could occur in a nuclear power plant. These sessions shall provide brigade members with experience in actual fire extinguishment and the use of emergency breathing apparatus under strenuous conditions encountered in fire fighting. These practice sessions shall be provided at least once per year for each fire brigade member.	
3. Drills	
a. Fire brigade drills shall be performed in the plant so that the fire brigade can practice as a team.	
b. Drills shall be performed at regular intervals not to exceed 3 months for each shift fire brigade. Each fire brigade member should participate in each drill, but must participate in at least two drills per year.	
A sufficient number of these drills, but not less that one for each shift fire brigade per year, shall be unannounced to determine the fire fighting readiness of the plant fire brigade, brigade leader, and fire protection systems and equipment. Persons planning and authorizing an unannounced drill shall ensure that the responding shift fire brigade members are not aware that a drill is being planned until it is begun. Unannounced drills shall not be scheduled closer than 4 weeks.	
At least one drill per year shall be performed on a "back shift" for each shift fire brigade.	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
c. The drills shall be preplanned to establish the training objectives of the drill and shall be critiqued to determine how well the training objectives have been met. Unannounced drills shall be planned and critiqued by members of the management staff responsible for plant safety and fire protection. Performance deficiencies of a fire brigade or of individual fire brigade members shall be remedied by scheduling additional training for the brigade members. Unsatisfactory drill performance shall be followed by a repeat drill within 30 days.	
d. At 3-year intervals, a randomly selected unannounced drill shall be critiqued by qualified individuals independent of the licensee's staff. A copy of the written report from such individuals shall be available for NRC review.	
e. Drills shall as a minimum include the following:	
(1) Assessment of fire alarm effectiveness.	
(2) Assessment of each brigade member's knowledge of his or her role in the fire fighting strategy for the area assumed to contain the fire. Assessment of the brigade member's conformance with established plant fire fighting procedures and use of fire fighting equipment, including self-contained breathing apparatus, communication equipment, and ventilation equipment to the extent practicable.	
(3) The simulated use of fire fighting equipment required to cope with the situation and type of fire selected for	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
the drill. The area and type of fire chosen for the drill should differ from those used in the previous drill so that brigade members are trained in fighting fires in various plant areas. The situation selected should simulate the size and arrangement of a fire that could reasonably occur in the area selected, allowing for fire development due to the time required to respond, to obtain equipment, and organize for the fire, assuming loss of automatic suppression capability.	
(4) Assessment of brigade leader's direction of the fire fighting effort as to thoroughness, accuracy, and effectiveness.	
4. Records	
Individual records of training provided to each fire brigade member, including drill critiques, shall be maintained for at least 3 years to ensure that each member receives training in all parts of the training program. These records of training shall be available for NRC review. Retraining or broadened training for fire fighting within buildings shall be scheduled for all those brigade members whose performance records show deficiencies.	
J. Emergency Lighting	J. Emergency Lighting
Emergency lighting units with at least an 8-hr battery power supply shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto.	Emergency lighting is provided as detailed in Section 9.5.3.
K. Administrative Controls	K. Administrative Controls
Administrative controls shall be established to minimize fire hazards in areas containing structures, systems, and components important to safety. These controls shall establish procedures to:	The WNP-2 plant complies with these requirements through implementation of the procedures of Reference F.7.8 which contain the program administrative controls. See Table F.3-1, paragraphs B.1 through B.5.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
1. Govern the handling and limitation of the use of ordinary combustible materials, combustible and flammable gases and liquids, high efficiency particulate air and charcoal filters, dry ion exchange resins, or other combustible supplies in safety-related areas.	
2. Prohibit the storage of combustibles in safety-related areas or establish designated storage areas with appropriate fire protection.	
3. Govern the handling of and limit transient fire loads such as combustible and flammable liquids, wood and plastic products, or other combustible materials in buildings containing safety-related systems or equipment during all phases of operating, and especially during maintenance, modification, or refueling operations.	
4. Designate the onsite staff member responsible for the in plant fire protection review of proposed work activities to identify potential transient fire hazards and specify required additional fire protection in the work activity procedure.	
5. Govern the use of ignition sources by use of a flame permit system to control operations. A separate permit shall be issued for each area where work is to be done. If work continues over more than one shift, the permit shall be valid for not more than 24 hr when the plant is operating or for the duration of a particular job when the plant is shutdown.	Ignition source permit extensions are strictly controlled during plant operating conditions.
6. Control the removal from the area of all waste, debris, scrap, oil spills, or other combustibles resulting from the work activity immediately following completion of the activity, or at the end of each work shift, whichever comes first. Maintain the periodic housekeeping inspections to ensure continued compliance with these administrative controls.	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
8. Control the use of specific combustibles in safety-related areas. All wood used in safety-related areas during maintenance, modification, or refueling operations(such as laydown blocks or scaffolding) shall be treated with a flame retardant. Equipment or supplies (such as new fuel) shipped in untreated combustible packing containers may be unpacked in safety-related areas if required for valid operating reasons. However, all combustible materials shall be removed from the area immediately following the unpacking. Such transient combustible material, unless stored in approved containers, shall not be left unattended during lunch breaks, shift changes, or other similar periods. Loose combustible packing material such as wood or paper excelsior, or polyethylene sheeting shall be placed in metal containers with tight-fitting self-closing metal covers.	Minor amounts of untreated wood are allowed to account for necessary tools and equipment used within plant areas.
9. Control actions to be taken by an individual discovering a fire, for example, notification of control room, attempt to extinguish fire, and actuation of local fire suppression systems.	
10. Control actions to be taken by the control room operator to determine the need for brigade assistance on report of a fire or receipt of alarm on control room annunciator panel, for example, announcing location of fire over PA system, sounding fire alarms, and notifying the shift supervisor and the fire brigade leader of the type, size, and location of the fire.	
11. Control the actions to be taken by the fire brigade after notification by the control room operator of a fire, for example, assembling in a determined location, receiving directions from the fire brigade leader, and discharging specific fire fighting responsibilities including selection and transportation of fire fighting equipment to fire location, selection of protective equipment, operating instructions for use of fire suppression systems, and use of preplanned strategies for fighting fires in specific areas.	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
12. Define the strategies for fighting fires in all safety-related areas presenting a hazard to safety-related equipment. These strategies shall designate:	
a. Fire hazards in each area covered by the specific prefire plans.	
b. Fire extinguishants best suited for controlling the fires associated with the fire hazards in that area and the nearest location of these extinguishants.	
c. Most favorable direction from which to attack a fire in each area in view of the ventilation direction, access hallways, stairs, and doors that are most likely to be free of fire, and the best station or elevation for fighting the fire. All access and egress routes that involve locked doors should be specifically identified in the procedure with the appropriate precautions and methods for access specified.	
d. Plant systems that should be managed to reduce the damage potential during a local fire and the location of local and remote controls for such management (e.g. any hydraulic or electrical systems in the zone covered by the specific fire fighting procedure that could increase the hazards in the area because of overpressurization or electrical hazards).	
e. Vital heat-sensitive system components that need to be kept cool while fighting a local fire. Particularly hazardous combustibles that need cooling should be designated.	
f. Organization of fire fighting brigades and the assignment of special duties according to job title so that all fire fighting functions are covered by any complete shift personnel complement. These duties include command control of the brigade,	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
transporting fire suppression and support equipment to the fire scenes, applying the extinguishant to the fire, communication with the control room, and coordination with outside fire departments.	
g. Potential radiological and toxic hazards in fire zones.	
h. Ventilation system operation that ensures desired plant air distribution when ventilation flow is modified for fire containment or smoke clearing operations.	
i. Operations requiring control room and shift engineer coordination or authorization.	
j. Instructions for plant operators and general plant personnel during fire.	
L. <u>Alternative and Dedicated Shutdown Capability</u>	L. <u>Alternative and Dedicated Shutdown Capability</u>
1. Alternative or dedicated shutdown capability provided for a specific fire area shall be able to (a) achieve and maintain subcritical reactivity conditions in the reactor, (b) maintain reactor coolant inventory, (c) achieve and maintain hot standby[4] conditions for a PWR (hot shutdown for a BWR); (d) achieve cold shutdown conditions thereafter. During the post-fire shutdown, the reactor coolant system process variables shall be maintained within those predicted for a loss of normal ac power, and the fission product boundary integrity shall not be affected; i.e. there shall be no fuel clad damage, rupture of any primary coolant boundary, or rupture of the containment boundary.	Alternative shutdown capability is provided for use in the event of a main control room fire. The term 'dedicated shutdown system' used in the fire hazards analysis and in related post-fire safe shutdown analyses refers to the preferred protection of Division 2 systems in fire areas which contain both redundant trains of post-fire safe shutdown systems. This term does not relate to 'dedicated shutdown capability' as defined in footnote 2 of Appendix R to 10 CFR 50. The systems used for post-fire safe shutdown are described in Section F.4.3.
2. The performance goals for the shutdown functions shall be:	

[4] As defined in the Standard Technical Specifications.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
a. The reactivity control function shall be capable of achieving and maintaining cold shutdown reactivity conditions.	
b. The reactor coolant makeup function shall be capable of maintaining the reactor coolant level above the top of the core for BWRs and within the level indication in the pressurizer for PWRs.	
c. The reactor heat removal function shall be capable or achieving and maintaining decay heat removal.	
d. The process monitoring function shall be capable of providing direct readings of the process variables necessary to perform and control the above functions.	
e. The supporting functions shall be capable of providing the process cooling, lubrication, etc., necessary to permit the operation of the equipment used for safe shutdown functions.	
3. The shutdown capability for specific fire areas may be unique for each such area, or it may be one unique combination of systems for all such areas. In either case, the alternative shutdown capability shall be independent of the specific fire area(s) and shall accommodated post-fire conditions where offsite power is available and where offsite power is not available for 72 hr. Procedures shall be in effect to implement this capability.	
4. If the capability to achieve and maintain cold shutdown will not be available because of fire damage, the equipment and systems comprising the means to achieve and maintain the hot	

[5] An acceptable method of complying with this alternative would be to meet Regulatory Guide 1.75 position 4 related to associated circuits and IEEE Standard 384-1974 (Section 4.5) where trays from redundant safety divisions are so protected that postulated fires affect trays from only one safety division.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
standby or hot shutdown condition shall be capable of maintaining such conditions until cold shutdown can be achieved. If such equipment and systems will not be capable of being powered by both onsite and offsite electric power systems because of fire damage, an independent onsite power system shall be provided. The number of operating shift personnel, exclusive of fire brigade members, required to operate such equipment and systems shall be onsite at all times.	
5. Equipment and systems comprising the means to achieve and maintain cold shutdown shall not be damaged by fire, or the fire damage to such equipment and systems shall be limited so that the systems can be made operable and cold shutdown can be achieved within 72 hr. Materials for such repairs shall be readily available onsite and procedures shall be in effect to implement such repairs. If such equipment and systems used prior to 72 hr after the fire will not be capable of being powered by both onsite and offsite electric power systems because of fire damage, an independent onsite power system shall be provided. Equipment and systems used after 72 hr may be powered by offsite power only.	
6. Shutdown system installed to ensure post-fire shutdown capability need not be designed to meet Seismic Category I criteria, single failure criteria, or other design basis accident criteria, except where required for other reasons, e.g. because of interface with or impact on existing safety system, or because of adverse valve actions due to fire damage.	
7. The safe shutdown equipment and systems for each fire area shall be known to be isolated from associated non-safety circuits in the fire area so that hot shorts, open circuits or shorts to ground in the associated circuits will not prevent operation of the safe shutdown equipment. The separation and barriers between trays and	

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
conduits containing associated circuits of one safe shutdown division and trays and conduits containing associated circuits or safe shutdown cables from the redundant division, or the isolation of the associated circuits such that a postulated fire involving associated circuits will not prevent safe shutdown.[5]	
M. Fire Barrier Cable Penetration Seal Qualification	M. Fire Barrier Cable Penetration Seal Qualification
Penetration seal designs shall use only noncombustible materials and shall be qualified by tests that are comparable to tests used to rate fire barriers. The acceptance criteria for the test shall include:	The WNP-2 plant complies with this requirement except that silicone foam is combustible. See Section F.2.2 for a discussion of penetration seal qualification.
N. Fire Doors	N. Fire Doors
Fire doors shall be self-closing or provided with closing mechanisms and shall be inspected semiannually to verify that automatic hold-open, release, and closing mechanisms and latches are operable. One of the following measures shall be provided to ensure they will protect the opening as required in case of fire: 1. Fire doors shall be kept closed and electrically supervised at a continuously manned location; 2. Fire doors shall be locked closed and inspected weekly to verify that the doors are in the closed position; 3. Fire doors shall be provided with automatic hold-open and release mechanisms and inspected daily to verify that doorways are free or obstructions; or 4. Fire doors shall be kept closed and inspected daily to verify that they are in the closed position.	See Sections F.2.2.1 and F.5.7 for a discussion of fire doors.

TABLE F.3-2

COMPARISON WITH THE SPECIFIC REQUIREMENTS
OF 10 CFR 50 APPENDIX R (Continued)

10 CFR 50 APPENDIX R SECTION	WNP-2 FIRE PROTECTION PROGRAM
The fire brigade leader shall have ready access to keys for any locked fire doors.	
Areas protected by automatic total flooding has suppression systems shall have electrically supervised self-closing fire doors or shall satisfy option 1 above.	
O. Oil Collection System for Reactor Coolant Pump	O. Oil Collection System for Reactor Coolant Pump
The reactor coolant pump shall be equipped with an oil collection system if the containment is not inerted during normal operation. The oil collection system shall be so designed, engineered, and installed that failure will not lead to fire during normal or design basis accident conditions and that there is reasonable assurance that the system will withstand the safe shutdown earthquake.[6]	The WNP-2 plant has a nitrogen inerted containment and therefore this requirement does not apply to WNP-2.

[6] See Regulatory Guide 1.29 - "Seismic Design Classification," Paragraph C.2.

F.4 FIRE HAZARDS ANALYSIS

The fire hazards analysis determines the adequacy of the fire protection features to prevent and mitigate the consequences of a postulated fire. A fire hazards analysis is performed for each fire area within the reactor building, the radwaste control building, the diesel generator building, the standby service water pump houses, reactor recirculation system (RRC) pump adjustable speed drive (ASD) building, and the turbine generator building.

The fire hazards analysis identifies the potential fire consequences based on consideration of the design basis fire, the location of post-fire safe shutdown equipment and cabling located within the area, the construction of the fire area, and the available fire protection systems. Potential fire consequences are evaluated to:

a. Ensure the capability to achieve and maintain safe shutdown,
b. Prevent radioactive release to ensure the health and safety of the public,
c. Ensure safe egress for employees, and
d. Provide for plant property protection.

The ability of the plant to attain and maintain post-fire safe shutdown is evaluated against the requirements of the following:

a. 10 CFR 50 Appendix A, General Design Criterion 3, Fire Protection,

b. 10 CFR 50 Appendix R, Section III.G, Fire Protection of Safe Shutdown Capability,

c. 10 CFR 50 Appendix R, Section III.J, Emergency Lighting, and

d. 10 CFR 50 Appendix R, Section III.L, Alternative and Dedicated Shutdown Capability.

Clarification on the above was obtained from various generic letters (Reference F.7.2.d).

The methodology used to perform the fire hazards analyses is detailed below.

F.4.1 PLANT FIRE AREA ARRANGEMENT

The plant buildings are divided into fire areas generally based on the location of equipment needed for safe post-fire shutdown and on the construction of the building walls, floor, and ceiling assemblies. A fire area is that portion of a building or plant site which is separated from other areas by barriers which are sufficient to withstand the fire hazards associated with the area and which will protect important equipment outside the area from a fire within the

area. Section F.4.4.3 provides a listing and description of the plant fire areas. Drawings which show the arrangement of the plant fire areas are contained in Section F.6.

F.4.2 DESIGN BASIS FIRE

The fire hazards analysis uses the concept of a "design basis fire" to estimate the magnitude and severity of a potential fire. Design basis fires are those postulated to result from the combustion of the exposed combustibles within the fire area, assuming that no manual or automatic fire fighting has been initiated. The effects of the design basis fire are evaluated to ensure the adequacy of the fire area boundaries and to evaluate the potential effects of the fire on plant equipment located within the area. The combustible loading for each fire area is contained in calculation FP-02-85-03.

The combustible loading value is intended to provide an approximate estimate of the probable maximum fire severity. The combustible load concept does not account for factors such as ceiling height, ventilation, combustible concentrations, or storage methods which may significantly affect actual fire growth. The combustible load is usually conservative as it assumes total combustion whereas more accurate methods account for residue and incomplete combustion. The combustible load provides a conservative, relative measure of expected fire severity in each plant fire area. This conservatism in the combustible loading calculation generally accounts for combustibles which are not specifically included in the area fire loading.

F.4.2.1 Combustible Loading Assumptions

To calculate the area combustible loading, the major sources of combustibles within each plant fire area are identified. The entire weight of cable insulation in cable trays (covered or open) is included in the combustible loading. Cables inside conduits and within fire rated raceway barriers are not considered in the overall area combustible loading calculation. Enclosures or electrical panels are expected to prevent the electrical cabling from significantly contributing to the general area fire hazard. The only exception is cabling inside main control room electrical panels which is included in the combustible loading calculation. Cabling within the main control room power generation control complex (PGCC) underfloor raceways is excluded due to the protective steel enclosures and Halon protection.

Similarly, oil or grease in totally enclosed bearing housings in which the oil or grease is not pressurized or recirculated (such as the grease inside a motor operator) is not included in the combustible load calculations. Flammable/combustible liquids stored inside listed storage cabinets are also not considered to contribute to the general area fire hazard.

The transient combustible loading is generally included in the area combustible loading calculation by adding a value of 8,400,000 Btu (corresponding to a 55-gal drum of oil) to the heat release for the fire area. Certain fire areas may have larger or smaller transient fire

loadings due to fire area location and use. The transient combustible value for the fire area is assumed to represent a bounding value of the potential transient fire loading and is not expected to exactly correlate with plant walkdown data.

F.4.2.2 Combustible Loading Calculations Methodology

The combustible loading values were developed as follows:

a. First, the major sources of combustibles (oil, electrical cable, charcoal, and storage) are identified. Data from plant equipment manuals is used when available to verify the oil and charcoal quantities. The amount of electrical cable within each area is obtained from electrical raceway information. Quantities of other materials were estimated during plant walkdowns.

b. Second, the heat release from each combustible is multiplied by its heat of combustion yielding the heat released. The lower heat of combustion value is used as the combustion products remain gaseous under fire conditions. This value represents a 'maximum' heat release as incomplete oxidation or partial burning in an actual fire would reduce the heat release. See Reference F.7.3.b for a list of material heat of combustion values (Btu/lb).

c. Next, the gross floor area (the floor area within the inside perimeter of the outside walls of the building with no deduction for interior walls, columns, or other features) of the fire area is calculated using dimensions taken from (or scaled from) plant drawings.

d. The total heat released (Btu) from the in-situ combustible materials in the fire area is totaled with the assumed heat release due to transient fire loading. This value is divided by the gross floor area (ft^2) yielding the fire loading for the fire area in Btu/ft^2.

e. The expected duration of the fire may be estimated from the combustible loading calculation by dividing the fire loading in the fire area by 80,000 Btu/ft^2. This value corresponds to a 1-hr fire loading based on Table 6-8A of the NFPA Fire Protection Handbook (Reference F.7.2.b).

f. The Section F.4.4.4 detailed Fire Hazards Analysis (FHA) does not list the specific combustible loading in Btu/ft^2 or expected fire duration. The detailed combustible loading analysis is in calculation FP-02-85-03 (Reference F.7.3.b). The detailed FHA, Section F.4.4.4, lists the relative fire area hazard severity as follows:

Low = 0 to 80,000 Btu/ft^2
Medium = between 80,000 and 160,000 Btu/ft^2
High = above 160,000 Btu/ft^2

The above is based on NFPA (Reference F.7.2.h) with additional conservative margin.

F.4.2.3 Fire Protection Engineering Evaluations

In accordance with the guidance of Generic Letter 86-10, fire protection engineering evaluations may be performed to assess the adequacy of alternatives to prescriptive fire protection guidance documents. Examples include deviations to NFPA codes, partial area suppression or detection, less than 3-hr barriers, etc., and typically involve a comparison of the hazards to the fire protection features. Fire protection engineering evaluations deviating from NRC committed guidance documents should be prepared/approved by a qualified fire protection engineer, meet Standard License Condition 2.c(14) and be maintained on file for NRC review.

F.4.3 POST-FIRE SAFE SHUTDOWN

The systems and equipment which are designated as post-fire safe shutdown equipment represent the minimum equipment which is necessary to bring the plant to a safe cold shutdown condition in the event of a fire in any area of the plant. Only that portion of post-fire safe shutdown equipment which is expected to be free of fire damage is credited for post-fire safe shutdown, although other plant systems and equipment could also be available for use after a fire.

The development of the post-fire safe shutdown equipment list is based on the following:

a. The post-fire safe shutdown systems must be capable of accommodating conditions where offsite power is available or where offsite power is not available for 72 hr.

b. Fires are not postulated to occur simultaneously with other plant accidents or design basis events such as a loss-of-coolant accident (LOCA), an operating basis earthquake, or a safe shutdown earthquake.

c. Single failure (including operator error) is not considered (i.e., only a single shutdown train is required to mitigate a design basis fire). For example, a single failure of a remote shutdown transfer switch is not considered in the analysis of the remote shutdown system.

d. All plant equipment is functional (not in test, maintenance, or out of service) at the time of fire.

e. The post-fire safe shutdown systems need not be designed to cope with other plant accidents such as pipe breaks or stuck valves, except those portions of the systems which interface with or impact existing safety systems.

f. The safe shutdown capability should not be adversely affected by a fire which results in the loss of all automatic function from unprotected circuits located in the area in conjunction with one worst case spurious actuation or signal resulting from a fire.

g. Fail safe circuits (electrical divisions 4, 5, 6, and 7) are designed to fail in a safe manner if subjected to fire damage. For example, reactor scram, once initiated, cannot be overridden as a consequence of fire.

h. Alternative shutdown systems used in the event of a main control room fire must meet the requirements of 10 CFR 50, Appendix R Section III.L, with the exception of the following:

   Section III.L.1 requires that "during post-fire shutdown, the reactor coolant system process variables be maintained within those predicted for a loss of normal ac power." The WNP-2 analysis is based on maintaining reactor parameters within those values predicted for the existing Chapter 15 transient analyses. Spurious signals are considered one at a time, and are evaluated to determine whether the signal could indirectly or directly affect safe shutdown capability. (Reference F.7.5.c).

i. Three phase power feeders are assumed not to fail in such a manner as to reconnect to an adjacent three phase power feeder and cause an electrically isolated motor to operate except for those supplying power to high-to-low pressure interface valves.

j. Due to low fire loading and/or available fire suppression and detection systems, the failure of Seismic Category I supports and steel raceways in such a manner that cross circuiting of cables between raceways or loss of safe shutdown equipment from falling debris is not considered to be credible.

k. Failure of nonseismically supported electrical components of lighting, communication, fire protection, and security systems have been evaluated to ensure post-fire safe shutdown components in Seismic Category I areas are not affected.

l. Stainless steel instrument sensing lines and their supports have been analyzed to ensure that the lines will not fail as a result of the temperature increases

resulting from potential fire conditions in the vicinity of the lines. In certain areas, the sensing lines are routed through areas which are estimated to have a localized fire loading which could result in support temperatures exceeding 1200°F. In these areas, the sensing line supports are protected by fire barriers.

m. A properly coordinated circuit protective device (fuse, breaker, etc.) will isolate any downstream fault that results from a design basis fire even if the protective device is in the fire area.

n. The emergency or abnormal response procedures allow the operator sufficient information to determine which equipment is available for post-fire shutdown in the event of a fire outside the main control room.

o. There are no actions (repairs) taken by plant staff to bring back into service a piece of equipment which has failed due to fire conditions and is necessary for safe post-fire shutdown.

To provide the capability to safely shut down with or without offsite power available, post-fire shutdown is accomplished using the suppression pool for reactor inventory and depressurization. (Reference F.7.3.c).

Post-fire safe shutdown may be initiated by a manual reactor scram or by an automatic scram resulting from a loss of offsite power with the accompanying loss of normal feedwater. The negative reactivity available due to control rod insertion upon scram will maintain subcriticality from event initiation to cold shutdown. The high pressure systems (e.g., HPCS or RCIC) are assumed to be unavailable for post-fire shutdown.

The main steam isolation valves (MSIVs) are closed manually or automatically by a loss of the grid. Vessel isolation occurs as the water level decreases and no high pressure makeup systems are available. Upon isolation, the vessel pressure increases resulting in the safety/relief valve (SRV) opening and discharging steam to the suppression pool. Manual operation of the automatic depressurization system (ADS) SRVs is initiated to rapidly depressurize the vessel and allow initiation of residual heat removal system in its alternative cooling mode. The automatic features of the systems such as the RHR logic circuitry or auto synchronizing of the diesel generator are not credited for post-fire safe shutdown.

At least five SRVs and one residual heat removal loop are available for post-fire shutdown for a fire in any area. In the event of a main control room fire, at least five SRVs are available (three SRV controls are provided on each remote shutdown panel). Depressurization is accomplished using five SRVs as a minimum, as prescribed in the Emergency Operating Procedures (EOPs). GE analysis shows that peak clad temperature and reactor pressure vessel (RPV) water level remain acceptable for a blowdown initiated when wide range water level instrument indicates TAF (-161 in. including loop inaccuracies) (Reference F.7.3.c). TAF is

shown to be reached at approximately 23 minutes after main steam line isolation, if no low pressure system injection occurs.

The RHR system is used in its alternate shutdown cooling mode to remove decay heat and maintain the suppression pool temperature below limits. Cooling water to the RHR system is supplied by the service water system.

Instrumentation for reactor vessel water level, reactor vessel pressure, suppression pool temperature, and suppression pool water level are used for process monitoring during post-fire shutdown.

Ventilation systems for the main control room, remote shutdown room, vital switchgear rooms, cable spreading room/cable chase, safe shutdown pump rooms, and MCC rooms in the reactor building are evaluated to ensure they remain available to support post-fire shutdown where required.

High to low pressure interfaces are defined as any low pressure piping that connects directly to the reactor coolant system boundary. To prevent a LOCA outside the primary containment from occurring due to a DBF, protection of at least one of two series high-to-low pressure interface valves is required. WNP-2 does not consider paths with three or more normally closed valves to be a concern during fire-generated spurious equipment operation. High to low pressure interface flow paths requiring two or less spurious actuations are evaluated relative to their safety significance. The following is a listing of high to low pressure interfaces evaluated for the effects of fire.

a. RHR-V-8 and RHR-V-9 - (during normal plant operation, power is removed from RHR-V-9). This precludes operation via spurious control circuit energization. The power cable is routed in a grounded steel conduit containing no energized circuits in fire areas R-1 and RC-3 to prevent valve opening.

b. RHR-V-123A and RHR-V-53A - during normal plant operation, power is removed from RHR-V-123A. This precludes operation via spurious control circuit energization. The power cable is routed in a grounded steel conduit containing no energized circuits in fire area R-1 to prevent valve opening.

c. RHR-V-123B and RHR-V-53B - same as above.

d. MS-V-1 and MS-V-2 - the spurious opening of these valves result in an equivalent small break LOCA inside containment with a potential for radiological release to the environment. Multiple system actuations will also occur as a result of the expected high drywell pressure. The results of the analysis are listed below:

1. RPV inventory loss is minimal with direct RPV inventory return to the suppression pool,

2. Resulting containment parameters are bounded by the small break LOCA analysis,

3. Multiple system actuations have no effect on safe shutdown, and

4. Radioactivity release will be minimal since containment will isolate on a FA signal limiting dose to less than 10 CFR 100 limits.

e. MS-V-16 and MS-V-19:

1. RPV inventory losses are well within the makeup capability of the protected RHR system,

2. RPV inventory blowdown is minimal and does not significantly affect suppression pool water inventory, and

3. The potential radioactivity releases offsite are well below 10 CFR 100 limits.

f. RWCU-FCV-33 and RWCU-V-34 or RWCU-V-35 - plant procedures direct the closure of a manual isolation valve RWCU-V-32 as part of the fire safe shutdown process.

g. RCIC-V-45 and RCIC-RD-1 and RCIC-RD-2:

1. RPV inventory losses are well within the makeup capability of the protected RHR system,

2. Flooding in secondary containment does not affect safe shutdown, and

3. The potential radioactivity releases offsite are well below 10 CFR 100 limits.

F.4.3.1 Normal Post-Fire Safe Shutdown Equipment

One train of the normal post-fire safe shutdown equipment is used to bring the plant to a safe cold shutdown condition from the main control room. The normal post-fire safe shutdown systems consist of two redundant trains (Division 1 and Division 2) as follows:

The Division 2 post-fire safe shutdown system consists of equipment and cabling of the following systems:

RHR B (alternate shutdown cooling mode Division 2),
SW B (Division 2),
ADS/MSRV (Division 2),
Supporting heating, ventilating, and air-conditioning (HVAC) systems (Division 2),
System status monitoring instrumentation (Division 2),
MSIVs (Division 2), and
Supporting electrical power, DG and battery (Division 2).

The Division 1 post-fire safe shutdown system consists of equipment and cabling of the following systems:

RHR A (alternate shutdown cooling mode, Division 1),
SW A (Division 1),
ADS/MSRV (Division 1),
Supporting HVAC systems (Division 1),
System status monitoring instrumentation (Division 1),
MSIVs (Division 1), and
Supporting electrical power including DG and battery (Division 1).

The automatic features of these systems, such as the RHR logic circuitry or auto-synchronizing of the diesel generator are not credited. Only those instruments which are designated as post-fire safe shutdown equipment have been evaluated to ensure their availability in the event of fire.

The normal post-fire safe shutdown equipment is listed in Table F.4-1.

F.4.3.2 Remote Post-Fire Safe Shutdown Equipment

In the event of a main control room fire, selected portions of the Division 1 and Division 2 post-fire safe shutdown systems are used to shut down the reactor from outside the control room. Necessary instrumentation and controls for three Division 1 and three Division 2 SRVs, Division 2 RHR, Division 2 service water, and supporting power and ventilation systems are located on the remote shutdown and other local panels. Manual transfer switches isolate the controls for certain components from the main control room.

The only operator actions which are credited prior to evacuation are manual reactor scram and MSIV closure. Prior to control room evacuation, the operators will request Security to unlock security doors required for remote shutdown and announce the reactor scram and control room evacuation. If time is available, prior to control room evacuation, the operators will also perform the following actions:

a. Manually initiate reactor core isolation cooling (RCIC),
b. Start SW loop A and B,
c. Trip the main generator, and
d. Transfer SM-7 and SM-8 to the backup transformer.

The MSIVs and the reactor protection system (RPS) are fail safe systems which are routed in grounded raceways to ensure that loss of power resulting from a fire will fail these circuits to a safe condition.

Following evacuation of the control room, the operators

a. Transfer control away from the control room to the remote shutdown and other local panels,

b. Start standby service water pump to provide cooling water to the diesel generator,

c. Start diesel generator 2 and manually sync to grid,

d. Initiate RHR in the alternate shutdown cooling mode (injection of suppression pool water directly into the reactor) when the reactor pressure is reduced below the RHR pump design operating pressure,

e. Operate a minimum of five SRVs using the controls at the remote and alternate remote shutdown panels when RPV level reaches 150 in. indicated, and

f. Monitor and take action to shed designated loads as required for a fire in the main control room which results in high impedance faults on cables powered from 125-V dc power.

Indication for the following parameters is located on the remote shutdown panels;

a. Reactor water level,
b. Reactor pressure,
c. Suppression pool water level,
d. Suppression pool water temperature,
e. Residual heat removal pump flow, and
f. Standby service water pump discharge pressure.

The Division 2 diesel generator supplied emergency lighting in the remote shutdown areas at el. 467 ft of the radwaste building has been evaluated to ensure the lighting will remain available in the event of a control room fire.

The remote post-fire shutdown system thus consists of the following:

a. RHR B (Division 2),
b. SW B (Division 2),
c. ADS/MSRV (Division 1 and Division 2),
d. Supporting HVAC systems (Division 2),
e. System status monitoring instrumentation, and
f. Supporting power train including DG-2 and Division 1 and Division 2 battery.

The automatic features of these systems, such as the RHR logic circuitry or auto-synchronizing of the diesel generator are not credited. Only those instruments which are designated as post-fire safe shutdown equipment been evaluated to ensure their availability in the event of fire.

Controls and instrumentation for the RCIC system are located on the remote shutdown panel. However, the RCIC system and the high-pressure core spray (HPCS) system have not been protected from the effects of a control room fire.

The major components for remote post-fire safe shutdown are listed in Table F.4-1.

F.4.4 FIRE AREA ANALYSES

F.4.4.1 Post-Fire Safe Shutdown

The potential consequences of fire damage are analyzed by evaluating the post-fire safe shutdown equipment by fire area. Post-fire safe shutdown equipment in the fire area is assumed damaged by the postulated fire, unless the equivalent level of fire protection specified by Appendix R, Section III.G is provided or the configuration is within the basis of an approved deviation.

For fire areas outside the main control room, the equipment/cabling within the area is reviewed to ensure that redundant post-fire shutdown systems remain available. First, the area is assigned as Division 1 or Division 2 based on the train of post-fire safe shutdown equipment which would be lost due to a fire in the area. Any cabling or equipment of the redundant division (which is credited for operation of post-fire safe shutdown) which is located within the area is then identified. Equipment and cabling within the main control room is evaluated to ensure that a fire will not prevent remote shutdown.

Potential high impedance cabling faults are reviewed as necessary to ensure the availability of the necessary power supplies for post-fire safe shutdown. Any spurious signal cables (those cables which could cause a malfunction if compromised by a hot short, open circuit, or short to ground) which could affect the post-fire safe shutdown are analyzed to identify the potential

effects of fire on post-fire safe shutdown capability. Only one spurious actuation alone, with the effects of that actuation, are assumed to occur at a time. Appropriate plant modifications have been implemented where the analysis indicated that additional protection was required.

In fire areas where extensive amounts of post-fire safe shutdown equipment from both divisions are present, a 'dedicated' shutdown analysis is used. This term refers to the protection of the preferred post-fire safe shutdown system equipment/cabling within such areas.

The adequacy of the construction of the fire area boundaries is evaluated as part of the fire hazards analysis by a comparison of the area fire hazards to the active and passive fire protection features and specific post-fire safe shutdown requirements.

The fire hazards analysis for certain areas is unique:

a. A fire hazards analysis is performed for primary containment (Fire Area R 2); however, the post-fire safe shutdown capability is not specifically evaluated as primary containment is inerted during power operation;

b. The main control room (Fire Area RC-10) is analyzed to ensure the remote shutdown system will remain available;

c. The Division 2 instrument rack rooms in the reactor building (Fire Areas E-IR-H22/P009, E-IR-H22/P021, E-IR-H22/P027, E-IR-73) are evaluated to ensure that the racks have been adequately separately from the surrounding fire area;

d. The cable spreading room (Fire Area RC-2) is analyzed by zone. The room is divided into three fire zones, a dedicated Division 2 protected fire zone, a Division 2 fire zone, and separating these two zones is a 20-ft noncombustible fire zone. Within the 20-ft noncombustible fire zone, RC-2C, the post-fire safe shutdown cables are protected by 1-hr fire barriers, and the non-post-fire safe shutdown cables are sprayed with Thermo-Lag to eliminate intervening combustibles and prevent a fire from propagating between the redundant divisions;

e. Fire Area TG-1 is subdivided into several fire zones. Except for Fire Zone TG-12, all fire zones are combined and a single analysis is performed. For Fire Zone TG-12, a separate dedicated analysis is performed and Division 2 post-fire safe shutdown circuits are protected; and

f. There are two fire areas, RC-2 cable spreading room and RC-3 cable chase, that have area-wide sprinkler and detection systems, which qualify as 1-hr fire areas.

In addition, Fire Zone TG-12 of Fire Area TG-1 has been justified as a 1-hr area (Reference F.7.3.s).

In the event of a fire in certain plant areas, some of the operator actions required to mitigate the effects of fire are as follows:

a. A fire in the cable spreading room (Fire Area RC-2A) or the turbine building (Fire Area TG-1) could result in the loss of switchgear E-SM-85. The switchgear supply breaker(s) from E-SM-8 should be tripped as necessary for diesel loading considerations.

b. A fire in the cable chase (Fire Area RC-3) could result in the loss of power to both control room chillers. Operator action may be required to manually align service water cooling for the Division 2 control room HVAC unit emergency cooling coil.

c. A fire in the reactor building (Fire Area R-1) or the cable chase (Fire Area RC-3) could cause spurious signals to the isolation valve circuitry. Caution should be used when resetting the nuclear steam supply system (NSSS) isolation logic using the isolation logic reset push buttons on control room panel H13-P601.

d. A fire in the control room chiller area (Fire Area RC-13) could interrupt ventilation from the battery rooms. Operator action should be taken within 40 hr to prevent hydrogen accumulation.

   A fire in the control room chiller area could also result in the loss of the fresh air supply to the main control room. If necessary, operator action will be taken to open doors.

e. A fire in the radwaste 467 ft vital island corridor (RC-19) could interrupt ventilation from the credited division battery room. Operator action should be taken within 40 hr to prevent hydrogen accumulation.

F.4.4.2 Control of Radioactive Release

A fire induced radioactive release to the environment can occur via one of the following mechanisms:

a. Inadvertent primary coolant release to the environment,

b. Inadvertent radwaste system release to the environment,

c. Contaminated smoke due to the combustion of radioactive material, and

d. Contaminated water produced as a product of fire suppression in areas containing radioactive material.

Normal plant operating procedures provide guidance for ensuring that appropriate design features are used to monitor and control the release of radioactivity to the environment which may occur as the result of a fire or fire fighting activities. Specific design features to be used will be determined at the time of the fire by health physics personnel and the Environmental Field Team, as necessary. The design features provided along with fire brigade training will ensure that any release of radiation due to fire will be controlled and monitored.

Reactor coolant system integrity is among several functional requirements necessary to achieve safe shutdown. Equipment necessary to meet these functional requirements has been identified and analyzed.

The liquid waste management system is discussed in Section 11.2. The system is designed to process potentially radioactive liquids from fire suppression activities in a manner which limits radiation exposure and controls the release of potentially radioactive material.

In the reactor building, turbine building, and radwaste building, contaminated liquid resulting from fire suppression activities in contaminated areas is routed through floor drains to the liquid waste management system. The HVAC exhaust vents in these buildings are provided with radiation monitors and can be isolated to limit the spread of smoke. In addition, procedural controls and fire brigade training stress the need to control and minimize the potential release of fire suppression water and smoke. Environmental field teams would be used as needed to monitor releases from the turbine generator, reactor, or radwaste buildings due to a significant fire.

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
[3]	RHR-P-2B [EO] [29]	R-4	RHR-P-2A [EO] [29]	R-5	RHR-P-2B [EO] [29]	R-4
CABLE	2SM8-50,51,52,55,56,57,61 2D12D-4, 8313-E12A-O12 8001-E12A-003	RC-2B, RC-2C* RC-3,* RC-7, RC-8, RC-9 RC-10, RC-19 TG-1* R-4	1RHR-47 1SM7-60, 61, 65, 66, 51 8201-E12A-002 1D11F-4	RC-2A, RC-3, RC-4, RC-10, RC-14, R-5 TG-1	2SM8-50, 51, 55 2D12D-5	RC-2B, RC-2C, RC-3, RC-4 RC-7, RC-8 RC-9, RC-19 TG-1 R-4
EQUIP	SM-8/RHR-2B, E-CP-C61/P001 H13-P601, P618, P680, P683 DP-S1-2D	EWD | 9E003	SM-7/RHR-2A DP-S1-1F, E-CP-ARS H13-P601, P682	EWD | 9E002	SM-8/RHR-2B E-CP-C61/P001 DP-S1-2D	EWD | 9E003

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
[7]	RHR-V-3B [VO/VO] [2]	R-4	RHR-V-3A [VO/VO]	R-5	RHR-V-3B [VO/VO]	R-4
CABLE	(2M88BB-140) 2M8BB-141 2M8BB-142, 143 8001-E12A-004	R-1* R-4 RC-2C,* RC-2B, RC-9, RC-3* RC-10	1M7BB-110, 111, 112, 113, 114 8201-E12A-003	R-1, R-5, RC-2A, RC-3, RC-10, RC-14	2M8BB-140, 141, 142 2P8AF-1	R-1, R-4 RC-2C, RC-2B RC-3, RC-3 RC-9
EQUIP	MC-8B-B/5B, E-CP-C61/P001 H13-P601, P680	EWD | 9E017	MC-7B-B/5B H13-P601, P682 E-CP-ARS	EWD | 9E016	MC-8B-B/5B, E-CP-C61/P001 PP-8A-F	EWD | 9E017

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-4B [VO/VO]	R-4	RHR-V-4A [VO/VO]	R-5	RHR-V-4B [VO/VO]	R-4
CABLE	(2M8BA-20) 2M8BA-22 2M8BA-23, 24 8001-E12A-006	R-1,* R-4 R-18, RC-2B, RC-2C,* RC-3* RC-9, RC-10	1M7BA-50, 52, 53, 54, 55 8201-E12A-004	R-1, R-5, RC-2A, RC-3 RC-10, RC-14	2M8BA-20, 22, 23 2P8AF-1	R-1, R-4 R-18, RC-2B RC-2C, RC-3 RC-9
EQUIP	MC-8B-A/2C, E-CP-C61/P001 H13-P601, P680	EWD | 9E019	MC-7B-A/3B H13-P601, P682 E-CP-ARS	EWD | 9E018	MC-8BA/2C, E-CP-C61/P001 PP-8A-F	EWD | 9E019

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-6B [VC/VC]	R-4	RHR-V-6A [VC/VC]	R-5	RHR-V-6B [VC/VC]	R-4
CABLE	(2M8BA-10) 2MB8BA-12 2M8BA-13, 14, 15, 16, 17, 18 8001-E12A-005	R-1,* R-4 RC-2B, R-18 RC-3,* RC-2C* RC-9 RC-10	1M7BA-40, 41, 42, 43, 44, 45, 46, 47 8201-E12A-004	R-1, R-5 RC-2A, RC-3 RC-10, RC-14 [2	2M8BA-10, 12, 13 2P8AF-1	R-1, R-4 R-18, RC-2B RC-2C, RC-3 RC-9
EQUIP	MC-8B-A/2B, H13-P601, P68 RHR-V-4B/LS6, RHR-V-24B/LS6 RHR-V27B/LS6, E-CP-C61/P001	EWD 9E022	MC-7B-A/3A RHR-V-4A/LS6, RHR-V-24A/LS6 RHR-V-27A/LS6, H13-P601, P682 E-CP-ARS	EWD 9E021	MC-8B-A/2B, E-CP-C61/P001 PP-8A-F E-CP-ARS, PP-7A-F	EWD 9E022

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-24B [VC/VC]	R-4	RHR-V-24A [VC/VC]	R-1	RHR-V-24B [VC/VC]	R-4
CABLE	(2M8BA-90) 2M8BA-92 2M8BA-93, 94, 95, 96 8318-E12A-011, 1801-E12A-010 8001-E12A-025	R-1,* R-4 R-18 RC-2B, RC-2C* RC-3,* RC-9 RC-10	1M7BA-110, 112, 113, 114, 115 8429-E12A-008 2901-E12A-007	R-1 RC-2A, RC-3, RC-10, RC-14	2M8BA-90, 92, 93 2P8AF-1	R-1, R-4 R-18 RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B-A/4B, E-CP-C61/P001 H13-P601, P618, P683	EWD 9E034	MC-7B-A/4D H13-P601, P629, P684 E-CP-ARS	EWD 9E033	MC-8B-A/4B, E-CP-C61/P001 PP-8A-F	EWD 9E034

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-27B [VC/VC]	R-4	RHR-V-27A [VC/VC]	R-1	RHR-V-27B [VC/VC]	R-4
CABLE	(2M8BA-150) 2M8BA-152 2M8BA-153, 154, 155, 96 8318-E12A-010, 1801-E12A-009 8001-E12A-025	R-1,* R-4 R-18 RC-2B, RC-2C* RC-3,* RC-9 RC-10	1M7BA-160, 162, 163, 164, 165 8429-E12A-007 2901-E12A-006	R-1 RC-2A, RC-3 RC-10, RC-14	2M8BA-150, 152, 153 2P8AF-1	R-1, R-4 R-18 RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B-A/5D, E-CP-C61/P001 H13-P601, P618, P683	EWD 9E038	MC-7B-A/5C H13-P601, P629, P684 E-CP-ARS	EWD 9E037	MC-8B-A/5D, E-CP-C61/P001 PP-8A-F	EWD 9E038

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
[6]	RHR-V-42B [VC/VO]	R-21	RHR-V-42A [VC/VO]	R-1	RHR-V-42B [VC/VO]	R-21
CABLE	2M8BA-100, 102, 103, 104 8318-E12A-007 1801-E12A-006	R-1,* R-18 R-21, RC-2B, RC-2C* RC-3, RC-9 RC-10	1M7BA-120, 122, 123, 124, 125 8429-E12A-004 2901-E12A-003	R-1, RC-2A, RC-3 RC-10, RC-14	2M8BA-100, 102, 103 2P8AF-1	R-1, R-18 R-21, RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B-A/4C, E-CP-C61/P00 H13-P601, P618, P683	EWD 9E044	MC-7B-A/5A H13-P601, P629, P684 E-CP-ARS	EWD 9E043	MC-8B-A/4C, E-CP-C61/P001 PP-8A-F	EWD 9E044

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-47B [VO/VO]	R-4	RHR-V-47A [VC/VO]	R-5	RHR-V-47B [VO/VO]	R-4
CABLE	(2M8BB-120) 2M8BB-121 2M8BB-122, 123 8001-E12A-005	R-1,* R-4 RC-2B, RC-2C* RC-3, RC-9 RC-10	1M7BB-90, 91, 92, 93, 94 8201-E12A-003	R-1 R-5 RC-2A, RC-3, RC-10, RC-14	2M8BB-120, 121, 122 2P8AF-1	R-1, R-4 RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B-B/4D, E-CP-C61/P00 H13-P601, P680	EWD 9E047	MC-7B-B/4D H13-P682, P601 E-CP-ARS	EWD 9E046	MC-8B-A/4C, E-CP-C61/P001 PP-8A-F	EWD 9E047

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-48B [VO/VC]	R-4	RHR-V-48A [VO/VC]	R-5	RHR-V-48B [VO/VC]	R-4
CABLE	(2M8BB-130) 131, 132, 133 8318-E12A-008 1801-E12A-007 8001-E12A-025	R-1,* R-4 RC-2B, RC-2C* RC-3,* RC-9 RC-10	1M7BB-100, 101, 102, 103, 104 8429-E12A-005 2901-E12A-004	R-1 R-5 RC-2A, RC-3 RC-10, RC-14	2M8BB-130, 131, 132 2P8AF-1	R-1, R-4 RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B-B/5A, E-CP-C61/P001 H13-P601, P618, P683 SB-R017	EWD 9E049	MC-7B-B/5A H13-P601, P629, P684 E-CP-ARS SB-R016	EWD 9E048	MC-8B-B/5A, E-CP-C61/P001 PP-8A-F SB-R017	EWD 9E049

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-FCV-64B [VC/VO-VC]	R-4	RHR-FCV-64A [VC/VO-VC]	R-5	RHR-FCV-64B [VC/V0-VC]	R-4
CABLE	(2M8BA-390) 2M8BA-391 2M8BA-319, 94, 96, 317, 320, 154 2RHR-76 8318-E12A-015, 1801-E12A-015 2SM8-51, 55, 2D12D-5	R-1,* R-4 R-18, RC-2B, RC-2C* RC-3,* RC-9 RC-10	1M7BA-180, 182, 183, 184, 185 8429-E12A-012 2901-E12A-010	R-1, R-5 RC-2, RC-3 RC-10, RC-14	2M8BA-319, 390, 391, 154 2P8AF-1, 2D12D-5, 2RHR-76 2SM8-51, 55	R-1, R-4 R-18 RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B-A/3D, E-CP-C61/P001 H13-P601, P618, P683 SM8/RHR-2B E-DP-S1-2D	EWD | 9E057	MC-7B-A/7B H13-P601, P629, P684 E-CP-ARS	EWD | 9E056	MC-8B-A/3D, E-CP-C61/P001 PP-8A-F	EWD | 9E057

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
[5]	RHR-V-49 [VC/VC]	R-4	N/A	N/A	RHR-V-49 [VC/VC]	R-4
CABLE	(2M8BB-230) 2M8BB-231 2M8BB-234, 2M8BB-232, 233 8322-B22H-005, 2201-B22H-003	R-1,* R-4 RC-2B, RC-2C* RC-3,* RC-9 RC-10			2M8BB-230, 231, 232, 234 2P8AF-1	R-1, R-4 RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B-B/7A, E-CP-C61/P001 H13-P601, P622, P683	EWD | 9E028			MC-8B-B/7A, E-CP-C61/P001 PP-8A-F	EWD | 9E057

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-FC-68B [VC/VO]	R-4	RHR-V-68A [VC/VO]	R-5	RHR-V-68B [VC/VO]	R-4
CABLE	2M8BB-220, 221, 222, 223, 224, 225, 226 8001-E12A-004	R-1,* R-4 RC-2B, RC-2C* RC-3,* RC-8 RC-9 RC-10	1M7BB-210, 211, 212, 213, 214, 215 8201-E12A-002	R-1, R-5 RC-2A, RC-3 RC-10, RC-14	2M8BB-220, 221, 222, 225 2P8AF-1	R-1, R-4 RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B-B/6D, E-CP-C61/P001 H22-P100, SM-8/SW1B (4), H13-P601, P680	EWD | 58E047	MC-7B-B/7A H13-P601, P682 E-CP-ARS	EWD | 58E046	MC-8B-B/6D, E-CP-C61/P001 H22-P100, PP-8A-F	EWD | 58E047

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
[8]	SW-P-1B [EO]	SW-2	SW-P-1A [EO]	SW-1	SW-P-1B [EO]	SW-2
CABLE	2SM8- 80, 81, 85, 86, 87, 89, 93, 256 2D12D-4, CM-A2-4-4 2M8A-45, 56, 57, 103, 150	SW-2, TG-1* DG-3, R-1*, R-4, R-5,* R-6, RC-2B RC-2C,* RC-3* RC-7, RC-8, RC-9, RC-10 RC-19	1SM7-80, 81, 87, 88 IM7A-42, 53, 59, 31, 34, 172 CM-A2-1-10, 1D11F-4 1IR21-64, 65, 66	SW-1, TG-1 DG-2, RC-2A RC-2C,* RC-3 RC-4, RC-5 RC-10, RC-14 RC-20	2SM8-80, 81, 85, 86, 89, 93, 256 2D12D-12 2M8A-45, 56, 57, 103, 150	SW-2, TG-1 DG-3, R-1 R-4, R-5 R-6, RC-2B RC-2C RC-3 RC-7, RC-9 RC-19
EQUIP	TB-R435, SM-8/SW1B (4) H22-P100, E-CP-CS2 DG2-8 (1), H13-P805, P820 TB-SW1508, E-MC-8A		MC-7A, SM-7/SW1A (7) DG1/7 AUX (1), SUPV PNL CS1 H13-P805, P840 E-CP-ARS, TB-W163, DP-S1-1F		TB-R435, SM-8/SW1B (4), H22-P100, E-CP-CS2 DG2-8 (1) TB-SW1508, E-MC-8A	
		EWD 58E003		EWD 58E001		EWD 58E003

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	SW-V-2B [VC/VO]	SW-2	SW-V-2A [VC/VO]	SW-1	SW-V-2B [VC/VO]	SW-2
CABLE	2M8A-40, 41, 42, 43, 44, 45, 46, 47, 48 CM-A2-4-4	SW-2, TG-1,* RC-2B, RC-2C,* RC-3C,* RC-7, RC-8, RC-10, RC-11	1M7A, 50, 51, 52, 53, 55, 56, 57, 58, 59 1IR21-20 CM-A2-1-10	SW-1, TG-1, DG-2, RC-2A, RC-2C,* RC-3 RC-4, RC-10 RC-14, RC-20	2M8A-40, 41, 42, 46, 47, 48 2P8AF-2	SW-2, TG-1, RC-2B, RC-2C, RC-3, RC-7, RC-9
EQUIP	TB-SW1508, IR-22, MC-8A/3C, SM-8/SW1B (4) H22-P100, E-CP-CS2 H13-P805, P820		TB-SW1507, IR-21, E-CP-ARS MC-7A/2D, SM-7/SW1A (7) TB-W163 H13-P805, P840, E-CP-CS1		TB-SW1508, IR-22 MC-8A/3C, PP-8A-F, H22-P100, E-CP-CS2	
		EWD 58E015		EWD 58E012		EWD 58E015

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA
	SW-TCV-11B [VO/VO]	RC-12	SW-TCV-11A [VC-VO/VO]	RC-11	N/A	N/A
CABLE	2COV2-20, 21, 22 2CHB-8,2P8AF-4,2P8AA-110 2COV5-3, 1, 4, 5; 2M8F-51	RC-12, RC-2B, RC-13, RC-2C* RC-3* RC-9, RC-10	1COV1-20, 21, 22 1, 4, 5 1COV5-3, 1CHA-8 1P7AA-170, M7F-31 1P7AE-12	RC-2A, RC-3 RC-10, RC-11 R-1 RC-13		
EQUIP	WMA-TE-11B, WMA-TT-11B COHV-2, MC-8F/4A, SW-TCV-11B, SW-PS-11B, CCH-CR-1B, E-PP-8AA, E-PP-8AF H13-P823, P891	EWD | 84E018	WMA-TE-11A, WMA-TT-11A COHV-1, COHV-5A, SW-PS-11A, SW-TCV-11A PP-7A-A, CCH-CR-11A PP-7A-E, E-MC-7F H13-P826, P892	EWD | 84E017		|

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	SW-V-12B [VO/VO]	SW-2	SW-V-12A [VC-VO/VO]	SW-1	SW-V-12B [VO/VO]	SW-2
CABLE	2MB8A-50, 51, 52, 53, 54, 56, 57, 103 CM-A2-4-5 25M8-81, 86, 256	SW-2, TG-1,* RC-2B, RC-2C,* RC-3,* RC-7, RC-8, RC-9, RC-10	1M7A, 30, 31, 32, 34, 37, 11R21-64, 65, 66, 67, 68, 69, CM-A2-1-08	SW-1, TG-1, DG-2, RC-2A, RC-2C,* RC-3 RC-14, RC-4 RC-10, RC-20	2MB8A-50, 51, 52, 54, 56, 57, 103 2P8AF-2 25M8-81, 86, 256	SW-2, TG-1, RC-2B, RC-2C, RC-3, RC-7, RC-8, RC-9
EQUIP	TG-SW1508, MC-8A/2D E-CP-CS2, H22-P100 H13-P805, P820, E-SM-8	EWD | 58E021	MC-7A/1D, TB-SW1507 E-CP-CS1 H13-P805, P840 E-CP-ARS, E-SM-7	EWD | 58E020	TB-SW1508, MC-8A/2D, E-SM-8 E-CP-CS2, H22-P100 PP-8A-F	EWD | 58E021

RHR SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	SW-PCV-38B [VO/VO]	SW-2	SW-PCV-38A [VC-VO]	SW-1	SW-PCV-38B [VC/VO]	SW-2
CABLE	THIS VALVE HAS BEEN LOCKED IN THE OPEN POSITION; ALL POWER HAS BEEN REMOVED.		THIS VALVE HAS BEEN LOCKED IN THE OPEN POSITION; ALL POWER HAS BEEN REMOVED.		THIS VALVE HAS BEEN LOCKED IN THE OPEN POSITION; ALL POWER HAS BEEN REMOVED.	
EQUIP		EWD | 58E031		EWD | 58E030		EWD | 58E031

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	DEA-FN-21 [EO]	DG-3	DEA-FN-11 [EO]	DG-2	DEA-FN-21 [EO]	DG-3
CABLE	2M8AA-30, 31, 32	DG-3	1M7AA-30, 31, 32	DG-2	2M8AA-30, 31, 32	DG-3
EQUIP	MC-8A-A/1D, 1 DGHV-2, DEA-DPS-21	EWD | 88E004	MC-7A-A/1D DGHV-1 DEA-DPS-11	EWD | 88E003	MC-8A-A/1D DGHV-2 DEA-DPS-21	EWD | 88E004

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	DEA-FN-22 [EO]	DG-3	DEA-FN-12 [EO]	DG-2	DEA-FN-22 [EO]	DG-3
CABLE	2M8AA-60, 61	DG-3	1M7AA-60, 61	DG-2	2M8AA-60, 61	DG-3
EQUIP	MC-8A-A/6E DGHV-2	EWD | 88E0023	MC-7A-A/7C	EWD | 88E021	MC-8A-A/6E	EWD | 88E023

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	DMA-FN-21 [EO]	DG-3	DMA-FN-11 [EO]	DG-2	DMA-FN-21 [EO]	DG-3
CABLE	2M8AA-10, 11	DG-3	1M7AA-20, 21	DG-2	2M8AA-10, 11	DG-3
EQUIP	MC-8A-A/1C DGHV-2	EWD | 88E013	MC-7A-A/1C DGHV-1 DEA-DPS-11	EWD | 88E012	MC-8A-A/1C DGHV-2	EWD | 88E013

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TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	DMA-FN-22 [EO]	DG-3	DMA-FN-12 [EO]	DG-2	DMA-FN-22 [EO]	DG-3
CABLE	2M8AA-20, 21	DG-3	1M7AA-20, 21	DG-2	2M8AA-20, 21	DG-3
EQUIP	MC-8A-A/1B DGHV-2	EWD | 88E007	MC-7A-A/1B DGHV-1	EWD | 88E006	MC-8A-A/1B DGHV-2	EWD | 88E007

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	PRA-FN-1B [EO]	SW-2	PRA-FN-1A [EO]	SW-1	PRA-FN-1B [EO]	SW-2
CABLE	2M8A-180, 181, 182, 183 2IR22-30, 31, 32 2MISC-1 2P8AG-1, 2P8AF-7	SW-2, TG-1,* DG-3, RC-1, RC-2B, RC-2C,* RC-3,* RC-8, RC-9	1M7AA-200, 201, 202, 203 1IR21-30, 31, 32 1P7AG-2	TG-1 SW-1 DG-2 RC-2A, RC-3 RC-10, RC-14 RC-20	2M8AA-180, 181, 182, 183 2IR22-30, 31, 32 2MISC 1 2P8AG-1, 2P8AF-7	SW-2, TG-1 DG-3, RC-1 RC-2B, RC-2C RC-3, RC-8 RC-9
EQUIP	SUPV PNL S2 & CS2, PP-8A-G PRA-dPS-1B, IR-22 SM8/SW1B, MC-8A-A/4B	EWD | 87E010	MC-7A-A/3D, PP-7A-G SUPV PNL S1 & CS1, IR-21 PRA-dPS-1A, SM-7/SW1A	EWD | 87E009	SUPV PNL S2 & CS2, PP-8A-G PRA-dPS-1B, IR-22 SM8/SW1A, MC-8A-A/4B	EWD | 87E010

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RRA-FN-3 [EO]	R-4	RRA-FN-2 [EO]	R-5	RRA-FN-3 [EO]	R-4
CABLE	2M8B-150, 151, 152	R-1,* R-4 R-18, RC-2B, RC-3* RC-8	1M7B-160, 161, 162	R-1, R-5 RC-2A, RC-3 RC-14	2M8B-150, 151, 152	R-1, R-4 R-18, RC-2B, RC-3 RC-8
EQUIP	MC-8B/4B SM-8/RHR-2B	EWD | 81E005	MC-7B/4B SM-7/RHR-2A (2)	EWD | 81E004	MC-8B/4B SM-8/RHR-2B (10)	EWD | 81E005

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RRA-FN-10 [EO] [27]	R-18	RRA-FN-11 [EO]	R-1	RRA-FN-10 [EO] [27]	R-18
CABLE	2M8B-100, 101, 102, 103, 104 CM-K2-3-5	R-1,* R-18 RC-2B, RC-2C* RC-3,* RC-9 RC-10	1M7B-200, 221, 222, 223 CM-K1-3-5	R-1 RC-2A, RC-3 RC-10	2M8B-100, 103, 104 2P8AF-12	R-1, R-18 RC-2B, RC-2C RC-3, RC-9
EQUIP	MC-8B/3D, FRTP, ROA-SPV-10, RC-2, H13-P812, P891	EWD | 81E009	RC-1, MC-7B/2C H13-P812, P892 ROA-SPV-11	EWD | 81E010	MC-8B-3D, FRTP, ROA-SPV-10, PP-8A-F	EWD | 81E009

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RRA-FN-14 [EO] [27]	R-4	RRA-FN-13 [EO]	R-1	RRA-FN-14 [EO]	R-4
CABLE	2M8BB-110, 111, 112, 113, 114 CM-K2-3-7	R-1,* R-4 RC-2B, RC-2C* RC-3,* RC-9 RC-10	1M7BB-150, 151, 152, 153 CM-K1-3-8	R-1 RC-2A, RC-3 RC-10	2M8BB-110, 113, 114 2P8AF-12	R-1, R-4 RC-2B, RC-2C RC-3 RC-9
EQUIP	MC-8B-B/1E, FRTP, ROA-SPV-14, RC-2 H13-P812, P891	EWD | 81E013	MC-7B-B/1E, RC-1 ROA-SPV-13 H13-P812, P892	EWD | 81E012	MC-8B-B/1E, FRTP ROA-SPV-14, PP-8A-F	EWD | 81E013

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA
	WEA-FN-53A [EO] [11]	RC-13	N/A	N/A	N/A	N/A
CABLE						
EQUIP						

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA
	WEA-FN-53B [E0] [11]	RC-13	N/A	N/A	N/A	N/A
CABLE						
EQUIP						

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA
	WMA-FN-51B [E0]	RC-12	WMA-FN-51A [E0] [10]	RC-11	N/A	N/A
CABLE	2M8F-20, 21 CM-K2-3-1	RC-2B, RC-3* RC-10, RC-12	1M7F-50, 51 CM-K1-3-1	RC-2A, RC-3 RC-10, RC-11		
EQUIP	MC-8F/2C H13-P826, P891	EWD 84E010	MC-7F/3E H13-P826 P892	EWD 84E008		

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	WMA-FN-52B [E0] [26]	RC-12	WMA-FN-52A [E0] [26]	RC-11	WMA-FN-52B [E0]	RC-12
CABLE	2M8F-30, 31, 32, 33 CM-K2-3-1	RC-2B, RC-2C* RC-3,* RC-9 RC-10, RC-12	1M7F-10, 11, 12 CM-K1-3-1	RC-2A, RC-3 RC-10, RC-11	2M8F-30, 32, 33 2P8AF-11	RC-2B, RC-2C RC-3, RC-9 RC-12
EQUIP	MC-8F/1B, C0HV-4 H13-P826, P891 FRTP	EWD 84E011, A, B	MC-7F/2C, C0HV-3 H13-P826, P892	EWD 84E009	MC-8F/1B, C0HV-4 FRTP, PP-8A-F	EWD 84E011

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	WMA-FN-53B [EO] [26]	RC-12	WMA-FN-53A [EO] [26]	RC-11	WMA-FN-53B [EO]	RC-12
CABLE	2M8F-50, 51, 55, 56 CM-K2-3-4	RC-2B, RC-2C* RC-3,* RC-9 RC-10, RC-12	1M7F-20, 21, 22, 25 CM-K1-3-3	RC-2A RC-3 RC-10, RC-11 RC-14	2M8F-50, 55, 56 2P8AF-11	RC-2B, RC-2C RC-3, RC-9 RC-12
EQUIP	MC-8F/1E, COHV-4 H13-P-826, P891 FRTP	EWD 84E005	MC-7F/1D, COHV-3 H13-P826, P892 E-CP-ARS	EWD 84E005	MC-8F/1E, COHV-4 FRTP, PP-8A-F	EWD 84E005

HVAC SYSTEM

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	WMA-EHC-8 [EO]	RC-6	WMA-EHC-7A & WMA-EHC-7B [EO]	RC-5	WMA-EHC-8	RC-6
CABLE	2M8A-190, 191, 192, 193, 194	RC-6 RC-7	1M7A-190, 191, 192, 193, 194 1M7A-200, 201, 202, 203, 204	RC-4, RC-5 RC-14	2M8A-190, 191, 192, 193, 194	RC-6 RC-7
EQUIP		EWD 84E050	E-MC-7A E-CNTR-WMA/EHC/7A E-CNTR-WMA/EHC/7B WMA-TS-7A, WMA-TS-7B	EWD 84E049	E-MC-8A E-CNTR-WMA/EHC/8 WMA-TS-8	EWD 84E050

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

ADS/SRV SYSTEM [19A, 19B]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	MS-RV-3D (Sol. B) [VC/VO]	R-2	MS-RV-3D (Sol. A&C) [VC/VO]	R-2	MS-RV-3D (Sol. A) [VC/VO]	R-2
CABLE	2ADS-31, 32 2D12A-5 3101-B22C-001, 8331-B22C-001	R-1* R-2 RC-2B, RC-3* RC-10	1ADS-35, 36 1D11A-8 8428-B22C,005 2801-B22C,0010	R-1, R-2 RC-2A, RC-3 RC-10, RC-14	1D11F-9 1ADS-36 1ADS-20	R-1 R-2 RC-2A, RC-3 RC-14
EQUIP	DP-S1-2A, H13-P683 TB-R313, TB-C513 H13-P631, P601	EWD | 1E038A	DP-S1-1A E-CP-ARS TB-R322, TB-C522 H13-P601, P628, P684	EWD | 1E038A	E-CP-ARS E-DP-S1/1F E-TB-R/322 E-TB-C/522	EWD | 1E038A

ADS/SRV SYSTEM [19A, 19B]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	MS-RV-4A (Sol. B) [VC/VO]	R-2	MS-RV-4A (Sol. A) [VC/VO]	R-2	MS-RV-4A (Sol. B) [VC/VO]	R-2
CABLE	2ADS-29, 32, 55 2D12A-5 3101-B22C-001, 8331-B22C-001,	R-1* R-2 RC-2B, RC-2C* RC-3,* RC-9 RC-10	1ADS-25, 37 1D11A-8 8428-B22C-006 2801-B22C-0011	R-1, R-2 RC-2A, RC-3 RC-10	2ADS-29, 32, 55 [24] 2D12D-5	R-1, R-2 RC-2B RC-2C RC-3, RC-9 RC-10*
EQUIP	DP-S1-2A, H13-P683 TB-R313, TB-C513 H13-P631, P601 E-CP-C61/P001	EWD | 1E036A	DP-S1-1A TB-R322, TB-C522 H13-P601, P628, P684	EWD | 1E036A		EWD | 1E036A

ADS/SRV SYSTEM [19A, 19B]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	MS-RV-4B (Sol. B) [VC/VO]	R-2	MS-RV-4B (Sol. A) [VC/VO]	R-2	MS-RV-48 (Sol. B) [VC/VO]	R-2
CABLE	2ADS-28, 33, 55 2D12A-5 8331-B22C-001, 4 3101-B22C-001	R-1,* R-2 RC-2B, RC-2C* RC-3* RC-9 RC-10	1ADS-24, 37 1D11A-8 8428-B22C-006 2801-B22C-0011	R-1, R-2 RC-2A, RC-3 RC-10	2ADS-28, 33, 55 [24] 2D12D-5	R-1, R-2 RC-2B, RC-2C RC-3 RC-9 RC-10*
EQUIP	DP-S1-2A, H13-P683 TB-R313, TB-C513 H13-631, P601 E-CP-C61/P001	EWD | 1E035A	DP-S1-1A TB-R322, TB-C522 H13-P601, P628, P684	EWD | 1E035A	DP-S1-2D, H13-P683, SB-R007 TB-R313, TB-C513 E-CP-C61/P001	EWD | 1E035A

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

ADS/SRV SYSTEM [19A, 19B]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	MS-RV-4C (Sol. B) [VC/VO]	R-2	MS-RV-4C (Sol. A) [VC/VO]	R-2	MS-RV-4C (Sol. B) [VC/VO]	R-2
CABLE	2ADS-25-33, 55 2D12A-5, 8331-B22C-002 3101-B22C-002 8331-B22C-004	R1-2B, R-2 RC-2B, RC-2C* RC-3,* RC-9 RC-10	1ADS-21, 37 1D11A-8 8428-B22C-006 2801-B22C-0011	R-1 R-2 RC-2A, RC-3 RC-10	2ADS-25, 33, 55 [24] 2D12D-5	R1, R-2 RC-2B, RC-2C RC-3, RC-9 RC-10*
EQUIP	DP-S1-2A, H13-P683 TB-R313, TB-C513 H3-P631, P601 E-CP-C61/P001	EWD | 1E032A	DP-S1-1A TB-R322, TB-C522 H13-P601, P628, P684	EWD | 1E032A	DP-S1-2D, H13-P683 SB-R007 TB-R313, TB-C513 E-CP-C61/P001	EWD | 1E032A

ADS/SRV SYSTEM [19A, 19B]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	MS-RV-5B (Sol. B) [VC/CO]	R-2	MS-RV-5B (Sol. A) VC/CO]	R-2	MS-RV-5B (Sol. A) [VC/VO]	RC-6
CABLE	2ADS-30, 32 2D12A-5 8331-B22C-001, 3101-B22C-001	R-1* R-2 RC-2B RC-3* RC-10	1ADS-19, 35, 36 1S11A-8 8428-B22C-005 2801-B22C-0010	R-1, R-2 RC-2A, RC-3 RC-10. RC-14	1ADS-36 1011F-8 1ADS-19	R-1 R-2 RC-2A RC-3 RC-14
EQUIP	DP-S1-2A, H13-P683, TB-R313, TB-C-513 H13-[631, 9601	EWD | 1E037A	DP-S1-1A E-CP-ARS TB-C522, TB-R322 H13-P601, P628	EWD | 1E037A	E-CP-ARS E-DP-S1/1F E-TB-R/322 E-TB-C/522	EWD | 1E037A

ADS/SRV SYSTEM [19A, 19B]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	MS-RV-5C (Sol. B) [VC/VO]	R-2	MS-RV-5C (Sol. A) [VC/VO]	R-2	MS-RV-5C (Sol. A) [VC/VO]	R-2
CABLE	2ADS-26, 33 2D12A-5 8331-B22C-001, 3101-B22C-002	R-1 R-2 RC-2B, RC-3* RC-10	1ADS-22, 35, 36 1D11A-8 2801-B22C-0011 8428-B22C-006	R-1 R-2 RC-2A, RC-3 RC-10, RC-14	1ADS-36 1011F-8 1ADS-22	R1, R-2 RC-2A, RC-3 RC-14
EQUIP	DP-S1-2A, H13-P683 TB-R313, TB-C513 H3-P631, P601	EWD | 1E033A	DP-S1-1A E-CP-ARS TB-C522, TB-R322 H13-P601, P628, P684	EWD | 1E033A	E-CP-ARS E-DP-S1/1F E-TB-R/322 E-TB-C/522	EWD | 1E033A

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

MSIV SYSTEM [9]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA
	MS-V-22A [VO/VC]	R-2	N/A	N/A	N/A	N/A
CABLE	2NS4-11 (2NS4-21, 22) 8322-B22H-001,2,3,4,7,8, 2201-B22H-001,2,3,7 2209-B22H-001, 221-B22H-001	R-1,* R-2 RC-2B, RC-3* RC-10				
EQUIP	TB-R313, TB-C513 H13- P601, P622, P683, P609, P611	EWD | 1E048				

MSIV SYSTEM [9]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA
	MS-V-22B [VO/VC]	R-2	N/A	N/A	N/A	N/A
CABLE	2NS4-9, (2NS4-19, 20) 8322-B22H-001,2,3,4,7,8, 2201-B22H-001,2,3,7 2209-B22H-001, 2211-B22H-001	R-1,* R-2 RC-2B, RC-3* RC-10				
EQUIP	TB-R313, TB-C513 H13-P601, P622, P683 P609, P611	EWD | 1E049				

MSIV SYSTEM [9]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA
	MS-V-22C [VO/VC]	RC-13	N/A	N/A	N/A	N/A
CABLE	2NS4-10 (2NS4-17, 18) 8322-B22H-001,2,3,4,7,8, 2201-B22H-001,2,3,7 2209-B22H-001, 2211-B22H-001	R-1,* R-2 RC-2B, RC-3* RC-10				
EQUIP	TB-R313, RB-C513 H13- P601, P622, P683, P609, P611	EWD | 1E050				

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

MSIV SYSTEM [9]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA
	MS-V-22D [VO/VC]	R-II	N/A	N/A	N/A	N/A
CABLE	2NS4-8, (2NS4-15, 16) 8322-B22H-001,2,3,4,7,8, 2201-B22H-001,2,3,7 2209-B22H-001, 2211-B22H-001	R-1,* R-2 RC-2B, RC-3* RC-10				
EQUIP	TB-R313, TB-C513 H13- P601, P622, P683, P609, P611	EWD 1E051				

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

APPENDIX R INSTRUMENTATION [29]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-FI-R603B [13]	RC-10	RHR-FI-R603A [13]	RC-10	RHR-FI-5 [13]	RC-9
CABLE	2RHR-35, 2P8AA-6 1301-E12A-001 8313-E12A-001	R-1* RC-2B, RC-3* RC-10 M-21	1RHR-4, 1P7AA-4, 1RHR-69 1201-E12A-001 8212-E12A-001	R-1 RC-2A RC-3 RC-10 RC-14	2RHR-92 2P8AF-1	R-1 RC-2B, RC-2C RC-3, RC-9 M-21
EQUIP	RHR-FT-N015B H22-P021 H13-P601, P613, P683	EWD | 91006	RHR-FT-N015A H22-P018 H13-P601, P612, P682 E-CP-ARS	EWD | 91005	RHR-FT-1 E-CP-C61/P001 (C61-N001) PP-8A-F	EWD | 91006

APPENDIX R INSTRUMENTATION [29]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	SW-FI-9B [15]	RC-10	SW-FI-9A [15]	RC-10	CRITICALITY INDICATION [14]	NA
CABLE	2MISC-1, 401, 402 2IR22-60 2P8AF-7, 2P8AG-1, 2P8AA-33 CBDB-1,CTCG2-2,6,CJB-TCG2-2,1	SW-2 TG-1* RC-1, RC-2B RC-2C,* RC-9, RC-10	1MISC-7, 401, 402 11R21-60, 1P7AG-2 CBDA-32, CTCGI-4, 15 1P7AA-18, CJB-TCG1-2.1	SW-1 TG-1 RC-2A, RC-3 RC-10		
EQUIP	SW-FT-8B, IR-22 SUPV PNL S2 & CS2 PP-8A-F, PP-8A-G H13-P720, P833, P893	EWD | 581009	SW-FT-8A, IR-21 SUPV PNL S1 & CS1 H13-P840, P841, P894 PP-7A-F	EWD | 581005		

APPENDIX R INSTRUMENTATION [29]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA [1]
	SW POND LEVEL [17]	N/A	N/A	N/A	SW-PI-32BR [16]	RC-9
CABLE					2IR22-67, 2MISC-433 2MISC-1 2P8AF-7, 2P8AG-1	SW-2 TG-1 RC-1, RC-9
EQUIP					SW-PT-32BR, IR-22 SUPV PNL S2 & CS2 H22-P100 PP-8A-F, PP-8A-G	EWD | 581008

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

APPENDIX R INSTRUMENTATION [29]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	CMS-LR-4 [18]	RC-10	CMS-LR-3 [18]	RC-10	CMS-LI-2R [18]	RC-9
CABLE	2IR63-41 CICG2-4.9, CJB-TCG-2.1 3301-CMS-001, 8001/E12A-012; 2P8AA-3 2P8AA-33, CBDG2V-2	R-1,* R-4 RC-2B, RC-3* RC-10	IP7AA-1 11R66-40, 41, 60 CTCG1-4.10, CJB-TCG1-2.1 4101-CMS-001 8201/E21A-003	R-1, R-7, R-8, RC-2A RC-3 RC-14	2MISC-432 2P8AF-2	R-1, R-4 RC-2B, RC-3 RC-9
EQUIP	CMS-LT-2 JB @ TS-6228, JB @ TS-1855 H13-P601, P833, P893 E-PP-8A-A	EWD | 251022	CMS-LT-1 IR-66 E-PP-7A-A H13-P601, P841, P894 E-CP-ARS	EWD | 251020	CMS-LT-2R H22-P100 E-PP-8A-F	– EWD | 251017

APPENDIX R INSTRUMENTATION [29]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA	COMPONENT	FIRE AREA [1]
	CMS-TR-6 [18]	RC-10	CMS-TR-5 [18]	RC-10	CMS-TI-43R [18]	RC-9
CABLE	CBDV-2, CBDG2V-2, CBDJ-12; 1301-E12A-004 2CACS-261 Thru 271 & 311, Thru 316, 2P8AA-33.3,6, CJB-TCG2-2.1; 8313-E12A-004 8313/E12A-004, 1301/E12A-003, CTCG2-3.3 & 3.4; E12A-012, 1401-CMS-007/2MISC-451	R-1,* R-2 RC-2B, RC-3* RC-10	CBDV-1, CBDGIV-1, CBDJ-11/ IMISC-861 1CACS-211 Thru 221,301 Thru 304,315,316, 1P7AA-1,18,4, CBJ-TCG1-2.1 8212/E12A-002, 1201/E12A-002 3101-SPTM-1, CTCG1-1,7 & 1.8, 8201-E12A-3, 1401-CMS-006/1MISC-862	R-1, R-2 RC-2A, RC-3 RC-10	2CACS-144, 315 2CACS-350 2P8AF-2	R-1, R-2 RC-2B, RC-3 RC-9
EQUIP	SPTM-TE-1B Thru 8B, 10, 12,14,16 EPA-X-107B, TB-C561, C501, R301, JB@TS-6228, JB@TS- 1855 H13-P601,P831,P893,P680,P613, P683,P814,P833, E-PP-8AA	EWD | 251035	SPTM-TE-1A Thru 8A,9,11,13,15 EPA-X-107A, TB-R300 TB-C500, TB-C560 H13-P601, P831, P894, P682, P841, E-PP-7AA	EWD | 251034	CMS-TE-43 EPA-X-107B, TB-R301 TB-C501, TB-C561 H22-P100, E-PP-8A-F	EWD | 251104

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

APPENDIX R INSTRUMENTATION

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	MS-LR/PR-R623B [12]	RC-10	MS-LR/PR-R623A [12]	RC-10	MS-LI-10 [12]	RC-9
CABLE	2NS4-52 2NS4-23, 2P8AA-3, 8 1301-B22H-001, 1813-B22H-001 8001-E12A-012, 8313-B22H-001 8318-E12A-013	R-1* RC-2B, RC-2C* RC-3,* RC9 RC-10	1NS4-26, 1P7AA-1, 2; 1NS4-54 1201-B22H-001, 8201-E21A-003 8212-B22H-001, 002	R-1 RC-2A, RC-3 RC-10, RC-14	2NS4-23 [24], 52 [24] 2P8AF-1	R-1, RC-2B, RC-2C RC-3, RC-9 RC-10*
EQUIP	E-C61A/P001 MS-LT-26D H22-P027, PP-8A-A H13-P601, P613, P618, P680, P683	M-27 EWD | 1E062	MS-LT-26A H22-P004, PP-7A-A H13-P601, P612, P682 E-CP-ARS	EWD | 1E061	C61-P001 H22-P027, MS-LITS-26D PP-8A-F H13-P683	M-27 EWD | 1E062

APPENDIX R INSTRUMENTATION [29]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	MS-LR/PR-R623B [12]	RC-10	MS-LR/PR-R623A [12]	RC-10	MS-PI-10 [12]	RC-9
CABLE	2NS4-53 2NS4-23, 2P8AA-3, 8 1301-B22H-001, 1813-B22H-001 8001-E12A-012, 8313-B22H-001 8318-E12A-013	R-1* RC-2B, RC-2C* RC-3,* RC9 RC-10	1NS4-26, 1P7AA-1, 2; 1NS4-55 1201-B22H-001, 8201-E21A-003 8212-B22H-001, 002	R-1 RC-2A, RC-3 RC-10, RC-14	2NS4-23 [24], 53 [24] 2P8AF-1	R-1, RC-2B, RC-2C RC-3, RC-9 RC-10*
EQUIP	E-C61A/P001 MS-PT-51B H22-P027, PP-8A-A H13-P601, P613, P618, P680, P683	M-27 EWD | 1E062	MS-PT-51A H22-P004, PP-7A-A H13-P601, P612, P682 E-CP-ARS	EWD | 1E061	C61-P001 (MS-PT-51B) H22-P027 PP-8A-F H13-P683	M-27 EWD | 1E062

APPENDIX R INSTRUMENTATION [29]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA
	[30]MS-SPV-126D [VO/VC]	M-27	[30]MS-SPV-126A [VO/VC]	RC-1	N/A	N/A
CABLE	2P8AA-6 BNS4-9006	R-1,* RC-3* RC-2B, RC-10 M-27	1P7AA-1 ANS4-9005 ANS4-9006	R-1, RC-3 RC-2A, RC-10		
EQUIP	E-PP-8AA E-CP-H13/P683 E-IR-P027 MS-TE-126D, MS-TS-126D	EWD | 1E062	E-PP-7AA E-CP-H13/P682 E-CP-H22/P004 MS-TE-126A, MS-TS-126A	EWD | 1E061		

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

HI-LO PRESS INTERFACE

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-9 [VC/VC] [23]	R-2	RHR-V-8 [VC/VC] [23]	R-1	RHR-V-9 [VC/VC] [23]	R-2
CABLE	2M8BA-311, 312, 313, 314, 315, 316, 321, 322 8322-B22H-006 2201-B22H-004	R-1,* R-2 R-18, RC-2B, RC-2C* RC-3,* RC-9 RC-10, RC-7	1M21A-20, 21, 22, 23, 24 8423-B22H-001 2301-B22H-001 1D11F-8	R-1 RC-2A, RC-3 RC-10, RC-14	2M8BA-311, 312, 313, 314, 316, 321, 322 2P8AF-1	R-1, R-2 R-18 RC-2B, RC-2C RC-3, RC-7, RC-9
EQUIP	MC-8B-A, E-CP-C61/P001 TB-R321, TB-R323 TB-C521, TB-C523, H22-P021, P022, H13-P601, P622, P683	EWD | 9E011	MC-S2-1A, E-CP-ARS H13-P684, P623, P601 H22-P006 H22-P018; DP-S1-1F	EWD | 9E024	MC-8B-A, C61-P001, TB-R321, TB-R323, TB-C521, TB-C523, H22-P021, P022; PP-8A-F	EWD | 9E011

HI-LO PRESS INTERFACE

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-123A [VC/VC] [23]	R-2	RHR-V-53A [VC/VC] [23]	R-1	RHR-V-123A [VC/VC] [23]	R-2
CABLE	2M8BA-501, 503, 504, 505, 506, 508 8322-E12A-002 2201-E12A-001	R-1,* R-2 R-18, RC-2B, RC-2C* RC-3,* RC-9 RC-10	1M7BA-130, 132, 133, 134, 135 8429-E12A-003 2901-E12A-002	R-1 RC-2A, RC-3 RC-10, RC-14	2M8BA-501, 503, 504, 505, 508 2P8AF-1	R-1, R-2 R-18 RC-2B. RC-2C RC-3, RC-9
EQUIP	C61-P001, MC-8B-A, TB-C513, TB-C521, TB-R313, TB-R321, TB-R475 H13-P601, P622, P683	EWD | 9E070	MC-7B-A H13-P601, P629, P684 E-CP-ARS	EWD | 9E054	MC-8B-A, C61-P001, TB-C513, TB-C521, TB-C313, TB-R321, TB-R475 PP-8A-F	EWD | 9E070

HI-LO PRESS INTERFACE

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	RHR-V-123B [VC/VC] [23]	R-2	RHR-V-53B [VC/VC] [23]	R-1	RHR-V-53B [VC/VC] [23]	R-1
CABLE	2M8BA-431, 432, 433, 434, 435 8322-E12A-001 2201-E12A-001	R-1,* R-2 R-18, RC-2B, RC-3* RC-10	1M7BA-580, 581, 582, 583 8429-E12A-012 2901-E12A-010	R-1 RC-2A, RC-3 RC-9 [23] RC-10	1M7BA-580, 581, 582 1P7AF-1	R-1 R-2A, RC-3 RC-9
EQUIP	MC-8B-A, TB-C513, TB-C521 TB-R313, RB-4321, TB-R475 H13-P601, P622, P683	EWD | 9E071	MC-7B-A C61-P001 H13-P601, P629, P684	EWD | 9E055	MC-7B-A, C61-P001 PP-7A-F	EWD | 9E055

TABLE F.4-1
POST-FIRE SAFE SHUTDOWN EQUIPMENT

POWER DISTRIBUTION [28]

	[1,2] DIVISION 2 SYSTEM		[1,2] DIVISION 1 SYSTEM		[1,2] REMOTE SHUTDOWN	
	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]	COMPONENT	FIRE AREA [1]
	SEE TABLE F.4-3		SEE TABLE F.4-3		SEE TABLE F.4-3	
CABLE	2SM8-10, 40, 110	RC-2B, RC-3*	1SM17-10,	RC-2A, RC-3	2SM28-10	RC-3, RC-6
	2SL83-10, 20	RC-6, RC-7	1SM7-10, 40, 110	RC-4, RC-5	2SM8-10, 40, 110	RC-7, RC-8
	2SL81-10	RC-8, RC-9	1SL73-10, 20	RC-10, RC-11	2SL83-10, 20	RC-9, RC-12
	2M8A-70, 71, 90, 140, 30	RC-10, RC-12	1SL712SL81-10	RC-14, RC-20	2SL81-10	DG-3
	2P8AB-2, 50, 60	DG-3	1M7B-10, 30	TG-1	2M8A-70, 71, 90, 140, 30	SW-2
	2M8AA-310, 311, 370	TG-1*	1M7BA-570	DG-2	2P8AB-2, 50, 60	TG-1
	2P8A-4, 100	SW-2	1M7A-60, 70, 71, 140, 20, 80	SW-1	2P8A-4, 100	R-1, R-18
	2M8AB-10, 20	R-1,* R-18	1P7AB-2, 50, 60	R-1	2M8B-10, 20	
			1M7AA-340, 341, 370		2D12-1, 2, 7, 8, 11	
	2P8AA-50		1P7A-5, 90			
CABLE	2D12-1, 2, 3, 6, 7, 8, 11		1P7AA-50, 2			
	2D12A-4		1D11-1, 2, 4, 6, 7, 9, 11		1D11-1, 4, 11	RC-4, RC-5
	2SM28-10		1D21-1, 2, 3, 4, 5, 10, 20, 30, 40			
			1M21A-80			

TABLE F.4-1
EXPLANATORY NOTES

[1] The equipment which is designated as part of the post-fire safe shutdown systems (PFSS) represents the minimum equipment necessary for safe post-fire shutdown. The post-fire safe shutdown system include not only the equipment itself, but also the power circuit and control logic elements that are necessary to support operation of the indicated equipment. The fire area code which identifies the PFSS lost and the credited PFSS is shown in Section F.4.4.3.

The equipment listed below has been deactivated (D), or has been locked in the open (O) or closed (C) position, as indicated, and has had all power removed.

SW-V-69B	(C)	SW-V-69A	(C)
SW-PCV-38A	(D)	SW-PCV-38B	(O)
SW-V-70B	(C)	SW-V-70A	(C)
RHR-V-26B	(C)	RHR-V-26A	(C)
RHR-V-87B	(C)	RHR-V-87A	(C)
RHR-V-11B	(C)	RHR-V-11A	(C)
RHR-V-65A	(D)	RHR-V-65B	(D)
SW-V-4A	(O)	SW-V-4B	(O)
SW-V-24A	(O)	SW-V-24B	(O)

[2] The following notation is used in this table:

An asterisk (*) by a fire area or fire zone listing indicates that post-fire safe shutdown cables are protected when routed within the fire area/zone indicated.

(XXXXX-XXX) = Cables shown in parentheses are power feeders or control cables. (See Note 25). Three phase power feeders are assumed not to fail in such a manner as to reconnect to adjacent three phase power feeders and cause electrically isolated motors to operate. Protection is not required for these cables, except for three phase power feeders that supply power to high/low pressure interface valves.

[VO] Where: VO - Valve Open
[VC] VC - Valve Closed
[EO] EO - Equipment Operable
[1,2] 1,2 - Note Numbers

These symbols listed next to component number indicates components operating requirements [Normal Operation/Event to Cold Shutdown Operation].

[3] RHR-P-3 maintains the RHR Loop B piping full of water and pressurized during normal plant operation. If this pump were to fail as a result of a postulated fire, the RHR B Loop piping will depressurize and begin to develop high point voids as water leaks out.

Evaluation

In response to FSAR Question 211.206, the Loop B leakage rate was determined to be approximately 1540 cm^3/hr (0.406 gal/hr). This is the maximum leakage rate, actual leakage rate would be expected to be less. The formation of high point voids will stop once the RHR Loop B pump is started. If this pump start takes place soon after the water leg pump fails, little, if any, water hammer will result. Based on the above, protection of the water leg pump is not required. Similarly Loop A leakage which utilizes LPCS-P-2 is approximately 1340 cm^3/hr (0.354 gallon per hour) and will require similar operation actions.

A satisfactory leak down rate test was conducted for RHR Loops A and B where pump start took place one hour after initiation of the test. Operator action is required to start the RHR pumps within one hour of a declared fire event to prevent system failure from water hammer.

[4] One of the series valves RHR-V-16B & 17B must remain closed to prevent diversion of coolant to the drywell spray header during alternate shutdown cooling.

Evaluation

Since only one spurious actuation is assumed to occur (at time-zero of a fire event) at any one time, and both valves are normally closed, only one valve can spuriously open. The other will remain closed to prevent flow diversion.

[5] Valves (RHR-V-40/49) allow heat-up of RHR piping from heat exchanger to RPV by draining water from the vessel to radwaste. If both valves should go open due to fire damage (hot shorts) during shutdown cooling, some RHR flow would be diverted to radwaste.

Evaluation

Since only one spurious actuation is assumed to occur (at time-zero of a fire event) at any one time, and both valves are normally closed, only one valve can spuriously open. The other will remain closed to prevent flow diversion.

TABLE F.4-1
EXPLANATORY NOTES

[6] During RHR alternate shutdown cooling mode operation following a postulated fire, coolant is injected to the reactor through RHR-V-42B. If RHR-V-53B opened due to hot shorts, RHR pump run out might occur which would be detrimental to the pump.

Evaluation

In RHR alternate shutdown cooling mode, flow exits the reactor vessel through a maximum of two manually opened SRVs. Initially, the flow is steam as the reactor vessel depressurizes. Upon initiation of RHR injection, the reactor vessel fills with water as do the main steam lines. At this point, flow through the SRVs changes from steam to water and the reactor pressure stabilizes at the pressure required to pass the RHR pump flow through the open SRVs. Test data for water flow through Crosby SRVs (NEDE-24988-P) yields a reactor pressure of approximately 140 psig to pass RHR pump flow through two SRVs. This pressure is well above that of pump run out conditions. Therefore, it can be concluded that RHR pump run out will not occur in alternate shutdown cooling mode if RHR-V-23 and/or RHR-V-53B were to open. Therefore, no protection is required for these valves and their associated cabling.

[7] Check valve RHR-V-89 will prevent flow from RHR to SW. SW flow into RHR is prevented by two normally closed series valves RHR-V-115 & 116 and only one is assumed to spuriously open. If valve V-115 spuriously opens, flow from the SW will be diverted through the 0.75 in. line and valve RHR-V-182 to the CRD room sump. No safe shutdown equipment will be affected. Flow will be terminated by operator action. Therefore, no protection is required.

[8A] Failure of valve SW-V-75A/B due to hot shorts does not affect the ability to safely shutdown the plant. There is a closed manual valve upstream (SW-V-75AA/BB) which would prevent diversion of standby service water. Operator actions shall be required if Fuel Pool makeup and/or cooling are necessary following a fire, for any of the following reasons:

1. To prevent the fuel pool temperature from exceeding 155°F;
2. To keep the fuel pool from boiling which would result in excessive moisture and flooding in the pump rooms;
3. To prevent fuel pool boil-off and fuel criticality during fuel storage.

Using a worst case scenario, as documented in Calculation NE 02-93-19 fuel pool makeup would be required within 6.82 hr of a fire. The post-fire shutdown system protects only one RHR Loop, and does not protect any fuel pool cooling components which will limit operator response.

NOTE: Portable sump pumps could be used to mitigate flooding and portable piping and pumps can be used for makeup. However, cooling may require some additional actions.

Therefore, no protection is required.

[8B] If either intertie valves SW-V-187A/B and SW-V-188A/B were to open as a result of fire damage (hot shorts) some SW flow would divert into the RCC System. Diverted flow would be limited by the 4² overflow on the RCC surge tank. Sufficient SW flow to the RHR heat exchanger would remain to remove reactor decay heat. Makeup to the spray ponds would not be required for a period of days. Effects of flooding due to RCC surge tank overflow would be countered by operator action to ensure that SW-V-188A(B) and SW-V-187A(B) are in their proper alignment (N-C), and to open their associated breakers within 50 minutes of the start of the fire (see Calculation ME-02-94-08). Therefore, no protection is required.

[8C] DELETED

[9] During RHR alternate shutdown cooling mode operation following a postulated fire, reactor water must be discharged through the SRVs to the suppression pool. Diversion of flow down the main steam lines to the turbine/condenser would result in loss of suppression pool inventory. Although not very probable, it is conceivable that sufficient water could be transferred to the turbine/condenser such that makeup to the reactor would be jeopardized.

Evaluation

Diversion of reactor coolant to the turbine/condenser requires that three series valves in at least one main steam line remain open from the following sets of valves:

1. MS-V-22A, B, C, D (Division II)
2. MS-V-28A, B, C, D (Division I)
3. Turbine Governor/stop valves and MS-V-146/Bypass Valves

Analysis of the four MS-V-22 & 28 valves shows that the circuits which control the valves will not remain open since they are installed in either protected raceway or in grounded raceways, all the way from the valves to the Control Room and are designed fail-safe.

In the event of a Control Room fire, the operator will manually scram the reactor and shut the MSIVs before evacuating the Control Room. If time is available, the operator will also trip the main generator. This latter action will cause the turbine governor valves to trip closed which will indirectly result in closure of the stop valves. The turbine bypass valves may open for a very short period of time to regulated pressure but will then close. Since only a single spurious actuation is considered, the two series MSIVs cannot remain open or reopen. Therefore, no further protection is required.

TABLE F.4-1
EXPLANATORY NOTES

[10] Loss of the emergency chillers (CCH-CR-1A/1B) will not affect safe shutdown. Cooling coil WMA-CC-51A-1 of air handling unit WMA-AH-51 has been valved for automatic operation on standby service water (valves SW-V822A, SW-V-823A open; valves SW-V-224A, SW-V-225A and SW-V-227A closed). The cooling capacity of the spray ponds is adequate to maintain the maximum Control Room temperature below 104°F. In the event of a fire in certain areas, operator action may be required to open valves SW-V-822B and 823B; and close valves SW-V-224B, SW-V-225B and SW-V-227B.

[11] Operator action should be initiated within 40 hr after the loss of a battery room exhaust fan (WEA-FN-53A/53B) due to fire (to prevent the accumulation of hydrogen gas). Portable smoke removal fans are staged to exhaust air if required. Power for the smoke removal fan is available from the remote shutdown panel.

[12] Reactor pressure and water level are displayed in the Control Room on two redundant, divisionally powered recorders. Sensing for these displays is accomplished through two (2) redundant and independent process instrument loops. One loop originates from vessel instrument nozzle taps located at 340° azimuth for the Division 2 recorder.

In containment routing of the process instrument lines within each loop is maintained to the azimuth of the vessel instrument nozzle taps associated with those loops. Furthermore, the instrument taps and associated containment penetrations are maintained to within approximately 5° of the same azimuth. The process instrument loops originate from the vessel at azimuths which are sufficiently separate to limit the effects of fire to no more than one loop. The azimuths of the containment penetrations and their respective instrument racks deviate as much as 19°. However, the radial distances to the racks provide assurance of adequate process line routing separation. The worst case fire effects on a single instrument loop, whether loss of indication or nonconservative indication, will not jeopardize required Control Room data since alternate instrumentation is available.

[13A] The process instrument loops for RHR flow consist of differential pressure sensing across flow elements for RHR injection paths A and B. The instrument loop for each RHR path consists of a process sensing line from each side of a flow element, each of which is routed in close proximity to one another to a flow (dP) transmitter. The fire effects on the process lines are considered equal, with equal boil-off in each line the result. The effects on differential pressure are thereby offsetting and considered to have no significant effect on sensed flow. Process fluid perturbations from boil-off are also considered to have no significant effect on instrument performance.

[13B] System pressure is only one of the variables that can be used to monitor system performance. Since system flow indication is provided in both the Control Room and remote shutdown areas, sufficient information is available to determine correct system operation.

[14] The GE remote shutdown design specification assumes that for a Main Control Room evacuation, the operator scrams the reactor and closes the MSIVs before leaving the Control Room. This implies that the operator takes action before damage to control circuitry could take place. Similarly, for a postulated fire outside the Main Control Room, it is assumed that the operator initiates and confirms shutdown before the control circuitry is damaged. Therefore, no critically instrumentation is protected.

[15] Operation of the SW System from the Main Control Room can be monitored by the flow indicator provided.

[16] For the case of a fire outside the Main Control Room, system pressure is not considered to be an essential indication for operator use since flow indication is available (see Evaluation for SW Flow). For a fire in the Main Control Room, indication of proper system function appears on the remote shutdown panels. SW flow is not indicated in this situation; however, SW pressure is available as well as positive indication and control switches for all valves required for proper system lineup. With SW pump discharge pressure and SW system valve lineup available, corrective action can be initiated for either pump or valve lineup problems.

[17] SW pond level indication is not considered essential since operator action would not be required for a period of days even in the event that the RHR/SW intertie valves were to open.

[18] Redundant suppression pool level and temperature instrumentation is provided in the Main Control Room. Fires postulated to occur in any plant area, except the Control Room, will not disable both redundant sets of instrumentation.

A postulated fire in the Main Control Room requires that plant control be transferred to the Remote Shutdown Room. This room has the controls necessary for aligning the Division 2 RHR System to draw water from the suppression pool, route through the RHR heat exchanger and return the flow to the RPV. No pipe breaks will occur during a fire that would cause RHR water to be lost and any water drawn from the suppression pool will be returned to the pool from the reactor vessel. Therefore, suppression pool level is expected to remain unchanged; however it can be monitored on the remote shutdown panel (see CMS-LI-2R). Similarly, since the suppression pool water is continuously cooled by the RHR heat exchanger, pool water temperature is expected to remain within specified limits; however it can be monitored (see CMS-TI-43R).

[19A] The maximum and/or minimum blowdown transients caused by inadvertent opening of the main steam relief valves due to hot shorts caused by a cable fire is bounded by the analyses provided in Calculation NE-02-84-30.

[19B] The Main Control Room design basis fire event requires that the plant be shutdown from the Remote Shutdown Room using manual initiation of the safety relief valves. General Electric analysis NEDO-24708A provides the general basis for this shutdown path while WNP-2 Calculation NE-02-86-10 provides a bounding analysis for the potential spurious actuation of the safety relief valves until manual control of at least five safety relief valves has been established at the remote shutdown panels. General Electric has provided a verification of NE-02-86-10.

TABLE F.4-1
EXPLANATORY NOTES

[20] Deleted. See Note 23.

[21] Deleted. See Note 23.

[22] Deleted. See Note 27.

[23] Power has been removed from RHR-V-9, 123A and 123B, during normal plant operation. The valve and power disconnect switch are maintained in the "isolate" position. The deenergized (isolated) power feeders have been routed in grounded steel conduits to protect it against external three-phase "hot shorts." Spurious control and power signals resulting from fire cannot cause the valve motor to energize. Hi/Lo interface control is preserved in the main control room and in the remote shutdown room by maintaining the power disconnect switch in the open (isolate) position. When the power disconnect switch is closed, interlocks would automatically close (isolate) the valves on high reactor pressure and will prevent RHR-V-9 from opening

[24] Cables 2NS4-23, 52, 53 and 2ADS-32, 33, 55 are protected from the effects of a Main Control Room fire by isolating the circuits required for remote shutdown within the 3 hour rated floor penetration seal.

[25] Deleted.

[26] The closure of fire damper WMA-FD-1 or 2 (located in Fire Area RC-13) would interrupt the fresh air intake to the Control Room. If the exhaust fan, WEA-FN-51, is damaged by fire while a fresh air supply is still available, the resulting overpressurization in the Control Room will be minimal. If necessary, the Control Room doors may be opened.

In the event of a fire in the Chiller Area (Fire Area RC-13), air handling units WMA-AH-52B and WMA-AH-53B should be turned off using the remote manual switches to prevent smoke from being drawn into the Cable Spreading Room or the Critical Switchgear Room.

See Calculation NE-02-94-035 for the discussion of the following issues:

1. HVAC ducts which may pass through the area but not directly communicate with the area.
2. The potential duct and duct hanger structural failures resulting from a fire.
3. The effects of fire damper closure on safe shutdown.

[27] The room heatup calculations indicate that fans RRA-FN-10 and RRA-FN-14 are not required to remain operable for post-fire safe shutdown.

[28A] Remote shutdown requires the operation of DG #2 from the local control panel.

[28B] Switchgear E-SM-8 bus is protected from the effects of a Main Control Room fire by transfer switches located on the switchgear and on the remote shutdown panels. The transfer switches provide isolation for electrical breakers E-CB-DG2/8, E-CB-8/DG2, E-CB-8/81, E-CB-8/83, E-CB-SW1B, E-CB-RHR/2B and current transformer shorting type transfer switches E-RMS-B/8/CT, E-RMS-8/81/CT, E-RMS-RHR/CT, and E-RMS-SW/CT. Operator action to reset spuriously operated lockout relays for the above indicated breakers is required after main control room isolation.

Certain switchgear breakers are tripped and/or isolated from reclosing in SM-8, SL-81, and SL-83: E-CB-8/85/1, ROA-CB-FN/1B, REA-CB-FN/1B, RCC-CB-P/1C and CCH-CB-CR1B.

[28C] Refer to FSAR Section 9.5.3 for a description of the plant emergency lighting.

[29] At WNP-2, the minimum Appendix R protected safe shutdown path utilizes the alternate shutdown cooling mode of the RHR System. Since the minimum protected path includes only a minimum of protected process and diagnostic instrumentation, the normal (assuming a full compliment of instrumentation) procedural steps for controlling the reactor in this mode of RHR have been revised accordingly. As such, control of the Alternate shutdown cooling mode of RHR uses the following available instrumentation; reactor vessel pressure, wide range reactor vessel water level, narrow range suppression pool level, suppression pool temperature, and RHR system flow.

[30] Appendix R requires the availability of reactor vessel level instrumentation presently located on instrument racks P004 (MS-LT-26A) and P027 (MS-LT-26D). The instrumentation reference legs must remain full and free of dissolved gases to provide reliable indication. This is accomplished by providing continuous flow to the reference legs from the CRD system. During DBF in an area where the tubing routes, the heated CRD backfill water will cause a decrease in the water density in the instrument reference legs. Isolation solenoid valves will isolate the flow from the CRD system when the temperature inside the tubing rises above a predetermined setpoint. The isolation of the "CRD system flow" will initiate the "notching phenomena", since this is a "long term" effect it will not prevent post-fire safe shutdown.

TABLE F.4-2

POST-FIRE SAFE SHUTDOWN EQUIPMENT CROSS-REFERENCE
POWER DISTRIBUTION EQUIPMENT

APPENDIX R DIVISION 2 SAFE SHUTDOWN AUX. PWR. DIST. EQUIP.			APPENDIX R DIVISION 1 SAFE SHUTDOWN AUX. PWR. DIST. EQUIP.			APPENDIX R REMOTE SHUTDOWN SYSTEM AUX. PWR. DIST. EQUIP.		
EPN #	BLDG./ELEV.	FIRE AREA	EPN #	BLDG./ELEV.	FIRE AREA	EPN #	BLDG./ELEV.	FIRE AREA
E-B1-2	RW/467	RC-6	E-B1-1	RW/467	RC-5	E-B1-2	RW/467	RC-6
E-C1-2	RW/467	RC-7	E-C1-1	RW/467	RC-4	E-C1-2	RW/467	RC-7
E-1N-2	RW/467	RC-7	E-1N-3	RW/467	RC-4	E-1N-3	RW/467	RC-4
E-DP-S1/2	RW/467	RC-7	E-DP-S1/1	RW/467	RC-4	E-DP-S1/2	RW/467	RC-7
E-DP-S1/2A	RW/501	RC-10	E-DP-S1/1A	RW/501	RC-10			
E-DP-S1/2D	RW/467	RC-9	E-DP-S1/1F	RW/467	RC-14	E-DP-S1/2D	RW/467	RC-9
E-DP-S1/2E	DG/441	DG-3	E-DP-S1/1E	DG/441	DG-2	E-DP-S1/2E	DG/441	DG-3
E-MC-8A	RW/467	RC-7	E-MC-7A	RW/467	RC-4	E-MC-8A	RW/467	RC-7
E-MC-8AA	DG/441	DG-3	E-MC-7AA	DG/441	DG-2	E-MC-8AA	DG/441	DG-3
E-MC-8B	RB/522	R-18	E-MC-7B	RB/522	R-1	E-MC-8B	RB/522	R-18
E-MC-8BA	RB/522	R-18	E-MC-7BA	RB/522	R-1	E-MC-8BA	RB/522	R-18
E-MC-8BB	RB/572	R-4	E-MC-7BB	RB/572	R-1	E-MC-8BB	RB/572	R-4
E-MC-8F	RW/525	RC-12	E-MC-7F	RW/525	RC-11	E-MC-8F	RW/525	RC-12
E-PP-8A	RW/467	RC-7	E-PP-7A	RW/467	RC-4	E-PP-8A	RW/467	RC-7
E-PP-8AA	RW/501	RC-10	E-PP-7AA	RW/501	RC-10	E-PP-7A	RW/467	RC-4
E-PP-8AAA	DG/441	DG-3	E-PP-7AAA	DG/441	DG-2	E-PP-8AAA	DG/441	DG-3
E-PP-8AB	SWPH-1B/441	SW-2	E-PP-7AB	SWPH-1A/441	SW-1	E-PP-8AB	SWPH-1B/441	SW-2
E-PP-8AF	RW/467	RC-9	E-PP-7AE	RB/471	R-1	E-PP-8AF	RW/467	RC-9
E-PP-8AG	SWPH-1B/441	SW-2	E-PP-7AG	SWPH-1A/441	SW-1	E-PP-8AG	SWPH-1B/441	SW-2
E-SL-81	RW/467	RC-8	E-SL-71	RW/467	RC-14	E-SL-81	RW/467	RC-8
E-SL-83	RW/467	RC-8	E-SL-73	RW/467	RC-14	E-SL-83	RW/467	RC-8
E-SM-DG2/8	DG/441	DG-3	E-SM-DG1/7	DG/441	DG-2	E-SM-DG2/8	DG-441	DG-3
E-SM-8	RW/467	RC-8	E-SM-7	RW/467	RC-14	E-SM-8	RW/467	RC-8
E-TR-8A	RW/467	RC-7	E-TR-7A	RW/467	RC-4	E-TR-8A	RW/467	RC-7
E-TR-8AAA	DG/441	DG-3	E-TR-7AAA	DG/441	DG-2	E-TR-8AAA	DG/441	DG-3
E-TR-8AF	SWPH-1B/441	SW-2	E-TR-7AF	SWPH-1A/441	SW-1	E-TR-8AF	SWPH-1B/441	SW-2
E-TR-8/81	RW/467	RC-8	E-TR-7/71	RW/467	RC-14	E-TR-8/81	RW/467	RC-8
E-TR-8/83	RW/467	RC-8	E-TR-7/73	RW/467	RC-14	E-TR-8/83	RW/467	RC-8
Fuse Box @ B1-2	RW/467	RC-6	E-B2-1	RW/467	RC-5	E-B1-1	RW/467	RC-5
E-TR-8AAA/1	DG/441	DG-3	E-DP-S2/1	RW/467	RC-4	E-DP-S1/1	RW/467	RC-4
E-TR-8AF/1	SWPH-1B/441	SW-2	E-C2-1	RW/467	RC-4	E-DP-S1/1F	RW/467	RC-14
DG-GEN-DG/2*	DG/441	DG-3	E-MC-S2/1A	RW/471	R-1	Fuse Box @ B1-1	RW/467	RC-5
RHR-DISC-V/9	RW/467	RC-7	TB-W93	RW/467	RC-5	Fuse Box @ B1-2	RW/467	RC-6
			Fuse Box @ B2-1	RW/467	RC-5	E-TR-7A/2	RW/467	RC-9
			Fuse Box @ B1-1	RW/467	RC-5	E-TR-8A/2	RW/467	RC-9
			E-TR-7A/1	RW/467	RC-4	DG-GEN-DG/2*	DG/441	DG-3
			E-TR-7AAA/1	DG/441	DG-2			
			E-TR-7AF/1	SWPH-1A/441	SW-1			
			DG-GEN-DG/1*	DG/441	DG-2			

* Includes all supporting components in fire area.

TABLE F.4-3

POST FIRE SAFE SHUTDOWN EQUIPMENT CROSS-REFERENCE
AUXILIARY EQUIPMENT

APPENDIX R DIVISION 2 SAFE SHUTDOWN AUX. EQUIP. EPN #	BLDG./ELEV.	FIRE AREA	APPENDIX R DIVISION 1 SAFE SHUTDOWN AUX. EQUIP. EPN #	BLDG./ELEV.	FIRE AREA	APPENDIX R REMOTE SHUTDOWN SYSTEM AUX. EQUIP. EPN #	BLDG./ELEV.	FIRE AREA
E-CP-COHV/2	RW/525	RC-12	E-CP-COHV/1	RW/525	RC-11	E-CP-COHV/4	RW/525	RC-12
E-CP-CIGV/4	RW/525	RC-12	E-CP-COHV/3	RW/525	RC-11	E-CP-CS2	RW/467	RC-9
E-CP-CS2	RW/467	RC-9	E-CP-COHV/5A	RW/501	RC-10	E-CP-DG/EP2	DG/441	DG-3
E-CP-DG/RP2	DG/441	DG-3	E-CP-CS1	RW/501	RC-10	E-CP-DGHV/II	DG/441	DG-3
E-CP-DGHV/11	DG/441	DG-3	E-CP-DG/RP1	DG/441	DG-2	E-CP-ARS	RW/467	RC-14
E-CP-FRTP	RW/467	RC-9	E-CP-DGHV/1	DG/441	DG-2	E-CP-LSP/S2	SWPH-1B/441	SW-2
E-CP-LSP/S2	SWPH-1B/441	SW-2	E-CP-ARS	RW/467	RC-14	E-CP-C61/P001	RW/467	RC-9
E-CP-C61A/POO1	RW/467	RC-9	E-CP-LSP/S1	SWPH-1A/441	SW-1	E-CP-RS	RW/467	RC-9
E-CP-P601	RW/501	RC-10	E-CP-C61/P001	RW/467	RC-9	E-IR-22	SWPH-1B/441	SW-2
E-CP-P609	RW/501	RC-10	E-CP-P601	RW/501	RC-10	E-IR-H22/P026	RB/522	R-1
E-CP-P611	RW/501	RC-10	E-CP-P612	RW/501	RC-10	E-JB-TB/SW1508	SWPH-1B/441	SW-2
E-CP-P613	RW/501	RC-10	E-CP-P628	RW/501	RC-10	E-JB-TB/C501	CONT/471	R-2
E-CP-P618	RW/501	RC-10	E-CP-P629	RW/501	RC-10	E-JB-TB/C522	CONT/522	R-2
E-CP-P622	RW/501	RC-10	E-CP-P682	RW/501	RC-10	E-JB-TB/C561	CONT/488	R-2
E-CP-P631	RW/501	RC-10	E-CP-P684	RW/501	RC-10	E-JB-TB/R301	RB/471	R-1
E-CP-P680	RW/501	RC-10	E-CP-P800	RW/501	RC-10	E-JB-TB/R322	RB/522	R-1
E-CP-P683	RW/501	RC-10	E-CP-P802	RW/501	RC-10	E-JB-TB/R435	RB/548	R-4
E-CP-P800	RW/501	RC-10	E-CP-P805	RW/501	RC-10	E-CNTR-WMA/EHC/8	RW/467	RC-6
E-CP-P801	RW/501	RC-10	E-CP-P812	RW/501	RC-10			
E-CP-P805	RW/501	RC-10	E-CP-P826	RW/501	RC-10			
E-CP-P812	RW/501	RC-10	E-CP-P831	RW/501	RC-10			
E-CP-P814	RW/501	RC-10	E-CP-P840	RW/501	RC-10			
E-CP-P820	RW/501	RC-10	E-CP-P841	RW/501	RC-10			
E-CP-P826	RW/501	RC-10	E-CP-P851	RW/501	RC-10			
E-CP-P831	RW/501	RC-10	E-CP-P892	RW/501	RC-10			
E-CP-P833	RW/501	RC-10	E-CP-RC/1	RW/501	RC-10			
E-CP-P891	RW/501	RC-10	E-IR-21	SWPH-1A/441	SW-1			
E-CP-P893	RW/501	RC-10	E-IR-H22/P004	RB/522	R-1			
E-CP-RC/2	RW/501	RC-10	E-IR-H22/P018	RB/501	R-1			
E-CP-RS	RW/467	RC-9	E-CNTR-WMA/EHC/7A	RW/467	RC-5			
E-CNTR-WMA/EHC/8	RW/467	RC-6	E-CNTR-WMA/EHC/7B	RW/467	RC-5			
E-CP-COHV/5B	RW/501	RC-10	E-IR-H22/P026	RB/522	R-1			
E-IR-22	SWPH-1B/441	SW-2						
E-IR-73	RB/522	IR-73						
E-IR-H22/P009	RB/471	M-9	E-IR-66	RB/501	R-1			
E-IR-H22/P021	RB/501	M-21	E-JB-TB/SW1507	SWPH-1A/441	SW-1			
E-IR-H22/P027	RB/522	M-27	E-JB-TB/C500	CONT/471 R-2	R-2			
E-JB-TB/SW1508	SWPH1B/441	SW-2	E-JB-TB/C560	CONT/488 R-2	R-2			
E-JB-TB/C501	CONT/471	R-2	E-JB-TB/R300	RB/471	R-1			
E-JB-TB/C513	CONT/522	R-2						
E-JB-TB/C561	CONT/488	R-2						
E-JB-TB/R301	RB/471	R-1						
E-JB-TB/R313	RB/501	R-1						
E-JB-TB/R435	RB/548	R-4						

F.4.4.3 Scope of WNP-2 Areas Evaluated in Fire Hazards Analysis

Fire areas included in the WNP-2 fire hazards analysis are those plant areas within the primary plant structure and those remote buildings with credited post-fire safe shutdown equipment. See the following table for the listing of evaluated fire areas. The fire area boundaries are shown as fire rated barriers on Figures F.6-1 through F.6-5.

The outdoor yard area is not analyzed as a fire area in the F.4 fire hazards analysis for the following reasons:

a. The yard does not contain any exposed post-fire safe shutdown equipment (no credited raceway access manholes or equipment),

b. Remote buildings credited in the fire protection program (service water pump house 1 and 2, circulating water pump house, water filtration building 33) with nonrated barriers are sufficiently separated from each other and from the plant that a single exposure fire would not spread to more than one building,

c. Where nearby exposure hazards exist, plant buildings have rated fire barriers. See Appendix F.2.14 through F.2.17, and

d. Yard fire hazards are not postulated to impair the yard fire protection water supply system.

The fire protection water supply buildings (circulating water pump house and water filtration building 33) are not analyzed as fire areas in the F.4 fire hazards analysis for the following reasons:

a. They do not contain any post-fire safe shutdown equipment, other than the fire pumps,

b. The water supply system has a sufficient capacity to provide the maximum water demand from either the primary or secondary supply,

c. The redundant water supply buildings are sufficiently separated that a single exposure fire would not spread between the subject buildings, and

d. The redundant water supply buildings are remote and would not be an exposure hazard to the plant.

The general service building (GSB) was originally considered in the fire hazards analysis. However, the GSB is not analyzed in the fire hazards analysis for the following reasons:

a. The building does not contain any credited post-fire safe shutdown,

b. The only safety-related equipment in the building are two motor-operated auxiliary steam isolation valves (AS-V-68A/68B) at 485 ft Column K.4-3.2. The isolation of the auxiliary steam system is safety-related function since it is a potential high energy line break (HELB) source to the reactor building which could affect the qualified life of safety-related equipment. Since a GSB fire would not cause a HELB and a reactor building HELB need not be considered concurrent with a fire, the GSB area of the safety-related valves does not warrant a fire hazards analysis,

c. The building is entirely isolated from the turbine and reactor building by 3-hr barriers, and

d. Although GSB sprinkler and detection system alarms annunciate in the control room and use plant power, their inoperability has no impact on post-fire safe shutdown.

The following is a listing of the WNP-2 fire areas and their post-fire safe shutdown code.

Diesel generator building - HPCS diesel generator room	#	DG-1
Diesel generator building - Diesel generator 1A room	1	DG-2
Diesel generator building - Diesel generator 1B room	2	DG-3
Diesel generator building - DG 1A diesel oil tank pump room	1	DG-4
Diesel generator building - DG 1B diesel oil tank pump room	2	DG-5
Diesel generator building - HPCS diesel oil tank pump room	#	DG-6
Diesel generator building - HPCS diesel day tank room	#	DG-7
Diesel generator building - DG 1A diesel day tank room	1	DG-8
Diesel generator building - DG 1B diesel day tank room	2	DG-9
Diesel generator building - Deluge valve equipment room	#	DG-10
Reactor building - General equipment area	D	R-1
Reactor building - Primary containment	U	R-2
Reactor building - HPCS pump room	#	R-3
Reactor building - RHR B pump room, pipe chase, pipe tunnels, H2 recombiner MCC room, heat exchanger rooms, and south valve rooms	2	R-4
Reactor building - RHR A pump room, pipe chase, pipe tunnels, heat exchanger rooms	D	R-5
Reactor building - RCIC pump room	2	R-6
Reactor building - RHR pump room	1	R-7

Reactor building - LPCS pump room	1	R-8
Reactor building - Stair A6	#	R-9
Reactor building - Elevator No. 2	#	R-10
Reactor building - Stair A5	#	R-11
Reactor building - Elevator No. 1	#	R-12
Reactor building - 422 ft lobby outside of stair A5	#	R-15
Reactor building - MCC room Division 2	2	R-18
Reactor building - South valve room	2	R-21
Reactor building - Instrument rack E-IR-H22/P009 enclosure	2	M-9
Reactor building - Instrument rack E-IR-H22/P021 enclosure	2	M-21
Reactor building - Instrument rack E-IR-H22/P027 enclosure	2	M-27
Reactor building - Instrument rack E-IR-73 enclosure	2	M-73
Radwaste control building - Radwaste general nonvital equipment area	2	RC-1
Radwaste control building - Cable spreading room		RC-2
Division 1 section — Fire zone RC-2A	D	
Division 2 section — Fire zone RC-2B	2	
20 ft noncombustible zone — Fire zone RC-2C	U	
Radwaste control building - Cable chase	D	RC-3
Radwaste control building - Electrical equipment room No. 1	1	RC-4
Radwaste control building - Battery room No. 1	1	RC-5
Radwaste control building - Battery room No. 2	2	RC-6
Radwaste control building - Electrical equipment room No. 2	2	RC-7
Radwaste control building - Switchgear room No. 2	2	RC-8
Radwaste control building - Remote shutdown room	2	
Radwaste control building - Main control room	U	RC-10
Radwaste control building - Unit A - air-conditioning room	1	RC-11
Radwaste control building - Unit B - air-conditioning room	2	RC-12
Radwaste control building - Communications room, instrument shop, chiller area, and HVAC chase	2	RC-13
Radwaste control building - Switchgear room No. 1	1	RC-14
Radwaste control building - Stair A8 and room C100	#	RC-15
Radwaste control building - Stair A7	#	RC-16
Radwaste control building - Elevator No. 4 and room C504	#	RC-17
Radwaste control building - Stair A13	#	RC-18
Radwaste control building - Corridor C205	2	RC-19
Radwaste control building - PASS area/pipe chase	1	RC-20
Reactor recirculation pump ASD building	#	ASD
Standby service water pump house 1A	1	SW-1
Standby service water pump house 1B	2	SW-2
Turbine generator building - General equipment area	D	TG-1
Turbine oil storage room — Fire zone TG-2	#	
Auxiliary boiler room — Fire zone TG-5	#	
Hydrogen seal oil room — Fire zone TG-7	#	

Turbine oil reservoir room	Fire zone TG-9	#	
West transformer vault	Fire zone TG-10	#	
East transformer vault	Fire zone TG-11	#	
441 ft southern corridors	Fire zone TG-12	D	
Turbine generator building - Stair A1		#	TG-3
Turbine generator building - Elevator No. 3		#	TG-4
Turbine generator building - Stair A3		#	TG-6
Turbine generator building - Stair A4		#	TG-8

LEGEND

Plant Fire Area Identification

The prefix of the fire area number corresponds to the building in which the fire area is located as follows:

ASD	Reactor recirculation pump ASD building
DG	Diesel generator building
R	Reactor building
RC	Radwaste/control building
S	Service building
SW	Standby service water pump house(s)
TG	Turbine generator building

See Figures F.6-1 through F.6-5 for fire area locations.

Explanation of Codes

This code indicates that this fire area does not contain equipment or cables for either division of post-fire safe shutdown equipment.

1 This code indicates that this fire area contains Division 1 post-fire safe shutdown equipment or cables.

2 This code indicates that this fire area contains Division 2 post-fire safe shutdown equipment or cables.

D This code indicates that this fire area contains equipment or cables of both divisions of post-fire safe shutdown equipment. These areas are dedicated fire areas where Division 2 post-fire safe shutdown systems are protected.

U This code indicates that this fire area has been uniquely analyzed for post-fire safe shutdown. Refer to the fire hazards analysis methodology in Section F.4.4.

F.4.4.4 Detailed Fire Hazards Analysis by Fire Area

FIRE AREA DG-1

1. Description

High-pressure core spray diesel generator room, el. 441 ft 0 in., 455 ft 0 in., and 472 ft 9 in.

2. Major equipment within the fire area

High-pressure core spray diesel generator
Air intake filter
Prefilter
Air handling units
Transformers
Motor-driven air compressor
Diesel-driven air compressor
Switchgear

Fire area is a safety-related area.

3. Construction of fire area boundaries

    a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

    b. Fire doors, dampers, and penetration seals maintain the rating of the barrier. Entrance door may not fully self-shut due to differential air pressure.

    c. The north entrance has a 7 in. curb. A 3 in. curb and nonrated barrier separate the switchgear area from the diesel engine area. The transfer pump rooms have a 7 in. door sill.

    d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

    a. The combustible loading is controlled in calculation FP-02-85-03.

    b. Combustible loading is classified as "low."

    c. Major combustibles include lubrication oil and electrical cable.

d. Major ignition hazards include diesel generator, diesel engine, electrical switchgear, dry transformers, and small diesel compressor.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Photoelectric smoke detectors in diesel generator area

   b. Ionization detectors in switchgear area

   c. Manual pull boxes

   d. Automatic preaction sprinkler system with heat actuating devices in diesel generator area. A pull box is provided for manual actuation.

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Hose lines from 2.5 in. outlets on yard hydrant

   c. Portable extinguishers

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. The HPCS diesel generator and associated equipment/cabling within the fire area is assumed to be damaged by the design basis fire. The HPCS system is not credited for post-fire safe shutdown. With no safe shutdown equipment/cables, fire will not prevent safe shutdown.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

   c. On sensing a high heat condition, the installed thermal detectors would open the preaction system control valve, allowing water to pressurize the sprinkler

system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

d. During periods of high differential air pressure on north fire door, strobe lights, and security position sensors ensure that personnel will manually shut the fire door.

e. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment.

f. Drain water is routed to the storm drain system. Curbs installed at the north corridor door and scuppers provided at the exterior door direct water discharge to the exterior yard area. Curbs and partition would help minimize water flow between diesel generator and switchgear area. Raised door sills to the transfer pump rooms will prevent common mode flooding from Fire Area DG-1. Flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-1 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-2

1. Description

Diesel generator 1A room, el. 441 ft 0 in., el. 455 ft 0 in., and el. 472 ft 9 in.

2. Major equipment within the fire area

Diesel generator 1A (Division 1)
Air intake filter
Prefilter
Air handling units
Motor-driven air compressor
Diesel/motor-driven air compressor
Switchgear

Fire area is a safety-related area.

3. Construction of fire area boundaries

 a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated. There is no barrier separating Fire Area DG-2 and DG-3 above the 472 ft 9 in. elevation of the upper vestibule room D301.

 b. Fire doors, dampers, and penetration seals maintain the rating of the barrier. Entrance door may not fully self-shut due to differential air pressure.

 c. The north entrance has a 7 in. curb. A 3 in. curb and nonrated barrier separate the switchgear area from the diesel engine area.

 d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

 a. The combustible loading is controlled in calculation FP-02-85-03.

 b. Combustible loading is classified as "low." A combustible free zone has been established between Fire Areas DG-2 and DG-3 at 472 ft 9 in. to prevent transient intervening combustibles. See Reference F.7.6.e.

 c. Major combustibles include lubrication oil and electrical cable.

d. Major ignition hazards include diesel generator, diesel engines, electrical switchgear, dry transformers, and grounding resistors.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

a. Photoelectric smoke detectors in diesel generator area

b. Ionization detectors in switchgear area

c. Manual pull boxes

d. Automatic preaction sprinkler system with heat actuating devices in diesel generator area. A pull box is provided for manual actuation.

6. Fire suppression/detection equipment outside but available to the fire area

a. 1.5 in. standpipe hose stations

b. Hose lines from 2.5 in. outlets on yard hydrant

c. Portable extinguishers

7. Safe shutdown systems

a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

a. The Division 1 diesel generator and associated equipment/cabling within the fire area are assumed to be damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

c. On sensing a high heat condition, the installed thermal detectors would open the preaction system control valve, allowing water to pressurize the sprinkler

system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

d. During periods of high differential air pressure on north fire door, strobe lights and security position sensors ensure that personnel will manually shut the fire door.

e. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment.

f. Drain water is routed to the storm drain system. Curbs installed at the north corridor door and scuppers provided at the exterior door direct water discharge to the exterior yard area. Curbs and partition would help minimize water flow between diesel generator and switchgear area. Flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-2 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-3

1. <u>Description</u>

Diesel generator 1B room, el. 441 ft 0 in., el. 455 ft 0 in., and el. 472 ft 9 in.

2. <u>Major equipment within the fire area</u>

Diesel generator 1B (Division 2)
Air intake filter
Prefilter
Air handling units
Motor-driven air compressor
Diesel/motor-driven air compressor
Switchgear

Fire area is a safety-related area.

3. <u>Construction of fire area boundaries</u>

   a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated. There is no barrier separating Fire Area DG-2 and DG-3 above the 472 ft 9 in. elevation of the upper vestibule room D301.

   b. Fire doors, dampers, and penetration seals maintain the rating of the barrier. Entrance door may not fully self-shut due to differential air pressure.

   c. The north entrance has a 7 in. curb. A 3 in. curb and nonrated barrier separate the switchgear area from the diesel engine area.

   d. See Figures F.6 for fire barrier locations and classifications.

4. <u>Fire hazards</u>

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include lubrication oil and electrical cable. A combustible free zone has been established between Fire Areas DG-2 and DG-3 at 472 ft 9 in. to prevent transient intervening combustibles. See Reference F.7.6.e.

d. Major ignition hazards include diesel generator, diesel engines, electrical switchgear, dry transformers, and grounding resistors.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Photoelectric smoke detectors in diesel generator area

   b. Ionization detectors in switchgear area

   c. Manual pull boxes

   d. Automatic preaction sprinkler system with heat actuating devices in diesel generator area. A pull box is provided for manual actuation.

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Hose lines from 2.5 in. outlets on yard hydrant

   c. Portable extinguishers

7. Safe shutdown systems

   a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The Division 2 diesel generator and associated equipment/cabling within the fire area are assumed to be damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

   c. On sensing a high heat condition, the installed thermal detectors would open the preaction system control valve, allowing water to pressurize the sprinkler

system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

d. During periods of high differential air pressure on north fire door, strobe lights and security position sensors ensure that personnel will manually the shut fire door.

e. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment.

f. Drain water is routed to the storm drain system. Curbs installed at the north corridor door and scuppers provided at the exterior door direct water discharge to the exterior yard area. Curbs and partition would help minimize water flow between diesel generator and switchgear area. Flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-3 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-4

1. Description

   DG 1A diesel oil tank transfer pump room, el. 441 ft 0 in.

2. Major equipment within the fire area

   Fuel oil pump
   Fuel oil storage tank - 60,000 gal located below grade

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

   b. Fire door and penetration seals maintain the rating of the barrier.

   c. A 7 in. raised door sill is present at the entrance door.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low." The contents of the diesel fuel oils storage tank is not considered to contribute to the room fire hazard based on the tank being underground with minimal room exposure and steel enclosure.

   c. Major combustibles include assumed transient combustibles and electrical cable.

   d. Major ignition hazards include transfer pump, room heater, and exhaust fan motor.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Pre-alarm thermal detector

   b. Automatic preaction sprinkler system with thermal detector

   NOTE: The preaction sprinkler system is provided for protection of the underground oil tank access housing.

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Hose lines from two 2.5 in. outlets on yard hydrant

   c. Portable extinguishers

   d. Manual pull box for alarm

   e. A pull box is provided for manual flooding of the system piping.

7. Safe shutdown systems

   This fire area contains Division 1 post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. The Division 1 diesel generator auxiliaries located within the fire area are assumed to be damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. The installed pre-alarm thermal detector is expected to sense the heat from a developing fire and alert the control room for response by the plant fire brigade. A high heat condition would also activate the thermal detector controlling the preaction system control valve, allowing water to pressurize the sprinkler system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

   c. East exterior wall need not be fire rated since fuel oil storage tank is buried underground and diesel fuel polishing building is adequately remote.

   d. Smoke would be removed through the operation of the room exhaust system or portable smoke removal equipment.

e. Water discharge could cause flooding in the transfer pump pit. Raised door sill would prevent water intrusion from Fire Area DG-1. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-4 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-5

1. Description

DG 1B diesel oil tank transfer pump room, el. 441 ft 0 in.

2. Major equipment within the fire area

Fuel oil pump
Fuel oil storage tank - 60,000 gal located below grade

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

b. Fire door and penetration seals maintain the rating of the barrier.

c. A 7 in. raised door sill is present at the entrance door.

d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low." The contents of the fuel oil storage tank is not considered to contribute to the room fire hazard based on the tank being underground with minimal room exposure and steel enclosure.

c. Major combustibles include assumed transient combustibles and electrical cable.

d. Major ignition hazards include transfer pump, room heater, and exhaust fan motor.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Pre-alarm thermal detector

   b. Automatic preaction sprinkler system with thermal detector

   NOTE: The preaction sprinkler system is provided for protection of the underground oil tank access housing.

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Hose lines from two 2.5 in. outlets on yard hydrant

   c. Portable extinguishers

   d. Manual pull box for alarm

   e. A pull box is provided for manual flooding of the system piping.

7. Safe shutdown systems

   This fire area contains Division 2 post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. The Division 2 diesel generator auxiliaries located within the fire area are assumed to be damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The installed pre-alarm thermal detector is expected to sense the heat from a developing fire and alert the control room for response by the plant fire brigade. A high heat condition would also activate the thermal detector controlling the preaction system control valve, allowing water to pressurize the sprinkler system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

   c. East exterior wall need not be fire rated since fuel oil storage tank is buried underground and diesel fuel polishing building is adequately remote.

   d. Smoke would be removed through the operation of the room exhaust system or portable smoke removal equipment.

e. Water discharge could cause flooding in the transfer pump pit. Raised door sill would prevent water intrusion from Fire Area DG-1. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-5 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-6

1. Description

   High-pressure core spray diesel oil tank transfer pump room, el. 441 ft 0 in.

2. Major equipment within the fire area

   Fuel oil pump
   Fuel oil storage tank - 50,000 gal located below grade
   Nitrogen pump

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

   b. Fire doors, dampers, and penetration seals maintain the rating of the barrier.

   c. A 7 in. raised door sill is present at the entrance door.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low." The contents of the fuel oil storage tank is not considered to contribute to the room fire hazard based on the tank being underground with minimal room exposure and steel enclosure.

   c. Major combustibles include assumed transient combustibles and electrical cable.

   d. Major ignition hazards include transfer pump, room heater, exhaust fan motor, and nitrogen pump motor.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Pre-alarm thermal detector

   b. Automatic preaction sprinkler system with thermal detector

   NOTE: The preaction sprinkler system is provided for protection of the underground oil tank access housing.

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Hose lines from two 2.5 in. outlets on yard hydrant

   c. Portable extinguishers

   d. Manual pull box for alarm

   e. A pull box is provided for manual flooding of the system piping.

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. The HPCS diesel generator auxiliaries located within the fire area are assumed to be damaged by the design basis fire. With no safe shutdown equipment/cables, fire will not prevent safe shutdown.

   b. The installed pre-alarm thermal detector is expected to sense the heat from a developing fire and alert the control room for response by the plant fire brigade. A high heat condition would also activate the thermal detector controlling the preaction system control valve, allowing water to pressurize the sprinkler system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

   c. East exterior wall need not be fire rated since fuel oil storage tank is buried underground and diesel fuel polishing building is adequately remote.

   d. Smoke would be removed through the operation of the room exhaust system or portable smoke removal equipment.

e. Water discharge could cause flooding in the transfer pump pit. Raised door sill would prevent water intrusion from Fire Area DG-1. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-6 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-7

1. Description

High-pressure core spray diesel day tank room, el. 441 ft 0 in.

2. Major equipment within the fire area

Fuel oil day tank - 3000 gal

Fire area is a safety-related area.

3. Construction of fire area boundaries

 a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

 b. Fire door, dampers, and penetration seals maintain the rating of the barrier.

 c. Door entrance has a 31 in. high door sill to contain an oil spill.

 d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

 a. The combustible loading is controlled in calculation FP-02-85-03.

 b. Combustible loading is classified as "high."

 c. The major combustible is fuel oil.

 d. There are no major ignition hazards in the area.

 e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

 a. Pre-alarm thermal detector

 b. Automatic preaction sprinkler system with thermal detector (same system as diesel generator area)

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Hose lines from 2.5 in. outlets on yard hydrant

   c. Portable extinguisher

   d. Manual pull boxes

   e. A pull box is provided for manual flooding of the system piping (which also includes diesel generator area piping).

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. The HPCS diesel generator auxiliaries located within the fire area are assumed to be damaged by the design basis fire. The HPCS system is not credited for post-fire safe shutdown. With no safe shutdown equipment/cables, fire will not prevent safe shutdown.

   b. The installed pre-alarm thermal detector is expected to sense the heat from a developing fire and alert the control room for response by the plant fire brigade. A high heat condition would also activate the thermal detector controlling the preaction system control valve, allowing water to pressurize the sprinkler system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

   c. The fire area has a much higher combustible loading fire severity duration than the surrounding 3-hr barriers. However, the fire area is equipped with a high density preaction sprinkler system which would effectively limit fire severity.

   d. Smoke would be removed through the operation of the room exhaust system or portable smoke removal equipment.

   e. Water discharge would cause flooding within the diked/enclosed room. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-7 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-8

1. Description

   DG 1A diesel day tank room, el. 441 ft 0 in.

2. Major equipment within the fire area

   Fuel oil day tank - 3000 gal

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

   b. Fire door, dampers, and penetration seals maintain the rating of the barrier.

   c. Door entrance has a 31 in. high door sill to contain an oil spill.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "high."

   c. Major combustible is fuel oil.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Pre-alarm thermal detector

   b. Automatic preaction sprinkler system with thermal detector

6. Fire suppression/detection equipment outside but available to the fire area

    a. 1.5 in. standpipe hose stations

    b. Hose lines from 2.5 in. outlets on yard hydrant

    c. Portable extinguisher

    d. Manual pull boxes.

    e. A pull box is provided for manual flooding of the system piping (which also includes diesel generator area piping).

7. Safe shutdown systems

    Fire area contains Division 1 post-fire safe shutdown equipment.

8. Potential consequences of a design basis fire

    a. The Division 1 diesel generator auxiliaries located within the fire area are assumed to be damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

    b. The installed pre-alarm thermal detector is expected to sense the heat from a developing fire and alert the control room for response by the plant fire brigade. A high heat condition would also activate the thermal detector controlling the preaction system control valve, allowing water to pressurize the sprinkler system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

    c. The fire area has a much higher combustible loading fire severity duration than the surrounding 3-hr barriers. However, the fire area is equipped with a high density preaction sprinkler system which would effectively limit fire severity.

    d. Smoke would be removed through the operation of the room exhaust system or portable smoke removal equipment.

    e. Water discharge would cause flooding within the diked/enclosed room. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-8 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-9

1. Description

DG 1B diesel oil day tank room, el. 441 ft 0 in.

2. Major equipment within the fire area

Fuel oil day tank - 3000 gal

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

b. Fire door, dampers, and penetration seals maintain the rating of the barrier.

c. Door entrance has a 31 in. high door sill to contain an oil spill.

d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "high."

c. Major combustible is fuel oil.

d. There are no major ignition hazards in the area.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

a. Pre-alarm thermal detector

b. Automatic preaction sprinkler system with thermal detector

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Hose lines from 2.5 in. outlets on yard hydrant

   c. Portable extinguisher

   d. Manual pull boxes

   e. A pull box is provided for manual flooding of the system piping (which also includes diesel generator area piping).

7. Safe shutdown systems

   Fire area contains Division 2 post-fire safe shutdown equipment.

8. Potential consequences of a design basis fire

   a. The Division 2 diesel generator auxiliaries located within the fire area are assumed to be damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The installed pre-alarm thermal detector is expected to sense the heat from a developing fire and alert the control room for response by the plant fire brigade. A high heat condition would also activate the thermal detector controlling the preaction system control valve, allowing water to pressurize the sprinkler system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

   c. The fire area has a much higher combustible loading fire severity duration than the surrounding 3-hr barriers. However, the fire area is equipped with a high density preaction sprinkler system which would effectively limit fire severity.

   d. Smoke would be removed through the operation of the room system or portable smoke removal equipment.

   e. Water discharge would cause flooding within the diked/enclosed room. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-9 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA DG-10

1. Description

   Diesel generator building deluge valve room, el. 455 ft 0 in.

2. Major equipment within the fire area

   Sprinkler alarm valves.

   Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

   b. Fire doors, dampers, and penetration seals maintain the rating of the barrier.

   c. See Figure F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles.

   d. Major ignition hazard is room heater units.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   None

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguisher

   b. Manual pull box for alarm

c. 1.5 in. standpipe hose station

7. Safe shutdown systems

This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

a. With no safe shutdown equipment/cables, fire will not prevent safe shutdown.

b. The available portable equipment is adequate to extinguish the design basis fire.

c. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment.

d. Drain water is routed to the storm drain system. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area DG-10 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-1

1. Description

Reactor building general equipment area, el. 422 ft 3 in., 441 ft 0 in., 471 ft 0 in., 501 ft 0 in., 522 ft 0 in., 548 ft 0 in., 572 ft 0 in., 606 ft 10.5 in., and 623 ft 10.5 in.

2. Major equipment

a. Elevation 422 ft - auxiliary condensate pump room/CRD pump room and northwest stairwell

Control rod drive pumps
Auxiliary condensate supply pumps
Backwash pump

b. Elevation 441 ft - train bay, southeast airlock and northeast airlock, and vestibule

None

c. Elevation 471 ft - general equipment area

Instrument racks, switchgear, monorails, hoists.

d. Elevation 492 ft - RHR pipe tunnels

Piping

e. Elevation 501 ft - general equipment area

Instrument racks, motor control center, TIP room, CRD repair room, and outage hot tool storage.

f. Elevation 522 ft - general equipment area

Control rod drive modules
Reactor water cleanup pumps
Instrument racks
Motor control center

g. Elevation 548 ft - general equipment area

Reactor building closed cooling pumps
Standby liquid control area
Fuel pool cooling heat exchangers and pumps

h. Elevation 563 ft - RHR pipe tunnels

Piping

i. Elevation 572 ft - general equipment area

Standby gas treatment units
Hydrogen recombiners
Reactor building sump vent emergency filter units
Motor control centers

j. Elevation 606 ft - operating floor

Spent fuel pool
Refueling platform and crane
Dryer/separator pool
Auxiliary work platform

k. Elevation 623 ft - elevator equipment rooms

Elevator motors

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. The reactor building fire area boundaries which interface with other fire areas are constructed of reinforced concrete and are 3-hr rated (except as described below). At el. 606 ft, the reactor building exterior walls are nonrated insulated metal panels. Exterior barriers below 440 ft are nonrated. The following floor plugs are 3-hr rated: 18 in. thick concrete floor plugs to the Division 1 and 2 RHR heat exchanger rooms; 18 in. and 24 in. thick concrete floor plugs to the 422 ft pump rooms, and 60 in. thick floor plugs to 522 ft ceiling of the steam tunnel.

Walls, floors, and ceilings interior to the fire area (not adjoining other fire areas) are also concrete, but are not credited as fire rated. The nonrated floors

above 471 ft have open stairways, open equipment hatches, and unsealed penetrations.

b. The reactor building general equipment area is separated from containment by a nonrated concrete bioshield wall and the metal shell of the primary containment vessel. The gap between the bioshield wall and the vessel is filled with a combustible insulating foam spacer. Kaowool ceramic fiber blanket is installed in piping penetrations to eliminate exposure of the foam to potential sources of ignition. See Section F.2.2.5 for more details.

c. Three hour fire barriers separate adjacent, redundant, safety-related, hazardous equipment within the fire area including the standby gas treatment units and hydrogen recombiner units on 572 ft.

d. Fire Area R-1 connects with Fire Area R-5 without a barrier in the 472 ft Column J.8 pipe tunnel and 563 ft Column J-K pipe tunnel.

e. The reinforced-concrete boundary with Fire Area R-15 at 441 ft is classified as nonrated but is constructed to meet a 3-hr fire rating.

f. The removable masonry block walls of the Fire Area R-4 and R-5 pipe chases (east wall, 471 ft to 547 ft) are not qualified as 3-hr rated.

g. See the individual fire area discussions of Fire Areas M-9, M-21, M-27, and M-73 for description of instrument rack enclosures.

h. The reactor building Fire Area R-1 has numerous specialty doors used in fire barriers (high range blast, air-tight, water-tight, radiation shielding, and bolted closed sliding). These doors are not listed as fire rated, but have equivalent construction. Stairwell doors are 1.5-hr rated, minimum. Elevators are 1.5-hr rated. Other nonspecialty doors in fire barriers are 3-hr rated.

i. Fire dampers and penetration seals maintain the rating of the barrier (except penetration R206-4236 and R206-5052). Various sealed electrical blockouts in nonrated floor/ceiling barriers are credited as vertical cable tray fire breaks.

j. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low." Since fire area covers approximately 78,500 ft^2, actual combustible loading varies.

   c. Major combustibles include Thermo-Lag 330-1, electrical cable, charcoal, and assumed transient combustibles.

   d. Zones of limited combustibles have been established within 10 ft of: 1) post-fire safe shutdown instrument tubing; 2) exterior of instrument rack rooms; and 3) containment mechanical penetrations. See Figure F.6-6. Combustible free zones have been established in the 492 ft and 563 ft pipe tunnel interface to Fire Area R-5.

   e. Major ignition hazards include: control rod drive pumps, auxiliary condensate supply pumps, switchgear, reactor water cleanup pumps, reactor building closed cooling pumps, fuel pool cooling pumps, standby gas unit charcoal filters, and hydrogen recombiner units.

   f. Equipment/piping within the area contain low level radioactive water and gas. There are typically no airborne radioactivity hazards within the area. Some portions of the fire area are high radiation zones.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors installed for general area coverage at el. 422 ft, 471 ft, 501 ft, and 572 ft.

   b. Photoelectric smoke detectors in the railroad air lock at el. 441 ft.

   c. Ultraviolet detectors installed on the operating floor level, el. 606 ft.

   d. 1.5 in. standpipe hose station in train bay air lock.

   e. Each reactor building sump vent charcoal filter unit is protected by a manual water spray system. Thermal detectors located within the unit initiate a high temperature alarm.

   f. Portable fire extinguishers at each floor level.

g. Manual pull boxes.

h. Each SGT unit is protected by three manual actuated water spray systems. Thermistor wires located within the SGT units initiate high temperature alarms.

6. Fire suppression/detection equipment outside but available to the fire area

   a. 150 ft long 1.5 in. hose stations at each floor level enclosed stairwell

   b. 2.5 in. yard hose stations for 441 ft train bay

7. Safe shutdown systems

   a. Fire area contains both Division 1 and Division 2 post-fire safe shutdown cables and Division 1 equipment. Division 2 post-fire safe shutdown cables are protected by 3-hr rated raceway barriers.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

   c. See following Consequences discussion for more details.

8. Potential consequences of a design basis fire

   a. Equipment and cabling for the Division 1 post-fire safe shutdown systems which is located within the area is assumed damaged by the design basis fire. Loss of all unprotected equipment in this fire area is not considered a credible event due to the low fire loading and geometrical configuration of the reactor building. Division 2 post-fire safe shutdown components/cabling within the fire area are protected from fire damage as follows:

      (1) Cabling for Division 2 post-fire safe shutdown components and certain associated circuits are protected by 3-hr rated raceway fire barriers

      (2) Protection of raceways, structural members, or other items routed over raceway fire barriers is not required due to the limited combustible loading and ceiling openings which would prevent a hot gas layer buildup. (Reference F.7.4.f)

      (3) Stainless steel instrument sensing lines routed within the area do not require exposure protection. Analysis indicates that the lines will not rupture. (Reference F.7.3.p). Certain instrument sensing line supports are protected with Thermo-Lag 330-1 from exposure fire damage where the analysis predicts that the average steel temperature in the support

could exceed 1100°F or point temperatures in the support could exceed 1200°F. (References F.7.3.i and F.7.4.l). Combustible controls ensure the above analyses remain valid (see Figure F.6-6). Even though Thermo-Lag 330-1 is technically a combustible material, it is still capable of adequately insulating steel supports.

(4) Fire affects on the instrumentation tubing of the RPV level transmitter reference legs (MS-LT-26A and MS-LT-26D), added to correct the "notching phenomena", is mitigated by a passive high temperature isolation scheme. See Item 1.10.02 of Reference F.7.3.k for more details.

b. Instrument rack fire areas M-9, M-21, M-27, and M-73 are enclosed with 3-hr rated partial height walls which would shield instruments and instrument tubing from a Fire Areas R-1 fire. The lack of a ceiling was approved in Reference F.7.4.f. Fire Area R-1 combustibles above the instrument rack fire areas are minimal. Combustibles are controlled within a 10 ft radius of the instrument rack fire areas (see Figure F.6-6). With Fire Area R-1 having two open stairwell shafts and various unsealed floor openings and a large equipment hatch, a hot gas layer will not drop to the level of the instrument rack fire areas. The raised curbs at each entrance doorway will prevent a combustible liquid spill from spreading into the instrument rack fire areas. (Reference F.7.3.r)

c. Containment mechanical penetrations within a 20 ft surface radius of Appendix R protected containment penetrations are 3-hr fire rated to ensure the combustible spacer/liner material does not ignite and damage the Division 2 cables in the liner area. Nonrated radiant energy Kaowool penetration seals, spatial separation, and combustible controls near other containment penetrations (see Figure F.6-6) provide adequate assurance that a fire will not reach the unprotected Division 2 post-fire safe shutdown circuits at the combustible liner. This level of protection was approved by Reference F.7.4.l.

d. The 472 ft and 563 ft pipe tunnel interfaces to Fire Area R-5 are void of in-situ combustibles and are controlled as combustible free zones. Fire Area R-1 and R-5 both contain Division 1 post-fire safe systems and rely on Division 2 for safe shutdown. Therefore, the lack of a fire barrier will not prevent safe shutdown.

e. The east walls of the Fire Area R-4 and R-5 vertical pipe chases are not constructed to meet a fire tested configuration; however, the design is adequate to limit the spread of fire.

f. Unqualified and 1.5-hr stairwell doors are adequate to limit the spread of fire.

g. See Fire Area RC-20 discussion of penetration R206-4236 PASS module. See Fire Area R-6 discussion of penetration R206-5052.

h. Penetrations R704-1001 and R704-1002 are not sealed to the reactor building elevated release chase. Below 572 ft, the chase is considered Fire Area TG-1. See TG-1 discussion for more details. With the unsealed penetrations a minimum of 80 ft above the turbine building roof, a reactor building fire would not spread to the turbine building.

i. Smoke or flame from a fire would activate an ionization or ultraviolet detector, which would alarm in the control room for fire brigade response. Reference F.7.4.f approved the lack of fire detection in some rooms.

j. The manual suppression equipment available is sufficient to control any reactor building fire. 150 ft long hose lengths are required to reach all areas. (Reference F.7.4.d)

k. Heat buildup within a sump vent charcoal filter unit would cause a temperature alarm in the main control room. The manual water spray system may be actuated locally if required to suppress a filter fire.

l. Heat buildup within an SGT filter unit would cause a temperature alarm in the main control room. The manual water spray system may be actuated from the main control room if required to suppress a charcoal fire. A LOCA/radioiodine induced charcoal fire would not result in excessive radiation release since, on a high charcoal filter temperature alarm, operators would switch over to the redundant SGT filter unit.

m. Smoke would be removed by operation of the building exhaust system. Large portable fan REA-FN-16 can be connected to the building exhaust system at the 471 ft and 572 ft. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

n. Water discharge could cause flooding until removed by the floor drain system or portable pumping. Water discharge would be removed by the floor drain system open, hatches, and stairs. Floor drains in this area are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

o. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-1 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-2

1. Description

Reactor primary containment drywell and suppression pool.

2. Major equipment within the fire area

Reactor recirculation pumps
Containment HVAC

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. The primary containment barrier consists of a steel ASME pressure vessel which varies from 1.5 in. at the vessel lower head to 0.75 in. at the drywell cone. See FSAR Section 3.8.2 for more details. See Section F.2.2.5 discussion for a more detailed discussion of bioshield wall and combustible liner.

b. Equipment and personnel hatches are nonrated, but due to their massive construction, they are considered more than adequate for the combustibles involved.

c. All mechanical penetrations are sealed. All cabling enters containment via sealed electrical penetration assemblies.

d. The suppression pool has concrete walls and floor with a nonrated watertight access hatch; penetrations are embedded.

e. See Figures F.6 for fire area boundary.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustibles include assumed transient combustibles, lubrication oil, and electrical cables.

d. Major ignition hazards include recirculation pumps and HVAC fans motors.

e. Equipment/piping within the area contain low level radioactive water and gas. There are airborne low level particulates and noble gases in the containment atmosphere during operation. The primary containment during outages is a potentially contaminated, high radiation zone.

5. Fire suppression/detection equipment within the fire area

a. There is no automatic fire suppression/detection equipment installed within primary containment.

b. Nitrogen inerted during plant operation.

c. Installed thermocouples monitor drywell conditions during plant operation (not part of the fire protection system).

6. Fire suppression/detection equipment outside but available to the fire area

a. Standpipe hose lines

b. Portable fire extinguishers

c. Manual pull boxes

7. Safe shutdown systems

a. Fire area contains both Division 1 and Division 2 post-fire safe shutdown cables and equipment. Primary containment is nitrogen inerted during plant operation.

b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

a. The primary containment has a nitrogen inerted atmosphere which will not support combustion. Post-fire safe shutdown equipment/cabling inside containment is not considered vulnerable to fire damage.

b. During periods where containment is not inerted, staged fire protection equipment and normal fire protection administrative controls ensure fire severity will be limited and fuel pool cooling will be available. The steel containment vessel and sealed penetrations provide adequate assurance that a fire would be contained.

c. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

d. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

e. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. <u>FHA conclusion</u>

A design basis fire within Fire Area R-2 is not possible during plant operation. Adequate manual suppression equipment is available during outages to limit possible fire damage. Therefore, systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-3

1. Description

High-pressure core spray pump room, el. 422 ft 3 in. and el. 444 ft 0 in.

2. Major equipment within the fire area

High-pressure core spray pump
High-pressure core spray water leg pump
Sump pumps
Room cooler

Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas (except R-2) are 3-hr rated. A hatch in the ceiling at 471 ft is covered by a 3-hr rated 24-in. thick concrete plug.

   b. Fire dampers and penetration seals maintain the rating of the barrier.

   c. Watertight doors and bolted-in-place sliding door are not listed as fire rated, but have equivalent construction.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include electrical cable transient combustible and lubricating oil.

   d. Major ignition hazards include HPCS pump, HPCS water leg pump, sump pumps, and cooler unit.

e. Equipment/piping within the area contain low level radioactive water and gas. There are typically no airborne radioactivity hazards within the area. Some portions of the fire area may be high radiation zones.

5. Fire suppression/detection equipment within the fire area

Three ionization detectors below 471 ft 0 in. ceiling

6. Fire suppression/detection equipment outside but available to the fire area

a. One manual pull box for alarm

b. Portable extinguisher

c. 1.5 in. standpipe hose station

7. Safe shutdown systems

This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

a. The HPCS pump and auxiliaries within the fire area are assumed to be damaged by the design basis fire. The HPCS system is not credited for post-fire safe shutdown. With no safe shutdown equipment/cables, fire will not prevent safe shutdown.

b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

c. Unqualified doors are adequate to limit the spread of fire.

d. Although the containment barrier is not considered 3-hr rated, it is adequate to prevent fire propagation and opposite side is suppression pool.

e. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

f. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains in this area are

routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

g. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-3 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-4

1. Description

   422 ft 3 in. RHR-B pump room (R-7)
   470 ft to 548 ft pipe chase
   471 ft southwest valve room (R-214)
   492 ft pipe tunnel
   548 ft south valve room (R-511)
   563 ft 1 in. pipe tunnel
   548 ft and 572 ft heat exchanger equipment rooms (R-505 and R-605)
   572 ft Division 2 hydrogen recombiner MCC room (R-612)

2. Major equipment within the fire area

   Residual heat removal pump 2B
   Sump pump
   Motor control centers - Division 2
   Residual heat removal heat exchangers
   Room coolers

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Barriers which interface with adjacent fire areas are 3-hr rated reinforced concrete, with the following exceptions. The containment barrier is not credited as fire rated. The east wall of the vertical pipe chase, from 471 ft to 547 ft is constructed of removable concrete block covered by steel decking and thus, is not qualified as 3-hr rated.

   b. A hatch at the ceiling of 471 ft and 572 ft is covered by a 3-hr rated 18-in. thick concrete plug.

   c. Radiation shield, bolted-in-place sliding and watertight doors are not listed as fire rated, but have equivalent construction. Other fire doors maintain the rating of the barrier.

   d. Fire dampers and penetration seals maintain the rating of the barrier.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include electrical cable, assumed transient combustibles, and lubricating oil.

   d. Major ignition hazards include RHR-B pump, motor control centers, sump pump, and cooler unit.

   e. Equipment/piping within the area contain low level radioactive water and gas. There are no airborne radioactivity hazards within the area. Some portions of the fire area may a be high radiation zone.

5. Fire suppression/detection equipment within the fire area

   All rooms of the fire area are equipped with ionization smoke detection except the pipe chase and pipe tunnels.

6. Fire suppression/detection equipment outside but available to the fire area

   a. Manual pull boxes on each elevation for alarm

   b. Portable extinguishers on each elevation

   c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

   a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The B RHR pump, associated equipment and cabling are assumed damaged or unavailable due to the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The mechanical integrity of excess flow check valve and instrument root valves within the 548 ft south valve room (R511) are protected from damage due to a

fire occurring elsewhere in secondary containment by the 3-hr rated barriers separating the room from the general floor area.

c. The east walls of the vertical pipe chase is not constructed per a fire tested configuration; however, the design is adequate to limit the spread of fire.

d. Unqualified doors and containment barrier are adequate to limit the spread of fire.

e. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

f. Smoke would be removed by the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

g. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

h. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-4 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-5

1. Description

   422 ft 3 in. RHR-A pump room (R-6)
   470 ft to 548 ft pipe chase
   492 ft pipe tunnel (west half)
   563 ft 1 in. pipe tunnel (west half)
   548 ft and 572 ft heat exchanger equipment rooms (R-507 and R-606)

2. Major equipment within the fire area

   Residual heat removal pump 2A
   Sump pumps
   Residual heat removal heat exchangers
   Room cooler

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Barriers which interface with adjacent fire areas are 3-hr rated reinforced concrete, with the following exceptions. The containment barrier is not credited as fire rated. The east wall of the vertical pipe chase, from 471 ft to 547 ft is constructed of removable concrete block covered by steel decking and thus, are not qualified as 3-hr rated. The 492 ft and 563 ft pipe tunnels connect with fire area R-1 without a barrier.

   b. A hatch at the ceiling of 471 ft and 572 ft is covered by a 3-hr rated 18-in. thick concrete plug.

   c. Radiation shield and watertight doors are not listed as fire rated, but have equivalent construction. Other fire doors are 3-hr rated.

   d. Fire dampers and penetration seals maintain the rating of the barrier.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low." Combustible free zones in 472 ft and 563 ft tunnels interface to Fire Area R-1.

   c. Major combustibles include Thermo-Lag 330-1, electrical cable, assumed transient combustibles, and lubricating oil.

   d. Major ignition hazards include RHR-A pump, sump pumps, and room cooler.

   e. Equipment/piping within the area contain low level radioactive water and gas. There are typically no airborne radioactivity hazards within the area. Some portions of the fire area may be a high radiation zone.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors at the ceiling of the pump room (471 ft).

   b. Ionization detector at 548 ft and at 572 ft within the heat exchanger room.

6. Fire suppression/detection equipment outside but available to the fire area

   a. Manual pull boxes on each elevation for alarm

   b. Portable extinguishers on each elevation

   c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

   a. Fire area contains both Division 1 and Division 2 post-fire safe shutdown cables and Division 1 equipment. Division 2 post-fire safe shutdown cables are protected by 3-hr rated raceway barriers.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The A RHR pump, associated equipment, and cabling are assumed damaged or unavailable due to the design basis fire. Cables for the Division 2 post-fire safe

shutdown systems are protected by 3-hr raceway barriers to ensure safe shutdown.

b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

c. The 472 ft and 563 ft pipe tunnel interfaces to Fire Area R-1 are void of in-situ combustibles and are controlled as combustible free zones. Fire Areas R-1 and R-5 both contain Division 1 post-fire safe systems and rely on Division 2 for safe shutdown. Therefore, the lack of a fire barrier will not prevent safe shutdown.

d. The east walls of the vertical pipe chase is not constructed per a fire tested configuration; however, the design is adequate to limit the spread of fire.

e. Unqualified doors and containment barrier are adequate to limit the spread of fire.

f. Smoke would be removed by the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

g. Water discharge could cause flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

h. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-5 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-6

1. Description

   Reactor core isolation cooling pump room, el. 422 ft 3 in. and el. 444 ft 0 in.

2. Major equipment within the fire area

   Reactor core isolation cooling pump
   Reactor core isolation cooling turbine
   Reactor core isolation cooling water leg pump
   Room cooler

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. The walls and ceiling which interface with adjacent fire areas (except R-2) are 3-hr rated reinforced concrete. A hatch in the ceiling at 471 ft is covered by a 3-hr rated 24 in. thick concrete plug.

   b. Watertight doors are not listed as fire rated, but have equivalent construction.

   c. Fire dampers and penetration seals maintain the rating of the barrier (except penetration R206-5052).

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include electrical cable and assumed transient combustibles.

   d. Major ignition hazards include RCIC pump/turbine, RCIC water leg pump, and room cooler.

   e. Equipment/piping within the area contain low level radioactive water and gas. There are typically no airborne radioactivity hazards within the area. Some portions of the fire area may be a high radiation zone.

5. Fire suppression/detection equipment within the fire area

   Ionization detectors below 471 ft 0 in. ceiling

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguisher

   b. 1.5 in. standpipe hose stations

   c. Manual pull box for alarm

7. Safe shutdown systems

   a. Fire area contains Division 2 post-fire safe shutdown cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The RCIC pump and auxiliaries within the fire area are assumed to be damaged by the design basis fire. The RCIC system is not credited for post-fire safe shutdown. Division 1 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

   c. Unqualified doors and containment barrier are adequate to limit the spread of fire.

   d. Penetration seal R206-5052 is adequate for the hazards. See Reference F.7.6.i for more details.

   e. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   f. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

g. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-6 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-7

1. Description

   Residual heat removal - C pump room, el. 422 ft 3 in. and el. 444 ft 0 in.

2. Major equipment within the fire area

   Residual heat removal pump 2C
   Residual heat removal water leg pump
   Sump pump
   Room cooler

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. The walls and ceiling which interface with adjacent fire areas (except R-2) are 3-hr rated reinforced concrete. A hatch in the ceiling at 471 ft is covered by a 3-hr rated 24-in. thick concrete plug.

   b. Watertight doors are not listed as fire rated, but have equivalent construction.

   c. Fire dampers and penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include assumed transient combustibles and lubrication oil.

   d. Major ignition hazards include RHR-C pump RHR water leg pump, sump pump, and room cooler.

   e. Equipment/piping within the area contain low level radioactive water and gas. There are typically no airborne radioactivity hazards within the area. Some portions of the fire area may be a high radiation zone.

5. Fire suppression/detection equipment within the fire area

   Ionization detectors below 471 ft 0 in. ceiling

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguisher

   b. 1.5 in. standpipe hose stations

   c. Manual pull box for alarm

7. Safe shutdown systems

   a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The RHR 2C pump and auxiliaries within the fire area are assumed to be damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

   c. Unqualified doors and containment barrier are adequate to limit the spread of fire.

   d. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   e. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

f. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-7 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-8

1. <u>Description</u>

   Low-pressure core spray pump room, el. 422 ft 3 in. and el. 444 ft 0 in.

2. <u>Major equipment within the fire area</u>

   Low-pressure core spray pump
   Low-pressure core spray water leg pump
   Room cooler

   Fire area is a safety-related area.

3. <u>Construction of fire area boundaries</u>

   a. The walls and ceiling which interface with adjacent fire areas (except R-2) are 3-hr rated reinforced concrete. A hatch in the ceiling at 471 ft is covered by a 3-hr rated 24-in thick concrete plug.

   b. Watertight doors are not listed as fire rated, but have equivalent construction.

   c. Fire dampers and penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. <u>Fire hazards</u>

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include assumed transient combustibles and lubrication oil.

   d. Major ignition hazards include LPCS pump, LPCS water leg pump, and room cooler.

   e. Equipment/piping within the area contain low level radioactive water and gas. There are typically no airborne radioactivity hazards within the area. Some portions of the fire area may be a high radiation zone.

5. <u>Fire suppression/detection equipment within the fire area</u>

   Ionization detectors below 471 ft 0 in. ceiling

6. <u>Fire suppression/detection equipment outside but available to the fire area</u>

   a. Portable extinguisher

   b. 1.5 in. standpipe hose stations

   c. Manual pull box for alarm

7. <u>Safe shutdown systems</u>

   a. Fire area contains Division 1 post-fire safe shutdown cables.

   b. See Tables F.4-1 through F.4-3 for specific credited cables.

8. <u>Potential consequences of a design basis fire</u>

   a. The LPCS pump and auxiliaries within the fire area are assumed to be damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

   c. Unqualified doors and containment barrier are adequate to limit the spread of fire.

   d. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   e. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

f. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-8 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-9

1. Description

   Reactor building stair A6

2. Major equipment within the fire area

   None

   Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. The stairwell extends from the 422 ft level to the elevator machine room at el. 623 ft of the reactor building. The walls and ceiling which interface with adjacent fire areas are 3-hr rated reinforced concrete.

   b. The doors to the stairwell are 1.5-hr rated, minimum.

   c. Penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. 1.5 in. standpipe hose stations

   b. Ionization detector at top of stairwell

c. Manual pull box at 623 ft

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes for alarm

   c. 1.5 in. standpipe hose station in 441 ft train bay.

7. Safe shutdown systems

This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, a stairwell fire will not prevent safe shutdown.

   b. The available portable equipment is adequate to extinguish the design basis fire.

   c. 1.5 hr fire doors are adequate to ensure safe egress and limit the spread of fire.

   d. Smoke would be removed through the operation of-portable smoke removal equipment.

   e. Without floor drains, water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area R-9 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-10

1. Description

   Reactor building elevator no. 2

2. Major equipment within the fire area

   Elevator car
   Elevator electric motor

   Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. The elevator shaft extends from the 422 ft level of the reactor building to the elevator machine room at el. 623 ft. The walls and ceiling which interface with adjacent fire areas are 3-hr rated reinforced concrete.

   b. The elevator doors are 1.5-hr rated. Stairwell door to elevator equipment room is 1.5-hr rated.

   c. Penetration seals and fire dampers maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles.

   d. The major ignition hazard is the elevator electric motor.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Photoelectric smoke detector in elevator equipment room.

   b. Portable extinguisher in elevator equipment room.

6. Fire suppression/detection equipment outside but available to the fire area

   a. Standpipe hose stations in adjacent stairwell and train bay

   b. Portable extinguishers

   c. Manual pull boxes for alarm

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, an elevator shaft fire will not prevent safe shutdown.

   b. The available portable equipment is adequate to extinguish the design basis fire.

   c. Grated opening on elevator equipment room floor would allow smoke in the shaft to reach the smoke detector.

   d. 1.5-hr fire doors are adequate to limit the spread of fire.

   e. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   f. Without floor drains, water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

   A design basis fire within Fire Area R-10 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-11

1. Description

   Reactor building stair A5

2. Major equipment within the fire area

   None

   Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. The stairwell extends from the 422 ft level to the el. 623 ft of the reactor building. The walls and ceiling which interface with adjacent fire areas are 3-hr rated reinforced concrete.

   b. The doors to the stairwell are 1.5-hr rated, minimum.

   c. Penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. 1.5 in. standpipe hose stations

   b. Ionization detector at top of stairwell

c. Portable extinguisher at 441 ft

6. Fire suppression/detection equipment outside but available to the fire area

a. Portable extinguishers

b. Manual pull boxes for alarm

c. Manual pull box at 623 ft

7. Safe shutdown systems

This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

a. With no safe shutdown equipment/cables or associated circuits, a stairwell fire will not prevent safe shutdown.

b. The available portable equipment is adequate to extinguish the design basis fire.

c. 1.5-hr fire doors are adequate to ensure safe egress and limit the spread of fire.

d. Smoke would be removed through the operation of portable smoke removal equipment.

e. Without floor drains, water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area R-11 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-12

1. Description

Reactor building elevator no. 1

2. Major equipment within the fire area

Elevator car
Elevator electric motor

Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. The elevator shaft extends from the 441 ft level of the reactor building to the elevator machine room at el. 623 ft. The walls and ceiling which interface with adjacent fire areas are 3-hr rated reinforced concrete.

   b. The doors to the elevator are 1.5-hr rated. Door to elevator equipment room is 1.5-hr rated.

   c. Penetration seals and fire dampers maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "medium." However, this is based on infrequent transport of large amounts of combustibles in the elevator car.

   c. Major combustible is assumed transient combustibles.

   d. The major ignition hazard is the elevator electric motor.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Photoelectric smoke detector in elevator equipment room

   b. Portable extinguisher in elevator equipment room

6. Fire suppression/detection equipment outside but available to the fire area

   a. Standpipe hose stations in adjacent stairwell

   b. Portable extinguishers

   c. Manual pull boxes for alarm

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, an elevator shaft fire will not prevent safe shutdown.

   b. The available portable equipment is adequate to extinguish the design basis fire.

   c. 1-hr fire doors are adequate to limit the spread of fire.

   d. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   e. Without floor drains, water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

   A design basis fire within Fire Area R-12 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-15

1. Description

   Lobby outside stair A5, el. 422 ft

2. Major equipment within the fire area

   Dry transformers

   Fire area is a safety-related area.

3. Construction of Fire Area Boundaries

   a. The walls which interface with adjacent fire areas are 3-hr rated reinforced concrete. The ceiling is not credited as fire rated, but is designed equivalent to 3-hr fire rated.

   b. The door to the stairwell is 1.5-hr rated, minimum. Watertight doors are not listed as fire rated, but have equivalent construction.

   c. Penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include assumed transient combustibles and polyethylene.

   d. Major ignition hazard is dry transformers.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Portable fire extinguisher

   b. Manual pull box for alarm

6. Fire suppression/detection equipment outside but available to the fire area

   a. Standpipe hose stations in adjacent stairwell

   b. Manual pull boxes for alarm

   c. Portable extinguishers

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, fire will not prevent safe shutdown.

   b. The available portable equipment is adequate to extinguish the design basis fire.

   c. Unqualified doors, 1-hr fire door and nonrated ceiling are adequate to limit the spread of fire.

   d. Smoke would be removed through the operation of portable smoke removal equipment.

   e. Without floor drains, water discharge would cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

   A design basis fire within Fire Area R-15 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-18

1. Description

   Division 2 MCC room, el. 522 ft 0 in.

2. Major equipment within the fire area

   Motor control centers - Division 2

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

   b. Fire doors, dampers, and penetration seals maintain the rating of the barrier.

   c. Foamglass interior insulation is noncombustible.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "medium."

   c. Major combustible is electrical cable.

   d. Major ignition hazard is motor control centers.

   e. Equipment/piping within the area contain low level radioactive water and gas. There are no airborne radioactivity hazards within the area.

5. Fire suppression/detection equipment within the fire area

   Ionization detector

6. Fire suppression/detection equipment outside but available to the fire area

   a. Manual pull boxes for alarm

b. Portable extinguishers

c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

a. The Division 2 motor control center and cabling within the fire area are assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

b. The installed smoke detector is expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

c. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

d. Water discharge would cause water to flow out into Fire Area R-1 based on the small room area. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drain is routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

e. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-18 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA R-21

1. Description

   South valve and pipe space room, el. 522 ft 0 in.

2. Major equipment within the fire area

   Large piping and valves

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated, except containment barrier.

   b. Fire door, dampers/blowout vent paths, and penetration seals maintain the rating of the barrier.

   c. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles.

   d. There are no major ignition hazards in the area.

   e. Equipment/piping within the area contain low level radioactive water and gas. There are no airborne radioactivity hazards within the area. Fire area is typically a high radiation zone.

5. Fire suppression/detection equipment within the fire area

   Ionization detector

6. Fire suppression/detection equipment outside but available to the fire area

   a. Manual pull boxes for alarm

b. Portable extinguishers

c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

b. See Tables F.4-1 through F.4-3 for specific credited cables.

8. Potential consequences of a design basis fire

a. The cabling for the Division 2 valves in this fire area is assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

c. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

d. Without floor drains, water discharge could cause water to flow out into Fire Area R-1 based on the small room area. The flooding will not impair the ability of the plant to reach safe shutdown.

e. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area R-21 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA M-9

1. Description

Instrument rack E-IR-H22/P009 enclosure, el. 471 ft 0 in.

2. Major equipment within the fire area

Instrument rack E-IR-H22/P009

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. The shield walls enclosing the instrument rack and floor are concrete and 3-hr rated. The containment barrier is nonrated. There is no ceiling to the enclosure, but the shield walls extends approximately 6 in. higher than the instrument rack.

b. The door to the room is 3-hr fire rated.

c. Penetration seals maintain the rating of the fire barriers.

d. A raised curb is installed at the doorway of the instrument rack enclosure fire area to further isolate the room.

e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustible is electrical cable. Storage of transient combustibles is not allowed in the fire area. See Figure F.6-6.

d. There are no major ignition hazards in the area.

e. Equipment/piping within the area contain low level radioactive water and gas.

5. Fire suppression/detection equipment within the fire area

   None (but detection is present in overhead area of Fire Area R-1)

6. Fire suppression/detection equipment outside but available to the fire area

   a. Manual pull boxes for alarm

   b. Portable extinguishers

   c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

   a. Fire area contains Division 2 post-fire safe shutdown tubing.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment.

8. Potential consequences of a design basis fire

   a. The Division 2 tubing in this fire area is assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The instrument rack enclosure provides exposure fire protection for Division 2 post-fire safe shutdown instrument tubing. The concrete partitions around the instrument rack function to protect the instrument racks from the radiant heat from a fire originating outside of the fire area. Convective heat and smoke would quickly dissipate in the overhead ceiling area. The low combustible loading and transient combustible controls within the instrument rack enclosure precludes the propagation of fire to the overhead enclosed cable trays. References F.7.4.f and F.7.4.j approved the lack of full fire area enclosure.

   c. The smoke detectors installed in the surrounding general equipment area are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

   d. Although the containment barrier is not considered 3-hr rated, it is adequate to prevent fire propagation.

   e. Without a floor drain (only raised equipment drain), water discharge could cause localized flooding. Flooding will not impair the ability of the plant to reach safe shutdown.

f. The raised curb at the fire area entrance would prevent a flammable liquid spill from spreading between the instrument rack fire area and Fire Area R-1.

g. Smoke would be removed through the operation of the building exhaust system. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

h. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area M-9 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA M-21

1. Description

Instrument rack E-IR-H22/P021 enclosure, el. 501 ft 0 in.

2. Major equipment within the fire area

Instrument rack E-IR-H22/P021

Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. The fire area boundaries enclosing the instrument rack room are concrete and 3-hr rated. There is no ceiling to the enclosure, but the shield walls extends approximately 6 in. higher than the instrument rack.

   b. The door to the room is 3-hr fire rated.

   c. Penetration seals maintain the rating of the fire barriers.

   d. A raised curb is installed at the doorway of the instrument rack enclosure fire area to further isolate the room.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is electrical cable and Thermo-Lag 330-1. Storage of transient combustibles is not allowed in the fire area. See Figure F.6-6.

   d. There are no major ignition hazards in the area.

   e. Equipment/piping within the area contain low level radioactive water and gas.

5. Fire suppression/detection equipment within the fire area

None (but detection is present in overhead area of Fire Area R-1)

6. Fire suppression/detection equipment outside but available to the fire area

    a. Manual pull boxes for alarm

    b. Portable extinguishers

    c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

    a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

    b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

    a. The Division 2 equipment/cabling in this fire area is assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

    b. The instrument rack enclosure provides exposure fire protection for Division 2 post-fire safe shutdown instrumentation. The concrete partitions around the instrument rack function to protect the instrument racks from the radiant heat from a fire originating outside of the fire area. Convective heat and smoke would quickly dissipate in the overhead ceiling area. The low combustible loading and transient combustible controls within the instrument rack enclosure precludes the propagation of the fire to the overhead enclosed cable trays. References F.7.4.f and F.7.4.j approved the lack of full fire area enclosure.

    c. The smoke detectors installed in the surrounding general equipment area are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

    d. Without a floor drain (only raised equipment drain), water discharge could cause localized flooding. Flooding will not impair the ability of the plant to reach safe shutdown.

    e. The raised curb at the fire area entrance would prevent a flammable liquid spill from spreading between the instrument rack fire area and Fire Area R-1.

f. Smoke would be removed through the operation of the building exhaust system. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

g. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area M-21 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA M-27

1. Description

   Instrument rack E-IR-H22/P027 enclosure, el. 522 ft 0 in.

2. Major equipment within the fire area

   Instrument rack E-IR-H22/P027

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. The shield walls enclosing the instrument rack and floor are concrete and 3-hr rated. The containment barrier is nonrated. There is no ceiling to the enclosure, but the shield walls extends approximately 6 in. higher than the instrument rack.

   b. The door to the room is 3-hr fire rated.

   c. Penetration seals maintain the rating of the fire barriers.

   d. A raised curb is installed at the doorway of the instrument rack enclosure fire area to further isolate the room.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is electrical cable. Storage of transient combustibles is not allowed in the fire area. See Figure F.6-6.

   d. There are no major ignition hazards in the area.

   e. Equipment/piping within the area contain low level radioactive water and gas.

5. Fire suppression/detection equipment within the fire area

   None (but detection is present in overhead area of Fire Area R-1)

6. Fire suppression/detection equipment outside but available to the fire area

   a. Manual pull boxes for alarm

   b. Portable extinguishers

   c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

   a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

   b. Division 1 CRD water injection instrument tubing passes over the fire area.

   c. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The Division 2 equipment/cabling in this fire area is assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The Division 1 CRD water injection tubing that passes over the instrument rack area could heat up due to the routing over the Division 2 fire area. However, the temperature isolation functions credited for post-fire safe shutdown would not be affected.

   c. The instrument rack enclosure provides exposure fire protection for Division 2 post-fire safe shutdown instrumentation. The concrete partitions around the instrument rack function to protect the instrument racks from the radiant heat from a fire originating outside of the fire area. Convective heat and smoke would quickly dissipate in the overhead ceiling area. The low combustible loading and transient combustible controls within the instrument rack enclosure precludes the propagation of the fire to the overhead enclosed cable trays and junction boxes. References F.7.4.f and F.7.4.j approved the lack of full fire area enclosure.

d. The smoke detectors installed in the surrounding general equipment area are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

e. Although the containment barrier is not considered 3-hr rated, it is adequate to prevent fire propagation.

f. Without a floor drain (only raised equipment drain), water discharge could cause localized flooding. Flooding will not impair the ability of the plant to reach safe shutdown.

g. The raised curb at the fire area entrance would prevent a flammable liquid spill from spreading between the instrument rack fire area and Fire Area R-1.

h. Smoke would be removed through the operation of the building exhaust system. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

i. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area M-27 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA M-73

1. <u>Description</u>

Instrument rack E-IR-73 enclosure, el. 522 ft 0 in.

2. <u>Major equipment within the fire area</u>

Instrument rack E-IR-73

Fire area is a safety-related area.

3. <u>Construction of fire area boundaries</u>

   a. The fire area boundaries enclosing the instrument rack room are concrete and 3-hr rated. There is no ceiling to the enclosure, but the shield walls extends approximately 6 in. higher than the instrument rack.

   b. The door to the room is 3-hr fire rated.

   c. Penetration seals maintain the rating of the fire barriers.

   d. A raised curb is installed at the doorway of the instrument rack enclosure fire area to further isolate the room.

   e. See Figures F.6 for fire barrier locations and classifications.

4. <u>Fire hazards</u>

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is electrical cable. Storage of transient combustibles is not allowed in the fire area. See Figure F.6-6.

   d. There are no major ignition hazards in the area.

   e. Equipment/piping within the area contain low level radioactive water and gas.

5. <u>Fire suppression/detection equipment within the fire area</u>

None (but detection is present in overhead area of Fire Area R-1)

6. Fire suppression/detection equipment outside but available to the fire area

   a. Manual pull boxes for alarm

   b. Portable extinguishers

   c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

   a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The Division 2 equipment/cabling in this fire area is assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The instrument rack enclosure provides exposure fire protection for Division 2 post-fire safe shutdown instrumentation. The concrete partitions around the instrument rack function to protect the instrument racks from the radiant heat from a fire originating outside of the fire area. Convective heat and smoke would quickly dissipate in the overhead ceiling area. The low combustible loading and transient combustible controls within the instrument rack enclosure precludes the propagation of the fire to the overhead enclosed cable trays. References F.7.4.f and F.7.4.j approved the lack of full fire area enclosure.

   c. The smoke detectors installed in the surrounding general equipment area are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

   d. Without a floor drain (only raised equipment drain), water discharge could cause localized flooding. Flooding will not impair the ability of the plant to reach safe shutdown.

   e. The raised curb at the fire area entrance would prevent a flammable liquid spill from spreading between the instrument rack fire area and Fire Area R-1.

f. Smoke would be removed through the operation of the building exhaust system. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

g. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA Conclusion

A design basis fire within Fire Area M-73 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-1

1. <u>Description</u>

General equipment nonvital areas, el. 437 ft 0 in., 452 ft 0 in., 467 ft 0 in., 487 ft 0 in., 501 ft 0 in., and 507 ft 0 in.

2. <u>Major equipment within the fire area</u>

a. Elevation 437 ft - general equipment area

Radwaste baling area (baled and drum waste)
Offgas equipment and charcoal adsorbers
Waste storage tank area
East high-high radwaste tank and pump rooms
Truck bay

b. Elevation 452 ft - glycol pumps area

Chiller pumps
Offgas equipment and charcoal adsorbers

c. Elevation 467 ft - general equipment area

Radwaste control room
Contaminated tool room
Mask issue room
Decontamination facility
Tool crib storage area
Motor control centers

d. Elevation 487 ft - general equipment area

Hot machine shop
Chemistry lab and offices
Relay room
Health physics storage

e. Elevation 507 ft - general equipment area

Mechanical equipment room
Filter demineralizer removal area

The majority of the fire area is not a safety-related area. However, rooms C102, C104, C105, C106, C108, C203, C204, C231, C229 (north of column L.9) do contain safety-related equipment.

3. Construction of fire area boundaries

   a. The radwaste building exterior walls are reinforced concrete below el. 467 ft and insulated metal siding from el. 467 ft to the roof.

   b. The radwaste building walls which interface with other fire areas are generally reinforced concrete and 3-hr fire rated. The boundary with Fire Area RC-15, above 467 ft, is 2-hr rated masonry. Two wall sections in the northwest corner from 487 ft to 507 ft are 2-hr rated masonry walls (Reference F.7.6.g). The walls which interface with Fire Area RC-9 are 2-hr rated.

   c. Fire dampers and penetration seals maintain the rating of the barrier. The blind corridor room C349 has nonrated penetration seals. (Reference F.7.6.g)

   d. Elevator doors are 1.5-hr fire rated. Normal stairwell doors are 1.5-hr fire rated, minimum. Stairwell low range blast and bullet resistant doors are not listed as fire rated, but have equivalent construction. Other 3-hr barriers have 3-hr fire doors.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low." Since fire area covers approximately 93,400 ft^2, actual combustible loading varies.

   c. Major combustibles include electrical cable, charcoal and lubrication oil.

   d. Major ignition hazards include electrical switchgear, charcoal filters, fan motors, dry transformers, pumps motors, and hot machine shop.

   e. Equipment/piping within the area contain low level radioactive water, radioactive liquid waste, concentrated radioactive liquid waste, radioactive charcoal, and radioactive demineralizer ion exchange resins. There are typically no airborne radioactivity hazards within the area. Some portions of the fire area are high and high-high radiation zones.

5. Fire suppression/detection equipment within the fire area

   a. Photoelectric smoke detectors

   b. Ionization detectors

   c. Portable extinguishers

   d. Manual pull boxes

   e. Wet pipe sprinklers over the storage areas on the 437 ft, 467 ft, and 487 ft elevation and the chemistry lab offices

   f. 1.5 in. standpipe hose stations

6. Fire suppression/detection equipment outside but available to the fire area

   a. Hose lines from 2.5 in. outlets on yard hydrants

   b. 1.5 in. standpipe hose stations in enclosed stairwells

7. Safe shutdown systems

   a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. Division 1 post-fire safe shutdown equipment and cabling located within this fire area is assumed damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. The smoke detectors installed in the surrounding general equipment area are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade.

   c. The walls which interface with Fire Area RC-9 are 6-in. thick reinforced concrete. Since this is the minimum thickness for a 3-hr rating and there are surface defects, the walls are credited as 2-hr rated. The penetration seals can only be qualified as 2-hr rated. This fire rating is adequate for the hazards and will prevent fire propagation.

d. Unqualified and 1.5-hr fire doors are adequate to limit the spread of fire. The blind corridor room C349 2-hr barrier and nonrated penetration seals are adequate to limit the spread of fire.

e. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. Roof smoke purge fan WEA-FN-7 is available to the 507 ft level. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material. Radiation monitors are located downstream from the building exhaust air HEPA filter bank would sample the air being discharged to the atmosphere.

f. Automatic sprinklers are installed to protect the storage areas on the 437 ft, 467 ft, and 487 ft elevations, and the 487 ft chemistry lab offices. A fire in one of these area is expected to be quickly controlled by the sprinkler discharge.

g. Room C405 is not equipped with a manual hose station. For a hose stream to reach the entire room, 200 ft of fire hose is required. This is not a safety-related area and adequate fire hose is available. See Table F.2-1 for associated code deviation.

h. A high heat condition in one loop of charcoal adsorbers will alarm in the control room. Closure of the associated adsorber inlet valve would limit the oxygen supply for combustion.

i. Water discharge could cause flooding until removed by the floor drain system, through open doors, or by portable pumping units. Floor drains in this area are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

j. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. <u>FHA conclusion</u>

A design basis fire within Fire Area RC-1 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-2

1. Description

Cable spreading room, el. 484 ft 0 in.

This fire area contains the following fire zones:

   a. RC-2A, northern cable spreading room

   b. RC-2B, southern cable spreading room

   c. RC-2C, central cable spreading room, 20 ft zone

2. Major equipment within the fire area

Cable trays

Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

   b. Fire doors, dampers, and penetration seals maintain the rating of the barrier.

   c. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "medium." Fire zone RC-2C is a 20 ft zone of no intervening combustibles.

   c. Major combustibles include electrical cable and Thermo-Lag 330-1.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors

   b. Portable extinguishers

   c. Manual pull boxes

   d. Automatic preaction sprinkler system

   e. Ionization detector in each return air duct system

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Portable extinguishers

7. Safe shutdown systems

   a. Fire zone RC-2A contains Division 1 and Division 2 post-fire safe shutdown cables. Division 2 is protected by 1-hr rated raceway barriers.

   b. Fire zone RC-2B contains Division 2 post-fire safe shutdown cables.

   c. Fire zone RC-2C is a 20 ft zone of no intervening combustibles, suppression, and detection. Fire zone contains Division 1 and 2 post-fire safe shutdown cables protected by 1-hr rated raceway barriers.

   d. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The cable spreading room fire area is divided into three fire zones. Fire zone RC-2A primarily contains Division 1 cabling. Fire zone RC-2B primarily contains Division 2 cabling. The divisional fire zones are separated by an intervening fire zone, RC-2C, in which all cables are coated with a layer of Thermo-Lag 330-1 to prevent fire propagation between the redundant divisional zones. Fire detection and a preaction sprinkler system are installed within the area. These fire protection features provided are expected to limit potential fire damage to a single zone, as follows:

(1) A fire in fire zone RC-2A is assumed to damage cabling for the Division 1 post-fire safe shutdown systems. Cabling for the Division 2 post-fire safe shutdown systems are protected by 1-hr rated raceway fire barriers within the fire zone where analysis indicates that fire damage to the cable could cause maloperation of the post-fire safe shutdown component.

(2) A fire in fire zone RC-2B is assumed to damage cabling for the Division 2 post-fire safe shutdown systems. The cabling that is routed within the zone was reviewed to ensure that fire damage will not impair the operation of the Division 1 post-fire safe shutdown systems.

(3) A fire in fire zone RC-2C is prevented by coating the exposed cabling with a 1-hr rated raceway barrier. (Reference F.7.4.j) Cables for the Division 1 and Division 2 post-fire safe shutdown systems are protected by 1-hr rated raceway fire barriers within the zone.

b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade. Activation of the ionization detectors causes the preaction system control valve to open, allowing water to pressurize the sprinkler system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

c. The raceway barrier load bearing supports may not be wrapped the entire distance to the concrete barrier. In addition, raceway and other structural members routed over the top of raceway barriers are not protected. This is acceptable since the entire fire area is equipped with a high density preaction suppression system which ensures steel members would not heat to the point of structural failure.

d. Smoke would be removed through the operation of smoke purge fan WEA-FN-52 or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

e. Water discharge could cause localized flooding. Certain floor penetration seals are watertight to prevent water intrusion to redundant fire areas below. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains in this area are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. FHA conclusion

A design basis fire within Fire Area RC-2 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-3

1. Description

   Cable chase, el. 467 ft 0 in., el. 501 ft 0 in., and el. 525 ft 0 in.

2. Major equipment within the fire area

   Cable trays

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

   b. Fire dampers and penetration seals maintain the rating of the barrier.

   c. Low range blast and airtight doors are not listed as fire rated, but have equivalent construction. Other fire doors maintain the rating of the barrier.

   d. The 467 ft east doorway is equipped with a 12 in. floor dike.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "high" (based mainly on small floor area in relation to large room volume).

   c. Major combustibles include electrical cable and Thermo-Lag 330-1.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors at the 501 ft and 525 ft levels

   b. Ionization detector in each return air duct system

c. Automatic preaction sprinkler system. A pull box is provided for manual actuation (located outside the area at el. 525 ft and at the 441 ft alarm valve).

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose stations

   b. Portable extinguishers

   c. Manual pull box for alarm

7. Safe shutdown systems

   a. Fire area contains both Division 1 and Division 2 post-fire safe shutdown cables. Division 2 post-fire safe shutdown cables are protected by 1-hr rated raceway barriers.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. A fire in this area could damage cabling for the Division 1 post-fire safe shutdown systems. The combination of full area fire detection, preaction sprinkler system, and 1-hr raceway barriers ensure Division 2 will be available for safe shutdown.

   b. A fire in this area could cause the loss of dc power to the air-side seal oil backup pump (SO-P-ASBU). A concurrent loss of offsite power would cause the loss of ac power to the air-side seal oil pump (SO-P-H2S). A scram would cause the shaft driven seal oil pump backup pump to coast down until the pressure was insufficient to contain the hydrogen. This scenario could result in friction at the bearings causing a secondary fire in Fire Area TG-1 at the generator bearings. However, such a fire would not spread to Fire Area TG-1, Fire Zone TG-12 which contains unprotected Division 1 post-fire safe shutdown cables. See Fire Area TG-1 FHA discussion for more details.

   c. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the plant fire brigade. Activation of the ionization detectors causes the preaction system control valve to open, allowing water to pressurize the sprinkler system piping. Sprinkler flow is initiated when further rise in ambient temperature actuates the fusible link elements on the sprinkler heads.

d. The raceway barrier load bearing supports may not be wrapped the entire distance to the concrete barrier. In addition, raceway and other structural members routed over the top of raceway barriers are not protected. This is acceptable since the entire fire area is equipped with a high density preaction suppression system which ensures steel members would not heat to the point of structural failure.

e. The fire area has a much higher combustible loading fire severity duration than the surrounding 3-hr barriers. However, the fire area is equipped with a high density preaction sprinkler system which would effectively limit fire severity.

f. Unqualified doors are adequate to limit the spread of fire.

g. Smoke would be removed through the operation of smoke purge fan WEA-FN-52 or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

h. Water discharge could cause localized flooding. The floor dike and gasketed door would help limited water spread to the 467 ft vital island rooms. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. FHA conclusion

A design basis fire within Fire Area RC-3 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-4

1. Description

   Division 1 electrical equipment rooms, el. 467 ft 0 in. (battery charger room no. 1 and RPS room no. 1)

2. Major equipment within the fire area

   Battery charger #1
   Motor control centers
   Reactor protection system M/G sets
   Inverters

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

   b. The majority of fire dampers are 1.5-hr rated; however some are 3-hr rated.

   c. Fire doors and penetration seals maintain the rating of the barrier.

   d. Doorways are equipped with a 3 in. raised curb.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is electrical cable.

   d. Major ignition hazards include dry transformers, motor control centers, MG set motor/generator, and inverters.

   f. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

    a. Ionization detectors at ceiling level

    b. Ionization detector in the return air duct

6. Fire suppression/detection equipment outside but available to the fire area

    a. Portable extinguishers

    b. Manual pull boxes

    c. 1.5 in. standpipe hose station

7. Safe shutdown systems

    a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

    b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

    a. The Division 1 electrical equipment and cabling within the area are assumed damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

    b. A fire in this area could cause the loss of ac power to the air-side seal oil backup pump (SO-P-ASBU). A concurrent loss of offsite power would cause the loss of ac power to the air-side seal oil pump (SO-P-H2S). A scram would cause the shaft driven seal oil pump backup pump to coast down until the pressure was insufficient to contain the hydrogen. This scenario could result in friction at the bearings causing a secondary fire in Fire Area TG-1 at the generator bearings. However, such a fire would not spread to Fire Area TG-1 Fire Zone TG-12 which contains unprotected Division 1 post-fire safe shutdown cables. See Fire Area TG-1 FHA discussion for more details.

    c. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

    d. Based on the low combustible loading, the 1.5-hr rated fire dampers are adequate to limit the spread of fire (Reference F.7.4.a).

e. Smoke would be removed by the operation of portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

f. Water discharge could cause localized flooding. Fire area does not have floor drains, but is equipped with a 3 in. raised curb at doorways. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area RC-4 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-5

1. Description

Battery room no. 1, el. 467 ft 0 in.

2. Major equipment within the fire area

Battery banks
Electrical panels
Dry transformers

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

b. The majority of fire dampers are 3-hr rated; however some are 1.5-hr rated.

c. Fire doors and penetration seals maintain the rating of the barrier.

d. East doorway is equipped with a 3 in. raised curb.

e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustible is electrical cable.

d. Major ignition hazard is arcing from shorted battery terminals, electrical panels, dry transformers, and unit heater.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors

   b. Ionization detector in return air and exhaust air duct

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes

   c. 1.5 in. standpipe hose station

7. Safe shutdown systems

   a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The Division 1 electrical equipment and cabling within the area are assumed damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. A fire in this area could cause the loss of dc power to the air-side seal oil backup pump (SO-P-ASBU). A concurrent loss of offsite power would cause the loss of ac power to the air-side seal oil pump (SO-P-H2S). A scram would cause the shaft driven seal oil pump backup pump to coast down until the pressure was insufficient to contain the hydrogen. This scenario could result in friction at the bearings causing a secondary fire in Fire Area TG-1 at the generator bearings. However, such a fire would not spread to Fire Area TG-1, Fire Zone TG-12 which contains unprotected Division 1 post-fire safe shutdown cables. See Fire Area TG-1 FHA discussion for more details.

   c. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

   d. Based on the low combustible loading, the 1.5-hr rated fire dampers are adequate to limit the spread of fire (Reference F.7.4.a).

e. Smoke would be removed by the operation of portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

f. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. East doorway is equipped with a 3 in. raised curb. The floor drain is routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. <u>FHA conclusion</u>

A design basis fire within Fire Area RC-5 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-6

1. Description

   Battery room no. 2, el. 467 ft 0 in.

2. Major equipment within the fire area

   Battery banks

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

   b. Fire dampers are 1.5-hr rated.

   c. Fire doors and penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles.

   d. Major ignition hazards include HVAC heating unit and shorted battery terminals.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors

   b. Ionization detector in return air and exhaust air duct

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes

   c. 1.5 in. standpipe hose station

7. Safe shutdown systems

   a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The Division 2 electrical equipment and cabling within the area are assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

   c. Based on the low combustible loading, the 1.5-hr rated fire dampers are adequate to limit the spread of fire (Reference F.7.4.a).

   d. Smoke would be removed by the operation of portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   e. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. The floor drain is routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. FHA conclusion

A design basis fire within Fire Area RC-6 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-7

1. Description

Division 2 electrical equipment rooms, el. 467 ft 0 in. (battery charger room no. 2 and RPS room no. 2)

2. Major equipment within the fire area

Battery charger no. 2
Motor control centers
Reactor protection system M/G set

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

b. Fire dampers are 1.5-hr rated.

c. Fire doors and penetration seals maintain the rating of the barrier.

d. Doorways are equipped with a 3 in. raised curb.

e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustible is electrical cable.

d. Major ignition hazards include battery charger no. 2, motor control centers, RPS M/G set and dry transformers.

e. There are no radioactive material or airborne radioactivity hazards.

5. <u>Fire suppression/detection equipment within the fire area</u>

   a. Ionization detectors at ceiling level

   b. Ionization detector in the return air duct

6. <u>Fire suppression/detection equipment outside but available to the fire area</u>

   a. Portable extinguishers

   b. Manual pull boxes

   c. 1.5 in. standpipe hose station

7. <u>Safe shutdown systems</u>

   a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. <u>Potential consequences of a design basis fire</u>

   a. The Division 2 electrical equipment and cabling within the area are assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

   c. Based on the low combustible loading, the 1.5-hr rated fire dampers are adequate to limit the spread of fire (Reference F.7.4.a).

   d. Smoke would be removed by the operation of portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   e. Water discharge could cause localized flooding. Fire area does not have floor drains, but is equipped with a 3 in. raised curb at doorways. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area RC-7 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-8

1. Description

Switchgear room no. 2, el. 467 ft 0 in.

2. Major equipment within the fire area

Division 2 switchgear
Division 2 transformers TR-8-81 and TR-8-83

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

b. Fire doors, dampers, and penetration seals maintain the rating of the barrier.

c. Doorways are equipped with a 3 in. raised curb. Oil-filled transformers are surrounded by 12 in. dikes.

d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "medium."

c. Major combustibles include transformer oil and electrical cable.

d. Major ignition hazards include Division 2 switchgear, oil-filled transformers, and neutral grounding resistors.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

a. Ionization detectors at ceiling level

b. Ionization detector in the return air duct system

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes

   c. 1.5 in. standpipe hose station

7. Safe shutdown systems

   a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The Division 2 electrical equipment and cabling within the area are assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

   c. Smoke would be removed by the operation of portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   d. Water discharge could cause localized flooding. Fire area does not have floor drains, but is equipped with a 3 in. raised curb at doorways. The flooding will not impair the ability of the plant to reach safe shutdown.

   e. Both oil-filled transformers are equipped with 12 in. high dikes to help prevent the spread of oil.

9. FHA conclusion

   A design basis fire within Fire Area RC-8 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-9

1. Description

Remote shutdown room, el. 467 ft 0 in.

2. Major equipment within the fire area

Remote shutdown panels

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated, except the two northwest chase walls are 2-hr fire rated.

b. Fire doors, dampers, and penetration seals maintain the rating of the barrier.

c. Doorways are equipped with a 3 in. raised curb.

d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustible is electrical cable.

d. Major ignition hazards include electrical panels and dry transformers.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

a. Ionization detectors at ceiling level

b. Ionization detector in the return air duct system

6. Fire suppression/detection equipment outside but available to the fire area

    a. Portable extinguishers

    b. Manual pull boxes

    c. 1.5 in. standpipe hose station

7. Safe shutdown systems

    a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

    b. This fire area contains remote shutdown panel used during a design basis fire in the main control room Fire Area RC-10.

    c. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

    a. The Division 2 electrical equipment and cabling within the area are assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

    b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

    c. The northwest chase walls which interface with Fire Area RC-1 are 6-in. thick reinforced concrete. Since this is the minimum thickness for a 3-hr rating and there are surface defects, the walls are credited as 2-hr rated. The penetration seals can only be qualified as 2-hr rated. This fire rating is adequate for the hazards and will prevent fire propagation.

    d. Smoke would be removed by the operation of smoke purge fan WEA-FN-52 or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

    e. Water discharge could cause localized flooding. Fire area does not have floor drains, but is equipped with a 3 in. raised curb at doorways. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area RC-9 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-10

1. Description

   Main control room, el. 501 ft 0 in.

2. Major equipment within the fire area

   Control panels, computers, and office area

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

   b. Fire dampers and penetration seals maintain the rating of the barrier.

   c. Low range blast/bullet resistant/airtight doors are not listed as fire rated, but have equivalent construction.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include electrical cable, vinyl flooring/carpet, and paper.

   d. Major ignition hazard is electrical panels.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors in the general area at suspended ceiling

   b. Ionization detectors in the shift manager's office

   c. Portable extinguishers

d. Manual pull boxes

e. Automatic Halon extinguishing systems in PGCC sub-floor sections longitudinal cable ducts with ionization and thermal detectors

f. Ionization detectors in PGCC termination cabinets and panels

g. Photoelectric detector in kitchen area

h. Automatic sprinkler system in the shift manager's office, pipe chase, restroom, and kitchen area.

6. Fire suppression/detection equipment outside but available to the fire area

a. 1.5 in. standpipe hose station

b. Portable fire extinguisher

c. One manual pull box

7. Safe shutdown systems

a. Fire area contains both Division 1 and Division 2 post-fire safe shutdown equipment and cables.

b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

a. The Division 1 and Division 2 equipment/cabling in Fire Area RC-10 is assumed damaged by the design basis fire. Should a fire render the main control room uninhabitable, remote post-fire shutdown is achieved from Fire Areas RC-9 and RC-14 using selected equipment which may be isolated from the effects of the fire, assuming offsite power may not be available. Primarily Division 2 and some Division 1 post-fire safe shutdown systems would remain operable to ensure safe plant shutdown. See Appendix F.4.3.2 discussion of remote post-fire safe shutdown methodology and equipment.

b. A fire in this area could cause the loss of dc power to the air-side seal oil backup pump (SO-P-ASBU). A concurrent loss of offsite power would cause the loss of ac power to the air-side seal oil pump (SO-P-H2S). A scram would cause the shaft driven seal oil pump backup pump to coast down until the pressure was insufficient to contain the hydrogen. This scenario could result in

friction at the bearings causing a secondary fire in Fire Area TG-1 at the generator bearings. However, such a fire would not spread to Fire Area TG-1, Fire Zone TG-12 which contains unprotected Division 1 post-fire safe shutdown cables. See Fire Area TG-1 FHA discussion for more details.

c. The main control room is constantly manned by operations personnel. A fire occurring in the control room or support areas is expected to be detected promptly. Based on the lack of combustibles, detection is not required above the suspended ceiling. Early warning is provided by the smoke detectors at suspended ceiling level and in the PGCC termination cabinets and panels.

d. A fire in the PGCC subfloor longitudinal cable ducts would be quickly detected by the installed ionization detectors. Thermal detectors will sense a high heat condition activating the Halon system into the sealed PGCC sub-floor section longitudinal cable ducts.

e. A fire in an office/support area would actuate the installed automatic sprinkler system to control the fire. The control room sprinkler and combustible wall paneling were approved per Reference F.7.4.f.

f. The main control room carpeting does not create a significant fire hazard. (References F.7.4.g and F.7.6.i)

g. Unqualified doors are adequate to limit the spread of fire.

h. Smoke would be removed by the operation of smoke purge fan WEA-FN-52 or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

i. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. <u>FHA conclusion</u>

A design basis fire within Fire Area RC-10 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-11

1. Description

Unit A air conditioning room, radwaste control building, el. 525 ft 0 in.

2. Major equipment within the fire area

Control room air conditioning unit A
Cable spreading room unit A
Critical switchgear room air conditioning unit A
Motor control centers

Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

   b. Fire dampers and penetration seals maintain the rating of the barrier.

   c. The chiller area door is 1.5-hr rated, minimum. The low range blast door is not listed as fire rated, but has equivalent construction.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is electrical cable.

   d. Major ignition hazards include motor control centers, HVAC fan motors, and charcoal filter.

   e. There are no radioactive material or airborne radioactivity hazards.

5. <u>Fire suppression/detection equipment within the fire area</u>

   a. Manually actuated water spray system in the charcoal emergency filter unit. Thermistor wires provide high temperature alarm in the main control room.

   b. Ionization detectors at ceiling level.

   c. Ionization detector in return air duct.

6. <u>Fire suppression/detection equipment outside but available to the fire area</u>

   a. Portable extinguisher

   b. 1.5 in. standpipe hose stations

   c. Manual pull box for alarm

7. <u>Safe shutdown systems</u>

   a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. <u>Potential consequences of a design basis fire</u>

   a. The Division 1 control room HVAC, cable spreading room HVAC, and critical switchgear HVAC units within the fire area are assumed damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

   c. Heat buildup within the charcoal filter unit would cause a temperature alarm in the main control room. The manual water spray system may be remotely actuated if required to suppress a charcoal filter fire.

   d. Unqualified and 1.5-hr door are adequate to limit the spread of fire.

   e. Smoke would be removed by the operation of portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

f. Water discharge could cause localized flooding. Floor penetration seals are pressure resistant to essentially no leakage and would prevent water intrusion into the main control room. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. FHA conclusion

A design basis fire within Fire Area RC-11 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-12

1. Description

Unit B air conditioning room, radwaste control building, el. 525 ft 0 in.

2. Major equipment within the fire area

Control room air conditioning unit B
Cable spreading room unit B
Critical switchgear room air conditioning unit B
Motor control centers

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

b. Fire dampers and penetration seals maintain the rating of the barrier.

c. The door from the chiller area is 1.5-hr rated, minimum. The low range blast/bullet resistant door/airtight is not listed as fire rated, but has equivalent construction.

d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustible is electrical cable.

d. Major ignition hazards include motor control centers, HVAC motors, and charcoal filter.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

    a. Manually actuated water spray system in the charcoal emergency filter unit. Thermistor wires provide high temperature alarm in the main control room.

    b. Ionization detectors at ceiling level.

    c. Ionization detector in return air duct.

    d. Portable extinguisher

6. Fire suppression/detection equipment outside but available to the fire area

    a. Portable extinguishers

    b. 1.5 in. standpipe hose stations

    c. Manual pull box for alarm

7. Safe shutdown systems

    a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

    b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

    a. The Division 2 control room HVAC, cable spreading room HVAC, and critical switchgear HVAC units within the fire area are assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

    b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

    c. Heat buildup within the charcoal filter unit would cause a temperature alarm in the main control room. The manual water spray system may be remotely actuated if required to suppress a filter fire.

    d. Unqualified and 1.5-hr door are adequate to limit the spread of fire.

e. Smoke would be removed by the operation of portable smoke removal equipment. HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

f. Water discharge could cause localized flooding. Floor penetration seals are pressure resistant to essentially no leakage and would prevent water intrusion into the main control room. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. FHA conclusion

A design basis fire within Fire Area RC-12 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-13

1. Description

Communications room, emergency chiller area, instrument shop, radwaste control building, el. 525 ft 0 in., and HVAC chase 484 ft to 525 ft.

2. Major equipment within the fire area

Communications equipment room, hot instrument shop, emergency chiller area.

Fire area is a safety-related area.

3. Construction of Fire Area Boundaries

   a. Fire area boundaries are constructed of reinforced concrete. Fire area boundaries which interface with other fire areas are 3-hr rated.

   b. Fire door assemblies have a 1.5-hr fire rating except the door at the bottom of the duct chase has a 3-hr fire rating.

   c. Fire dampers are 3-hr fire rated dampers or have doors in frames similar to fire door frames.

   d. Penetration seals maintain the rating of the barrier.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include paper, electrical cable and wood.

   d. Major ignition hazard is electrical communication cabinets.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors in the communications shop

   b. Ionization detectors in the corridor

   c. Portable extinguishers

   d. Manual pull box

   e. Ionization detector in the corridor return air duct (served by Division 2 only)

   f. 1.5 in. standpipe hose station

6. Fire suppression/detection equipment outside but available to the fire area

   a. 1.5 in. standpipe hose station

   b. Manual pull station

7. Safe shutdown systems

   a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

   b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The cabling for the Division 2 cable spreading HVAC and critical switchgear HVAC units within the fire area is assumed damaged due to the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

   b. Fire damage to the emergency chillers could occur. The standby service water supply to the control room air handling unit cooling coil will remain available.

   c. The closure of fire dampers could interrupt the fresh air intake to the main control room. If necessary, the control room doors may be opened.

   d. 1.5-hr fire doors and fire door type fire dampers are adequate to limit the spread of fire (Reference F.7.4.f).

e. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

f. Smoke would be removed by portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

g. Water discharge could cause localized flooding. Floor penetration seals are pressure resistant to essentially no leakage and would prevent water intrusion into the main control room. Flooding will not impair the ability of the plant to reach safe shutdown. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. FHA conclusion

A design basis fire within Fire Area RC-13 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-14

1. Description

Switchgear room no. 1, radwaste/control building, el. 467 ft 0 in.

2. Major equipment within the fire area

Division 1 switchgear
Division 1 transformers TR-7-71 and TR-7-73
Alternate shutdown panel

Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

   b. Fire doors, dampers, and penetration seals maintain the rating of the barrier.

   c. Doorways are equipped with a 3 in. raised curb and oil-filled transformers are surrounded by 12 in. dikes.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "medium."

   c. Major combustibles include transformer oil and electrical cable.

   d. Major ignition hazards include electrical switchgear, oil-filled transformers, and neutral grounding resistors.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detectors at ceiling level

   b. Ionization detector in the return air duct system

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes for alarm

   c. 1.5 in. standpipe hose station

7. Safe shutdown systems

   a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

   b. Fire area also contains alternate remote shutdown panel used during a main control room fire.

   c. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

   a. The Division 1 electrical equipment and cabling within the area are assumed damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

   c. Smoke would be removed by portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   d. Water discharge could cause localized flooding. Fire area does not have floor drains, but is equipped with a 3 in. raised curb at doorways. The flooding will not impair the ability of the plant to reach safe shutdown.

   e. Both oil-filled transformers are equipped with 12 in. high dikes to help prevent the spread of oil.

9. FHA conclusion

A design basis fire within Fire Area RC-14 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-15

1. Description

   Radwaste building, stair A8 and room C100

2. Major equipment within the fire area

   None

   Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. The stairwell extends from the 437 ft level to the 507 ft level of the radwaste building. The fire area boundary is concrete or masonry and is 3-hr rated (except floor).

   b. The doors to the stairwell are 1.5-hr rated, minimum.

   c. Penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. 1.5 in. standpipe hose stations

   b. Ionization detector at top of stairwell

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes for alarm

   c. Hose lines from 2.5 in. outlets on yard hydrants

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, a stairwell fire will not prevent safe shutdown.

   b. The available portable equipment is adequate to extinguish the design basis fire.

   c. 2-hr fire barriers and 1.5-hr fire doors are adequate to ensure safe egress and limit the spread of fire.

   d. Smoke would be removed through portable smoke removal equipment.

   e. The no floor drains, water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

   A design basis fire within Fire Area RC-15 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-16

1. Description

   Radwaste/control building, stair A7

2. Major equipment within the fire area

   None

   Fire area is not a safety-related area, but is used for access to perform post-fire safe shutdown operator actions.

3. Construction of fire area boundaries

   a. The stairwell extends from the 437 ft level to the 525 ft level of the radwaste/control building. The walls of the area are concrete and are 3-hr fire rated.

   b. The low range blast stairwell doors are not listed as fire rated, but have equivalent construction.

   c. Penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. <u>Fire suppression/detection equipment within the fire area</u>

   a. 1.5 in. standpipe hose stations

   b. Ionization detector at top of stairwell

   c. Manual pull boxes at 452 ft and 525 ft

6. <u>Fire suppression/detection equipment outside but available to the fire area</u>

   a. Portable extinguishers

   b. Manual pull boxes for alarm

7. <u>Safe shutdown systems</u>

   This fire area contains no post-fire safe shutdown components or cabling.

8. <u>Potential consequences of a design basis fire</u>

   a. With no safe shutdown equipment/cables or associated circuits, a stairwell fire will not prevent safe shutdown.

   b. The available portable equipment is adequate to extinguish the design basis fire.

   c. Unqualified doors are adequate to ensure safe egress and limit the spread of fire.

   d. Smoke would be removed through the operation of portable smoke removal equipment.

   e. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. <u>FHA conclusion</u>

   A design basis fire within Fire Area RC-16 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-17

1. Description

Radwaste/control building, elevator no. 4, and room C504 vestibule

2. Major equipment within the fire area

Elevator electrical motor

Fire area is not a safety-related area.

3. Construction of fire area boundaries

a. The elevator shaft extends from the 437 ft level to the 525 ft level of the radwaste/control building. The walls of the area are concrete and are 3-hr fire rated.

b. The elevator doors are 1.5-hr rated. Hourly rating of elevator door C500 and equipment room door C512 is not credited. Stairwell door C501 at 525 ft is a low range blast door which is not listed as fire rated, but has equivalent construction.

c. Penetration seals and fire dampers maintain the rating of the barrier.

d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

d. The major ignition hazard is the elevator electric motor.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

Photoelectric smoke detector in elevator equipment room.

6. Fire suppression/detection equipment outside but available to the fire area

    a. Portable extinguishers

    b. Manual pull boxes for alarm

    c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

    This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

    a. With no safe shutdown equipment/cables or associated circuits, an elevator shaft fire will not prevent safe shutdown.

    b. The available portable equipment is adequate to extinguish the design basis fire.

    c. Grated opening on elevator equipment room floor would allow smoke in the shaft to reach the smoke detector.

    d. Unqualified and 1.5-hr fire doors are adequate to limit the spread of fire.

    e. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to defect radioactive smoke which may result from the combustion of radioactive material.

    f. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

    A design basis fire within Fire Area RC-17 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-18

1. <u>Description</u>

Radwaste/control building, stair A13

2. <u>Major equipment within the fire area</u>

None

Fire area is not a safety-related area.

3. <u>Construction of fire area boundaries</u>

a. The stairwell extends from the 467 ft level vital island to the cable spreading room on the 484 ft level of the radwaste/control building. The fire area boundaries are concrete and 3-hr fire rated.

b. The doors to the stairwell are 1.5-hr rated, minimum.

c. Penetration seals maintain the rating of the barrier.

d. See Figures F.6 for fire barrier locations and classifications.

4. <u>Fire hazards</u>

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

d. There are no major ignition hazards in the area.

e. There are no radioactive material or airborne radioactivity hazards.

5. <u>Fire suppression/detection equipment within the fire area</u>

1.5 in. standpipe hose station

6. Fire suppression/detection equipment outside but available to the fire area

    a. Portable extinguishers

    b. Manual pull boxes for alarm

7. Safe shutdown systems

    This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

    a. With no safe shutdown equipment/cables or associated circuits, a stairwell fire will not prevent safe shutdown.

    b. The available portable equipment is adequate to extinguish the design basis fire.

    c. Since the stairwell is void of in-situ combustibles, the lack of fire detection is acceptable.

    d. 1.5-hr fire doors are adequate to ensure safe egress and limit the spread of fire.

    e. Smoke would be removed through the operation of portable smoke removal equipment.

    f. With no drains, water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

    A design basis fire within Fire Area RC-18 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-19

1. Description

Corridor C-205, radwaste/control building, el. 467 ft 0 in.

2. Major equipment within the fire area

Cabling

Fire area is a safety-related area.

3. Construction of fire area boundaries

a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

b. The majority of fire dampers are 3-hr rated; however some are 1.5-hr rated.

c. Fire doors and penetration seals maintain the rating of the barrier.

d. RC-18 stairwell door is 1.5-hr rated, minimum. The low range blast doors are not listed as fire rated, but have equivalent construction. Other fire doors maintain the rating of the barrier.

e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

a. The combustible loading is controlled in calculation FP-02-85-03.

b. Combustible loading is classified as "low."

c. Major combustible is electrical cable.

d. Major ignition hazard is a dry transformer.

e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

a. Ionization detectors

b. Portable extinguishers

c. One manual pull box

6. Fire suppression/detection equipment outside but available to the fire area

a. 1.5 in. manual hose stations

b. Manual pull boxes

7. Safe shutdown systems

a. Fire area contains Division 2 post-fire safe shutdown cables.

b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

a. The Division 2 cabling within the area is assumed damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

c. Based on the low combustible loading, the 1.5-hr rated fire dampers/doors and unqualified doors are adequate to limit the spread of fire (Reference F.7.4.a).

d. Smoke would be removed by the operation of portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

e. Water discharge could cause localized flooding. The 12 ft dike in RC-3 and 3 in. curbs in adjacent fire areas without drains would help limit water spread to other fire areas. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drain is routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

9. FHA conclusion

A design basis fire within Fire Area RC-19 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA RC-20

1. Description

Pipe chase (el. 467 ft) and PASS area (el. 487 ft) - radwaste building

2. Major equipment within the fire area

PASS cabinets
Cable trays

Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

   b. Fire doors are 1.5-hr rated, minimum. Entrance door at 467 ft is normally locked.

   c. Fire dampers are 3-hr rated at 467 ft and 1.5-hr rated at 487 ft.

   d. Penetration seals maintain the rating of the barrier, except R206-4236 is nonrated.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is electrical cable.

   d. Major ignition hazard is the PASS control panel.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

Ionization detectors at 487 ft PASS room ceiling.

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. 1.5 in. standpipe hose station

7. Safe shutdown systems

   a. Fire area contains Division 1 post-fire safe shutdown cables.

   b. See Tables F.4-1 through F.4-3 for specific credited cables.

8. Potential consequences of a design basis fire

   a. The Division 1 cabling within the area is assumed damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

   b. The installed smoke detectors are expected to detect the products of combustion from a fire in its initial stages of growth and alert the control room for response by the fire brigade.

   c. Based on the low combustible loading, the 1.5-hr rated fire damper and doors are adequate to limit the spread of fire.

   d. Penetration R206-4236 is the PASS module. The penetration has numerous tubes supported by steel plates on each side and a center sleeve through the wall to the reactor building. There is no penetration sealant in the outer area and the center sleeve can not be sealed since it is a vent line. The east side of the penetration is in the Fire Area R-4 pipe chase which is void of combustibles. The Fire Area RC-20 side has a steel enclosure which is sufficiently substantial to act as a secondary containment barrier. The enclosure has minimal combustible cables. This unique penetration design is adequate for the adjacent hazards.

   e. Smoke would be removed by the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   f. With no floor drains, water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area RC-20 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA SW-1

1. Description

Standby service water pump house 1A, el. 431 ft 0 in. and el. 441 ft 0 in.

2. Major equipment within the fire area

Standby service water pump A
High-pressure core spray service water pump

Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. The exterior pump house walls and ceiling are reinforced concrete and are nonrated.

   b. The pump house doors are nonrated.

   c. The pump house is remote from other fire areas.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include assumed transient combustibles, transformer oil, and electrical cable.

   d. Major ignition hazard is standby service water pumps.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detector in cable vault

   b. Thermal detector in pump area

c. Portable extinguisher

d. Manual pull box

6. Fire suppression/detection equipment outside but available to the fire area

Hose lines from 2.5 in. outlets on yard hydrants

7. Safe shutdown systems

a. Fire area contains Division 1 post-fire safe shutdown equipment and cables.

b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

a. The Division 1 standby service water pump and associated equipment and cabling within the fire area are assumed to be damaged by the design basis fire. Division 2 post-fire safe shutdown systems would remain operable.

b. The developing fire would activate an installed smoke or thermal detector, initiating an alarm in the control room for fire brigade response. Manual hose stations are available.

c. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment.

d. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains in this area are routed back to the service water pond.

9. FHA conclusion

A design basis fire within Fire Area SW-1 will be confined near the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA SW-2

1. Description

   Standby service water pump house 1B, el. 431 ft 0 in. and el. 441 ft 0 in.

2. Major equipment within the fire area

   Standby service water pump B

   Fire area is a safety-related area.

3. Construction of fire area boundaries

   a. The exterior pump house walls and ceiling are reinforced concrete and are nonrated.

   b. The pump house doors are nonrated.

   c. The pump house is remote from other fire areas.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustibles include assumed transient combustibles, transformer oil and electrical cable.

   d. Major ignition hazard is standby service water pumps.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Ionization detector in cable vault

   b. Thermal detector in pump area

   c. Portable extinguisher

   d. Manual pull box

6. Fire suppression/detection equipment outside but available to the fire area

Hose lines from 2.5 in. outlets on yard hydrants

7. Safe shutdown systems

a. Fire area contains Division 2 post-fire safe shutdown equipment and cables.

b. See Tables F.4-1 through F.4-3 for specific credited equipment and cables.

8. Potential consequences of a design basis fire

a. The Division 2 standby service water pump and associated equipment and cabling within the fire area are assumed to be damaged by the design basis fire. Division 1 post-fire safe shutdown systems would remain operable.

b. The developing fire would activate an installed smoke or heat detector, initiating an alarm in the control room for fire brigade response. Manual hose stations are available.

c. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment.

d. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown. Floor drains in this area are routed back to the service water pond.

9. FHA conclusion

A design basis fire within Fire Area SW-2 will be confined near the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA TG-1

1. Description

Turbine generator building general equipment areas, el. 441 ft 0 in., el. 471 ft 0 in., and el. 501 ft 0 in. Also includes 441 ft N/S corridor between radwaste and reactor buildings, diesel building 441 ft E/W corridor and old laundry room D113, and reactor building main steam tunnel.

This fire area includes the following fire zones:

a. TG-2 - turbine oil storage room

b. TG-5 - auxiliary boiler room

c. TG-7 - hydrogen seal oil room

d. TG-9 - turbine oil reservoir room

e. TG-10 - west transformer vault

f. TG-11 - east transformer vault

g. TG-12 - 441 ft southern corridors

2. Major equipment

a. Elevation 441 ft

(1) Transformers
(2) Service air compressors
(3) Reactor feed pumps
(4) Reactor feed pump turbines
(5) Main condenser
(6) Steam jet air ejectors
(7) Condensate pumps
(8) Condensate booster pumps
(9) Health physics clothing storage area
(10) Relief valve test enclosure
(11) Turbine lube oil storage unit
(12) Main lube oil transfer pump
(13) Turbine oil pump
(14) Turbine lube oil conditioner

(15) Auxiliary boiler
(16) Air handling units

b. Elevation 471 ft

(1) Transformers
(2) Neutral grounding transformer
(3) Feedwater heaters
(4) Electrohydraulic fluid supply pumps and DEH reservoir
(5) Switchgear, motor control centers
(6) Generator bus ducts, exciter cubicles
(7) Turbine oil reservoir

c. Elevation 501 ft

(1) Transformer
(2) Heating, ventilating, and air-conditioning units
(3) Motor control centers
(4) Electrical panels
(5) Feedwater heaters
(6) Turbine generator

The majority of the fire area is not a safety-related area. However, areas adjacent main steam lines and room C202 do contain safety-related equipment/cables. In addition, the entire Fire Zone TG-12 is a safety-related area.

3. <u>Construction of fire area boundaries</u>

a. The turbine building walls which interface with other fire areas are generally reinforced concrete and 3-hr rated. Portions of stairwells are 2-hr rated masonry construction. Two wall sections in the southwest corner from 487 ft to 507 ft are 2-hr masonry walls. (Reference F.7.6.f) The steam tunnel interfaces with the nonrated containment barrier. Floor plugs in 522 ft of steam tunnel are 3-hr rated.

b. See Figures F.6 for rating of exterior barriers due to turbine building exposures.

c. Elevator doors are 1.5-hr rated. Stairwell doors are 1.5-hr rated, minimum. The low range blast, high range blast, airtight, and bullet resistant doors are not listed as fire rated, but have equivalent construction. Other fire doors maintain the rating of the barrier.

d. Fire dampers and penetration seals maintain the rating of the barrier. The blind corridor room C349 has nonrated penetration seals. (Reference F.7.6.g)

e. Floor dikes are present at various locations where combustible oil leakage hazards are present.

f. See Figures F.6 for fire barrier locations and classifications.

g. Within the fire area, the high hazard areas are isolated as follows:

(1) Turbine oil storage room - Fire Zone TG-2

(a) Most walls are 8 in. nominal masonry. The east wall and ceiling are reinforced concrete. All are 3-hr rated. (Reference F.7.3.a)

(b) Fire door and dampers maintain the rating of the barrier.

(c) Penetration seals in concrete barriers are 3-hr rated. Penetration seals in masonry walls are 2-hr rated.

(d) Doorway has an 8 in. high dike to help contain an oil spill.

(e) See Figures F.6 for fire barrier locations and classifications.

(2) Hydrogen seal oil room - Fire Zone TG-7

(a) Most walls are 8 in. nominal masonry. The south wall, ceiling and lower portion of east wall are reinforced concrete. All are 3-hr rated. (Reference F.7.3.a)

(b) Fire door and dampers maintain the rating of the barrier.

(c) Penetration seals in concrete barriers are 3-hr rated. Penetration seals in masonry walls are 2-hr rated.

(d) Doorway has an 8 in. high dike to help contain an oil spill.

(e) See Figures F.6 for fire barrier locations and classifications.

(3) Turbine oil reservoir room - Fire Zone TG-9

(a) Most walls are 8 in. nominal masonry. The west wall, ceiling, and floor are reinforced concrete. All are 3-hr rated with the

exception of an open ceiling hatch. The open hatch is protected by a water spray system.

(b) Fire door and dampers maintain the rating of the barrier.

(c) Penetration seals in concrete barriers are 3-hr rated. Penetration seals in masonry walls are 2-hr rated.

(d) Doorway has an 8 in. high dike to help contain an oil spill.

(e) See Figures F.6 for fire barrier locations and classifications.

(4) Auxiliary boiler room - Fire Zone TG-5

(a) Most walls are 8 in. nominal masonry. The north and east wall and ceiling are reinforced concrete. All are 3-hr rated. (Reference F.7.3.a)

(b) Fire door and dampers maintain the rating of the barrier.

(c) Penetration seals in concrete barriers are 3-hr rated. Penetration seals in masonry walls are 2-hr rated.

(d) See Figures F.6 for fire barrier locations and classifications.

(5) West transformer vault (Division A makeup water transformer 75-72) - Fire Zone TG-10

(a) Most walls are 8 in. nominal masonry. The north and ceiling are reinforced concrete. All are 3-hr rated. (Reference F.7.3.a)

(b) Fire door and dampers maintain the rating of the barrier.

(c) Penetration seals in concrete barriers are 3-hr rated. Penetration seals in masonry walls are 2-hr rated.

(d) A 12 in. high dike surrounds the transformer to help contain an oil spill.

(e) See Figures F.6 for fire barrier locations and classifications.

(6) East transformer vault (Division B makeup water transformer 85-82) - Fire Zone TG-11

(a) Most walls are 8 in. nominal masonry. The north wall and ceiling are reinforced concrete. All are 3-hr rated. (Reference F.7.3.a)

(b) Fire door and dampers maintain the rating of the barrier.

(c) Penetration seals in concrete barriers are 3-hr rated. Penetration seals in masonry walls are 2-hr rated.

(d) A 12 in. high dike surrounds the transformer to help contain an oil spill.

(e) See Figures F.6 for fire barrier locations and classifications.

(7) 441 ft south corridors - Fire Zone TG-12 (includes rooms C121, D113, and D104)

(a) Fire zone is not a high hazard area, but has a large concentration of cable trays. Zone TG-12 extends a significant distance into the radwaste and diesel building structures. The north end of the fire zone at column H.3 has no rated fire barrier.

(b) This is the only fire zone of Fire Area TG-1 which contains a substantial amount of safety-related circuits. Division 2 post-fire safe shutdown circuits are protected by 1-hr rated raceway fire barriers.

(c) Fire area boundaries are constructed of reinforced concrete and are 3-hr rated.

(d) Fire doors, fire dampers, and penetration seals maintain the rating of the barrier. Airtight doors are not listed as fire rated, but have equivalent construction. Entrance doors to Fire Areas DG-1/2/3 may not fully self-shut due to differential air pressure.

(e) See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. The fire area combustible loading is classified as "low." Since the fire area covers approximately 164,250 ft^2 actual combustible loading varies. The combustible loading of the higher hazard fire zones would be classified as "medium or high."

   c. Major combustibles include lubrication oil, electrical cable, transformer oil, and Thermo-Lag 330-1. An approved flammable gas storage area is located in the sprinklered 441 ft NE truck bay.

   d. Major ignition hazards include: ignition of turbine lube oil through various methods, turbine generator hydrogen, reactor feedwater pump/turbines, transformers, electrical pump motors, auxiliary boiler, switchgear, motor control centers, generator bus ducts, and exciter cubicles.

   e. Equipment/piping within the area contain low level radioactive water and gas. There are typically no airborne radioactivity hazards within the area. The turbine bay, condenser bay, and heater bay are high radiation zones during plant operation.

5. Fire suppression/detection equipment within the fire area

See Figures F.6-7 through F.6-9 for suppression system coverage.

   a. Wet pipe sprinkler systems are installed for the protection of the following areas:

      (1) Auxiliary boiler room
      (2) Mechanical vacuum pump room
      (3) Steam jet air ejector rooms
      (4) North side of condenser, el. 441 ft and el. 471 ft
      (5) South side of condenser, el. 441 ft and el. 471 ft
      (6) Turbine bearings el. 501 ft
      (7) West end of building, el. 441 ft
      (8) West End of building and under generator, el. 471 ft
      (9) Heater bay area, el. 471 ft
      (10) Office building and restroom, el. 501 ft
      (11) Oil piping at north end of condenser, el. 471 ft

b. Deluge water spray systems are installed for the protection of the following areas:

   (1) Turbine lube oil storage tank room

   (2) Trace oil piping located in the corridor, east end of building, el. 441 ft

   (3) Reactor feedwater pump rooms

   (4) Hydrogen seal oil room

   (5) Turbine oil reservoir and oil coolers room, el. 471 ft

c. A preaction sprinkler system is installed to protect the portion of Fire Zone TG-12 where fire rated raceway barriers are located.

d. A 6 ton capacity carbon dioxide (CO_2) system is installed to protect the generator exciter housing. A manual CO_2 hose reel is located on the 501 ft elevation. Manual release stations are located at both 441 ft and 501 ft. See Section F.2.4.5 for more details.

e. 1.5 in. standpipe hose stations

f. Portable fire extinguishers (normal and wheeled)

g. Smoke, thermal, and UV flame detectors are located in certain high hazard locations within the fire area.

h. Manual pull boxes

i. Foam carts and inductors for use with fire hose

j. Dry chemical system for hazardous material storage module(s).

6. <u>Fire suppression/detection equipment outside but available to the fire area</u>

   a. 1.5 in. standpipe hose stations in stairways

   b. Hose lines from 2.5 in. outlets on yard hydrants

7. Safe shutdown systems

   a. Fire Zone TG-12 contains both Division 1 and Division 2 post-fire safe shutdown cables. Division 2 post-fire safe shutdown cables are protected by 1-hr rated raceway barriers, and partial area fire suppression, and detection. Other areas of Fire Area TG-1 contain no post-fire safe shutdown equipment/cables.

   b. See Tables F.4-1 through F.4-3 for specific credited cables.

8. Potential consequences of a design basis fire

   a. Equipment and cabling for the Division 1 post-fire safe shutdown systems which is located within the area is assumed damaged by the design basis fire. Loss of all unprotected equipment in this fire area is not considered a credible event due to the low fire loading and geometrical configuration. Cabling for Division 2 post-fire safe shutdown components in the 441 ft radwaste/reactor building corridor (Fire Zone TG-12) are protected by 1-hr rated raceway fire barriers. Fire detection and a preaction sprinkler system are installed in the vicinity of the protected cabling. The adequacy of the partial area suppression and detection are further justified in Reference F.7.3.s. Division 2 post-fire safe shutdown systems would remain operable.

   b. The raceway barrier load bearing supports may not be wrapped the entire distance to the concrete barrier. In addition, raceway and other structural members routed over the top of raceway barriers are not protected. This is acceptable since the portion of the fire zone with raceway barriers is equipped with a high density preaction suppression system which ensures steel members would not heat to the point of structural failure.

   c. A fire in this fire area could potentially cause a loss of offsite power. Since the post-fire safe shutdown analysis assumes a loss of offsite power, onsite power will ensure safe shutdown.

   d. The developing fire would activate a smoke, thermal or flame detector, initiating an alarm in the control room for fire brigade response. Manual hose stations are available.

   e. The main turbine is equipped with a wet-pipe sprinkler system at the 501 ft exposed bearings and east governor area, 471 ft turbine underskirt, condenser area, heater bay, and 441 ft condenser area. Thermal detectors and ceiling mounted UV detectors would annunciate in the continuously manned main control room. This level of protection is adequate for any expected turbine fire.

f. With no heat actuated roof vents in the turbine building roof, a worst case turbine generator fire (turbine blade failure rupturing a fire system main or branch line) could cause partial collapse of the roof structural steel. Proper turbine maintenance and inspections limit the potential for such a worst case event.

g. The only post-fire safe shutdown equipment in Fire Area TG-1 is in Fire Zone TG-12. Based on the large separation, plant configuration and installed suppression systems, a worst case turbine generator fire would not propagate to areas of Fire Zone TG-12. Thus, a secondary hydrogen fire (concurrent with a primary fire in either Fire Areas RC-3/4/5/10 and a loss of offsite power) would not prevent safe shutdown.

h. Fire Zones TG-2 and TG-9 have a much higher combustible loading than the surrounding 3-hr barriers. However, these rooms are equipped with a high density deluge system which would limit fire severity.

i. The barrier between the redundant feedwater pumps is not fire rated. However, the barrier has minimal openings and each pump has a high density deluge system. This level of protection is considered adequate.

j. Fire Zones TG-10 and TG-11 contain high voltage transformers without a suppression system. However, the zones have fire detection and 3-hr rated barriers. This, level of protection is adequate.

k. Containment barrier interface to Fire Area TG-1, in main steam tunnel, is adequate to limit the spread of fire.

l. The north yard transformers are less than 50 ft from the turbine building and are not equipped with fire rated shield walls. However, the transformers are equipped with deluge fire suppression and the north wall is 2-hr rated to 471 ft. This level of protection is adequate.

m. The generator isophase bus ducts penetrate the north turbine building wall above the level that is fire rated and the bus ducts are not internally sealed as approved in Reference F.7.4.1. With the low voltage bushings approximately 30 ft below the point where the isophase bus ducts enter the turbine building, a transformer malfunction would not result in oil entering the turbine building through the bus ducts.

n. There are five oil-filled, indoor, high voltage transformers (four at 471 ft west end and one at 501 ft east end of the turbine building). These transformers are

not equipped with fire suppression systems. Each transformer has a surrounding 12 in. dike to contain an oil leak and is covered by general area fire detection. This level of protection is considered adequate protection for the nonsafety-related transformers.

o. Hazardous material storage module(s) have a high concentration of flammable paint and chemicals. The module steel enclosure and dry chemical system(s) are adequate to contain a HazMat module fire.

p. Unqualified and 1.5-hr doors are adequate to limit the spread of fire. Strobe lights and security position sensors on DG-1/2/3 entrance doors ensure that personnel will promptly shut the doors, even during periods of high differential HVAC air pressure.

q. The masonry barriers of Fire Zones TG-2, TG-5, TG-7, TG-9, TG-10, and TG-12 are hollow cell 7-5/8 in. thickness. Although this meets a 3-hr rating, (Reference F.7.3.a) the penetration seals are 2-hr rated. Based on various other design limitations, upgrade of all penetrations to a 3-hr fire rating is not possible. In Fire Zones TG-2 and TG-9, the equivalent fire durations exceed 2 hr. However, these rooms are equipped with a high density deluge sprinkler systems which would effectively limit fire severity. These barriers enclose fire zones, not fire areas and are classified as nonessential fire rated. The 2-hr rated penetration seals in masonry walls are adequate to limit the spread of fire.

r. The masonry barriers and penetration seals which interface with Fire Areas TG-3, TG-6, TG-8 are credited as 2-hr rated. The 2-hr rating is adequate for safe egress during a TG-1 fire.

s. The south turbine building ceiling interfaces with the reactor building elevated release chase. The chase is Fire Area TG-1 to 572 ft, but above is Fire Area R-1. Although the floor slab of chase is 3-hr rated, the north, east and west walls of the elevated release chase are not fire rated. The south wall of the elevated release chase is 3-hr rated to 572 ft, but has two unsealed penetrations above 611 ft into the reactor building. Even though the north, east and west walls of the elevated release chase are not fire rated, they do not have penetrations and would prevent a worst case turbine building fire from entering the upper levels of the reactor building through the unsealed penetrations, 80 ft above, or unrated barrier section above 572 ft.

t. The flammable gas cylinder storage area is located in the sprinklered 441 ft NE truck bay. Cylinders are securely fastened to the storage rack and are remote from any plant safety related equipment.

u. Smoke would be removed by operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

v. Water discharge would be removed by the floor drain system open, hatches, and stairs. Water discharge could cause localized flooding until removed by the floor drain system or portable pumping. Based on the enclosure of the condenser shield walls, suppression water during a turbine fire would be primarily contained within the condenser area. Floor drains are routed to the liquid waste processing system to contain and control potentially contaminated water produced by fire suppression activities.

w. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area TG-1 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA TG-3

1. Description

   Turbine generator building, east stair A1

2. Major equipment within the fire area

   None

   Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. The stairwell extends from the 441 ft level to the 518 ft 6 in. level of the turbine generator building. The barriers of the area are concrete or masonry block. The portions of the boundary which interface with the service building, Fire Zone TG-2 and Fire Area TG-4 are 3-hr rated. Other portions which interface with Fire Area TG-1 are 2-hr rated.

   b. The doors to the stairwell are 1.5-hr rated, minimum.

   c. Penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. 1.5 in. standpipe hose stations

   b. Ionization detector at top of stairwell

   c. Wet-pipe sprinkler system

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes for alarm

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, a stairwell fire will not prevent safe shutdown.

   b. The available portable equipment and sprinkler system are adequate to extinguish the design basis fire.

   c. The masonry barriers and their penetration seals which interface with Fire Area TG-1 are 2-hr rated. The 2-hr rating is adequate to ensure a stairwell fire will not spread to adjacent fire areas.

   d. The 1.5-hr fire doors are adequate to ensure safe egress and limit the spread of fire.

   e. Smoke would be removed through the operation of portable smoke removal equipment.

   f. Without a floor drain, water discharge would cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

   A design basis fire within Fire Area TG-3 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA TG-4

1. Description

Turbine generator building east, elevator no. 3

2. Major equipment within the fire area

Elevator electric motor

Fire area is not a safety-related area.

3. Construction of fire area boundaries

    a. The elevator shaft extends from the 441 ft level to the 518 ft 6 in. level of the turbine building. The walls and ceiling of the area are concrete and 3-hr rated.

    b. The elevator doors are 1.5-hr rated. Equipment room entrance door is 1.5-hr rated, minimum.

    c. Fire dampers and penetration seals maintain the rating of the barrier.

    d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

    a. The combustible loading is controlled in calculation FP-02-85-03.

    b. Combustible loading is classified as "low."

    c. Major combustible is assumed transient combustibles.

    d. The major ignition hazard is the elevator electric motor.

    e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

    a. Photoelectric detector in elevator equipment room.

    b. Portable extinguisher in elevator equipment room.

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes for alarm

   c. 1.5 in. standpipe hose stations

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, an elevator shaft fire will not prevent safe shutdown.

   b. The available portable equipment is adequate to extinguish the design basis fire.

   c. 1.5-hr fire doors are adequate to limit the spread of fire.

   d. Smoke would be removed through the operation of the building exhaust system or portable smoke removal equipment. The HVAC exhaust air is monitored to detect radioactive smoke which may result from the combustion of radioactive material.

   e. Water discharge could cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

   A design basis fire within Fire Area TG-4 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA TG-6

1. Description

   Turbine generator building, NE stair A3

2. Major equipment within the fire area

   None

   Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. The stairwell extends from the 441 ft level to the 501 ft level of the turbine generator building. The walls are primarily masonry block and ceiling is concrete. All wall and ceiling barriers are 2-hr rated.

   b. The doors to the stairwell are 1.5-hr rated, minimum.

   c. Penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

   d. There are no major ignition hazards in the area.

   e. There are typically no radioactive material or airborne radioactivity hazards within the area. Stairwell is adjacent the turbine condenser area and is considered a high radiation zone during plant operation.

5. Fire suppression/detection equipment within the fire area

   a. 1.5 in. standpipe hose stations

   b. Ionization detector at top of stairwell

   c. Wet-pipe sprinkler system

6. Fire suppression/detection equipment outside but available to the fire area

   a. Portable extinguishers

   b. Manual pull boxes for alarm

   c. Hose lines from 2.5 in. outlets on yard hydrants

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, a stairwell fire will not prevent safe shutdown.

   b. The available portable equipment and sprinkler system are adequate to extinguish the design basis fire.

   c. The masonry barriers and their penetration seals which interface with Fire Area TG-1 are 2-hr rated. The 2-hr rating is adequate to ensure a stairwell fire will not spread to TG-1.

   d. The 1.5-hr fire doors are adequate to ensure safe egress and limit the spread of fire.

   e. Smoke would be removed through the operation of portable smoke removal equipment.

   f. Without a floor drain, water discharge would cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

   g. Procedural controls and fire brigade training guide fire brigade members to monitor contamination during fire brigade activities and take specific actions to control the release of contaminated fire suppression water and smoke.

9. FHA conclusion

A design basis fire within Fire Area TG-6 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA TG-8

1. Description

   Turbine generator building, NW stair A4

2. Major equipment within the fire area

   None

   Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. The stairwell extends from the 441 ft level to the 501 ft level of the turbine generator building. The walls are primarily masonry block and ceiling is concrete. All wall and ceiling barriers are 2-hr rated.

   b. The doors to the stairwell are 1.5-hr rated, minimum.

   c. Penetration seals maintain the rating of the barrier.

   d. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is assumed transient combustibles. However, procedural controls deter storage of combustibles in stairwells.

   d. There are no major ignition hazards in the area.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. 1.5 in. standpipe hose stations

   b. Ionization detector at top of stairwell

c. Wet-pipe sprinkler system

6. Fire suppression/detection equipment outside but available to the fire area

a. Portable extinguishers

b. Manual pull boxes for alarm

c. Hose lines from 2.5 in. outlets on yard hydrants

7. Safe shutdown systems

This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

a. With no safe shutdown equipment/cables or associated circuits, a stairwell fire will not prevent safe shutdown.

b. The available portable equipment and sprinkler system are adequate to extinguish the design basis fire.

c. The masonry barriers and their penetration seals which interface with Fire Area TG-1 are 2-hr rated. The 2-hr rating is adequate to ensure a stairwell fire will not spread to TG-1.

d. The 1.5-hr fire doors are adequate to ensure safe egress and limit the spread of fire.

e. Smoke would be removed through the operation of portable smoke removal equipment.

f. Without a floor drain, water discharge would cause localized flooding. The flooding will not impair the ability of the plant to reach safe shutdown.

9. FHA conclusion

A design basis fire within Fire Area TG-8 will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

FIRE AREA ASD

1. Description

Reactor recirculation pump ASD building, floor el. 441 ft 0 in.

NOTE: Fire area is only the ASD building; however, fire hazards analysis includes areas immediately adjacent to the building.

2. Major equipment within the fire area

(Inside ASD building) electrical cabinets, capacitors, electrical cables, circulating pumps. (Outside ASD building) transformers, heat exchangers, link reactors.

Fire area is not a safety-related area.

3. Construction of fire area boundaries

   a. Walls on west and north side are 2-hr rated.

   b. Turbine building wall is 3-hr rated from 441 ft to 501 ft (Column D.3-H).

   c. Wall separating transformers and two walls north of transformers are 2-hr rated.

   d. Fire door and penetration seals maintain the rating of the barrier.

   e. See Figures F.6 for fire barrier locations and classifications.

4. Fire hazards

   a. The combustible loading for the ASD building (excluding exterior equipment) is controlled in calculation FP-02-85-03.

   b. Combustible loading is classified as "low."

   c. Major combustible is electrical cable.

   d. Major ignition hazard is electrical panels.

   e. There are no radioactive material or airborne radioactivity hazards.

5. Fire suppression/detection equipment within the fire area

   a. Full building automatic preaction system activated by ionization detectors or manual pull station.

   b. Transformers have deluge system activated by thermal detectors or manual pull stations.

   c. Portable extinguishers.

6. Fire suppression/detection equipment outside but available to the fire area

   a. Hose lines from 2.5 in. outlets on hydrants

   b. Exterior manual pull stations for activation and alarm of deluge systems

   c. Fire department connection to suppression systems

7. Safe shutdown systems

   This fire area contains no post-fire safe shutdown components or cabling.

8. Potential consequences of a design basis fire

   a. With no safe shutdown equipment/cables or associated circuits, an ASD fire will not prevent safe shutdown.

   b. The adjacent Turbine building 3-hr fire rated wall will prevent fire spread into other plant areas.

   c. The west and north walls are 2-hr rated, but have Hilti penetrations seals which are 2-hr "F" rated as opposed to "T" rated as required by Section F.2.2.1. This level of protection is adequate to prevent fire propagation between the ASD building and the yard.

   d. The preaction system is expected to limit the severity of a design basis fire within the building.

   e. The deluge systems are expected to limit the severity of a transformer fire.

   f. Smoke would be removed through the operation of the building ventilation system or portable smoke removal equipment.

g. Sprinkler discharge would be contained within the building in two large floor trenches.

h. The transformers are equipped with a sump to contain any oil leakage. Prolonged deluge system discharge would cause overflow of the sump. The grade slopes away from the transformers to a yard french drain.

9. FHA conclusion

A design basis fire within Fire Area ASD will be confined to the fire area and systems needed for post-fire safe shutdown will remain free of fire damage.

F.5 ESSENTIAL FIRE PROTECTION SYSTEM OPERABILITY/TESTING PROGRAM

This section contains the operability requirements, compensatory actions, and testing requirements for the essential fire protection systems. These requirements are only applicable to those portions of the fire protection systems which are designated as essential (systems needed to support post-fire safe shutdown and other important systems in safety-related areas). Changes to the essential fire protection system operability requirements, compensatory actions, and testing requirements are performed in accordance with the requirements of License Condition 2.c.14.

The essential fire protection systems are detailed in the paragraphs below.

F.5.1 OPERABILITY/TESTING PROGRAM BASIS

F.5.1.1 Fire Detection Instrumentation

The operability of the fire detection instrumentation ensures that both adequate warning capability is available for prompt detection of fires and that fire suppression systems which are actuated by fire detectors will discharge extinguishing agent in a timely manner. Prompt detection and suppression of fires will reduce the potential for damage to safety-related equipment and is an integral element in the overall facility fire protection program.

Fire detectors that are used to actuate fire suppression systems represent a critically important component of a plant's fire protection program. The loss of detection capability for fire suppression systems, actuated by fire detectors, represents a significant degradation of fire protection for any area.

Fire detectors which function to provide early warning are installed to help limit fire damage by ensuring prompt notification of a developing fire. Although not as critical as fire detectors which actuate fire suppression systems, the loss of early warning fire detection also represents a degradation of the fire protection within an area.

The establishment of frequent fire tours in the affected areas is required to provide detection capability until the inoperable instrumentation is restored to operability.

F.5.1.2 Fire Suppression Systems

The operability of the fire suppression systems ensures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety-related equipment is located. The essential fire suppression system consists of the water system, spray and/or sprinkler systems, Halon systems, and fire hose stations. The collective capability of the fire suppression systems is adequate to minimize potential damage to safety-related equipment and is a major element in the facility fire protection program.

In the event that portions of the fire suppression systems are inoperable, alternate backup fire fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service. In the event the fire suppression water system becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant.

The surveillance requirements provide assurances that the minimum operability requirements of the fire suppression systems are met.

F.5.1.3 Fire Rated Assemblies

Operable fire area boundaries minimize the possibility of a single fire involving more than one fire area prior to detection and extinguishment. Fire area boundaries (including wall/floor barriers, penetration seals, fire doors, and fire dampers) provide adequate fire resistance to ensure fire will not spread to adjacent fire areas containing redundant systems important to safe shutdown.

Operable raceway fire barriers (including electrical raceway fire-rated wraps and fireproofing on instrument tubing steel supports) provide fire resistance to ensure the operability of the protected safe shutdown division within a fire area.

Essential fire rated assemblies are periodically inspected to verify their operability. Compensatory measures are instituted during periods when they are not operable.

F.5.1.4 Operability

A fire protection system or component is considered operable when it is capable of performing its specified function(s). The fire protection system or component is considered to have this capability when

a. It satisfies the applicable operability requirements of this section,

b. It has been tested periodically in accordance with the requirements of this section, and

c. Its required auxiliaries are capable of performing their intended function.

F.5.1.5 Testing Intervals

The periodic tests listed in this section shall be performed within the specified intervals with a maximum allowable extension not to exceed 25% of the specified maintenance interval. Periodic tests need not be performed on inoperable equipment. Testing which would require

entry into high radiation areas is performed when radiation levels allow. However, there are some areas of the plant that remain high radiation areas at all times which will require an ALARA evaluation to determine the respective testing interval.

F.5.1.6 Fire Tours for High Radiation or Contaminated Areas

Up to 8 hr is allowed to establish compensatory measures for inoperable fire rated assemblies, sprinkler systems, and fire detection systems in high radiation or contaminated areas which require the installation of video or portable detection systems. Where radiation levels allow, perform a fire tour of the area within 2 hr of impairment to ensure no fire hazards or accumulations of transient combustibles are present.

F.5.2 ESSENTIAL FIRE SUPPRESSION WATER SYSTEM

F.5.2.1 Essential Fire Suppression Water System Operability Requirements

F.5.2.1.1 The fire suppression water system shall be operable at all times with

a. At least two of the three fire suppression pumps, each with a capacity of 2000 gpm pumping from the circulating water basin, and the 2500 gpm diesel-driven pump pumping from the secondary water supply tank, with their discharge aligned to the fire suppression header,

b. Two separate fire water supplies with a minimum contained volume of

   1. 300,000 gal in the circulating water pump house inlet basin, and
   2. 284,640 gal in the secondary water supply tank,

c. An operable flow path capable of taking suction from the circulating water pump house inlet basin and the secondary water supply tank and transferring the water to the fire main ring header and system branch lines. The operability of the flow path from the branch lines to the water suppression systems, hose stations, or hydrants is addressed in Sections F.5.3, F.5.5, and F.5.6 respectively.

d. The following operable components make up the two fire suppression water supply "systems" discussed in Section F.5.2.2.

   1. Primary - Circulating water basin AND two of the following fire pumps (FP-P-1, FP-P-2A, FP-P-2B) AND an operable flow path to the fire main ring header branch lines.

2. Secondary - Bladder tank FP-TK-110 AND fire pump FP-P-110 AND an operable flow path to the fire main ring header branch lines.

F.5.2.2 Essential Fire Suppression Water System Compensatory Measures

a. With one fire suppression water supply system inoperable, restore the water supply to operable status within 7 days or provide an alternate backup pump or supply.

b. With both fire suppression water supply systems inoperable, establish a backup fire suppression water system within 24 hr or within 1 hr initiate action to place the plant in

   1. Startup within the next 6 hr,
   2. Hot shutdown within the following 6 hr, and
   3. Cold shutdown within the subsequent 24 hr.

F.5.2.3 Essential Fire Suppression Water System Testing Requirements

F.5.2.3.1 The fire suppression water system shall be demonstrated operable:

a. At least once per 7 days by verifying the minimum contained water supply volume,

b. At least once per month on a staggered test basis by starting each electric motor-driven fire suppression pump and operating it for at least 15 minutes.

c. At least once per quarter by verifying that each valve (manual, power operated, or automatic) in the flow path is in its correct position,

d. At least once per year by performance of a fire suppression header flush,

e. At least once per year by cycling each testable valve in the flow path through at least one complete cycle of full travel,

f. At least once per 18 months by performing a system functional test which includes simulated automatic actuation of the system throughout its operating sequence,

   1. Verifying that each automatic valve in the flow path actuates to its correct position,

2. Verifying that each circulating water basin supplied fire suppression pump develops at least 2000 gpm at a system head of 250 ft and that secondary water supplied unit develops at least 2500 gpm at a system head of 325 ft,

3. Cycling each valve in the flow path that is not testable during plant operation through at least one complete of full travel, and

4. Verifying that each fire suppression pump starts (sequentially) to maintain the fire suppression water system pressure greater than or equal to 95 psig,

g. At least once per 5 years by performing a flow test of the system in accordance with Section 5/Chapter 8 of the Fire Protection Handbook, 18th Edition, published by the National Fire Protection Association.

F.5.2.3.2 Both diesel-driven fire suppression pumps shall be demonstrated operable at least once per month by

a. Verifying the fuel storage tanks contain at least 150 gal of fuel, and

b. Starting the diesel-driven pump from ambient conditions and operating it for greater than or equal to 30 minutes.

F.5.2.3.3 Each diesel-driven fire pump starting battery bank and charger shall be demonstrated operable:

a. At least once per month by verifying that

1. The electrolyte level of each cell is above the plates,

2. The cell specific gravity, corrected to 77°F and full electrolyte level, is greater than or equal to 1.200, and

3. The overall battery voltage is greater than or equal to 12 or 24 V as applicable.

b. At least once per quarter by verifying that the specific gravity is appropriate for continued service of the battery.

c. At least once per 18 months by verifying that

1. The batteries and battery racks show no visual indication of physical damage or abnormal deterioration, and

2. Battery-to-battery terminal connections are clean, tight, free of corrosion, and coated with anticorrosion material.

F.5.3 ESSENTIAL SPRAY AND SPRINKLER SYSTEMS

F.5.3.1 Essential Spray and Sprinkler System Operability Requirements

The following preaction, deluge spray, and sprinkler systems shall be operable whenever the equipment protected by the spray and/or sprinkler system is required to be operable:

a. Radwaste building:

   1. Cable spreading room, el. 484 ft, system #6,

   2. Cable chase and corridor, el. 441 ft to 525 ft, system #66,

   3. Control building emergency charcoal filters, el. 525 ft, system #WMA-DV-54A and #WMA-DV-54B, and

   4. Control room, el. 501 ft, automatic sprinklers in office areas only.

b. Diesel generator building:

   1. DG room 1A and day tank room, el. 441 ft, system #79,
   2. DG 1B day tank pump room, el. 441 ft, system #80,
   3. DG room 1B and day tank room, el. 441 ft, system #81,
   4. DG 1A day tank pump room, el. 441 ft, system #82,
   5. HPCS DG room and day tank room, el. 441 ft, system #83, and
   6. HPCS DG day tank pump room, el. 441 ft, system #84.

c. Reactor building:

   1. Standby gas treatment system charcoal filters, SGT-FL-1A, SGT-CF-1A-1, SGT-CF-1A-2, SGT-FL-1B, SGT-CF-1B-1, SGT-CF-1B-2, el. 572 ft, and

   2. Sump vent filter system charcoal filters, REA-FU-2A, REA-FU-2B, el. 572 ft.

F.5.3.2 Essential Spray and Sprinkler System Compensatory Measures

a. With one or more of the above required spray and/or sprinkler systems inoperable, within 1 hr

1. Establish a continuous fire tour with backup fire suppression equipment for those areas in which redundant system or components could be damaged (system #65 or system #66). In lieu of posting a continuous fire tour, the pre-action valve on the inoperable system may be manually tripped to fill the pre-action system piping and allow the system to provide wet pipe sprinkler system coverage until restored to operability,

2. For other areas, establish an hourly fire tour.

b. For inoperable sprinkler system in the main control room, compensatory measures are satisfied by the continuously manned control room staff.

F.5.3.3 Essential Spray and Sprinkler System Testing Requirements

Each of the above required spray and sprinkler systems shall be demonstrated operable:

a. At least once per quarter by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position.

b. At least once per year by cycling each testable valve in the flow path through at least one complete cycle of full travel.

c. At least once per 18 months:

1. By performing a system functional test which includes simulated automatic actuation of the system, and:

(a) Verifying that the automatic valves in the flow path actuate to their correct positions on a detector test signal, and

(b) Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel.

2. By a visual inspection of the dry pipe spray and sprinkler system headers to verify their integrity, and

3. By a visual inspection of each deluge nozzle's spray area to verify that the spray pattern is not obstructed.

d. At least once per 5 years by performing an air flow test through each open head spray and sprinkler header and verifying each open head spray and sprinkler nozzle is unobstructed.

F.5.4 ESSENTIAL HALON SYSTEMS

F.5.4.1 Essential Halon Systems Operability Requirements

The 18 Halon systems in the power generation control complex (PGCC) units in the control room shall be operable at all times with the storage tanks having at least 95% of full charge weight and 90% of full charge pressure.

F.5.4.2 Essential Halon System Compensatory Measures

Compensatory measures are satisfied by the continuously manned control room staff.

F.5.4.3 Essential Halon System Testing Requirements

Each of the above required Halon systems shall be demonstrated operable:

a. At least once per year by verifying Halon storage tank pressure,

b. At least once per 18 months by verifying the system initiates a Halon discharge signal, manually and automatically, on receipt of a simulated actuation signal,

c. At least once per 3 years by verifying Halon storage tank weight, and

d. At least once per 5 years by performance of a flow test through accessible headers and nozzles to ensure no blockage.

F.5.5 ESSENTIAL FIRE HOSE STATIONS

F.5.5.1 Essential Fire Hose Station Operability Requirements

The fire hose stations shown in Table F.5-1 shall be operable at all times.

F.5.5.2 Essential Fire Hose Station Compensatory Measures

With one or more of the fire hose stations shown in Table F.5-1 inoperable, within 1 hr, provide gated wye(s) on the nearest operable hose station(s). One outlet of the wye shall be connected to the standard length of hose provided for the hose station. The second outlet of the wye shall be connected to a length of hose sufficient to provide coverage for the area left

unprotected by the inoperable hose station. Where it can be demonstrated that the physical routing of the fire hose would result in a recognizable hazard to operating technicians, plant equipment, or the hose itself, the fire hose shall be stored in a roll at the outlet of the operable hose station. Signs shall be provided above the gated wye(s) to identify the proper hose to use.

F.5.5.3 Essential Fire Hose Station Testing Requirements

Each of the fire hose stations shown in Table F.5-1 shall be demonstrated operable:

a. At least once per quarter by an inspection of the fire hose cabinets accessible during plant operation to ensure all required equipment is at the station.

b. At least once per 18 months by

   1. Visual inspection of the fire hose stations to ensure all required equipment is at the station,

   2. Removing the hose for inspection and reracking, and

   3. Inspecting all gaskets and replacing any degraded gaskets in the couplings.

c. At least once per 3 year by:

   1. Partially opening each hose station valve to verify valve operability and no flow blockage, and

   2. Replacing existing hose with a hose that has satisfactorily passed a hose hydrostatic test at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater.

TABLE F.5-1

ESSENTIAL FIRE HOSE STATIONS

	Location	Floor Elevation (ft)	Hose Rack Identification
1.	Reactor building, standpipe RB-1	422	FB-HS-RB-11
2.	Reactor building, standpipe RB-1	441	FP-HS-RB-12
3.	Reactor building, standpipe RB-1	471	FP-HS-RB-13
4.	Reactor building, standpipe RB-1	501	FP-HS RB-14
5.	Reactor building, standpipe RB-1	522	FP-HS-RB-15
6.	Reactor building, standpipe RB-1	548	FP-HS-RB-16
7.	Reactor building, standpipe RB-1	572	FP-HS-RB-17
8.	Reactor building, standpipe RB-1	606	FP-HS-RB-18
9.	Reactor building, standpipe RB-2	422	FP-HS-RB-21
10.	Reactor building, standpipe RB-2	441	FP-HS-RB-22
11.	Reactor building, standpipe RB-2	471	FP-HS-RB-23
12.	Reactor building, standpipe RB-2	501	FP-HS-RB-24
13.	Reactor building, standpipe RB-2	522	FP-HS-RB-25
14.	Reactor building, standpipe RB-2	548	FP-HS-RB-26
15.	Reactor building, standpipe RB-2	572	FP-HS-RB-27
16.	Reactor building, standpipe RB-2	606	FP-HS-RB-28
17.	Railroad car airlock	441	FP-HS-RB-29
18.	Radwaste building, standpipe RWB-1	467	FP-HS-RWB-13
19.	Radwaste building, standpipe RWB-1	487	FP-HS-RWB-14
20.	Radwaste building, standpipe RWB-1	507	FP-HS-RWB-15
21.	Radwaste building, standpipe RWB-1	525	FP-HS-RWB-16
22.	Turbine generator-DG building corridor	487	FP-HS-RWB-25
23.	Radwaste building, stair A-13	467	FP-HS-RWB-26
24.	Radwaste building, in corridor	487	FP-HS-RWB-28
25.	Radwaste building, in corridor	467	FP-HS-RWB-29
26.	Radwaste control room corridor	501	FP-HS-RWB-31
27.	Diesel generator building, in corridor	441	FP-HS-DG-41
28.	Diesel generator building	441	FP-HS-DG-40
29.	Radwaste building	525	FP-HS-RWB-33

F.5.6 ESSENTIAL YARD FIRE HYDRANTS AND HYDRANT HOSE HOUSES

F.5.6.1 Essential Yard Fire Hydrant/Hydrant Hose House Operability Requirements

The yard fire hydrants and associated hydrant hose houses shown in Table F.5-2 shall be operable at all times.

F.5.6.2 Essential Yard Fire Hydrant/Hydrant Hose House Compensatory Measures

With one or more of the yard fire hydrants or associated hydrant hose houses shown in Table F.5-2 inoperable, within 24 hr attach sufficient additional lengths of 2.5 in. diameter hose located in an adjacent operable hydrant hose house to provide service to the unprotected area(s).

F.5.6.3 Essential Yard Fire Hydrant/Hydrant Hose House Testing Requirements

Each of the yard fire hydrants and associated hydrant hose houses shown in Table F.5-2 shall be demonstrated operable:

a. At least once per 6 months, verify the hose house tamper seal is not broken.

b. At least once per 6 months by visually inspecting each yard fire hydrant and verifying that the hydrant barrel is drained and that the hydrant is not damaged.

c. At least once per year by

   1. Replacing existing hose with a hose that has satisfactorily passed a hose hydrostatic test at a pressure of 150 psig or at least 50 psig above maximum fire main operating pressure, whichever is greater,

   2. Replacement of all degraded gaskets in couplings,

   3. Performing a flow check of each hydrant, and

   4. Visual inspection to ensure all required equipment is at the hose house.

TABLE F.5-2

ESSENTIAL YARD FIRE HYDRANTS
AND ASSOCIATED HYDRANT HOSE HOUSES

Location	Identification
1. South side of diesel generator building	T-1A
2. Southeast corner of diesel generator building	HT-1B
3. West side of radwaste building	HT-1G
4. South side of radwaste building	HT-1H
5. Northwest of standby service water pump house 1A	HT-1M
6. North side of standby service water pump house 1B	HT-1N
7. West side of radwaste and turbine generator buildings	HT-1R

F.5.7 ESSENTIAL FIRE RATED ASSEMBLIES

F.5.7.1 Essential Fire Rated Assembly Operability Requirements

Essential Fire Rated Assemblies are divided into two categories: (1) fire area boundaries (including wall/floor barriers, penetration seals, fire doors and fire dampers), which separate fire areas with redundant systems important to safe shutdown and (2) raceway fire barriers (including electrical raceway fire-rated wraps, and steel fireproofing for electrical raceway fire-rated wraps and instrument tubing), which provide fire resistance to protect redundant systems important to safe shutdown within a fire area. Essential fire rated assemblies shall be operable at all times.

F.5.7.2 Essential Fire Rated Assembly Compensatory Measures

F.5.7.2.1 With one or more of the essential fire rated assemblies inoperable, establish the following compensatory measures:

a. Without operable fire detection or automatic fire suppression on either side of the barrier, establish a continuous fire tour, and

b. With operable fire detection or automatic fire suppression on at least one side of the barrier, establish an hourly fire tour.

F.5.7.2.2 With one or more of the essential fire area boundaries operable but nonconforming, establish the following compensatory measure(s):

a. Without operable fire detection or automatic fire suppression on either side of the barrier establish an hourly fire tour, and

b. With operable fire detection or automatic fire suppression on at least one side of the barrier establish a shiftly fire tour. Shiftly fire tours must be performed at least once per 12 hr.

F.5.7.2.3 Where at least one side of the barrier is accessible, compensatory measures shall be established within 1 hr of determining inoperability or operable but nonconforming status.

F.5.7.3 Essential Fire Rated Assembly Testing Requirements

F.5.7.3.1 Each of the above required fire rated assemblies and penetration sealing devices shall be verified operable at least once per 18 months by performing a visual inspection of

a. The exposed surface of each fire rated assembly,

b. Each fire window and associated hardware, and

c. At least 10% of each type of sealed penetration. If apparent changes in appearance or abnormal degradations are found, a visual inspection of an additional 10% of each type of sealed penetration shall be made. This inspection process shall continue until a 10% sample with no apparent changes in appearance or abnormal degradation is found. Samples shall be selected such that each penetration seal will be inspected at least once per 15 years.

F.5.7.3.2 For each of the above required personnel access fire doors:

a. Semiannually ensure (1) door latch is operable[1] and (2) closing mechanism is operable[2]

b. Weekly ensure: (1) door is closed and (2) door is free from physical damage which could impair its function.

F.5.7.3.3 For each of the above required equipment hatch fire doors:

a. Annually: (1) door latch is operable,[1] and (2) closing mechanism is operable[2,3] and (3) door is free from physical damage which could impair its function, and

b. Weekly, ensure door is closed.

F.5.7.3.4 Each of the above required fire dampers shall be verified operable at least once per 2 years by performing a visual inspection of the exposed surface and associated hardware of each damper.

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[1] Applicable to hollow-metal swinging and watertight fire doors only.

[2] Not applicable to watertight, high-range blast and shielding doors. Not applicable to normally closed rolling and sliding doors.

[3] Not applicable to doors R413 and R610.

F.5.8 ESSENTIAL FIRE DETECTION INSTRUMENTATION

F.5.8.1 Essential Fire Detection Instrumentation Operability Requirements

As a minimum, the fire detection instrumentation for each fire detection zone shown in Table F.5-3 shall be operable whenever the equipment protected by the fire detection instrumentation is required to be operable.

F.5.8.2 Essential Fire Detection Instrumentation Compensatory Measures

With one or more of the essential fire detection instruments shown in Table F.5-3 inoperable, within 1 hr establish an hourly fire tour in the area of the inoperable fire detector(s). For inoperable detection in the main control room, compensatory measures are satisfied by the continuously manned control room staff.

F.5.8.3 Essential Fire Detection Instrumentation Testing Requirements

F.5.8.3.1 Each of the fire detection instruments shown in Table F.5-3 which are accessible during normal plant operation shall be demonstrated operable by

a. Performance of a channel functional test of each smoke detector at least once per year,

b. Performance of a channel functional test of each thermal detector at least once per 2 years,

c. Performance of a channel functional test of each flame detector at least once per year, and

d. Verification of the sensitivity of each smoke detector in accordance with procedures developed in conjunction with the manufacturer's recommendations at least once per 2 years. Sensitivity testing may be extended to once per five years for those detectors that have successfully completed the previous two 2-year tests.

F.5.8.3.2 Each of the fire detection instruments shown in Table F.5-3 which are not accessible during normal plant operation shall be demonstrated operable by

a. Performance of a channel functional test of each smoke detector during each cold shutdown exceeding 24 hr unless performed in the previous year,

b. Performance of a channel functional test of each thermal detector during each cold shutdown exceeding 24 hr unless performed in the previous year,

c. Performance of a channel functional test of each flame detector during each cold shutdown exceeding 24 hr unless performed in the previous year, and

d. Verification of the sensitivity of each smoke detector in accordance with procedures developed in conjunction with the manufacturer's recommendations during each cold shutdown exceeding 24 hr unless performed in the previous two years. Sensitivity testing may be extended to once per 5 years for those detectors that have successfully completed the previous two 2-year tests.

TABLE F.5-3

ESSENTIAL FIRE DETECTION INSTRUMENTATION

Location

1. Reactor building el. 422 ft 3 in.

   CRD pump room
   Auxiliary condensate pump room

2. Reactor building el. 441 ft

   Railroad airlock

3. Reactor building el. 444 ft

   RHR 2A pump room R2
   RHR 2B pump room R1
   RHR 2C pump room R4
   RCIC pump room R3
   LPCS pump room R5
   HPCS pump room R6

4. Reactor building el. 471 ft

   MCC room
   General area

5. Reactor building el. 501 ft

   General area

6. Reactor building el. 522 ft

   MCC room Division 2
   General area
   RHR valve room

TABLE F.5-3

ESSENTIAL FIRE DETECTION INSTRUMENTATION (Continued)

Location

7. Reactor building el. 548 ft

Fuel pool heat exchanger room A and pump room
General area
RHR heat exchanger room

8. Reactor building el. 572 ft

Hydrogen recombiner control room Division 2
RHR heat exchanger room 1A
RHR heat exchanger room 1B
General floor area

9. Reactor building el. 606 ft 10.5 in.

General floor area

10. Radwaste and control building el. 467 ft

Electrical equipment room No. 1
Battery room No. 2
Switchgear room No. 1
Electrical equipment room No. 2
Battery room No. 2
Switchgear room No. 2
Remote shutdown room
Corridor C-205

11. Radwaste and control building el. 484 ft

Cable spreading room

TABLE F.5-3

ESSENTIAL FIRE DETECTION INSTRUMENTATION (Continued)

Location

12. Radwaste and control building el. 501 ft

Cable room ceiling
Control room PGCC
U679
U680
U681
U682
U683
U684
U685
U686
U687
U688
U689
U690
U800
U840
U891
U892
U893
U894

13. Radwaste and control building el. 525 ft

Cable chase
Unit A air conditioning room
Unit B air conditioning room

14. Standby service water pump house 1A

Pump house
Electrical vault

TABLE F.5-3

ESSENTIAL FIRE DETECTION INSTRUMENTATION (Continued)

Location

15. Standby service water pump house 1B

    Pump house
    Electrical vault

16. Turbine generator corridor el. 441 ft

    TG-1 corridor

17. Diesel generator building el. 441 ft

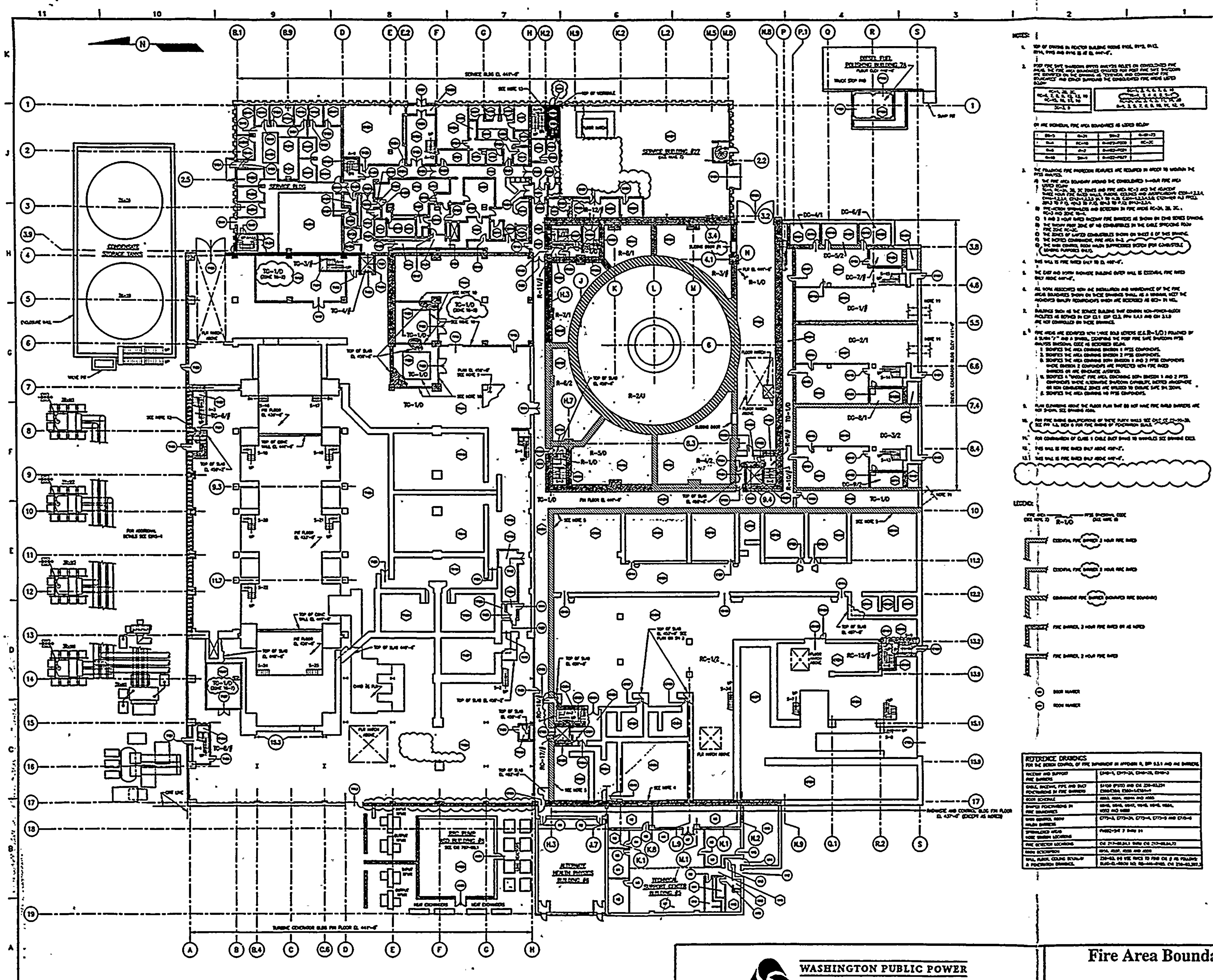
    1A diesel generator room
    1A diesel day tank room
    1A diesel oil tank room
    1B diesel generator room
    1B diesel day tank room
    1B diesel oil tank room
    HPCS diesel generator room
    HPCS diesel day tank room
    HPCS diesel oil tank pump room

18. Diesel generator building el. 455 ft

    1A diesel exhaust room

F.6 FIRE PROTECTION ARRANGEMENT DRAWINGS

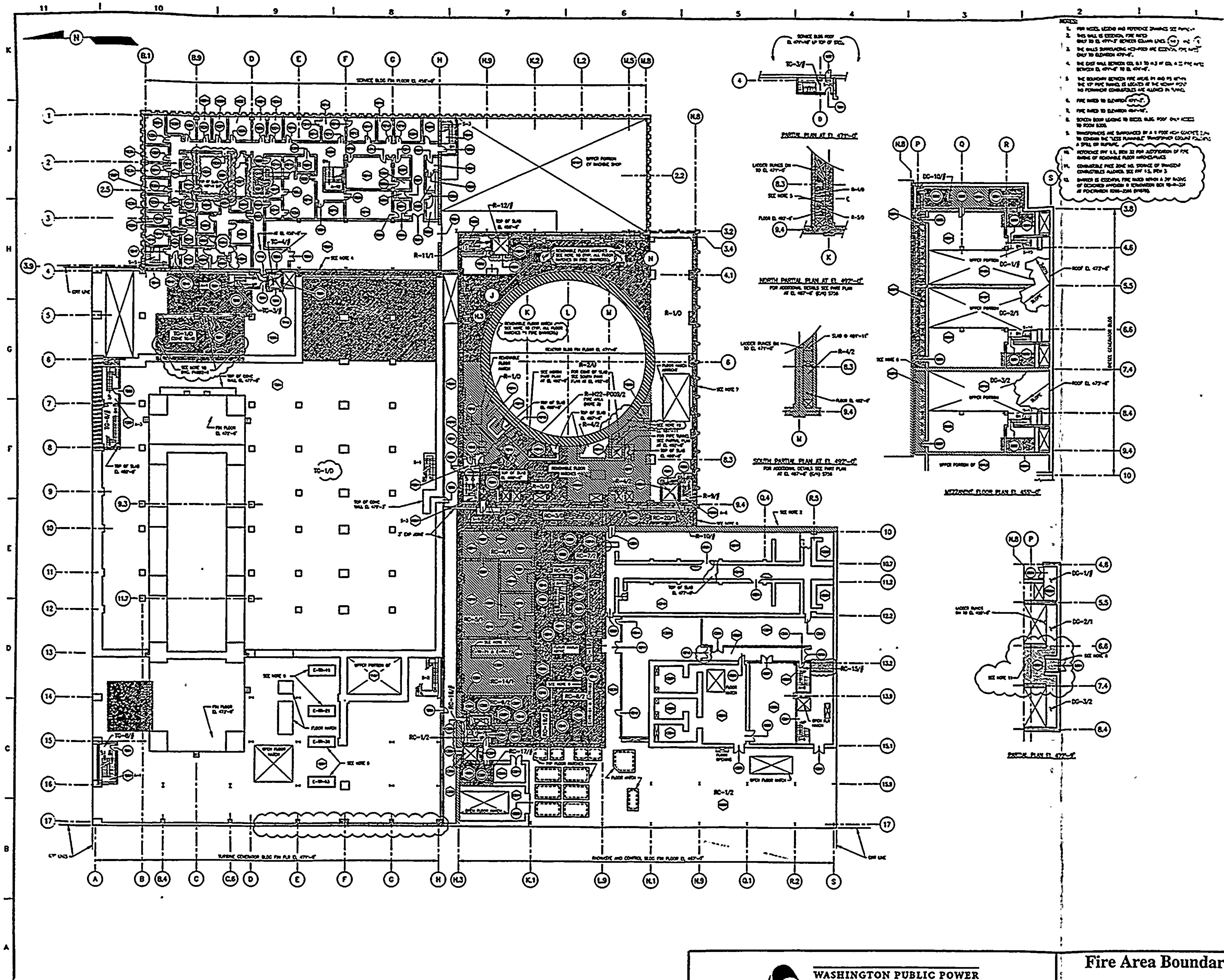
FM892-1	Fire Area Boundary Plan - Ground Floor
FM892-2	Fire Area Boundary Plan - Mezzanine Floors
FM892-3	Fire Area Boundary Plan - Operating Floor
FM892-4	Fire Area Boundary Plan - Reactor Building Miscellaneous Elevations
FM892-5	Fire Area Boundary Plan - Miscellaneous Floors and Buildings
FM892-6	Zones of Limited Combustibles, Reactor Building
FM892-7	Fire Suppression System Plan 437', 441'
FM892-8	Fire Suppression System Plan 467', 471'
FM892-9	Fire Suppression System Plan 501', 525'
FM892-10	Fire Suppression System Plan, Reactor Building, Miscellaneous Elevations
FM892-11	Fire Suppression System Plan, Miscellaneous, Floors and Buildings



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Area Boundary Plan - Ground Floor

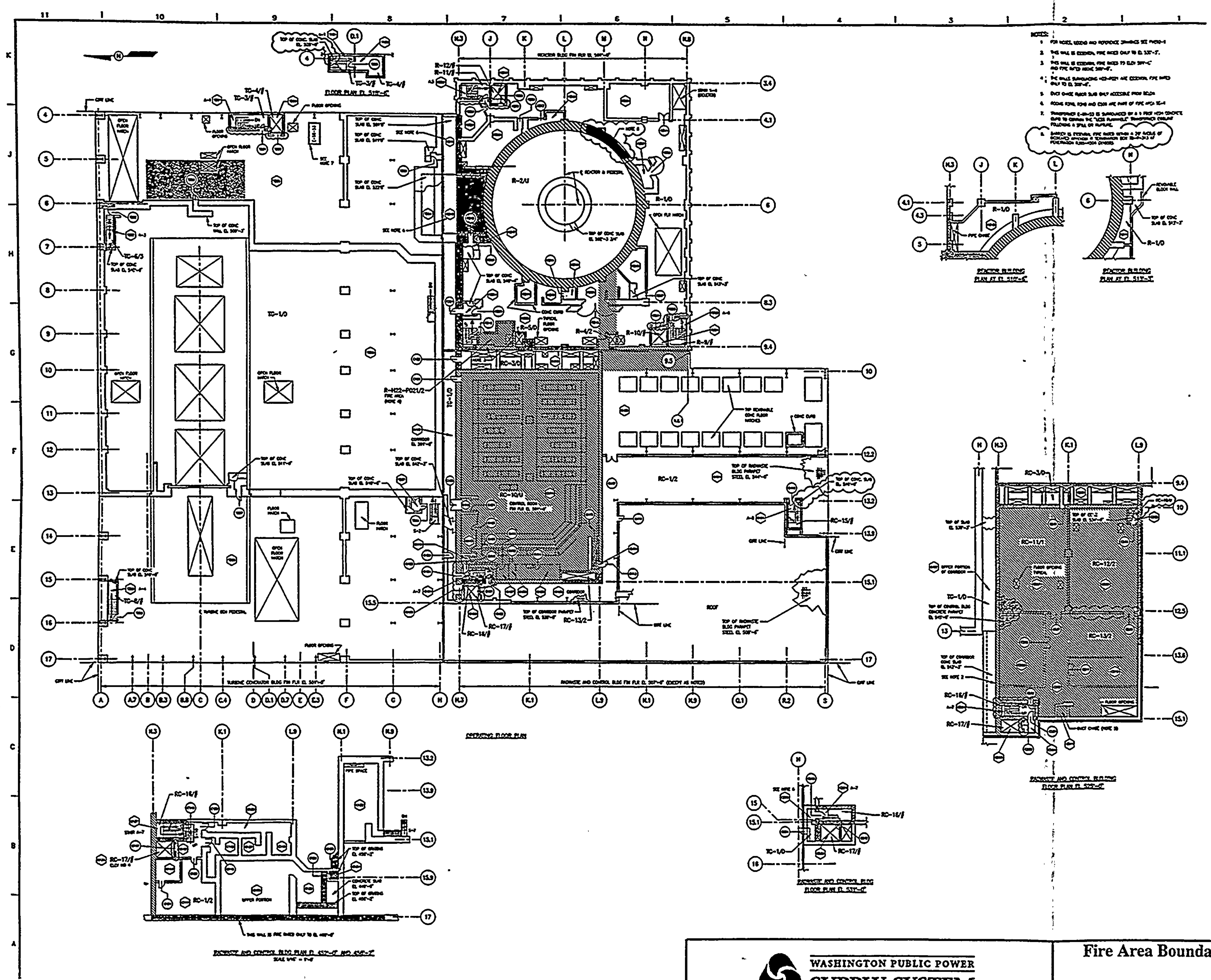
Draw. No. FM892-1 | Rev. 5 | Figure F.6-1



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Area Boundary Plan - Mezzanine Floors

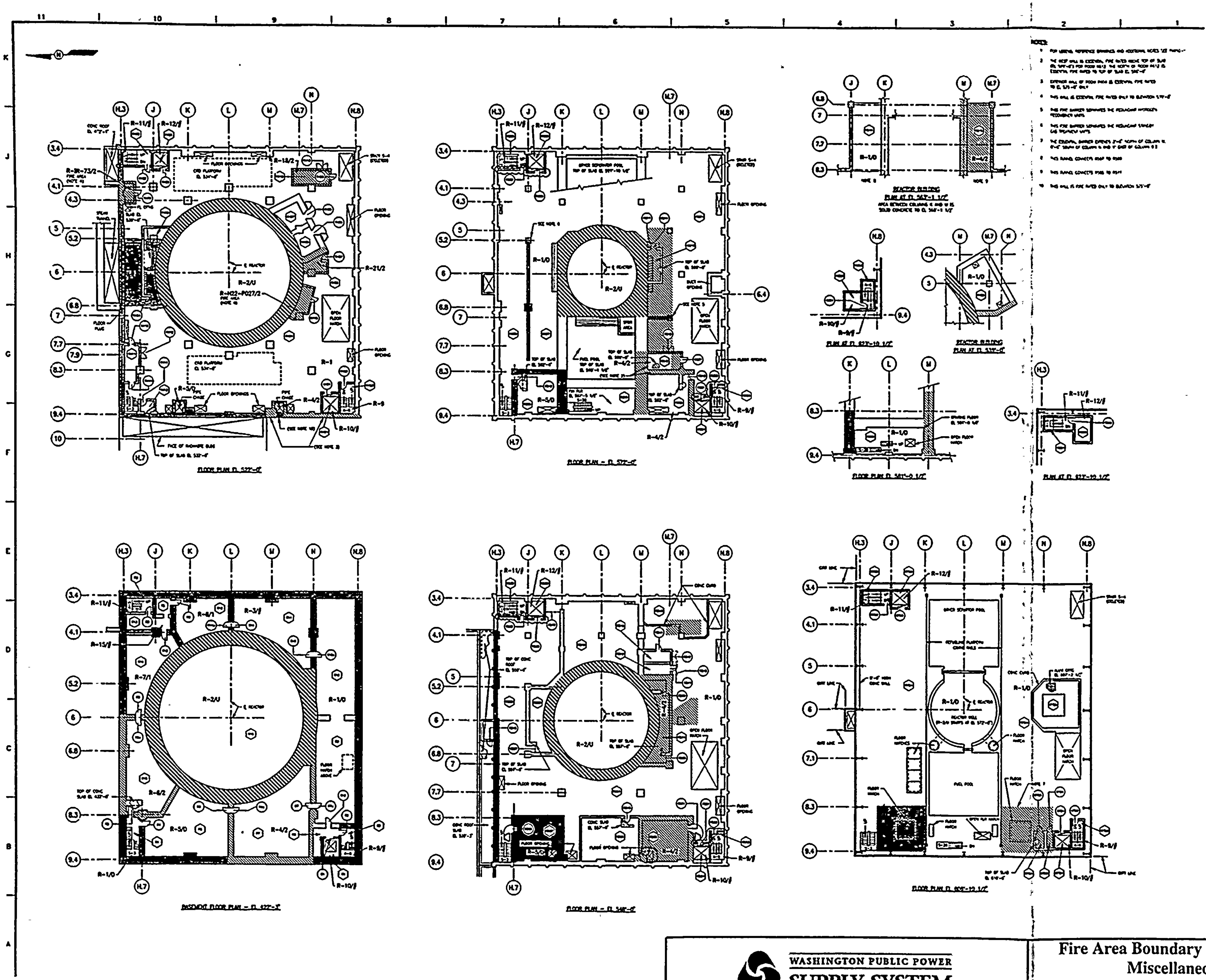
Draw. No.	FM892-2	Rev.	5	Figure	F.6-2



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Area Boundary Plan - Operating Floors

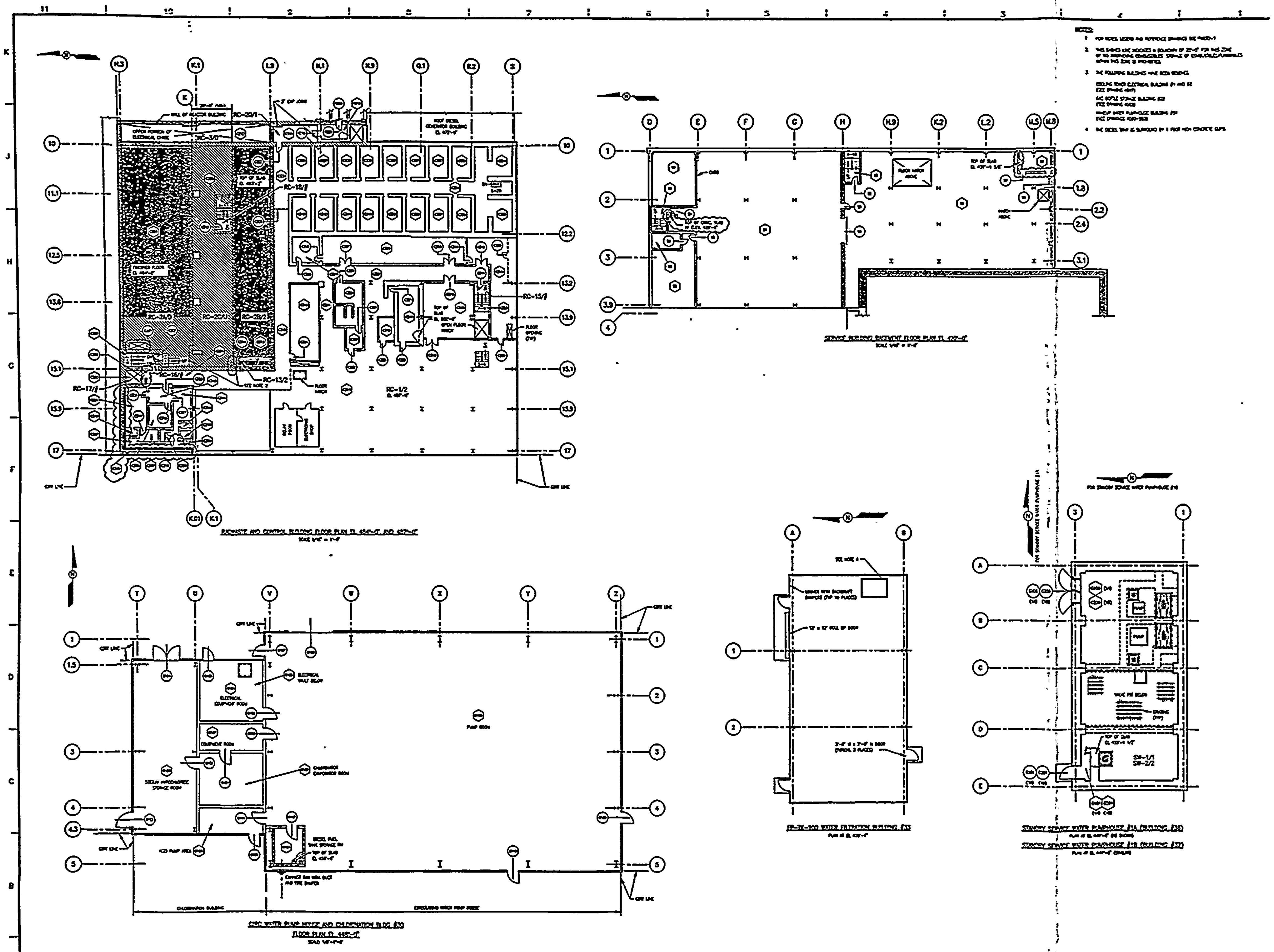
Draw. No.	FM892-3	Rev.	3	Figure	F.6-3



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Area Boundary Plan - Reactor Building
Miscellaneous Elevations

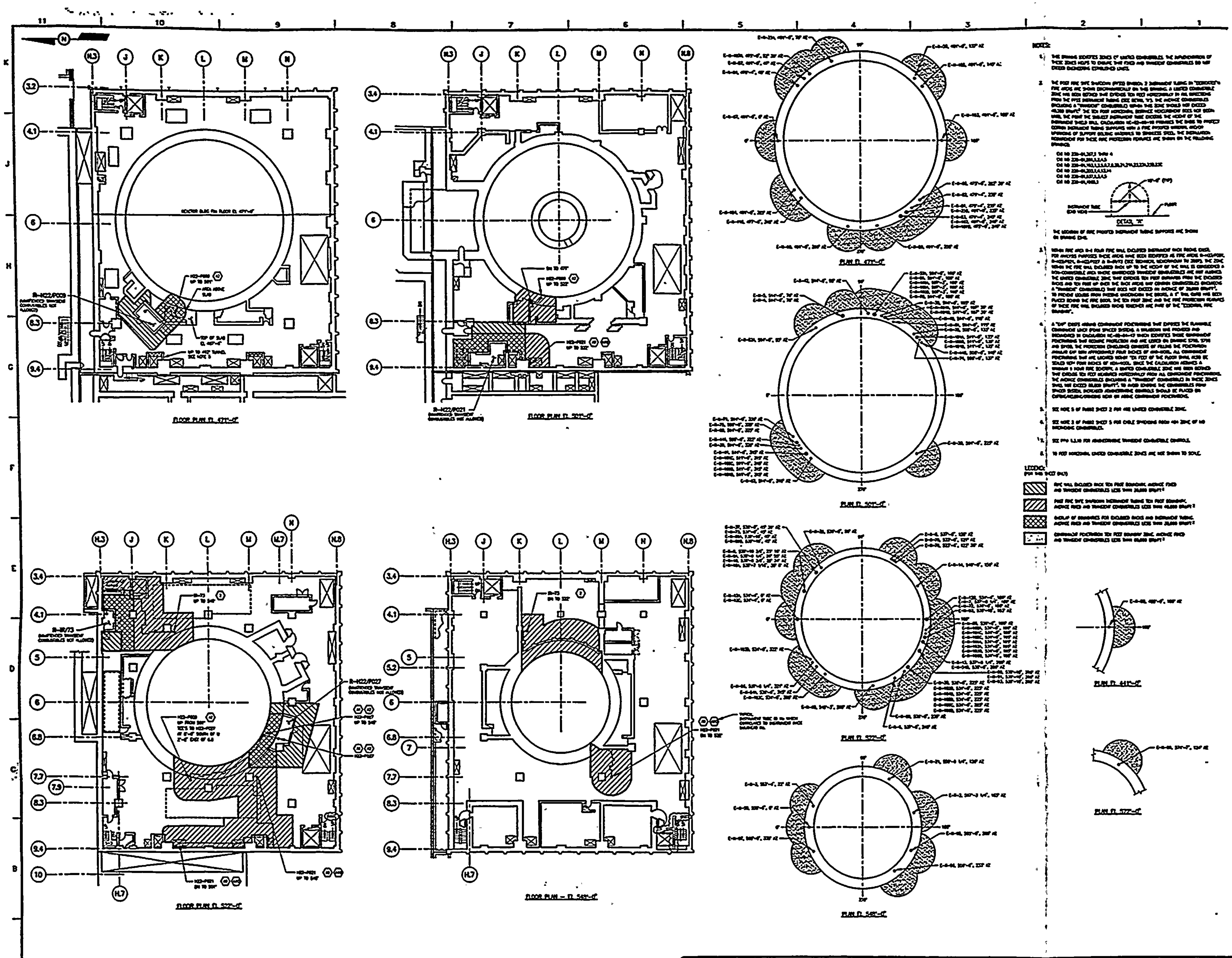
Draw. No. FM892-4	Rev. 2	Figure F.6-4



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Area Boundary Plan - Miscellaneous Floors and Buildings

Draw. No.	FM892-5	Rev.	3	Figure	F.6-5

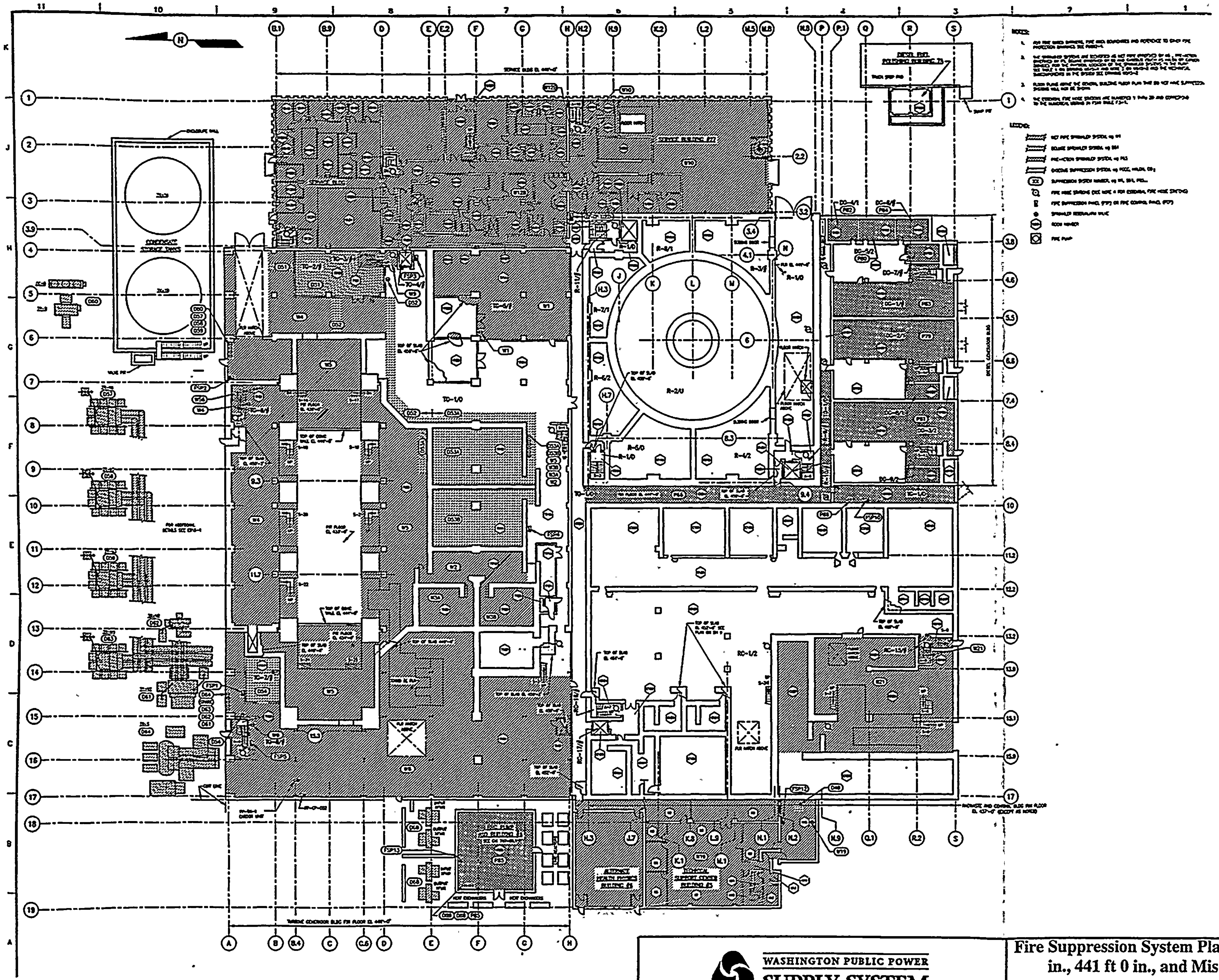


Zones of Limited Combustibles - Reactor Building

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Draw. No.	FM892-6	Rev.	3	Figure	F.6-6

Amendment 53
November 1998

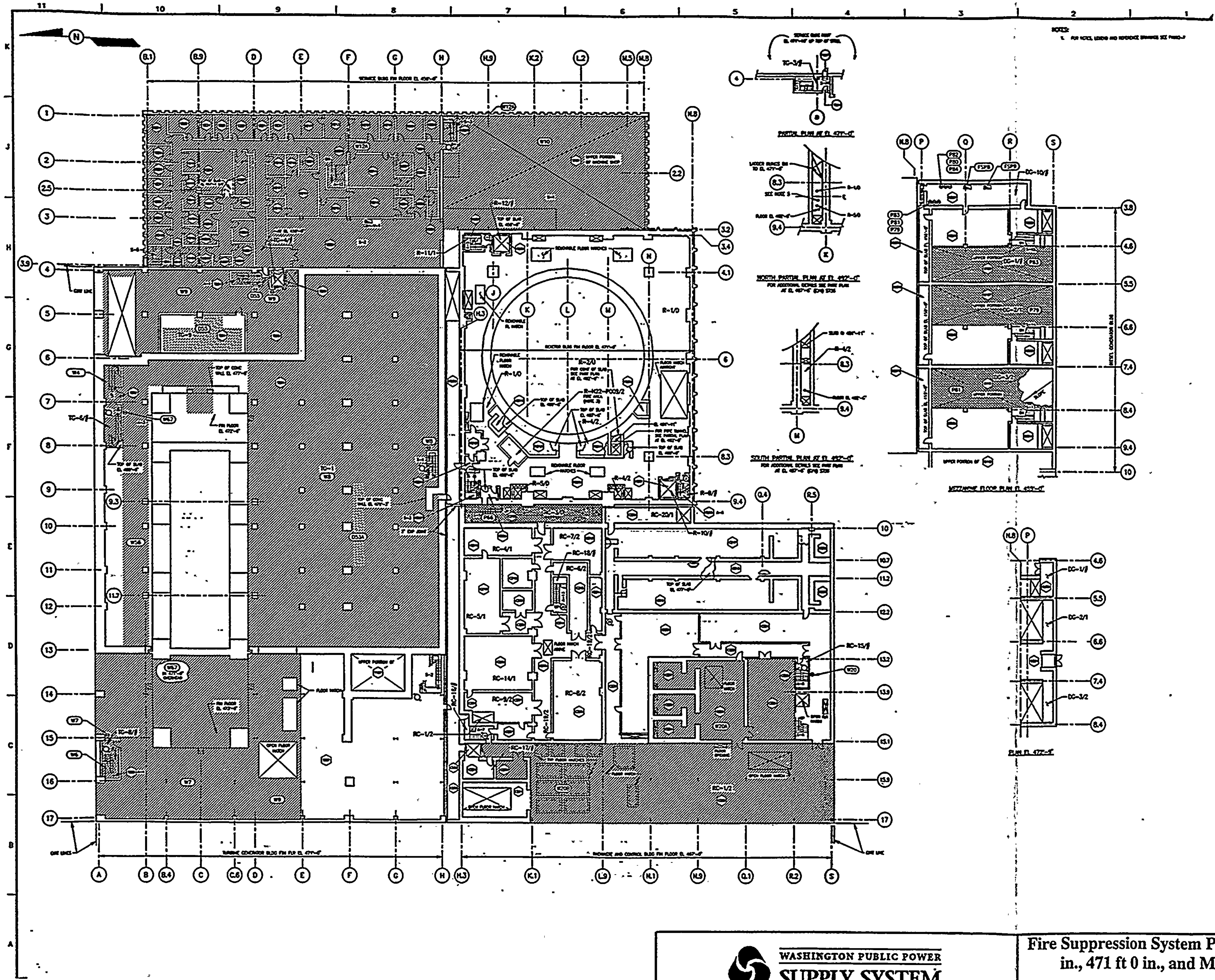


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Suppression System Plan - Elevations 437 ft 0 in., 441 ft 0 in., and Miscellaneous Floors

Draw. No. FM892-7	Rev. 1	Figure F.6-7

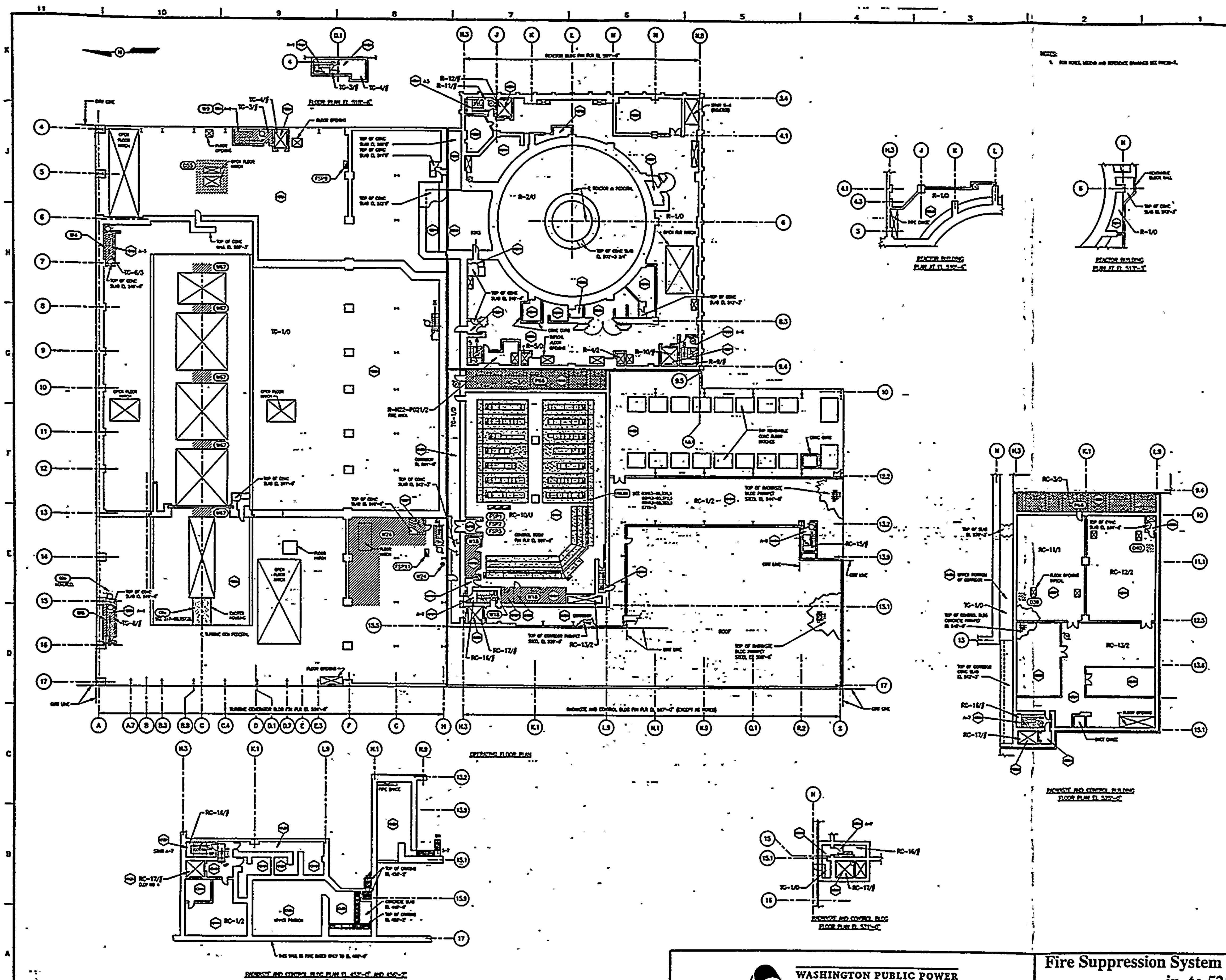
Form No. 960690



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Suppression System Plan - Elevations 467 ft 0 in., 471 ft 0 in., and Miscellaneous Floors

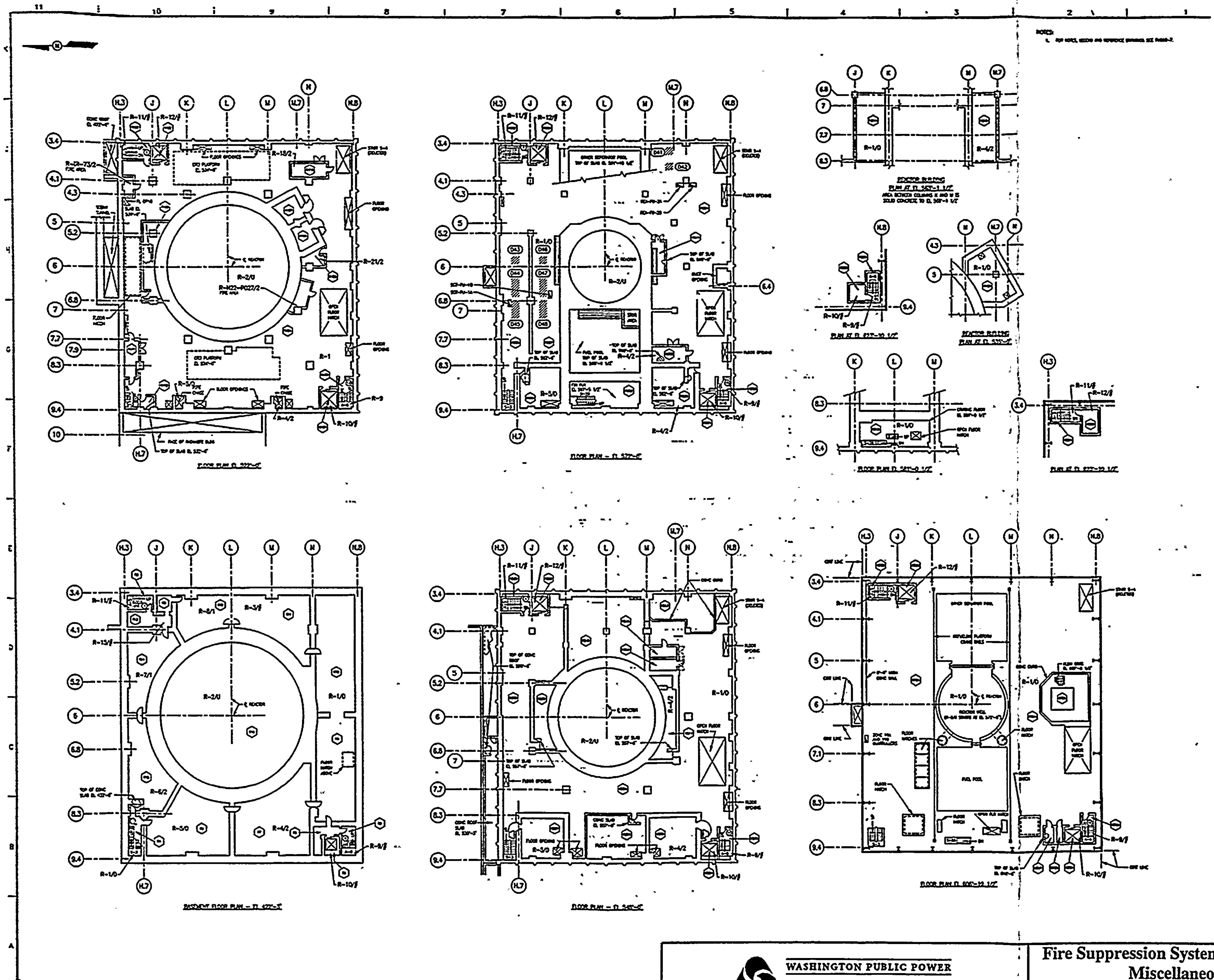
Draw. No. FM892-8	Rev. 0	Figure F.6-8



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Suppression System Plan - Elevations 501 ft 0 in. to 525 ft 0 in.

Draw. No. FM892-9 | Rev. 0 | Figure F.6-9

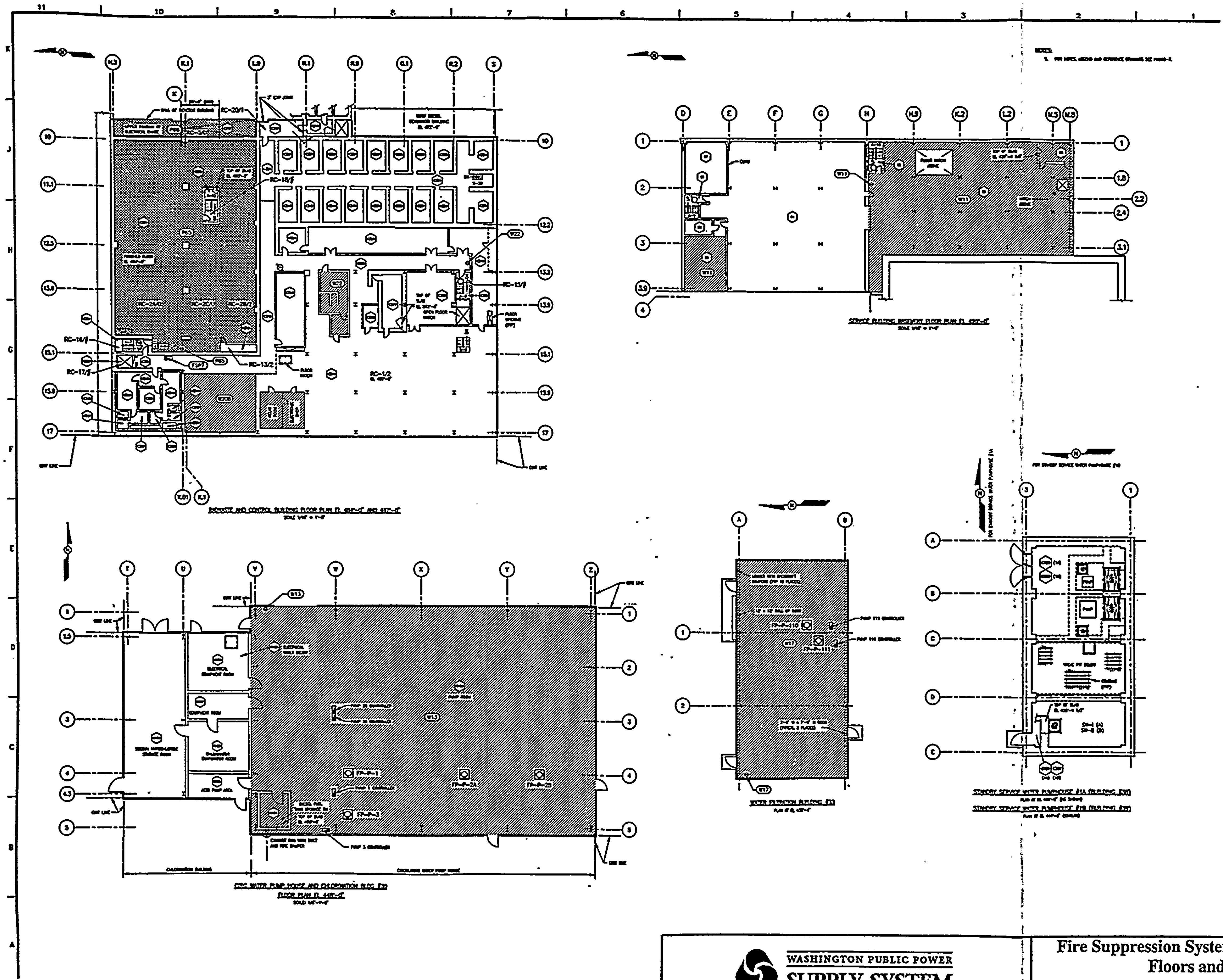


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Suppression System Plan - Reactor Building
Miscellaneous Elevations

Draw. No.	FM892-10	Rev.	0	Figure	F.6-10

Amendment 53
November 1998



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Fire Suppression System Plan - Miscellaneous Floors and Buildings

Draw. No. FM892-11 | Rev. 0 | Figure F.6-11

Form No. 960690

F.7 FIRE PROTECTION PROGRAM REFERENCES

F.7.1 REGULATORY DOCUMENTS/OTHER FSAR FIRE PROTECTION COMMITMENTS

a. 10 CFR 50.48, Fire Protection.

b. 10 CFR 50, Appendix A, General Design Criterion 3, Fire Protection. (See Section 3.1.2.1.3.)

c. 10 CFR 50 Appendix R, Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979. (See Table F.3-2.)

d. Section 8.3.1.4, Independence of Redundant Systems

e. Section 9.5.2, Communication Systems

f. Section 9.5.3, Plant Lighting Systems

g. Sections 13.1.2.3.4 and 13.2.2.5, Fire Brigade

F.7.2 INDUSTRY GUIDANCE

a. Branch Technical Position (BTP) Auxiliary Power Conversion Systems Branch (APCSB) 9.5-1, Appendix A, Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976 (See Table F.3-1.)

b. BTP Chemical Engineering Branch (CMEB) 9.5-1 Guidelines for Fire Protection for Nuclear Power Plants, Rev. 2, July 1, 1981

c. NUREG 0800 Standard Review Plan, Section 9.5.1, Fire Protection Program, Rev. 3, July 1981

d. BTP APCSB 3-1, Protection Against Postulated Piping Failures in Fluid Systems Outside Containment (attached to SRP 3.6.1)

e. NRC Inspection and Enforcement Manual, Inspection Procedure 64100, Post-Fire Safe Shutdown, Emergency Lighting and Oil Collection, Inspection Procedure 64704, Fire Protection/Prevention Program.

f. NRC Generic Letters (GL), applicable sections of: GL 77-02, GL dated 9/7/79, GL 81-04, GL 81-12, GL dated 4/7/82, GL 82-21, GL 83-33, GL 85-01, GL 86-10, GL 86-10 Supplement 1, GL 88-12, GL 88-20 Supplement 4, GL 92-08, GL 92-08 Supplement 1, GL 93-06

g. NRC Information Notices (IN), applicable sections of: IN 80-05, IN 80-11, IN 82-28, IN 83-41, IN 83-69, IN 84-09, IN 84-16, IN 84-34, IN 84-57, IN 84-92, IN 85-09, IN 85-85, IN 86-17, IN 86-35, IN 87-14, IN 87-50, IN 88-04, IN 88-04 Supplement 1, IN 88-05, IN 88-05, IN 88-56, IN 88-60, IN 88-64, IN 89-52, IN 89-63, IN 90-23, IN 91-17, IN 91-47, IN 91-77, IN 91-79, IN 92-18, IN 92-28, IN 92-46, IN 92-52, IN 92-55, IN 92-82, IN 93-40, IN 93-41, IN 94-12, IN 94-22, IN 94-26, IN 94-28, IN 94-31, IN 94-35, IN 94-58, IN 94-86, IN 94-86 Supplement 1, IN 95-27, IN 95-33, IN 95-36, IN 95-36 Supplement 1, IN 95-48, IN 95-49, IN 95-49 Supplement 1, IN 95-52, IN 97-01, IN 97-37, IN 97-59, IN 97-82

h. NRC Policy Paper, Secretary of Commission (SECY), applicable sections of: SECY-81-114, SECY-82-268, SECY-83-269, SECY-85-306 and 306B, SECY-93-143, SECY-93-232, SECY-94-090, SECY-94-127, SECY-95-034, SECY-96-134, SECY-96-146, SECY-97-127

i. National Fire Protection Association (NFPA) Codes. See Section F.2.1 for major committed codes.

j. Fire Protection Handbook, National Fire Protection Association, Boston, Massachusetts

k. Underwriters Laboratories (UL) listings from UL Building Materials Directory and UL Fire Resistance Directory (current editions)

l. ASTM E 84-1981, Standard Test Method for Surface Burning Characteristics of Building Materials

m. ASTM E 119-1988, Fire Test of Building Construction and Materials

n. ASTM E 136-1982, Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C

o. UL 910-1985, Test Method for Fire and Smoke Characteristics of Electrical and Fiber Optic Cables Used in Air Handling Spaces

p. Factory Mutual Approval Guide (current editions)

q. IEEE 383-1974, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations

r. Regulatory Guide 1.52, Revision 1, Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Plants

s. ANSI A21.4, Cement-Mortar Lining for Cast-Iron and Ductile-Iron Pipe Fittings for Water

t. ASME Boiler and Pressure Vessel Code, Section III, Rules for the Construction of Nuclear Power Plant Components

u. ANI Fire/All-Risk Guidelines, American Nuclear Insurers, Farmington, Connecticut.

v. Washington Administrative Code (WAC)

F.7.3 CALCULATIONS/TECHNICAL MEMOS

a. CE-02-90-39, Fire Resistance Rating of Hollow Concrete Block

b. FP-02-85-03, Combustible Loading Calculation (prepared for development of Amendment 45 only)

c. GE-NE-L12-00824-01, dated September 1994, Safe Shutdown Appendix R Analyses

d. NE-02-85-19, Revised Appendix R Safe Shutdown Analysis

e. NE-02-84-17, Bio-Shield Penetration Analysis for Fire Protection

f. NE-02-86-23, Temperature Response of Structural Components to Appendix R Fire

g. NE-02-86-39, Evaluation of Structural Supports for One Hour Fire Barriers

h. NE-02-86-44, Temperature Response of Cables in One Hour Fire Areas

i. NE-02-88-10, Appendix R Analysis - Vital Instrument Sensing Line Supports

j. NE-02-94-08, Appendix R Dose Evaluation

k. NE-02-94-35, Post-fire Safe Shutdown System Impacts

l. FP Flooding calculations: 5.51.54, 5.51.55, 5.51.58, 9.04.00, 9.09.10, 9.09.40, 9.09.75, 9.09.76, 9.09.77, 9.09.78, FP 02-87-10, FP 02-87-11, OER 81100C

m. 740-110-HR & SR, Room Heatup Evaluation for Appendix R

n. B&R 2.05.01, Calculation for Battery and Battery Charger 250 V DC and 24 V DC

o. B&R 2.06.20, Calc for Cable Ampacity Verification for Conduit and Tray

p. B&R 7.10.12, Calculation For FP of Instrument Tubing

q. TM-1308, Evaluation of Potential Plant Transients Due to Postulated 10 CFR 50 Appendix R Fire

r. TM-2007, Reactor Building Instrument Rack Fire Hazards Analysis

s. TM-2008, Evaluation of the 441 Ft Corridor Fire Protection Features for Appendix R Compliance

t. TM-2043, Augmented Quality Requirements

u. TM-2075, Mitigation of Radiological Releases from a Fire

v. TM-2103, Leakage Requirements of Penetration Seals

w. ME-02-89-11, Calculation of Frost Protection of Warehouse Complex Fire Mains

F.7.4 APPLICABLE NRC SAFETY EVALUATION REPORTS

a. NUREG-0892, Safety Evaluation Report related to the operation of WPPSS Nuclear Project No. 2, March 1982

b. NUREG-0892, Safety Evaluation Report related to the operation of WPPSS Nuclear Project No. 2, Supplement 1, August 1982

c. Fire Protection Supplemental Safety Evaluation Report -WPPSS Nuclear Project No. 2, dated December 27, 1982

d. Fire Protection Supplemental Safety Evaluation Report - WPPSS Nuclear Project No. 2, dated March 17, 1983

e. NUREG 0892, Safety Evaluation Report related to the operation of WPPSS Nuclear Project No. 2, Supplement No. 3, May 1983

f. NUREG 0892, Safety Evaluation Report related to the operation of WPPSS Nuclear Project No. 2, Supplement No. 4, December 1983

g. Letter dated August 24, 1986, Supplemental Safety Evaluation

h. Letter dated March 14, 1986, Safety Evaluation Report Washington Nuclear Project No. 2 Appendix R Requirements - Noncompliance

i. Letter R. M. Bernero to D. F. Kirsh, dated December 4, 1986, Evaluation of WNP-2 Fire Protection Analysis, with attached Safety Evaluation Report

j. Letter dated November 11, 1987, Fire Protection Safety Evaluation Report FSAR Amendment No. 37, Washington Nuclear Project Number 2 (WNP-2)

k. Letter dated May 12, 1989, Safety Evaluation Report

l. Letter dated May 22, 1989, Safety Evaluation by the Office of Nuclear Reactor Regulation Evaluating Implementation of the Approved Fire Protection Program, Washington Public Power Supply System Nuclear Project No. 2

m. Letter dated May 25, 1989, Issuance of Amendment No. 67 to Facility Operating License No. NPF-21 - WPPSS Nuclear Project No. 2. [includes new Fire Protection License Condition 2.c.(14)]

F.7.5 OTHER MISCELLANEOUS

a. Letter GO2-82-396, dated April 22, 1982, WNP-2 Response to SER on FSAR Section 9.5.1 Fire Protection Program

b. Letter GO2-83-243, dated March 21, 1983, Subject: Fire Protection Safe Shutdown Analysis

c. Letter GO2-86-613, dated June 30, 1986, Subject: WNP-2 Fire Protection Program, Request for Additional Information

d. Letter GO2-88-006, dated January 6, 1988, Subject: WNP-2 Fire Protection Reevaluation Status Report

e. Letter GO2-88-008, dated January 11, 1988, Subject: Nuclear Plant No. 2 Fire Protection and Safety Shutdown Capability, Response to Safety Evaluation Report

f. Letter GO2-88-090, dated April 15, 1988, Subject: Nuclear Plant No. 2 Fire Protection and Safety Shutdown Capability, Response to Safety Evaluation Report, Supplemental Information

g. Letter GO2-88-155, dated July 15, 1988, Subject: Nuclear Plant No. 2 Fire Protection and Safety Shutdown Capability, Response to Safety Evaluation Report, Supplemental Information

h. Letter GO2-88-222, dated October 28, 1988, Subject: Nuclear Plant No. 2 Fire Protection and Safety Shutdown Capability, Response to Safety Evaluation Report, (Revised Response)

i. Letter GO2-88-256, dated November 30, 1988, Subject: Nuclear Plant No. 2 Fire Protection Reevaluation Report -Status Report

j. GE Topical Report NEDO-10466-A, Power Generation Control Complex Design Criteria and Safety Evaluation (same as March 1978 NEDO-10466 referenced in SER)

k. Operational Quality Assurance program (OQAP)

l. WNP-2 Emergency Preparedness Plan

m. Engineering Standards Manual NES-7, Safe Shutdown Analysis, Section 10 CFR 50, Appendix R Fire

n. Engineering Standards Manual EES-1, Cable and Raceway Penetration Schedule (CARPS) Users Manual

o. Engineering Standards Manual EES-5, General Fuse Selection Criteria

p. Design Specification Division 300, Section 306, Fire Protection Detection and Suppression System

q. Penetration Seal Tracking System (PSTS) Database

r. Warnock Hersey International Fire Test File WHI-0495-0799 and 0800, Report of the Fire Endurance and Hose Stream Testing of Fire Rated Door Assembly Installed with Excessive Clearances, WNP-2 QA Vault Reel 502, Location 1-69

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

F.7.6 FIRE PROTECTION ENGINEERING EVALUATIONS

a. Fire Protection File (FPF) 1.1 Items 13 through 61, Overall Qualification of Penetration Seals

b. FPF 1.1 Item 12, Penetration Seal Fire Test Review Acceptance Criteria

c. FPF 1.1 Item 16, Internal Conduit Sealing Criteria

d. FPF 1.5 Item 2, Consolidation of Fire Areas R-17 and R-19 with Fire Area R-4

e. FPF 1.7 Item 19, Evaluation of WNP-2 Vertical Cable Tray Fire Breaks

f. FPF 1.5 Item 3, Evaluation of Fire Area Boundary Between Fire Area DG-2 and DG-3

g. FPF 1.5 Item 4, Thermo-Lag Coated Wall and Blind Corridor

h. FPF 3.2 Item 3, Emergency Diesel Fuel Flash Point

i. FPF 1.1 Item 56, GL 86-10 Evaluation - Seal R206-5052

F.7.7 FIRE PROTECTION REFERENCE DRAWINGS

a. FM892-1, Fire Area Boundary Plan - Ground Floor

b. FM892-2, Fire Area Boundary Plan - Mezzanine Floors

c. FM892-3, Fire Area Boundary Plan - Operating Floor

d. FM892-4, Fire Area Boundary Plan - Reactor Building Miscellaneous Elevations

e. FM892-5, Fire Area Boundary Plan - Miscellaneous Floors and Buildings

f. FM892-6, Zones of Limited Combustibles, Reactor Building

g. FM892-7, Fire Suppression System Plan 437', 441'

h. FM892-8, Fire Suppression System Plan 467', 471'

i. FM892-9, Fire Suppression System Plan 501', 525'

j. FM892-10, Fire Suppression System Plan, Reactor Building, Miscellaneous Elevations

k. FM892-11, Fire Suppression System Plan, Miscellaneous, Floors and Buildings

l. M515-1, Flow Diagram - Fire Protection System

m. M515-2, Flow Diagram - Fire Protection System - Details

n. M515-3, Flow Diagram - Fire Protection System - CO_2 Distribution

o. E948, Raceway Fire Barrier Location Drawings

F.7.8 FIRE PROTECTION PROGRAM IMPLEMENTING PROCEDURES

a. SWP-FPP-01, Nuclear Fire Protection Program includes

   1. Program objectives
   2. Technical and administrative program elements
   3. Nuclear fire protection program elements
   4. Design elements
   5. Quality assurance program elements
   6. Training program elements

b. PPM 1.3.10, Plant Fire Protection Program, includes

   1. Emergency response capability (Fire Brigade)
   2. Fire response and reporting
   3. Surveillance, inspection, and testing
   4. Safe shutdown capability
   5. Miscellaneous use of fire system water

c. PPM 1.3.10A, Control of Ignition Sources

d. PPM 1.3.10B, Active Fire System Operability and Impairment Control

e. PPM 1.3.10C, Control of Transient Combustibles

f. PPM 1.3.57, Barrier Impairment

g. PPM 4.12.4.1, Fire

h. PPM 4.12.1.1, Control Room Evacuation and Remote Shutdown

i. PPM 15 Volume Series Inspection, Test, and Surveillance Procedures

j. Industrial Safety Manual, Chapter 4, Fire Safety

k. Fire Protection Program Manual

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QUALITY ASSURANCE

17.1 QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

The quality assurance requirements during design and construction were defined in the FSAR and were revised through Amendment 30 in June 1983. This section is no longer applicable since these phases are completed.

There are four principal participants in WNP-2 design and construction quality programs. They are the Owner, Washington Public Power Supply System (WPPSS); the Architect/Engineer (AE), Burns and Roe, Inc. (B&R); the Nuclear Steam Supply System (NSSS) Supplier, General Electric Company (GE); and the Construction Manager (CM), Bechtel Power Corporation.

a. The Supply System, as the owner and Licensee, has overall responsibility for assuring that the plant is designed and constructed in accord with approved Quality Assurance Programs (QAPs). The Supply System WNP-2 Project Quality Assurance organization provides management overview of the other elements of the site QAPs. Section 17.1.1 describes the Supply System WNP-2 QAP.

b. Burns and Roe, Inc. provides Architect/Engineer and related services for WNP-2. Section 17.1.2 describes the B&R QAP.

c. The General Electric Company (GE) provides NSSS design, fabrication, and erection/construction services for WNP-2. Section 17.1.3 describes the GE QAP.

d. The Bechtel Power Corporation provides construction management services for WNP-2. This service consists primarily of direction and coordination of site contractor activities and includes related Quality Assurance/QC services. Section 17.1.4 describes the Bechtel QAP.

17.1.1 WASHINGTON PUBLIC POWER SUPPLY SYSTEM QUALITY ASSURANCE PROGRAM

The Supply System has implemented a QAP for the design, procurement, and construction of WPPSS Nuclear Project No. 2 (WNP-2). This QAP has been implemented in accordance with requirements of Appendix B to 10 CFR 50. The applicable requirements of Appendix B, 10 CFR 50 are applied to those items classified as WPPSS Quality Class I due to their relationship to a nuclear safety function.

As the license applicant, the Supply System is responsible for the plant. Therefore, the Supply System WNP-2 QAP and its implementation has been structured to assure that design, procurement, and construction activities are accomplished in accordance with sound engineering principles and practices. Systems, components, and structures that are safety-related, in the context of 10 CFR 20, 10 CFR 50, and 10 CFR 100, are required to be designed, specified, fabricated, installed, and tested in accordance with applicable regulatory requirements, codes, standards, specifications, and procedures.

The description of the Supply System WNP-2 Design and Construction QAP which follows is of the program as it currently exists. This program evolved from the original quality program which first appeared in Appendix D.O of the PSAR. The changes involved in this evolution process include: NRC requested changes; updates in organization responsibilities and authorities; and the incorporation of new requirements.

17.1.1.1 Organization

The Supply System Managing Director is responsible to the Board of Directors for the overall management of Supply System activities, including the establishment and implementation of policies. The Managing Director resolves issues involving quality brought to his attention because of failure to reach resolution at lower levels of management. Overall Supply System organization is shown on Figure 17.1-1.

The Managing Director has the ultimate responsibility for the QAP. The Managing Director shall ensure that the program is implemented and maintained by assigning the appropriate authority and responsibility to the Director of Licensing and Assurance.

The Deputy Managing Director has the authority to implement the policies of the Managing Director. The Deputy Managing Director is accountable to the Managing Director and is responsible for:

a. *Coordinating and integrating the activities of Supply System organizations,*

b. *Supporting and advising the Managing Director on the performance of Supply System functions and evaluation of such, and*

c. *Acting for the Managing Director, as required.*

The Director of Licensing and Assurance reports and is accountable to the Managing Director for the overall development, implementation, and verification of the Supply System Quality Assurance and Nuclear Safety and Regulatory programs to ensure compliance with regulations, codes, and standards. These responsibilities include:

a. *Determining the adequacy and effectiveness of program implementation,*

b. *Maintaining cognizance of changing regulatory requirements and providing controlled interface between the Supply System and regulatory agencies,*

c. *Exercising authority to stop nonconforming work of any Supply System Contractor or Supplier organization, and*

d. *Administering corporate and project Quality Assurance and Nuclear Safety and Regulatory program activities.*

The Director of Licensing and Assurance operates through the Manager of Construction Quality Assurance, the Manager of Audits, and the Manager of Nuclear Safety and Regulatory Programs.

The Director of Operations reports and is accountable to the Managing Director for development and implementation of policies and programs supporting the design, construction, and operational phases of Nuclear Power projects WNP-1, WNP-2, and WNP-3, and the extended construction delay of WNP-4/5. The Director of Operations carries out his responsibilities through the Director of Generation; the Director of Technology; and the Program Directors of WNP-1, WNP-2, and WNP-3.

The Director of Power Generation reports to the Director of Operations and is responsible for ensuring that the calibration of measuring and test equipment is performed in accordance with approved procedures which establish calibration frequencies, procedures used, recall methods, identification requirements, tolerances and records required to establish equipment history and calibration data.

The Director of Power Generation carries out his responsibilities through the Manager, Generation Services; the Manager, Generation Maintenance; and the Supervisor of Instrumentation Maintenance and Calibration. The Plant Manager and Test and Startup also report to the Director of Power Generation. Startup activities are conducted in accordance with the Operational QAP, Topical Report WPPSS-QA-004, as referenced in Section 17.2.

The Director, Technology reports to the Director of Operations and is responsible for:

a. *Providing technical and engineering support to the project,*

b. *Assisting the project engineering organization in providing technical direction to the Architect Engineer,*

c. *Assisting the project in performing technical overview of Supply System activities,*

d. *ASME Code consultation to the project, including interfacing with ASME,*

e. *Performing and managing selected technical programs, having applicability to several projects, including preoperational environmental monitoring, and geology,*

f. *Providing independent technical evaluations when requested by the Director of Operations, and*

g. *Overall Supply System records management policy. Implementation of the policy with regard to functions described in this manual is the responsibility of all Directorates, as applicable.*

To accomplish this role, the Director of Technology operates through the Assistant Directors, Technology for Systems Engineering, Generation Engineering, WNP-2 Plant Engineering, and Fuel and Environment.

The Director of Support Services reports to the Managing Director and is responsible for the development and implementation of policies and programs which support design, construction, and operation of Supply System plants in the areas of safety and security. Areas in which the Director of Support Services provides support for the projects include industrial safety and fire protection, technical training, administration, and security. To accomplish this role, the Director of Support Services operates through the Manager, Technical Training Programs; the Manager, Administration; the Manager, Health and Safety Programs; and the Manager, Security Programs.

The Chief Financial Officer reports to the Managing Director and is responsible, through the Manager of Central Materials and Procurement, for the development of corporate material management and procurement policy, and the procurement and control of corporate, multiple-project and specialized materials and related services required to support the design and construction of Supply System nuclear power plants.

The Program Director is directly accountable to the Director of Operations and is responsible for the safe, successful, and timely completion of construction of the nuclear plant (including those responsibilities assigned to the Owner by Section III of the ASME Code). The Program Director accomplishes Project responsibilities by managing and directing the AE who performs the design; the CM who manages the construction on the Project; and Project Supply System personnel. See Figures 17.1-2, 17.1-4, and 17.1-5.

The Deputy Program Director reports to the Program Director and is responsible for managing and directing the completion of the design, construction, and turnover to Operations

of the power plant in accordance with established requirements. These responsibilities include:

- *a.* *Monitoring AE/CM internal performance and also monitoring their management of other Contractor's performance against established requirements; determines corrective measures and/or gives direction and advice, as necessary,*
- *b.* *Ensuring necessary licenses and permits are obtained, and*
- *c.* *Providing Project-level reviews and reports, as necessary or directed.*

The manager of each WNP-2 department or organization, as well as the manager of each Supply System home office support organization, is responsible for:

- *a.* *Identifying those activities within his organization which are quality-related,*
- *b.* *Establishing and clearly defining the duties and responsibilities of personnel within his organization who execute those quality-related activities, and*
- *c.* *Ensuring that quality-related activities are accomplished by qualified personnel in accordance with approved procedures, as required.*

The principal WNP-2 project organizations are shown on Figures 17.1-2 and 17.1-3. A description of the primary quality-related functions follows.

The project Engineering Manager reports to the Program Director and is responsible for the timely completion of design for effective field engineering support of the construction effort and for the direction of the AE. Included in his responsibilities are:

- *a.* *Managing the design activities of the Project and ensuring its technical adequacy. This includes all actions necessary to ensure a plant design which is constructable, which conforms to all regulatory requirements and corporate commitments that are necessary to receive and retain an operating license, and which is safe and efficient to operate;*
- *b.* *Those engineering activities which provide solutions and prevention of technical construction restraints which ensure the technical adequacy of the completed construction. In addition, the project Engineering Manager is responsible for dispositioning Supply System-originated nonconformances; and*
- *c.* *Continuous review of the plant design as it applies to NRC commitments and safety requirements.*

The project CM is responsible to the program Director for construction activities at the project, including the direction of the CM. Included in his responsibilities are:

a. *Providing the necessary management, monitoring, control, and reporting elements that are necessary to ensure performance of the CM.*

b. *Overview of CM for receiving, storage, issuance, and maintenance of Supply System prepurchased equipment and material from the time of receipt at the project (or release from the Contractor) until it is transferred to the final control of the Supply System.*

The Site Administration Manager is responsible to the program Director for providing support services which include management of project facilities, services, personnel services, budget control, procedure development and control; and

a. *Shall be responsible for establishing, developing, implementing, and maintaining procedures/instructions for controlling the receipt, distribution, encoding, retention, and disposition of prepurchased equipment, Supply System, AE, CM, and Contractor quality assurance records.*

b. *Shall be responsible for the receipt, control, preservation, and retrieval of project construction records.*

These responsibilities are carried out through the Manager, Records Management, and the Facilities/General Services Supervisor.

The Business Manager reports to the program Director. The Business Manager ensures that Corporate Contract Management policies and procedures are implemented which include management of contract administration, procurement, materials management, and materials control.

a. *Supervisor, Contract Administration provides contract administration support including construction contract administration, claims management, contract data reporting, bid preparation, evaluation, and award processing;*

b. *Manager, project procurement provides purchasing, renting, leasing, or otherwise obtaining materials, equipment, supplies, services, and related phases of contract administration including preparation, award of contracts, and administration;*

c. *Manager, project Material Control provides receiving, handling, warehousing, excess materials, and storage until installed; and*

d. *Materials Management provides Project inventory control support, coordination of material, identifies material needed, startup, and operations support.*

The Manager, Program Control reports to the Program Director WNP-2, and is responsible for:

a. *Overall administration and coordination of the Project budget, including analyses of Owner's cost, construction management forecasts, and AE estimates,*

b. *Overall analysis and reporting for the performance measurement system,*

c. *Financial verification and processing of payments to contractors and vendors, and*

d. *Coordination and administration of the change management system.*

The Manager of Project Licensing reports directly to the Manager, Regulatory Programs and is matrixed to the Program Director. The Manager, Project Licensing is responsible for:

a. *Providing coordinated Project-level management of licensing activities,*

b. *Developing and implementing Project licensing policies consistent with Corporate policies, and*

c. *Ensuring technical adequacy of licensing submittals.*

The Manager, Construction Quality Assurance reports to the Director, Licensing and Assurance and is responsible for the development and implementation of the QAP during the Nuclear Power Plant Design and Construction phases. He is also responsible for Procurement QA; plant modifications; qualification and certification of Supply System nondestructive examination and inspection personnel, and other personnel requiring certification; surveillance of nondestructive examination and inspection activities.

The Manager of Procurement Quality Assurance reports to the Manager of Construction Quality Assurance and is primarily responsible for the definition and implementation of the source surveillance/audit program for verification of activities performed by Supply System vendors (including the NSSS vendors). The Manager of Procurement Quality Assurance is specifically responsible for:

a. *Review of and concurrence with procurement documents for items and services (other than nuclear fuel) initiated by Corporate personnel,*

b. *Performance of preaward surveys/evaluations of vendors/suppliers, and maintaining and distributing an updated listing of those approved,*

c. *Planning, coordination, and performance of source surveillances, source inspections, and source audits to verify implementation of Supply System direct-purchase Supplier QA/QC Programs,*

d. *Review and/or approval of offsite Supply System- administrated vendor/supplier quality assurance/ quality control procedures and programs,*

e. *Perform receipt-inspection of items received at the Corporate Warehouse and Corporate extensions,*

f *Verify that received items are handled and stored correctly,*

g. *Ensure training of receiving inspectors,*

h. *Provide program overview of AE vendor surveillance activities,*

i. *Quality assurance vendor surveillance of offsite Supplier activities,*

j. *Audits, surveillances, and/or surveys of suppliers of items, materials, or services who do not have ASME Certification, and*

k. *Provide overview of NSSS vendors.*

The Project Quality Assurance Manager reports to the Manager, Construction Quality Assurance and is matrixed to the Program Director. The Project Quality Assurance Manager is responsible for:

a. *Verification of the implementation of Quality Assurance Requirements Manual,*

b. *Verifying adequate implementation of an approved stop work authority program and directing a stop work order should conditions so dictate,*

c. *Assurance of a program for identification and reporting of nonconformances,*

d. *Verification, by audits and surveillances, that the AE, CM, selected contractors, and other Project organizations are implementing applicable quality requirements,*

e. *Ensuring that adequate staffing is obtained to implement the QAPs at the Project,*

f. *The assignment of adequately trained an qualified/certified personnel to perform quality verification activities,*

g. *Overview of AE/CM approval of Contractor procedures and instructions,*

h. *Reporting significant conditions adverse to quality to the Program Director and the Director, Licensing and Assurance, and*

i. *Reporting quality problems and trends to the Manager, Construction Quality Assurance for use in developing standards for Licensing and Assurance management systems to preclude repetition of quality assurance problems.*

The Manager of Audits reports to the Director, Licensing and Assurance and is responsible for maintaining an organization of qualified auditors responsible for verifying implementation of the QAP as follows:

a. *Performing quality assurance audits of internal Supply System organizations and external organizations (e.g., AE/CM); except for Management Audits,*

b. *Developing audit and surveillance schedules and selecting qualified personnel to perform the activities of this function,*

c. *Certification of Audit Team Leaders,*

d. *Training of audit personnel,*

e. *Participating in audits and providing overview of AE activities,*

f. *Periodic review of Corporate and project audit reports to identify any quality trends which may constitute a need for corrective action, and*

g. *Maintenance of audit records.*

The Manager of Nuclear Safety and Regulatory programs reports to the Director of Licensing and Assurance and is responsible for the development and implementation of policies and programs which support design, construction, and operation of Supply System plants in the areas of Nuclear Safety and Regulatory Programs. Areas in which the Manager of Nuclear Safety and Regulatory Programs provides support for the Projects include nuclear safety assurance, environmental compliance, and licensing. The Manager, Nuclear Safety and Regulatory Programs is responsible for establishment and maintenance of Supply System/regulatory interfaces and ensuring that nuclear licensing transmittals receive an adequate, competent, and timely review prior to making commitments. To accomplish this

role, the Manager, Nuclear Safety and Regulatory Programs operates through the Manager, Regulatory Programs and the Manager, Programs and Safety Performance.

17.1.1.2 Quality Assurance Program

The Supply System has established and implemented a QAP for the design, procurement, and construction phase of the WNP-2 facility. The QAP is based on the assignment of quality classifications which impose applicable quality requirements to structures, systems, and components.

The Supply System QAP and the supporting procedures and instructions comply with the requirements of Appendix B to 10 CFR Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants", and applicable regulatory guides as specified in Section 1.8.2 of the FSAR.

The Supply System's design and construction activities at WNP-2 are performed in accordance with the policies established by the WPPSS QAP Manual for Design and Construction.

A matrix of the Supply System QAP procedures and the corresponding criteria of 10 CFR 50, Appendix B, appears in the table below followed by description of the scope covered by these procedures.

10 CFR 50, Appendix B Criteria	*Supply System QAR*
Organization	*QAR-1*
Quality Assurance Program	*QAR-2*
Design Control	*QAR-3*
Procurement Document Control	*QAR-4*
Instructions, Procedures and Drawings	*QAR-5*
Document Control	*QAR-6*
Control of Purchased Materials, Equipment and Services	*QAR-7*
Identification and Control of Material, Parts and Components	*QAR-8*

Control of Special Processes	*QAR-9*
Inspection	*QAR-10*
Test Control	*QAR-11*
Control of Measuring and Test Equipment	*QAR-12*
Handling, Storage and Shipping	*QAR-13*
Inspection, Test and Operating Status	*QAR-14*
Nonconforming Materials, Parts or Components	*QAR-15*
Corrective Action	*QAR-16*
Quality Assurance Records	*QAR-17*
Audits	*QAR-18*

a. Organization - QAR-1

Establishes an organizational structure that will direct the resources of the Supply System and its contractors to engineer, design, procure, fabricate, manufacture, install, construct, and test the Supply System Nuclear projects to maximize safety, reliability, and efficiency.

b. Program - QAR-2

Defines the QAP established by the Supply System for design and construction. Included in this program is a system for classifying structures, systems, components, design characteristics, and procurement documents to determine the Quality Assurance activities associated with each item.

c. Design Control - QAR-3

Establishes a system of independent reviews to ensure applicable quality regulatory, code, and design basis requirements are properly translated into design and procurement documents for each structure, system, and component.

The documented review provides a check for design adequacy, inspectability, and compatibility with intended usage.

d. *Procurement Document Control - QAR-4*

Establishes a system to ensure that procurement documents and changes thereto incorporate the technical and quality assurance requirements necessary to ensure the quality and integrity of procured material, equipment, and services.

e. *Instructions, Procedures, and Drawings - QAR-5*

Establishes system defining the requirements and responsibilities controlling the preparation, review, approval, and release of instructions, procedures, and drawings which implement quality requirements.

f. *Document Control - QAR-6*

Establishes a system to control the issuance of documents, including changes thereto, which prescribe activities affecting quality.

g. *Control of Purchased Material, Equipment, and Services - QAR-7*

Establishes a system to ensure material, equipment and services are procured in accordance with the requirements specified in the procurement documents.

h. *Identification and Control of Materials, Parts and Components - QAR-8*

Establishes a system for the identification and control of material, parts, components, equipment and partially-completed assemblies to ensure that items incorporated into the plant are of proper configuration and, when necessary, traceable to all supporting quality assurance documentation.

i. *Control of Special Processes - QAR-9*

Establishes a system for the control of special processes.

j. *Inspection - QAR-10*

Establishes a system which ensures the program requirements for inspection are delineated in the specifications and contracts and ensures that inspection and surveillance activities are performed in accordance with predetermined requirements delineated in written instructions in a planned and systematic manner.

k. *Test Control - QAR-11*

Establishes a system to ensure that plant testing activities are performed in accordance with predetermined requirements, approved, and delineated in written instructions.

l. *Control of Measuring and Test Equipment - QAR-12*

Establishes a system for the control, calibration, and adjustment of tools, gauges, instruments, and other inspection, measuring, testing, and maintenance devices at specified periods to ensure the usage of proper type, range, and accuracy necessary to verify conformance to established requirements.

m. *Handling, Storage, and Shipping - QAR-13*

Establishes system to control the handling, storage, shipping, cleaning, and preservation of material, parts, components, and equipment in accordance with written and approved procedures, instructions and recommendations, to ensure that the designed integrity and functionality of the item are maintained.

n. *Inspection, Test, and Operating Status - QAR-14*

Establishes a system to indicate the inspection, test, and operating status for all structures, systems, or components to preclude the inadvertent bypassing of their inspection and test requirements and to prevent their inadvertent operation.

o. *Nonconforming Material, Parts, or Components - QAR-15*

Establishes a system to ensure that nonconformances are identified, documented, segregated or otherwise controlled, prevented from inadvertent use or installation and that notification of actions taken is transmitted to the affected parties.

p. *Corrective Action - QAR-16*

Establishes a system to ensure that significant conditions adverse to quality are identified, the cause determined, documented, brought to the attention of upper management, corrected as soon as possible, and that measures are taken to preclude repetition.

q. *Quality Assurance Records - QAR-17*

Establishes a system for the control and maintenance of all records sufficient and necessary to provide objective evidence of the activities affecting quality.

r. *Audits - QAR-18*

Establishes a system of audits to be performed in a planned and systematic manner to verify compliance and effectiveness of the Supply System QAP.

The WNP-2 Project Management Instructions (PMI) Manual delineates the responsibilities of and interfaces between project organizations. Each project organization is responsible for developing and using implementing procedures/instructions for their assigned functions.

Quality Assurance Instructions, Project Procurement Manuals, and other procedures or instructions pertinent to specific departmental functions describe the measures used to implement the provisions of the programs.

The Supply System Quality Assurance Manager assigned to the WNP-2 Project is responsible for establishing and administering the WNP-2 Quality Assurance policies, goals, and objectives of the QAP and verifying adequate implementation.

The WNP-2 Quality Assurance personnel have the authority and responsibility to perform the necessary actions, including provisions for stop work authority, to accomplish their assignments.

To ensure that WNP-2 Project personnel who perform quality-related activities are cognizant of the quality requirements, they are provided training and indoctrination as prescribed by the Project Training Program. The initial indoctrination includes discussions as to the purpose of applicable codes and standards and familiarization with Appendix B, 10 CFR Parts 50, 50.55(e), and 10 CFR Part 21. The training phase includes instructions on the Project QA policies and instructions on specific quality activities directly related to individual job functions. Personnel whose activities require specific qualifications such as nondestructive testing, audit, inspection, and testing are suitably evaluated, trained as appropriate, and certified.

Training sessions are an ongoing activity and are appropriately documented. Nondestructive test, audit, test, and inspection personnel qualification records are maintained.

The WNP-2 QAP is audited on a regular basis by the Home Office Supply System Audit Section.

Contractors who perform safety-related work include the AE, NSSS Supplier, and CM. These contractors are required to establish and implement QAPs consistent with the applicable requirements of 10 CFR Part 50, Appendix B. These programs are reviewed for adequacy by WNP-2 Project personnel. The AE, NSSS Supplier, and Construction Management Contractor quality-related functions are controlled in accordance with the programs described in Sections 17.1.2, 17.1.3, and 17.1.4, respectively.

17.1.1.3 Design Control

Burns and Roe, as AE, is responsible for specifying the overall design of the project, except that GE is responsible for design of the NSSS system. Design by other project organizations (contractors) is performed in accordance with an approved QAP. The details of the Burns and Roe and GE WNP-2 QAPs are described in Sections 17.1.2 and 17.1.3 respectively.

Design control is performed by project organizations in accordance with approved procedures and/or instructions.

Design input, such as design bases, performance requirements, regulatory requirements, appropriate quality standards, and industry codes and standards are properly identified, documented, and translated into design documents, such as drawings and specifications.

Procedures describe the controls established for the review, approval, release, distribution, and revision of design documents involving design interfaces.

Changes in design, including field changes, and the reason for changes, are documented, controlled, and reviewed in accordance with measures commensurate with those applied to the original activity.

Computer programs for quality affecting activities are controlled, in accordance with quality program requirements of the user organization.

17.1.1.4 Procurement Document Control

Procurement of material, equipment, and services for the Project is accomplished through procurement specifications contracts, or purchase orders which are prepared, reviewed, and approved by cognizant personnel. Procedures require that procurement documents incorporate the applicable quality assurance, regulatory code, and design requirements. The procurement documents require that bidders submit a QAP or plan for major contracts describing their policies, procedures, and systems to be utilized in the control of quality throughout the applicable phases of production, from design to final shipment, erection, or installation.

Procurement documents provide requirements for suppliers to submit or make available for review applicable documents such as drawings, specifications, procedures, instructions,

inspection and test records, and quality assurance records to the Project for review and/or approval.

Procurement documents require suppliers to provide measures for retention, control, and maintenance of their Quality Assurance records procurement documents specify the appropriate records to be delivered to the Project prior to or with delivery.

When source surveillance is required ,procurement documents require suppliers to provide right of access to their facilities, procedures, and records for inspection and audit by Project personnel. Procurement documents issued after January 1978 require the supplier to establish measures for reporting 10 CFR Part 21 reportable deficiencies and disposition of nonconformances from procurement document requirements. Procurement documents require that the supplier retain the responsibility for monitoring and evaluating their sub-tier suppliers' performance to specified requirements.

Procurement documents for spare or replacements contain original, equivalent, or improved technical requirements including codes and standards and current applicable QAP requirements.

Changes and revisions to procurement documents are subject to the same or equivalent review/approval requirements as the original document.

17.1.1.5 <u>Instructions, Procedures, and Drawings</u>

Activities affecting quality are described in procedures, instructions, and drawings and the activities are conducted in accordance with these documents.

Procedures, instructions, and drawings include adequate quantitative and qualitative acceptance criteria to ascertain that the prescribed activities have been satisfactorily accomplished.

Procedures, instructions, and drawings are subject to review to assure that applicable codes, standards, and acceptance/rejection criteria are included. Review, approval, or information requirements are included in contract documents.

17.1.1.6 <u>Document Control</u>

A document control system is implemented by the Project. The requirements ensure that documents, including changes, are reviewed, approved, and released in a timely manner to the locations where the activity is being performed. The Project prepares procedures, instructions, and drawings as necessary to ensure that activities such as design, procurement, manufacturing, construction and installation, testing, inspection, auditing, calibration, and special processes are adequately prescribed and the necessary quality requirements are stated.

Changes to these documents require review and/or approval commensurate to that performed on the original document.

Contractors/subcontractors involved in activities affecting quality are required to establish measures for document control which satisfy project requirements.

Changes to specifications and drawings require approval of the cognizant Engineering personnel. As required by Procurement Documents, changes to supplier and contractor drawings and procedures are reviewed and approved by the Project Organization. Changes to documents such as specifications and drawings are indicated by a revision, change order, or equivalent documented methods.

Project drawings and specifications, supplier and contractor drawings, current revisions, addenda, and changes in design and engineering change notices are released in a controlled manner.

To preclude the inadvertent use of obsolete or superseded documents, a Project drawing/specification status report is periodically issued. These reports indicate the current revision to AE drawings and specifications and related changes, addenda, and design and engineering change notices. Site contractors are required to establish measures to ensure that obsolete or superseded documents are controlled to prevent their inadvertent use.

17.1.1.7 Control of Purchased Material, Equipment, and Services

Prior to award of contract, Quality Assurance, Engineering, and other personnel, as required, perform an evaluation of accepted bids to determine the supplier's capability to meet procurement requirements. The evaluation may consist of a direct survey of the prospective supplier's facility and personnel or, a review and evaluation of the implementation of his QAP, or evaluation of the supplier's history of providing satisfactory products to the project, or evaluation of the supplier's current records supported by objective evidence.

Surveillance of suppliers, as required, during fabrication, inspection, testing, and shipment of materials, equipment, and components is performed to provide assurance that material, equipment, and services conform to procurement document requirements. Surveillances are conducted by qualified personnel in accordance with established plans and to procedures that identify the attributes or processes to be witnessed and/or verified and the acceptance criteria. Those items which are simple and standard in design, manufacture, and test, or where quality characteristics can be verified by standard inspections or tests after delivery, are accepted during receiving inspection with no source surveillance. Receiving inspection is performed in accordance with written procedures or instructions.

Measures are established to provide for delivery of documentation from the supplier to the site, prior to or with delivery. These documents provide objective evidence:

a. That the items conform to the procurement quality requirements such as specifications, codes, and standards,

b. That the required tests, examinations, and inspections have been performed, and

c. That nonconformances have been dispositioned as required.

17.1.1.8 Identification and Control of Materials, Parts, and Components

Measures are established to identify and control materials, parts, and components including partially completed subassemblies. Requirements for identification and traceability are determined during initiation of design documents and are specified in procurement specifications and on drawings.

These measures require that items important to the safety of the Project are identified in a manner (i.e., heat/lot number, part number, serial number, etc.) that can be traced to the appropriate documentation, or group of documents, such as drawings, specifications, purchase orders, material certifications, etc. The identification is maintained and verified, as required, throughout fabrication, installation, and use of the item.

Implementation of these measures is accomplished by the responsible contractors in accordance with approved procedures.

Verification that items are properly identified is performed during vendor surveillance and receiving inspection activities.

During receipt inspection, materials, parts, and components are identified as acceptable or unacceptable. Where practicable, unacceptable items are physically segregated from acceptable items. Items identified as unacceptable may be released for installation provided the following conditions are met:

a. Traceability and identification is maintained,

b. The item can be brought to an acceptable condition without damage to associated equipment or structures, and

c. Controls are established to ensure retrievability and, when applicable, limit the use of the item.

17.1.1.9 *Control of Special Processes*

Measures are established for the procedural control of special processes that require interim in-process controls in addition to that inspection and/or examination to ensure achievement of required quality. Examples of these processes are coating/plating, heat treating, welding material cleaning, and nondestructive testing (NDT).

Special processes specified in fabrication/construction documents are controlled and are performed by qualified personnel using approved procedures and equipment evaluated to ensure compliance in accordance with applicable codes, standards, and specifications. Special processes delineated in the procurement documents may require that the applicable contractors submit procedures for review and approval.

17.1.1.10 *Inspection*

Measures are established to assure that an inspection program is planned and scheduled.

Equipment manufacturers, installers, and constructors are required by procurement documents to perform the inspection necessary to verify that items conform to established criteria. Procurement documents also require that inspection activities are performed in accordance with documented instructions, procedures, and drawings, as applicable.

Measures are implemented to ensure that inspections and/or tests are performed on work operations as necessary to verify quality, that personnel performing inspections are independent of the individual or group performing the activity being inspected and are qualified to the requirements of the applicable codes, standards, and company programs. Records of certification of qualification are maintained in a current status. Inspection planning provides measures to identify mandatory inspection hold points for contractor inspection personnel. Where appropriate, procedures, instructions, and checklists used in performing inspections, include as a minimum:

a. *Identification of characteristics and activities to be inspected,*

b. *Identification of the individuals or groups responsible for inspection,*

c. *Acceptance/rejection criteria,*

d. *Inspection method, and*

e. *Inspection reports attesting to the completion of inspection and the identity of the inspector or data recorded.*

The inspection program provides that modification, repairs, and replacements are inspected in accordance with the original design and inspection requirements or acceptable alternatives.

Construction inspection, and receiving inspection at the Project Site is performed by Construction Management Contractor Quality Control and/or installing contractor Quality Control personnel for those activities within the scope of their responsibility. Construction Management Contractor Quality Control personnel perform receiving inspection functions on project supplied materials, parts and components. Construction Management Quality Assurance personnel perform surveillance/audit functions on these activities to ensure compliance with project requirements.

The Supply System Project Quality Assurance performs surveillance/audit functions on the preceding activities.

17.1.1.11 *Test Control*

A test program is established to specify the requirements and to provide for identification of the testing necessary to demonstrate that structures, systems, and components perform satisfactorily in service.

Testing as addressed in this section pertains to tests performed on prepurchased equipment and materials and, tests performed by the contractors on installed equipment, components, structures, and systems.

The necessary testing requirements are specified in written procedures which incorporate or reference the acceptance limits contained in design and procurement documents and provide that:

a. *Calibrated test instrumentation and equipment is available,*

b. *Tests are performed under suitable environmental conditions with adequate test methods,*

c. *Tests are conducted by appropriately trained and qualified personnel,*

d. *Items which are modified, repaired, and replaced are tested in accordance with the same requirements which were applied to the original items or an approved alternate, and*

e. *Test results are documented and evaluated to ensure that test requirements have been satisfied.*

17.1.1.12 Control of Measuring and Test Equipment

Measures are established to ensure that tools, gauges, instruments, and other measuring and testing devices are identified, controlled, adjusted, and calibrated at intervals necessary to maintain accuracy within specified limits.

Suppliers and site contractors whose activities are quality affecting are required to implement control of measuring and test equipment in accordance with approved procedures. These procedures contain provisions that:

a. *Devices are adjusted and calibrated at prescribed intervals against certified standards having valid relationships to nationally recognized standards, or, if no national standard exists, the basis for calibration is documented.*

b. *Measuring and test equipment is calibrated at specific intervals based on the required accuracy, purpose, extent of use, stability characteristics, and other conditions affecting measurement control.*

c. *Measuring and test equipment is calibrated against reference standards. Records are maintained and equipment adequately identified to indicate calibration status and usage.*

d. *When measuring and test equipment is found to be out of calibrations written procedures describe provisions for documenting and evaluating the validity of previous inspections and tests and, for repeating the original inspection or test using calibrated equipment where necessary to establish acceptability of suspect items.*

e. *Supplier and contractor procedures specified in procurement documents are reviewed and approved prior to starting work.*

17.1.1.13 Handling, Storage, and Shipping

Measures are established to control the handling, storage, shipping, cleaning, and preservation of material and equipment to prevent damage or deterioration. Appropriate procedures are prepared in accordance with design specification requirements and manufacturer's instructions to provide for special handling, storage, maintenance, cleaning, and preservation. These activities are accomplished in accordance with approved procedures or instructions.

Where required, procedures address requirements for special protective environments such as inert gas atmosphere, moisture content levels, and temperature levels and require that:

a. *Procurement documents establish requirements for handling, shipping, storage, preservation, and maintenance.*

b. *Items are stored in accordance with their classifications as delineated in Project instructions.*

c. *Storage areas are monitored to assure that the required storage integrity is maintained.*

17.1.1.14 *Inspection, Test, and Operating Status*

Measures are established to indicate that inspections and tests performed on structures, systems and components are known throughout fabrication, installation and test. Indicators such as tags, stamps, labels, travelers, or other suitable means are utilized to indicate the status of the item. Where required, structures, systems and components such as valves, switches, electrical, and rotating equipment are tagged or locked out to prevent inadvertant use.

Project organizations and contractors involved in inspection, test, and operation of equipment, components, and systems are required to prepare and implement procedures for the control of these items and activities. Procedures include requirements that specified inspections and tests are performed, that application and removal of status indicators are controlled, that bypassing of quality affecting tests and inspections are controlled, and that systems containing inoperative, malfunctioning or nonconforming items, structures, or components are identified and controlled to prevent inadvertant operation.

17.1.1.15 *Nonconforming Materials, Parts, or Components*

Measures are established for the control of material, parts, components, or services that do not conform to specified requirements.

To prevent inadvertent use or installation, the QAPs of the Project organization, site contractors, subcontractors, and suppliers establish control for identification, documentation, segregation, review, disposition, and notification to affected organizations of non-conforming materials, parts, components, or services.

Written procedures contain provisions:

a. *For the handling, processing and dispositioning of nonconforming materials, parts, components, or services,*

b. *For the identity of the individuals or groups with the authority and responsibility for the review, disposition and approval of nonconforming items,*

c. *That nonconforming items are identified as such, by the appropriate status indicator and are physically segregated where practical from acceptable items until dispositioned,*

d. *That rework or repair of nonconforming items be subject to the same, or an equal test or inspection as was originally imposed, or an approved alternate, and the inspection, testing, rework and/or repair activities are documented,*

e. *That nonconformance reports are reviewed for potential 10 CFR 50.55(e) and Part 21 reportability,*

f. *For identification and control of conditional released items,*

g. *That measures are established in procurement documents to require offsite vendors and suppliers to include their nonconformance reports, which deviate from procurement documents, as a part of their Quality Assurance records, and*

h. *That site contractors and subcontractors document deviations from contract requirements, and nonconformances dispositioned "use-as-is" or "repair" are submitted to the project for review and/or concurrence.*

Nonconformance documentation identifies the nonconforming item, describes the nonconformance and the disposition of the nonconformance, identifies any special inspection requirements and the completion of inspection, and contains required signatures/approvals.

Construction Management Contractor Quality Assurance is responsible for the review of these nonconformance reports to ascertain that they have been dispositioned, approved, and closed out.

Reviews include trend studies, corrective action adequacy, and reporting to appropriate levels of management.

The AE is responsible to provide acceptance of disposition for those conditions for which they have assigned technical responsibility. When technical responsibility has not been assigned to the AE, or another design contractor, or when technical requirements are not affected or technical responsibility has been assumed by the Supply System, the Supply System will provide acceptance of disposition.

17.1.1.16 Corrective Action

Measures are established to provide for the prompt identification, evaluation, and correction of conditions adverse to quality such as nonconformances, failures, malfunctions, deficiencies, deviations, defective material, and equipment.

The QAPs for the project organization and onsite contractors are required to establish provisions:

a. *That corrective action is implemented in accordance with procedures,*

b. *That corrective action for significant conditions adverse to quality identify the cause and include actions to preclude recurrence,*

c. *That follow-up is performed to verify implementation and close out of corrective action,*

d. *That for significant conditions adverse to quality, the cause and the corrective action taken are reported to cognizant management levels, and*

e. *That Corrective Action Reports are reviewed for potential 10 CFR 50.55(e) and Part 21 reportability.*

17.1.1.17 *Quality Assurance Records*

Measures are established to assure that sufficient records are maintained to provide documentary evidence of the quality of items and the activities affecting quality.

Quality Assurance records include:

a. *Test logs,*
b. *Results of reviews of inspection, tests, audits, and material analysis,*
c. *Surveillance and audit documents,*
d. *Qualification of personnel, procedures and equipment,*
e. *Drawings, as-built drawings and specifications,*
f. *Procurement documents,*
g. *Calibration procedures and reports, and*
h. *Nonconformance and corrective action reports.*

Inspection and test records contain as applicable:

a. *Type of inspection, test, or examination,*
b. *Identity of inspector or data recorded,*
c. *Date and results of inspection/test,*
d. *Acceptability,*
e. *Action taken relative to deficiencies noted, and*
f. *Identification with the applicable item or activity.*

Suppliers, vendors, and contractors are required to furnish Quality Assurance records prior to or on delivery of equipment, supplies, structures, or systems, or retain them if required by contractual agreement.

Procedures are established and contain provisions for the identification of individuals or groups responsible for record transmittals, retention, and maintenance, and provisions for ensuring that records are identifiable and retrievable.

Record storage facilities are constructed, located and secured to prevent destruction by fire, flooding, theft, and deterioration by extremes in temperature and humidity.

17.1.1.18 Audits

Measures are established to provide a system for conducting audits to verify compliance with all aspects of the QAP and to determine the effectiveness of the program. All aspects include activities associated with:

a. Indoctrination and training programs,
b. Interface control between the Supply System and the principal Contractors,
c. Corrective action, calibrating, and nonconformance control systems, and
d. SAR commitments.

The project organizations and principal contractors have established and implemented an audit system which includes objective evaluations of quality-related practices, procedures, activities, and records. The system ensures that the necessary audit functions are performed to preestablished written procedures or checklists, in a planned and systematic manner, and are conducted by trained and qualified personnel who do not have direct responsibility in the areas being audited.

The audit system provides for external audits to be performed, as appropriate, by the home office, project organization, and principal contractors on their suppliers, vendors, and contractors, and internal audits to be performed within each organization.

Audits are planned and scheduled on the basis of the status and safety importance of the activities being performed. They are initiated early enough and performed at regular intervals to ensure the QAP is effectively implemented during design, procurement, manufacture, construction, and installation.

Audits are documented and reviewed with the level of management responsible for the area audited and, where required, follow-up action including reaudit of the deficient areas is performed.

Audit data is evaluated to assure that the QAP is effective and properly implemented and the results are reported to management for review and assessment.

The Supply System WNP-2 quality affecting activities are audited on a scheduled basis by the Supply System home office audit group.

17.1.2 THE BURNS AND ROE, INC. QUALITY ASSURANCE PROGRAM

17.1.2.1 Introduction

The Burns and Roe, Inc. (B&R) QAP for the WPPSS Nuclear Project No. 2 (WNP-2) has evolved during the design and construction of WNP-2. The original B&R QAP was described in the Atomic Energy Commission accepted Preliminary Safety Analysis Report (PSAR) for WNP-2, Appendix D.O. This QAP was implemented until February 1978, when WPPSS assumed responsibility for Construction Management, Site Quality Assurance, and Vendor Surveillance of selected prepurchased equipment contracts. The B&R QAP was implemented during this phase of the WNP-2 PSAR Deviation Request No. 15 WP. In this phase, B&R was responsible for the AE scope of the engineering and design of WNP-2 and provided experienced Quality Assurance personnel to carry out the Supply System's assumed responsibilities. On June 1, 1981 B&R implemented their Quality Assurance Topical Report, B&ROE-COM4-1-NP-2A, approved by the Nuclear Regulatory Commission, with documented exceptions for the B&R engineering and design and procurement activities for WNP-2.

17.1.2.2 The Burns & Roe, Inc. Quality Assurance Topical Report

The QAP for WNP-2 was implemented by B&R on June 1, 1981 and is based on the B&R Quality Assurance Topical Report with documented exceptions, WNP-2 Final Safety Analysis Report (FSAR) commitments, WPPSS direction and the B&R contractual responsibilities for the design and construction of WNP-2. The B&R responsibilities for the WNP-2 Project are engineering and design, and procurement activities for assigned prepurchased equipment contracts. The exceptions to the Quality Assurance Topical Report are identified in the following subparagraphs.

17.1.2.3 Exceptions to the Burns & Roe, Inc. Quality Assurance Topical Report

17.1.2.3.1 Chapter 1 - Organization

Paragraph 4.1.2

The B&R WNP-2 Project Organization chart is shown as Figure 17.1-4.

Paragraph 4.3

Construction Management is not within B&R scope of services.

17.1.2.3.2 Chapter II - Quality Assurance Program

Paragraph 2.1

The US NRC Regulatory Guides applicable to WNP-2 are identified in Section 1.8.3 of the WNP-2 FSAR.

Paragraph 4.6

Under the B&R WNP-2 QAP, satisfactory accomplishment of the following quality affecting functions shall be verified:

a. *The design process is accomplished in accordance with established procedures.*

b. *Specifications contain appropriate quality requirements.*

c. *For those prepurchased equipment contracts for which Burns and Roe performs the vendor surveillance function:*

   1. *Contractors' QAPs and procedures are adequate,*

   2. *Nonconformances are identified and dispositions provided, and*

   3. *Material receiving, inspection, and storage functions are performed in accordance with established procedures.*

d. *Surveillance of the activities performed by Contractors whose sole function is to provide engineering and design services.*

e. *Audits of the quality affecting activities described above are performed on a scheduled basis.*

17.1.2.3.3 Chapter III - Design Control

Paragraph 2.1

10 CFR 50, Appendix B and ANSI N45.2 are the basis for the B&R design control program.

Paragraph 4.1

The detailed design effort is based only on an approved project criteria document.

Paragraph 5

Additional design reviews/verifications have been performed on a sampling of previously issued system designs by the performance of special design reviews in accordance with project procedure WNP-2-ED-013.

Burns & Roe, Inc. procedures for design control have been upgraded to verify that future issued designs and modifications comply with applicable codes, standards, and design requirements.

17.1.2.3.4 Chapter IV - Procurement Document Control

Paragraph 3.4

Records to be retained, controlled and maintained by a supplier are not identified in the specification.

Paragraph 4

The appropriate commercial requirements are established by WPPSS and/or B&R and may be incorporated during the initial preparation of the technical specification. WPPSS prepares the potential bidders list.

Paragraph 5

Award is determined by WPPSS using the bid evaluation prepared by B&R.

Paragraph 6

Technical specifications are not normally conformed. When technical specifications are conformed, the changes are reviewed and approved in accordance with the same procedure used for the original technical specification.

Paragraph 7

Later procurement of spare or replacement parts shall be to the original or improved technical requirements. Impositions of Quality Assurance requirements will be in accordance with the Quality Assurance requirements of the existing specification for procurement of components

which are added to existing contracts. The latest WNP-2 Project Quality Programs are imposed on new procurements.

17.1.2.3.5 Chapter V - Instructions, Procedures, and Drawings

Paragraph 2.2

Burns and Roe, Inc. review of Quality Assurance plans required by procurement documents is limited to those prepurchased contracts for which B&R performs the vendor surveillance function.

Paragraph 2.5

Burns and Roe verification of the implementation of instructions, procedures, and drawing programs is limited to those prepurchased contracts for which B&R performs the vendor surveillance function.

17.1.2.3.6 Chapter VI - Document Control

Paragraph 2.1

The B&R WNP-2 QAP, in regard to document control, does not govern the following:

- *a. Procurement documents, except for prepurchased equipment contracts for which B&R performs the vendor surveillance function,*
- *b. Quality Assurance plans, except for the B&R Quality Assurance Plan and the quality assurance plans prepared by prepurchased equipment contracts for which B&R performs the vendor surveillance function,*
- *c. Contractor manufacturing, inspection, and testing procedures, except for those prepared by prepurchased equipment contracts for which B&R performs the vendor surveillance function,*
- *d. Construction and operational test procedures, and*
- *e. Nonconformance reports, except for those prepared by prepurchased equipment contracts for which B&R performs the vendor surveillance function.*

<u>Paragraph 2.3</u>

Changes to documents listed in Paragraph 2.1 may be made and implemented prior to the official revision of the document provided an advance change system exists and is controlled by approved project instruction and/or procedures.

<u>Paragraphs 2.6 and 2.7</u>

Burns and Roe verification of Contractor's document control programs is limited to those prepurchased contracts for which B&R performs the vendor surveillance function.

17.1.2.3.7 Chapter VII - Control of Purchased Material, Equipment, and Services

<u>Paragraph 3</u>

Recommended bidder lists are not prepared by B&R.

<u>Paragraph 4.2</u>

Quality Assurance audits are performed after contract award.

<u>Paragraph 4.3</u>

Recommendations for award are made by project management to WPPSS and WPPSS approves and makes the award.

<u>Paragraph 4.4</u>

Records of B&R bid evaluations and recommendation are only maintained by B&R for the supplier selection process.

<u>Paragraphs 5 and 6</u>

Surveillance plans are approved by the Manager of Vendor Surveillance and are subject to Project Quality Assurance review.

<u>Paragraphs 6.3 and 7</u>

Not applicable to B&R WNP-2 QAP.

17.1.2.3.8 Chapter VIII - Identification and Control of Material Parts and Components

Paragraph 2.1

Verification of identification of components, assemblies and subassemblies is performed by B&R only on prepurchased contracts for which B&R performs a final inspection prior to shipment.

17.1.2.3.9 Chapter IX - Control of Special Processes

Paragraphs 2.5 and 2.6

Only when performing the function of vendor surveillance on prepurchased contracts does B&R evaluate and verify a Contractor's special process control program.

17.1.2.3.10 Chapter X - Inspection

Paragraph 2.1

The applicability of US NRC Regulatory Guides is as committed in Section 1.8.3 of the WNP-2 FSAR. Mandatory hold points for prepurchased contracts are established after contract award and are contained in the Vendor Surveillance Plan for each Contract.

Paragraph 2.4

Verification that the contractor's inspection program is being effectively implemented is accomplished by a series of surveillances and audits performed by quality assurance personnel for those prepurchase contracts which Burns and Roe has retained the vendor surveillance function.

17.1.2.3.11 Chapter XI - Test Control

Paragraph 2.1

The applicability of US NRC Regulatory Guides are as committed in Section 1.8.3 of the WNP-2 FSAR.

Paragraph 2.6

Verification of the implementation of a Prepurchase Contractor's test control program is performed by B&R for prepurchased contracts when B&R performs the vendor surveillance function.

17.1.2.3.12 Chapter XII - Control of Measuring and Test Equipment

Paragraph 2.3

Selected prepurchase contractor programs for the control of measuring and test equipment are subject to engineering review and approval by B&R.

Paragraph 2.4

Verification that the program for the control of measuring and test equipment is being effectively implemented is ensured by a series of surveillances and audits performed by quality assurance personnel for those prepurchase contracts which Burns and Roe has retained the vendor surveillance function.

17.1.2.3.13 Chapter XIII - Handling, Storage, and Shipping

Paragraph 2.3

Only selected prepurchase contractor programs for the control of handling, preservation, storage, cleaning, packaging, and shipping of items are subject to review and approval by Burns and Roe, Inc. personnel. This procedurally controlled and documented review is the responsibility of the cognizant system or component engineer and includes review by a quality assurance engineer. Project management, based on comments generated during the review, makes an approval determination.

Paragraph 2.4

Not applicable to B&R WNP-2 QAP.

Paragraphs 2.5, 2.6, and 2.7

These requirements are applicable to those prepurchased contracts for which B&R performs the vendor surveillance function.

Paragraph 2.8

Verification of the implementation of Contractor programs for handling, storage, and shipping is performed by B&R only for prepurchased contracts when B&R performs the vendor surveillance function.

17.1.2.3.14 Chapter XIV - Inspection, Test, and Operating Status

Paragraph 2.3

Not applicable to B&R WNP-2 QAP.

Paragraph 2.4

Selected prepurchase contractor programs for inspection, test, and operating status are subject to engineering review and approval by B&R, for prepurchased contracts which B&R has retained by vendor surveillance function.

Paragraph 2.5

Verification that the inspection, test, and operating status program is being effectively implemented is ensured by a series of surveillances and audits performed by quality assurance personnel for prepurchased contracts which B&R has retained the vendor surveillance function.

17.1.2.3.15 Chapter XV - Nonconforming Materials, Parts, or Components

Paragraph 2.2

Nonconformance reports are not included in final data packages forwarded to B&R. Nonconformance reports on the WNP-2 Project are not issued or analyzed for quality trends by B&R.

Paragraph 2.3

Selected prepurchase contractor nonconformance control.programs are subject to engineering review and approval by B&R.

Paragraph 2.4

All nonconformance reports for those conditions for which B&R has the assigned technical responsibility require engineering review and approval by B&R. Such dispositioned nonconformance reports must be concurred in by the B&R Quality Assurance Manager or designated Quality Assurance Engineers.

Paragraph 2.5

Not applicable to the B&R WNP-2 QAP.

17.1.2.3.16 Chapter XVI - Corrective Action

No deviations.

17.1.2.3.17 Chapter XVII - Quality Assurance Records

No deviations.

17.1.2.3.18 Chapter XVIII - Audits

Paragraph 2.10

Not applicable to B&R WNP-2 QAP.

Paragraph 2.11

The audit program on material and equipment suppliers applies only to those prepurchased contracts for which B&R performs the vendor surveillance function.

17.1.3 GENERAL ELECTRIC COMPANY QUALITY ASSURANCE PROGRAM

The applicable QAP and detailed procedures of the WNP-2 NSSS and fuel have evolved during the design and construction phases of the WNP-2 plant. The original GE program for WNP-2 was implemented in 1968 and is described in the PSAR, Appendix D. The program at that time was in accordance with the Nuclear Energy Division (NED) quality objectives for safety and reliable systems and components as set forth in the "Blue Book" issued August 20, 1968. On October 1, 1969, the "Blue Book" was replaced with the "Green Book", Revision 0, which incorporated the intent of the then "Proposed Atomic Energy Commission (AEC) Quality Assurance (QA) Criteria." The "Green Book" has proceeded through several revisions since 1969. The latest revision is NEDO-11209-04A, dated October 1980. Table 17.1-1 is a matrix showing the entire evolutionary process which the GE program has undergone since August 1968 and identifies related NRC and industry standards that were applied. The actual version in effect at any point in time controlled the QA measures applied to WNP-2 by GE for work when it was initiated, consistent with any necessary contractual adjustments to update from the 1970 base date of the contract with WPPSS. For example, any work initiated after March 1978, applies the criteria represented by "Green Book" (NEDO-11209-04A). Note that those portions dealing with the Standard Reactor Island (STRIDE) are not applicable to WNP-2 in that WNP-2 is not provided a STRIDE by GE.

In so far as the NSSS is concerned, GE positions and commitments to regulatory guides and ANSI Standards, as made in the applicable revisions of NEDO-11209, take precedence over the positions and commitments described in the FSAR Chapter 3.

17.1.4 BECHTEL POWER CORPORATION QUALITY ASSURANCE PROGRAM

17.1.4.1 Quality Assurance Topical Report

The Bechtel QAP Plan for use by the Bechtel Power Corporation during Construction Management and System Completion of WPPSS Project WNP-2 is described in the NRC-approved Bechtel Topical Report BQ-TOP-1, Revision 3A, Bechtel Quality Assurance Program for Nuclear Power Plants.

17.1.4.2 Scope of Responsibility

This section describes Bechtel responsibilities for providing quality-related services in Construction Management and Systems Completion to the Supply System on the WNP-2 Project. The scope of responsibility differs from that indicated in BQ-TOP-1 in that Bechtel does no function as the responsible design engineering organization. Therefore, those provisions in BQ-TOP-1 associated with design engineering do not apply.

Bechtel will have an engineering management group under the direction of the Project Engineering Manager. This group will provide engineering management staff support capability to the Supply System. Engineering personnel will assist in developing the scope and relative priority of remaining engineering activities and will interface with Supply System licensing personnel. Bechtel may perform engineering design assignments on a task basis. Such design tasks will meet design requirements established by the AE (B&R) and will be performed to the applicable requirements of BQ-TOP-1.

Bechtel will perform construction in the completion of systems, structures, components as assigned by the Supply System, utilizing materials provided by the Supply System.

Construction Management provisions for quality-related services include:

a. *Receiving, including receipt inspection of Supply System purchased items;*

b. *Storage and maintenance of Supply System purchased items;*

c. *Contractor/vendor QA documentation review, retention, and turnover to the Supply System;*

d. *Review and approval of onsite contractor quality-related procedures and manuals;*

e. *QA/QC audit and surveillance inspection over onsite contractor activities;*

f. *Administration of the project program for controlling nonconforming items;*

g. Administration of the project program for control of design documents, and

h. Procurement services, including procurement supplier quality services, in support of construction activities.

17.1.4.3 *<u>Project-Unique Modification to BQ-TOP-1, Revision 3A</u>*

a. Introduction, Page 3 - Replace Regulatory Guide 1.58 (August 1973) with Regulatory Guide 1.58, Revision 1 (September 1980).

b. Introduction, Page 3 - Add Regulatory Guide 1.146 "Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants" (Revision 0, 1978). See Section 1.8.3 for compliance statement.

c. Introduction, Page 3 - Replace ANSI Standard N45.2.12-1974 with Regulatory Guide 1.144, "Auditing of Quality Assurance Programs for Nuclear Power Plants" (Revision 1, 1980). See Section 1.8.3 for compliance statement.

d. Section 1, Organization, Subsection 1.5.1, Page 10 - Replace Subsection 1.5.1 with Attachment 1.

e. Section 1, Organization, Subsection 1.5.2, Page 10 - Replace Subsection 1.5.2 with Attachment 2.

f. Section 1, Organization, Subsection 1.5.4, Page 11- Replace Subsection 1.5.4 with Attachment 3.

g. Section 2, Quality Assurance Program (Subparagraphs 2 and 4), Page 23 - Change Regulatory Guide 1.58 (August 1973) to Regulatory Guide 1.58, Revision 1 (September 1980).

h. Section 2, Quality Assurance Program (Subparagraph 3), Page 23 - Change ANSI N45.2.12 to ANSI N45.2.23.

i. Change "Project Engineer" to "Project Engineering Manager" throughout.

j. Table 1, "Bechtel Quality Program Documents", Page 57 and 58 - Add to Table 1 the Project Documents shown on Attachment 4.

k. Add Figure 15, Bechtel Projects Management Organization, Attachment 5.

l. Add Figure 16, Quality Assurance/Quality Control Organization, Attachment 6.

m. *Appendix A, Bechtel Position on QA NRC Regulatory Guides and ANSI Standards - Delete 5th paragraph (A-7) on Page A-1; Delete pages A-7 through A-13 entirely. Delete 11th paragraph (A-22) on Page A-1; delete Pages A-22 and A-23 entirely.*

n. *Appendix B, Division Quality Policies, Scope, and Relationship to 10 CFR 50, Appendix B - Add Project Nuclear Quality Assurance Manual as shown by Attachment 7.*

ATTACHMENT 1

The Manager of Projects (Attachment 5) is the senior Bechtel representative assigned to the WNP-2 Project. The Manager of Projects reports to the Division Manager of Project Operations and is responsible for providing overall project direction to ensure the consistent and coordinated application of Bechtel policies and skills for the benefit of the WNP-2 Project. The Manager of Project's staff includes a Deputy Manager of Projects and other managers to coordinate activities in labor relations, the quality program, and administrative services.

ATTACHMENT 2

QUALITY ASSURANCE

The SFPD QA Manager (SFHO) is independent of the other managers within the division and has the authority to carry out the responsibilities listed below in directing the Division QAP. He is assisted by a staff of Quality Assurance Managers (SFHO) assigned to functional areas of Program, Technical Services, Training, Project QA, and Audit. The SFPD QA Manager's (SFHO) functions for the WNP-2 Project include:

a. *Provide technical guidance and concurrence for the WNP-2 Project QAP for conformance with the requirements of 10 CFR 50, Appendix B;*

b. *Formulate and approve Division Quality Assurance Department Procedures which define responsibilities, authority, and functions of SFPD home office staff Quality Assurance Department personnel. Review and concur with the WNP-2 PQAM and revisions;*

c. *Maintain an awareness of WNP-2 project status, through management audit and day-to-day contact with the Manager of Quality, and provide assistance to the Manager of Quality to ensure timely and effective implementation of the WNP-2 QAP;*

d. *Formulate and conduct management QA audits to assure compliance with the WNP-2 Nuclear Quality Assurance Manual (NQAM) and implementing procedures, and identify quality problems; identify the need for corrective action and initiate, recommend, coordinate or provide solutions; and verify implementation of solutions and corrective actions;*

e. *Provide and maintain a qualified and suitably trained staff of Quality Assurance Engineers to carry out required project and staff functions. Assign Quality Assurance Engineer(s) to the WNP-2 project and provide them with administrative direction through the QA Manager - Projects (SFHO);*

f. *Formulate and implement programs to provide indoctrination and training of Quality Assurance Department Personnel to ensure that suitable proficiency is maintained; and*

g. *From information supplied by the Manager of Quality, provide quarterly reports to the Division Manager and Manager of Quality Assurance, evaluating the status and adequacy of the WNP-BPC QAP, and advising of any problems requiring program revision or special attention including recommendations for corrective actions. At least annually, a meeting is held with the Division*

Manager (SFHO) and his staff on the subject of status and adequacy of the Division QAP. The Manager of Quality participates in this meeting to cover the status and adequacy of the WNP-2 QAP.

MANAGER OF QUALITY

The Manager of Quality receives administrative, technical, and project direction from the Manager of Projects, and is responsible for the project and technical direction of the WNP-2 QAP. The Manager of Quality receives technical guidance for QA and QC from the SFPD QA Manager (SFHO) and Chief Construction Quality Control Engineer (SFHO) respectively. He is assisted by, and provides project and technical direction to the Project Quality Assurance Engineer and Project Construction Quality Control Engineer (Attachment 6). The Manager of Quality is independent of the other line managers within the Project Management organization and has the authority to carry out the responsibilities listed below in directing the QAP including authority to stop work or control further processing. The Manager of Quality's functions include:

a. *Provide technical and project direction to Quality Assurance Engineers assigned to the Supply System projects;*

b. *Formulate and approve, after review and concurrence by the SFPD QA Manager (SFHO) the Supply System Projects SAR and QAPs as defined in the Supply System Project's NQAMs. The NQAMs shall be in conformance with the requirements of 10 CFR 50, Appendix B, the TPO Quality Program Policy Manual, and the appropriate Project SAR;*

c. *Formulate and approve, after review and concurrence by the SFPD QA Manager (SFHO) the revisions to the Supply System Projects SARS and NQAMs. Coordinate revisions to implementing procedures to improve effectiveness of the QAP and update the program;*

d. *Formulate and approve, after review and concurrence by the SFPD QA Manager (SFHO) the Project Quality Assurance Department Procedures and revisions for Supply System Projects which define responsibilities, authority, and functions of Supply System Projects Quality Assurance personnel;*

e. *Review quality-related procedures and manuals prepared by centralized support functions outside of the Division (e.g., Procurement, C&S, M&QS) to verify conformance with requirements of the Supply System Projects NQAMs and approve, through the Manager of Quality Assurance BPC, for use as part of the QAP on the Supply System projects;*

f. *Maintain an awareness of project status, through contact with the Manager of Projects and ensure timely and effective implementation of the QAP;*

g. *Direct the performance of project audits to ensure compliance with Supply System projects NQAMs and implementing procedures, and to identify quality problems; identify the need for corrective action and initiate, recommend, coordinate or provide solutions; and verify implementation of solutions and corrective actions;*

h. *Provide quarterly reports to the SFPD QA Manager (SFHO) evaluating the status and adequacy of the Supply System projects QAP and advising of any problems requiring program revision or special attention, including recommendations for corrective actions;*

i. *Review Division standard criteria for specifying QAP requirements applicable to contractors and subcontractors, and approve for use on the Supply System projects; and*

j. *Coordinate the Quality Assurance and Quality Control functions for the Supply System Projects with the Division groups having quality functions, and with groups outside the Division having quality functions, e.g., M&QS, C&S, and PSQD.*

ATTACHMENT 3

DIVISION CONSTRUCTION

The Manager of Division Construction provides technical and administrative direction of the Construction Department personnel. The Manager of Division Construction (SFHO) is assisted by CMs (SFHO), Chief Construction Engineers (SFHO), where assigned, and the Chief Construction Quality Control Engineer (SFHO). Construction Managers (SFHO) are responsible for the management and technical direction of assigned projects, and for ensuring that construction projects are provided with appropriate personnel and are following prescribed division practices and procedures for conduct of construction activities. Chief Construction Engineers (SFHO) are responsible for providing division standard work procedures to the projects.

Formal quality verification inspection and onsite contractor surveillance inspection activities performed by Bechtel are the responsibility of Construction Quality Control. The Chief Construction Quality Control Engineer (SFHO) is responsible for providing administrative direction to the Construction Quality Control Engineers assigned to the WNP-2 Project. The Chief Construction Quality Control Engineer's functions include:

a. *Provide administrative direction to the Project Construction Quality Control Engineer,*

b. *Assign quality control engineers to the project,*

c. *Assist with the training and qualification of construction quality control engineers, and*

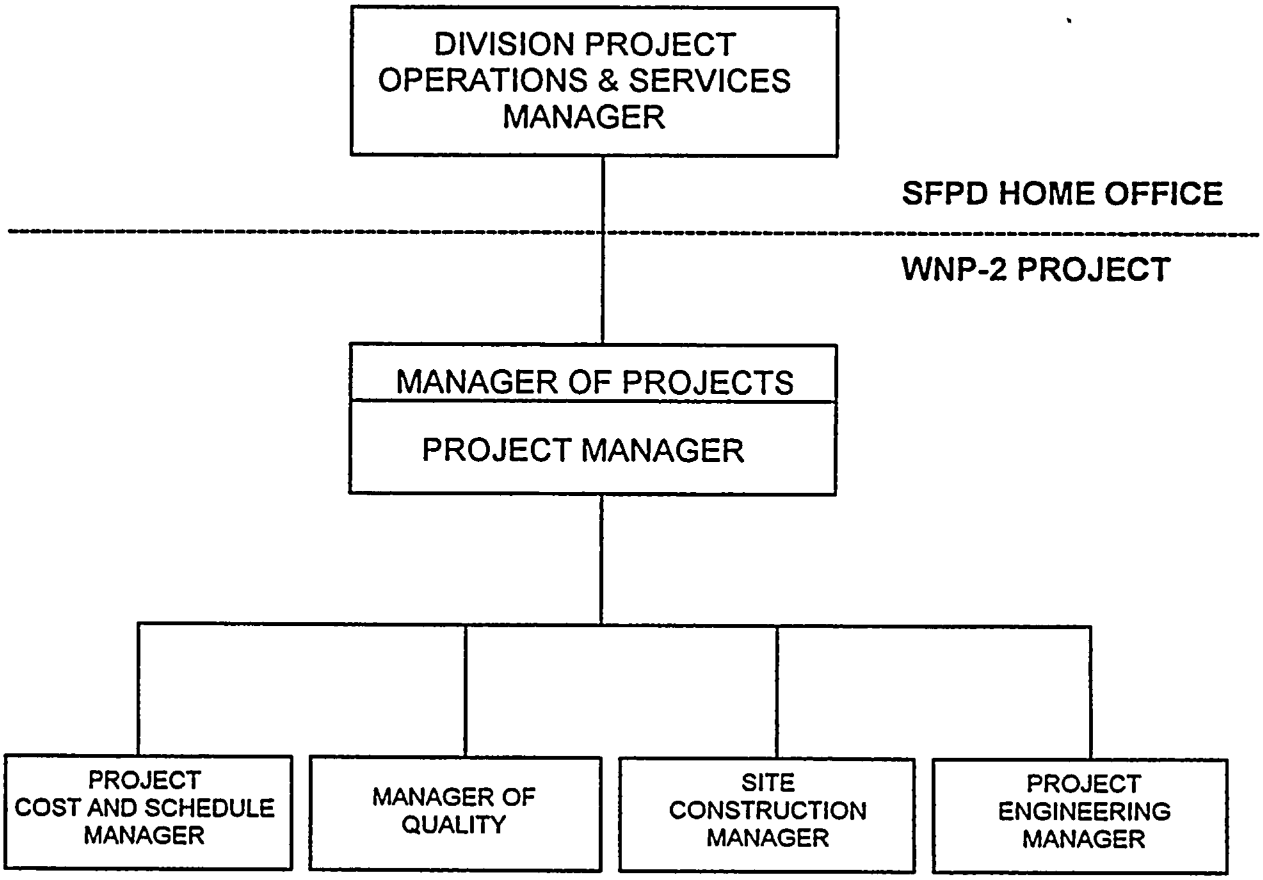
d. *Provide technical guidance to the Manager of Quality for the preparation of quality control procedures and instructions.*

ATTACHMENT 4

WNP-2 PROJECT QUALITY PROGRAM DOCUMENTS

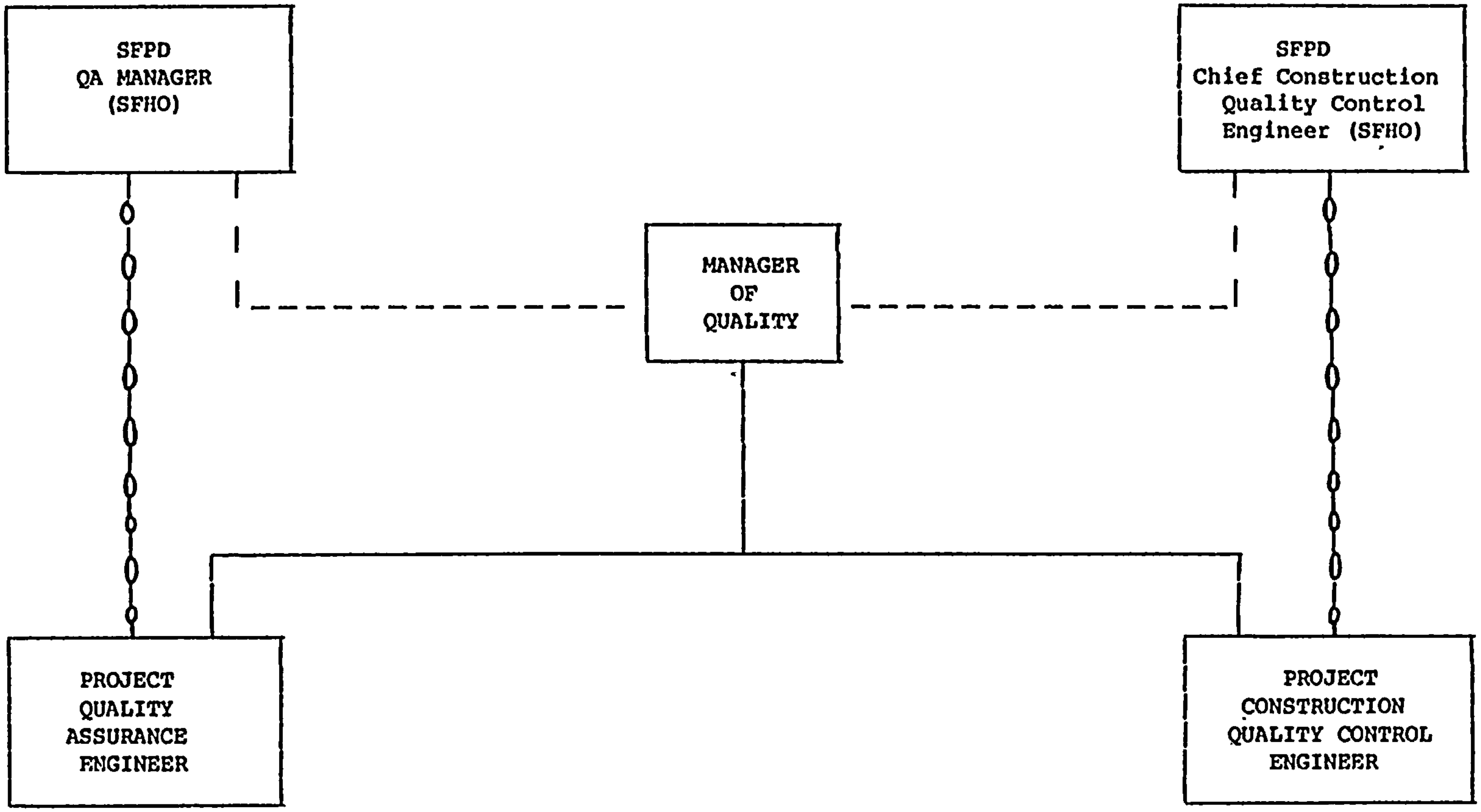
Documents	*Originating Authority*	*Review for QA Policy and Program Requirements*	*Authorizing Approval*	*Contents*
WNP-2 Nuclear Quality Assurance Manual (NQAM)	*Project QA Engineer*	*SFPD QA Manager (SFHO)*	*Manager of Quality*	*Quality program policy. Based on Division policy as contained in SFPD Standard NQAM*
WNP-2 Project QA manual (PQAM)	*Project QA Engineer*	*SFPD QA Manager (SFHO)*	*Manager of Quality*	*Procedures for conducting Project QA activities*
WNP-2 construction Quality Control Manual (CQCM)	*Project Construction*	*Project QA Engineer*	*Manager of Quality*	*Responsibilities and procedures for construction QC activities*
WNP-2 Construction Procedures	*Project Field Engineer*	*Project QA Engineer*	*Chief Construction Engineer (SFHO)*	*Responsibilities and requirements for construction site activities*
WNP-2 Bechtel Quality Assurance Manual ASME Nuclear Components	*Manager of Codes and Standards*	*Manager of Quality and SFPD - QA Manager (SFHO)*	*President - BPC and appropriate authorized code inspection agency*	*Policies and procedures for overall Bechtel Program applicable to ASME work*
Engineering Department Project Instructions	*Project Engineering Manager*	*Project QA Engineer*	*SFPD Engineering Manager*	*Responsibilities and requirements for engineering departments activities*
WNP-2 Field Procurement Procedures [individual jobsite instructions (IJI)]	*Project Field Procurement Manager*	*Project QA Engineer*	*Manager of Field Procurement*	*Responsibilities and requirements for field procurement activities*
Procurement Supplier Quality Manual	*Manager Procurement Supplier Quality*	*Manager QA - BPC*	*Manager Procurement Supplier Quality*	*Procedures for procurement, supplier quality activities*
Field Procurement	*Manager Field Procurement*	*Manager QA - BPC*	*Manager Field Procurement*	*Procedures for field procurement activities*

ATTACHMENT 5



ATTACHMENT 6

QUALITY ASSURANCE/QUALITY CONTROL ORGANIZATION



LEGEND AND NOTE

——— PROJECT AND TECHNICAL DIRECTION

- - - - TECHNICAL GUIDANCE AND COORDINATION

—o—o— ADMINISTRATIVE DIRECTION

NOTE: The SFPD QA Manager (SFHO) is responsible for performing management QA audits of the WNP-2 Project Quality Assurance/Quality Control Organization

Amendment 53
November 1998

APPENDIX B
DIVISION QUALITY POLICIES, SCOPE, AND RELATIONSHIP
TO 10 CFR 50, APPENDIX B
WNP-2 NUCLEAR QUALITY
ASSURANCE MANUAL

SAN FRANCISCO POWER DIVISION

Section 0

10CFR50 APP. B CRIT.	SUBJECT	1 Table of contents	2 QA Program Applicability	3 QA Program Definition	4 Definitions	5 Fire Protection QA Program	6 Radwaste Management System QA Program	7 Seismic II/I QA Program	8 Matrix
I	ORGANIZATION		●	●	●				
II	QUALITY ASSURANCE PROGRAM		●	●					
III	DESIGN CONTROL								
IV	PROCUREMENT DOCUMENT CONTROL								
V	INSTRUCTIONS, PROCEDURES, AND DRAWINGS			●					
VI	DOCUMENT CONTROL			●					
VII	CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES								
VIII	IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS								
IX	CONTROL OF SPECIAL PROCESSES								
X	INSPECTION								
XI	TEST CONTROL								
XII	CONTROL OF MEASURING AND TEST EQUIPMENT								
XIII	HANDLING, STORAGE AND SHIPPING								
XIV	INSPECTION, TEST, AND OPERATING STATUS								
XV	NONCONFORMING MATERIAL, PARTS OR COMPONENTS								
XVI	CORRECTIVE ACTION								
XVII	QUALITY ASSURANCE RECORDS								
XVIII	AUDITS								

Section I

10CFR50 APP. B CRIT.	SUBJECT	1 Organization Charts	2 SFPD Organization	3 Project QA Team	4 Project Management Team	5 Project Engineering Team	6 Project Construction Team	7 Project Organization Charts	8 Procurement Department	9 Materials & Quality Services Department	10 Bechtel Power Corporation	11 Construction Department
I	ORGANIZATION	●	●	●	●	●	●	●	●	●	●	●
II	QUALITY ASSURANCE PROGRAM	●										
III	DESIGN CONTROL											
IV	PROCUREMENT DOCUMENT CONTROL											
V	INSTRUCTIONS, PROCEDURES, AND DRAWINGS											
VI	DOCUMENT CONTROL											
VII	CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES											
VIII	IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS											
IX	CONTROL OF SPECIAL PROCESSES											
X	INSPECTION											
XI	TEST CONTROL											
XII	CONTROL OF MEASURING AND TEST EQUIPMENT											
XIII	HANDLING, STORAGE AND SHIPPING											
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XV	NONCONFORMING MATERIAL, PARTS OR COMPONENTS											
XVI	CORRECTIVE ACTION											
XVII	QUALITY ASSURANCE RECORDS											
XVIII	AUDITS											

Section II and Section III

10CFR50 APP. B CRIT.	SUBJECT	II-1 Design Control Procedures	II-2 Design Process and Change Control	II-3 Design Verification	II-4 Design Interface	II-5 Specialty Group Design Control	III-1 Supplier Evaluation	III-2 Field Procurement	III-3 Supplier Control & Source Surveillance	III-4 Supplier Document Processing
I	ORGANIZATION									
II	QUALITY ASSURANCE PROGRAM	●								
III	DESIGN CONTROL	●	●	●	●	●				
IV	PROCUREMENT DOCUMENT CONTROL						●	●		
V	INSTRUCTIONS, PROCEDURES, AND DRAWINGS	●								
VI	DOCUMENT CONTROL	●								
VII	CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES						●	●	●	
VIII	IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS									
IX	CONTROL OF SPECIAL PROCESSES									
X	INSPECTION								●	●
XI	TEST CONTROL			●						
XII	CONTROL OF MEASURING AND TEST EQUIPMENT									
XIII	HANDLING, STORAGE AND SHIPPING									
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XV	NONCONFORMING MATERIAL, PARTS OR COMPONENTS									
XVI	CORRECTIVE ACTION	●								
XVII	QUALITY ASSURANCE RECORDS									●
XVIII	AUDITS									

Section IV

10CFR50 APP. B CRIT.	SUBJECT	1 Construction Site Quality Program	2 Mat'l Rec, Stor, Maint, Hand, & Cont.	3 Field Inspection and Test	4 Nonconforming Materials	5 Control of Measuring and Test Equipment	6 System T/O for Preoperational Testing	7 Field Contractor/Subcontractor Control	8 Control of Special Processes
I	ORGANIZATION								
II	QUALITY ASSURANCE PROGRAM	●	●	●		●			●
III	DESIGN CONTROL								
IV	PROCUREMENT DOCUMENT CONTROL								
V	INSTRUCTIONS, PROCEDURES, AND DRAWINGS	●							
VI	DOCUMENT CONTROL	●							
VII	CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES		●	●	●			●	
VIII	IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS		●		●				
IX	CONTROL OF SPECIAL PROCESSES								●
X	INSPECTION			●				●	●
XI	TEST CONTROL			●			●		
XII	CONTROL OF MEASURING AND TEST EQUIPMENT					●			
XIII	HANDLING, STORAGE AND SHIPPING	●	●					●	
XIV	INSPECTION, TEST, AND OPERATING STATUS			●			●		
XV	NONCONFORMING MATERIAL, PARTS OR COMPONENTS				●				
XVI	CORRECTIVE ACTION				●				
XVII	QUALITY ASSURANCE RECORDS								
XVIII	AUDITS								

Section V and Section VI

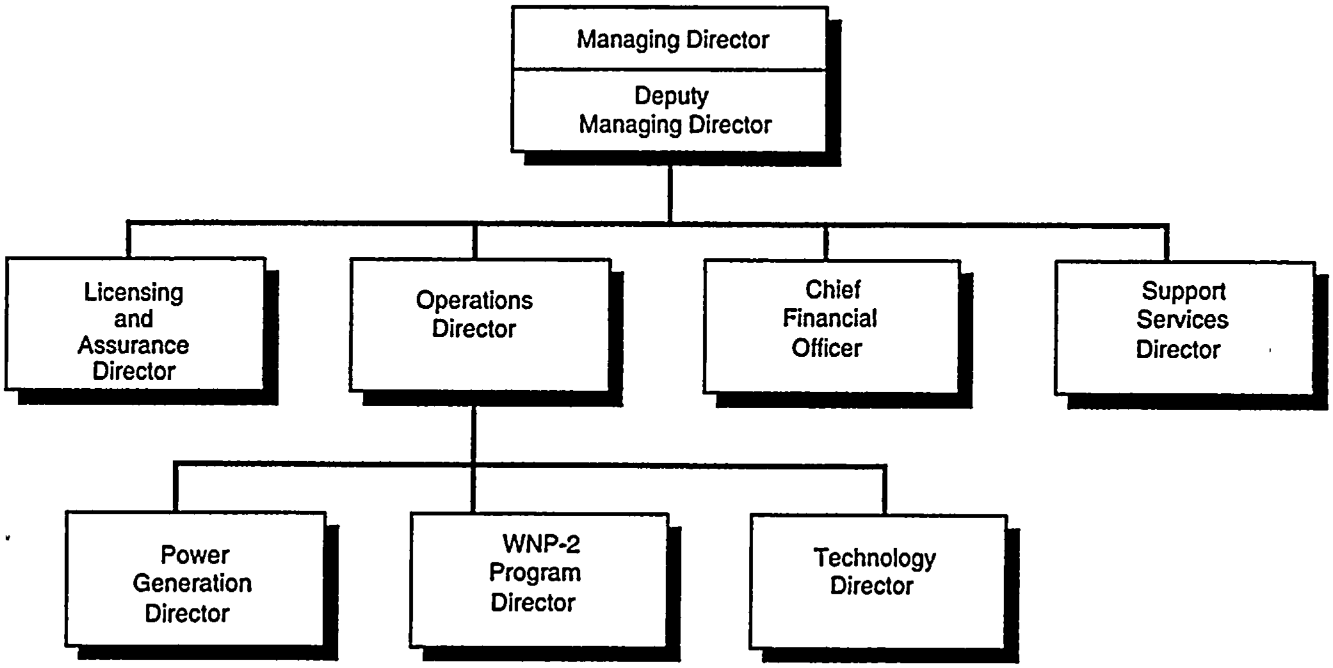
10CFR50 APP. B CRIT.	SUBJECT	V-1 NQAM Policies and Revisions	V-2 Quality Assurance Procedures	V-3 Indoctrination, Training & Qualification	V-4 Management Corrective Action	V-5 Stop Work	V-6 Procedure Control	V-7 Quality Assurance Records	V-8 Quality Action Requests	V-9 Status and Adequacy Review	VI-1 Quality Audit System
I	ORGANIZATION										
II	QUALITY ASSURANCE PROGRAM	●	●	●						●	
III	DESIGN CONTROL										
IV	PROCUREMENT DOCUMENT CONTROL										
V	INSTRUCTIONS, PROCEDURES, AND DRAWINGS	●	●				●				
VI	DOCUMENT CONTROL						●				
VII	CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES										
VIII	IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS										
IX	CONTROL OF SPECIAL PROCESSES										
X	INSPECTION										
XI	TEST CONTROL										
XII	CONTROL OF MEASURING AND TEST EQUIPMENT										
XIII	HANDLING, STORAGE AND SHIPPING										
XIV	INSPECTION, TEST, AND OPERATING STATUS										
XV	NONCONFORMING MATERIAL, PARTS OR COMPONENTS					●					
XVI	CORRECTIVE ACTION				●				●		
XVII	QUALITY ASSURANCE RECORDS							●			
XVIII	AUDITS			●							●

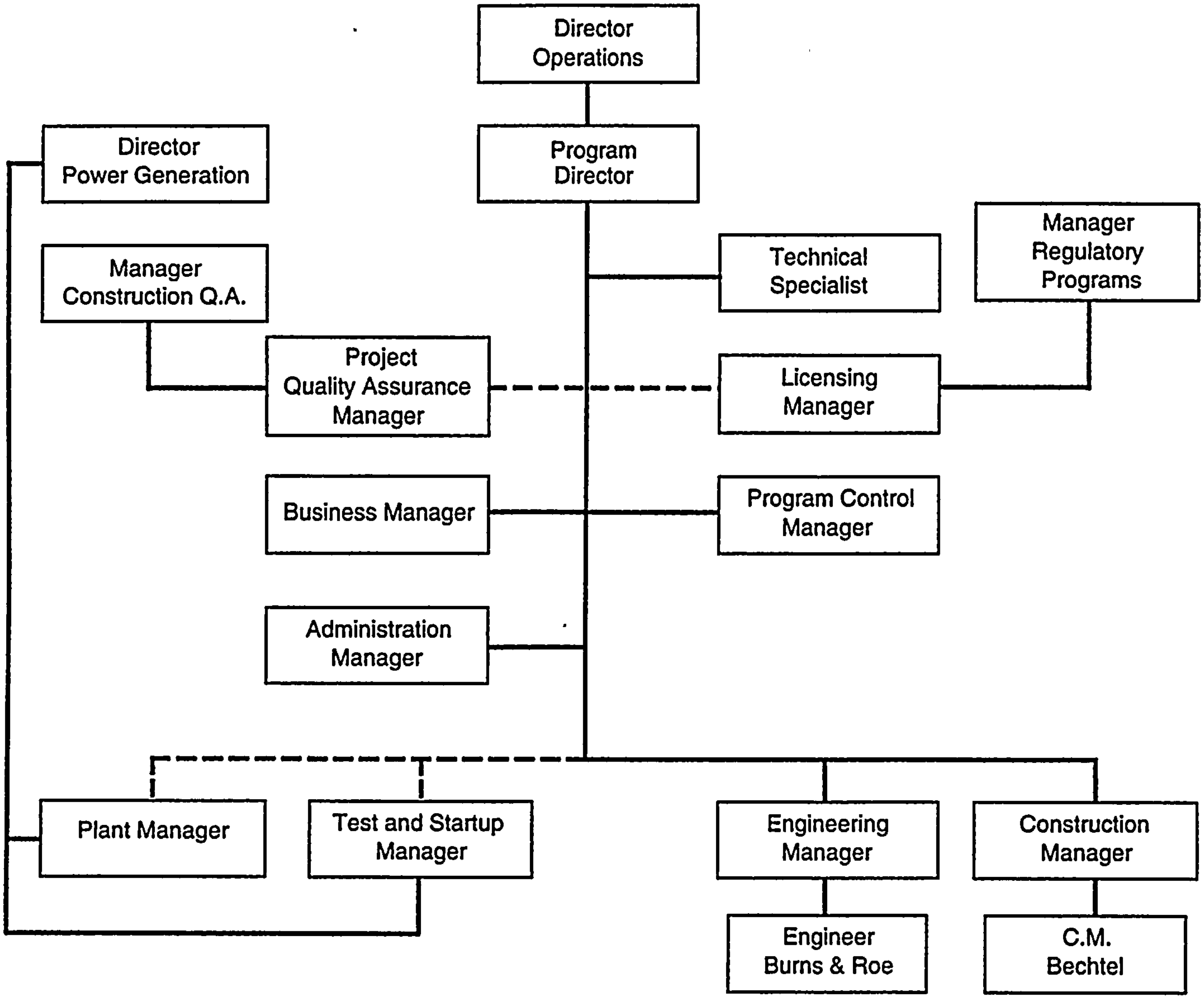
ATTACHMENT 7

TABLE 17.1-1

GENERAL ELECTRIC QUALITY ASSURANCE EVOLUTIONARY PROCESS

Date of Effectiveness	NED Quality Objectives - Safe and Reliable Systems and Components	Intent of Proposed AEC QA Criteria	Intent of 10 CFR 50 Appendix B (proposed)	10 CFR 50 Appendix B	ANSI N45.2	AEC Regulatory Guide 1.28	ASME B&P Code	QA Related Regulatory Guide and ANSI Standards
8/20/68	Blue Book							
10/1/69	Green Book Rev. 0	X						
5/1/70	Green Book Rev. 1	X						
9/15/71	Green Book Rev. 2		X					
6/1/72	Green Book Rev. 3			X	X			
3/1/73	Green Book Rev. 4 (NEDO-11209)			X	X			
5/7/74	Green Book Rev. 5 (NEDO-11209-01)			X	X	X	X	X
12/12/75	Green Book (NEDO-11209-02)			X	X	X	X	X
11/76	Green Book (NEDO-11209-03A)			X	X	X	X	X
3/31/78	Green Book (NEDO-11209-04A)			X	X	X	X	X
10/80	Green Book (NEDO-11209-04A)			X	X	X	X	X


Managing Director
Deputy Managing Director
Licensing and Assurance Director
Operations Director
Chief Financial Officer
Support Services Director
Power Generation Director
WNP-2 Program Director
Technology Director

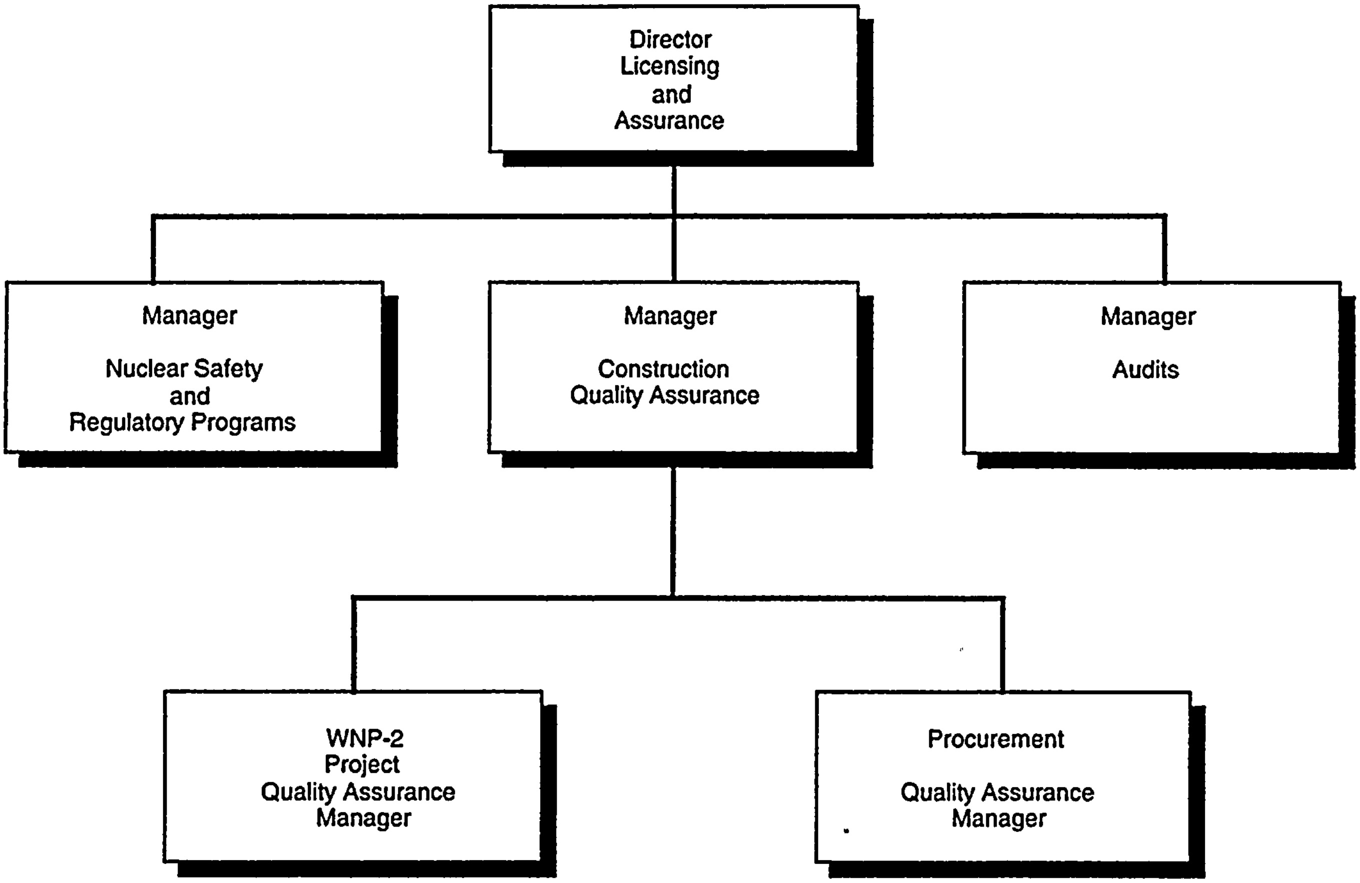


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Supply System WNP-2 Organization Chart

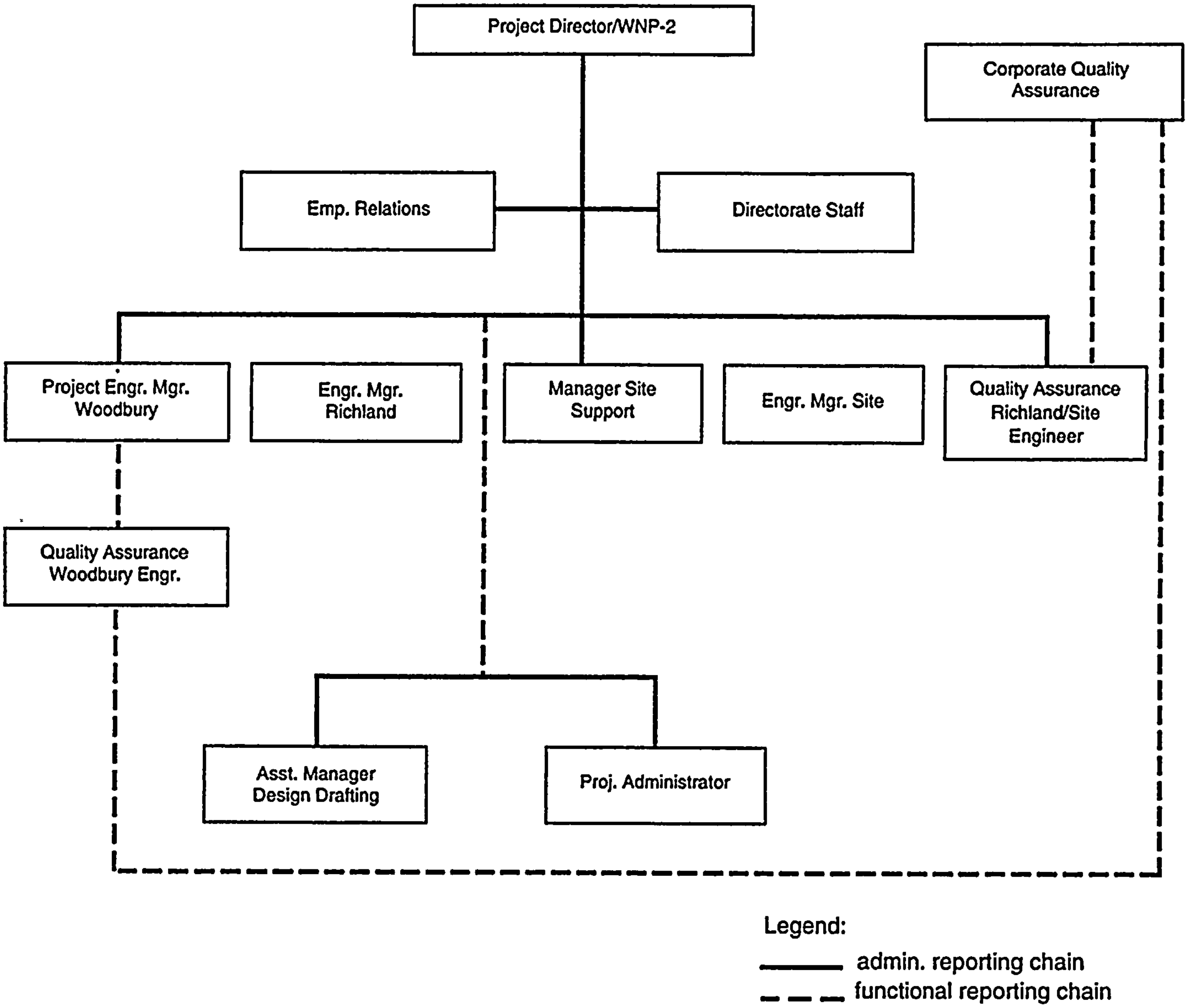
Draw. No. 960222.80	Rev.	Figure 17.1-2

Form No. 960690

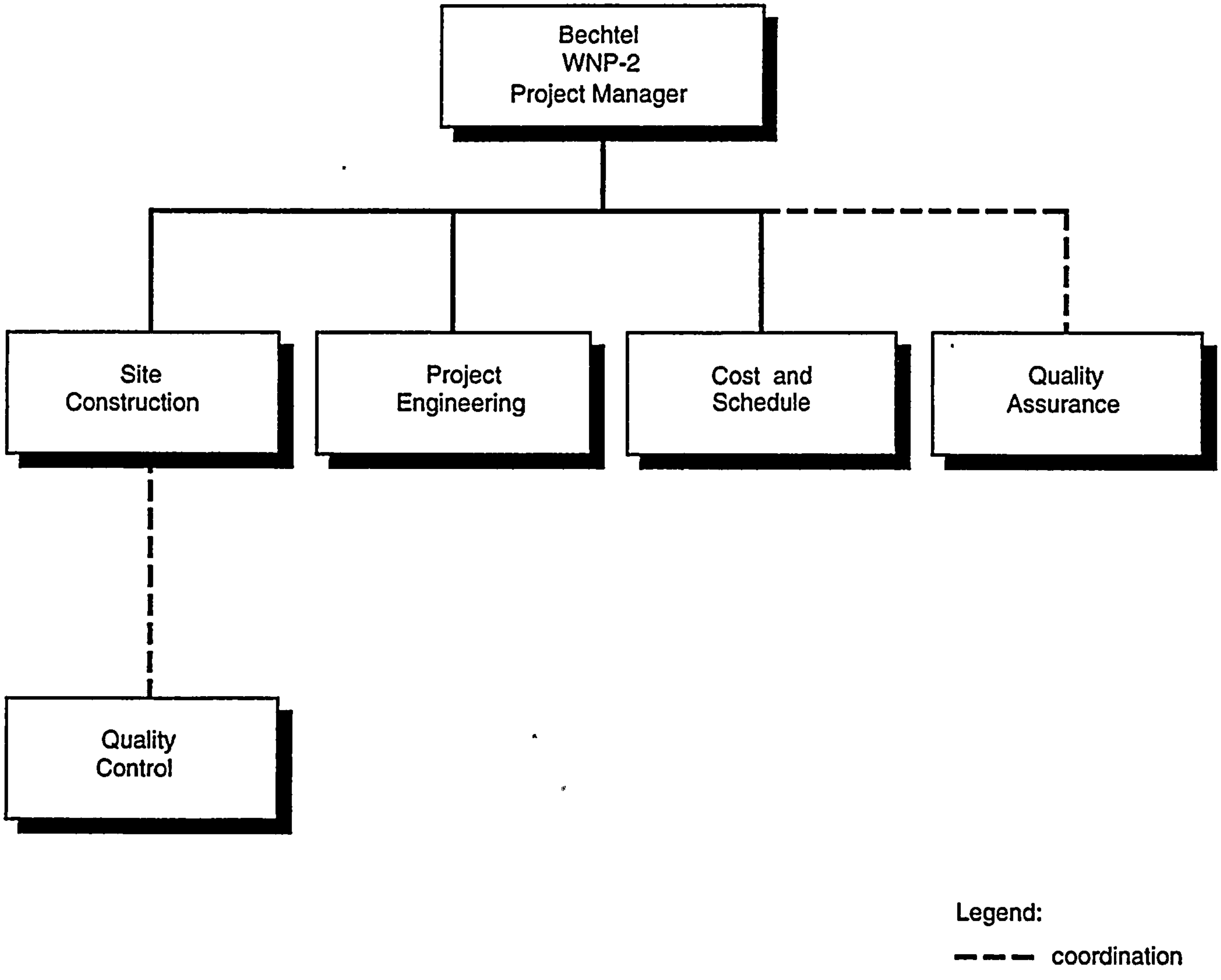


WNP-2 Project Management Organization Chart

Draw. No. 960222.81 | Rev. | Figure 17.1-3



Burns and Roe, Inc. WNP-2 Organization Chart



Bechtel WNP-2 Organization Chart

17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

The WNP-2 program for quality assurance during the operations phase is provided separately in the Washington Public Power Supply System Operational Quality Assurance Program Description (WPPSS-QA-004).

Appendix B

WNP-2 RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

TABLE OF CONTENTS

Appendix B

WNP-2 RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

LIST OF TABLES

I.A.1.2 Shift Supervisor Responsibilities

Position (NUREG-0578, 2.2.1.A)

a. The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

b. Plant procedures shall be reviewed to ensure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:

    1. The responsibility and authority of the shift supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The idea shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

    2. The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.

    3. If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

c. Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function of the shift supervisor is to provide for ensuring safety.

d. The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for

ensuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

Clarification

The table attached provides clarification to the above position.

WNP-2 Position

The administrative duties of the shift manager have been reviewed; inappropriate functions were delegated to other personnel including the shift support supervisor. The shift support supervisor will assist the shift manager by directing personnel assigned to perform balance-of-plant operating functions and by performing shift administrative duties.

WNP-2 procedures have been reviewed to ensure that the shift manager, control room supervisor, shift support supervisor, and operator functions are defined adequately to establish the shift manager as the commanding authority for plant operations relative to other plant management. The shift manager is to ensure the safe operation of the plant under all conditions. During an emergency, the responsibility for directing and controlling the actions of the operating crew to place and maintain the plant in a safe condition rests with the shift manager. During accident conditions, the shift manager will normally be in the control room at all times until properly relieved. He may elect to direct recovery activities at the scene of the accident.

This principle has been reinforced by management directive that emphasizes that the shift manager's primary responsibility is the safe operation of the plant under all conditions.

The shift manager's administrative duties will be reviewed annually by the operations manager to ensure that administrative responsibilities do not interfere with the primary responsibility.

Appropriate documentation will be available onsite for review by the Nuclear Regulatory Commission (NRC) I&E Branch.

This position has been accepted in the NRC Staff Safety Evaluation Report NUREG-0892 dated March 1982, section 13.5.1.8.

TABLE I.A.1.2-1

SHIFT SUPERVISOR RESPONSIBILITIES (2.2.1.A)

NUREG-0578 Position (Position Number)	Clarification
Highest Level of Corporate Management (1.)	Vice President, Nuclear Operations
Periodically Reissue (1.)	Annual Reinforcement of Company Policy
Management Direction (1.)	Formal Documentation of Shift Personnel, All Plant Management, Copy to IE Region
Properly Defined (2.0)	Defined in Writing in a Plant Procedure
Until Properly Relieved (2.B)	Formal Transfer of Authority, Valid SRO License, Recorded in Plant Log
Temporarily Absent (2.C)	Any Absence
Control Room Defined (2.C)	Includes Shift Manager Office Adjacent to the Control Room
Designated (2.C)	In Administrative Procedures
Clearly Specified	Defined in Administrative Procedures
SRO Training	Specified in ANS 3.1(Draft) Section 5.2.1.8
Administrative Duties (4.)	Not Affecting Plant Safety
Administrative Duties Reviewed (4.)	On Same Interval as Reinforcement: i.e., Annual by Vice President, Nuclear Operations

This requirement was met before fuel loading. See NUREG-0578, Section 22.1a, Item 4 and NRC letters of September 27 and November 9, 1979

I.A.2.1 Immediate Upgrading of Operator and Senior Operator Training and Qualification

Position (NUREG-0737)

Effective December 1, 1980, an applicant for a senior reactor operator (SRO) license will be required to have been a licensed operator for 1 year.

Applicants for SRO either come through the operations chain (C operator to B operator to A operator, etc.) or are degree-holding staff engineers who obtain licenses for backup purposes.

In the past, many individuals who came through the operator ranks were administered SRO examinations without first being an operator. This was clearly a poor practice and the letter of March 28, 1980, requires reactor operator experience for SRO applicants.

However, the NRC does not wish to discourage staff engineers from becoming licensed SROs. This effort is encouraged because it forces engineers to broaden their knowledge about the plant and its operation.

In addition, to attract degree-holding engineers to consider the shift supervisor's job as part of their career development, the NRC should provide an alternate path to holding an operator's license for 1 year.

The track followed by a high school graduate (a non-degreed individual) to become an SRO would be 4 years as a control room operator, at least one of which would be as a licensed operator, and participation in an SRO training program that includes 3 months on shift as an extra person.

The track followed by a degree-holding engineer would be, at a minimum, 2 years of responsible nuclear power plant experience as a staff engineer, participation in an SRO training program equivalent to a cold applicant training program, and 3 months on shift as an extra person in training for an SRO position.

Holding these positions ensures that individuals who will direct the licensed activities of licensed operators have had the necessary combination of education, training, and actual operating experience prior to assuming a supervisory role at the facility.

The staff realizes that the necessary knowledge and experience can be gained in a variety of ways. Consequently, credit for equivalent experience should be given to applicants for SRO licenses.

Applicants for SRO licenses at a facility may obtain their one year operating experience in a licensed capacity (operator or senior operator) at another nuclear power plant. In addition,

actual operating experience in a position that is equivalent to a licensed operator or senior operator at military propulsion reactors will be acceptable on a one-for-one basis. Individual applicants must document this experience in their individual applications in sufficient detail so that the staff can make a finding regarding equivalency.

Applicants for SRO licenses who possess a degree in engineering or applicable sciences are deemed to meet the above requirement, provided they meet the requirements set forth in sections A.1.a and A.2 in enclosure 1 in the letter from H. R. Denton and all power reactor applicants and licensees, dated March 28, 1980, and have participated in a training program equivalent to that of a cold senior operator applicant.

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.

Clarification

None.

WNP-2 Position

WNP-2 was not yet in operation at the imposition of this requirement, however, all initial license applicants went through a training program designed to supply the equivalent of the reactor operator experience not available to them, and as such, license applicants who successfully completed the Cold License Training Program at the SRO level were scheduled to take an SRO exam. Those license candidates who successfully completed the program at the RO level were scheduled to take an RO exam.

Individuals applying for an SRO license 1 year after fuel load have been required to have been an RO for at least 1 year, unless previous experience in an equivalent position at another nuclear plant or at a military propulsion reactor precluded the need for it. License applicants falling in the latter category have been documented on a case-by-case basis regarding equivalency. In addition, SRO license applicants who possess a degree in engineering or applicable sciences are considered to meet the 1 year experience requirement as an RO provided they

a. Satisfy the requirements set forth in sections A.1.a and A.2 in enclosure 1 of the letter from H. R. Denton to all power reactor applicants and licensees, dated March 28, 1980, and

b. Have participated in a training program equivalent to that of a cold SRO applicant.

This position has been accepted in the WNP-2 Safety Evaluation Report NUREG-0892 dated March 1982, section 13.2.1.1.

The italicized information is historical and was provided to support the application for an operating license.

I.C.1 GUIDANCE FOR THE EVALUATION AND DEVELOPMENT OF PROCEDURES FOR TRANSIENTS AND ACCIDENTS

Position *(NUREG-0737)*

In the letters of September 13 and 27, October 10 and 30, and November 9, 1979, the Office of Nuclear Reactor Regulation required licensees of operating plants, applicants for operating licenses and licensees of plants under construction to perform analyses of transients and accidents, prepare emergency procedure guidelines, upgrade emergency procedures, including procedures for operating with natural circulation conditions, and to conduct operator retraining (see also Item I.A.2.1). Emergency procedures are required to be consistent with the actions necessary to cope with the transients and accidents analyzed. Analyses of transients and accidents were to be completed in early 1980 and implementation of procedures and retraining were to be completed 3 months after emergency procedure guidelines were established; however, some difficulty in completing these requirements has been experienced. Clarification of the scope of the task and appropriate schedule revisions are being developed. In the course of review of these matters on Babcock and Wilcox (B&W) designed plants, the staff will follow up on the bulletin and orders matters relating to analysis methods and results, as listed in NUREG-0660, Appendix C (see Table C.1, Items 3, 4, 16, 18, 24, 25, 26, 27; Table C.2,Items 4, 12, 17, 18, 19, 20; and Table C.3, Items 6, 35, 37, 38, 39, 41, 47, 55, 57).

Changes to Previous Requirements and Guidance:

a. Modification to Clarification

1. Addresses owners' group and vendor submittals.

2. References to task action plan Items I.C.8 and I.C.9.

3. Scope of procedures review is explained.

4. Establishes configuration control of guidelines for emergency procedures.

b. Modification to Implementation

1. Deleted reference to NUREG-0578, Recommendation 2.1.9 for Item I.C.1(a)2, inadequate core cooling.

The complete NRC position description and clarification is contained in NUREG-0737 - Task I.C.1.

This requirement is to be completed by fuel load.

Clarification

None.

WNP-2 Position

WNP-2 has participated, and continues to participate, in the BWR Owner's Group program to develop Emergency Procedure Guidelines for General Electric Boiling Water Reactor. Following are a brief description of the submittals to date, and a justification of their adequacy to support guidelines development.

a. Description of Submittals

1. NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," August 1979; including additional sections submitted in prepublication form since August 1979.

(a) Section 3.1.1 (Small Break LOCA).

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) Section 3.2.1 (Loss of Feedwater) - revised and resubmitted in prepublication from March 31, 1980.

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) *Section 3.2.2 (Other Operational Transients) - submitted in prepublication form March 31, 1980; revised and resubmitted in prepublication form August 22, 1980.*

Description and analysis of each FSAR Chapter 15 event resulting in a reactor system transient; demonstration of applicability of analyses of FSAR 3.1.1, 3.2.1, and 3.5.2.1 to each event; demonstration of applicability of Emergency Procedure Guidelines to each event.

(d) *Section 3.3 (BWR Natural and Forced Circulation).*

Description of natural and forced circulation cooling; factors influencing natural circulation, including noncondensables; re-establishment of forced circulation under transient and accident conditions.

(e) *Section 3.5.2.1 (Analyses to Demonstrate Adequate Core Cooling) - submitted in prepublication form November 30, 1979; revised and resubmitted in prepublication form September 16, 1980.*

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

(f) *Section 3.5.2.3 (Diverse Methods of Detecting Adequate Core Cooling) - submitted in prepublication form December 28, 1979.*

Description of indications available to the BWR operator for the detection of adequate core cooling (detailed instrument responses are described in FSAR 3.1.1, 3.2.1, and 3.5.2.1).

(g) *Section 3.5.2.4 (Justification of Analysis Methods) - submitted in pre-publication form September 16, 1980.*

Description and justification of analysis methods for extremely degraded cases treated in FSAR 3.5.2.1.

2. *BWR Emergency Procedure Guidelines (Revision 3).*

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.

3. *NEDO-24708A, Revision 1, December 1980.*

b. *Adequacy of Submittals:*

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

WNP-2 believes that in view of these findings, no further detailed justification of the analysis 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 of Reference 1 identifies several such areas. WNP-2 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 reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures" is complete.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, Supplement 5 dated April 1984, section 13.5.2.2.

References

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

I.C.2 SHIFT AND RELIEF TURNOVER PROCEDURES

Position

The licensees shall review and revise as necessary the plant procedure for shift and relief turnover to ensure the following:

a. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisors to complete and sign. The following items, as a minimum, shall be included in the checklist.

   1. Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

   2. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console (what to check and criteria for acceptable status shall be included in the checklist).

   3. Identification of systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement (this shall be recorded as a separate entry on the checklist).

b. Checklists or logs shall be provided for completion by the offgoing and ongoing auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by themselves could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist).

c. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedure (for example, periodic independent verification of system alignments).

Clarification

None.

WNP-2 Position

The control room operator's checklist will be designed to do the following:

a. Ensure that critical plant parameters are monitored and are within allowable limits,

b. Ensure the availability and correct alignment of essential systems, and

c. Identify all systems or components which are in a degraded mode of operation and compare each length of time in the degraded mode to Technical Specifications action requirements.

The off-going and on-coming shift manager, control room supervisor, and on-coming control room operator positions will signify checklist status and content.

A checklist designed for balance-of-plant shift turnover will identify any equipment under maintenance or test which could either (a) by itself degrade a system which is critical to the prevention and mitigation of operational transients and accidents or (b) initiate an operational transient.

The off-going or on-coming shift support supervisors and the on-coming equipment operators with rounds will signify checklist status and content for the balance-of-plant checklists.

WNP-2 will establish a system to evaluate the effectiveness of the shift and relief turnover procedure.

With WNP-2 receiving an operating license December 19, 1983, and going through test and startup phases prior to that date the shift and relief turnover procedures have been under continuous scrutiny for over 2 years. This has resulted in changes reviewed and accepted by the Plant Operations Committee to increase the efficiency and effectiveness of the procedures.

I.C.4 CONTROL ROOM ACCESS

Position (NUREG-0578 2.2.2.A)

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support the operation, and to predesignated NRC personnel. Provisions shall include the following:

a. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access, and

b. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside of the control room.

Clarification

None.

WNP-2 Position

A WNP-2 procedure has been implemented to establish the shift manager (SRO) and, in his absence, the control room supervisor (SRO) as the authority and responsibility for limiting access to the control room. Nonessential personnel are excluded from the control room when their presence is hampering operations. Nonessential personnel are defined as those not required by the shift manager to assist in safe plant operation and may include anyone not normally assigned a shift control room position. If required, plant security can be used to enforce the policy.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 13.5.1.8.

Additionally, procedures establish the same line of succession for control room authority and responsibility in the event of an emergency. The procedures specifically address lines of communication and authority for management personnel not in direct command of operations and assigned responsibilities outside the control room. Instructions or orders impacting operations are reviewed by the operations manager and transmitted to the shift manager.

I.C.6 GUIDANCE ON PROCEDURES FOR VERIFYING CORRECT PERFORMANCE OF OPERATING ACTIVITIES

Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to ensure 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.

Clarification

Item I.C.6 of the NRC Task Action Plan (NUREG-0660) and Recommendation 5 of NUREG-0585 propose requiring that licensees' procedures be reviewed and revised, as necessary, to ensure that an effective system of verifying the correct performance of operating activities is provided. An acceptable program for verification of operating activities is described below.

The American Nuclear Society has prepared a draft revision to ANSI Standard N18.7-1972 (ANS 3.2), "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." A second proposed revision to Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," which is to be issued for public comment in the near future, will endorse the latest draft revision to ANS 3.2 subject to the following supplemental provisions:

a. Applicability of the guidance of Section 5.2.6 should be extended to cover surveillance testing in addition to maintenance.

b. In lieu of any designated senior reactor operator (SRO), the authority to release systems and equipment for maintenance or surveillance testing or return-to-service may be delegated to an onshift SRO, provided provisions are made to ensure that the shift supervisor is kept fully informed of system status.

c. Work permits involving tagging for maintenance or surveillance testing are verified by the shift manager (or his designee) for correct implementation of control measures. Independent verification by qualified individuals is made for installation or removal of temporary modifications such as jumpers, lifted leads or bypass lines. Routine independent verification of equipment status at the location of the equipment will be performed for return-to-service activities of all important safety-related equipment having no control room status indications. These verifications will be by qualified equipment operators.

d. Equipment control procedures should include assurance that control room operators are informed of changes in equipment status and the effects of such changes.

e. For the return-to-service of equipment important to safety, a second qualified operator should verify proper systems alignment unless functional testing can be performed without compromising plant safety, and all equipment, valves, and switches involved in the activity are correctly aligned.

NOTE: A licensed operator possessing knowledge of the systems involved and the relationship of the systems to plant safety would be a "qualified" person. The staff is investigating the level of qualification necessary for other operators to perform these functions.

For plants that have or will have automatic system status monitoring as discussed in Task Action Plan Item I.D.3, NUREG-0660, the extent of human verification of operations and maintenance activities will be reduced. However, the need for such verification will not be eliminated in all instances.

WNP-2 Position

WNP-2 will prepare or revise procedures as necessary to implement an effective system for verification of operating activities important to safety. These procedures were implemented prior to fuel load. The preparation of these procedures was guided by ANS 3.2 Section 5.2.6 and the following supplemental provisions.

a. ANS 3.2 Section 5.2.6 will be applied to both maintenance and technical specification surveillances as described below.

b. The shift manager has the designated responsibility for implementing procedures for release of systems and equipment for maintenance or surveillance testing and for return-to-service. This responsibility may be delegated to a licensed SRO. The shift manager will remain informed by reviewing records and receiving turnover.

c. Clearance tagging for maintenance or surveillance testing are independently verified by the shift manager (or his designee) for correct implementation of control measures. Independent verification is also made for installation or removal of temporary modifications such as jumpers, lifted leads, or bypass lines on safety-related or fire protection systems not controlled by approved procedures. Routine independent verification of equipment status at the location

of the equipment will be performed for return-to-service activities of all safety-related and fire protection equipment having no control room status indications.

d. Equipment control procedures are implemented through the control room such that control room personnel are aware of changes being made in equipment status and the effects of such changes.

e. Routine independent verification of status at the location of safety-related or fire protection equipment is limited to return-to-service activities performed prior to startups following refueling or long-term outages in accordance with the ALARA concept to limit accumulation of personnel radiation exposures. In addition to the above, independent verification of safety-related locked valves will be made whenever their status is changed.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 13.5.1.8.

I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

Position

Obtain nuclear steam supply system (NSSS) vendor review of low power testing procedures to further verify their adequacy.

This requirement must be met before fuel loading (NUREG-0694).

Clarification

None.

WNP-2 Position

The NSSS vendor (General Electric Company) has reviewed and documented the low power testing procedures, power ascension test procedures, and emergency procedures. This review considered the BWR Emergency Procedure guidelines submitted to the NRC on behalf of BWR Owners' Group on June 30, 1980, by letter from R. H. Buchholz to D. G. Eisenhut.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 13.5.2.3 and confirmed in I&E Inspection 84-04.

I.C.8 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NEAR-TERM OPERATING LICENSE APPLICANTS

Position

Correct emergency procedures, as necessary, based on 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, stream line break, or steam-generated tube rupture).

This action will be completed prior to issuance of a full-power license (NUREG-0694).

Clarification

None.

WNP-2 Position

WNP-2 has developed procedures based on the BWR Owners' Group Emergency Procedure Guidelines. These procedures are further addressed in response to I.C.1, Short-Term Accident Analysis and Procedure Revision.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 13.5.2.3.

I.D.1 CONTROL ROOM DESIGN REVIEWS

Position

In accordance with Task Action Plan I.D.1, Control Room Design Reviews (NUREG-0660), 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 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 (NUREG-0737).

Clarification

NRR is presently developing human engineering guidelines to assist each licensee and applicant in performing detailed control room review. A draft of the guidelines has been

published for public comment as NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation." The due date for comments on this draft document was September 29, 1980. NRR will issue the final version of the guidelines as NUREG-0700, by February 1981, after receiving, reviewing, and incorporating substantive public comments from operating reactor licensees, applicants for operating licenses, human factors engineering experts, and other interested parties. NRR will issue evaluation criteria, by July 1981, which will be used to judge the acceptability of the detailed reviews performed and the design modification implemented.

Applicants for operating licenses who will be unable to complete the detailed control room design review prior to issuance of a license are required to perform a preliminary control room design assessment to identify significant human factors problems. 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 and will emphasize the following aspects of the control room:

a. The adequacy of information presented to the operator to reflect plant status for normal operation, anticipated operational occurrences, and accident conditions,

b. The groupings of displays and the layout of panels,

c. Improvements in the safety monitoring and human factors enhancement of controls and control displays,

d. The communications from the control room to points outside the control room, such as the onsite technical support center, remote shutdown panel, offsite telephone lines, and to other areas within the plant for normal and emergency operation,

e. The use of direct rather than derived signals for the presentation of process and safety information to the operator,

f. The operability of the plant from the control room with multiple failures of nonsafety-grade and nonseismic systems,

g. The adequacy of operating procedures and operator training with respect to limitations of instrumentation displays in the control room,

h. The categorization of alarms, with unique definition of safety alarms, and

i. The physical location of the shift supervisor's office either adjacent to or within the control room complex.

Prior to the onsite review/audit, NRR will require a copy of the applicant's preliminary assessment and additional information which will be used in formulating the details of the onsite review/audit.

<u>WNP-2 Position</u>

WNP-2 has undertaken an aggressive program to complete a control room review program in accordance with this task.

The schedule and activities for the review of the WNP-2 Control Room and submittal of an assessment report to the NRR are as follows:

a. A preliminary assessment of WNP-2's Control Room based on the BWR Owners' Subgroup review program draft criteria and NRC draft document NUREG/CR-158 was submitted to NRR in January 1982.

b. A Detailed Control Room Design Review (DCRDR) Preliminary Report based on a review of the WNP-2 Control Room by the BWR Owners' Group and WNP-2 in-house Human Factors Task Force against the BWR Owners' Group Control Room Design Review Program Plan and NUREG-0700 was submitted to NRR in April 1983.

c. Based on NRR reviews of the preliminary DCRDR report and onsite audit, a Response to NRC Human Factors Engineering Preliminary Design Assessment Audit Report was submitted to NRR in October 1983.

d. A WNP-2 Control Room Design Review Program Plan documenting the WNP-2 methodology and resources used, in accordance with NUREG-0700, was submitted in February 1984.

e. A DCRDR Final Report, per the WNP-2 operating license was submitted to NRR on November 1, 1985, Letter GO2-85-758.

The schedule and activities for the implementation of corrections for the WNP-2 Control Room are as follows:

a. All major hardware and procedural findings noted during the preliminary DCRDR report were completed prior to fuel load.

b. All residual findings and findings noted in the DCRDR final report are scheduled to be completed during the first refueling outage.

The NRC Safety Evaluation Report (SER) for the WNP-2 DCRDR was issued as Reference 1. The Supply System responded to the SER in Reference 2. By Reference 3 the Supply System stated that all DCRDR items had been implemented. In Reference 4 the NRC stated that based upon the Reference 3 submittal, they found that WNP-2 satisfies all of the DCRDR requirements of Supplement 1 to NUREG-0737 and that TMI Item I.D.1.2 was considered closed (note that NUREG 0737 and its Supplement 1 do not have an Item 1.D.1.2; only I.D.1).

References:

1. *Letter, G. W. Knighton (NRC) to G. C. Sorensen (SS), "Detailed Control Room Design Review (TAC No. 56181)," dated October 13, 1987.*

2. *Letter, G. C. Sorensen (SS) to NRC, "Nuclear Plant No. 2, Detailed Control Room Design Review (TAC No. 56181)," GO2-88-074, dated March 29, 1988.*

3. *Letter, G. C. Sorensen (SS) to NRC, "Nuclear Plant No. 2, Operating License NPF-21 Detailed Control Room Design Review (TAC No. 56181)," GO2-91-198, dated October 29, 1991.*

4. *Letter, P. L. Eng (NRC) to G. C. Sorensen (SS), "Status of TMI Item I.D.1.1, 'Detailed Control Room Design Review' (DCRDR) at Washington Public Power Supply System Nuclear Project No. 2 (WNP-2) (TAC NO. 56181)," dated November 13, 1991.*

I.G.1 PREOPERATIONAL AND LOW-POWER TESTING

Position (NUREG-0660)

The objective is to increase the capability of the shift crews to operate facilities in a safe and competent manner by assuring that training for plant changes and off-normal events is conducted. Near-term operating license facilities will be required to develop and implement intensified training exercises during the low-power testing programs. This may involve the repetition of startup tests on different shifts for training purposes. Based on experience from the near-term operating license facilities, requirements may be applied to other new facilities or incorporated into the plant drill requirement (Item I.A.2.5). Review comprehensiveness of test programs.

NRR will require new operating licensees to conduct a set of low-power tests to accomplish the requirements. The set of tests will be determined on a case-by-case basis for the first few

plants. Then NRR will develop acceptance criteria for low-power test programs to provide "hands on" training for plant evaluation and off-normal events for each operating shift. It is not expected that all tests will be required to be conducted by each operating shift. Observation by one shift of training of another shift may be acceptable.

NRR will develop criteria in conjunction with initial near-term operating license reviews.

Licensees will (1) define training plan prior to loading fuel, and (2) conduct training prior to full-power operation.

Clarification

None.

WNP-2 Position

The Supply System committed to meet the intent of NUREG-0660 by performance of a special low power test subprogram which provided supplemental operator training in the areas of response to abnormal plant conditions and familiarity with critical systems. The special subprogram amplified the well-established training value of the Startup Test Program (STP) through (1) instruction on the content, goals, and requirements of the program, (2) addition of selected special tests to the STP to demonstrate abnormal scenarios and uses of critical systems and/or emergency operating procedures to control them, and (3) utilization of the knowledge and experience gained during the STP in the training programs for future operators.

The overall Startup Test Program is outlined in Chapter 14 while the conduct of operations is discussed in Chapter 13. During the preoperational and power ascension test phases, the operations personnel were intimately involved in the performance of the various test procedures. With the impetus provided by the responsible test phase organization, the operations staff was charged with establishing the required plant/system conditions, initiating and controlling the desired test transient and returning the plant/system to its normal condition. The operations staff provided the physical ability to accomplish the Startup Test Program. In this fashion, the completion of the Startup Test Program provided an unparalleled training opportunity for the operators.

The following outlines those additional actions the Supply System implemented to augment the extensive training benefits inherent in the existing STP program:

I. Development and Implementation of a Training Course on the STP

A. General Classroom Instruction (prior to testing)

1. STP Overview

a. Organization, Delineation of Responsibilities, Goals

b. Administrative and Emergency Procedures

c. Preop and Power Ascension Test Schedule

2. Review Selected STP Specifics, for example;

a. Pertinent Preop Test Purposes, Procedures, Anticipated Results

b. Integrated System Cold Functional Tests

c. Fuel Loading, Heatup, Power Ascension Test Purposes, Procedures, Anticipated Results

d. Special Test Subprogram Test Purposes, Procedures, Anticipated Results

3. Review Expected Utilization of STP Data

a. Documentation of Plant Safety

b. Feedback/Confirmation of Anticipated Results

B. Test Phase Instruction Performed by Test Director on a Shift Basis (during testing)

1. Review of the Immediate Test Schedule

2. Discussion of the Impending Tests: Procedures, Anticipated Results, Precautions

3. Review/Disseminate Plant Response Data from Previous Shift(s)

C. Post-STP Completion Instruction Performed by Test director (following testing)

1. Review Plant Design Changes/System Modifications Required

II. Development and Performance of a Special Test Subprogram

A. Additional RCIC System Tests

1. RCIC Operation Following Loss of AC Power to the System

2. RCIC Operation to Prove DC Separation

B. Integrated Reactor Vessel Level Instrumentation Functional Test

C. Integrated Containment Pressure Instrumentation Functional Test

D. Simulated Loss of Control and Instrument Air Test

E. Repetition of Some Normal STP Tests, for example:

1. Feedwater Pump Trip/Recirc Runback Demonstration

2. Turbine Trip/Generator Load Rejection Within Bypass Valve Capacity

3. Pressure Regulator Setpoint Changes

4. Recirculation Pump Trips

5. Feedwater Level Setpoint Changes

III. Utilization of the STP Data

A. Refine the WNP-2 Simulator Response Models, as appropriate

B. Incorporate a Major Plant Transient Response Section in Operator Training Program, as appropriate

C. Update License Program Training and Requalification Material, as appropriate.

It was anticipated that every participating member of the operations staff would obtain valuable knowledge and experience through participation in the WNP-2 Startup Test Program. Each received appropriate classroom instruction and through judicious scheduling of tests, most were exposed to a variety of plant/system transient responses (or review of results thereof). The training received is continually reinforced through normal requalification program refinements. Future license candidates also benefit from the training material upgrades resulting from the STP experience.

With this program outline, the Supply System met the intent of NUREG-0660, Item I.G.1. Specific details of the training program, additional test procedures, and documentation methods have been developed and are available for onsite NRC I&E review.

This position has been accepted in the NRC Safety Evaluation Report (NUREG-0892, dated December 1982, section 14.)

II.B.1 REACTOR COOLANT SYSTEM VENTS

Position

Each applicant and licensee shall install reactor coolant system (RCS) and reactor vessel head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensable 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 50, "General Design Criteria." The vent system shall be designed with sufficient redundancy that ensures 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:

a. Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for LOCAs 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.

b. 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.

Clarification

a. General

1. The important safety function enhanced by this venting capability is core cooling. For events beyond the present design basis, this venting capability will substantially increase the plant's ability to deal with large quantities of noncondensable gas which could interfere with core cooling.

2. Procedures addressing the use of the RCS vents should define the conditions under which the vents should be used as well as the conditions under which the vents should not be used. The procedures should be directed toward achieving a substantial increase in the plant being able to maintain core cooling without loss of containment integrity for events beyond the design basis. The use of vents for accidents within the

normal design basis must not result in a violation of the requirements of 10 CFR 50.44 or 10 CFR 50.46.

3. The size of the reactor coolant vents is not a critical issue. The desired venting capability can be achieved with vents in a fairly broad spectrum of sizes. The criteria for sizing a vent can be developed in several ways. One approach which may be considered is to specify a volume of noncondensable gas to be vented and in a specific venting time. For containments particularly vulnerable to failure from large hydrogen releases over a short period of time, the necessity and desirability for contained venting outside the containment must be considered (e.g., into a decay gas collection and storage system).

4. Where practical, the RCS vents should be kept smaller than the size corresponding to the definition of LOCA (10 CFR 50, Appendix A). This will minimize the challenges to the emergency core cooling system (ECCS) since the inadvertent opening of a vent smaller than the LOCA definition would not require ECCS actuation, although it may result in leakage beyond technical specification limits. On PWRs, the use of new or existing lines whose smallest orifice is larger than the LOCA definition will require a valve in series valve that can be closed from the control room to terminate the LOCA that would result if an open vent valve could not be reclosed.

5. A positive indication of valve position should be provided in the control room.

6. The reactor coolant vent system shall be operable from the control room.

7. Since the RCS vent will be part of the RCS pressure boundary, all requirements for the reactor pressure boundary must be met, and, in addition, sufficient redundancy should be incorporated into the design to minimize the probability of an inadvertent actuation of the system. Administrative procedures, may be a viable option to meet the single-failure criterion. For vents larger than the LOCA definition, an analysis is required to demonstrate compliance with 10 CFR 50.46.

8. The probability of a vent path failing to close, once opened, should be minimized; this is a new requirement. Each vent must have its power supplied from an emergency bus. A single failure within the power and control aspects of the reactor coolant vent system should not prevent

isolation of the entire vent system when required. On BWRs, block valves are not required in lines with safety valves that are used for venting.

9. Vent paths from the primary system to within containment should go to those areas that provide good mixing with containment air.

10. The reactor coolant vent system (i.e., vent valves, block valves, position indication devices, cable terminations, and piping) shall be seismically and environmentally qualified in accordance with IEEE 344-1975 as supplemented by Regulatory Guide 1.100, 1.92 and SEP 3.92, 3.43, and 3.10. Environmental qualifications are in accordance with the May 23, 1980 Commission Order and memorandum (CLI-80-21).

11. Provisions to test for operability of the reactor coolant vent system should be part of the design. Testing should be performed in accordance with subsection IWV of Section XI of the ASME Code for Category B valves.

12. 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-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.

b. BWR Design Considerations

1. Since the BWR Owners' Group has suggested that the present BWR designs have an inherent capability to vent, a question relating to the capability of existing systems arises. The ability of these systems to vent the RCS of noncondensable gas generated during an accident must be demonstrated. Because of differences among the head vent systems for BWRs, each licensee or applicant should address the specific design features of this plant and compare them with the generic venting capability proposed by the BWR Owners' Group. In addition, the ability

of these systems to meet the same requirements as the PWR vent system must be documented.

2. In addition to RCS venting, each BWR licensee should address the ability to vent other systems, such as the isolation condenser which may be required to maintain adequate core cooling. If the production of a large amount of noncondensable gas would cause the loss of function of such a system, remote venting of that system is required. The qualifications of such a venting system should be the same as that required for PWR venting systems.

c. PWR Vent Design Considerations

1. Each PWR licensee should provide a capability to vent the reactor vessel head. The reactor vessel head vent should be capable of venting noncondensable gas from the reactor vessel hot legs (to the elevation of the top of the outlet nozzle) and cold legs (through head jets and other leakage paths).

2. Additional venting capability is required for those portions of each hot leg that cannot be vented through the reactor vessel head vent or pressurizer. It is impractical to vent each of the many thousands of tubes in a U-tube steam generator; however, the staff believes that a procedure can be developed that ensures sufficient liquid or steam can enter the U-tube region so that decay heat can be effectively removed from the RCS. Such operating procedures should incorporate this consideration.

3. Venting of the pressurizer is required to ensure its availability for system pressure and volume control. These are important considerations, especially during natural circulation.

WNP-2 Position

The reactor coolant vent line is located at the very top of the reactor vessel as shown in the schematic (Figure 3.6-43). This 2-in. line contains two safety-related Class 1E motor-operated valves (MS-V-1 and MS-V-2) that are operated from the control room. The location of this line permits it to vent the entire RCS normally connected to the reactor pressure vessel (RPV), with the exception of the reactor coolant isolation cooling (RCIC) head spray piping which comprises approximately 0.6 ft^3 of volume above the elevation of the RPV. This small volume was considered in the original design of the RCIC system and is of no consequence to its operation. In addition, since this vent line is part of the original design for the WNP-2 unit, it has already been considered in all the design basis accident analyses contained elsewhere in the FSAR.

The WNP-2 BWR/5 is provided with 18 power-operated safety grade relief valves which can be manually operated from the control room to vent the RPV. The point of connection to the vent lines (main steam lines) from near the top of the vessel to these valves is such that accumulation of gases above that point in the vessel will not affect natural circulation of the reactor core.

These power-operated relief valves satisfy the intent of the NRC position. Information regarding the design, qualification, power source, etc., of these valves is provided in Section 5.2.2.

The BWR Owners' Group position is that the requirement of single failure criteria for prevention of inadvertent actuation of these valves, and the requirement that power be removed during normal operation, are not applicable to BWRs. These valves serve an important function in mitigating the effects of transients and at WNP-2 provide ASME code overpressure protection. Therefore, the addition of a second "block" valve to the vent lines would result in a less safe design and a violation of the code. Moreover, the inadvertent opening of a relief valve in a BWR is a design basis event and is a controllable transient.

In addition to these power-operated relief valves, the WNP-2 BWR/5 includes various other means of high-point venting. Among these are

a. Normally closed reactor vessel head vent valves, operable from the control room, which discharge to the drywell;

b. Normally open reactor head vent line, which discharges to a main steam line;

c. Main steam-driven RCIC system turbines, operable from the control room, which exhaust to the suppression pool; and

d. Main steam-driven reactor feedwater pumps operable from the control room, which exhaust to the plant condenser when not isolated. Condenser gases are continuously processed through the offgas system.

Although the power-operated relief valves fully satisfy the intent of the venting requirement, these other means also provide protection against the accumulation of noncondensables in the RPV.

Under most circumstances, no selection of vent path is necessary because the relief valves [as part of the automatic depressurization system (ADS)], high-pressure core spray (HPCS), and RCIC will function automatically in their designed modes to ensure adequate core cooling and provide continuous venting to the suppression pool.

Analyses of inventory-threatening events with very severe degradations of system performance have been conducted. These were submitted by GE for the BWR Owners' Group to the NRC Bulletins and Orders Task Force on November 30, 1979. The fundamental conclusion of these studies was that if only one ECCS is injecting into the reactor, adequate core cooling would be provided and the production of large quantities of hydrogen would be avoided. Therefore, it is not desirable to interfere with ECCS functions to prevent venting.

The small-break accident (SBA) guidelines emphasize the use of HPCS/RCIC as a first line of defense for inventory-threatening events which do not quickly depressurize the reactor. If these systems succeed in maintaining inventory, it is desirable to leave them in operation until the decision to proceed to cold shutdown is made. Thus the reactor will be vented via RCIC turbine steam being discharged to the suppression pool. Termination of this mode of venting could also terminate inventory makeup if the HPCS had failed also. This would necessitate reactor depressurization via the safety/relief valve (SRV), which of course is another means of venting.

If the HPCS/RCIC are unable to maintain inventory, the SBA guidelines call for use of ADS or manual SRV actuation to depressurize the reactor so that the low-pressure coolant injection (LPCI) and/or low-pressure core spray (LPCS) systems can inject water. Thus, the reactor would be vented via the SRV to the suppression pool. Termination of this mode of venting is not recommended. It is preferable to remain unpressurized; however, if inventory makeup requires HPCS or RCIC restart, that can be accomplished manually by the operator. It is more desirable to establish and maintain core cooling than to avoid venting. If the HPCS/RCIC and SRVs are not operable (a very degraded and extremely unlikely case), another emergency means of venting the reactor must be used. It is emphasized, however, that such emergency venting would be in the interest of core cooling and, therefore, could be employed under Emergency Procedure Guidelines.

It is thus concluded that there is no reason to interfere with ECCS operation to avoid venting. It is further concluded that the Emergency Procedure Guidelines, by correctly specifying operator actions for HPCS, RCIC, and SRV operation, also correctly specify operator actions to vent the reactor.

In the event of HPCS failure and continued vessel pressurization, the effect of noncondensables in the RCIC turbine steam was evaluated for three cases:

1. Continuous evolution of noncondensables due to radiolysis,

2. Quasi-continuous evolution of noncondensables due to core heatup, and

3. The presence of a quantity of noncondensables in the reactor at the time of HPCS/RCIC startup.

Case 1 is a normal operating mode for RCIC and is of no concern.

For Case 2 to exist, the core must be uncovered. Such a condition requires multiple failures as shown in the degraded cooling analyses. Core uncovery is prevented (or cladding heatup into the rapid oxidation range is prevented) when only one ECCS is operating. For small pipe brake or a loss of feedwater, which would allow the reactor to remain at pressure, the HPCS and/or RCIC pumps would maintain inventory and there would be no substantial hydrogen production. If neither HPCS nor RCIC could maintain inventory, the reactor would be automatically or manually depressurized via SRVs (or via the break, for larger breaks). Low-pressure water injection systems (LPCI or LPCS) would then make up inventory. With the core covered neither the rapid generation of noncondensables nor their accumulation would be possible.

The performance of RCIC under Case 3 is of concern only if there has been a very substantial production of hydrogen due to core uncovery and there is a need to start the RCIC. This is extremely unlikely and an intolerable circumstance, because it could arise only if the core were allowed to remain uncovered for a long period with the reactor at high pressure. Automatic depressurization system operation and explicit operating instructions and the Emergency Operator Guidelines are intended to preclude this. If the level has fallen with the reactor at high pressure, the vessel would be depressurized either automatically or manually to permit low pressure injection independent of RCIC performance.

In the post-LOCA condition, it is possible to have noncondensable gases come out of solution while operating the residual heat removal (RHR) system. These gases would accumulate at the top of the RHR heat exchanger since this is a system high point and an area of relatively low flow. Gases trapped here will be vented through a 2-in. vent line with two safety-related Class 1E motor-operated valves (MO-F073A and MO-F074A or MO-F073B and MO-F074B) operated from the control room (as shown in Figure 5.4-15). As this vent line and associated valves are part of the original design, they have also been considered in the design basis accident analysis contained elsewhere in the FSAR.

The result of a break in the SRV discharge piping, or any of the other pipe lines for the systems enumerated above, would be the same as a small steam line break. A complete steam line break is part of the WNP-2 design basis, and smaller size breaks have been shown to be of lesser severity. A number of reactor system blowdowns due to stuck-open relief valves (also equivalent to a small steam line break) have confirmed this in practice. Thus no new analyses are required to show conformance with 10 CFR 50.46.

Because the relief valves and RCIC will vent the reactor continuously, and because containment hydrogen calculations in normal safety analysis calculations assume continuous venting, no special analyses are required to demonstrate "that the direct venting of noncondensable gases with perhaps high hydrogen concentrations does not result in violation of combustible gas concentration limits in containment."

Conclusion and Comparison with Requirements

The conclusion from this vent evaluation for WNP-2 are as follows:

a. Reactor vessel head vent valves exist to relieve head pressure (at shutdown) to the drywell via remote operator action;

b. The reactor vessel head can be vented during operating conditions via the SRVs to the suppression pool;

c. The RCIC system provides an additional vent pathway to the suppression pool;

d. The size of the vents is not a critical issue because BWR SRVs have substantial capacity, exceeding the full power steaming rate of the nuclear boiler;

e. The SRVs vent to the containment suppression pool, where discharged steam is condensed without causing a rapid containment pressure/temperature transient;

f. The SRVs are not smaller than the NRC defined small LOCA. Inadvertent actuation is a design basis event and a demonstrated controllable transient;

g. Inadvertent actuation is of course undesirable, but since the SRVs serve an important protective function, no steps such as removal of power during normal operation should be taken to prevent inadvertent actuation;

h. An indication of SRV position is provided in the control room per NUREG-0737, Item II.D.3. Temperature sensors in the discharge lines confirm possible valve leakage;

i. Each SRV is remotely operable from the control room;

j. Each SRV is seismically and Class 1E qualified;

k. Block valves are not required, so block valve qualifications are not applicable;

l. No new 10 CFR 50.46 conformance calculations are required because the vent provisions are part of the systems in the plant's original design and are covered by the original design bases; and

m. Plant procedures govern the operator's use of the relief mode for venting reactor pressure. These procedures are available for NRC inspection at the WNP-2 plant.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 5.4.3.1.

II.B.3 POSTACCIDENT SAMPLING CAPABILITY

Position

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 hr) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18.75 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 hr) 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 auxiliary 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 or 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).

Clarification

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

a. 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 hr or less from the time a decision is made to take a sample.

b. The licensee shall establish an onsite radiological and chemical analysis capability to provide, within the 3-hr time frame established above, quantification of the following:

1. 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),

2. Hydrogen levels in the containment atmosphere,

3. Dissolved gases (e.g., H_2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids, and

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

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

d. 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 H_2 gas in reactor coolant samples is considered adequate. Measuring the O_2 concentration is recommended but is not mandatory.

e. The time for a chloride analysis to be performed is dependent on two factors: (1) if the plant's coolant water is seawater or brackish water, and (2) 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 hr 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.

f. 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 General Design Criterion (GDC) 19 (Appendix A, 10 CFR 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 20

(NUREG-0578) to the GDC 19 criterion (October 30, 1979, letter from H. R. Denton to all licensees.)

g. 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.)

h. 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.

i. The licensee's radiological and chemical sample analysis capability shall include provisions to

   1. Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guides 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.

   2. 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.

j. 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.

k. In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:

   1. 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 samples should be representative of the reactor coolant in the core area and the 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.

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

3. Guidelines for analytical or instrumentation range are given in Table II.B.3-1.

WNP-2 Position

WNP-2 is using a General Electric postaccident sampling system capable of sampling the primary containment and reactor building atmosphere and of obtaining liquid samples from the reactor, RHR loops, and various reactor building sumps. This system is designed to obtain grab samples which may be analyzed onsite or transported to offsite facilities for more detailed analysis if necessary. The sample station is located in the radwaste building and is shielded to reduce radiation exposure rates to the operator. All remote-operated valves are controlled from this area. Lead pigs are provided for radiation protection when transporting samples either to onsite facilities or offsite. A more detailed description follows.

Gas samples will be obtained from locations in the drywell, the suppression pool atmosphere, and from the secondary containment atmosphere. The sample system is designed to operate at pressures ranging from subatmospheric to maximum design pressures of the primary and secondary containment. Heat-traced sample lines are used outside the primary containment to prevent precipitation of moisture and resultant loss of particulates and iodines in the sample lines. The gas samples may be passed through a particulate filter and silver zeolite cartridge for determination of particulate activity and iodine activity by subsequent analysis of the samples on a gamma spectrometer system. Alternatively, the sample flow bypasses the particulate/iodine sampler, is chilled to remove moisture, and a 15-ml grab sample can be taken for determination of gaseous radioactivity and for gas composition by gas chromatography. This size sample vial has been adopted for all gas samples to be consistent with present offgas sample vial counting factors.

Reactor coolant samples will be obtained from two points in the jet pump pressure instrument system when the reactor is at pressure. The jet pump pressure system has been determined to be an optimum sample point for accident conditions. The pressure taps are well protected

from damage and debris. If the recirculation pumps are secured, the water level will be raised about 18 in. above normal. This provides natural circulation of the bulk coolant past the taps. Also, the pressure taps are located sufficiently low to permit sampling at a reactor water level even below the lower core support plate.

A single sample line is also connected to both loops in the RHR system. This provides a means of obtaining a reactor coolant sample when the reactor is depressurized and at least one of the RHR loops is operated in the shutdown cooling mode. Similarly, a suppression pool liquid sample can be obtained from the RHR loop lined up in the suppression pool cooling mode. Samples from the five drain sumps in the reactor building are also available.

The sample system isolation valves are controlled from the local control panel. The sample system is designed for a purge flow of 1 gpm, which is sufficient to maintain turbulent flow in the sample line. Purge flow is returned to the suppression pool. The high flush flow also serves to alleviate cross-contamination of the samples when switching from one sample point to another.

All liquid samples are taken into septum bottles mounted on sampling needles. The sample station is basically a bypass loop on the sample purge line. In the normal lineup, the sample flows through a conductivity cell (readable range 0.1 to 1000 µS/cm) and then through a ball valve bored out to 0.10-ml volume. Flow through the sample panel is established, the valve is rotated 90°, and a syringe is used to flush the sample plus a measured volume of diluent (generally 10 ml) through the valve and into the sample bottle. This provides a dilution of 100:1 to the sample. Alternatively, the valve sampling sequence can be repeated 10 times to provide a 1-ml sample diluted 10:1. The sample is transported to the laboratory for further dilution and subsequent analysis. Alternatively, the sample flow can be diverted through a 70-ml bomb to obtain a large pressurized volume. This 70-ml volume can be circulated and depressurized into a known volume gas expansion chamber. The pressure change in this chamber will be used to calculate the total dissolved gases in the reactor coolant. A grab sample of these gases may be taken through a septum port for subsequent analysis. Ten milliliter aliquots of this degassed liquid can also be taken for on or offsite chemical analyses requiring a relatively large sample. A radiation monitor in the liquid sample enclosure monitors liquid flow from the sample station to provide immediate assessment of the sample activity level. This monitor also provides information as to the effectiveness of the demineralized water flushing of the sample system following sample operation. The control instrumentation is installed in two 2 ft x 2 ft x 6 ft high standard cabinet control panels. One panel contains the conductivity and radiation level readouts. Another control panel contains the flow, pressure and temperature indicators, and the various control valves and switches.

A graphic display panel, installed directly below the main control panel, 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 operation.

Appropriate sample handling tools, a gas sampler vial positioner and gas vial cask are available to the operator at the sampling station. The gas vial is installed and removed by use of the vial positioner through the front of the gas sampler. The vial is then manually placed down in the cask with the positioner which allows the vial to be maintained about 3 ft from the individual performing the operation.

The small-volume (10 ml) liquid sample is remotely obtained through the bottom of the sample station by use of the small-volume cask and cask positioner. The cask positioner holds the cask and positions the cask directly under the liquid sampler. The sample vial is manually raised within the cask to engage the hypodermic needles. When the sample vial has been filled, the bottle is manually withdrawn into the cask. The sample vial is always contained within lead shielding during this operation. The cask is then lowered and sealed prior to transport to the laboratory.

A large-volume cask and cask positioner is available for transporting large liquid samples. A 21-ml bottle is contained within a lead shielded cask. This sample bottle is raised from its location in the cask to the sample station needles for bottle filling. The sample station will only deliver 10 ml to this sample bottle. When filled, the bottle is withdrawn into the cask. The sample bottle is always shielded by 5 to 6 in. of lead when in position under the sample station and during the fill and withdraw cycles, thus reducing operator exposure.

The cask is transported to the required position under the sample station by a dolly cask positioner. When in position this cask is hydraulically elevated approximately 1.5 in. by a small hand pump for contact with the sample station shielding under the liquid sample enclosure floor. The sample bottle is raised, held, and lowered by a simple push/pull cable. The cask is sealed by a threaded top plug that inserts above the sample bottle. The weight of this large-volume cask is approximately 700 lb.

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

The power supply to the sample station and all associated equipment will not be shed during accident conditions. The system design is such that a sample can be drawn and analyzed within the required 3 hr, after a 1 hr preparation time.

The postaccident sampling station will provide conductivity measurements in line as an indicator of liquid chemical concentrations and changing chemical conditions. The system allows collection of grab samples for gas analysis of O_2, N_2, H_2, and direct gamma

spectrometric determination of aliquots of gas samples. The system also allows collection of iodine samples on a silver zeolite cartridge to minimize noble gas interference in the determination of iodine isotopic content. Liquid samples will be analyzed for pH using a semimicro pH electrode and additionally analyzed for boron and chloride using ion chromatography. An aliquot of the sample may also be analyzed for gross activity or isotopic content by gamma ray spectrometry. All laboratory analysis meet Regulatory Guide 1.97 requirements for sensitivity and range, with the exception of the range for dissolved gases. However, the analytical capability for dissolved gases is consistent with the maximum dissolved gas concentrations expected for BWRs.

The postaccident sample system will be used quarterly for operability testing. During this testing a reactor coolant sample will be taken and analyzed for gamma isotopic content. In addition, a containment atmosphere sample will be taken and analyzed for gas composition and gamma isotopic content. The results of these analyses will be compared, where possible, to results obtained through normal plant sampling systems to verify the representatives of postaccident system samples. Classroom and practical factors training will be provided on system operation, as well as proper handling and analysis of highly radioactive samples. Refresher training will be provided annually.

A yearly drill will be performed in which the postaccident sample system will be used to obtain samples. These samples will be drawn, transported, and analyzed for accident parameters as if they were postaccident highly radioactive samples.

Based on information developed by General Electric, the Supply System has developed plant-specific procedures for the determination of the extent of core damage under accident conditions. The procedures provide for distinguishing between fuel cladding failure and fuel melt based on isotopes present and concentration. The extent of damage is based on concentrations present of isotopic mixture of xenon, krypton, iodine, and cesium.

The estimated maximum potential whole body dose to retrieve a reactor coolant sample under worst-case accident conditions is 0.36 rem; the source being airborne noble gas activity in the radwaste building from effluent releases. Lapsed time is about 1 hr.

The maximum dose rate from a 0.1 ml reactor coolant sample (1 hr decay) in a 4-in.-thick lead transport cask is less than 5 mR/hr at 1 ft. Exposure to analyze a sample is expected to be less than 100 mR.

All valves used are fully qualified for the environment in which they are located inside and outside reactor containment.

Power for the postaccident sampling equipment is supplied from either Division 1 or Division 2 critical power sources and will be available during accident conditions.

The staff review of this position in NUREG-0892, dated December 1982, recognized several issues requiring resolution and consolidated them in Licensing Condition 9. Subsequent Supply System submittals, primarily Amendment 23 to the FSAR, resulted in the staff finding the postaccident sampling system acceptable in Supplement 4 NUREG-0892, section 9.3.2.4. A requirement to have the system completed and operable prior to exceeding 5% power was made a condition to the license (NPF-21 issued December 20, 1983). Supply System letter GO2-84-272 dated April 27, 1984, reported the system completed and operable thus satisfying the licensing condition.

II.F.1.3 Containment High-Range Radiation Monitor

Position

Radiation level monitors with a maximum range of 10^8 R/hr shall be installed in containment. 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.

Clarification

a. Provide two radiation monitor systems in containment which are documented to meet the requirements of Table II.F.1-3.

b. The specification of 10^8 R/hr in the above position was based on a calculation of postaccident containment radiation levels that included both particulate (beta) and photon (gamma) radiation. A radiation detector that responds to both beta and gamma radiation cannot be qualified to post-LOCA containment environments but gamma-sensitive instruments can be so qualified. 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.

c. 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.

d. For BWR Mark III containments, two such monitoring systems should be inside both the primary containment (drywell) and the secondary containment.

e. 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. Monitors that use thick shielding to increase the upper range will underestimate postaccident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gammas and are not acceptable.

WNP-2 Position

WNP-2 concurs with the intent of this position and has installed high range gamma detection monitors in the following primary containment locations:

a. 515 ft level Azimuth 290°and
b. 516 ft level Azimuth 51.5°.

The detectors are unshielded and mounted on the wall in areas least influenced by shielding due to surrounding piping, etc. They are accessible for calibration and will be calibrated according to the Technical Specifications. Plant drawings will be revised to reflect their addition and location.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated December 1982, section 12.3.4.1.

TABLE II.F.1-3

CONTAINMENT HIGH-RANGE RADIATION MONITOR

Requirement	-	The capability to detect and measure the radiation level within the reactor containment during and following an accident.
Range	-	1 rad/hr to 10^8 rads/hr (beta and gamma) or alternatively 1 R/hr to 10^7 R/hr (gamma only).
Response	-	60 keV to 3 MeV photons, with linear energy response ±20%) for photons of 0.1 MeV to 3 MeV. Instruments must be accurate enough to provide usable information.
Redundant	-	A minimum of two physically separated monitors (i.e., monitoring widely separated spaces within containment).
Design and qualification	-	Category 1 instruments as described in Appendix A, except as listed below.
Special calibration	-	In situ calibration by electronic signal substitution is acceptable for all range decades above 10 R/hr. In situ calibration for at least one decade below 10 R/hr shall be by means of calibrated radiation source. The original laboratory calibration is not an acceptable position due to the possible differences after in situ installation. For high-range calibration, no adequate sources exist, so an alternate was provided.
Special environmental qualifications	-	Calibrate and type-test representative specimens of detectors at sufficient points to demonstrate linearity through all scales up to 10^6 R/hr. Prior to initial use, certify calibration of each detector for at least one point per decade of range between 1 R/hr and 10^3 R/hr.

II.F.1.4 Containment Pressure Monitor

Position

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.

Clarification

a. Design and qualification criteria are outlined in Appendix A;

b. Measurement and indication capability shall extend to 5 psia for subatmospheric containments;

c. Two or more instruments may be used to meet requirements. However, instruments that need to be switched from one scale to another scale to meet the range requirements are not acceptable;

d. Continuous display and recording of the containment pressure over the specified range in the control room is required; and

e. The accuracy and response time specifications of the pressure monitor shall be provided and justified to be adequate for their intended function.

WNP-2 Position

WNP-2 has designed a system to meet this criteria. A description of the WNP-2 system is provided in Section 7.5.

The range, accuracy, and response time of these instruments are

Range	= -5 to +3 psig 0 to 25 psig 0 to 180 psig
Instrument accuracy (loop)	= ±2% of full scale
Response time	= 0 to 100% full scale in less that 1 sec

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, sections 6.2.1.1.1 and 7.5.2.6.

II.F.1.5 Containment Water Level Monitor Position

A continuous indication of containment water level shall be provided in the control room for all plants. A narrow range.instrument shall be provided for PWRs and cover the range from the bottom to the top of the containment sump. A wide range instrument shall also be provided for PWRs and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000-gal capacity. For BWRs, a wide range instrument shall be provided and cover the range from the bottom to 5 ft above the normal water level of the suppression pool.

Clarification

a. The containment wide-range water level indication channels shall meet the design and qualification criteria as outlined in Appendix A. The narrow-range channel shall meet the requirements of Regulatory Guide 1.89;

b. The measurement capability of 600,000 gal is based on recent plant designs. For older plants with smaller water capacities, licensees may propose deviations from this requirement based on the available water supply capability at their plant;

c. Narrow-range water level monitors are required for all sizes of sumps but are not required in those plants that do not contain sumps inside the containment;

d. For BWR pressure-suppression containments, the ECCS 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; and

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

WNP-2 Position

In WNP-2, the variable to be measured is the suppression chamber water level. WNP-2 has expanded its suppression chamber water level instruments to cover this requirement. A description is provided in Section 7.5.

The accuracy and response time of this instrument are

Instrument accuracy = ± of full scale
Instrument response time = 0 to 100% of full scale in less than 1 sec

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, sections 6.2.1.1.2 and 7.5.2.6.

II.F.1.6 Containment Hydrogen Monitor

Position

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.

Clarification

a. Design and qualification criteria are outlined in Appendix A,

b. The continuous indication of hydrogen concentration is not required during normal operation,

   If an indication is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of safety injection, and

c. The accuracy and placement of the hydrogen monitors shall be provided and justified to be adequate for their intended function.

WNP-2 Position

WNP-2 concurs with the intent of this position. The existing monitors are redundant and provide continuous display and redundant recording in the control room. The instruments are seismically and environmentally qualified to Class 1 requirements with a range of 0-30% hydrogen concentration. A complete design description is provided in Section 6.2.5.2.

The accuracy of this instrument is

Instrument accuracy (loop) = ±0.2% H_2 in the range 2-6 H_2 and
±2.0% for remainder of full scale

II.F.2 INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING

Position

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 (NUREG-0737).

Clarification

None.

WNP-2 Position

WNP-2 is actively participated in the efforts of the BWR Owner's Group (BWROG) and the Licensing Review Group (LRG) to develop an industry understanding of NRC's concerns and an approach to detect inadequate core cooling.

An analysis of in-core thermocouples, as proposed in recently published Safety Evaluation Reports applicable to BWRs, led the BWROG, LRG, and WNP-2 to conclude that in-core thermocouples did not serve as effective instruments for detection of inadequate core cooling and did not substantially improve the safety of the plant. The two major deficiencies of incore thermocouples are inadequate (i.e., long) response time and potentially erroneous indications. In addition, a risk assessment of the effect on the addition of in-core thermocouples has concluded that even if in-core thermocouples were arbitrarily assumed to provide an effective backup to the plant water level detectors, overall plant risk would not be significantly reduced. Based on this risk analysis, in-core thermocouples were not considered to be a cost effective modification for WNP-2. The results of the above studies were presented to the NRC by the BWROG and LRG executives in a meeting in Bethesda on December 17, 1981.

In Operating License NF-21 issued December 19, 1983 the staff conditioned the license to "implement the staff's requirements regarding additional instrumentation for detection of inadequate core cooling which may result from the staff's review of the BWR Owner's Group reports (SLI 8211 and SLI 8218)...." Generic Letter 84-23 comprised the staff's review and requested additional information. The Supply System response to Generic Letter 84-23, Letter GO2-84-617 dated November 27, 1984, satisfied the licensing condition and closed this issue.

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

Position

Review all valve positions, positioning requirements, positive controls, and related test and maintenance procedures to ensure proper engineered safety feature (ESF) functioning. See NRC Bulletins 79-06A Item 8, 79-06B Item 7, and 79-08 Item 6.

This requirement shall be met before fuel loading.

Clarification

None.

WNP-2 Position

Directives on valve positioning requirements, positive controls, and test and maintenance procedures associated with ESF systems have been prepared. Motor-operated valves in safety systems are normally maintained in a configuration such as to require the least number of valve automatic movements on system actuation. System initiation logic is such that valves automatically move to the required position when required. The position of vital manual ECCS valves is controlled by the use of and documentation of locks on valve handwheels. In addition, numerous vital manual valves have position status indicating lights in the WNP-2 control room.

WNP-2 is equipped with ESF system status displays, which continuously monitor the ESF systems and provide indication to the operator of a system bypass or inoperability introduced during testing or maintenance which renders the system(s) unable to respond to an initiation signal. Typical parameters monitored include the following:

a. Valve position,
b. Power available to motor-operated valves,
c. Initiation logic power available,
d. Power sources (including emergency diesels) available, and
e. Breaker status.

Alarms are provided on a system level basis. Indication is provided on a component level basis.

Surveillance and testing procedures for ESF systems will include checks to ensure the system is returned to standby status on completion of testing.

When ESF equipment is removed from service for maintenance, WNP-2 procedures require documentation of removal and return to service. Functional tests of equipment returned to service following maintenance are required by these procedures to ensure operability. NUREG-0892, the WNP-2 Safety Evaluation Report, discussed this issue and listed confirmation of procedures as confirmatory issue No. 22. Supply System letter GO2-83-247 dated March 23, 1983, "Confirmatory Issue No. 22, Assurance of ESF Functioning (II.K.1.5) and Safety-Related System Operability Status (II.K.1.10)," satisfied the confirmatory issue, subsequently listed as resolved in Supplement 4 to NUREG-0892.

II.K.1.22 Proper Functioning of Heat Removal Systems

Position

Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense. (IE Bulletin 79-08).

Clarification

None.

WNP-2 Position

WNP-2 letter GO2-80-107, dated May 23, 1980, responded to IE Bulletin 79-08. Additional information pertaining to the above requirement is provided below.

Initial Core Cooling:

Following a loss of feedwater and reactor scram, a low reactor water level signal (level 2) will automatically initiate main steam line isolation valve closure. At the same time this signal will put the HPCS and RCIC systems into the reactor coolant makeup injection mode. These systems will continue to inject water into the vessel until a high water level signal (level 8) automatically trips RCIC and closes the HPCS injection valve. The HPCS pump remains running on minimum flow bypass.

Following a high reactor water level 8 trip, the HPCS injection valve will automatically reopen when reactor water level decreases to low water level 2. The RCIC system will automatically reinitiate after a high water level 8 trip when reactor water level decreases to low water level trip 2.

The HPCS and RCIC systems have redundant supplies of water. Normally they take suction from the condensate storage tank (CST). The HPCS and RCIC systems suctions will automatically transfer from the CST to the suppression pool if the CST water is depleted or, for the HPCS system, the suppression pool water level increases to a high level.

The RCIC system will start automatically on receipt of a low water level (level 2) initiation signal. On receipt of this initiation signal, the following events occur simultaneously unless otherwise noted:

a. Test bypass valves to condensate storage tank closes (if open);

b. Steam supply valve to turbine opens;

c. Pump discharge injection valve opens when the turbine steam supply valve is open;

d. Gland seal system starts;

e. Cooling water supply valve to lube oil cooler opens;

f. Pump suction valve from condensate storage tank opens (if closed);

g. The turbine control system brings the turbine up to speed as soon as the steam supply valve leaves its full closed position. Pump discharge flow develops as soon as the pump discharge pressure is sufficient to open the check valve between the pump and the reactor vessel. As pump discharge and steam inlet pressure change with a variable reactor pressure range, the control signal will be sent to the turbine to maintain constant steady state pump flow; and

h. When pump discharge pressure reaches a predetermined pressure, the minimum flow valve opens until system flow reaches a predetermined flow, then it will close.

The HPCS system will start automatically upon receipt of a low water level (level 2) initiation signal. Upon receipt of this initiation signal, the following events occur simultaneously unless otherwise noted:

a. High-pressure core spray diesel generator starts;

b. High-pressure core spray pump starts;

c. High-pressure core spray suction valve and HPCS injection valve open;

d. Condensate storage tank and suppression pool test return and bypass valves close (if open);

e. Minimum flow bypass valve automatically opens if HPCS pump is delivering pressure and system flow is low. Minimum flow bypass valve automatically closes when the flow rate from the pump reaches a predetermined flow;

f. High-pressure core spray service water pumps starts; and

g. High-pressure core spray room cooler fan starts.

The operator can manually initiate the HPCS and RCIC systems from the control room before the level 2 automatic initiation level is reached. The operator has the option of manual control after automatic initiation. The operator can verify that these systems are delivering water to the reactor vessel by

a. Verifying reactor water level increases when systems initiate,

b. Verifying systems flow using flow indicators in the control room, and

c. Verifying system flow is to the reactor by checking control room position indication of motor-operated valves. This ensures no diversion of system flow to other than the reactor.

Therefore, the HPCS and RCIC can maintain reactor water level at full reactor pressure and until pressure decreases to where low pressure systems such as the LPCS of LPCI can maintain water level.

Containment Cooling:

After reactor scram and isolation and establishment of satisfactory core cooling, the operator would start containment cooling. This mode of operation removes heat resulting from SRV discharge to the suppression pool. This would be accomplished by placing the RHR system in the containment/suppression pool cooling mode, or the suppression pool spray mode, i.e., RHR suction from and discharge to the suppression pool. A summary of the operator actions is given in the following:

a. Start the associated RHR standby service water (SW) pump, if not already running,

b. Open the SW pump discharge valve, if not already open,

c. Open the SW loop return valve, if not already open,

d. Start the associated RHR pump,

e. Close the associated RHR heat exchanger bypass valve,

f. Adjust system flow by adjusting the RHR test return valve if in the suppression pool cooling mode, and

g. Open the suppression pool spray valve if in the spray mode.

The Operator could verify proper operation of the RHR system containment cooling function from the control room by the following:

a. Verifying RHR and SW system flow using system control room flow indicators,

b. Verifying correct RHR and SW system flow paths using control room position indication of motor-operated valves, and

c. On branch lines that could divert flow from the required flow paths, closing the motor-operated valves and noting the effect on RHR and SW flow rate.

Extended Core Cooling:

When the reactor has been depressurized, the RHR system can be placed in the long-term shutdown cooling mode. The operator manually terminates the containment cooling mode of one of the RHR loops and places the loop in the shutdown cooling mode as follows:

a. Trip the RHR pump to be used for shutdown cooling,

b. Close associated motor-operated valve in the suppression pool suction and LPCI discharge line to the vessel,

c. Open shutdown cooling suction valves from and discharge valves to the reactor vessel, and

d. Restart the RHR pump.

In this operating mode, the RHR system can cool the reactor to cold shutdown. Proper operation and flow paths in this mode can be verified by methods similar to those described for the containment cooling mode.

In conclusion, the WNP-2 plant design is fully adequate to meet the intent of the requirements of auxiliary heat removal when the main system is inoperable.

II.K.1.23 Reactor Vessel Level Instrumentation

Position

Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information regarding plant status. Instruct operators to utilize other available information to initiate safety systems (IE Bulletin 79-08).

Clarification

None.

WNP-2 Position

NEDO-24708 describes the multiple water level instrumentation provided in the BWR control room for the operator. An outline of the specific indication for WNP-2 is provided in the following paragraphs, which fully meets the intent of the plant requirements and the NRC requirements.

Reactor vessel water level in the WNP-2 BWR is continuously monitored by four recorders for normal, transient, and accident conditions. These four instruments are divided into two divisions of two instruments each to provide an overlapping range from above the maximum operating level to below the active core. Thus, adequate information is provided to the operator for manual initiation of safety actions and for assurance of the vessel water level at all times.

Those sensors used to provide automatic safety equipment initiation are arranged in a four-quadrant vessel tap configuration with the four sensors divided electrically between two divisions.

In addition, the operating procedures will reflect the requirements for the operators to also rely on the information provided by other plant parameter indications relating to vessel level.

A separate set (to that described above) of range level instrumentation provides reactor level control via the reactor feedwater system. This set also indicates or records in the control room. Additionally, an upset range (0-180 in.) and a shutdown range (0-400 in.) are provided for operator information.

The safety-related systems or functions served by safety-related reactor water level instrumentation are the following:

RCIC
HPCS
LPCS
RHR/LPCI
ADS
Nuclear steam supply shutoff system (NSSSS)
Reactor protection system (RPS)
Standby gas treatment system (SGTS)
Emergency power system
Secondary containment isolation
Main control room and critical switchgear HVAC
Standby service water system
Containment instrument air system
Trip of nonessential loads

Low reactor vessel water level is used in the initiation logic of all systems listed above. In addition, the RCIC and HPCS systems shut down on high reactor vessel water level. HPCS and RCIC will automatically restart if low reactor level is again reached (see response to TMI Items II.K.1.22 and II.K.3.13, respectively, for further discussion). Additional information about reactor vessel level instrumentation is also provided in Section 5.2 and in Figure 3.6-43.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated March 1982, section 7.5.2.1.

II.K.3.21 <u>*Restart of Core Spray and Low Pressure Coolant Injection Systems*</u>

<u>*Position*</u>

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 is 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.

Clarification

Modification of system design should be made in accordance with those requirements set forth in Sections 4.12, 4.13, and 4.16 of IEEE Standard 279-1971 with regard to protective function bypasses and completion of protective action once initiated.

WNP-2 Position

WNP-2 as a participant in the BWR Owner's Group endorses the position presented in the letter dated December 29, 1980, from D. B. Waters to the NRC (attention D. G. Eisenhut), Subject: "BWR Owner's Group Evaluation of NUREG-0737 Requirements." The position presented in enclosure 2 to this letter concludes that the current system design is adequate and no design changes are required. WNP-2 concurs in this position.

It should be noted that this design allows the operator to evaluate the plant and avoid an automatic restart that may have an adverse impact on the situation.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 7.3.2.1.

II.K.3.25 Effect of Loss of Alternating-Current Power on Pump Seals

Position

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.

Clarification

The intent of this position is to prevent excessive loss of reactor coolant system (RCS) inventory following an anticipated operational occurrence. Loss of ac power for this case is construed to be loss of offsite power. If seal failure is the consequence of loss of cooling water to the reactor coolant pump (RCP) seal coolers for 2 hr, due to loss of offsite power, one acceptable solution would be to supply emergency power to the component cooling water pump. This topic is addressed for Babcock and Wilcox (B&W) reactors in Item II.K.2.16.

WNP-2 Position

WNP-2, as a participant in the BWR Owners' Group, endorses the position developed by General Electric for the Owners' Group. This position has been transmitted in a letter from the BWR Owners' Group to the NRC, T. J. Dente to Darrell G. Eisenhut, dated

September 21, 1981. In this supplement to the BWR Owners' Group evaluation of NUREG-0737, Item II.K.3.25, General Electric presented test data from a test performed at the Bingham Pump Company's test facility in 1973 on the WNP-2 recirculation pump. During the operability testing of the pump at rated temperature and pressure the seal cavity was deprived of seal purge and the external heat exchanger was deprived of coolant. As a result, the seal cavity temperature exceeded 270°F. Test personnel visually monitored pump leakage for more than five hours and observed no leakage beyond the capability of the 1-in. seal drain lines, less than 5 gpm. These test results provide confirmation that loss of cooling to the Bingham pump seal for 5 hr does not lead to unacceptable seal leakage. This loss is easily compensated for by normal water level controls and presents no hazard to the health and safety of the public.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 15.1.2.

II.K.3.44 *Adequate Core Cooling for Transients with a Single Failure*

Position

For anticipated transients combined with the worst single failure and 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 (NUREG-0737).

Clarification

None.

WNP-2 Position

WNP-2 as a member of the BWR Owners' Group endorses the following position statement and analysis prepared by GE on behalf of the Owners' Group:

Introduction:

This report has been prepared as the BWR Owners' Group generic response to NUREG-0737 Task Item II.K.3.44 which addresses the issue of adequate core cooling for transients with a single failure for those plants identified in Table II.K.3.44-4.

At the outset it should be noted that the conditions described in II.K.3.44 (i.e., transients plus single failures) go beyond the current BWR design basis and that the item's reference to transients with multiple failures goes beyond the regulatory requirements as specified in Regulatory Guide 1.70, Revision 3. The multiple failures specified involve consideration of a

stuck-open relief valve (SORV) combined with the worst single failure. GE and the Owners' Group continues to support the current BWR design basis approach. This report is intended to provide information to address Item II.K.3.44, but does not reflect our intention to change the current BWR design basis approach.

It is shown that, for the GE BWR/2 through BWR/6 plants, the core remains covered for any transient with the worst single failure. This is achieved without any operator action to manually initiate ECCS or other inventory makeup systems. The worst transient with the worst single failure is shown to be the loss of feedwater (LOF) event with a failure of the high pressure ECCS or one isolation condenser (IC) loop, whichever is applicable.

For the bounding LOF event, studies which included even more degraded conditions have been documented in Reference 1. The degraded conditions cover the failure of HPCS (or HPCI or FWCI or IC) and one SORV. Reference 1 shows that the core will remain covered and therefore that no fuel failure would occur.

Criteria, Scope and Assumptions:

NUREG-0737 Item II.K.3.44 requires that the licensees demonstrate adequate core cooling to prevent the fuel from incurring significant damage for the anticipated transients combined with the worst single failure. To meet this requirement, either one of the following two criteria should be satisfied:

a. *The reactor core remains covered with water until stable conditions are achieved, or*

b. *No significant fuel damage results from core uncovery.*

For BWR plants, this report will show that Criterion 1 is met. The report makes the following assumptions:

a. *A representative plant of each BWR product line, BWR/2 through BWR/6, is used to represent all of the plants of that product line,*

b. *The anticipated transients as identified in NRC Regulatory Guide 1.70, Revision 3 were considered,*

c. *The single failure is interpreted as an active failure, and*

d. *All plant systems and components are assumed to function normally, unless identified as being failed.*

Discussion:

Table II.K.3.44-1 lists all of the transients which were considered in this study. The event sequence of each transient was examined for each product line to determine the impact on core cooling. The following three factors were used to determine the worst transient and the worst single failure:

a. Reduction or loss of main feedwater or coolant makeup or heat removal systems, especially high pressure systems, e.g., HPCI, feedwater coolant injection (FWCI), HPCS, RCIC or isolation condenser (IC),

b. Steam release paths causing rapid reactor coolant inventory loss, e.g., SRVs, turbine, or turbine bypass valves, and

c. Power level, especially the timing of scram.

Based on these considerations, a comparison was made among the transients in Table II.K.3.44-1.

In Reference 2, the events of Table II.K.3.44-1 are compared in detail for a typical BWR/4 plant. In particular the impact on core cooling for each transient is evaluated by comparison to the analysis results for the LOF event in the section titled "Applicability of Analyses." It is found that the LOF event is the most severe transient from the core cooling viewpoint due to its rapid depletion of reactor coolant inventory. This conclusion has generic applicability to all BWR product lines covered by this study.

The same approach was also used to select the single failures which would pose the greatest challenge to core cooling. Among all of the possible failures considered (Table II.K.3.44-2 the following failures are identified as the most important ones:

a. Failure of HPCI or HPCS or FWCI or one IC loop, whichever is applicable,
b. Failure of RCIC, and
c. One of the SRVs, which has opened as a result of the transient, fails to close.

Items a and b are the possible limiting failures because they represent loss of high pressure inventory makeup or heat removal systems which would be relied on following a loss of feedwater event. Item c is a possible limiting failure, because it results in the largest steam release rate from the vessel compared to other possible release paths (e.g., a stuck-open turbine bypass valve). No other failures identified in Table II.K.3.44-2 result in a direct challenge to core cooling capability.

Because of the relatively low steam loss capacity through one SORV (Item c) compared to the makeup water capacity of the highest capacity makeup water system, the failure of the highest

capacity high pressure makeup system (Item a) would be worse than a stuck-open relief valve (Item c). For example, for a typical BWR/4, representative values of HPCI makeup and SRV flow are 18% and 6% of rated feedwater flow, respectively. Because of the higher makeup rate of HPCI/HPCS relative to RCIC (3% of rated feedwater flow), Item a would be worse than Item b. Table II.K.3.44-3 lists the worst combination of transient and single failure for the GE BWR product lines covered by this study.

Even with the worst single failure in combination with the LOF event, the RCIC or at least one IC loop will function to provide makeup and/or to remove decay heat while the vessel pressure remains high. The design basis for the RCIC or the IC is such that they are capable of removing decay heat with the vessel being isolated. Analyses of the LOF event with the worst single failure have been performed to support this conclusion. For example, for BWR/2 plants, such analyses are documented in Reference 1, Table 3.2.1.1.5-5. These analyses show that the isolation condenser heat removal capacity is greater than the decay heat generation rate and will lead to a safe and stable condition. Similar analysis have been performed for representative plants with the RCIC system. These analyses show that for the worst transient with the worst single failure, the minimum water level for different BWR product lines ranges from 6 ft to 11 ft above the top of the active fuel.

With even more degraded conditions, i.e., one SORV in addition to the worst case transient with the worst single failure, reference plant analyses in Reference 1, Tables 3.2.1.1.5-9 and 3.2.1.1.5-10 show that for the plants analyzed the RCIC system can automatically provide sufficient inventory to keep the core covered even with a single failure plus a SORV. This capability is not a design basis for the RCIC system, and not all plants have been analyzed to demonstrate this capability. If a plant should not have this capability, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV. It should be noted that manual depressurization is the proper operator action for all plants during loss of inventory conditions when the high pressure cooling system(s), are unable to restore and maintain RPV level. These proper operator actions are allowed for in the NUREG-0737 requirement.

For plants without RCIC, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV.

Conclusion:

The anticipated transients in NRC Regulatory Guide 1.70, Revision 3, were reviewed for all BWR product lines BWR/2 through BWR/6 from a core cooling viewpoint. The LOF event was identified to be the most limiting transient which would challenge core cooling. The BWR is designed so that the high pressure makeup or inventory maintenance systems or heat removal systems (HPCI, HPCS, FWCI, RCIC or IC) are independently capable of maintaining the water level above the top of the active fuel given a loss of feedwater. The detailed analyses

show that even with the worst single failure in combination with the LOP event, the core remains covered.

Furthermore, even with more degraded conditions involving one SORV in addition to the worst transient with the worst single failure, studies show that the core remains covered during the whole course of the transient either due to RCIC operation or due to manual depressurization.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 15.1.2.

References:

1. *Section 3.2.1 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, March 31, 1980.*

2. *Section 3.2.2 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, June 30, 1980.*

3. *Section 3.5.2.1 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, August 31, 1979.*

TABLE II.K.3.44-1

SUMMARY OF INITIATING TRANSIENTS
(Reference: NRC Regulatory Guide 1.70, Revision 3)

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1. *Loss of feedwater heating*
2. *Feedwater controller failure - maximum demand*
3. *Pressure regulator failure - open*
4. *Inadvertent safety/relief valve opening*
5. *Inadvertent residual heat removal (RHR) shutdown cooling operation*
6. *Pressure regulator failure - closed*
7. *Generator load rejection*
8. *Turbine trip*
9. *Main steam isolation valve (MSIV) closure*
10. *Loss of condenser vacuum*
11. *Loss of normal ac power*
12. *Loss of feedwater flow*
13. *Failure of RHR shutdown cooling*
14. *Recirculation pump trip*
15. *Recirculation flow control failure - decreasing flow*
16. *Rod withdrawal error*
17. *Abnormal startup of idle recirculation pump*
18. *Recirculation flow control failure - increasing flow*
19. *Fuel loading error*
20. *Inadvertent startup of high pressure core spray (HPCS) or high pressure coolant injection (HPCI) or feedwater coolant injection (FWCI) or isolation condenser (IC), whichever is applicable.*

TABLE II.K.3.44-2

LIST OF SINGLE FAILURES WHICH CAN POTENTIALLY DEGRADE THE COURSE OF A BWR TRANSIENT

1. *One or all of the bypass valves fail to modulate open when required.*
2. *One of the bypass valves, which has opened as a result of the transient, fails to close.*
3. *Failure to trip the turbine or feedwater pumps on high water level.*
4. *One main steam isolation valve (MSIV) fails to close when required.*
5. *One of the safety/relief valves fails to open when required.*
6. *One of the safety/relief valves, which has opened as a result of the transient, fails to close.*
7. *Failure to trip one recirculation pump.*
8. *Failure to run back the recirculation pumps.*
9. *Failure of high pressure coolant injection (HPCI) or high pressure core spray (HPCS) or feedwater coolant injection (FWCI) or one isolation condenser (IC) loop, whichever is applicable.*
10. *Failure of reactor core isolation cooling (RCIC) or one IC loop, whichever is applicable.*
11. *Failure of one low pressure coolant injection (LPCI) loop or the low pressure core spray (LPCS) system.*
12. *Loss of one residual heat removal (RHR) system heat exchanger.*
13. *A single control rod stuck while the remainder of the control rods are moving.*
14. *Failure to achieve the rod block function (i.e., a single control rod will withdraw upon erroneous withdrawal demand).*
15. *Loss of one diesel generator if loss of ac power was the initiating event.*

TABLE II.K.3.44-3

WORST CASE OF TRANSIENT WITH A SINGLE FAILURE FOR DIFFERENT BWR PRODUCT LINES

Product Line	*Transient with a Single Failure (Worst Case)*
BWR/2	*LOF + Failure of one IC loop (Oyster Creek only)* *LOF + Failure of FWCI (Nine Mile Point only)*
BWR/3	*LOF + Failure of FWCI (Millstone only)* *LOF + Failure of HPCI (others)*
BWR/4	*LOF + Failure of HPCI*
BWR/5	*LOF + Failure of HPCS*
BWR/6	*LOF + Failure of HPCS*

TABLE II.K.3.44-4

PARTICIPATING UTILITIES[a]
NUREG-0737

Boston Edison	*Pilgrim 1*
Caroline Power & Light	*Brunswick 1 and 2*
Commonwealth Edison	*LaSalle 1 and 2, Dresden 1-3, Quad Cities 1 and 2*
Georgia Power	*Hatch 1 and 2*
Iowa Electric Light & Power	*Duane Arnold*
Jersey Central Power & Light	*Oyster Creek 1*
Niagara Mohawk Power	*Nine Mile Point 1 and 2*
Nebraska Public Power District	*Cooper*
Northeast Utilities	*Millstone 1*
Philadelphia Electric	*Peach Bottom 2 and 3; Limerick 1 and 2*
Power Authority of the State of New York	*FitzPatrick*
Tennessee Valley Authority	*Browns Ferry 1-3; Hartsville 1-4, Phipps Bend 1 and 2*
Vermont Yankee Nuclear Power	*Vermont Yankee*
Detroit Edison	*Enrico Fermi 2*
Mississippi Power & Light	*Grand Gulf 1 and 2*
Pennsylvania Power & Light	*Susquehanna 1 and 2*
Washington Public Power Supply System	*WNP-2*
Cleveland Electric Illuminating	*Perry 1 and 2*
Houston Lighting & Power	*Allens Creek*
Illinois Power	*Clinton Station 1 and 2*
Public Service of Oklahoma	*Black Fox 1 and 2*
Long Island Lighting	*Shoreham*

[a] *Report applies to plants included herein whose owners participated in the report development.*

II.K.3.45 *Evaluation of Depressurization with Other than Automatic Depressurization System*

Position

Analyses to support depressurization modes other than full actuation of the ADS (e.g., early blowdown with one or two SRVs) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown (NUREG-0737).

Clarification

None.

WNP-2 Position

WNP-2 as a member of the BWR Owners' Group endorses the following position statement and analysis prepared by GE on behalf of the Owners' Group.

The evaluation of alternate modes of depressurization other than full actuation of the Automatic Depressurization System (ADS) is made for those plants listed in Table II.K.3.45-5 with regard to the effect of such reduced depressurization rates on core cooling and vessel integrity.

Depressurization by full ADS actuation constitutes a depressurization from about 1050 psig to 180 psig in approximately 3.3 minutes. Such an event, which is not expected to occur more than once in the lifetime of the plant, is well within the design basis of the reactor pressure vessel. This conclusion is based on the analysis of several transients requiring depressurization via the ADS valves. Results of these analyses indicate that the total vessel fatigue usage is less than 1.0. Therefore, no change in the depressurization rate is necessary. However, to comply with the above request reduced depressurization rates were analyzed and compared with the full ADS actuation. The alternate modes considered cause vessel pressure to traverse the same pressure range in (1) depressurization case 1 (ranges from 6-10 minutes depending on plant size and ADS capacity), and (2) depressurization case 2 (ranges from 15-20 minutes). The case 2 depressurization bounds the possible increase in depressurization time by producing an undesirably long core uncovered time. The case 1 depressurization gives the results of an intermediate depressurization. These modes are achieved by opening a reduced number of relief valves. These blowdown rates are illustrated by Figure II.K.3.45-1.

Assumptions:

The major assumptions used for the core cooling analysis are as follows:

a. *No high pressure cooling systems are available,*

b. *All low pressure ECCS is available, and*

c. *Assumptions as stated in NEDO-24708, Section 3.1.1.3, "Justification of Analysis Methods," which includes the use of 1978 ANS Decay Heat (mean value).*

Results:

a. *Vessel Integrity*

The depressurization events considered are full ADS blowdown and blowdown over 10 and 20 minute intervals. The reactor vessel stresses for these events are within the acceptance stress limits defined by ASME Code Section III for emergency conditions (Level C). The core support structures and other safety-related internal components are also within applicable emergency condition stress limits.

The ADS operating conditions which affect fatigue usage of vessel or core support structures are not significantly different for fast and slow blowdown events. Specific calculations of fatigue usage are not required for emergency conditions (Level C). However, available pressure vessel fatigue analyses show the usage per event to be <0.1 per full ADS event.

In summary, reactor vessel and core support structure integrity is assured for the blowdown rates considered if an ADS event should occur, and reduced rates of depressurization do not significantly decrease fatigue usage.

b. *Core Cooling Capability*

Examination of the reduced depressurization rates under consideration with respect to core cooling concerns shows that:

1. *Vessel depressurization for a case 2 blowdown (15-20 minutes) causes the core to be uncovered for a lengthy period of time even assuming system initiation at the earliest reasonable time.*

2. *Vessel depressurization for a case 1 blowdown (6-10 minutes), when actuated at the same level as the full ADS case, will result in less vessel inventory* at *the time of ECCS injection and can result in longer periods of core uncovery.*

3. *Vessel depressurization for a case 1 blowdown (6-10 minutes) when actuated considerably earlier than at the ADS initiation setpoint can result in some improvement in core cooling. However, the operator is required to act more quickly in these cases (i.e., within 1-6 minutes after the accident). This earlier depressurization also reduces the time available to start high pressure system injection and hence to avoid the need for manual depressurization. It also increases the frequency of depressurization.*

The results of the calculations are presented in Tables II.K.3.45-1 through II.K.3.45-4. They show the total core uncovered time and remaining vessel inventory at the time of low pressure ECCS injection. A discussion of these results follows below.

Discussion:

The results are based upon calculations performed with the assumptions stated earlier using a representative BWR/3 and a BWR/6 to show consistency of results across the product lines. The transients considered are an outside steam line break and a stuck-open relief valve. The ADS will depressurize the vessel to the low pressure ECCS injection setpoint when no high pressure cooling systems are available. The depressurizations used are initiated at different times based on the downcomer water level. The first initiation time considered is when the water level is at the top of the active fuel which is consistent with the original design for most plants and thus is the basis for comparison. The second initiation time considered is the downcomer water level of 34 feet from the bottom of the vessel which still provides the operator with a reasonable time to attempt to start the high pressure systems. The last initiation time considered is the high pressure makeup system setpoint (Level 2 for BWR/6 and Level 1 for BWR/3) plus 60 seconds which is the earliest time in which depressurizaton could be expected to occur.

The core cooling criteria used in assessing the impact of a reduced depressurization rate are:

a. *Inventory in the core and lower plenum at the time of low pressure ECCS injection as predicted by the SAFE model (Reference 1), and*

b. *The total time which the top of the active fuel (TAF) remains uncovered as predicted by the SAFE model (Reference 1).*

The first criterion demonstrates the increased mass loss due to boiloff for the longer blowdown, since mass loss due to flashing will be independent of the depressurization rate providing the boundary pressure values are the same for all the rates. The second criterion is a measure of the resultant core temperature.

Table II.K.3.45-1 gives the results for a BWR/6 assuming an outside steam line break. As the length of depressurization is increased the vessel inventory at the time the ECCS injection decreases and the total core uncovered time increases. Table II.K.3.45-1 further shows that the actuation times based on higher water levels (i.e., 34 ft and Level 2 +60 sec) longer depressurizations exhibit the same trends. Furthermore, for any particular depressurization rate, raising the actuation level increases the vessel inventory at ECCS injection and decreases the total core uncovered time. However, this also decreases the time the operator has available to try to get high pressure level control systems working in order to avoid the need to depressurize.

Table II.K.3.45-2 shows that these same results are exhibited for the case of a stuck-open relief valve. Table II.K.3.45-3 shows the results for a BWR/3 assuming an outside steam line break. Examination of the table shows the same trends as Table II.K.3.45-1, and therefore the results are applicable to all product lines. Table II.K.3.45-4 shows that these general trends are independent of the models used by exhibiting the same trends for a BWR/3 using standard Appendix K licensing assumptions.

Conclusion:

The cases considered show that no appreciable improvement can be gained by a slower depressurization based on core cooling considerations. A significantly slower depressurization rate will result in increased core uncovered time. A moderate decrease in the depressurizaton rate necessitates an earlier actuation time resulting in less time available for operator action to start high pressure ECCS without significant benefit to vessel fatigue usage. This will also result in an increased frequency of ADS actuation.

Finally, it is of paramount importance to note that the ADS is not a normal core cooling system; it is a backup for high pressure cooling systems (feedwater, RCIC, HPCI/HPCS). If ADS operation is ever required in a BWR, it will be because core cooling is threatened. Since a full ADS blowdown is well within the design basis of the reactor pressure vessel and ADS is properly designed to minimize the threat to core cooling, no change in the depressurization rate is necessary.

<u>Reference:</u>

1. NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," August 1979.

TABLE II.K.3.45-1

RESULTS FOR BWR/6 OUTSIDE STEAM LINE BREAK
NO HIGH PRESSURE SYSTEMS AVAILABLE

Depressurization Case	Depressurization Initiation		Core Uncovered Time (sec)	Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)
	Level	Time (sec)		
Full ADS	TAF[a]	1086.0	26	1.603×10^5
Case 1	TAF	1086.0	117	1.528×10^5
Case 1	34'	610.6	10	1.779×10^5
Full ADS	Level 2[b] +60 sec	78.3	No uncovery	1.993×10^5
Case 1	Level 2 +60 sec	78.3	No uncovery	1.937×10^5
Case 2	Level 2	78.3	390	1.755×10^5

[a] *Top of active fuel.*
[b] *High pressure initiation setpoint plus 60 sec.*

TABLE II.K.3.45-2

*RESULTS FOR BWR/6 STUCK-OPEN RELIEF VALVE
NO HIGH PRESSURE SYSTEMS AVAILABLE*

Depressurization Case	Depressurization Initiation		Core Uncovered Time (sec)	Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)
	Level	Time (sec)		
Full ADS	TAF[a]	642.6	No uncovery	1.836×10^5
Case 1	TAF	642.6	15	1.787×10^5
Case 1	34'	391.8	No uncovery	1.889×10^5
Case 1	Level 2[b] +60 sec	77.7	No uncovery	1.961×10^5

[a] Top of active fuel.
[b] High pressure initiation setpoint plus 60 sec.

TABLE II.K.3.45-3

RESULTS FOR BWR/3 OUTSIDE STEAM LINE BREAK
NO HIGH PRESSURE SYSTEMS AVAILABLE

Depressurization Case	Depressurization Initiation		Core Uncovered Time (sec)	Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)
	Level	Time (sec)		
Full ADS	TAF[a]	1527.8	155	2.027×10^5
Case 1	TAF	1527.8	170	1.975×10^5
Case 1	34'	701.6	51	2.291×10^5
Full ADS	Level 1[b] +60 sec	364.4	No uncovery	2.446×10^5
Case 1	Level 1 +60 sec	364.4	10	2.394×10^5

[a] Top of active fuel.
[b] High pressure initiation setpoint plus 60 sec.

TABLE II.K.3.45-4

RESULTS FOR BWR/3 OUTSIDE STEAM LINE BREAK ON APPENDIX K ASSUMPTIONS WITH NO HIGH PRESSURE SYSTEMS

Depressurization Case	Depressurization Initiation		Core Uncovered Time (sec)	Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)
	Level	Time (sec)		
Full ADS	TAF[a]	759.4	264	1.960×10^5
Case 1	TAF	759.4	277	1.913×10^5
Full ADS	Level 1[b] +60 sec	145.6	175	2.210×10^5
Case 1	Level 1 +60 sec	145.6	191	2.165×10^5

[a] *Top of active fuel.*
[b] *High pressure initiation setpoint plus 60 sec.*

TABLE II.K.3.45-5

PARTICIPATING UTILITIES [a]
NUREG-0737

Boston Edison	*Pilgrim 1*
Caroline Power & Light	*Brunswick 1 and*
Commonwealth Edison	*LaSalle 1 and Dresden 2 and Quad Cities 1and 2*
Georgia Power	*Hatch 1 and 2*
Iowa Electric Light & Power	*Duane Arnold*
Jersey Central Power & Light	*Oyster Creek 1*
Niagara Mohawk Power	*Nine Mile Point 1 and 2*
Nebraska Public Power District	*Cooper*
Northeast Utilities	*Millstone 1*
Northern States Power	*Monticello*
Philadelphia Electric	*Peach Bottom 2 and 3; Limerick 1 and 2*
Power Authority of the State of New York	*FitzPatrick*
Tennessee Valley Authority	*Browns Ferry 1-3; Hartsville1-4, Phipps Bend 1 and 2*
Vermont Yankee Nuclear Power	*Vermont Yankee*
Detroit Edison	*Enrico Fermi 2*
Long Island Lighting	*Shoreham*
Mississippi Power & Light	*Grand Gulf 1 and 2*
Pennsylvania Power & Light	*Susquehanna 1 and 2*
Washington Public Power Supply System	*WNP-2*
Cleveland Electric Illuminating	*Perry 1 and 2*
Houston Lighting & Power	*Allens Creek*
Illinois Power	*Clinton Station 1and 2*
Public Service of Oklahoma	*Black Fox 1 and 2*

[a] *Report applies to plants included herein whose owners participated in the report development.*

II.K.3.46 *Response to List of Concerns from ACRS Consultant (Michelson Concerns)*

Position

General Electric should provide a response to the Michelson concerns as they relate to BWRs. See NUREG-0660, Appendix C, Table c.3, Item 46 (Reference 1) and NUREG-0626, Section 4, Item A.17 (Reference 6c).

Clarification

None.

WNP-2 Position

GE, acting for the BWR Owners' Group, responding to these concerns in a letter, "Response to Questions Posed by Mr. C. Michelson," R. H. Buchholz (GE) to D. F. Ross, dated February 21, 1980. Submittal of this letter completes the action required by this task.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, Section 6.3.6.

III.D.3.3 Improved Inplant Iodine Instrumentation Under Accident Conditions

Position (NUREG-0737)

a. 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.

b. Each applicant for a fuel-loading license to be issued prior to January 1, 1981 shall provide the equipment, training, and procedures necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.

Clarification

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 ziolite) for the following reasons:

a. 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.

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

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

d. 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.

For applicants with fuel loading dates prior to January 1, 1981, provide by fuel loading (until January 1, 1981) the capability to accurately detect the presence of iodine in the region of

interest following an accident. This can be accomplished by using a portable or cart-mounted iodine sampler with attached single-channel analyzer (SCA). The SCA window should be calibrated to the 365 KeV of Iodine-131 using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

WNP-2 Position

WNP-2 is responding to this position as follows: Four fixed, one mobile continuous air monitoring system, and one movable local alarming continuous air monitor are provided for air sampling in plant areas where personnel may be present during accident conditions. In addition, 10 low volume air sampling systems will be strategically located throughout the plant in frequently occupied areas to continuously draw air samples for subsequent analysis.

Grab samples will be obtained using varying volume air samplers that are both ac and dc powered.

Movable local alarming continuous air monitors are placed at predetermined plant locations for personnel protection and to substantiate the quality of the plant breathing atmosphere. These monitors have local readouts (charts) and radioiodine sampling capabilities.

The Supply System is currently using activated charcoal cartridges for radioiodine analysis and is evaluating the attributes of silver zeolite. On completion of a satisfactory evaluation the Supply System will, where applicable, incorporate silver zeolite into its air sampling program. The charcoal cartridges are used in conjunction with a Ge (Li) gamma spectroscopy system located in a low background, low contamination area such as the radiochemistry lab in the near site facility. Prior to analysis, cartridges are purged in a fume hood using plant air, instrument air, bottled air, or bottled nitrogen which is stored onsite.

Station procedures are provided for obtaining and evaluating both routine and non-routine air samples. In addition to initial training provided for Health Physics/Chemistry personnel, periodic drills are conducted in accordance with the WNP-2 Emergency Plan.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated December 1982, Section 12.5.2.

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I.1 INTRODUCTION

The italicized information is historical and was provided to support the application for an operating license.

The Licensing Review Group (LRG) was formed in April 1980 to provide a vehicle for expediting the licensing process for General Electric (GE) boiling water reactors (BWR). The group was made up of six utilities, GE, and the consulting firm of KMC. Membership was at both the executive and technical level.

All applicants were in the near-term operating license (NTOL) stage of the licensing process. The basis of establishing the LRG consisted of the fact that most issues for NTOL BWR plants are identical or very similar. It was felt that this common ground could be used advantageously in the NRC review process. The NRC assigned a Project Licensing Manager to interface with the LRG.

All utilities represented in the LRG are identified below. The plants indicated are ordered chronologically in the licensing process, with LaSalle County-1 being the first for which NRC issued a Safety Evaluation Report (SER).

Plant	*Utility*
LaSalle County-1	*Commonwealth Edison Company*
Zimmer	*Cincinnati Gas and Electric Company*
Shoreham	*Long Island Lighting Company*
Susquehanna-1	*Pennsylvania Power and Light Company*
Fermi-2	*Detroit Edison Company*
WNP-2	*Washington Public Power Supply System*

The LRG worked on a lead plant concept with LaSalle County-1 acting as the lead plant. Subsequent to the issuance of the SER for LaSalle, NRC issued SERs for Zimmer, Shoreham, Susquehanna, and Fermi (refer to References 1 through 5).

Interface with staff from various branches of NRC identified issues for the specific branches. Often, the issues consisted of a question or questions previously developed by NRC. Whenever possible, a common position on the issue was developed which was applicable to all plants. In some cases, however, uniqueness of design or other variables precluded a common position.

Plant unique positions were then developed. This appendix is for WNP-2, but uses common positions when applicable.

The order of presentation for an issue is as follows: The issue is presented, then the details of the issue follow under the "Question" heading. The response is then given. The numbers in parentheses (e.g., 5.4.4, 6.2) reference the applicable sections in the FSAR. Applicable questions are referenced as appropriate since in many instances the issue was previously addressed in a WNP-2 question response.

References:

1. *U.S. Nuclear Regulatory Commission (NRC), NUREG-0519, "Safety Evaluation Report by the Office of Nuclear Reactor Regulation in the Matter of Commonwealth Edison Company, LaSalle County Station, Units No. 1 and 2," Dockets No. 50-373/374.*

2. *NRC, NUREG-0528, Supplement No. 1, "SER by the Office of Nuclear Reactor Regulation, NRC, in the Matter of Cincinnati Gas and Electric Company, William H. Zimmer Nuclear Power Station, Unit 1," Docket No. 50-358.*

3. *NRC, Office of Nuclear Reactor Regulation, NUREG-0420, "SER Related to the Operations of Shoreham Nuclear Power Station, Unit No. 1, Docket No. 50-322, Long Island Lighting Company," April 1981.*

4. *NRC, Office of Nuclear Reactor Regulation, NUREG-0776, "SER Related Operation of Susquehanna Steam Electric Station, Units 1 and 2, Dockets No. 50-387 and 50-388, Pennsylvania Power and Light Company, Allegheny Electric Cooperative, Inc.," April 1981.*

5. *NRC, Office of Nuclear Reactor Regulation, NUREG-0798, "SER Related to the Operation of Enrico Fermi Atomic Power Plant, Unit No. 2, Docket No. 50-341, Detroit Edison Company et al.," July 1981.*

I.2 CONTAINMENT SYSTEMS BRANCH

ISSUE: CSB-1 STEAM BYPASS OF THE SUPPRESSION POOL (6.2.1.1)

Question:

The applicant approach to suppression pool bypass is not consistent with Branch Technical Position CSB 6-5. The applicant must commit to perform a low power surveillance leakage test of the containment at each refueling outage.

Response:

The response to above stated concern is provided in response to Question 031.070.

ISSUE: CSB-2 POOL DYNAMIC LOCA AND SRV LOADS

Question:

The staff has completed its review of the short-term program and developed acceptance criteria. We require that the applicant commit to our acceptance criteria or justify any exceptions taken.

Response:

NRC acceptance criteria as well as the supplements thereto are being reviewed and adhered to where possible. Where exceptions are taken, such as in the case of SRV load definition (see Reference 1), or chugging load definition (see Reference 2), these exceptions are being discussed and reviewed with the staff.

References:

1. *"SRV Loads - Improved Definition and Application Methodology for Mark II Containments" (submitted in August 1980).*

2. *"Chugging Loads - Revised Definition and Application Methodology for -Mark II Containments" (based on 4TCO Test Results) (submitted in July 1981).*

ISSUE: CSB-3 CONTAINMENT PURGE SYSTEM

Question:

A 2-inch vent line exists in the purge system to bleed off excess primary containment pressure during operation. We require the applicant to evaluate this 2-inch bypass purge system in light of the criteria of Branch Technical Position CSB 6-4.

Response:

The 2-inch bypass valves, used for pressure control during operation, are located in parallel with each purge system exhaust valve. These 2 inch-150# globe valves meet all the design requirements of the containment isolation system. They are designed to the same pressure/temperature ratings of the containment and purge valves and are designed to close within 4 sec against the 45 psig containment design pressure. All four bypass valves can be remotely operated from the control room, are designed to close an F, A, and Z isolation signals and are being operationally qualified against applicable seismic and hydrodynamic loads.

ISSUE: CSB-4 COMBUSTIBLE GAS CONTROL (6.2.5)

DELETED

ISSUE: CSB-5 CONTAINMENT LEAKAGE TESTING

DELETED

I.3 CORE PERFORMANCE BRANCH

ISSUE: CPB-1 LOAD ASSESSMENT OF FUEL ASSEMBLY COMPONENTS

Question:

The proposed addition of Appendix A to SRP 4.2 provides guidance for the analysis of fuel assembly components and acceptance criteria for fuel assembly response to externally applied forces. The applicant's fuel assembly capability should be assessed accordingly.

Response:

General Electric has completed development of fuel assembly loads modeling and results acceptance criteria both deemed to be in accordance with the requirements of Appendix A to SRP 4.2. The LRG lead plant (LaSalle) has been evaluated accordingly with acceptable results, which were forwarded to the NRC June 8, 1981. A similar analysis will be performed for WNP-2.

ISSUE: CPB-2 WATERSIDE CORROSION

Question:

The applicant has not addressed the potential for fuel corrosion failure similar to that which occurred at the Vermont Yankee plant.

Response:

As indicated in the General Electric presentation given to the NRC in December 1979, the failures appeared to be associated with a metallic incursion in the feedwater. This event has occurred only once in the BWR operating history and is unlikely to reoccur.

Subsequent to this event, General Electric provided an operation recommendation for corrosion product control which should preclude this type of event at WNP-2. The Supply System plans to employ those General Electric operating recommendations which have been proven to be effective at several operating BWR plants for maintaining water quality parameters at or below GE's water quality specification limits.

References:

1. *Letter from R. E. Engel (GE) to M. Tokar (NRC), MFN-172-80, "Corrosion Product Control", dated October 3, 1980.*

ISSUE: CPB-3 CHANNEL BOX WEAR

Question:

Provide more detailed and specific information on the Channel Box Wear concern as applicable to the WNP-2 design.

Response:

General Electric observed wear on the water rods in 8 x 8R fuel assemblies in the fall of 1979. In the referenced letter it was concluded that the observed wear does not affect the functionality of the water rods in the bundle or plant safety.

Since the observed wear General Electric has modified the 8 x 8R water rod design. To improve the margin of reliability of the 8 x 8R fuel design, a modification to the water rod and spacer positioning/water rod has been developed. This modified design has shorter water rod and spacer positioning/water rod lower end plugs, and modified expansion springs on the upper end plugs. These changes have been shown to be effective by successful operation of the short shank 8 x 8 fuel design and from extensive flow-induced vibration testing. This modified water rod concept is being installed on new fuel, such as for WNP-2, as a prudent means of assuring increased margin of fuel reliability. Thus, the modification does not constitute an unreviewed safety question to WNP-2 based on the criteria given in 10 CFR 50.59.

Reference:

1. *Letter, J. S. Charnley (GE) to T. A. Ippolito (NRC), "Water Rod Lower End Plug Inspection Results," dated July 28, 1980.*

ISSUE: CPB-4 FUEL CLADDING, SWELLING, AND RUPTURE MODELS

Question:

The applicant has not provided information to assure that for the fuel cladding in a LOCA "the degree of swelling and incidence of rupture are not underestimated" as required by Appendix K of 10 CFR 50.46. The procedures proposed in NUREG-0630 introduce additional conservatism and should be utilized to perform supplemental calculations to the current ECCS analyses.

Response:

General Electric recently transmitted supplemental calculations to the NRC, "Fuel Swell and Rupture Model - Experimental Data Review and Sensitivity Studies," May 15, 1981. This

document contains a discussion of the first stress and circumferential strain data applicable to the BWR, and presents results from the sensitivity studies performed comparing the NUREG-0630 models with the current GE models.

Hoop stress versus rupture temperature sensitivity studies were performed using a combination of the two curves (adjusted GE stress curve and NUREG-0630). These studies resulted in a change in PCT of ±10°F. Even though this PCT impact is small, GE proposes to review the current stress model to incorporate the adjusted curve. Implementation of the adjusted curve will be coincidental with implementation of the complete LOCA model improvement package. Also, the document shows that NUREG-0630 perforation strain versus temperature curve is not applicable to BWR fuel and that substitution of a bounding NUREG-0630 curve into the current GE ECCS analysis has negligible effect on the peak clad temperature (PCT). Based on this, it is maintained that the current GE strain model is valid for the BWR and should continue to be used for ECCS calculations at WNP-2.

Reference:

1. *Letter, R. H. Buchholz (GE) to L. S. Rubenstein (NRC), "General Electric Fuel Clad Swelling and Rupture Model," dated May 15, 1981.*

ISSUE: CPB-5 FISSION GAS RELEASE

Question:

Provide more detailed and specific information on the Fission Gas Release concern as applicable to the WNP-2 design.

Response:

The effects of high burnups and subsequent fission gas release on fuel thermal-mechanical design analyses was addressed in the proprietary General Electric presentation to the NRC on Extended Burnups, March 24, 1981. Burnups to 50 GWd/MT are considered in the stress analyses documented in NEDE-24011-PA. This analysis is applicable to WNP-2 fuel.

ISSUE: CPB-6 STABILITY ANALYSIS

Question:

Please refer to NRC Question 221.009 for this question.

Response:

Please refer to the response to NRC Question 221.009.

ISSUE: CPB-7 CHANNEL BOX DEFLECTION

Question:

The applicant has not referenced General Electric Licensing Topical Report NEDE-21354-P which describes the fuel channel design. Of specific concern is the commitment to control rod driveline friction testing recommended in Section 4.4.2 of NEDE-21354-P.

Response:

To resolve the channel box deflection issue, the Supply System has initiated a channel management program for WNP-2. The elements of this program include:

a. *Compiling complete operating history records for each channel. Data to be collected include channel location, orientation of welded sides, exposure, and control history.*

b. *Compiling complete analytical history records for each channel including fast fluence (>1 MeV), and flux gradient history.*

c. *Measurement of post-operation channel box deflection.*

The Supply System is planning to measure channel box deflection after each refueling outage for selected channels which are discharged to the spent fuel pool. The reuse of discharged channels will be determined based upon these measurements as compared to predetermined criteria. Other items which will be addressed in this program include development of channel manufacturing history data and analytical, predictive capability.

The Channel Management Program has already resulted in some potential improvement in channel operation. Data from Commonwealth Edison measurements which recently became available indicate that major channel bow may be a strong function of channel manufacturing history rather than location of the channel within the core. Their data indicate that prime candidates for channel bow are manufactured from two pieces of stock material not from the same original material batch. Also, Commonwealth Edison channels which experienced major bow, in many cases, were never on the core periphery.

Based on this information, the Supply System has identified which of the WNP-2 channels are manufactured from mismatched halves (75 out of 764) and we have set up special plans to

manage the use of these channels to minimize potential channel bow. These measures include taking advantage of core locations which are not adjacent to control blades and, in addition, identification of locations of minimal exposure and fast flux tilt.

In addition to the above channel management program, the Supply System is proposing to take a number of operational actions to monitor channel distortion in the core. Prior to startup after each reload, scram time testing and rod notch testing will be performed. For rods which fail the above test, the pressure test described in NEDE-21534-P (4.4.2) will then be performed.

I.4 INSTRUMENTATION AND CONTROL SYSTEMS BRANCH

ISSUE: ICSB-1 PHYSICAL SEPARATION AND ELECTRICAL ISOLATION (7.1.4, 7.2.3, and 7.6.3)

Question:

In the applicant's design, Class 1E instrumentation do not adhere to adequate separation criteria, have not been qualified, and do not adhere to separation of Class 1E to non-Class 1E instrumentation.

Response:

WNP-2 Class 1E instrumentation has been reevaluation to the requirements NUREG-0588, Category II, as described in the Equipment Qualification Report referenced in 3.11. Class 1E instrumentation is adequately separated as described in the response to Question 031.100 and as additionally agreed to in WNP-2 docket letter G02-81-146, dated June 18, 1981.

ISSUE: ICSB-2 ANTICIPATED TRANSIENT WITHOUT SCRAM (ATWS)

Question:

We require that the applicant agrees to implement plant modifications on a scheduled basis in conformance with the Commission's final resolution of ATWS. In the event that LaSalle starts operation before necessary plant modifications are implemented, we require some interim actions be taken by LaSalle in order to reduce, further, the risk from ATWS events.

The applicant will be required to:

a. Develop emergency procedures to train operators to recognize an ATWS event, including consideration of scram indicators, rod position indicators, flux monitors, vessel level and pressure indicators, relief valve and isolation valve indicators, and containment temperature, pressure, and radiation indicators.

b. Train operators to take action in the event of an ATWS including consideration of immediately manual scramming the reactor by using the manual scram buttons followed by changing rod scram switches to the scram position, stripping the feeder breakers on the reactor protection system power distribution buses, opening the scram discharge volume drain valve, prompt actuation of the standby liquid control system, and prompt placement of the RHR in the pool cooling mode to reduce the severity of the containment conditions.

Response:

See the response to RSB-22.

ISSUE: ICSB-3 TEST TECHNIQUES (7.1.4)

Question:

In order to perform routine surveillance testing, it is necessary for the applicant to pull fuses. We consider that this design does not satisfy the requirements of IEEE Standard 279-1971, Paragraphs 4.11 and 4.20.

Response:

The responses to Questions 031.039 and 031.061 address this issue. Part (b) of the response to Question 031.039 is repeated below:

> *"In no instance will it be necessary during testing... to either lift leads or remove fuses."*

ISSUE: ICSB-4 SAFETY SYSTEM SETPOINTS (7.1.4)

Question:

The range of Class 1E system sensors may be exceeded in the worst case combination of setpoint and accuracy.

Response:

a. *All calculated setpoints (taking into account drift) will be within sensor range and will be in accord with Technical Specification Limits.*

b. *Certain setpoints are dependent upon actual plant location or operation (i.e., background radiation) and can only be determined at a later date. If an incompatibility exists with regard to sensor range the instrument will be replaced. This position applies for all instruments where conflicts are detected.*

ISSUE: ICSB-5 DRAWINGS

Question:

The one line drawings and schematics contradict the functional control drawings and system description which are provided in the FSAR. Furthermore, contact utilization charts contradict the actual schematics.

Response:

The contradiction between the drawings and the system descriptions has been eliminated as the result of a major effort spent in rewriting Chapter 7 with this concern in mind. With regard to inconsistencies between the functional control diagrams and schematics, all FSAR drawings and those listed in Chapter 1.7 are updated and distributed every 6 months.

ISSUE: ICSB-6 RCIC CLASSIFICATION

Question:

Refer to Question 031.015 and LRG Issue RSB-6.

Response:

Refer to responses to Question 031.015 and LRG Issue RSB-6.

ISSUE: ICSB-7 SAFETY-RELATED DISPLAY (7.5)

Question:

The design of the safe shutdown indication does not satisfy the requirements of IEEE Standard 279-1971, Paragraph 4.10.

Response:

WNP-2 safety-related display instrumentation will be designed to comply with the requirements of Regulatory Guide 1.97, Revision 2. Section 7.5 has been amended to discuss the degree of conformance for WNP-2 for each indication applicable as described in Regulatory Guide 1.97 and IEEE Standard 279-1971.

ISSUE: ICSB-8 ROD BLOCK MONITOR (7.6)

Question:

The applicant does not agree that the rod block monitor is a protection system.

Response:

The NRC has conducted an extensive review of the RMCS including refueling interlocks RBM, RWM, RSCS on various dockets. Plants with open items having similar designs will be conformed to the Zimmer design (i.e., the resolution will be reviewed and resolution bases if applicable will be incorporated).

The Zimmer design review has been completed and the issue resolved. This closure basis will be relied upon. WNP-2 system is similar to the design proposed for the Zimmer plant as delineated below:

a. *The four flow monitors are interconnected by armored cable and shield cables and there are open spaces around the cables which penetrate fire barriers between redundant channels.*

b. *Both rod block monitor channels are connected by data buses which are enclosed in a metal shield and run along the top of the cabinet.*

c. *The wiring of the rod block monitor bypass switch satisfies the WNP-2 separation criteria.*

d. *The rod block monitor is a modified design and contains multiplexing circuitry which interfaces with the new reactor manual control system.*

Items a, b, and c have been verified at WNP-2 site as to their existence. The NRC met with General Electric on Item d. and the staff has approved the current design and transient analysis with the addition of periodic technical specification testing to assure system operability. * *WNP-2 will include a surveillance requirement in the Technical Specification for the rod block monitor.*

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* *A GE/NRC generic meeting was held in Bethesda on January 22, 1981 to discuss the new reactor manual control system utilized on most NTOL plants. The NRC has been concerned for many years about the appropriateness of utilizing the RBM (not fully safety grade) in transient mitigation.*

ISSUE: ICSB-9 MSIV LEAKAGE CONTROL SYSTEM

Question:

We identified a single failure to the MSIV leakage control system which could lead to possible failure of the system during testing or operation.

Response:

Please see the revised response to Question 031.076.

I.5 MATERIALS ENGINEERING BRANCH

ISSUE: MTEB-1 PRESERVICE AND INSERVICE INSPECTION OF CLASS 1, 2, AND 3 COMPONENTS PER 10 CFR 50.55a(g)

Question:

Preservice and inservice inspection of Class 1, 2, and 3 components have not been submitted.

Response:

The response to the above stated concern is provided in the response to Question 121.010.

ISSUE: MTEB-2 EXEMPTIONS FROM APPENDIX G AND H TO 10 CFR 50
MTEB-3 (5.1.4) (5.3.2) (5.3.3)

Question:

The WNP-2 reactor vessel does not meet the specific requirements of Appendix G and H to 10 CFR 50. Identify and justify your exemptions.

Response:

WNP-2, as a member of the Licensing Review Group (LRG), has submitted information of fracture toughness and surveillance program requirements to show compliance with Appendix G and H to 10 CFR 50. This submittal (Reference 1) was similar to that which has been approved by the NRC for the preceding LRG members (LaSalle County, Susquehanna, Shoreham, Zimmer, and Fermi-2).

Reference:

1. *Letter GO2-81-532, G. D. Bouchey to A. Schwencer, "Appendix G and H Information, Responses to Materials Engineering Branch - Component Integrity Section," dated December 18, 1981.*

ISSUE: MTEB-4 REACTOR TESTING AND COOLDOWN LIMITS (5.3)

Question:

Insufficient information has been submitted for us to assess that the methods used to provide stress intensity values, are equivalent to those obtained from Appendix G of ASME Code; clarification and justification of the methods used to construct the operating pressure temperature limits should be provided.

Response:

WNP-2 has provided information to show compliance with the methods of Appendix G of Section III of the ASME Boiler and Pressure Code (Summer 1972 Addenda). Compliance with Appendix G for this vessel is to provide operating limitations on pressure and temperature based on fracture toughness. These operating limits assure that a margin of safety against a nonductile failure of this vessel is the same as that for a vessel built to the Summer 1972 Addenda.

The specific temperature limits for operation when the core is critical are based on an approved modification to 10 CFR 50, Appendix G, Paragraph IV.A.2.c. The approved modification and justification for it is given in GE Licensing Topical Report NEDO-21778-A (Reference 1).

See Reference 1 to MEB-2 and MEB-3.

Reference:

1. *Letter to Dr. G. G. Sherwood (GE) from Olan V. Parr (NRC), "Review of General Electric Topical Report, Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors," November 13, 1978 (see GE Transmittal T-1727).*

ISSUE: MTEB-5 GENERAL DESIGN CRITERION 51

Question:

The applicant must demonstrate that the primary containment pressure boundary at WNP-2 meets the requirements of General Design Criterion 51 of 10 CFR 50.

Response:

GDC-51 requires that under operating, maintenance, testing, and postulated accident conditions (1) the ferritic materials of the containment pressure boundary behave in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized.

The WNP-2 containment system includes a ferritic steel primary containment vessel and head enclosed by a reinforced concrete shield structure. The ferritic materials of the containment pressure boundary that were considered in the evaluation for compliance to GDC-51 are those that have been applied in the fabrication of the containment vessel and head, equipment hatch, personnel lock, and penetrations and components of the fluid system including valves required to isolate the system. These components are the parts of the containment system that are not backed by concrete and must sustain loads during the performance of the containment function under the conditions cited by GDC-51.

WNP-2 containment pressure boundary is comprised of ASME Code Class I, Class 2, and MC components. Based upon the review performed by the NRC, it was determined that the fracture toughness requirements in ASME Code Editions and Addenda typical of those used in the design of the WNP-2 containment may not ensure compliance with GDC-51 for all areas of the containment pressure boundary. The basis for this decision was that the fracture toughness criteria that had been applied in construction differ in Code classifications and Code Edition and Addenda. Therefore, the Class I, Class 2, and Class MC components of the WNP-2 containment pressure boundary were reviewed according to the fracture toughness requirements of the Summer 1977 Addenda of Section III for Class 2 components and fracture toughness data presented in NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing of PWR Steam Generator and Reactor Coolant Pump Supports."

Based on review of the available fracture toughness data and material fabrication histories, and the use of correlations between metallurgical characteristics and material fracture toughness, it was concluded that the ferritic materials in the WNP-2 containment pressure boundary meet the fracture toughness requirements that are specified for Class 2 components by the 1977 Addenda of Section III of the ASME Code. Compliance with these Code requirements provide reasonable assurance that the WNP-2 reactor containment pressure boundary materials will behave in a non-brittle manner, that the probability of rapidly propagating fracture will be minimized, and that the requirements of GDC-51 are satisfied.

I.6 MECHANICAL ENGINEERING BRANCH

ISSUE: MEB-1 ASYMMETRICAL LOCA AND SSE AND ANNULUS PRESSURIZATION LOADS ON REACTOR VESSEL INTERNALS AND SUPPORTS (3.9.2)

Question:

Document your reevaluation of the safety-related systems and components based upon the load combinations, response combination methodology, and acceptance criteria required by us as presented at our meeting of December 12, 1978. (Reference letter dated September 18, 1978.)

Response:

This issue was discussed at the Mechanical Engineering Branch (MEB) Safety Evaluation Report (SER) meeting held September 29 through October 1, 1981, for WNP-2. Load combinations and acceptance criteria are provided in the responses to the MEB SER questions 23 and 25, presented at that meeting (see Table MEB-1-1). Results of the reevaluation will be provided in the New Loads update of 3.9, to be provided in a future amendment.

TABLE MEB-1-2

LOAD COMBINATION AND ACCEPTANCE CRITERIA
FOR ASME CODE CLASS 1, 2, AND 3
NSSS PIPING AND EQUIPMENT

Load Combination	Design Basis	Evaluation Basis	(Service Level)
$N + SRV_{(ALL)}$	Upset	Upset	(B)
$N + OBE$	Upset	Upset	(B)
$N + OBE + SRV_{(ALL)}$	Emergency	Upset	(B)
$N + SSE + SRV_{(ALL)}$	Faulted	Faulted*	(D)
$N + SBA + SRV$	Emergency	Emergency*	(C)
$N + IBA + SRV$	Faulted	Faulted*	(D)
$N + SBA + SRV_{(ADS)}$	Emergency	Emergency*	(C)
$N + SBA + OBE + SRV_{(ADS)}$	Faulted	Faulted*	(D)
$N + IBA + OBE + SRV_{(ADS)}$	Faulted	Faulted*	(D)
$N + SBA/IBA + SSE + SRV_{(ADS)}$	Faulted	Faulted*	(D)
**N + LOCA + SSE	Faulted	Faulted*	(D)

LOAD DEFINITION LEGEND

Normal (N) - *Normal and/or abnormal loads depending on acceptance criteria.*

OBE - *Operational basis earthquake loads.*

SSE - *Safe shutdown earthquake loads.*

SRV - *Safety/relief valve discharge induced loads from two adjacent valves (one valve actuated when adjacent valve is cycling).*

SRV_{ALL} - *The loads induced by actuation of all safety/relief valves which activate within milliseconds of each other (e.g., turbine trip operational transient).*

TABLE MEB-1-2 (Continued)

SRV_{ADS}	-	*The loads induced by the actuation of safety/relief valves associated with automatic depressurization system which activate within milliseconds of each other during the postulated small or intermediate size pipe rupture.*
LOCA	-	*The loss-of-coolant accident associated with the postulated pipe rupture of large pipes (e.g., main steam, feedwater, recirculation piping).*
$LOCA_1$	-	*Pool swell drag/fallout loads on piping and components located between the main vent discharge outlet and the suppression pool water upper surface.*
$LOCA_2$	-	*Pool swell impact loads on piping and components located above the suppression pool water upper surface.*
$LOCA_3$	-	*Oscillating pressure induced loads on submerged piping and components during condensation oscillations.*
$LOCA_4$	-	*Building motion induced loads from chugging.*
$LOCA_5$	-	*Building motion induced loads from main vent air clearing.*
$LOCA_6$	-	*Vertical and horizontal loads on main vent piping.*
$LOCA_7$	-	*Annulus pressurization loads.*
SBA	-	*The abnormal transients associated with a small break accident.*
IBA	-	*The abnormal transients associated with an intermediate break accident.*

* *All ASME Code Class 1, 2, and 3 piping systems which are required to function for safe shutdown under the postulated events shall meet the requirements of NRC's "Interim Technical Position Function Capability of Passive Components" - by MEB.*

** *The most limiting case combination among $LOCA_1$ through $LOCA_7$.*

ISSUE: MEB-2 PREOPERATIONAL VIBRATION ASSURANCE PROGRAM (3.9.2, 3.9.5)

Question:

Additional information is required concerning the basis for the allowable vibration amplitude derived and clarification of the use of twice this allowable is acceptable.

Response:

This item has been closed by MEB prior to LRG review. It is not documented in lead plant or subsequent plant SERs. For additional information see responses to Questions 110.022, 110.023, and 110.024.

ISSUE: MEB-3 DYNAMIC RESPONSE COMBINATION USING THE SRSS TECHNIQUE

Question:

We are studying the problem of utilizing the square-root-of-the-sum-of-the-squares (SRSS) for determining responses other than LOCA and SSE as you have used. By not utilizing the absolute sum method, the review may be extended if we do not agree that the SRSS methodology is applicable.

Response:

The response to this issue was provided during the Mechanical Engineering Branch meeting for WNP-2, September 29 through October 1, 1981. (See Attachment 1.)

ATTACHMENT 1

Question No. 26
(3.9.3.1)

The methods of combining responses to all of the loads requested in (a) above is required. Our position in this issue for Mark II plants is outlined in NUREG-0484, Revision 1, "Methodology for Combining Dynamic Responses". However, since the primary containment for the WNP-2 plant is a free-standing steel pressure vessel and the plant is in a higher seismic zone, the staff will require that the criteria in Section 4 of NUREG-0484, Revision 1, "Criteria for Combination of Dynamic Responses Other Than Those of SSE and LOCA," be satisfied if the square-root-of-the-sum-of-the-squares method of combining these responses is used. (Reference Regulatory Position E (2) in the enclosure to a letter from J. R. Miller, NRC, to Dr. G. G. Sherwood, GE, "Review of General Electric Topical Report NEDE-24010-P," dated June 19, 1980.) The conclusions of NUREG-0484, Revision 1, are based on the studies performed by GE in NEDE-24010-P and BNL in NUREG/CR-1330. The applicant must demonstrate that an SRSS combination of dynamic responses achieves the 84% nonexceedance probability level because of the difference in containment and seismic level which were not included in the earlier studies.

Response:

When a seismic response from a high seismic input, like that from Hanford, is combined with another dynamic response (e.g., SRV discharge loads), depending on the relative magnitudes of the two responses being combined, the shape of the cumulative distribution function (CDF) of the combined response will change. If the maximum magnitude of one of the responses is very large compared to the other response being combined, the CDF curve will almost be vertical and it is immaterial if these two responses are combined using the SRSS or the Absolute Sum (ABS) rule. However, if the maximum magnitudes of the two responses are about equal, use of SRSS vs. ABS rule to combine the responses will cause significant difference in the combined response. In addition, in this case, the CDF curve will be more like S-shaped with the non-exceedance probability (NEP) of SRSS being close to 84%. In the generic Mark II study, examples from both such cases were considered with more examples from the case with responses of comparable magnitudes. This study showed that all these Mark II cases meet the requirements of NUREG-0484. Hence the GE Topical Report NEDE-24010-P, "Technical Bases for the Use of SRSS Method for Combining Dynamic Loads for Mark II Plants," is also applicable to WNP-2 with high seismic input.

The impact of the free-standing steel primary containment is discussed in the areas as follows:

a. *Vessel and Internals*

Vessel and internals are not attached to and not affected by the steel containment.

b. *Piping Systems and Floor Mounted Equipment*

The dynamic input to these components at their containment support locations may be affected by the steel containment response to the dynamic loads under consideration and hence, may be different from that obtained from concrete containment. However, the frequencies contributing to the responses of major structures and components in both types of plants will not be significantly different but will fall into the same general range.

The structural frequencies will only determine the magnitude of amplification or attenuation of the response. For multi-frequency random-type dynamic loads, the components of input loads whose frequencies coincide with the structural natural frequencies will be amplified and these components will dominate the response. Although the predominant response of a particular structural component may vary somewhat in frequency between the concrete and steel containment configuration, the variances are expected to be small for the range of frequencies of interest for major structures because of the similarities in systems, types of structural configurations, construction materials, and massiveness of buildings. Therefore, key characteristics of the responses (duration of strong response motion and number of peaks) are primarily determined by the input component loads to the structure, and because of the similarity of the dynamic nature of the input loads due to earthquake, SRV, and LOCA for both types of containment, their structural responses will have similar dynamic characteristics. Hence, the response of the mechanical components and piping systems supported from the two types of containments will also be similar. Hence, the use of SRSS combinations for combining the dynamic responses for the WNP-2 application will be demonstrated to meet the 84% non-exceedance probability level.

ISSUE: MEB-4 OBE PLUS SRV FATIGUE ANALYSIS

Question:

Clarify your consideration of the cyclic loadings due to the operating basis earthquake (OBE) and safety/relief valve actuation in your NSSS fatigue analysis.

Response:

For the NSSS piping, 50 peak OBE cycles are used. For other NSSS equipment and components, a generic study serves as the basis for 10 peak OBE cycles. As shown in Reference 1, 10 peak OBE cycles can envelope the cumulative fatigue damage of hundreds of less severe earthquake cycles. Section 3.9 of the FSAR was revised to reflect this position.

The methodologies used to evaluate the fatigue effects due to combined SRV and OBE loads are documented in Reference 2. In the fatigue analysis of NSSS equipment, piping, reactor pressure vessel, and RPV internal components, the actual calculated loads due to OBE and SRV are combined to show compliance with upset limits of fatigue.

References:

1. *Letter from R. Artigas to R. Bosnak, "Number of OBE Fatigue Cycles in the BWR NSSS Design," September 17, 1981.*

2. *Letter from R. B. Johnson to R. Bosnak, "GE Position on Fatigue Analysis," June 29, 1981.*

ISSUE: MEB-5 STRESS CORROSION CRACKING OF STAINLESS STEEL COMPONENTS - DESIGN MODIFICATION

Question:

You are requested to review all ASME Code Class 1, 2, and 3 pressure boundary piping, safe ends and fitting material, including weld metal at your facility to determine if the material selection, processing guidelines, or inspection requirements set forth in NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," are satisfied.

Response:

The response to the above stated concern is provided in the response to NUREG-0313, Revision 1, which was submitted to the NRC September 2, 1981, via G02-81-268,

G. D. Bouchey to A. Schwencer, "Hardship Exemption Request for Implementation of NUREG-0313, Revision 1."

ISSUE: MEB-6 PUMP AND VALVE OPERABILITY ASSURANCE PROGRAM (3.9.3.2)

Question:

Additional information has been requested regarding your analytical and testing methods for your pump and valve operability assurance program.

Response:

a. Pumps

In addition to the tests called for in the FSAR, active safety-related pumps have been analyzed to find the natural frequencies of the pump. When these frequencies were above the ZPA of the seismic floor response spectra, static analyses were performed on the pumps. When the analyses established that the resultant stresses in the pumps were below allowables and the deflections under these loads were less than clearances between moving parts, operability was established. No pumps have been identified which need to have additional testing or analysis to establish operability.

b. Valves

In addition to the tests mentioned in the response to Question 110.032, seismic analyses have been and are being performed on the active safety-related valves which were not prototypically tested. The tests, along with the analysis showing clearance at critical points, demonstrate operability under normal plus SSE loading.

Where the analyses do not show clearances, the valves are being retested as part of the requalification program. If the test and/or analyses did not include hydrodynamic loads where applicable, the valves are being retested or reanalyzed using the proper loading as part of the requalification program.

Where valve accelerations resulting from piping analyses are not yet known, the peak acceleration for frequencies over 8 hz on the 0.005 damping floor response spectra is used as input acceleration for valve analysis and testing. The acceptability of this criteria are being established by comparing piping analysis accelerations to these peaks. The test reports, analyses, and requalification

plans were made available and audited by the NRC-SQRT (Seismic Qualification Review Team) and NRC-PVORT (Pump and Valve Operability Review Team) during November 1982.

ISSUE: MEB-7 BOLTED CONNECTIONS FOR SUPPORTS (3.9.3)

Question:

You have not provided the allowable limits for buckling for the reactor vessel support skirt subjected to faulted conditions. In addition, we requested information concerning the design of support bolts and bolted connections.

Response:

The responses to Questions 24 (Attachment 1) and 42 (Attachment 2) from the WNP-2 draft SER respond to this issue.

ATTACHMENT 1

Question No. 24
(3.9.3.1)

Several references are made in Table 3.9.2(a) through 3.9.2(ac) to allowable stresses for bolting. Specifically, what loading combinations and allowable stress limits are used for bolting for (a) equipment anchorage, (b) component supports, and (c) flange connections. Where are these limits defined?

Response:

a. *Floor Mounted Equipment*

1. *Equipment Anchorage Bolting*

The floor anchored mechanical equipment (pumps, heat exchangers, and RCIC turbine) in GE's scope of supply are mounted on a concrete floor or a steel structure. The design of concrete anchor bolts for the equipment mounted on concrete floor, and the responsibility to prescribe and meet the necessary codes and stress limits are in the AE's scope of supply. The design of attachment bolts for the equipment mounted on steel structure, and the responsibility to prescribe and meet the necessary codes and stress limits are also in the AE's scope of supply. GE works with the interface limit of 10,000 psi in tension or shear for the only purpose of sizing bolt holes in the equipment base, based on the required nominal size and number of bolts for maximum loads.

2. *Component Support Bolting*

(a) *RWCU Pump*

The support bolting of this non-safety essential pump is designed for the effects of pipe load and SSE load to the requirements of the ASME code, Section III, Appendix XVII. The stress limits of 0.41Sy for tension and 0.15Sy for shear are used.

(b) RCIC Turbine

The pump-to-base plate bolting is designed as follows:

(1) Normal Plus Upset

a) Primary membrane:

1.0S

b) Primary membrane plus bending:

1.5S, where S is the allowable stress limit per the ASME Code Section III, Appendix I, Table 1-7.3.

(2) Emergency or Faulted

Stresses shall be less than 1.2 times the allowable limits for "Normal plus Upset" given above.

(c) Flanged Connection Bolting

There are no flange type connections in component supports.

b. Piping Supports and Pipe Mounted Equipment (Valves and Pump) Supports

The supports are hanger and snubber type (including clamps) linear standard components as defined by the ASME Code Section III, Subsection NF. The bolts used in these supports meet criteria of NF-3280 for Service Levels A and B and NF-3230 for Service Levels C and D. (Note: NF-3280 is applicable to bolting for Service Levels A and B. NF-3230 is applicable to linear supports; it refers to Appendix VII which is applicable to bolting for Service Levels C and D.)

ATTACHMENT 2

<u>Question No. 42</u>
(3.9.3.4)

The applicant's response to NRC Question 110.029 is not completely acceptable. Paragraph 3.9.3.4 implies that the reactor vessel support skirt was designed to an allowable compressive load of 0.8 material yield stress. It is not clear how the applicant's design would meet the staff's acceptable allowable load of two-thirds of critical buckling load. In addition, the applicant has assumed the critical buckling stress as the material yield stress at temperature. Provide basis for this assumption.

<u>Response</u>:

This issue was addressed and approved by the NRC on the Susquehanna DSER docket.

Refer to the response to Susquehanna DSER 3.9.3-6. A similar response is provided as follows:

Per GE design specification, the permissible compressive load on the reactor vessel support skirt cylinder (plate and shell type component support) was limited to 90% of the load which produces yield stress, divided by the safety factor for the condition being evaluated. The effects of fabrication and operational eccentricity was included. The safety factor for faulted conditions was 1.125.

An analysis of reactor pressure vessel support skirt buckling for faulted conditions shows that the support skirt has the capability to meet ASME Code Section III, Paragraph F-1370(c) faulted condition limits of 0.67 times the critical buckling strength of the support at temperature assuming that the critical buckling stress limit corresponds to the material yield stress at temperature. The faulted condition analyzed included the compressive loads due to the design basis maximum earthquake, the overturning moments and shears due to the jet reaction load resulting from a severed pipe, and the compressive effects on the support skirt due to the thermal and pressure expansion of the reactor vessel. The expected maximum earthquake loads for the Hanford 2 reactor vessel support skirt are less than 50% of the maximum design basis loads used in the buckling analysis described; therefore, the expected faulted loads are well below the critical buckling limits of Paragraph F-1370(c) for this reactor vessel support skirt. The expected earthquake loads for this reactor were determined using the seismic dynamic analysis methods described in Section 3.7.

Based on currently defined faulted condition loads including annulus pressurization and SSE loads, the maximum compressive stress in the support skirt for axial and bending loads is less than the upset condition allowables determined by the methods of NB-3133.6 of the ASME Code. This assures satisfactory margin against buckling for the faulted condition loads.

ISSUE: MEB-8 PUMP AND VALVE INSERVICE TEST PER 10 CFR 50.55a(g)

Question:

You have not submitted your proposed program for the inservice testing of pumps and valves as required by 10 CFR 50.55a(g).

Response:

The WNP-2 pump and valve inservice test program plant was submitted to the NRC via letter GO2-81-322, G. D. Bouchey to A. Schwencer, "Pump and Valve Test Program Plan," dated October 1, 1981.

ISSUE: MEB-9 REVIEW OF IN SITU TEST PROGRAM OF THE SAFETY/RELIEF VALVE

Question:

No specific question identified for this issue.

Response:

Extensive in-plant SRV actuation test programs have been implemented at Caorso (Italy) and Tokai-2 (Japan), two BWR plants with Mark II containment configuration and equipped with x-quenchers of a design essentially identical to those used in WNP-2. Test results from the above programs, which are available to the NRC, have been used to develop an improved SRV discharge load definition for specific application to WNP-2 (see Report, "SRV Loads, Improved Definition for Mark II Containments, Proprietary Section") and to confirm that the difference between bulk pool temperature and local pool temperature at the quencher discharge is within the value assumed in the suppression pool temperature transient analysis for WNP-2. As stated in Reference 3, implementation of additional SRV tests to measure or confirm the adequacy of the SRV load definition is unnecessary, but an in-plant test to measure local to bulk pool temperature difference will be performed.

References:

1. *Letter GO2-80-172, D. L. Renberger to B. J. Youngblood, "Submittal of SRV Report," dated August 8, 1980.*

2. *Letter, J. J. Verderber to B. J. Youngblood, "Submittal of Proprietary SRV Report," dated August 27, 1980.*

3. *Letter GO2-81-524, G. D. Bouchey to A. Schwencer, "Suppression Pool Temperature Transient Analysis and In-Plant SRV Test," dated December 15, 1981.*

ISSUE: MEB-10 CRACKING OF JET PUMP HOLD-DOWN BEAMS

Question:

Additional information is required concerning the actions being taken by the licensee to preclude cracking of the jet pump hold-down beams.

Response:

As discussed in response to IE Bulletin 80-07, WNP-2 will comply with the GE generic resolution. Since the jet pump hold-down beams have already been installed, WNP-2 will reduce the beam preload from 30 kips to 25 kips which is expected to increase beam operating time to crack initiation at the 2.5% probability level to a range of 19 to 40 years. Also, during operation, periodic inspections will be conducted as part of our overall in-service inspection program. Inspection frequencies will be developed in the future based on lead plant inspection results and the results of future testing at General Electric. (See Reference 1.)

References:

1. *Letter, G. D. Bouchey to R. L. Tedesco, GO2-80-279, "Cracking of BWR Jet Pump Hold Down Beams," dated December 4, 1980.*

ISSUE: MEB-11 CONTROL ROD DRIVE RETURN LINE

Question:

We have not completed our review of GE Topical Report NEDE-21821-2A addressing reactor feedwater nozzle/sparger design modification for cracks nor have we completed GE's generic modification to the control rod drive return nozzle. This may require additional request for information.

Response:

The Supply System's response to NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Line Nozzle Cracking," has been completed. The current status of our position on the CRD cracking problem is as follows:

a. *CRD return line has been cut and capped as allowed by NUREG-0619, page 31.*

b. *CRD return line has been rerouted through redundant equalizing valves to the exhaust water header.*

c. *The control rod drive preoperational test will demonstrate that the system is fully operational and that all components including the hydraulic drive mechanisms, pumps, and flow control valves function properly. The CRD system will be configured with the modifications noted in the NRC concern.*

d. *In order to assure satisfactory system operation with the single failure of an equalizing valve, the proposed design modification will include the addition of two equalizing valves installed in a parallel configuration. The failure of either valve will not impair CRD operation for any foreseen operating or accident condition.*

e. *There will be no increased potential for carbon steel corrosion products to be deposited in the drives. All lines in the WNP-2 hydraulic system after the drive water filters are made of stainless steel.*

f. *The NRC requested GE by letter of January 28, 1980, to recalculate the makeup flow capacity for the 251-inch BWR-5 without the CRD return line. This generic information has been provided by letter of May 2, 1980, from R. L. Gridley, GE, to D. G. Eisenhut, NRC, concurrently with this docketed response for LaSalle. The results indicate that the 251-inch BWR-5 CRD system without a return line (capped Nozzle 10) can achieve a vessel makeup flow in excess of its calculated boiloff rate of 180 gpm. This confirms the same boiloff rate as previously documented in a March 14, 1979, submittal from GE. Furthermore, since the CRD system is not designed to perform an ECCS function, the additional testing to demonstrate the required return flow capacity to the vessel is not warranted.*

ISSUE: MEB-12 CONFIRMATORY PIPING ANALYSIS

<u>Question:</u>

This item is comprised of two issues:

a. *The NRC requires piping system data for the purpose of running confirmatory stress calculations to assure compliance with IE Bulletin 79-14.b.*

b. *Documentation of the preoperational vibration test program for all ASME, Section III, Class 1, 2, and 3 high energy piping systems and all Seismic Category I portions of moderate and high energy piping systems.*

Response:

a. *A summary of WNP-2 inspection program and the design control measures utilized to assure an adequate design for the Seismic Category I piping systems are contained in a letter from D. L. Renberger to R. H. Engelken, " WPPSS Nuclear Project No. 2, IE Bulletin 79-14," dated September 7, 1979 (Reference 1). Presently, WNP-2 has an established program to develop as-built drawings documenting the final configuration of the piping systems together with their supports. The preparation of the as-built drawings is currently underway and these as-built drawings will provide the basis for the final design assessment of the piping systems. However, in order for NRC to proceed with the confirmatory piping analysis and to verify the compliance of the design data with the as-built configuration, Reference 3 provided the necessary piping design data as requested in Reference 2.*

b. *The preoperational/startup piping vibration program includes all Class 1, 2, and 3 high energy piping systems inside Seismic Category I structures or those portions of high energy systems whose failures could adversely affect the functioning of safety-related structures, systems, or components. The program also includes all Seismic Category I portions of moderate energy piping systems outside containment.*

All systems contained in the preoperational/startup vibration program, as documented in Section 14.2, are operated at rated flow and the piping system is either visually inspected or monitored for steady state vibration by remote readout transducers. If during this initial system operation visual observation indicated that piping vibration is significant, measurements are made with a hand-held vibrograph. The results will then be reviewed by the appropriate engineering group to determine the acceptability of the measured vibration values. For the main steam, recirculation, feedwater, RCIC,and SRV discharging piping, the measured vibration is compared against test acceptance criteria. The results are also reviewed by the responsible piping design organization to confirm proper system performance. Documentation of the test results and engineering evaluation performed on them becomes a part of the Startup Test Program files. A summary report is generated and would be available for NRC review following commercial operation.

References:

1. *Letter from D. L. Renberger to R. H. Engelken, "WPPSS Nuclear Project No. 2, IE Bulletin 79-14," dated September 7, 1979, GO2-79-156.*

2. *Letter from R. L. Tedesco to R. L. Ferguson, "Confirmatory Piping Analysis for WNP-2," dated June 22, 1981.*

3. *Letter G. D. Bouchey to L. J. Auge (Manager, Energy Technology Center), dated September 9, 1981, GO2-81-279.*

I.7 POWER SYSTEMS BRANCH

ISSUE: PSB-1 LOW OR DEGRADED GRID VOLTAGE

Question:

The electrical system does not meet our requirements for protection under low or degraded voltage conditions.

Response:

NRC requirements for protection under low or degraded voltage conditions are detailed in Question 040.036 which references revised 8.3.1.1.1 and 8.3.1.2.4.3.

ISSUE: PSB-2 TEST RESULTS FOR THE DIESEL GENERATORS (8.3.2)

Question:

Test results for the diesel generators to indicate margin have not been submitted.

Response:

PSB-2 identifies two margin tests to be accomplished during the preoperational testing of the diesels. The first, a "steady-state margin test," involves loading the unit in excess of the total design accident loads to demonstrate some margin over the total design requirements. The other test, a "start-load margin test," involves applying a step function load in excess of the largest motor to demonstrate the start-load capability of the set with some margin.

Preoperational testing of WNP-2 emergency diesels will include subjecting the diesels to 100% rated load as well as loading the units to their two-hour rating, both of which are larger than the combined design accident loads.

During the loss of power tests, occurring during the preoperational testing phase, a test will be made to demonstrate the start-load capability of the units over that which is required. This test involves loading the diesel generator to 100% design load and dropping the largest motor on the associated bus. This motor will then be restarted. This test demonstrates the diesel generator unit has the capability to start the largest motor on its respective bus while concurrently feeding the rest of the bus loads and still remain within the voltage and frequency requirements of Regulatory Guide 1.9.

The HPCS diesel generator will not be required to fulfill the requirements of Regulatory Guide 1.9, with respect to the voltage and frequency drop, during this particular test as clarified in 8.3.1.2.1.4. Preoperational test results will be available for NRC review during the normal inspection enforcement period.

ISSUE: PSB-3 CONTAINMENT ELECTRICAL PENETRATIONS

Question:

The reactor electrical penetrations do not conform to Regulatory Guide 1.63 and test results do not demonstrate that the electrical penetrations can maintain their integrity for maximum fault current.

Response:

NRC concerns regarding electrical penetration capability under maximum fault (short circuit) conditions are expressed in LaSalle FSAR Question 040.106. That question addresses the effect upon containment integrity of fault current i^2t, assuming failure of the circuit primary protective overcurrent device.

LaSalle's response took credit for the fusing properties of cable external to the penetration conductors to provide overcurrent protection backup to the primary overcurrent device. The response reflected a common Licensing Review Group (LRG) position.

The LaSalle SER rejects the LRG position, advising that credit cannot be given for assumed equipment failure (cable fusing). It mandates that fault current protection devices (circuit breakers and/or fuses) to backup the primary over-current protective devices be provided as required to limit fault current surges to levels less than those for which the penetrations are qualified.

NRC concerns in this area are addressed to WNP-2 in Questions 040.031 and 040.035. These questions were not as explicit regarding the NRC concern as was the question addressed to LaSalle. The WNP-2 response to Question 040.035 predated much of the NRC/LaSalle dialogue and requires revision.

The original response to Question 040.034 provided data indicating the capability of penetration primary overcurrent protective devices to clear faults before penetration i^2t capability is exceeded.

Additional analysis has been performed to determine the maximum i^2t available at electrical penetrations for the case of failure of the circuit primary protective devices to function, which requires the backup overcurrent protective device to clear the fault. Where the analysis

demonstrates that penetration i^2t capability is exceeded, a second overcurrent protective device has been added in series with the circuit primary overcurrent protective device.

The responses to Question 040.034 and 040.035 have been revised to reflect the results of this analysis.

ISSUE: PSB-4 ADEQUACY OF THE 120 V AC RPS POWER SUPPLY (8.4.7)

Question:

The applicant committed to the generic resolution, or to expedite their license, will commit to the surveillance requirements which were applied to Hatch-2.

Response:

The Supply System is committed to implement, prior to fuel loading, the RPS MG set design modification developed by General Electric for generic application. The FSAR has been revised to reflect the design modification.

ISSUE: PSB-5 THERMAL OVERLOAD MARGIN

Question:

We require the applicant to provide the detailed analysis and/or criteria which was used to select setpoints for the thermal overload protection devices for valve motors in safety systems and the details as to how these devices will be tested.

Response:

Motor thermal overloads for Class 1E motor-operated valves (MOVs) are chosen two sizes larger than those which would be required based upon normal full load running current. The resultant overload protection (approximately 140% of motor full load current) permits MOVs to operate for extended periods of time at moderate overloads; tripping occurs just prior to motor damage.

Class 1E motor control centers are located in environmentally controlled rooms such that overload ambient temperature variation is not a significant factor.

Initial testing of overload heaters serving safety-related MOVs is performed by the Supply System during the Test and Startup Program. This testing is accomplished by injecting a test

current through the overload device, thus, simulating an overcurrent of the motor operator and verifying that the device stops valve travel by deenergizing the motor starter and/or alarms at the appropriate alarm panel, as applicable. Acceptance criteria for these tests are derived by manufacturers' curves for the devices or applicable codes and standards where available.

Periodic surveillance testing of thermal overloads serving safety-related MOVs will be in accordance with the WNP-2 technical specifications. A representative sample of at least 25% will be tested at least once per 18 months, such that all will be tested once per six years. The test itself will be essentially the same as that described above.

ISSUE: PSB-6 RELIABILITY OF DIESEL GENERATOR

Question:

No specific question identified for this issue.

Response:

The reliability of starting and accepting design load in the required time was fully demonstrated for the Div. 1 and Div. 2 D-Gs by the successful completion of the 300 Start Qualification Test performed on D-G Unit 1 in accordance with NRC BTP-EICSB-2 prior to shipment. The reliability of the HPCS D-G has been verified by a prototype test on an eventually identical unit. See Reference 4.

In response to other concerns on the reliability of all the D-G units, see the responses to, Questions 040.080 through 040.089.

The HPCS D-G (Div. 3) has been given preoperational tests to demonstrate the reliability of starting and accepting design load in the required time, and that the system has adequate margin in all respects, such as starting time, accelerating time, engine torque, and long-term carrying capability.

The 300 Start Qualification Test Report for D-G Unit 1 is available for the NRC's review at the plant site. See Reference 2.

The HPCS D-G (Div. 3) Site Preoperational Test Report is available to the NRC for review at the plant site. See Reference 3.

References:

1. NRC Branch Technical Position EICSB-2

2. *Prototype 300 Start Qualification Test Report, B&R File No. 53-00-7014 and 53-00-7015.*

3. *HPCS D-G Acceptance Test, PT-7.2-A*

4. *GE Document No. NEDO-10905-3, Licensing Topical Report-High-Pressure Core Spray System Power Supply Unit.*

ISSUE: PSB-7 PERIODIC DIESEL GENERATOR TESTING

Question:

Diesel generator testing once every 18 months is required by Regulatory Guide 1.108.

Response:

The Technical Specifications for WNP-2 comply with Regulatory Guide 1.108 requirements for testing the diesel generators on 18-month intervals. In addition, a test has been included to verify that after an interruption of onsite power the loads are shed from the emergency buses and that subsequent loading of the onsite sources is through the load sequencer. See the response to Question 040.037.

I.8 REACTOR SYSTEMS BRANCH

ISSUE. RSB-1 INTERNALLY GENERATED MISSILES (3.5.1)

Question:

The applicant has not supplied the information to show that all safety-related systems and components within the containment, including the containment, are protected from missiles.

With regard to missiles sizes of concern, what is the valve size below which, if failure should occur in a high pressure system, damage to other components within the primary containment would not be significant? State criteria used to determine this size. Identify all valves in the primary containment larger than this size and identify the missile protection provided for each valve (either physical location or barrier).

Response

All safety-related systems and components at WNP-2 are protected from credible plant. A response identifying criteria and methodology and the final results for inside and outside containment in the third quarter of 1982 (letter no. G02-82-672).

Valve parts are not postulated as credible missile sources if double retention features exist or bonnet bolting is shown to have high margins of safety. All valves in our plant were evaluated on this basis and it was concluded that valves are not credible missile sources.

ISSUE: RSB-2 CONTROL ROD SYSTEM (4.6.2)

Question:

As a result of eliminating the control rod drive system return line, we are reviewing generically with regard to the impact on control rod drive system performance. Consequently, we require the applicant to submit system performance data directly applicable to WNP-2 and will require the applicant to conform to the conclusion of the generic study as applicable to WNP-2.

Response:

See the response to MEB-11.

See also the revised response to Question 211.019.

References:

1. *Letter, G. G. Sherwood (GE) to E. G. Case (NRC), "Control Rod Drive (CRD) Return Line Removal," dated January 27, 1978.*

2. *Letters, G. G. Sherwood (GE) to V. Stello (NRC) and R. J. Mattson (NRC), "Control Rod Drive (CRD) Return Line Removal," dated July 14, 1978.*

3. *Letters, G. G. Sherwood (GE) to V. Stello (NRC) and R. J. Mattson (NRC), "Control Rod Drive (CRD) Return Line Removal," dated February 22, 1979.*

ISSUE: RSB-3 SAFETY/RELIEF VALVES (5.2.2 and 6.3.2)

Question:

Additional information is required both for qualification test and operating experience with the applicant's safety/relief valves.

Response:

The response to the above stated concern is provided in the revised response to Question 211.051. Also refer to response to Question 211.209.

ISSUE: RSB-4 TRIP OF RECIRCULATION PUMPS TO MITIGATE ATWS (5.2.2)

Question:

We require reperformance of the overpressure analysis to consider the effect of the ATWS RPT.

Response:

Section 5.2.2 was revised as part of the ODYN analysis which has been submitted to the NRC.

This section incorporates the confirmatory analysis of the overpressure protection report including the ATWS recirculation pump trip. Also see revised response 15.8 and response to Question 211.049.

ISSUE: RSB-5 DETECTION OF INTERSYSTEM LEAKAGE (5.2.5)

Question:

We requested that the applicant show how it intends to detect leakage from the reactor coolant systems into both the low pressure coolant injection (3 trains) and low pressure core spray systems as required by Regulatory Guide 1.45.

Response:

Intersystem leakage will be detected by pressure instrumentation with control room readout in accordance with Regulatory Guide 1.45. The response to WNP-2 FSAR Question 211.009 provides information on this issue.

ISSUE: RSB-6 REACTOR CORE ISOLATION COOLING PUMP SUCTION

Question:

The applicant must supply further information to determine whether the RCIC pump suction has to be automatically switched from the condensate storage tank to the suppression pool in the event of a safe shutdown earthquake and concomitant failure of the condensate storage tank.

Response:

As stated in the response to Question 211.046, an automatic safety-grade switchover to a Seismic Category I supply (suppression pool) has been provided. A description of the automatic switchover has been provided in the response to Question 211.146.

ISSUE: RSB-7 SHUTDOWN UNINTENTIONALLY OF THE REACTOR CORE ISOLATION COOLING SYSTEM

Question:

Show how the design of the RCIC protection system prevents unintentional shutdown of the system, when the system is required, because of spurious ambient temperature signals from areas in and around the system (especially in the RCIC pump room)

Response:

See the revised response to Question 211.010.

ISSUE: RSB-8 RHR ALTERNATE SHUTDOWN DEMONSTRATION

Question:

The applicant must perform tests to show that flow through the safety/relief valves is adequate to provide the necessary fluid relief required consistent with the analyses reported in Section 15.2.9 of the FSAR.

Response:

Refer to the revised response to Question 211.025. Also, NUREG-0737, Item II D.1 is related to Issue RSB-8. A discussion on NUREG-0737 items is contained in Appendix B.

ISSUE: RSB-9 CATEGORIZATION OF VALVES WHICH ISOLATE RHR FROM REACTOR COOLANT SYSTEM (5.4.2)

Question:

We require that the valves which serve to isolate the residual heat removal system from the reactor coolant system be classified Category A/C in accordance with the provisions of Section XI of the ASME code.

Response:

Please refer to RSB-13.

ISSUE: RSB-10 AVAILABLE NET POSITIVE SUCTION HEAD

Question:

The applicant must verify that the suction lines in the suppression pool leading to the ECCS pumps are designed to preclude adverse vortex formation and air injection which could effect pumps performance.

Response:

All ECCS suction lines in the suppression pool have been designed with large diameter piping (24 inches) to reduce inlet velocity. In the worst conceivable case, where there is a leak from an ECCS pump suction line into the largest of the ECCS pump rooms, the water level in the suppression pool is calculated to equalize at elevation 455'-9". In the calculation, no credit is taken for makeup to the suppression pool nor for pumping water leaking into the affected room/ suppression pool. The RCIC pump suction is an 8-inch pipe. The submergence of the top edge of the suction piping with suppression pool water level at 455 ft-9 in. is as follows:

		Penetrations	Depth (C.L.)	Submergence
RHR Loop	"A"	(X-35)	447'-0"	7.8'
	"B"	(X-32)	447'-0"	7.8'
	"C"	(X-36)	447'-7"	7.2'
LPCS		(X-34)	447'-7"	7.2'
HPCS		(X-31)	438'-9"	16.0'
RCIC		(X-33)	452'-0"	3.4'

The minimum depth at which vortex formation at the suction inlets will be prevented is:

	Flow Rate (max)	Velocity	Submergence
RHR	8000 gpm	5.674 fps	2.41'
LPCS	7800 gpm	5.533 fps	2.35'
HPCS	7175 gpm	5.089 fps	2.16'
RCIC	600 gpm	3.295 fps	0.84'

The RCIC pump suction will have 2.5 ft of submergence. The inlet to each of the ECCS lines is at least 5 ft deeper than required to preclude vortexing, and therefore, vortex formation is not considered a problem.

See also the response to Question 211.062 for further information.

ISSUE: RSB-11 ASSURANCE OF FILLED ECCS LINE (6.3.2)

Question:

Instrumentation is not sufficiently sensitive to detect voids at the top of ECCS pipe lines. The applicant must provide adequate instrumentation to assure filled ECCS lines.

Response:

Filled ECCS lines are assured by:

- a. *Jockey pump system on same division as system being filled,*
- b. *Pressure switch on pump discharge with control room annunciation,*
- c. *Technical Specification surveillance - upon high point vents to check for air.*

See also the response to Question 211.079 for additional information.

ISSUE: RSB-12 OPERABILITY OF ADS

Question:

Show that the air supply to the ADS is sufficient for the extended operating time required and is assured by reliability data that the ADS will function as required.

Response:

Safety-related backup to the CIA system is provided by redundant, independent nitrogen gas bottle banks. Upon loss of CIA, the system will be automatically isolated as the backup nitrogen supply is automatically fed into the system. The nitrogen bottle supply is sized for a 30-day supply to the seven ADS valves. The nitrogen supply can farther be backed up by a portable auxiliary nitrogen supply (if necessary) which can be connected outside the reactor building. Please refer to Section 9.3.1.2.2 and the responses to Questions 031.121 and 211.048.

ISSUE: RSB-13 LEAKAGE RATE TESTING OF VALVES USED TO ISOLATE REACTOR COOLANT SYSTEM (5.3.2)

DELETED

ISSUE: RSB-14 OPERABILITY OF ECCS PUMPS (6 3.2)

Question:

The applicant must provide assurance that the ECCS pumps can function for an extended time (maintenance free) under the most limiting post-LOCA conditions.

Response:

This issue has been closed on Zimmer, Shoreham, and LaSalle dockets on the basis of information presented in response to NRC questions. Similar information has been provided on the rest of the dockets. The response to WNP-2 Question 211.072 has been revised to include the latest information available.

NUREG-0737 Task II.B.2 is related to the issue discussed above and is addressed in Appendix B of the FSAR. The shielding evaluation referred to in Appendix B will show that the ECCS pumps will operate for the accident duration (assumed to be six months), using the source terms from II.B.2.

ISSUE: RSB-15 ADDITIONAL LOCA BREAK SPECTRUM (6.3)

Question:

The staff does not concur that the Zimmer LOCA analysis is an appropriate break spectrum for WNP-2 because of: 1) higher power level in WNP-2, 2) different fuel assembly design in WNP-2, and 3) higher PCTs predicted for WNP-2.

The staff requires that the applicant provide the following LOCA analyses to complete the break spectrum:

a. *One additional recirculation line break with a C_D coefficient 0.6 times the DBA, using the large break model analysis.*

b. *One additional recirculation line break (0.02 ft^2) using the small break model analysis.*

Response:

This issue has been closed on the LaSalle docket on the basis of information presented in response to NRC questions. Similar information has been provided in the revised response to WNP-2 FSAR Question 211.068.

ISSUE: RSB-16 LOCA ANALYSIS (6.3.4)

Question:

You have analyzed the effect on the DBA-LOCA of instantaneous closure of the flow control valve (FCV) in the unbroken loops. This overly conservative result indicated an increase in peak clad temperature (PCT) of 300°F which, if added to the DBA-LOCA PCT, would be in excess of the maximum PCT criterion of 10 CFR 50.46.

Response:

The response to this issue was provided in Amendment No. 11 as a response to Question 211.083. The response to this question is summarized and expanded upon below.

FCV closure in the unbroken loop is not expected to occur during the LOCA event. However, even if the FCV were signaled to close for some unlikely reason (LOCA plus two failures: failure of drywell high pressure signal such that FCV lockup does not occur, and failure of FCV controls), backup electronic velocity-limiters are included in the recirculation control system to limit FCV velocity to 10 ± 1% actuator stroke rate. Additional multiple specific component failures in these limiters must occur to cause full closure of the FCV at velocities in excess of this value. The combined probability of occurrence of these specific failure modes during LOCA is less than 10^{6} per year. Accordingly, the electronically limited rate of 10 ± 1% of FCV actuator stroke/rate is considered a realistic yet conservative closure rate.

Using approved standard licensing models, ECCS analyses were performed to determine the effect (sensitivity) on peak cladding temperature from FCV closure at the 11% per second rate. The calculated maximum peak temperature increase was ≤45°F for WNP-2. This contrasts markedly with the approximate 300°F rise in cladding temperature associated with an arbitrary assumption of instant closure of the FCV, as was cited on another BWR/5 docket.

Thus, the peak cladding temperature effect is concluded to be very small. The probability of FCV fast closure simultaneously with a LOCA is extremely remote. Accordingly, fast FCV closure in conjunction with the DBA-LOCA is not expected to occur and need not be compared to the maximum PCT criterion of 10 CFR 50.46.

ISSUE: RSB-17 OPERATOR ACTION, ANALYSIS OF CRACK IN THE RHR LINE (6.3.4)

Question:

Provide the following information related to pipe breaks or leaks in high or moderate energy lines outside containment associated with the RHR system when the plant is in a shutdown cooling mode.

a. Provide the discharge rate from pipe breaks for the systems outside containment used to maintain core cooling. This valve should be consistent with the requirements of SRP 3.6.1 and BTP APCSB 3-1.

b. Determine the time frame available for recovery based on these discharge rates and their effect on core cooling.

c. Describe the alarms available to alert the operator to the event, the recovery procedures to be utilized by the operator, and the time available for operator action.

A single failure criterion consistent with SRP 3.6.1 and BTP ABCSB 3-1 should be applied in the evaluation of the recovery procedures utilized.

Response:

a. The RHR system is a low pressure system, and all of the piping outside of the primary coolant pressure boundary is classified as "moderate energy" piping and, according to the NRC standards cited, only cracks (i.e., not breaks) are considered in moderate energy piping. Reactor vessel pressure must be decreased to below 135 psig before the RHR system can be connected to the reactor vessel. The largest suction pipe is 24 in. Schedule 40 pipe. A crack in this pipe corresponding to the maximum crack size would produce a flow rate of 1443 gpm, with no allowance for flow reduction due to two-phase flow. This is the maximum possible in any RHR system pipe. A crack of this magnitude would be detected by the leak detection system or area radiation detectors and sump alarms. Isolation of the reactor would occur by operator action, or automatically from the leak detection system or from the reactor protection system on Level 3 reactor water level.

b. If a break should occur in one RHR shutdown cooling loop outside the containment during shutdown, the following action is taken upon detection and isolation. The main steam isolation valves will be reopened and reactor excess

steam will blow down to the main condenser until the shutdown cooling process via the other RHR loop is established. Time: less than 1 hour.

The redundant shutdown cooling loop components are also not assumed to fail under the cited NRC requirements of BTP APCSB 3-1.

If the pipe crack should occur in the common manifold supplying both redundant loops, the isolation mechanism is the same as before, but recovery would require reversion to the alternate shutdown configuration discussed in Section 15.2.9. In this configuration, vessel water is circulated from the suppression pool to the RHR heat exchanger to the vessel with return to the suppression pool via the ADS discharge lines. Time: less than 1 hour.

If the pipe crack should occur in the RHR service water piping, sump alarms would result in operator isolation of that loop and establishment of cooling in the redundant shutdown loop. Time: less than 1 hour.

In evaluating the above analysis, the following is also offered. If the main condenser vacuum has been lost and the MSIVs are already closed prior to the crack occurrence, reestablishment of condenser vacuum, MSIV reopening, vessel inventory control, and restart of steam dump to the main condenser is possible in about 2 hours. Vessel inventory can be controlled by overflow through the reactor water cleanup system if too high, and by use of feedwater pumps or HPCS/LPCS/LPCI if too low. Vessel pressure is controlled by manual operation of safety/relief valves on MSIV closure as required.

c. *The alarms available have been described in the response to part (a) and part (b) of this question. The recovery procedures to be utilized by the operator, and the time available for operator action are provided below.*

A special analysis was made by a hypothesized crack in the BWR suction line outside of primary containment during operation in the shutdown cooling mode. This analysis was performed with the standard GE LOCA models. For this event, the realistic or actual system conditions are as follows:

> *No high pressure systems are available for water inventory restoration, i.e., no feedwater, no HPCS, and no RCIC, but the reactor water level is at normal elevation at the start of this event. Vessel pressure is less than 150 psia and the MSIVs are closed at the start of this event. The decay heat is approximately 1% of rated power, i.e., approximately 4 hours have elapsed subsequent to reactor scram or shutdown.*

For a conservative solution to this hypothetical event, the following sequence of events and conditions were assumed to exist or ensue from the hypothesized crack in the suction line:

a. *Crack occurs in the RHR lines water; level decreases to reactor vessel Level 3; then RHR isolation commences and is completed 40 seconds later.*

b. *System pressure rises as a result of the isolation to where the vessel pressure reaches the SRV setpoint, thus causing them to open, blow down, and reclose.*

c. *Inventory depletion results from blowdown and from leakage out of these cracked lines.*

d. *The operator manually actuates ADS to reduce vessel pressure to where the low pressure ECCS can replenish the water inventory.*

e. *Water level is restored to within normal limits to protect the core from over temperature.*

Results are presented in Figures I.8-1 through I.8-4 for a bounding calculation of this event. The standard Appendix K assumptions were used along with these conservative initial conditions.

a. *The timing index was started at the RHR isolation (when Level 3 was attained) to neglect the time for the level to fall from normal water level to Level 3 (about 2 minutes).*

b. *An initial pressure of 1055 psia was assumed to neglect the pressure rise time from the 150 psia (pressure permissive for shutdown cooling) upon completion of the RHR isolation to the 1055 pressure attainment. This results in increased mass loss during the 40-second isolation period due to greater driving pressure. It also decreases the time increment needed for pressure to attain the relief valve setpoint.*

c. *The analysis assumes that scram occurs coincident with the start of the timing instead of 4 hours earlier. This assumption maximizes the peak clad temperature and steam production during the transient thus driving more fluid from the vessel and prolonging the blowdown phase.*

d. *Only one LPCS and one LPCI loop were assumed to be available throughout the event. Operator action does not include possible diversion of the other two LPCI loops from the RHR mode.*

e. *The crack area used in the analysis is defined consistently with the MEB 3-1 guidance for crack size. This crack area is consistent with FSAR postulates.*

Results from this conservative analysis show that more than 20 minutes are available for the operator to depressurize the vessel. Once the system pressure is below the LPCI or LPCS shutoff head, the reactor water level is restored to normal limits very rapidly. The maximum clad temperature is much less than the arbitrary 2200°F limitation.

ISSUE: RSB-18 LOCA ANALYSIS - DIVERSION OF LOW PRESSURE COOLANT INJECTION SYSTEM (6.3.4)

Question:

The issue is... "If low pressure coolant injection diversion prior to ten minutes is allowed by design, then procedural restrictions alone are not sufficient unless analyses are submitted which show compliance with 10 CFR 50.46 for diversion earlier than ten minutes."

Response:

Analyses of BWR performance following a small break LOCA and LOCA mitigation under degraded conditions have been performed by General Electric as a part of the BWR Owners' Group program. Analyses bases, assumptions, and conclusions are discussed in GE report NEDO-24708A, Revision 1, December 1980, entitled, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors." Reference is made to 3.1.1 (Small Break LOCA) and 3.5.2 (Inadequate Core Cooling). It should be noted that these analyses were performed utilizing "realistic" assumptions as defined in 3.1.1.2 and 3.5.2.4. The conclusion, 3.5.2.1.8, summarizes the capability of the BWR to maintain adequate core cooling, even under severely degraded conditions resulting from multiple failures and operator errors, following a loss of inventory either through a pipe break or through the safety relief/valve.

Based on the first group of analyses presented, it was concluded that for any plant and any loss of inventory event, the ability of ADS and one low pressure ECC system provides adequate core cooling if no high pressure injection is available. These analyses covered the case of multiple mechanical or electrical failures and operator errors that might have caused the failure of the system, assumed to be unavailable.

The second set of analyses addressed the condition of the vessel being at high pressure with a low water level. It was shown that operator actions either to initiate high pressure systems or to depressurize the vessel and initiate at least one low pressure system, terminate this condition

and assure adequate core cooling. The analyses showed that even for such severely degraded transients, there is sufficient time for operator action to mitigate the consequences.

The third set of analyses addressed the condition of the vessel being at low pressure with a low water level but with the low pressure systems not injecting. It was shown that operator actions either to start the low pressure systems injecting into the vessel or to initiate the high pressure systems, terminate this condition and assure adequate core cooling.

For all analyses, it was shown that the process variable information available to the operator in the control room is sufficient to adequately warn of an inventory threatening event and to present the information the operator needs to assure that appropriate actions are taken to maintain adequate core cooling. The control room indications will not mislead the operator when taking corrective actions. Even under the extremely degraded conditions considered in these analyses, the BWR requires only the most basic operator actions to mitigate the consequences of an inventory threatening event.

If the operator were to divert LPCI prior to ten minutes post-LOCA, such an action would be considered an operator error. Since the current ECCS performance evaluation already assumes the accident, a loss of offsite power and a worst active single failure, an additional operator error is considered to be an additional Appendix K assumption. It is therefore appropriate that the "realistic" assumption analyses be considered for this situation as stated in the conclusion in NEDO-24708A "for any plant and any loss of inventory event, the adequate availability of ADS and one low pressure ECC system provides adequate core cooling..."

This analysis is deemed acceptable to provide satisfactory assurance of acceptable event consequences, in consideration of the equipment failures and operator errors assumed.

To resolve the concern of the NRC staff that premature diversion of low pressure coolant injection (LPCI) flow to containment sprays could adversely effect core cooling, the WNP-2 symptom based emergency procedures will be carefully constructed to caution the operator against such diversion unless "adequate core cooling is assured." These procedures, which were developed with the assistance of the BWR Owners' Group and reviewed and accepted by the NRC staff, clearly identify LPCI diversion as secondary to the core cooling requirements except in those instances, outside the plant design envelope, which involve multiple failures and for which maintenance of containment integrity is required to minimize risk to the environment.

ISSUE: RSB-19 FAILURE OF FEEDWATER HEATER (15.1)

Question:

The applicant's analysis for the failure of the feedwater heater indicates that the temperature drop is no greater than 100°F. At a domestic boiling water reactor an actual feedwater temperature occurred which demonstrated a temperature difference of 150°F. The applicant must justify the decrease in temperature drop used for this event or recalculate the transient by using a justified temperature decrease to assure conformance with applicable criteria.

Response:

Refer to revised response to Question 211.087.

ISSUE: RSB-20 USE OF NONRELIABLE EQUIPMENT IN ANTICIPATED OPERATIONAL TRANSIENTS (15.1)

Question:

In analyzing anticipated operational transients, the applicant took credit for equipment which has not been shown to be reliable. Our position is that this equipment be identified in the technical specifications with regard to availability, setpoints, and surveillance testing. The applicant must submit its plan for implementing this requirement along with any system modification that may be required to fulfill the requirement.

Response:

The response to the above stated concern is provided in response to Questions 211.085, 211.086, and 211.155.

ISSUE: RSB-21 USE OF NON-SAFETY GRADE EQUIPMENT IN SHAFT SEIZURE ACCIDENT (15.3)

Question:

The applicant included the use of non-safety grade equipment in his analysis for shaft seizure and shaft break accidents. We require that these accidents be reanalyzed without allowance for the use of non-safety grade equipment.

Response:

The response to the above stated concern is provided in the revised response to Question 211.092. Questions 211.185 and 211.211 also reference this concern.

ISSUE: RSB-22 ATWS (15.2.1)

Question:

We require that the applicant agrees to implement plant modifications on a scheduled basis in conformance with the Commission's final resolution of ATWS. In the event that LaSalle starts operation before necessary plant modifications are implemented, we require some interim actions be taken by LaSalle in order to further reduce the risk from ATWS events. The applicant will be required to:

a. Develop emergency procedures to train operators to recognize an ATWS event, including consideration of scram indicators, rod position indicators, flux monitors, vessel level and pressure indicators, relief valve and isolation valve indicators, and containment temperature, pressure, and radiation indicators.

b. Train operators to take action in the event of an ATWS including consideration of immediately manual scramming the reactor by using the manual scram buttons followed by changing rod scram switches to the scram position, stripping the feeder breakers on the reactor protection system power distribution buses, opening the scram discharge volume drain valve, prompt actuation of the standby liquid control system, and prompt placement of the RHR in the pool cooling mode to reduce the severity of the containment conditions.

Response:

See 1.5.1.1.2 for a discussion of WNP-2 modifications which addresses compliance to the final ATWS rule. The required procedure development and operator training were accomplished prior to fuel load.

ISSUE: RSB-23 PEACH BOTTOM TURBINE TRIP TESTS (4.4.1, 4.4.2)

Question:

These tests have been evaluated and assessed using the ODYN computer code.

Response:

The NRC has completed their review of the ODYN Code. See the Safety Evaluation Report letter of November 4, 1980.

Also, see Chapters 4 and 15. The appropriate sections of these chapters have been revised utilizing results of re-analysis of required transients using the ODYN Code. See the revised response to Question 211.049.

Refer also to RSB-4.

ISSUE: RSB-24 MCPR (4.4.1, 4.4.2, 15.1)

Question:

After completion of over-pressure analysis, the minimum critical power ratio must be recalculated taking into consideration the turbine trip without bypass event.

The transient of generator load rejection without bypass results in an MCPR equal to 1.02 which is below the safety limit of 1.06. The applicant classified this event an infrequent occurrence which would allow some fuel damage. We do not concur with this classification for this event, and we require that the operating limit be modified to satisfy the MCPR limit of 1.06.

Response:

The response to the above stated concern is provided in revised response to Question 211.084.

ISSUE: RSB-25 GEXL CORRELATION

Question:

Although we conclude that the GEXL correlation is acceptable for initial core load, we are concerned that GEXL correlation may not be conservative for reload operation.

Response:

WNP-2 will use the applicable correlation to predict the onset of transition boiling for all reloads.

ISSUE: RSB-26 STABILITY EVALUATION

Question:

Please refer to NRC Question 221.009 for this question.

Response:

Please refer to the response to NRC Question 221.009.

ISSUE: RSB-27 SCRAM DISCHARGE VOLUME

Question:

The applicant should assess, reevaluate, and possibly modify the present scram system in light of the incident at Browns Ferry 3, where a manual scram failed to insert all control rods.

Response:

The WNP-2 scram discharge volume (SDV) design has been evaluated against the NRC generic study "BWR Scram Discharge System Safety Evaluation" of December 1, 1980. The results of this evaluation indicated that the current WNP-2 scram discharge system design was acceptable with implementation of some minor modifications. A summary of the evaluation results and the required modifications are provided below.

a. *Hydraulic Coupling - The current SDV design provides two separate scram discharge volume headers, with an integral instrumented volume (IV) at the end of each header. This design configuration ensures a direct hydraulic couple between the SDVs and IVs.*

b. *Instrumentation - The existing level sensors (six total) are all of one design, i.e., float type (magnetrol) level switches. To meet the specified requirements, six additional diverse level sensors will be added to provide full redundancy for level monitoring and scram initiation. In addition, all level instrumentation will be relocated and repiped directly to the IVs rather than being connected to the vent and drain lines.*

c. *Vent and Drain Lines - The WNP-2 design incorporates an independent vent and drain system for the SDV. The scram discharge headers are presently vented directly to the reactor building atmosphere and the system drain is piped directly from the bottom of the IVs to the building's radioactive drain system. A second vent valve and drain valve will be added to provide redundant SDV isolation during a reactor scram.*

d. *Surveillance Testing - Additional surveillance test procedures will be implemented to ensure operability of the level instruments, vent and drain isolation valves, as well as the overall system.*

Please refer to response to Question 010.041.

ISSUE: RSB-28 SRV SURVEILLANCE

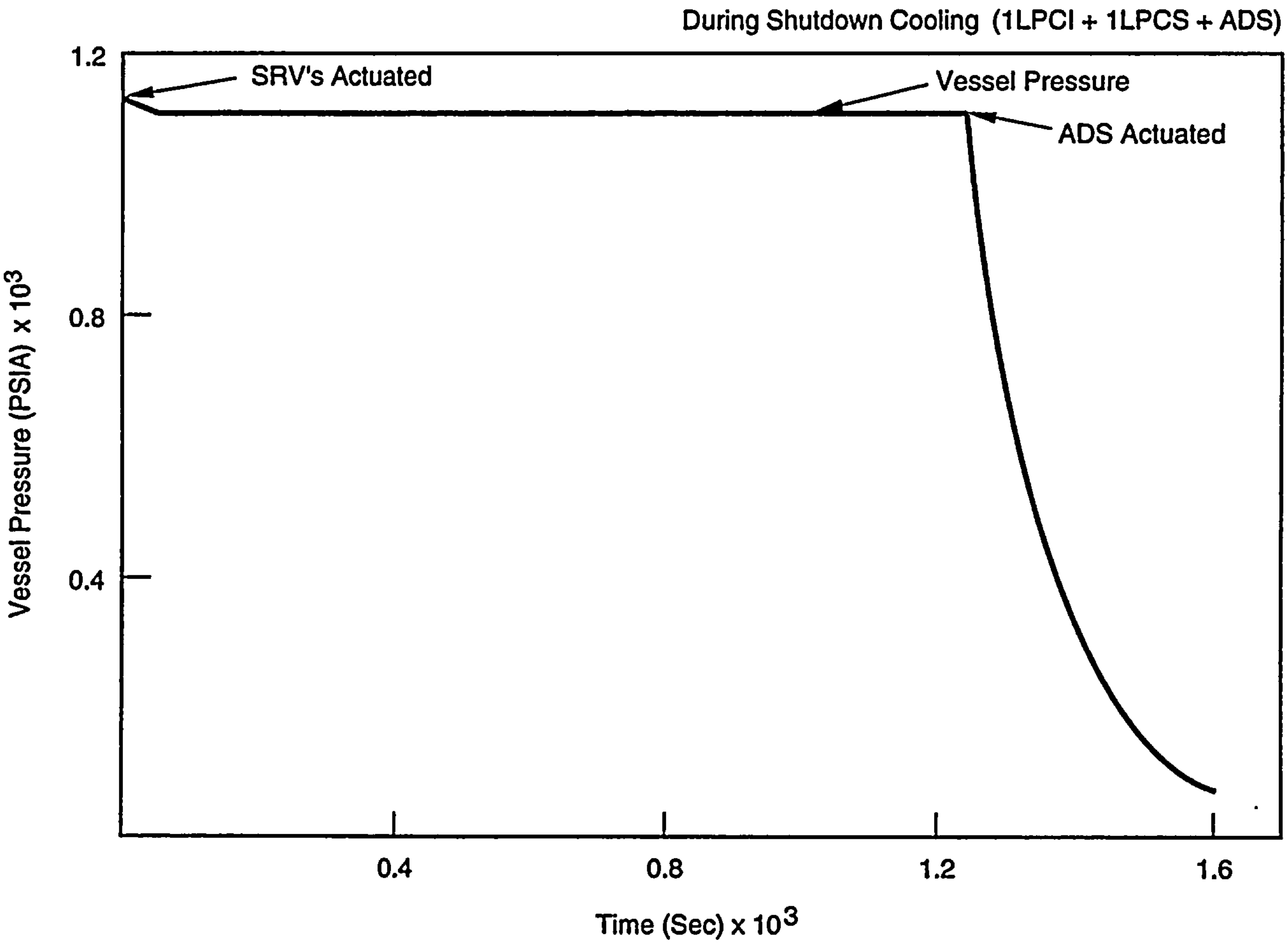
Question:

A safety/relief valve surveillance program should be developed to record operating and maintenance experience to facilitate identification of generic safety/relief valve problems.

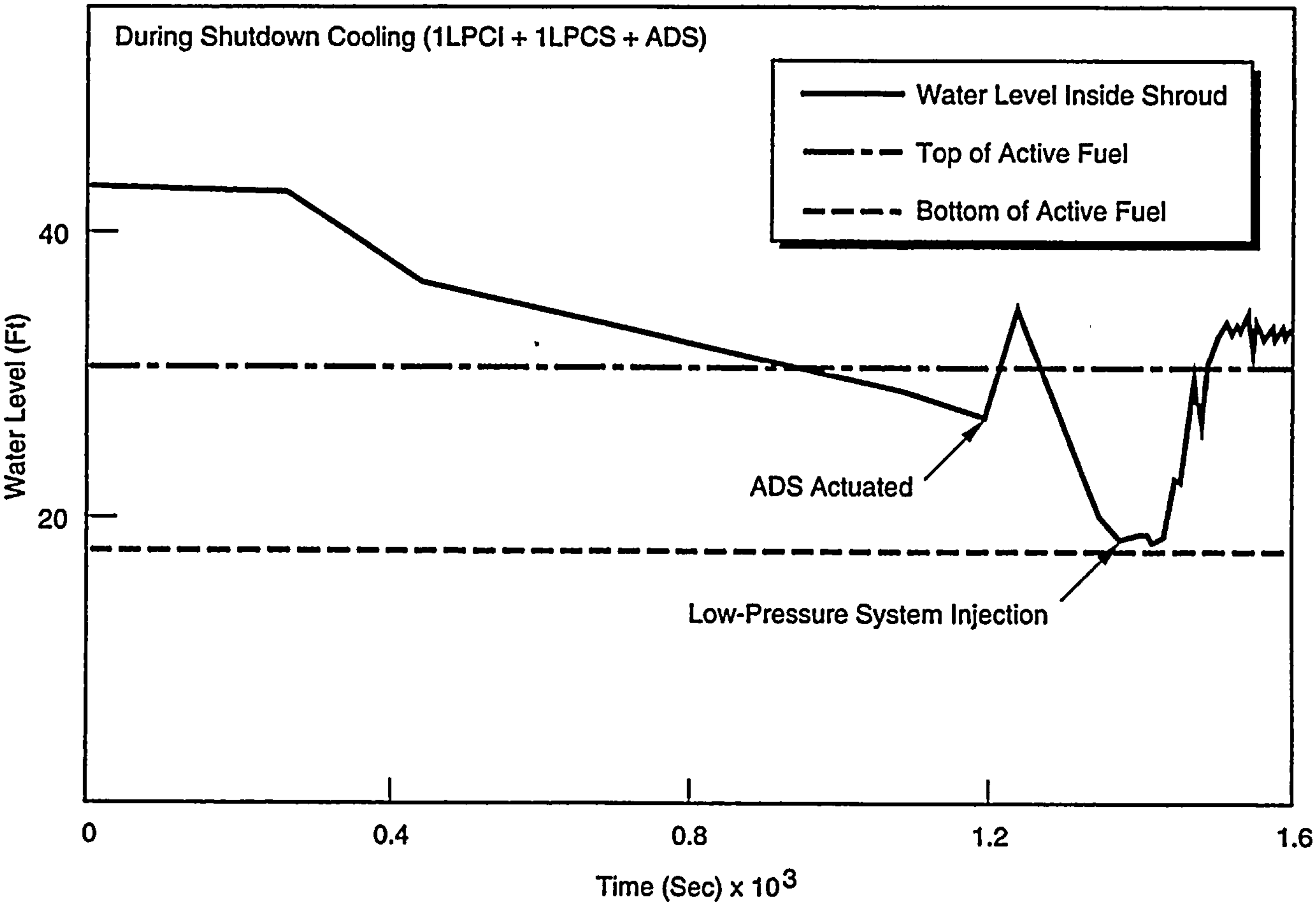
Response:

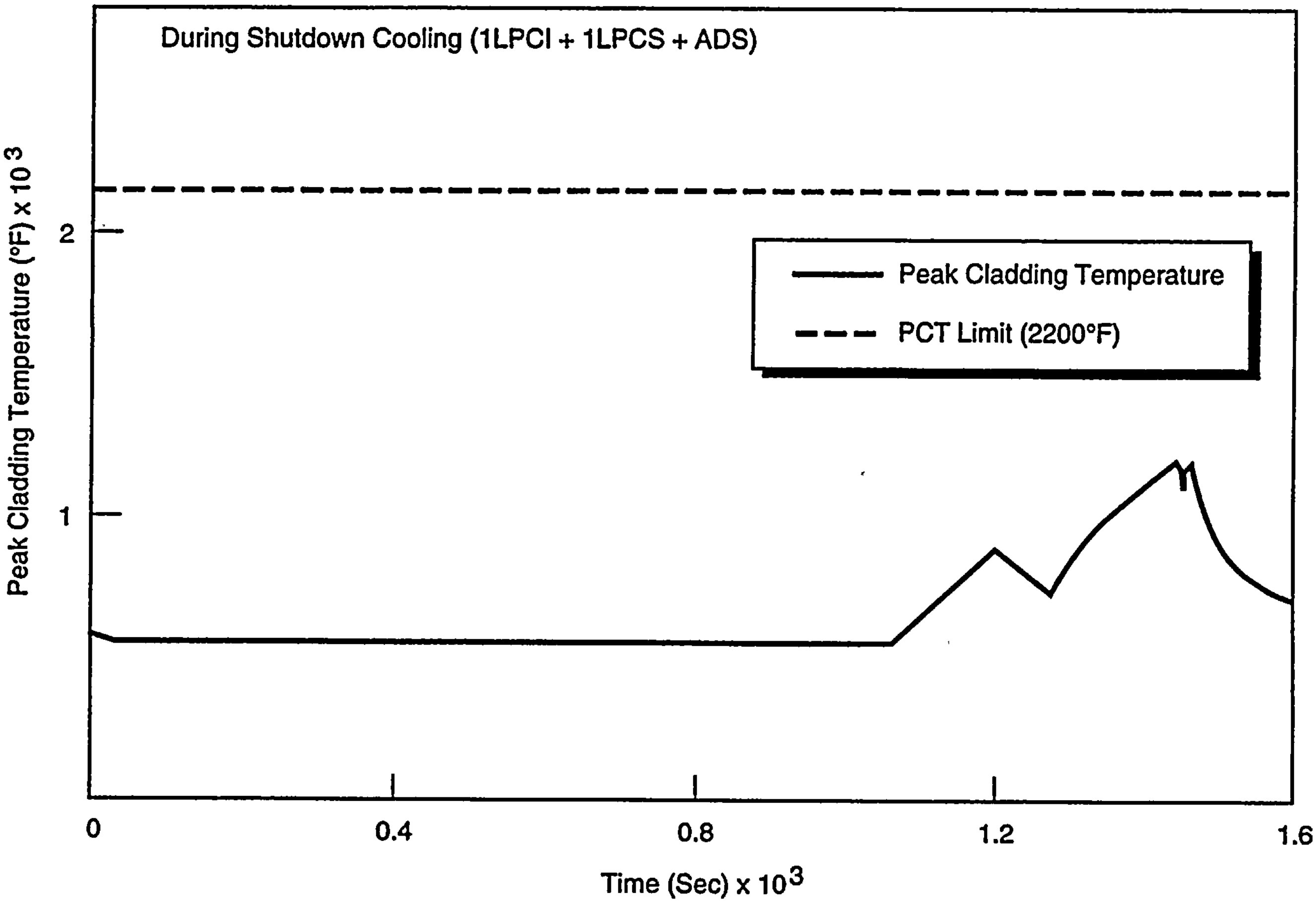
WNP-2 will develop a surveillance program for safety/relief valves similar to that being developed by the BWR Owners' Group submitted to the NRC by letter G02-81-563, G. D. Bouchey to A. Schwencer, "LRG Appendix I," dated December 30, 1981.

The WNP-2 safety/relief valve surveillance program will be available for onsite review.

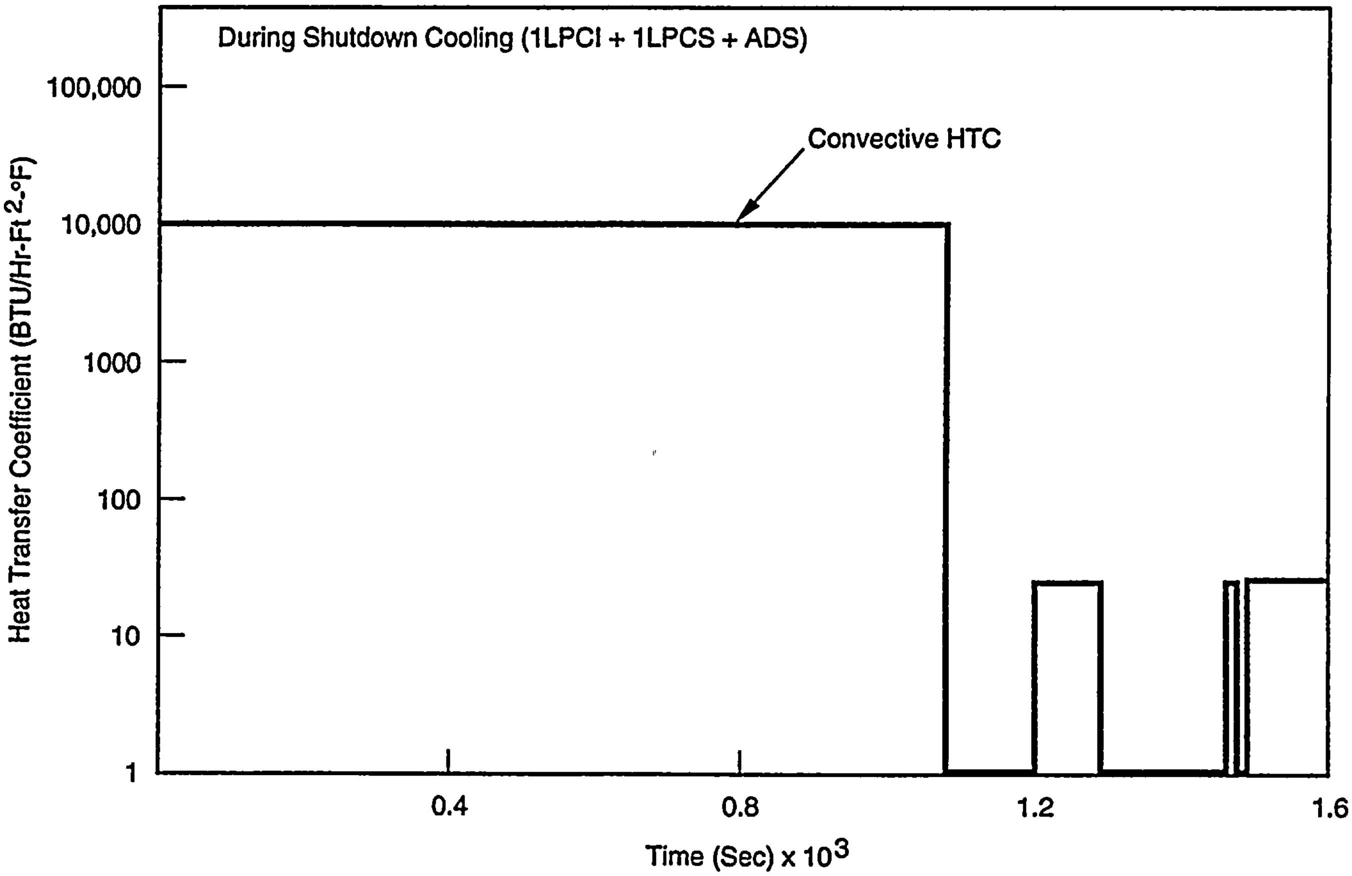


WASHINGTON PUBLIC POWER SUPPLY SYSTEM NUCLEAR PLANT 2 FSAR	Vessel Pressure Versus Time for a Crack in the RHR Line		
	Draw. No. 970187.15	Rev.	Figure I.8-1


During Shutdown Cooling (1LPCI + 1LPCS + ADS)
Water Level Inside Shroud
Top of Active Fuel
Bottom of Active Fuel
40
20
Water Level (Ft)
ADS Actuated
Low-Pressure System Injection
0
0.4
0.8
1.2
1.6
Time (Sec) x 10^3



Peak Cladding Temperature Versus Time for a Crack in the RHR Line


During Shutdown Cooling (1LPCI + 1LPCS + ADS)
Convective HTC
Heat Transfer Coefficient (BTU/Hr-Ft 2-°F)
100,000
10,000
1000
100
10
1
0.4
0.8
1.2
1.6
Time (Sec) x 10^3

Appendix J

SHIELDING EVALUATION REPORT

Burns and Roe, Inc., performed the analysis of radiation levels occurring inside primary containment, assembled, edited, reviewed, and approved this technical report for the Washington Public Power Supply System.

EDS Nuclear Incorporated performed the analysis of radiation levels occurring in the reactor building secondary containment under subcontract to Burns and Roe, Inc. Later revisions have been issued by the Supply System to incorporate plant changes.

The Washington Public Power Supply System performed the analysis of radiation levels occurring in areas outside the reactor building secondary containment.

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Appendix J

SHIELDING EVALUATION REPORT

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SUMMARY

The Three Mile Island (TMI-2) accident has generated a concern that during an accident in which significant core damage occurs, the postaccident operations requiring the use of systems containing contaminated fluid may induce abnormally high radiation doses to safety-related equipment and components which make it difficult to operate the systems. The NRC initially addressed this concern with NUREG-0578 and NUREG-0737 and recommended a design review to evaluate the functional capability of safety-related equipment and radiation exposure to personnel during the postulated post-LOCA operations.

Radiation levels have been determined for all areas containing safety-related equipment, vital areas, and access routes which are required for the postulated post-LOCA operation.

Radiation levels determined for safety-related equipment inside primary containment. The analysis included the shadow shielding effect of installed equipment and the effect of iodine plateout were used to more accurately calculate the radiation levels inside containment.

Radiation levels were determined for safety-related equipment. The radiation source term leaking into secondary containment was reduced by the loss of halogens to plateout inside primary containment.

Radiation levels calculated for safety-related equipment outside secondary containment are reported in Table J.6-1.

Figures J.6-11 through J.6-21 identify the vital areas which require personnel access on either a continuous or infrequent basis during post-LOCA operations.

Safety-related equipment will either be qualified for the radiation level it functions in, or it will be relocated to a radiation zone it is qualified for, or it will be replaced with comparable equipment which is qualified for the particular radiation level that has been determined.

Vital areas and access routes were evaluated for post-LOCA operations and are reported in Table J.6-2 and Figures J.6-11 through J.6-21. All areas and access routes are in compliance with NUREG-0737.

ABSTRACT

This report presents a radiation shielding design review of the equipment and systems of the Washington Public Power Supply System Nuclear Project Unit 2 (WNP-2). The original report was prepared in September 1982. The equipment and systems are evaluated on the basis of a postulated accident which in addition to normal plant radiation levels during its 40-year life may contain highly radioactive fluids. This design review recommended by the NRC (NUREG-0578 and NUREG-0737) evaluates the functional capability of safety-related equipment and personnel radiation exposure during the postaccident operations.

This design review evaluates the postaccident radiation conditions for personnel located in vital areas (areas which require access or occupancy during the post-LOCA scenario) on either a continuous or infrequent basis.

The postulated loss-of-coolant accident (LOCA) scenarios and the operations of the safety-related systems were reviewed. Radioactive sources contained within each system were developed. Radiation levels were calculated at safety-related equipment locations, as well as at selected locations outside the reactor building to which access may be required for postaccident operations.

J.1 INTRODUCTION

This report presents a detailed description of the results and the review of plant shielding and radiation environmental conditions for equipment and systems which may be used in postaccident operations for WNP-2. The review was initiated in response to Section 2.1.6.b of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendation," and to Part II.B.2 of NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident."

The design review determined the postaccident radiation environmental conditions for equipment required for postaccident operations inside the primary containment, inside the secondary containment, and outside the secondary containment.

The 6-month total postaccident radiation dose rate as a function of time and the integrated dose were calculated at safety-related equipment locations inside the WNP-2 reactor building, inside primary containment, and at selected locations (vital areas) outside the reactor building.

Section J.2 discusses the regulatory requirements on which this report is based and provides a description of the tasks performed for this shielding evaluation.

Section J.3 provides the systems review and source term assumptions used as input for the definition of the postaccident radiological environment.

Section J.4 discusses the work performed during this project relating to safety-related equipment located outside of the reactor building and the access and occupancy of vital areas. This consists of the calculation of dose rates outside the reactor building.

Section J.5 discusses the methods of calculation including the use of computer codes, identifying the parameters that have a significant effect on the radiation dose rates, and the dose rate and cumulative dose calculation procedure.

Section J.6 presents a summary of the results.

J.2 REQUIREMENTS

General Design Criterion 4 (10 CFR 50 Appendix A) requires that systems and components important to safety be designed to accommodate the environmental conditions associated with accidents. The Three Mile Island (TMI-2) accident has generated a concern that during an accident in which significant core damage occurs, the postaccident operations requiring the use of systems containing contaminated fluid may induce abnormally high radiation doses to safety-related equipment and components which may make it difficult to operate the systems. The NRC Lessons Learned Task Force initially addressed this concern in Section 2.1.6.b of NUREG-0578 (Reference J.7-1) and recommended a design review be performed on such systems so that the functional capability of safety-related equipment located in close proximity to the resulting high radiation field will not be unduly degraded.

Described in this section is a discussion of the current regulatory requirements and guidelines used.

J.2.1 SHIELDING EVALUATION REGULATORY REQUIREMENTS

NUREG-0578 Section 2.1.6.b requires that each licensee 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 scope of the review includes the following:

a. Identification of the locations of vital areas and safety-related equipment,

b. Evaluation of the radiation level at each location, and

c. Provision for adequate access to vital areas and assurances of postaccident equipment operation through design changes, increased permanent or temporary shielding, or postaccident procedural controls.

To perform this review, the NRC has provided guidance in the following documents ("documents of record"):

a. NUREG-0578, Section 2.1.6.b, Reference J.7-1,

b. NUREG-0588, Revision 1, Section 1.4, Reference J.7-2,

c. NUREG-0660, Section II.B.2, Reference J.7-3,

d. Clarification Letter to NUREG-0578, dated September 5, 1980, Section II.B.2, Reference J.7-4,

e. NUREG-0737, Section II.B.2, Reference J.7-5,

f. IE Bulletin No. 79-01B, Reference J.7-6, and

g.. IE Bulletin 79-01B, Supplement 2, dated September 30, 1980, Reference J.7-7.

The regulatory requirements in the above mentioned documents are summarized in the following sections.

J.2.1.1 Accident Analysis Requirements

The postaccident radiation environment should be based on the most severe design basis accidents (DBA) during or following which equipment must remain functional. This includes the consideration of the entire spectrum of loss-of-coolant accident (LOCA) events which can lead to a degraded core condition. These accident conditions include the following:

a. Loss-of-coolant accident events which completely depressurize the primary system, and

b. Loss-of-coolant accident events in which the primary system may not be depressurized.

J.2.1.2 Source Term Assumptions

The radioactive source terms for the postulated accident conditions as described in Section J.2.1.1 should be equivalent to the source terms recommended in Regulatory Guides 1.3 and 1.7 and Standard Review Plan Section 15.6.5. The source term assumptions consistent with current licensing requirements used for equipment qualification and access evaluations are summarized as follows:

a. The fission product fractions assumed to be released from the fuel rods during a LOCA are the following:

Noble gases	100%
Halogens	50%
Remaining fission products	1%

For the analyses, 50% of the halogens and 1% of the solids were assumed to be diluted into the suppression pool and liquid carrying systems. The halogens were also assumed to be in the airborne source while iodines were assumed in the plateout source. Thus, some care is necessary in summing calculated doses to prevent double counting of the sources. The post-LOCA source contribution from liquid and plateout sources are analyzed separately and the worst dose is

tabulated for that evaluation rather than the sum of both doses. Thus, double counting of the fission product fractions is eliminated where possible;

b. The above release is assumed to occur and be distributed instantaneously at the start of the accident. The plateout is assumed to occur over an effective time of 5 hr after the accident;

c. Until depressurized, liquid in the reactor coolant system (RCS) and other systems which are not isolated from the core and which contain the reactor coolant at the start of the LOCA contain 100% noble gases, 50% halogens, and 1% of the remaining fission products. These radioactive materials are mixed homogeneously in a volume no greater than the RCS liquid space;

d. Liquid in the suppression pool and any system not isolated from the core at the start of the LOCA, and containing only liquid from a depressurized source, is assumed to contain 50% halogens and 1% of the remaining fission products. These radioactive materials are diluted homogeneously in a volume no greater than the combined volumes of the suppression pool and the RCS liquid space;

e. The primary containment atmosphere and systems which are not isolated from the primary containment atmosphere at the start of the LOCA are assumed to contain at least 100% noble gases and 50% halogens initially. These radioactive materials are diluted homogeneously in a volume no greater than the combined volumes of the drywell and suppression pool air spaces; and

f. Primary containment plateout source term is obtained by allowing the airborne halogens released (50%) to plateout on primary containment surfaces in accordance with the guidelines presented in NUREG/CR-0009 until the airborne elemental iodine concentration is decreased by a factor of 200.

J.2.1.3 Vital Area Access Requirements

As defined in NUREG-0737 (Reference J.7-5), a vital area is an area which will or may require occupancy to permit an operator to help in the mitigation of an accident or perform postaccident operations. The accident scenarios discussed in Section J.2.1.1 and the source term assumptions in Section J.2.1.2 are used for the evaluation of vital area access and occupancy. The total radiation exposure to personnel in vital areas should not be in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident. For areas requiring continuous occupancy (e.g., the control room, onsite technical support center, etc.), the dose rate criteria limits the total radiation exposure to less than 15 mrem/hr (averaged over 30 days).

J.2.1.4 Systems Containing the Sources

Systems considered in the shielding review are those systems that could have the potential of containing a high level of radioactivity postaccident. For those systems connected directly to the RCS or to the primary containment atmosphere and not isolated at the start of the accident, the radioactivity is assumed to be instantaneously mixed within the unisolated parts of the system.

J.2.1.5 Safety-Related Equipment (C1E/SRM)

The safety-related (C1E/SRM) equipment list contains all equipment necessary to mitigate the consequences of an accident, bring the plant to a safe shutdown condition, and provide long-term cooling capability. This list includes equipment located inside as well as outside the primary containment.

J.2.2 SHIELDING EVALUATION TASK DESCRIPTION

The shielding evaluation tasks which have been completed to date are as follows:

a. Review all accident scenarios and accident conditions that could result in a limiting radiation environment for all the pieces of safety-related equipment on the C1E/SRM (safety-related) list that are located in the reactor building;

b. Identify systems and components that could potentially contain radioactive materials postaccident;

c. Generate source term assumptions based on regulatory requirements discussed in Section J.2.1;

d. Calculate accident radiation service conditions for the safety-related equipment located inside the reactor building;

e. Calculate gamma dose rates at selected locations outside the reactor building due to radioactive sources inside the reactor building;

f. Identify vital areas and equipment to evaluate the access to and occupancy of the vital areas in accordance with the requirements listed in Section J.2.1;

g. Conduct a primary containment analysis of LOCA events in which the RCS may not depressurize (or may repressurize) with a degraded core condition. The primary containment radiation environment was determined with the use of 100% noble gases, 50% halogens, and 1% of the remaining fission products for the period of time during which the activity is isolated to the RCS;

h. Calculate the radiation dose to safety-related equipment in the reactor building from post-LOCA airborne radiation and from normal piping sources inside primary containment streaming through the bioshield wall penetrations; and

i. The safety-related equipment list contains all equipment required to "mitigate" the consequences of an accident, bring the plant to a safe shutdown condition, and provide long-term cooling capability. The completeness of the safety-related equipment list has been verified.

J.2.3 SHIELDING EVALUATION ITEM DELETED FROM SHIELDING ANALYSIS CONSIDERATION

WNP-2 has addressed all the issues needed to comply with the NUREG-660 II.B.2 position except as follows: WNP-2 takes exception to the portion of the task that specifies that a review of "safety-related" equipment which may be degraded by radiation during postaccident operation be provided for a non-LOCA, high-energy line break source term. The pipe break/missile analysis described in Sections J.3.5 and J.3.6 addresses nonmechanistic pipe breaks inside and outside containment. These pipe breaks do not lead mechanistically to a radiation release due to fuel failures beyond those allowed in normal operation. Hence, the source term identified and applied outside containment is entirely hypothetical and would be a new design basis beyond the scope of current regulations.

J.3 ANALYTICAL METHODOLOGY

To develop the method used in the calculation of radiation doses, a review of all the postulated accident scenarios and system operations were performed. Source term assumptions were developed based on the results of accident analysis and system review, as well as the regulatory guidelines described in Section J.2.1. The systems and components inside the reactor building that have the potential of becoming contaminated during or following the accident were identified.

The following subsections describe these activities in greater detail. Section J.3.1 describes the accident scenario chosen for this analysis. Section J.3.2 identifies all the contaminated systems. Section J.3.3 describes the source term assumptions generated for each contaminated system. Section J.3.4 identifies the time period considered for this study.

J.3.1 ACCIDENT SCENARIO

The accident analyses consistent with FSAR Chapter 15 for small- and large-break loss-of-coolant accidents (LOCAs) were considered. The entire spectrum of LOCA conditions that could result in a degraded core configuration was reviewed and it was concluded that there is no single accident scenario that could result in a limiting radiation environment for all the safety-related equipment located in the reactor building. Therefore, the accident scenario chosen here is based on a nonmechanistic LOCA in which core damage is experienced at the beginning of the accident. Primary containment isolation is assumed to be achieved prior to radioactivity transport.

A review of the postaccident operation of the C1E/SRM (safety-related) systems was conducted. The result of this review indicated that the worst-case accident for the steam supply system (highest source term) was the pressurized reactor coolant system (RCS). For the liquid systems [the emergency core cooling system (ECCS), the residual heat removal (RHR), and the reactor core isolation cooling (RCIC) systems], as well as the primary containment atmosphere and primary containment atmosphere control (CAC) system, the worst-case accident is the depressurized reactor coolant system with the post-LOCA core release functions dispersed within the primary containment.

J.3.2 CONTAMINATED SYSTEMS

To perform the radiation dose calculations, it was necessary to identify the systems which would or could contain highly radioactive materials during the postaccident period. Systems required to operate during the postaccident period are as follows:

a. Systems necessary to mitigate the consequences of a large- or small-break LOCA,

b. Portions of systems that are in communication with systems containing radioactive liquids or gases, and

c. Defined by the NRC as being required, such as the gaseous radwaste system (see Section J.3.2.3).

J.3.2.1 Systems Included for Primary Containment Analysis

The following systems were considered:

a. High-pressure core spray (HPCS),

b. Low-pressure core spray (LPCS),

c. RHR,

d. RCIC,

e. Floor drains and equipment drains (FDR-EDR),

f. Reactor water cleanup (RWCU),

g. Main steam (MS),

h. Reactor recirculation (RRC),

i. Sample lines (PSR),

j. Automatic depressurization system (ADS), and

k. Low-pressure coolant injection (LPCI) function of the RHR system after depressurization.

J.3.2.2 Systems Included for Secondary Containment Analysis

The following systems were considered:

a. RCIC,
b. RHR,
c. LPCI,
d. LPCS,
e. HPCS,
f. CAC, the hydrogen recombiners,

g. MS, up to second isolation valve,
h. MS line isolation valve-leakage control system (MSIV-LCS),
i. Primary containment,
j. Secondary containment atmosphere, and
k. Standby gas treatment (SGT).

The following systems were also considered due to their potential to affect isolation valves or extend the primary containment source terms into secondary containment.

a. Containment atmosphere monitoring (CMS),

b. Containment supply purge (CSP),

c. Containment exhaust purge (CEP),

d. Blank penetrations,

e. Personnel access doors into the wetwell and drywell,

f. Instrumentation penetrations, and

g. All post-LOCA inboard and outboard isolation valves and their connected piping sources.

J.3.2.3 Systems Excluded

All systems required to mitigate the consequences of an accident have been included. Of those systems recommended for consideration in regulatory documents, one system (gaseous radwaste) has been excluded.

The gaseous radwaste is isolated by the primary containment and reactor vessel isolation control system and will not receive contaminated gas unless operation is manually initiated. The WNP-2 operating and accident procedures do not take credit for nor anticipate using this system. Since WNP-2 philosophy is based on containment of the core releases within the primary containment, this system will not be required and was, therefore, excluded from consideration.

J.3.3 SOURCE TERM ASSUMPTIONS

Regulatory requirements specify that source terms equivalent to those recommended in Regulatory Guides 1.3 and 1.7 and Standard Review Plan Section 15.6.5 be used in the LOCA accident analysis. Additional guidance is given in NUREG-0588 (Reference J.7-2) and NUREG-0737 (Reference J.7-5) and is documented in Section J.2.1. Source term assumptions

were generated based on the review of the operation of the safety systems. Because a nonmechanistic LOCA scenario was chosen for this analysis, the worst contaminated situation for the fluid contained within each system was conservatively assumed. Tables J.3-1, J.3-2, and J.3-3 list the assumptions involved in the distribution of fission products used in this analysis. These assumptions are consistent with the regulatory requirements discussed in Section J.2.1.

A review of the operation of each of the systems discussed in Section J.3.2 was also conducted. This review identified the source of contaminated fluid contained within each system postaccident. Using the source term assumptions discussed in Tables J.3-1, J.3-2, and J.3-3, together with the results of this system review, the limiting source term (activity divided by dilution factor) was determined for each system. Table J.3-4 is a summary of the system operations and source term assumptions developed for each contaminated system identified in Section J.3.2.

J.3.4 TIME PERIOD CONSIDERED FOR STUDY

All systems were conservatively assumed to become contaminated at the start of the accident and remain contaminated until the integrated radiation dose reached it asymptotic value. It was noted that the integrated dose becomes nearly asymptotic to a constant value beyond about 6 months. Therefore, 6 months is the time period chosen for accident dose qualification in this report.

TABLE J.3-1

DISTRIBUTION OF FISSION PRODUCTS IN THE WORST POST-LOSS-OF-COOLANT ACCIDENT SITUATION FOR AREAS INSIDE CONTAINMENT DEPRESSURIZED REACTOR COOLANT SYSTEM

	Primary Containment [a] Air and Steam Space		Suppression Pool and Reactor Coolant System Water Volume	
Fission Products	Fraction [b]	Dilution Volume [c]	Fraction [b]	Dilution Volume [c]
Noble gases	100%	Drywell air plus	0%	Suppression pool water and RCS water volume
Halogens	50% [d,e]	Suppression pool	50%	
Particulates	0%	Air	1%	

[a] A uniform distribution between drywell and suppression pool atmosphere has been assumed.

[b] Expressed in percentage (%) of total core inventory at end-of-life conditions (1000 days at 3556 MWt).

[c] Represents the total volume in which the fraction of core fission products is assumed to be homogeneously mixed.

[d] In calculating the radiation dose at a particular location, it is not necessary to assume that all source distribution assumptions are conservative simultaneously. Instead, a set of mutually compatible assumptions will be used which gives the maximum dose for the location being considered. The post-LOCA source contributors are used to calculate independent doses for each contributor. The worst dose is tabulated for that system rather than the sum of all contributors (i.e., 50% halogens airborne and 50% halogens in the water). Thus double counting of the fission product fractions is eliminated.

[e] First order iodine plateout occurs during the first 5-6 hr of the post-LOCA time frame when the elemental halogen concentration is reduced by a factor of 200. This methodology is in accordance with NUREG/CR-0009. Of the halogens released, 95.5% is available for plateout. Virtually all of the available halogens plateout within the initial 5 hr after the accident (0.5% remain airborne).

TABLE J.3-2

DISTRIBUTION OF FISSION PRODUCTS IN THE WORST POST-LOSS-OF-COOLANT ACCIDENT SITUATION FOR AREAS INSIDE CONTAINMENT PRESSURIZED REACTOR COOLANT SYSTEM[a]

	Drywell Air Space[a]	Suppression Pool Water Volume and Air Space[a]	Reactor Coolant System Water Volume[a]		Reactor Coolant System Steam Space[a]	
Fission products	Fraction[b]	Fraction[b]	Fraction[b]	Dilution Volume[c]	Fraction[b]	Dilution Volume[c]
Noble gases	0%	0%	100%[d]	RCS water volume[e]	100%[e]	Normal RCS steam space[f]
Halogens	0%	0%	50%[g]		25%	
Particulates	0%	0%	1%		0%	

[a] The reactor coolant system will remain pressurized for a short period of time (17 hr) and then will be depressurized.

[b] Expressed in percentage (%) of total core inventory at end-of-life conditions (1000 days at 3556 MWt).

[c] Represents the total volume in which the fraction of core fission products is assumed to be homogeneously mixed.

[d] The 100% of noble gases, present during the 17 hr of the pressurized RCS during a LOCA, are homogeneously mixed in the water and steam dilution volumes identified.

[e] The dilution volume is the RCS water volume plus the RWCU lines up to the isolation valves, RHR lines to the isolation valves, and the RRC lines during the 17 hr of the pressurized RCS scenario.

[f] The dilution volume is the normal RCS steam space plus the MS lines up to the isolation valves during the 17 hr of the pressurized RCS scenario.

[g] In calculating the radiation dose at a particular location, it is not necessary to assume that all source distribution assumptions are conservative simultaneously. Instead, a set of mutually compatible assumptions will be used which gives the maximum dose for the location being considered. The post-LOCA source contributors are used to calculate independent doses for each contributor. The worst dose is tabulated for that system rather than the sum of all contributors (i.e., 50% halogens airborne and 50% halogens in the water). Thus double counting of the fission product fractions is eliminated.

TABLE J-3.3

DISTRIBUTION OF FISSION PRODUCTS IN THE WORST POST-LOSS-OF-COOLANT ACCIDENT SITUATION FOR AREAS OUTSIDE CONTAINMENT

	Primary Containment Air Space		Suppression Pool Water Volume		Reactor Coolant System Steam Space[a]		Reactor Coolant System Water Volume[a]	
Fission Products	Fraction[b]	Dilution Volume[c]	Fraction[b]	Dilution Volume[c]	Fraction[b]	Dilution Volume[c]	Fraction[b]	Dilution Volume[c]
Noble gases	100%	Drywell	0%	Suppression pool water plus RCS water	100%	Normal	100%	RCS
Halogens	50%[d]	Air plus	50%[e]		25%	RCS	50%	Water
Particulates	0%	Suppression pool air	1%		0%	Steam space	1%	Volume

[a] Based on pressurized reactor coolant system.

[b] Expressed in percentage (%) of total core at end-of-life conditions (1000 days at 3556 MWt).

[c] Represents the total volume in which the fraction of core fission products is assumed to be homogeneously mixed.

[d] 95% of the halogens released from the core are assumed to plateout within approximately 5 hr as allowed by NUREG/CR-0009. The plateout dose was considered in the total calculation of radiation dose to equipment inside primary containment.

[e] In calculating the radiation dose at a particular location, it is not necessary to assume that all source distribution assumptions are simultaneously conservative. Instead, a set of mutually compatible assumptions will be used which gives the maximum dose for the location being considered. The post-LOCA source contributions are used to calculate independent doses for each contributor. The worst dose is tabulated for that system rather than the sum of total contributors (i.e., 50% halogens airborne and 50% halogens in the water). Thus double counting of the fission of product fractions is eliminated.

TABLE J.3-4

SYSTEM OPERATION AND SOURCE TERM ASSUMPTIONS

System	Operation Postaccident	Contaminated Space	Source Term Assumptions
HPCS	Suction from condensate storage tank and/or suppression pool and discharge to the reactor vessel.	Suppression pool	(1)
LPCS	Suction from suppression pool and discharge to the reactor vessel.	Suppression pool	(1)
LPCI	Suction from suppression pool and discharge to the core.	Suppression pool	(1)
(6) RCIC steam system	Steam bleed-off from reactor steam space is used to drive the RCIC turbine, and exhausts into the suppression pool.	RCS steam space	(2)
RCIC liquid system	Suction from condensate storage tank or suppression pool and discharge to the reactor vessel.	Suppression pool	(1)
RHR system	(1) Shutdown cooling mode - suction from reactor recirculation system suction line and discharge into the reactor recirculation discharge line.	RCS liquid space	Note a
	(2) Alternate shutdown cooling mode - suction from suppression pool and discharge to core recirculates and cools the water in the suppression pool.	Suppression pool	(1) Note b
	(3) Containment spray cooling mode - suction from suppression pool and discharge into the drywell and suppression pool.	Suppression pool	(1)
	(4) Reactor steam condensing mode.	System mode deleted from plant	

TABLE J.3-4

SYSTEM OPERATION AND SOURCE TERM ASSUMPTIONS (Continued)

System	Operation Postaccident	Contaminated Space	Source Term Assumptions
Main steam supply (MS)	Stagnant steam from the reactor vessel terminates at the second MSIV.	RCS steam space	(2)
MSIV-LCS (MSLC)	Steam bleed-off from main steam line, diluted, and discharged into the SGTS.	RCS steam space	(2) Note c
SGT filters (SGTS)	Process the halogens from primary containment leakage and MSIV-LCS.	Primary containment and secondary containment atmosphere	(3)
CAC	Process the primary containment atmosphere (hydrogen recombination).	Primary containment atmosphere	(4)
Primary containment (PCN)	Primary containment is isolated postaccident.	Primary containment atmosphere	(4)
Suppression pool	The primary function of the suppression pool is to contain and condense the blowdown from the RCS postaccident.	Suppression pool liquid	(1)
Secondary containment (SCN)	The primary function of the secondary containment is to contain all the leakage from the primary containment postaccident.	Primary containment atmosphere	(5)
Sample lines	Actuated to obtain primary containment atmosphere samples per NUREG-0737 (Reference J.7-5).	Primary containment atmosphere	(2)
Sample lines	Actuated to obtain liquid samples per NUREG-0737.	RCS liquid space	(1)
Reactor water cleanup (RWCU)	Reactor water cleanup system isolated during post-LOCA. Liquid up to the second isolation valve is considered contaminated.	RCS liquid	(1)
Reactor recirculation (RRC)	Suction from RRC system suction line and discharge into the reactor recirculation discharge line.	RRC liquid; RCS liquid	(1)

TABLE J.3-4

SYSTEM OPERATION AND SOURCE TERM ASSUMPTIONS (Continued)

System	Operation Postaccident	Contaminated Space	Source Term Assumptions
Floor drains and equipment drains (FDR/EDR)	Liquid from ruptured pipes or leaky seals discharged into the suppression pool.	RCS liquid	(1)
Automatic depressurization system (ADS)	Automatic or manual depressurization of the reactor vessel by blowdown of the RCS into the suppression pool.	RCS steam	(2)
Automatic depressurization system (ADS)	Alternate shutdown cooling mode with reflood of reactor vessel and discharge into suppression pool.	Suppression pool	(1)
Containment monitoring system (CMS)	Continues to monitor primary containment atmosphere conditions.	Isolation of primary containment into secondary containment	(4)
Containment supply purge (CSP)	Isolated - no action required.	Isolation of primary containment into secondary containment	(4)
Containment exhaust purge (CEP)	Isolated - no action required.	Isolation of primary containment into secondary containment	(4)
Blank penetrations	None	Isolation of primary containment into secondary containment	(4)
Personnel access doors to primary containment	None	Isolation of primary containment into secondary containment	(4)
Instrumentation penetrations	None	Isolation of primary containment into secondary containment	(4)
All post-LOCA inboard and outboard isolation valves	As defined per WNP-2 system requirements post-LOCA	Isolation valves and their connected piping which extends into secondary containment	Note d

TABLE J.3-4

SYSTEM OPERATION AND SOURCE TERM ASSUMPTIONS (Continued)

Source Term Assumptions

(1) 50% halogens and 1% solid fission products diluted with suppression pool water plus RCS water.

(2) 100% noble gases and 25% halogens diluted with the RCS steam space.

(3) 50% halogens leaked from the primary containment is assumed to be deposited in the SGT filters at the rate of 0.67% per day. See Section J.5.3.3.1 for justification. 100% noble gases pass through also but are not absorbed.

(4) 100% noble gases and 50% halogens diluted with the primary containment air space. First order iodine plateout (0-95% elemental iodine) inside primary containment was considered.

(5) Assumptions involved in the calculation of source terms for secondary containment atmosphere are discussed in Section J.5.3.2.1.

(6) Based on a pressurized reactor coolant system.

[a] According to accident mitigation procedures, this mode of operation is not used after a degraded core condition is identified.

[b] Full discussion of source term assumptions for alternate shutdown cooling are presented in Section J.5.3.3.1.

[c] For the portion of system after the distribution header, credit is taken for dilution by clean air. See Section J.5.3.3.1 for justification.

[d] For all isolated systems the source term for the isolation valves will be primary containment atmosphere unless the penetration is filled with water that remains during the post-LOCA scenario. All penetrations and their associated isolation valves which contain a flowing fluid during post-LOCA operations are analyzed with the post-LOCA source term of that flowing fluid.

J.4 ACCESS AND OCCUPANCY OF VITAL AREAS

NUREG-0578 initiated the requirement for a design review to identify the location of vital areas in which personnel occupancy may be unduly limited by the radiation fields during postaccident operations. It required that each licensee provide adequate access to vital areas through design changes, increased permanent or temporary shielding, or postaccident procedural controls. NUREG-0737 further makes the point that the purpose of this design review is to determine what actions can be taken over the short-term to reduce radiation levels and increase the capability of operators to control and mitigate the consequences of an accident.

This shielding evaluation includes the calculation of gamma dose rates at selected locations outside the reactor building due to radioactive sources inside. The radioactive source terms obtained from ORIGEN computer calculations coupled with recommendations from Regulatory Guide 1.109 were the basis for the assumptions used in evaluating vital areas and access routes outside the reactor building.

J.4.1 DOSE RATES OUTSIDE THE REACTOR BUILDING

An analysis was conducted to determine the dose rates at selected locations outside the reactor building for personnel access purposes. The radiation level in the various areas outside the reactor building is defined by the following three radioactive sources:

a. Direct gamma ray dose from radioactive piping located inside the reactor building and attenuated through the walls of the reactor building,

b. Gamma shine dose from airborne activity inside the reactor building, and

c. Gamma dose from airborne activity outside the reactor building.

Radiation levels outside the reactor building were determined by the zone dose method as discussed in Section J.5.4. Representative zones were chosen at selected locations outside the reactor building such as ground level outside the railroad bay, sampling room, etc. The worst point in a zone was chosen to be the point directly outside the reactor building wall, at a height of 6 ft above floor elevation, at a lateral point determined by inspection to receive the highest dose along that wall.

The zones outside the reactor building are indicated by the letters Y and Z in the various elevations. The shine dose contribution to areas outside the reactor building (Zones Y and Z) were included in the dose calculations shown in Figures J.6-11 through J.6-18.

Attachment J.H presents the methodology used to calculate the radiation doses for the various vital areas.

J.4.2 VITAL AREAS AND ACCESS ROUTES OUTSIDE THE REACTOR BUILDING

Radiation calculated for the access routes were based on the assumption that no individual would be in an access route longer than 30 minutes for the first 8 hr after the postulated LOCA before reaching the vital area of interest.

The assumption was also made that no individual would occupy an infrequent occupied vital area longer than 30 minutes for the first 8 hr after the postulated LOCA.

All integrated radiation doses calculated for time spent in the access routes and vital areas were less than the guidelines presented in NUREG-0737.

J.4.3 VITAL AREAS AND ACCESS ROUTES INSIDE THE REACTOR BUILDING

Analysis has been completed to take credit for a vital area in the reactor building railroad bay and on the west side of the 522-ft el. The analysis of reactor building zones is discussed in Section J.5.3. The access route to the reactor building is discussed in Sections J.4.1 and J.4.2. See Section J.6.3 for a description of the access to the 522-ft el. of the reactor building.

J.5 METHODS

Due to the large number of C1E/SRM components in primary containment, it was decided to calculate the worst point dose from each of the major sources in the drywell and wetwell, and then sum the doses for a conservative estimate of the total integrated dose.

The secondary containment radiation dose assessment portion of the shielding evaluation was initiated by dividing the reactor building into radiation zones. Because of the large number of radioactive piping and safety-related equipment in the building, the division of the various regions of the secondary containment into radiation zones permits a precise, detailed calculation of the total integrated dose at the "worst target" location. The methods for performing the calculations are discussed in detail in the following sections.

The radiation dose assessment of safety-related equipment outside of the reactor building was done by calculating the radiation dose of each vital area where safety-related equipment was located. The assumptions and methodology used to perform these calculations are discussed in detail in the following sections and in Attachment J.H.

J.5.1 THE USE OF COMPUTER CODES

The two computer codes used in the primary containment shielding evaluation were ORIGEN2 and QAD-CG. Descriptions of the two codes are found in References J.7-8, J.7-9, J.7-10, and J.7-17. ORIGEN2 was used to compute the radioactive source terms (inside containment) used by QAD-CG to calculate the radiation doses from piping and various pieces of equipment.

The three computer codes used in the original secondary containment radiation shielding review were ORIGEN, SCAP-BR, and QAD-P5A. Descriptions of the codes are found in References J.7-10, J.7-11, and J.7-18. ORIGEN computes the radioactive source terms used by QAD-P5A to compute the radiation from piping and other source configurations to pieces of equipment. SCAP-BR computes the radiation dose contribution to safety-related equipment in the reactor building from primary containment airborne radiation streaming through the bioshield wall penetrations.

ORIGEN and ORIGEN2 are fission product source term codes which solve the equations of radioactive growth and decay for large numbers of isotopes. The codes have been used to calculate the radioactivity of fission products and fuel materials that were assumed to be released from the reactor core during the postulated loss-of-coolant accident (LOCA) to become the primary containment source terms for the dose rate calculations. SCAP-BR is similar to QAD-CG with the added capability to determine the radiation dose contribution due to scattering.

J.5.2 SOURCE TERM DEVELOPMENT FOR PRIMARY CONTAINMENT

The radiation level at any given location inside the primary containment of WNP-2 following the postulated LOCA such as that described in Section J.3.1 is determined from the following major source contributors:

a. Gamma ray dose from airborne radioactive sources suspended in the drywell and wetwell inside primary containment (airborne gamma dose),

b. Gamma ray dose from piping and/or equipment containing contaminated fluids which are recirculated inside primary containment (direct gamma dose),

c. Gamma and beta ray dose from iodines plated out inside primary containment (iodine plateout), and

d. Beta ray dose emitted by airborne radioactive sources suspended in the drywell and wetwell inside primary containment (airborne beta dose).

The initial phase of this analysis was concerned with the determination of radioactive source terms for the liquids and gases inside primary containment. The ORIGEN2 computer code was used for this calculation. The fission product inventory at the end of fuel life (1000 days irradiation at a power level of 3556 MWt) was assumed to be available for release immediately following the accident. The release fractions and resulting concentrations of noble gases, halogens, and other fission products in the gaseous and liquid fluids were computed. A detailed description of the analysis including the assumptions used is provided in Attachment J.F.

J.5.3 SOURCE TERM DEVELOPMENT FOR SECONDARY CONTAINMENT

The radiation level at a given location inside the secondary containment of WNP-2 following an accident such as that described in Section J.3.1 is defined by the following major source contributors:

a. Gamma ray dose from airborne radioactive sources inside secondary containment (airborne gamma dose),

b. Gamma ray dose from radioactive sources suspended in the drywell and the wetwell inside primary containment (containment shine dose),

c. Gamma ray dose from piping and/or equipment containing contaminated fluids which are recirculated inside the reactor building (direct gamma dose),

d. Beta ray dose emitted by airborne radioactive sources inside secondary containment (airborne beta dose), and

e. Gamma ray dose from liquid piping and airborne radioactive sources inside primary containment which stream through bioshield wall penetrations into secondary containment (bioshield penetration streaming dose).

The initial phase of this analysis was concerned with the definition of radioactive source terms for the liquid and gas containing systems. The ORIGEN computer code was used for this calculation. The fission products at the end of fuel life (1000 days irradiation at a power level of 3556 MWt) were assumed to be available for release immediately following the accident. The released fractions of noble gases, halogens, and other fission products to the gaseous and liquid sources were computed. Subsequent fission product depletion and daughter product generation were then calculated for 20 time periods, covering a total period of 1 year. A detailed description of the analysis, including the assumptions used, as well as results of the source terms, is found in Attachment J.B and Reference J.7-12.

J.5.3.1 Parametric Studies for Direct Piping Dose in Secondary Containment

The purpose of the parametric study was to identify the parameters which have a significant effect on the radiation dose rates inside secondary containment. The computer code QAD-P5A was used to develop a correlation scheme for the significant parameters such that a simplified procedure for calculating radiation dose rates for complex source and receptor geometries can be developed. The dose rate at a target distance of 8 ft radially outwards from the centerline of an 8-in. schedule 40 pipe, infinitely long (standard pipe), was first calculated and defined as the standard dose rate. The results of this parametric study were then correlated as a set of correction factors to the standard dose rate. A simplified procedure was developed to calculate the dose rates and cumulate doses for complicated source-target configurations by using these correction factors. The development of these correction factors and the result of the parametric study inside secondary containment is discussed in Attachment J.B.

J.5.3.2 Dose Rate and Cumulative Dose Calculation Procedure

The results of the source term calculations and those of the parametric study were used to generate and cumulate doses for complicated source target configurations inside secondary containment. The following steps were taken to define the radiation service conditions for the pieces of safety-related equipment:

a. Based on the accident scenarios, contaminated systems, and assumptions defined in Section J.3, the radioactive source terms for liquid-containing and gas-containing systems were developed;

b. Radiation zones were selected and the radiation zone boundaries were carefully defined based on shield wall locations, contaminated piping locations, and locations of safety-related C1E/SRM equipment;

c. The radiation environment in each secondary containment zone (zone dose) was calculated (see Attachment J.B for the procedure). A zone dose is the radiation dose (gamma) that bounds the magnitude of dose received by all the pieces of safety-related C1E/SRM equipment located within that zone;

d. The zone dose as calculated in step c was used, as a first cut, to qualify all the pieces of safety-related C1E/SRM equipment located within that zone; and

e. For the pieces of safety-related C1E/SRM equipment that could not be qualified for the conservative radiation environment calculated in step c, the integrated dose for that piece of equipment was redefined based on a more realistic and refined approach.

J.5.3.2.1 Calculation of Airborne Gamma Doses Inside Secondary Containment

The time-dependent post-LOCA activity levels as calculated by the ORIGEN computer code were used as input for the calculation of the airborne gamma dose rates and integrated doses inside the cubicles in the secondary containment. The assumptions used in this analysis are as follows:

a. Activity that leaks into the secondary containment is homogeneously mixed with the secondary containment atmosphere prior to its removal from the atmosphere through the standby gas treatment system (SGTS);

b. The SGTS flow rate of 2430 scfm was assumed to be the flow rate of the effluent air. This is equivalent to one reactor building air change per day;

c. Air that leaks out of the primary containment flows directly and totally into the secondary containment. Bypass leakage was not considered;

d. Geometric factors were used to convert the semi-infinite cloud gamma dose to a finite gamma dose; and

e. Primary containment leakage rate of 0.05 wt %/day was considered.

Justifications of the above assumptions are stated in Attachment J.B. The equations that were used for the gamma dose calculations are described in Attachment J.B. Primary containment airborne beta dose results are discussed in Attachment J.G.

J.5.3.2.2 Procedure for the Calculation of Radiation Zone Dose in Secondary Containment

As discussed previously, the gamma radiation level at a given location inside the secondary containment of WNP-2 following a LOCA is determined for four types of radioactive source distributions:

a. Fission products suspended in the atmosphere of the secondary containment (airborne gamma dose),

b. Gamma irradiation from the primary containment (shine dose),

c. Direct gamma irradiation from the radioactive fluid contained inside recirculating pipes (direct dose), and

d. Gamma ray dose from liquid piping and airborne radioactive sources inside primary containment which stream through bioshield wall penetrations into secondary containment (bioshield penetration streaming dose).

The dose contributed by each of these sources is determined by the location of the equipment, the time-dependent distribution of the source, and the effects of shielding.

A step-by-step procedure for calculating radioactive zone doses is shown in Attachment J.C. The methods presented in that procedure make it possible to calculate the worst case gamma dose from the above-mentioned source contributors inside radiation zones of the secondary containment. In general, this procedure for determining zone doses consists of a correction factor method for calculating direct dose rates.

As discussed in Attachment J.B, the correction factor method for calculating dose rates provides a convenient and fairly precise way of determining direct dose rates due to generic pipe segments. For radioactive fluid contained within components of geometry other than generic pipe segments, such as residual heat removal (RHR) heat exchangers, SGTS filters, hydrogen recombiners, etc., special QAD-P5A computer modeling was performed to calculate the gamma dose contribution due to those systems. A brief description of the guidelines used in modeling special components is found in Attachment J.B.

An evaluation of beta dose is necessary for qualification of safety-related equipment that is beta sensitive and not adequately protected against beta radiation. The beta dose analysis for secondary containment is presented in Section J.5.5. Beta dose is discussed in more detail in Attachment J.D as related to secondary containment radiation contributors.

J.5.3.3 Calculation of Radiation Doses Due to Special Systems and Components Inside Secondary Containment

As discussed in Attachments J.B and J.C, the correction factor method for calculating gamma dose rates and integrated doses is involved with the application of the dose correction factors (pipe diameter, pipe length, and radial distance correction factors) to a standard dose rate curve. A standard dose is defined as the gamma radiation measured at a target distance of 8 ft and emitted by radioactive sources contained within the suppression pool liquid and recirculated within infinitely long 8-in. schedule 40 piping. The systems that contain such radioactive fluids are the reactor coolant system, high-pressure core spray, low-pressure core spray, and residual heat removal systems. Other systems which contain fluids of different source terms and dilutions are considered special sources. The systems that need to be considered for special sources are the following:

a. Standby gas treatment system filters,
b. Containment atmosphere control (CAC) system,
c. Main steam system, and
d. Main steam isolation valve leakage control system (MSIV-LCS).

J.5.3.3.1 Source Term Assumptions in Secondary Containment

The assumptions for the calculations of source terms inside secondary containment for special source systems are listed as follows:

Standby Gas Treatment System Filters

a. The SGTS filters will be loaded by halogens at the rate of 0.67% primary containment free volume per day. This consists of 0.5% per day of primary containment leakage and 0.17% per day of leakage due to the MSIV-LCS system. No holdup of this activity in the secondary containment is assumed;

b. The released halogen fraction is 50% of the core halogen inventory. This halogen fraction is assumed to be composed of 95.5% elemental, 2% organic, and 2.5% particulate halogens; and

c. The particulate halogens are assumed to be homogeneously distributed within the prefilters and the particulate filters, while the elemental and organic halogens are assumed to be homogeneously distributed within the charcoal filters.

Assumption a is consistent with the assumptions used in the accident analysis (Reference J.7-13 and Section J.3.1).

Assumption b is the NRC recommended assumption for the distribution of halogen inventory (Reference J.7-14).

Assumption c is necessary because the time-dependent distribution of activity within a filter is unknown. The homogeneous assumption, therefore, is considered appropriate and conservative for zone dose assessment.

Containment Atmosphere Control System

The function of the CAC system is to process the primary containment atmosphere to remove oxygen after a LOCA accident. Therefore, this system is assumed to be filled with gaseous source containing 2.5% halogens and 100% noble gases diluted with the primary containment free volume.

Main Steam System

The main steam lines are located inside and outside the primary containment; they include the main steam lines in the steam tunnel and the RCIC turbine supply and exhaust lines. The radioactive source term for this system is assumed to be composed of 100% noble gases and 25% halogens, distributed throughout the reactor coolant system (RCS) steam space.

Alternate (Suppression Pool) Shutdown Cooling

To prevent failure of the RHR pumps due to excessive radiation exposure, the alternate shutdown cooling mode is the only allowable mode for shutdown cooling once a degraded core condition has been identified.

A small pipe-break accident will take approximately 6 hr to depressurize from 1000 psi to 150 psi through automatic depressurization system (ADS) valve actuations. Post-LOCA samples are required within the first 2 hr after the accident. Thus, a degraded core condition will be identified if it exists prior to shutdown cooling action. Once a degraded core is identified and the reactor is sufficiently depressurized, within 17 hr after the accident, the ADS valves actuation will be maintained to dilute the primary coolant source concentration with the suppression pool since the alternate shutdown cooling mode will be used for decay heat removal.

For the large pipe-break accident the primary coolant source concentration will be diluted with suppression pool due to blowdown of the vessel through the large break or automatic actuation of the ADS valves. Once the vessel has been depressurized the water level in the vessel will be maintained with the emergency core cooling systems while decay heat is removed by suppression pool cooling.

Thus, in all degraded core scenarios the primary coolant is diluted with the suppression pool prior to initiating the suppression pool shutdown cooling mode.

Main Steam Isolation Valve Leakage Control System

The MSIV-LCS system of WNP-2 is a vacuum-type system which collects leakage between and downstream of the closed isolation valves and then releases it to the atmosphere through the SGTS. Leakage through the valve stems (maximum leakage of 11.5 scfh as described in Reference J.7-15) is directed to a distribution header or low-pressure manifold where clean air is brought in to dilute the contaminated steam before exhausting to the SGTS filter unit at a rated flow rate of 50 scfm. Thus the source term in the portion of piping system before the distribution header is conservatively assumed to be the same as that of the main steam system. For the portion of the piping after the header, credit is taken for the dilution by the clean air. This assumption is consistent with that recommended in Reference J.7-16.

J.5.3.3.2 Secondary Containment Analysis Method

The correction factor method is used for the calculation of the direct dose contribution due to the piping systems described in Section J.5.3.3, with the exception of the SGTS filter system. A description of the analysis of the SGTS filter is documented in Attachment J.D. Generic piping dose rate and integrated dose (dose at a target distance of 8 ft away from the centerline of an infinitely long 8-in. schedule 40 pipe) for each system were developed using the source term assumptions discussed in Section J.5.3.1 and are shown in Attachment J.B. Parametric studies were also performed to investigate the variation of dose rates due to pipe diameter, pipe length, and target distance for pipe segments containing source terms. The gaseous source term correction factors derived as a result of this parametric study (described in Attachment J.B), together with the generic dose rate curves generated for each system, were used to calculate the direct gamma dose contribution on a target.

J.5.3.3.3 Calculation of Radiation Doses Inside Secondary Containment on Generic Mechanical Equipment

Table J.5-1 is a sample list of generic mechanical equipment that are on the safety-related equipment list. For conservatism, the direct dose on the containment pieces of generic mechanical equipment is assumed to be the fluid contact dose. Figure J.5-1 is an illustration of the point where the direct dose is calculated on a piping segment.

The secondary containment source term assumptions developed in Section J.5.5.4.1 are used for the calculation of radioactive source terms for different systems, and the fluid contact dose was calculated using QAD-P5A by following the guidelines set forth in Attachment J.C. Figures J.5-2 through J.5-4 are 6-month integrated fluid contact doses versus pipe diameter.

These curves are intended to give conservative, upper-bound direct gamma dose estimates for the qualification of the pieces of generic mechanical equipment and components in the various systems. To use these curves to calculate the direct doses on generic mechanical equipment, the following steps should be taken.

a. Identify the system on which the equipment or component is located,

b. Identify the diameter of the contaminated pipe on which the equipment is located, and

c. The 6-month integrated dose for that piece of equipment or component can be determined by reading the appropriate curve.

J.5.4 SOURCE TERM DEVELOPMENT FOR C1E/SRM EQUIPMENT OUTSIDE THE REACTOR BUILDING

The radiation level at any given location outside the reactor building of WNP-2 following the postulated LOCA as described in Section J.3.1 is determined from the following major source contributors:

a. Direct gamma dose from radioactive piping located inside the reactor building and attenuated through the walls of the reactor building,

b. Gamma shine dose from airborne activity inside the reactor building, and

c. Gamma ray dose from airborne activity outside the reactor building.

A detailed description of the method of analysis, including the assumptions used, as well as results of the source terms is found in Attachment J.H.

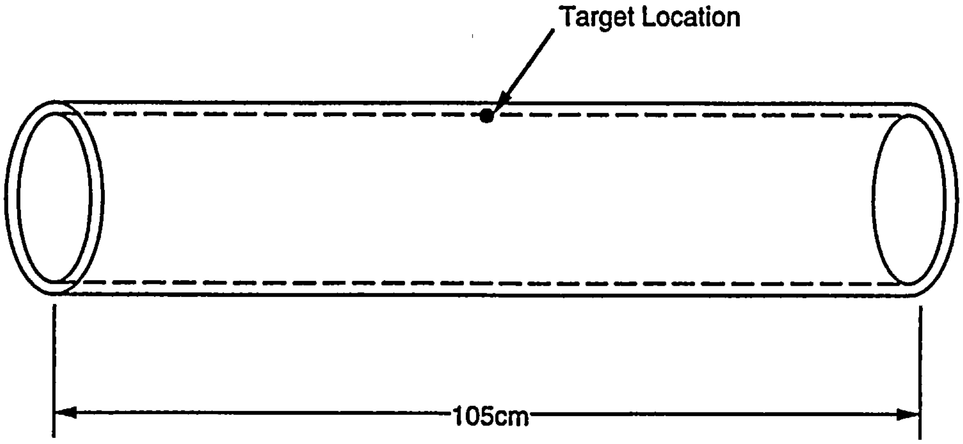
J.5.5 METHODOLOGY OF BETA DOSE ANALYSIS

The finite source volume used for the beta dose analysis in secondary containment is a sphere surrounded by a shell of sufficient thickness to stop all outside beta particles from entering the source volume. This finite spherical source volume is conservative for any generalized source shape (the dose at the center of the sphere is higher than the dose at any point of any generalized source shape of equal total volume). A discussion of this beta analysis methodology is presented in Attachment J.D.

TABLE J.5-1

GENERIC MECHANICAL EQUIPMENT

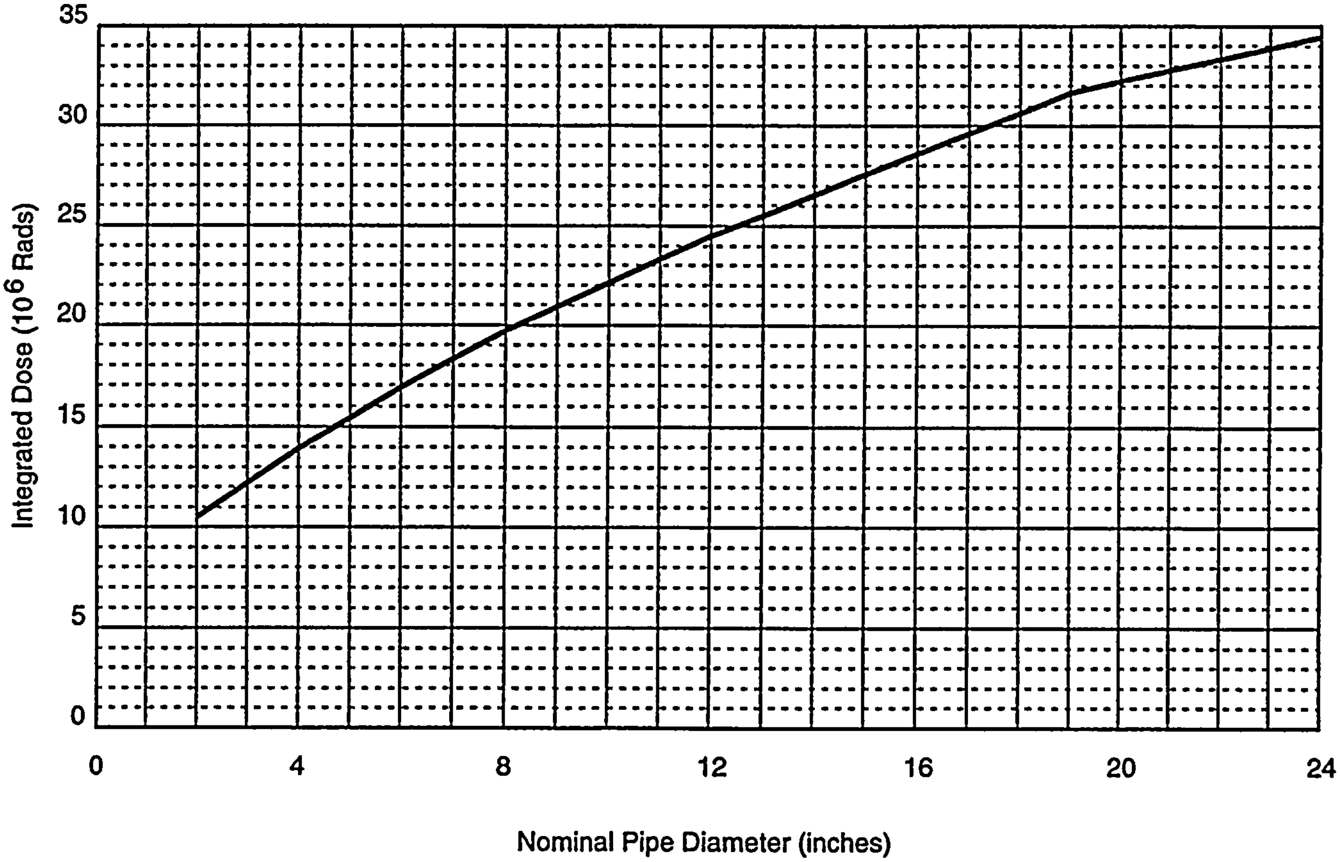
Valve packing
Lubricants
Seals
Expansion joints
Pressure relief valve
Flow element
Rupture disk
Gasket material
Conductivity element
Valve
Strainers
Steam traps
Filters (piping)
Temperature elements
Tanks
Moisture separators
Evaporator
Heat exchanger
Air washer (scrubber)
Pumps



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Dose Model Liquid Source

Draw. No. 970187.23 | Rev. | Figure J.5-1

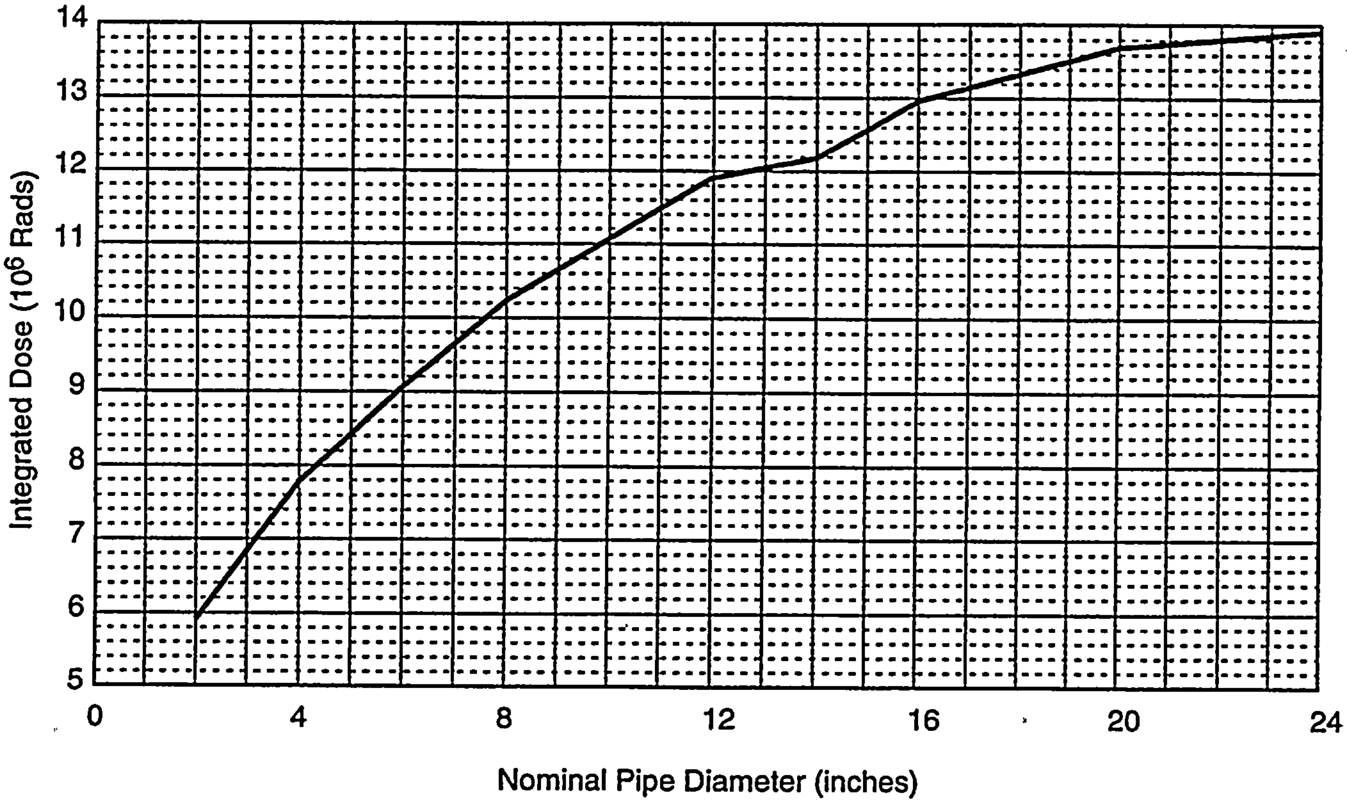


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

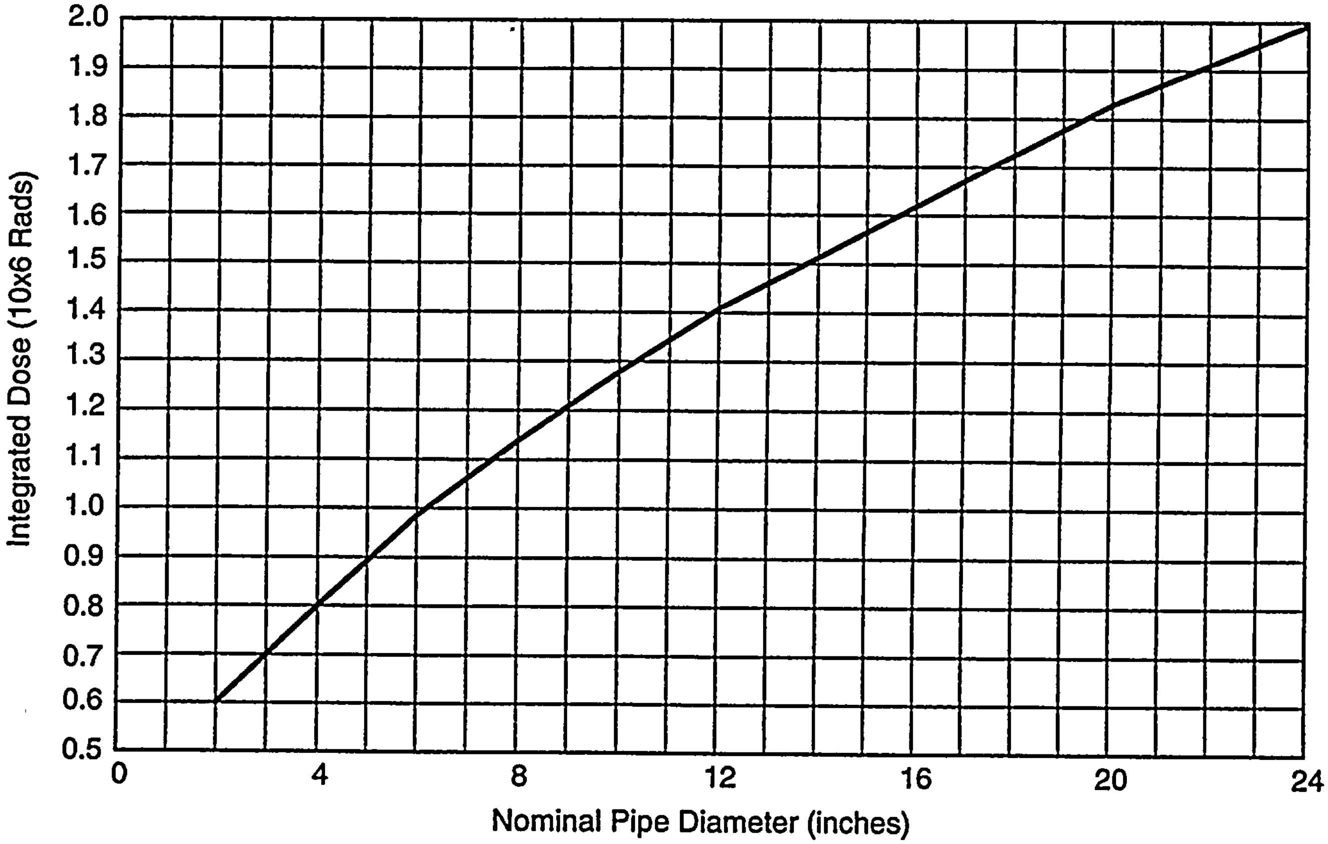
Sixth Month Integrated Fluid Contact Dose for MS, RCIC (Steam) System, and MSLC System Upstream of the Header

Draw. No. 960222.63	Rev.	Figure J.5-2

Form No. 960690



Sixth Month Integrated Fluid Contact Dose for Pipes Containing Liquid Source Term (RHR, HPCS, LPCS, RCIC Liquid Systems)



Sixth Month Integrated Fluid Contact Dose for Pipes Containing CAC Gaseous Source Term

J.6 RESULTS

All loss-of-coolant accident (LOCA) scenarios and accident conditions that could result in a limiting radiation environment for all the WNP-2 safety-related equipment on the C1E* list were reviewed and analyzed accordingly. Shielding (shield doors) was constructed for zones 522D, 572N, 572D, and 572H due to the radiation exposure of safety-related equipment in these zones.

In addition a shield wall was designed and installed on the southeast portion of the 501 ft el. against the bioshield wall to protect C1E* equipment from RRC piping radiation sources (normal operation) which stream through penetrations X-100A, X-105A, and X-100B.

The completeness of the safety-related equipment list has been verified. The safety-related equipment list contains all equipment required to "mitigate the consequences of an accident, bring the plant to safe shutdown conditions and provide long-term cooling capability."

Systems that could potentially contain radioactive material during and following the accident have been identified as listed in Sections J.3.2.1 and J.3.2.2.

The accident radiation doses indicated in Section J.6.1 and Table J.6-1 generated as a result of this analysis, are intended solely for the purpose of the qualification of safety-related equipment.

J.6.1 PRIMARY CONTAINMENT RADIATION RESULTS

Due to the large number of safety-related components it was deemed impractical to calculate the integrated dose to each piece of equipment. Therefore, the worst point dose from each of the major sources in the drywell and wetwell was calculated, and then summed for a conservative estimate of the total integrated dose. The dose sum of the worst-case source contributors in the drywell is 7.6×10^7 rads, but 7.4×10^7 rads is used as the worst-case dose for the equipment qualification program. All of the worst-case contributors cannot be present for a particular accident. Thus, the largest worst-case dose is calculated for the depressurized reactor coolant system. The worst-case dose is applied to safety-related equipment with an elevation within 5 ft of core midplane. Safety-related equipment in the drywell outside this elevation span is assigned a dose of 7.0×10^7 rads. In the wetwell, the maximum gamma dose above the suppression pool is 9.5×10^7 rads (see Section J.F.3 for discussion on photon energy and anticipated dose reduction of the above results). These results include the contributions from all major gamma sources within primary containment during normal operation as well as the 6-month period contribution following a postulated LOCA. Tables J.F-1 and J.F-2 give a breakdown of the integrated dose contribution from each of the

* Environmental qualification (EQ) of safety-related mechanical (SRM) equipment has been eliminated from the overall WNP-2 EQ program.

major gamma sources to the drywell and the wetwell. The 40-year integrated gamma doses due to normal operation are taken from Reference J.7-20.

This methodology for determining a worst-case dose for equipment in the drywell is not valid for the region inside the sacrificial shield wall or under the reactor pressure vessel. A point-specific radiation dose calculation is required for all components present in either of these two regions.

Specific calculations have been performed for equipment that was evaluated individually for total integrated dose. Results of these calculations are summarized in Reference J.7-26.

In accordance with Section 1.4(8) of Reference J.7-2, only the gamma dose need be considered for "shielded components." Since beta radiation is so readily attenuated, virtually any enclosure of sensitive components will be sufficient to classify the component as "shielded." A review of all safety-related equipment located inside primary containment determined that most C1E* equipment is sufficiently shielded against beta radiation. Thus, the beta dose contribution is excluded from the total integrated radiation doses compiled for equipment qualification purposes unless a beta-sensitive component is not adequately protected from the airborne beta environment. When required to include beta dose contributions, a finite source volume is used. The source volume is a sphere surrounded by a shell of sufficient thickness to stop all beta particles from entering the source volume. This finite spherical source volume is conservative for any generalized source volume shape (the dose at the center of the sphere is higher than the dose at any point of any generalized source shape of equal total volume). A discussion of the results is presented in Attachment J.G.

J.6.2 SECONDARY CONTAINMENT RADIATION RESULTS

The integrated direct gamma dose (40 years and 6 months LOCA - direct gamma, gamma shine, and airborne gamma) was evaluated for the worst target of all C1E* equipment in each zone and is used for qualification of all the other C1E* equipment in that zone. The 40-year integrated gamma doses (Figures J.6-1 through J.6-10) are taken from References J.7-20 and J.7-21. The direct gamma dose contribution outside primary containment due to sources inside the primary containment was investigated. Safety-related equipment located in the direct shine path through the penetrations was evaluated in Reference J.7-23. All post-LOCA radiation dose contributions to safety-related equipment from streaming through the bioshield wall penetrations were included in the radiation doses. Evaluation of bioshield wall penetrations identified radiation dose problems associated with some of those penetrations (Reference J.7-24). The post-LOCA evaluation of safety-related equipment assumed the C1E* equipment was shielded for 40-year normal operations. To adequately protect C1E* equipment a concrete wall was designed and installed for penetrations X-100A, X-105A, and X-100B. The

* Environmental qualification (EQ) of safety-related mechanical (SRM) equipment has been eliminated from the overall WNP-2 EQ program.

remaining penetrations evaluated (Reference J.7-25) were surveyed during plant startup to confirm radiation analysis calculations.

Airborne beta doses outside containment were evaluated in accordance with the methodology described in Section J.5.5 and Attachment J.D. The beta dose contribution is excluded from the total integrated radiation doses compiled for equipment qualification purposes unless a beta sensitive component is not adequately protected from the airborne beta environment.

J.6.3 RADIATION RESULTS IN THE VITAL AREAS AND ACCESS ROUTES

Figures J.6-11 through J.6-19 present the vital areas and access routes located outside the reactor building. Figures J.6-20 and J.6-21 present the vital areas and access routes located inside the reactor building. The doses indicated on each figure are also the 6-month LOCA integrated gamma doses to be used for C1E* (safety-related) equipment qualification purposes. Table J.6-1 also presents a summary of the 6-month LOCA integrated gamma doses on all C1E* equipment located in WNP-2 vital areas.

Figures J.6-20 and J.6-21 show the access route in the reactor building for operation of SW-V-75AA and SW-V-75BB, the manual isolation valves for the service water to fuel pool cooling makeup water supply.

Radiation levels of vital areas and access routes were determined at selected locations outside the reactor building due to radioactive sources inside the reactor building and release of radiation activity from the reactor building elevated vent. The vital areas and access routes analyzed are consistent with those discussed in NUREG-0737, Item II.B.2 (Reference J.7-5). The radiation levels determined for the vital areas and access routes identified in Figures J.6-11 through J.6-21 are summarized in Table J.6-2. All of the vital areas and access routes have radiation levels less than the guidelines presented in NUREG-0737.

The total dose received at a vital area during a post-LOCA scenario is obtained by summing the exposure dose enroute to the vital area and the radiation dose at the vital area. These doses are listed in Table J.6-2.

The analysis completed for vital areas and access routes assumed that except for the reactor building railroad bay and on the west side of the 522-ft el. there would be no access to equipment or areas located within the reactor building during the post-LOCA scenario. The exceptions are shown in Figures J.6-20 and J.6-21 and Table J.6-2. Access to the reactor building railroad bay for 3 hr is allowed to provide the ability to fill or exchange N_2 bottles. The entry to the west side of the 522-ft el. is to allow SW-V-75AA and/or SW-V-75BB to be opened (see Section J.3.1.2.6.2.1.2). These valves are readily accessible and the entire

* Environmental qualification (EQ) of safety-related mechanical (SRM) equipment has been eliminated from the overall WNP-2 EQ program.

opening evolution for one of these valves would take 2.17 minutes and could be performed as early as 9.0 hr with the resulting exposure of 4 rem. Under worst-case conditions, at least one of these valves would need to be opened by 10 hr. Once a manual valve is opened, the spent fuel pool level can be controlled with the motor-operated valve from the main control room.

TABLE J.6-1

SIX-MONTH TOTAL INTEGRATED DOSE (LOSS-OF-COOLANT ACCIDENT) TO AREAS CONTAINING WNP-2 C1E EQUIPMENT OUTSIDE THE REACTOR BUILDING

Vital Area Description	Radiation Level[a] Direct Gamma Shine +Airborne Gamma (rads)
Control room (el. 501 ft)	0.21
Technical support center	0.21
Sale area (el. 487 ft)	6.5
Nitrogen supply to ADS accumulators (el. 437 ft)	3.9
Standby service water pump valves	1.7
Remote shutdown room (el. 467 ft)	3.9
Switchgear room 1 (el. 467 ft)	3.9
Switchgear room 2 (el. 467 ft)	3.9
Radwaste control room (el. 467 ft)	3.9
Battery racks, direct current battery chargers two motor control centers (MCCs) (el. 467 ft)	3.9
Three MCCs and three switchgears (el. 437 ft)	3.9
Direct current battery charger and rack (el. 437 ft)	3.9
Diesel oil tanks (el. 437 ft)	3.9
Solid radwaste control panel and decontamination station control panel (el. 437 ft)	3.9

[a] Volume correction factors for a semi-infinite cloud were applied to the control room and technical support center. If the volume correction factors were to be applied to all areas, the integrated dose would be reduced by a minimum of fivefold.

TABLE J.6-2

WNP-2 VITAL AREAS AND ACCESS ROUTE LIST OF RADIATION EXPOSURE TO PERSONNEL DURING THE REQUIRED POST-LOSS-OF-COOLANT ACCIDENT OPERATIONS

Vital Area Description	Radiation Exposure		
	Gamma Whole Body (rem)	Thyroids (rem)[a]	Beta Skin (rads)
Control room (el. 501 ft)[b]	0.21	0.21[c]	0.95
Technical support center[b]	0.21	0.21[c]	0.95
Security center[b]	3.1	13.4[d]	4.8
Auxiliary security center[b]	1.7		2.7
Sample analysis area (EOC)[b]	0.0013	-	-
Standby service water pump valves (cooling ponds)[e]	0.3	0.94[d]	0.46
All infrequently occupied vital areas inside the radwaste and diesel generator buildings[b]	0.13[f]	1.6[d]	0.48
Sampler for elevated release duct (roof turbine building)[e]	2.5	8.0[d]	3.8
Reactor building railroad bay (N_2 bottles)[g]	0.4	-	-
Reactor building 522-ft el. (SW-V-75AA and/or SW-V-75BB[h]	4.00	-	-
Postaccident sample area (el. 487 ft)[e]	0.36	3.2[d]	0.96
Access Routes			
All access routes inside the radwaste and diesel generator buildings[e]	0.13[f]	1.6[d]	0.48
All access routes[i] outside the radwaste and diesel generator buildings[e]	0.53	1.6[d]	0.8

TABLE J.6-2

WNP-2 VITAL AREAS AND ACCESS ROUTE LIST OF RADIATION EXPOSURE TO PERSONNEL DURING THE REQUIRED POST-LOSS-OF-COOLANT ACCIDENT OPERATIONS (Continued)

[a] If self-contained respiratory equipment (SCBA) is used, the thyroid dose will essentially equal the whole-body dose.

[b] Area of continuous occupancy.

[c] Assumes self-contained respiratory equipment was used by personnel during 0-3 hr post-LOCA situation.

[d] No respiratory equipment was assumed.

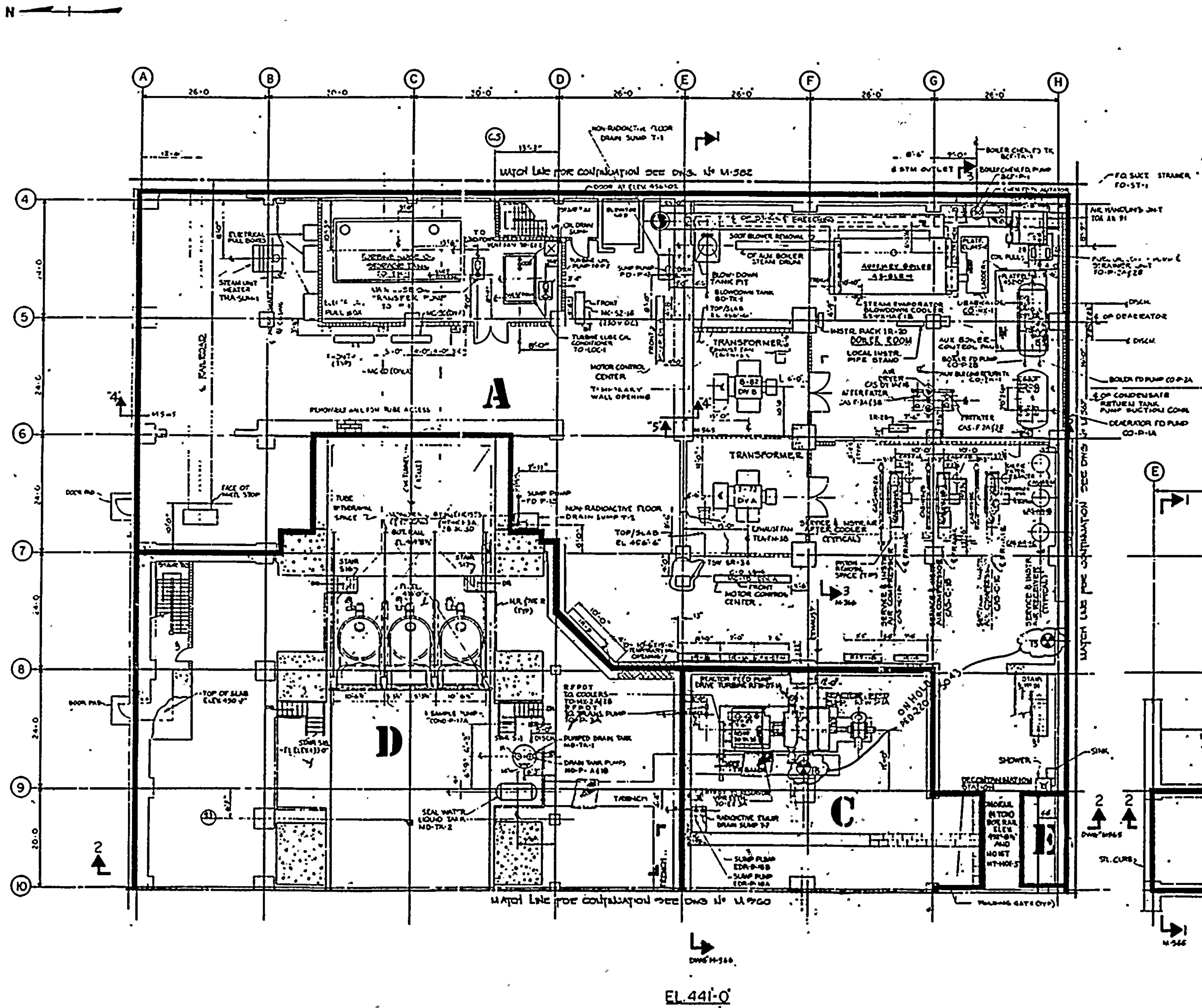
[e] Area occupied 0.5 hr at times after 1 hr into the LOCA.

[f] A volume correction factor for the semi-infinite cloud was included in the calculation.

[g] Assumes entry after 12 days post-LOCA for 3-hr occupancy with respiratory equipment for railroad bay portion of reactor building <u>only</u>.

[h] Assumes entry after 9.0 hr post-LOCA for a 2.17-minute evolution to open SW-V-75AA or SW-V-75BB with respiratory equipment and in full PC gear following access routes shown in Figures J.6-20 and J.6-21. The 2.17 minutes consists of a 1.83-minute transit (1.5 minutes in 522K and 0.33 minutes in 522H) and a 0.33-minute occupancy time in 522H.

[i] Extremely conservative analysis since the plume of airborne radioactivity cannot simultaneously cover all access routes.

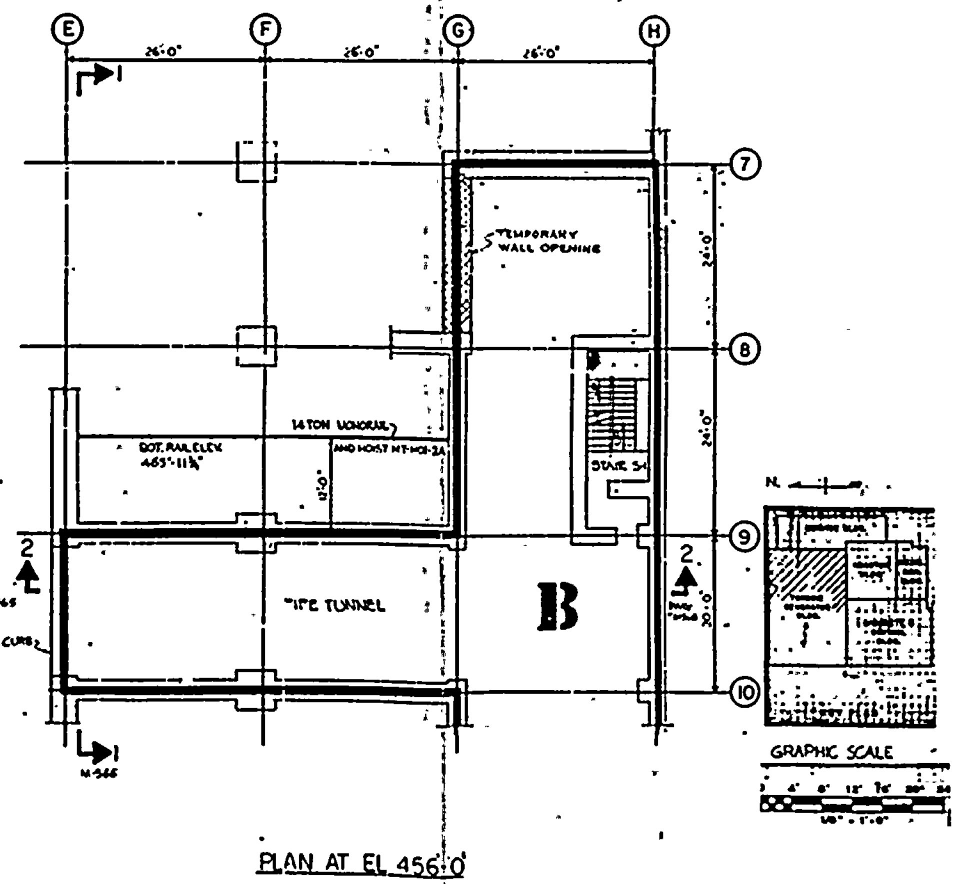


FORTY YEARS NORMAL OPERATION INTEG. DOSE*	
ZONE A	8.8×10^2
ZONE B	3.6×10^5
ZONE C	3.1×10^5
ZONE D	8.3×10^5
ZONE E	5.3×10^3

*VALUES ARE WORST CASE SURFACE DOSES FOR THE ZONES INDICATED

ON HOLD PED-220-I-5043

NOTE: RADIATION AREA DETECTORS MARKED THUS ⊗ DEFINES LOCATION & STATION NO. OF ONE (1) SET OF SENSOR, AUX. UNIT & AUDIO ALARM. FOR LOCATION & SCHEDULE SEE DWG M832 SH...

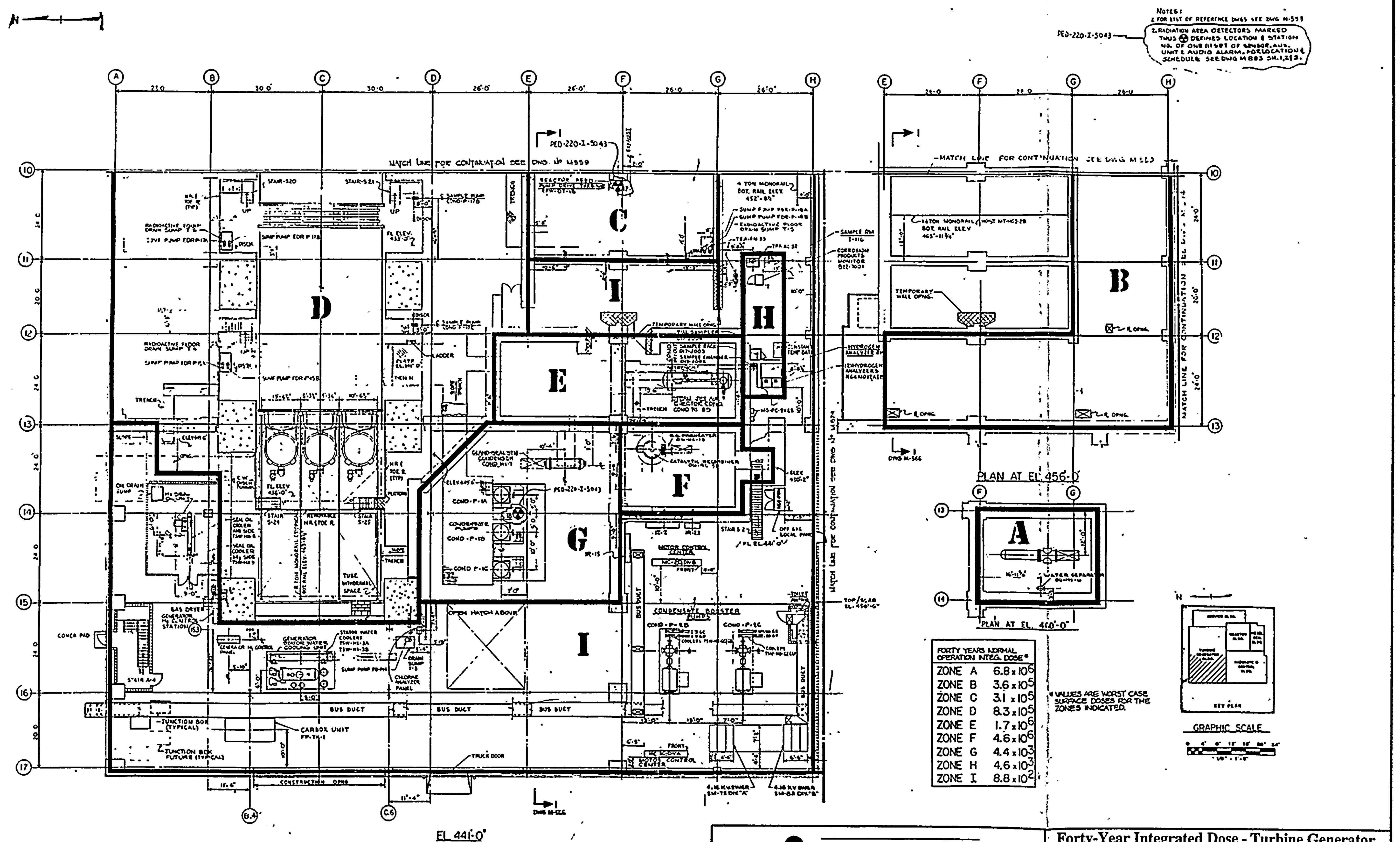


WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Turbine Generator Building (El. 441 ft 0 in.)

Draw. No.	Rev.	Figure	J.6-1.1

Form No. 960690



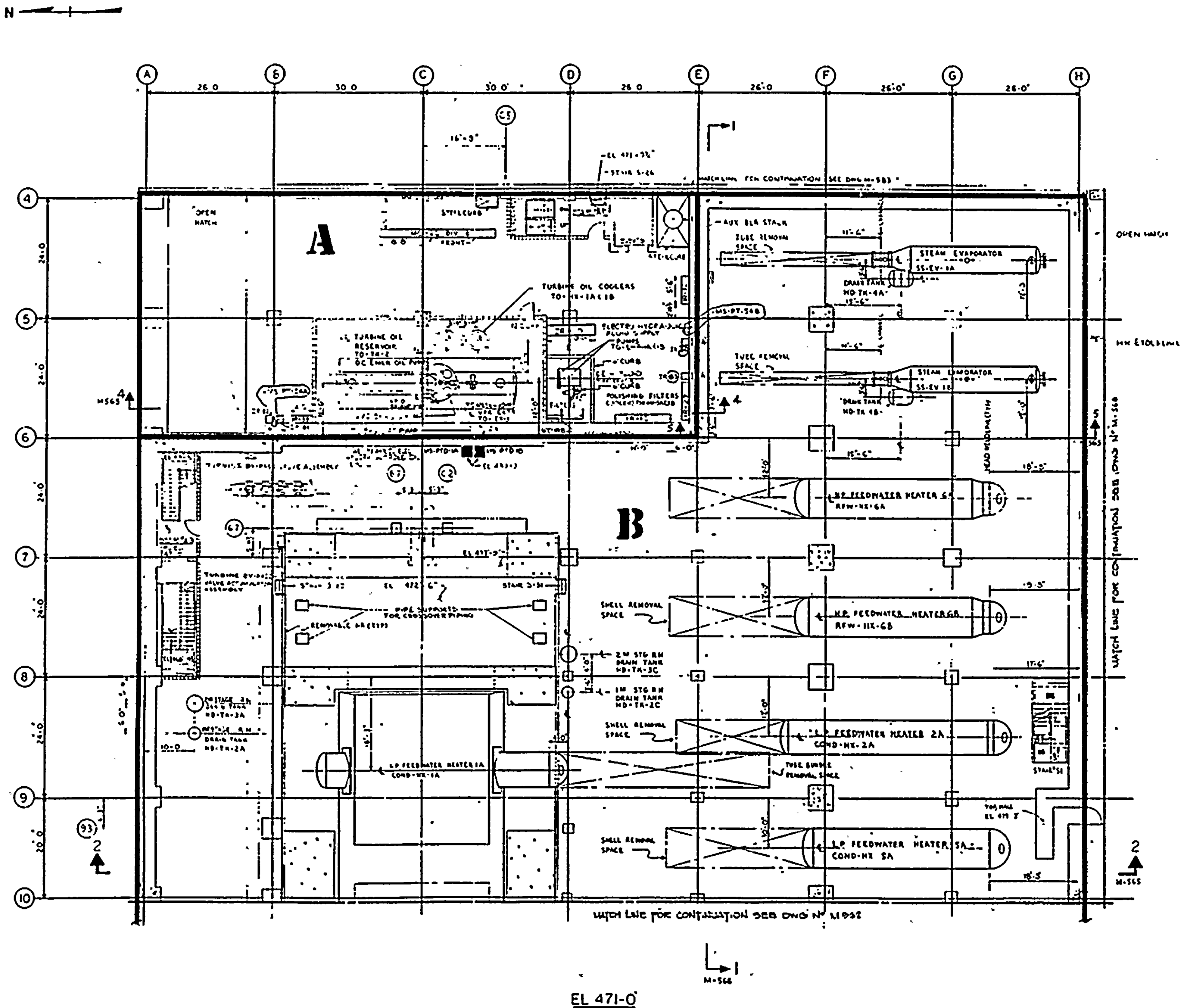
FORTY YEARS NORMAL OPERATION INTEG. DOSE*	
ZONE A	6.8×10^6
ZONE B	3.6×10^5
ZONE C	3.1×10^5
ZONE D	8.3×10^5
ZONE E	1.7×10^6
ZONE F	4.6×10^6
ZONE G	4.4×10^3
ZONE H	4.6×10^3
ZONE I	8.8×10^2

* VALUES ARE WORST CASE SURFACE DOSES FOR THE ZONES INDICATED.

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

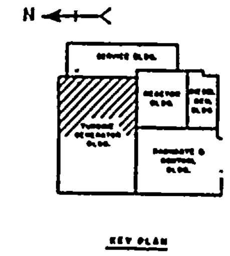
Forty-Year Integrated Dose - Turbine Generator Building (El. 441 ft 0 in.)

Draw. No.	Rev.	Figure J.6-1.2



FORTY YEARS NORMAL OPERATION INTEG. DOSE*	
ZONE A	8.8×10^2
ZONE B	1.2×10^6

* VALUES ARE WORST CASE SURFACE DOSES FOR THE ZONES INDICATED.

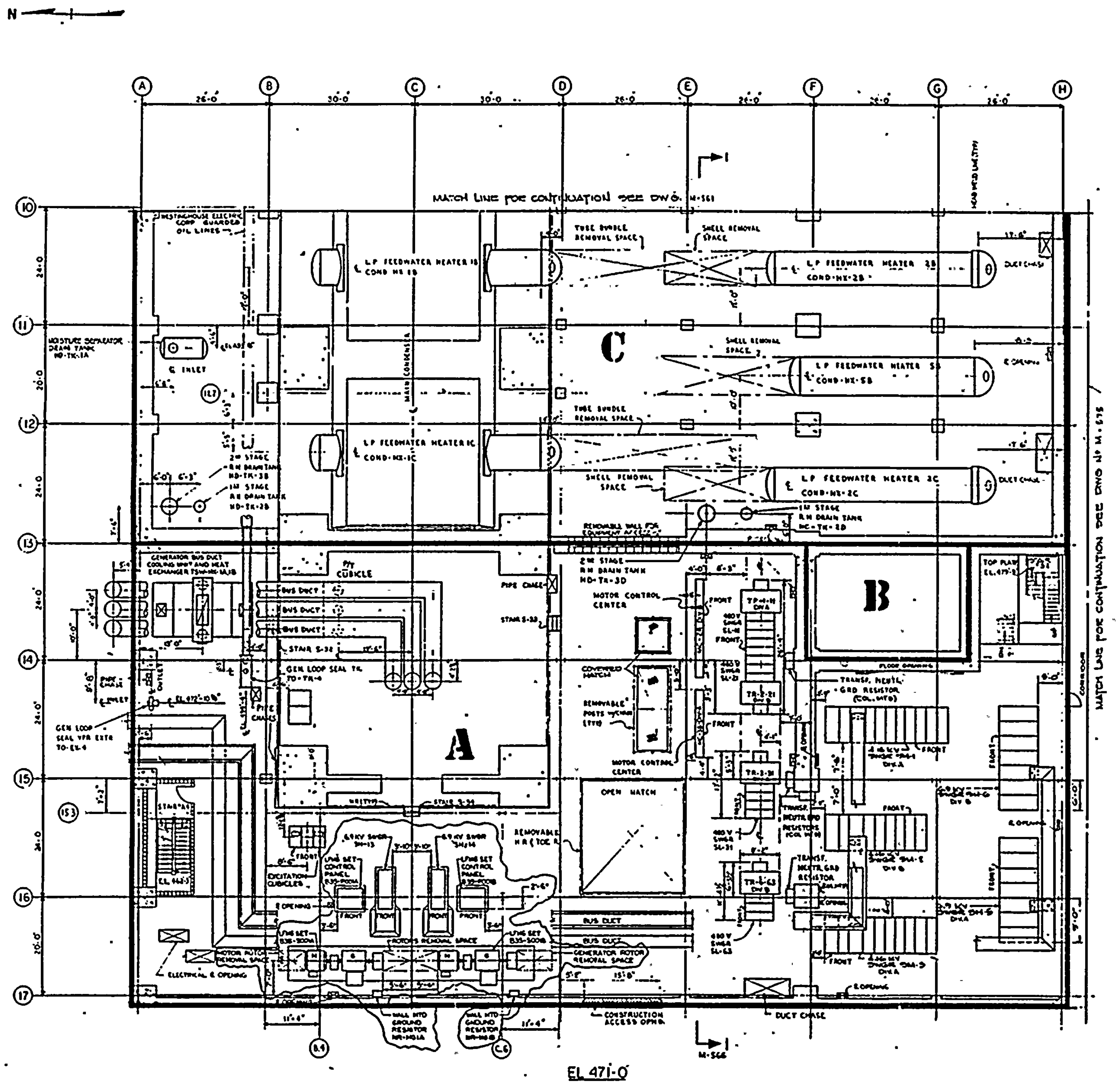


WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Turbine Generator Building (El. 471 ft 0 in.)

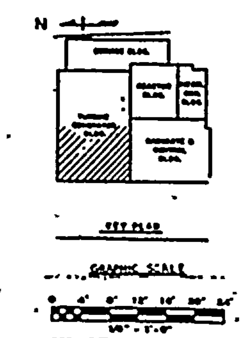
Draw. No.	Rev.	Figure J.6-2.1

NOTE:
FOR LIST OF REFERENCE DWGS SEE DWG NO M-559



FORTY YEARS NORMAL OPERATION INTEG. DOSE*	
ZONE A	8.8×10^2
ZONE B	4.6×10^6
ZONE C	1.2×10^6

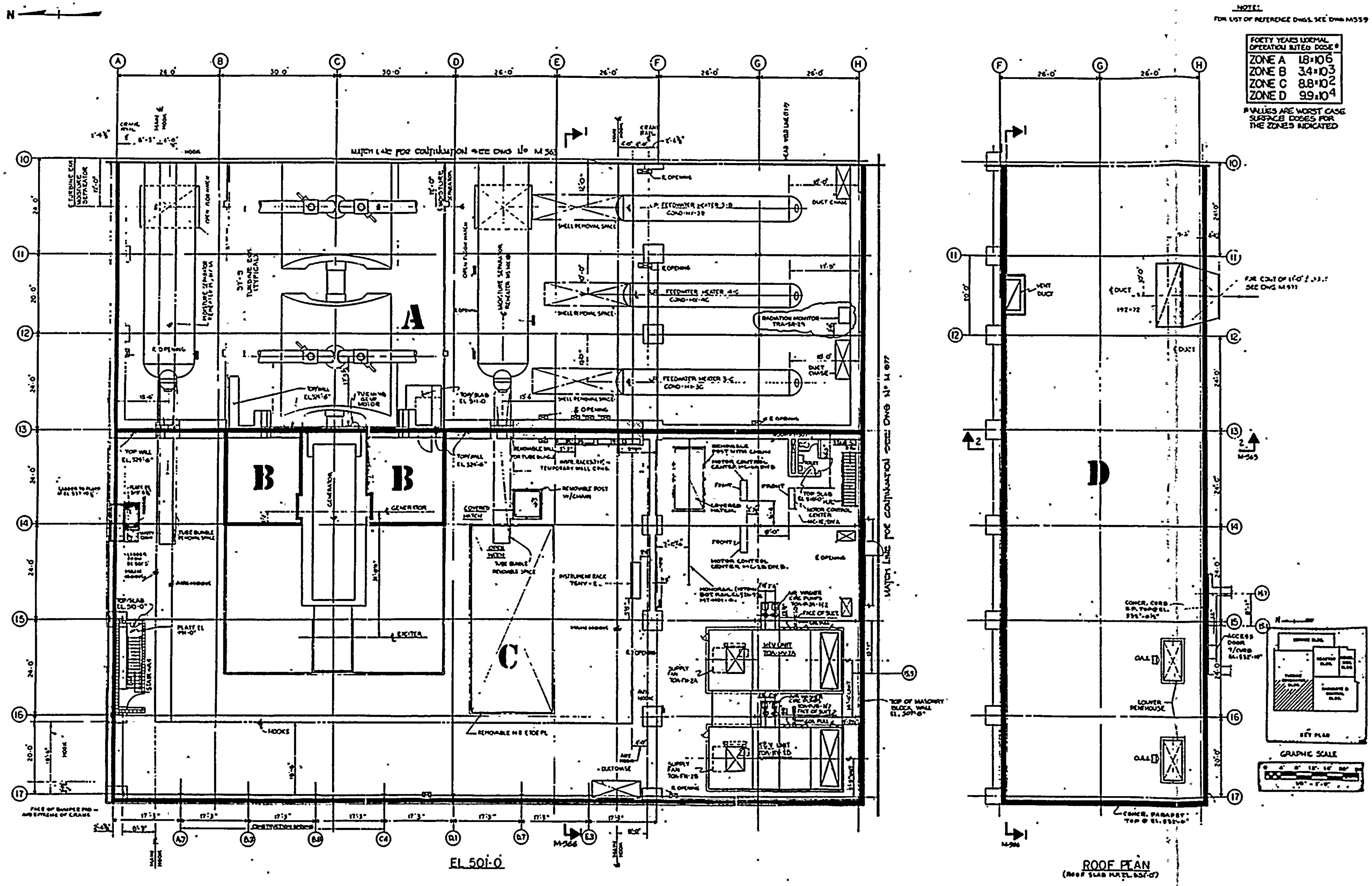
* VALUES ARE WORST CASE SURFACE DOSES FOR THE ZONES INDICATED.



WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Turbine Generator Building (El. 471 ft 0 in.)

Draw. No.	Rev.	Figure	J.6-2.2



NOTE:
FOR LIST OF REFERENCE DWGS. SEE DWG M559

FORTY YEARS NORMAL OPERATION INTEG DOSE*	
ZONE A	1.8×10^{6}
ZONE B	3.4×10^{3}
ZONE C	8.8×10^{2}
ZONE D	9.9×10^{4}

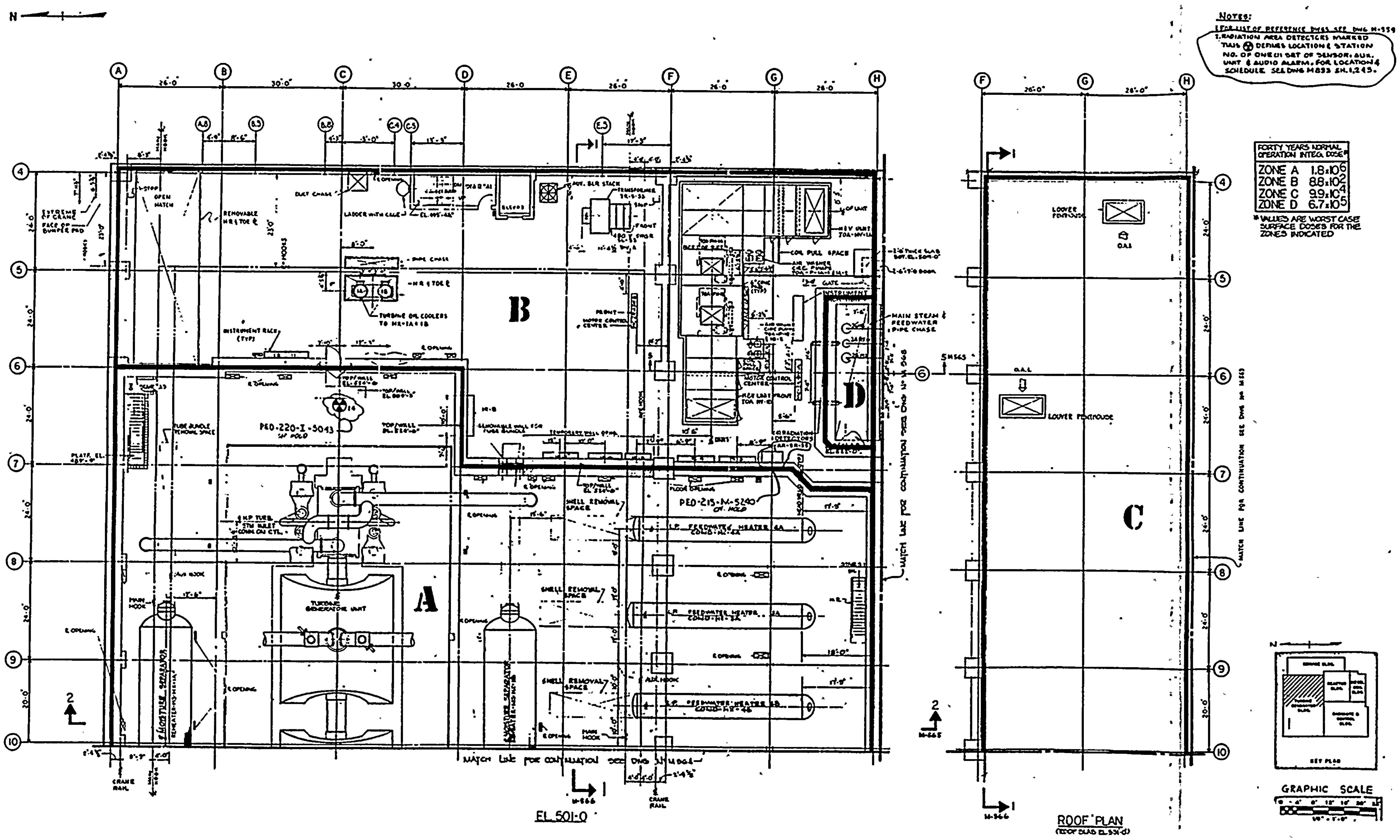
*VALUES ARE WORST CASE SURFACE DOSES FOR THE ZONES INDICATED

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Turbine Generator Building (El. 501 ft 0 in.)

Draw. No.	Rev.	Figure	J.6-3.1

Form No. 960690

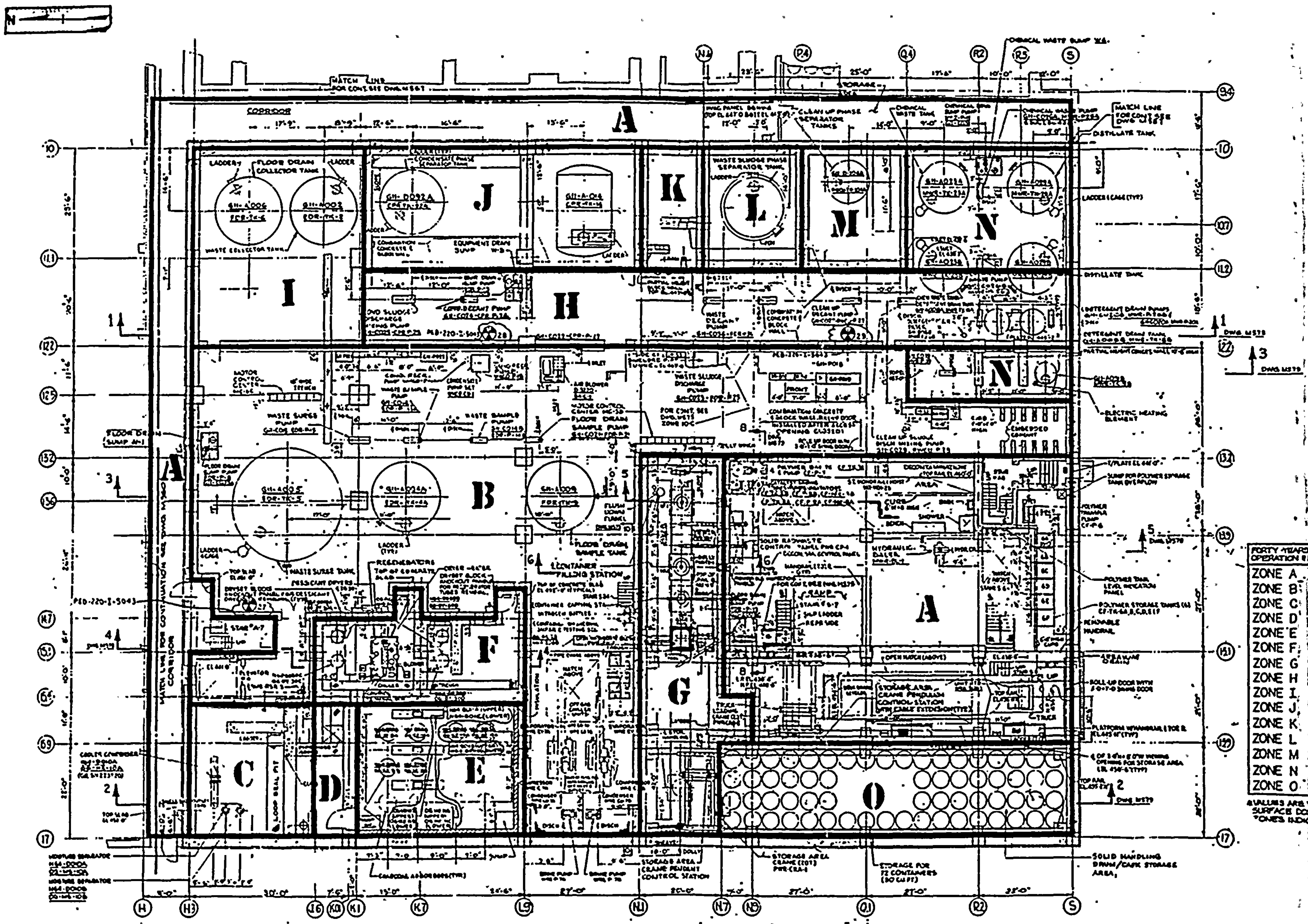


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Turbine Generator Building (El. 501 ft 0 in.)

Draw. No.	Rev.	Figure	J.6-3.2

Form No. 960690



NOTE:
1. RADIATION AREA DETECTORS MARKED THUS ● DEFINES LOCATIONS STATION NO. OF ONE (1) SET OF SENSOR, AUX. UNIT & AUDIO ALARM. FOR LOCATION & SCHEDULE SEE DWG M403 SH.1,2&3.

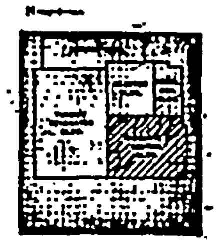
PED-220-I-5043

REFERENCE DRAWINGS

1. M560 - GENERAL ARRANGEMENT - GROUND FLOOR PLAN - TURBINE GENERATOR BUILDING.
2. M562 - GENERAL ARRANGEMENT - MEZZANINE FLOOR PLAN - TURBINE GENERATOR BUILDING.
3. M564 - GENERAL ARRANGEMENT - OPERATING FLOOR PLAN - TURBINE GENERATOR BUILDING.
4. M567 - GENERAL ARRANGEMENT - PLAN EL. 422'3" EL. 441'0" & EL. 444'0" REACTOR BUILDING.
5. M568 - GENERAL ARRANGEMENT - PLAN EL. 471'0" & EL. 501'0" REACTOR BUILDING.
6. M569 - GENERAL ARRANGEMENT - PLANS EL. 522'0" & EL. 548'0" REACTOR BUILDING.
7. M575 - GENERAL ARRANGEMENT - EL. 437'0" & PARTIAL PLANS - RADWASTE BUILDING.
8. M576 - GENERAL ARRANGEMENT - EL. 484'0" EL. 467'0" & PARTIAL PLANS - RADWASTE BUILDING.
9. M577 - GENERAL ARRANGEMENT - EL. 501'0" 507'0" & 525'0" - RADWASTE BUILDING
10. M578 - GENERAL ARRANGEMENT - SECTIONS - RADWASTE BLDG.
11. M579 - GENERAL ARRANGEMENT - SECTIONS - RADWASTE BLDG.
12. M587 - GENERAL ARRANGEMENT - PLAN & SECTION DIESEL GENERATOR BLDG.
13. E775 - CONTROL ROOM ARRANGEMENT - EL. 501'0" - RADWASTE BUILDING
14. A581 - LABORATORY LAYOUT
15. A548 - PLANS - TOILETS & LOCKER ROOMS

FORTY YEARS NORMAL OPERATION INTEG. DOSE*	
ZONE A	8.8×10^2
ZONE B	5.3×10^3
ZONE C	3.4×10^5
ZONE D	1.2×10^6
ZONE E	9.5×10^9
ZONE F	8.0×10^6
ZONE G	1.6×10^6
ZONE H	8.5×10^5
ZONE I	7.0×10^6
ZONE J	1.8×10^6
ZONE K	2.4×10^6
ZONE L	2.1×10^6
ZONE M	1.5×10^7
ZONE N	3.5×10^4
ZONE O	5.3×10^8

*VALUES ARE WORST CASE SURFACE DOSES FOR THE ZONES INDICATED

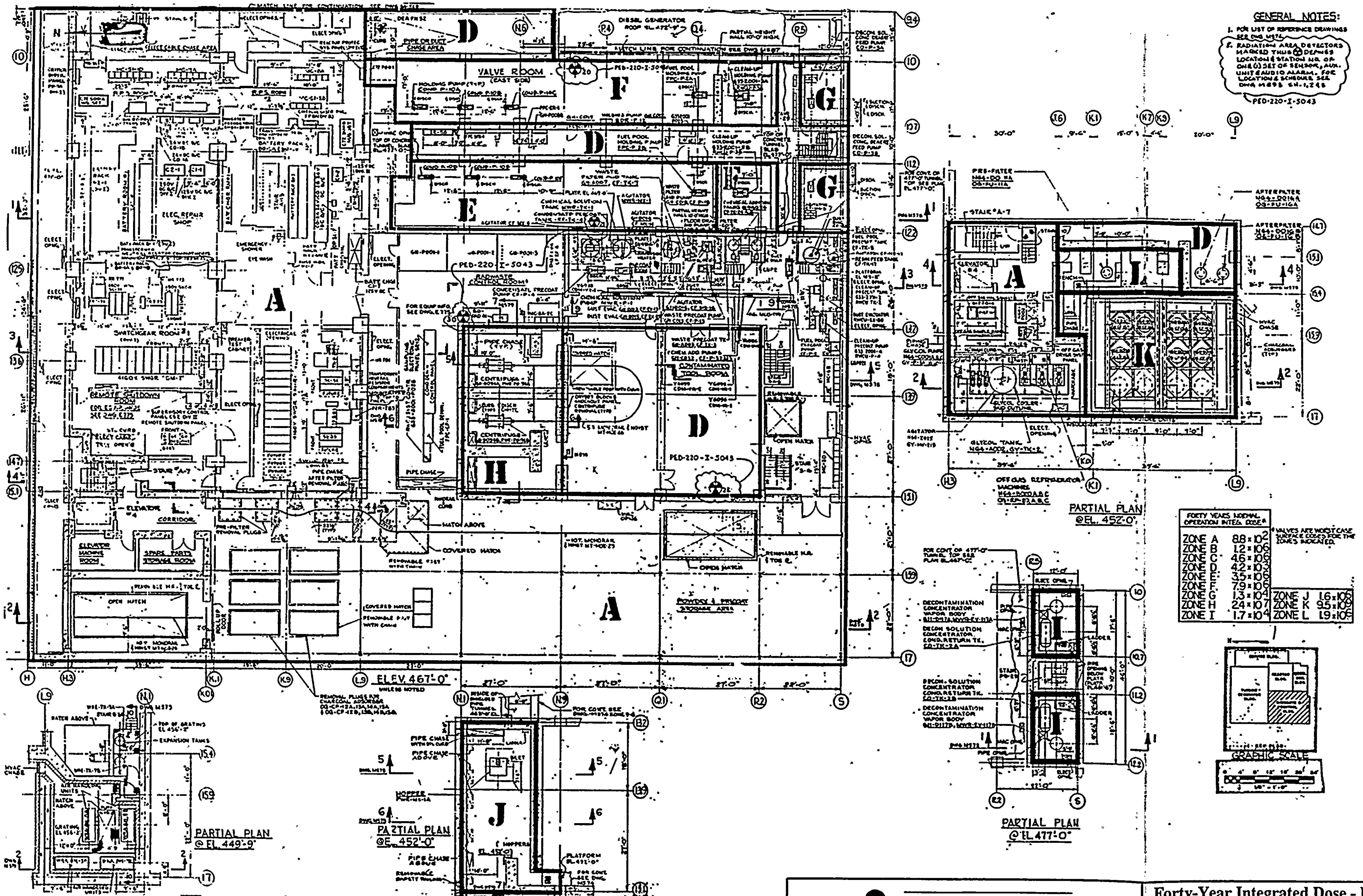


GRAPHIC SCALE

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Radwaste Building (El. 437 ft 0 in.)

Draw. No. | Rev. | Figure J.6-4



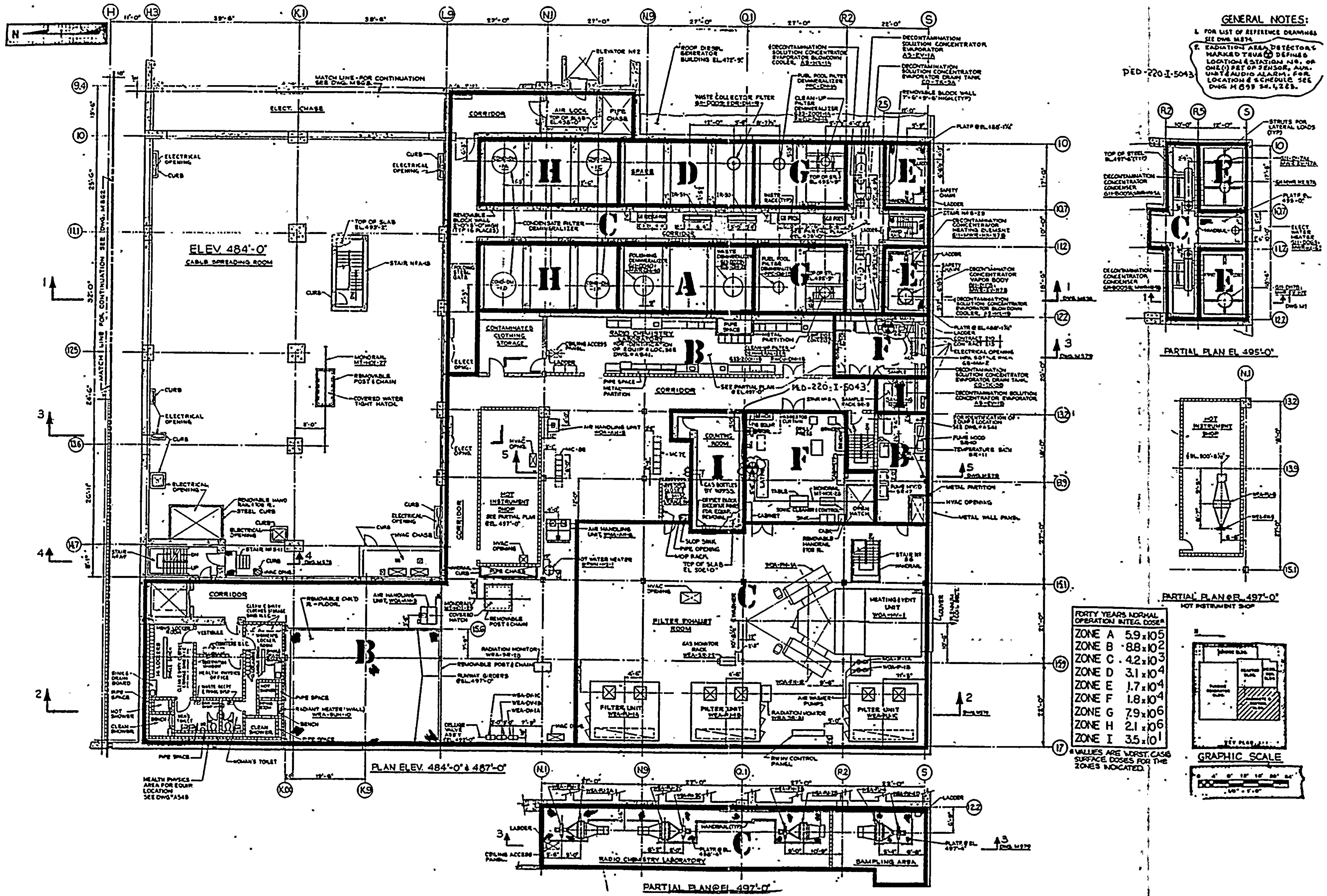
FORTY YEARS NORMAL OPERATION INTEG. DOSE*			
ZONE A	8.8 × 10^2	ZONE J	1.6 × 10^8
ZONE B	1.2 × 10^6	ZONE K	9.5 × 10^9
ZONE C	4.6 × 10^6	ZONE L	1.9 × 10^6
ZONE D	4.2 × 10^3		
ZONE E	3.5 × 10^6		
ZONE F	7.9 × 10^6		
ZONE G	1.3 × 10^4		
ZONE H	2.4 × 10^7		
ZONE I	1.7 × 10^4		

WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Radwaste Building (El. 467 ft 0 in.)

Draw. No. | Rev. | Figure J.6-5

Form No. 960690



FORTY YEARS NORMAL OPERATION INTEG. DOSE*	
ZONE A	5.9×10^5
ZONE B	8.8×10^2
ZONE C	4.2×10^3
ZONE D	3.1×10^4
ZONE E	1.7×10^4
ZONE F	1.8×10^4
ZONE G	7.9×10^6
ZONE H	2.1×10^6
ZONE I	3.5×10^1

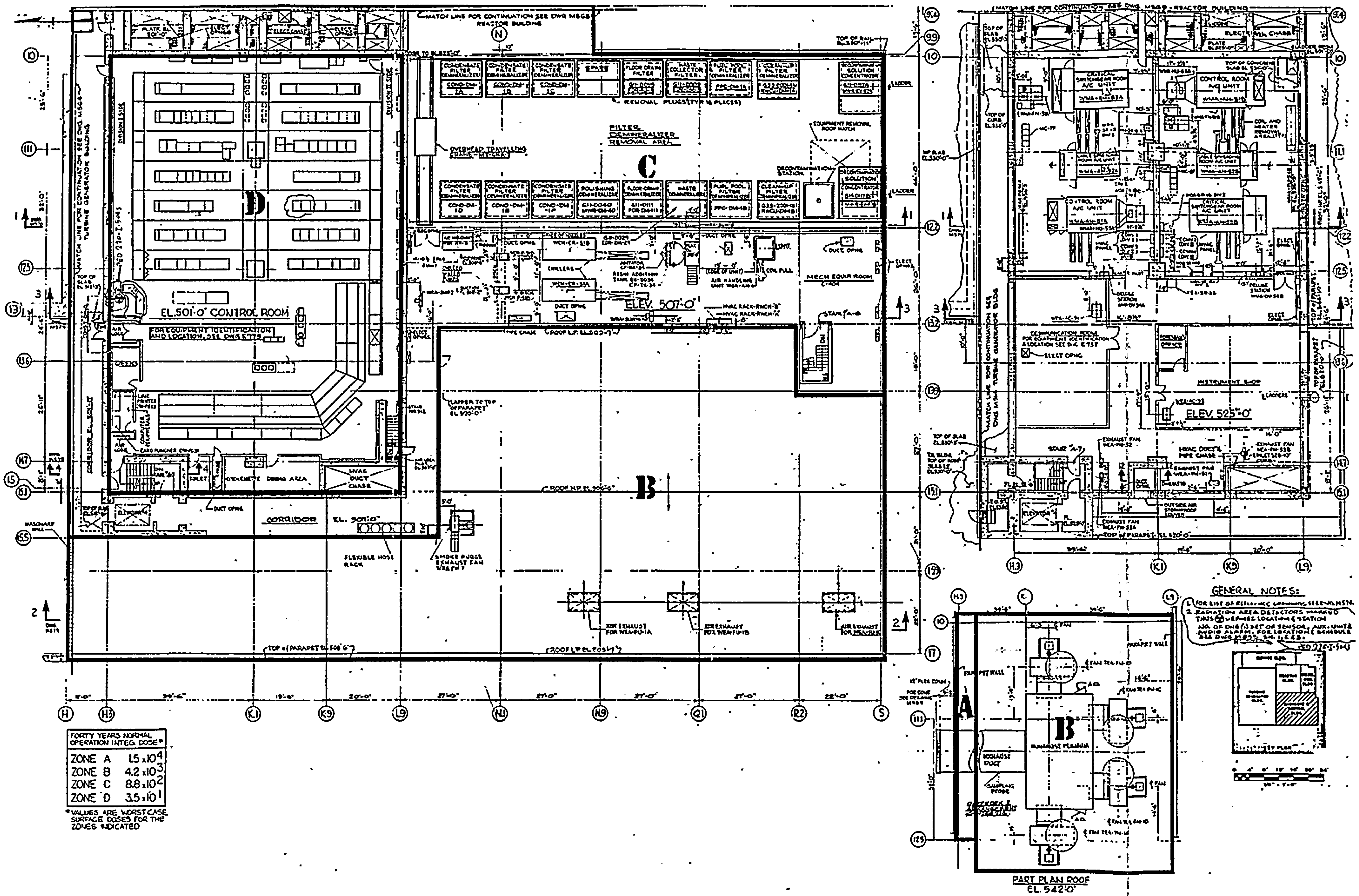
*VALUES ARE WORST CASE SURFACE DOSES FOR THE ZONES INDICATED.

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Radwaste Building (El. 484 ft 0 in.)

Draw. No.	Rev.	Figure	J.6-6

Form No. 960690



FORTY YEARS NORMAL OPERATION INTEG. DOSE*	
ZONE A	1.5×10^4
ZONE B	4.2×10^3
ZONE C	8.8×10^2
ZONE D	3.5×10^1

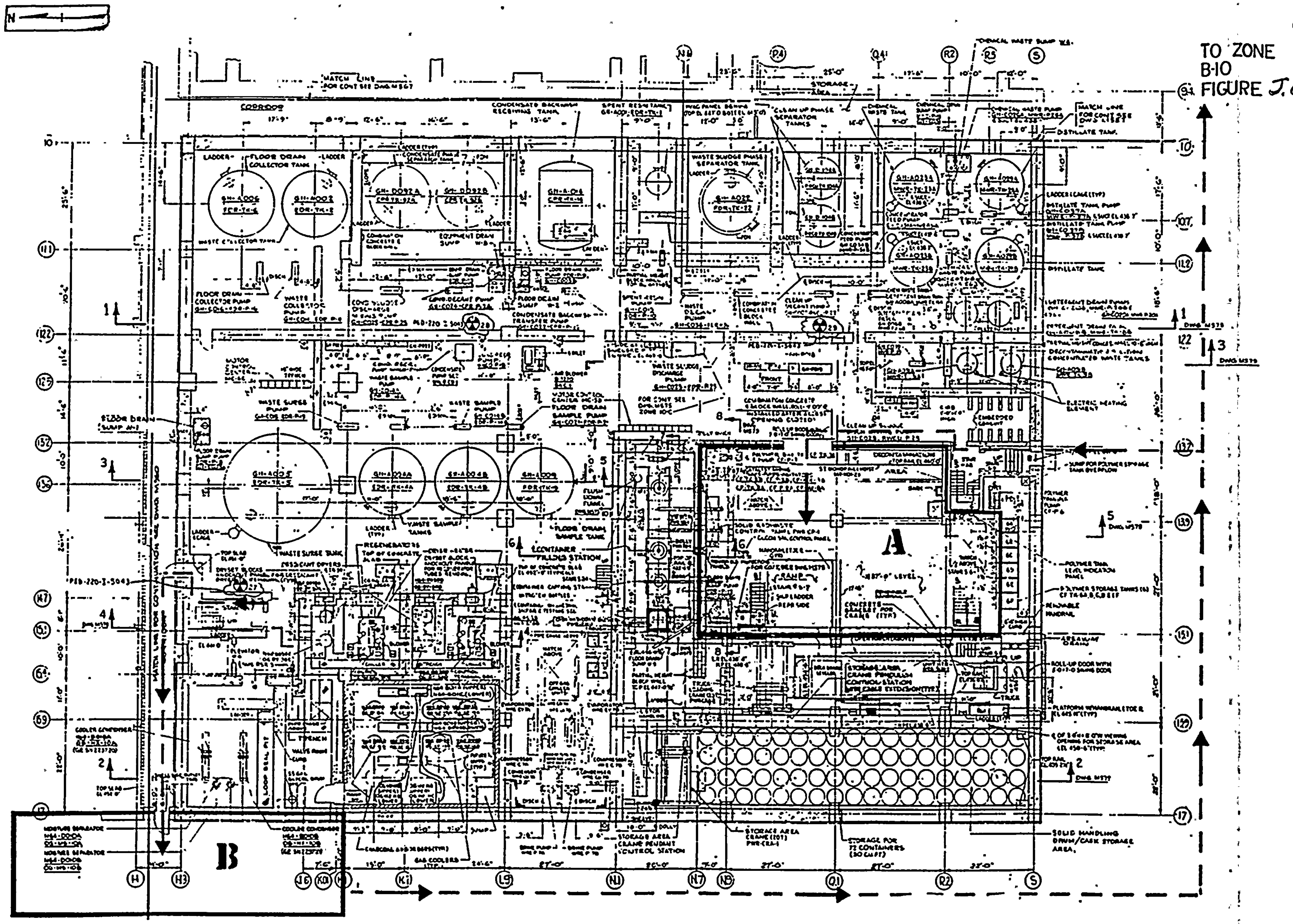
*VALUES ARE WORST CASE SURFACE DOSES FOR THE ZONES INDICATED

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Forty-Year Integrated Dose - Radwaste Building
(El. 501 ft 0 in.)

Draw. No.	Rev.	Figure J.6-7

Amendment 53
November 1998



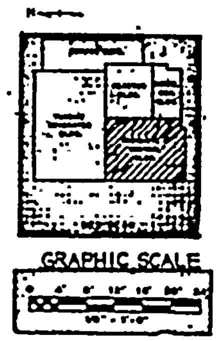
REFERENCE DRAWINGS

1. M560 - GENERAL ARRANGEMENT - GROUND FLOOR PLAN - TURBINE GENERATOR BUILDING.
2. M562 - GENERAL ARRANGEMENT - MEZZANINE FLOOR PLAN - TURBINE GENERATOR BUILDING.
3. M564 - GENERAL ARRANGEMENT - OPERATING FLOOR PLAN - TURBINE GENERATOR BUILDING.
4. M567 - GENERAL ARRANGEMENT - PLAN EL. 422'3", EL. 441'0" & EL. 444'0" REACTOR BUILDING.
5. M568 - GENERAL ARRANGEMENT - PLAN EL. 471'0" & EL. 501'0" REACTOR BUILDING.
6. M569 - GENERAL ARRANGEMENT - PLANS EL. 522'0" & EL. 548'0" REACTOR BUILDING.
7. M575 - GENERAL ARRANGEMENT - EL. 437'0" & PARTIAL PLANS - RADWASTE BUILDING.
8. M576 - GENERAL ARRANGEMENT - EL. 484'0" EL. 467'0" & PARTIAL PLANS - RADWASTE BUILDING.
9. M577 - GENERAL ARRANGEMENT - EL. 507'0" 507'0" & 525'0" RADWASTE BUILDING.
10. M578 - GENERAL ARRANGEMENT - SECTIONS - RADWASTE BLDG.
11. M579 - GENERAL ARRANGEMENT - SECTIONS - RADWASTE BLDG.
12. M587 - GENERAL ARRANGEMENT - PLAN & SECTION DIESEL GENERATOR BLDG.
13. E775 - CONTROL ROOM ARRANGEMENT - EL. 507'0" - RADWASTE BUILDING.
14. A541 - LABORATORY LAYOUTS
15. A548 - PLANS - TOILETS & LOCKER ROOMS

RADIATION ZONES FOR OCCUPANCY AND ACCESS DURING POST-ACCIDENT OPERATION*
ZONE A SOLID RADWASTE CONTROL PANEL AND DECONTAMINATION STATION CONTROL PANEL, 3.9 RADS DOSE.
ZONE B TECHNICAL SUPPORT CENTER 0.21 RADS DOSE

*VALUES INDICATE WORST TARGET INTEGRATED DOSE AT 6 MONTHS FOR THE ZONES INDICATED

— — — — ACCESS ROUTE



GRAPHIC SCALE

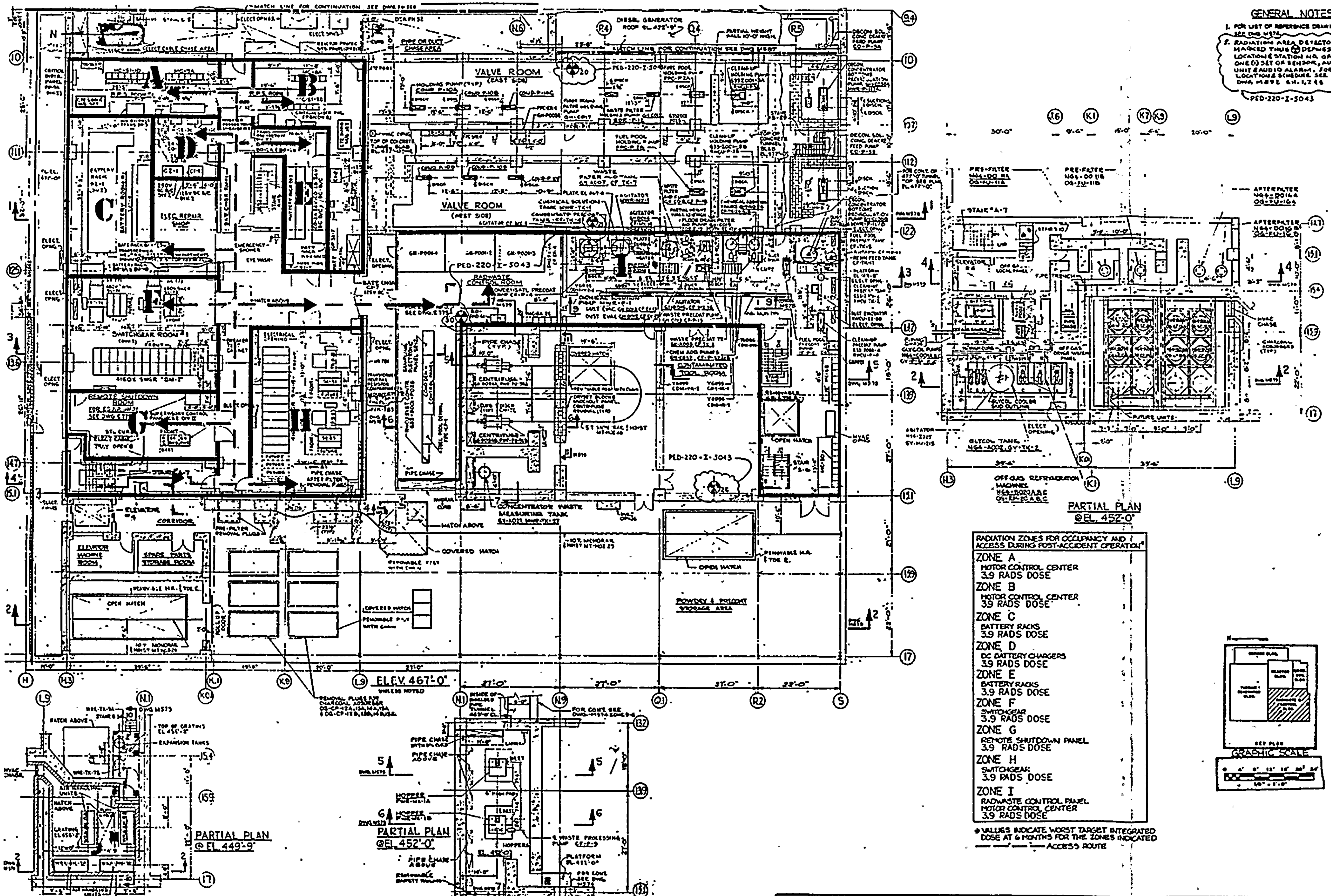
WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Areas and Access Routes - Radwaste Building (El. 437 ft 0 in.)

Draw. No.	Rev.	Figure J.6-8

Form No. 960690

Amendment 53
November 1998

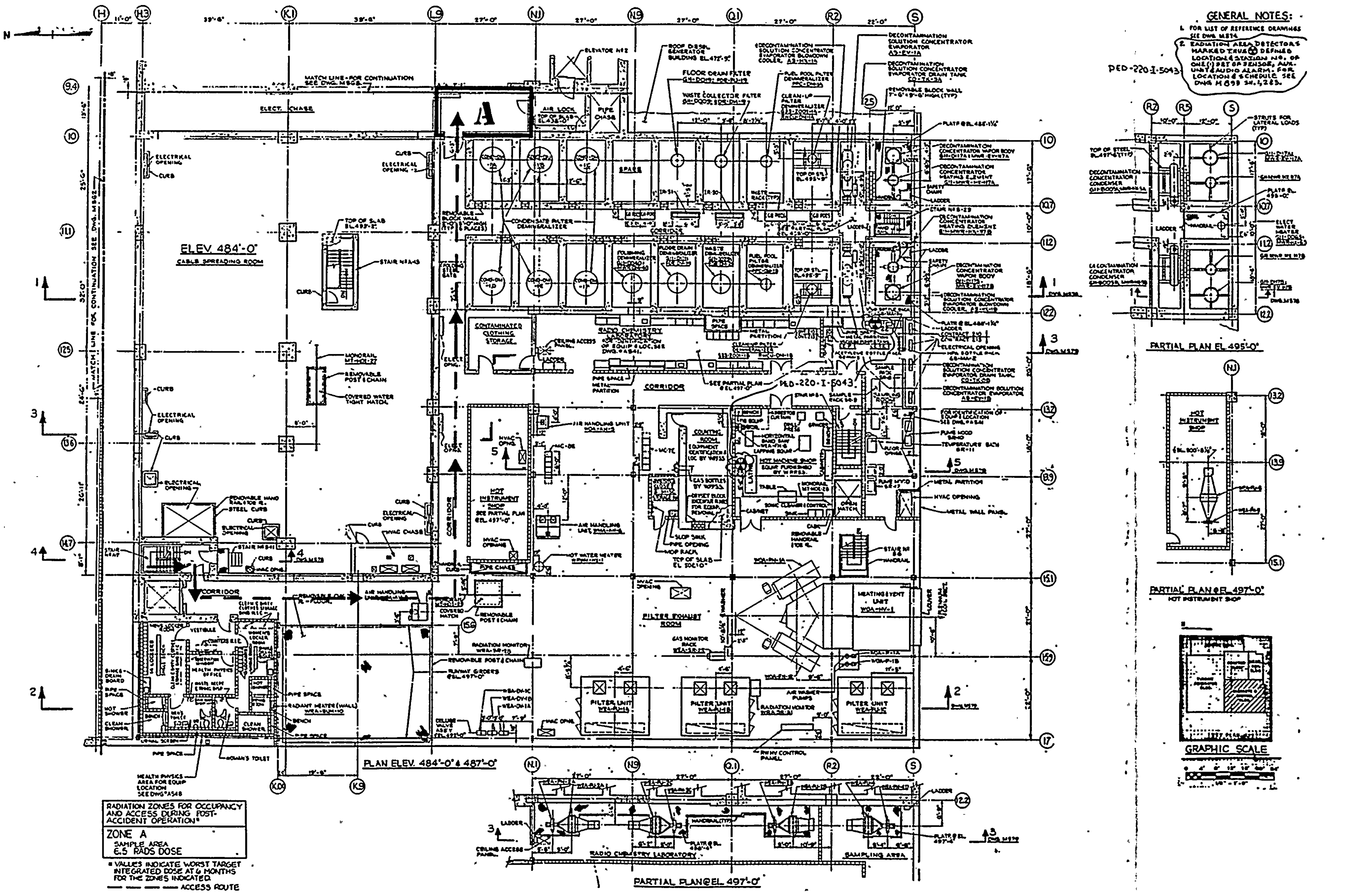


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Areas and Access Routes - Radwaste Building (El. 467 ft 0 in.)

Draw. No.	Rev.	Figure J.6-9

Form No. 960690

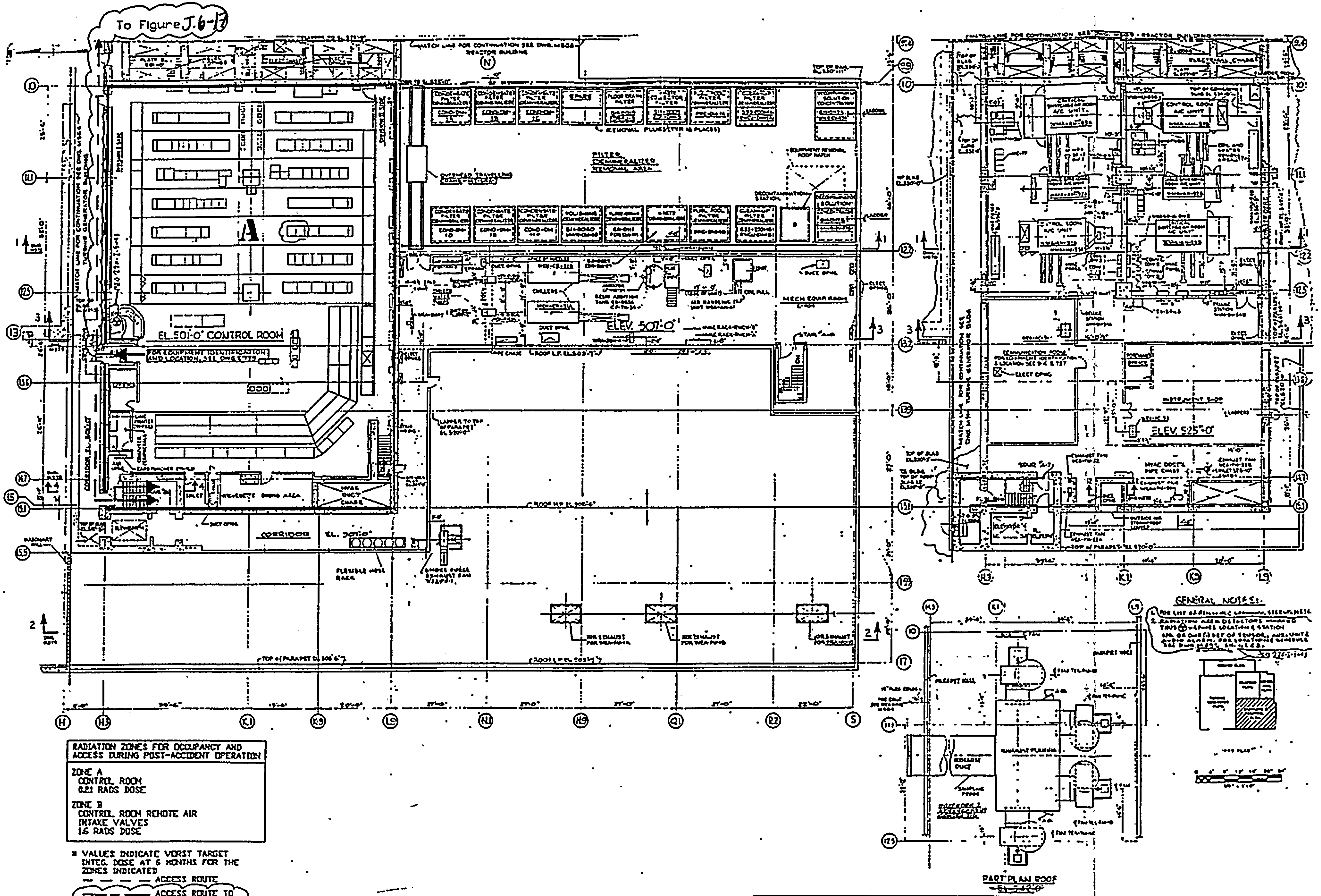


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Areas and Access Routes - Radwaste Building (El. 484 ft 0 in.)

Draw. No.	Rev.	Figure	J.6-10

Form No. 960690



RADIATION ZONES FOR OCCUPANCY AND ACCESS DURING POST-ACCIDENT OPERATION

ZONE A
CONTROL ROOM
0.21 RADS DOSE

ZONE B
CONTROL ROOM REMOTE AIR INTAKE VALVES
1.6 RADS DOSE

* VALUES INDICATE WORST TARGET INTEG. DOSE AT 6 MONTHS FOR THE ZONES INDICATED

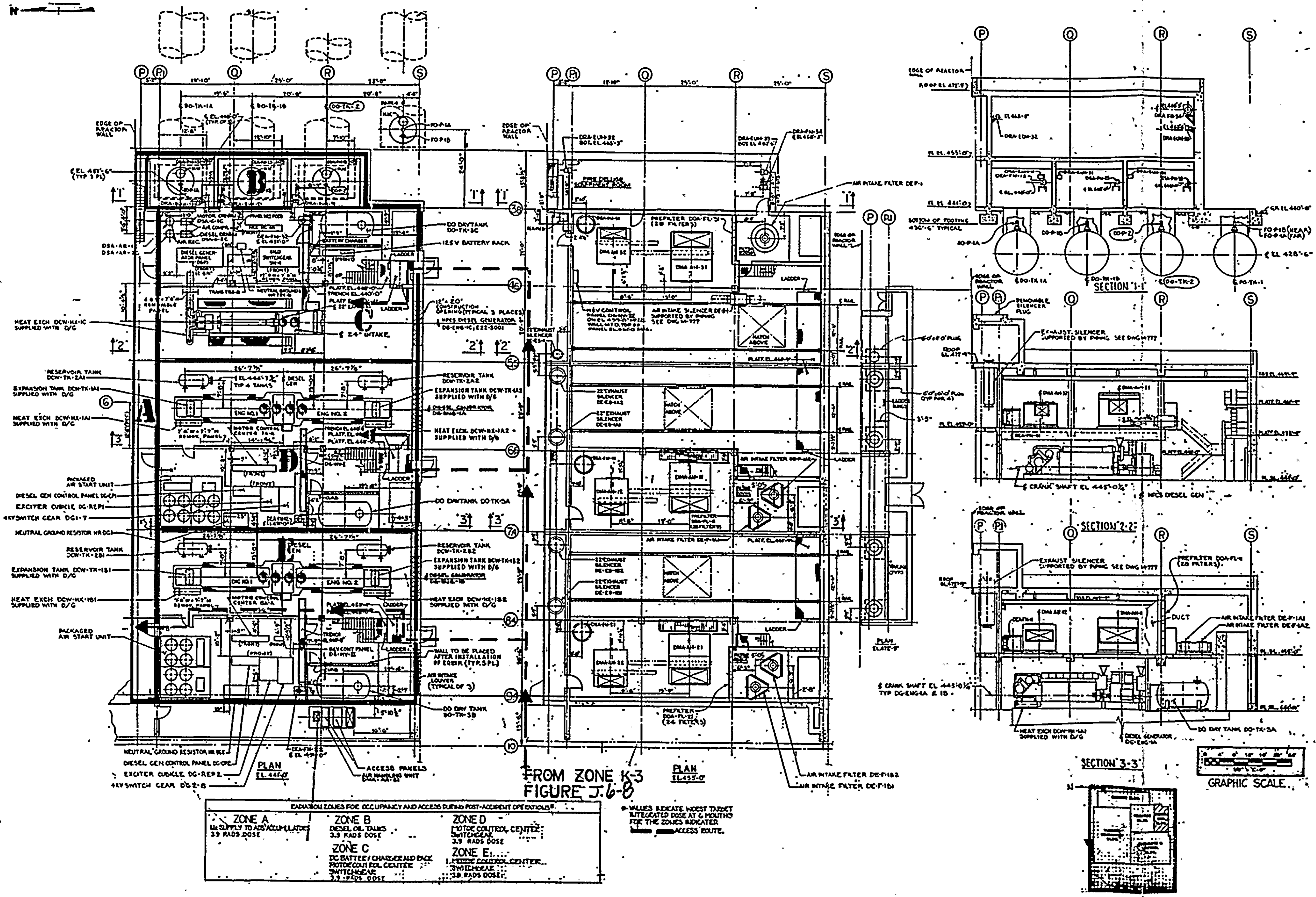
— — — — ACCESS ROUTE

— — — — ACCESS ROUTE TO SV-V-75AA AND SV-V-75BB. FSAR SECTION 1.2.2.11.3.

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Areas and Access Routes - Radwaste Building (El. 501 ft 0 in.)

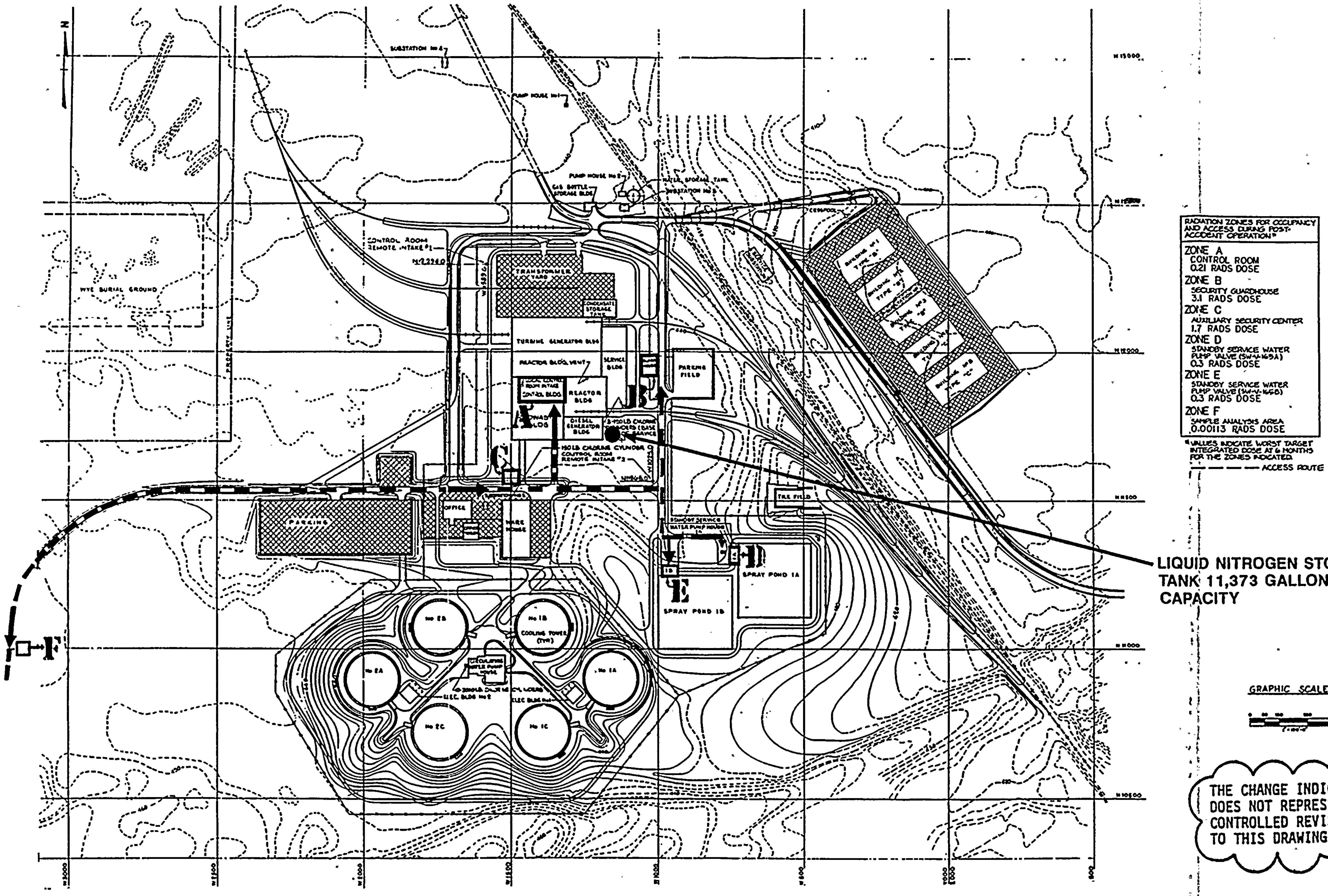
Draw. No.	Rev.	Figure	J.6-11



WASHINGTON PUBLIC POWER SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Areas and Access Routes - Diesel Generator Building (El. 441 ft 0 in.)

Draw. No.	Rev.	Figure	J.6-12

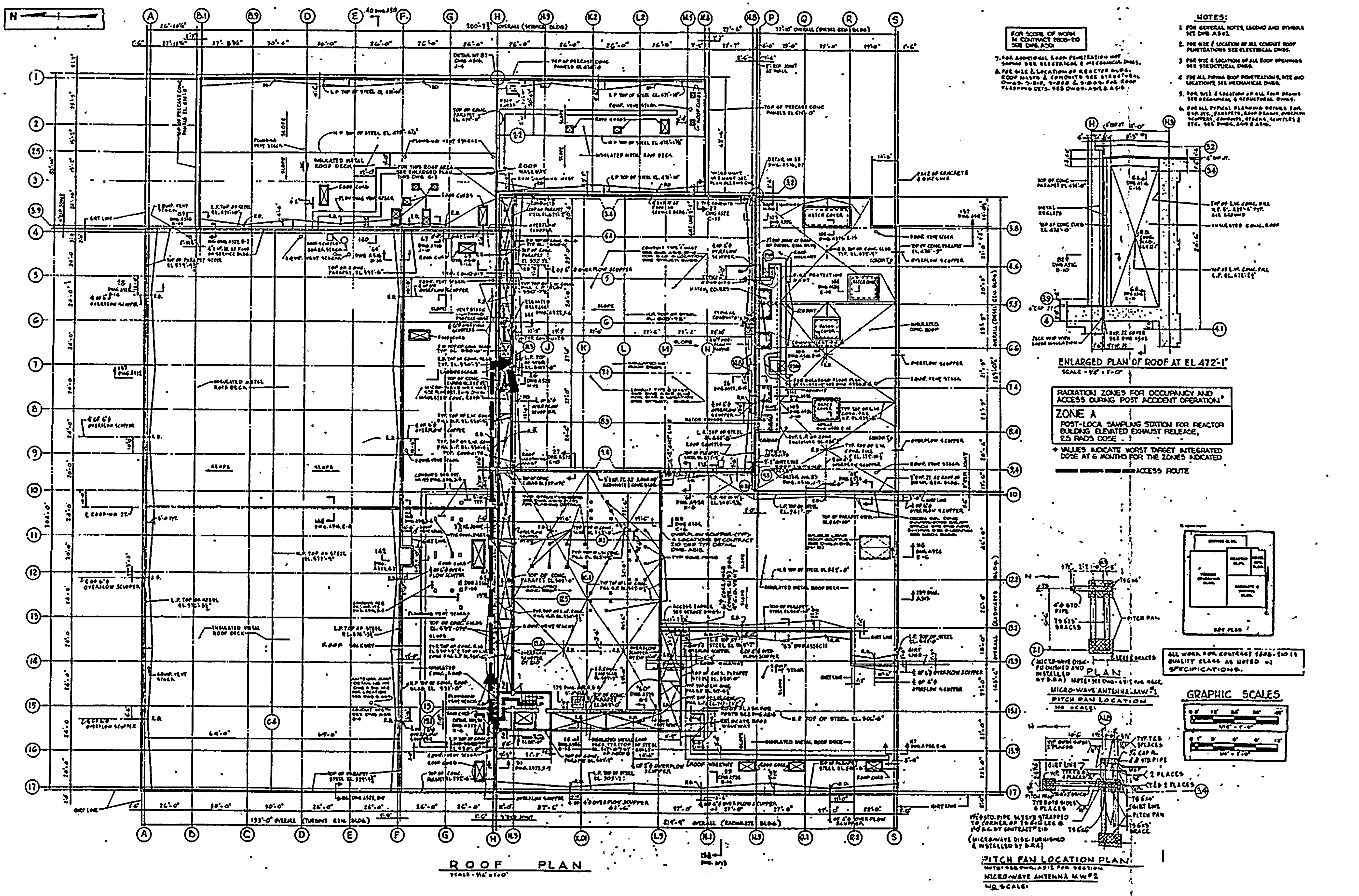


THE CHANGE INDICATED DOES NOT REPRESENT A CONTROLLED REVISION TO THIS DRAWING.

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Areas and Access Routes - WNP-2 Site

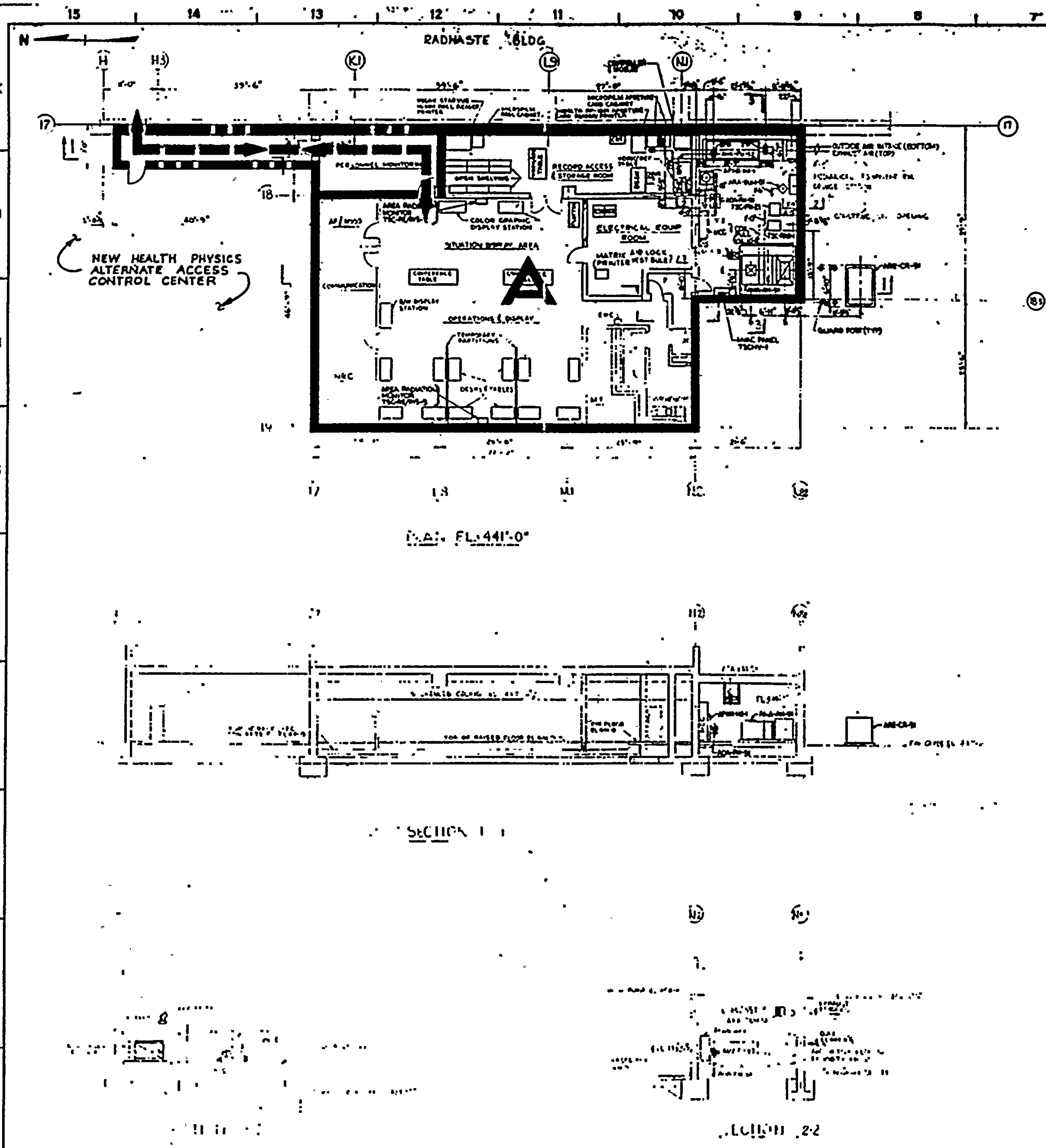
Draw. No.	Rev.	Figure J.6-13



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Areas and Access Routes - Post-LOCA Sampling (WNP-2 Roof)

Draw. No.	Rev.	Figure	J.6-14



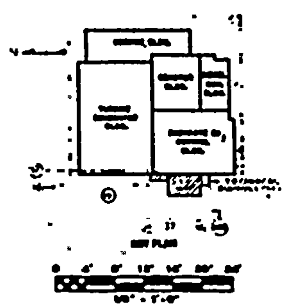
RADIATION ZONE FOR OCCUPANCY AND ACCESS DURING POST ACCIDENT OPERATION *

ZONE A
TECHNICAL SUPPORT CENTER
0.21 RADS DOSE

ACCESS ROUTE

* VALUES INDICATE WORST TARGET INTIGRATED DOSE AT 6 MONTHS FOR THE ZONE INDICATED.

REFERENCE DRAWINGS

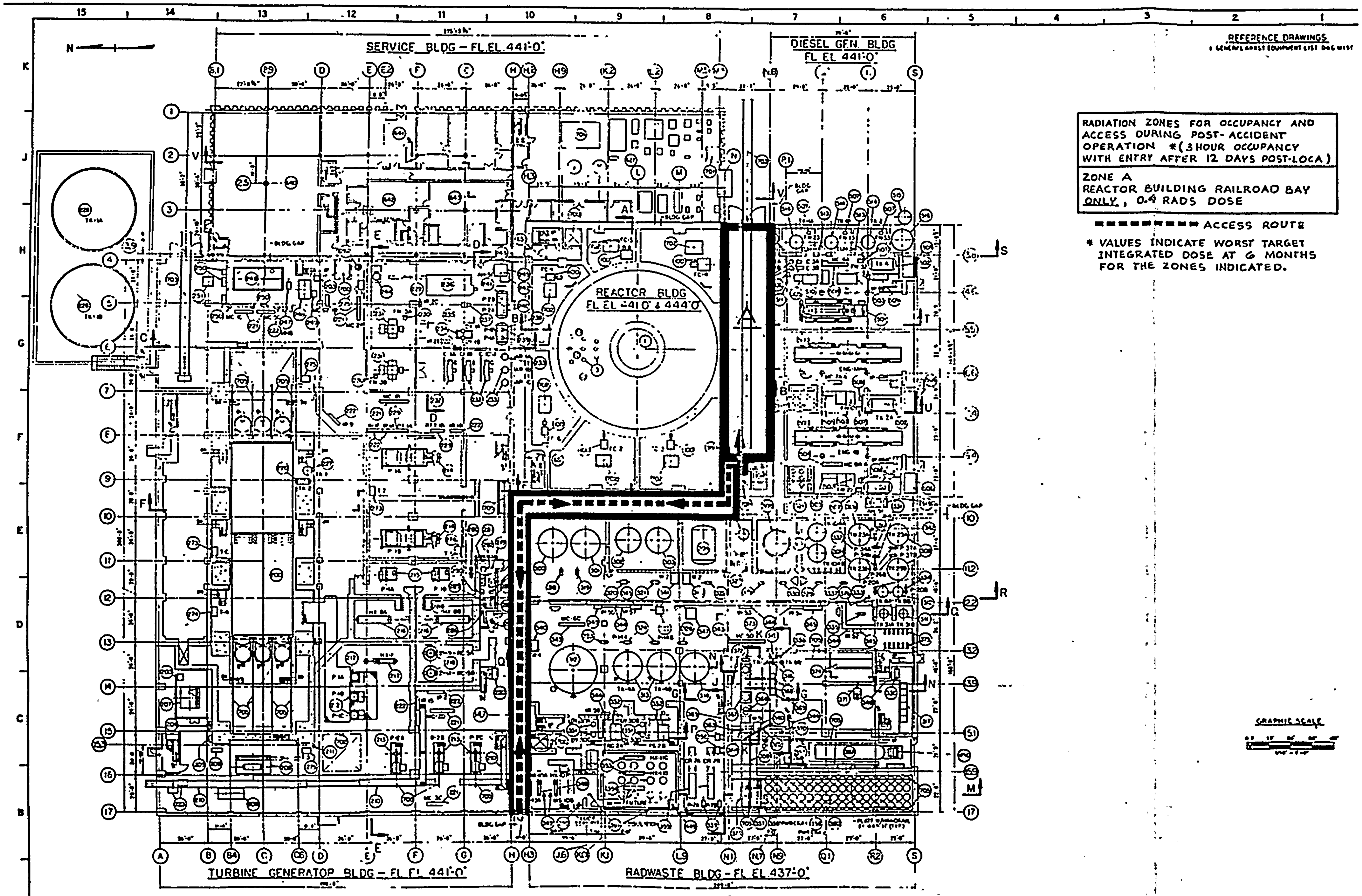


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Area and Access Routes - Technical Support Center (El. 437 ft 0 in.)

Draw. No.	Rev.	Figure J.6-15

Form No. 960690

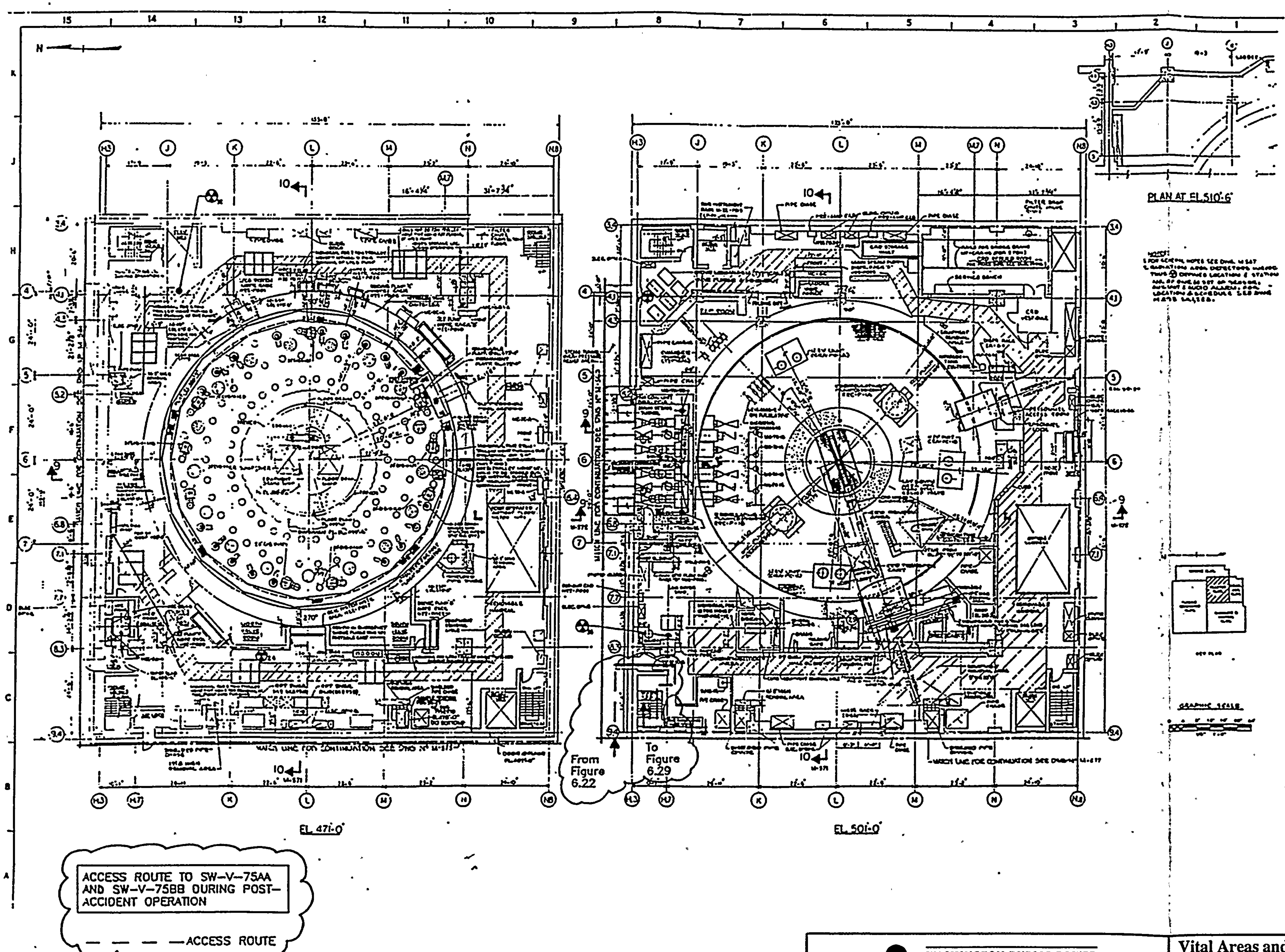


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Vital Area and Access Routes to Reactor Building Railroad Bay (El. 441 ft 0 in.)

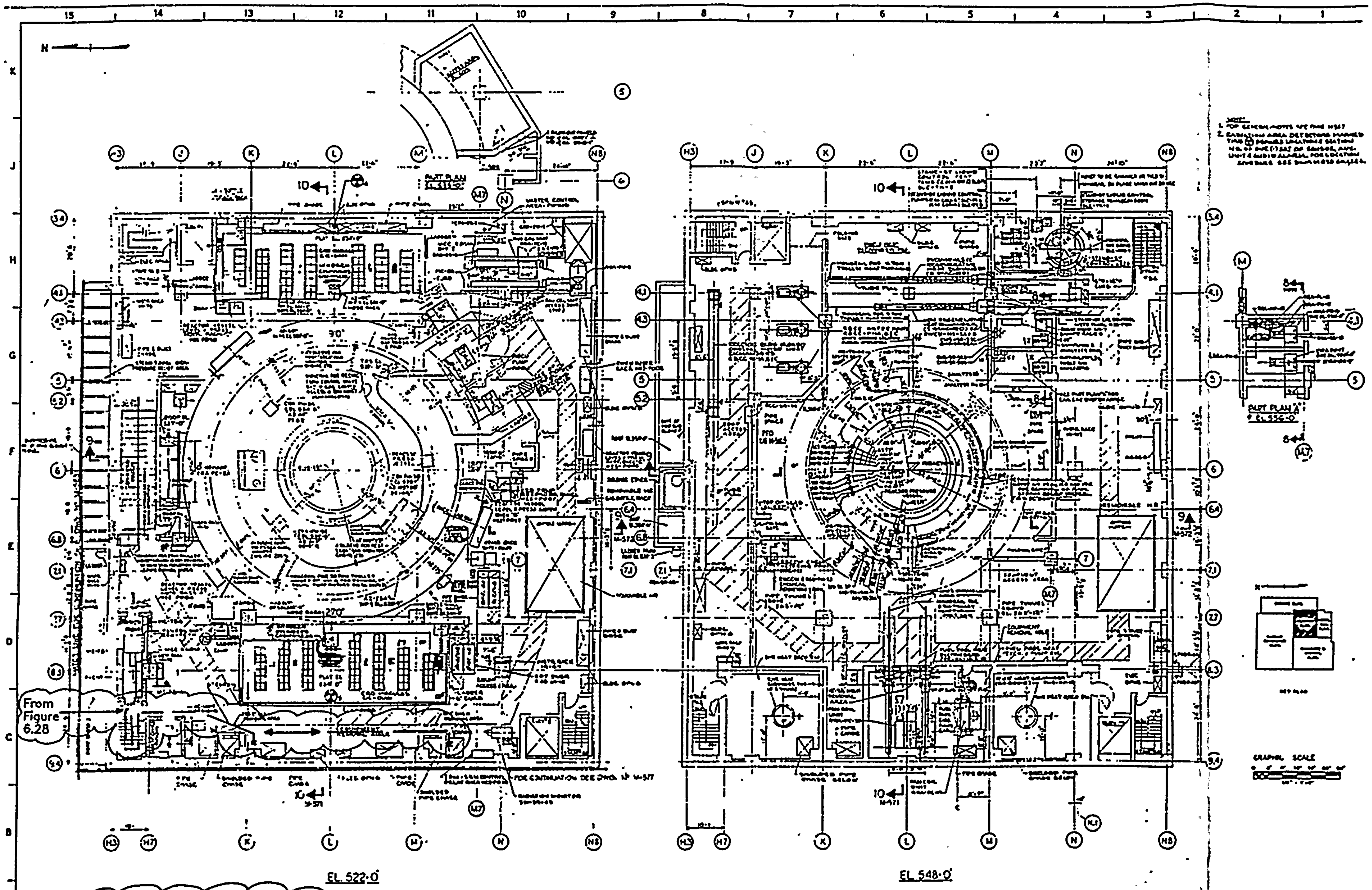
Draw. No.	Rev.	Figure J.6-16

Form No. 960690



Vital Areas and Access Routes - Reactor Building (El. 471 ft 0 in. and 501 ft 0 in.)

Draw. No.	Rev.	Figure	J.6-17



ACCESS ROUTE TO SW-V-75AA AND SW-V-75BB DURING POST-ACCIDENT OPERATION

• VALVE LOCATION

— — — — ACCESS ROUTE

WASHINGTON PUBLIC POWER SUPPLY SYSTEM

NUCLEAR PLANT 2 FSAR

Vital Areas and Access Routes - Reactor Building (El. 522 ft 0 in. and 548 ft 0 in.)

Draw. No.	Rev.	Figure J.6-18

J.7 REFERENCES

J.7-1 NUREG-0578, "TMI Lessons Learned Task Force Status Report and Short-Term Recommendations."

J.7-2 NUREG-0588, Rev. 1, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment."

J.7-3 NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident."

J.7-4 Clarification letter to NUREG-0578, September 5, 1980.

J.7-5 NUREG-0737, "Clarification of TMI Action Plant Requirements."

J.7-6 IE Bulletin No. 79-01B, "Environmental Qualification of Class 1E Equipment."

J.7-7 Supplement No. 2 to IE Bulletin 79-01B, September 30, 1980.

J.7-8 Oak Ridge National Laboratory, "ORIGEN2, Isotope Generation and Depletion Code - Matrix Exponential Method," ORNL Report No. CCC-371.

J.7-9 J. F. Perkins, U.S. Army Missile Command, Redstone Arsenal, Alabama, Report No. RR-TR-63-11 (July, 1963).

J.7-10 Oak Ridge National Laboratory, "Modifications of the Point-Kernel QAD-P5A," ORNL-4181, July 1968.

J.7-11 Oak Ridge National Laboratory, "ORIGEN-79, Isotope Generation and Depletion Code - Matrix Exponential Method," ORNL Report No. CCC-217.

J.7-12 EDS Report No. 01-0740-1138, Revision 0, "Source Term Report," December 1980.

J.7-13 WPPSS, WNP-2 FSAR, Section 15.6.5.5.1.1.

J.7-14 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.

J.7-15 WPPSS, WNP-2 FSAR, Sections 6.7.2 and 6.7.3.

J.7-16 Standard Review Plan, Section 15.6.5, "Loss of Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary."

J.7-17 Oak Ridge National Laboratory, "QAD-CG, A Combinitorial Geometry Version of QAD-P5A, A Point-Kernal Code," ORNL Report No. CCC-307.

J.7-18 Byoun, Yoon and Babel, Paul J., "Description of Computer Program (SCAP-BR)," User's Manual.

J.7-19 Impell Calculation #0740-004-019, "Fluid Contact Dose Calculation."

J.7-20 Letter BRWP-RO-81-288, dated July 29, 1981, "Forty-Year Integrated Dose for Radiation Zones in the Reactor Building."

J.7-21 Letter BRWP-RO-81-181, dated September 29, 1981, "Forty-Year Integrated Dose for Radwaste and Turbine Buildings."

J.7-22 Burns and Roe calculation 5.01.78.

J.7-23 Burns and Roe calculation 5.01.030, "Total Accident Integrated Dose to Equipment in the Reactor Building From Primary Containment Penetration Streaming."

J.7-24 Letter BWRP-RO-82-186, dated June 18, 1982, "Bioshield Wall Penetrations with Unresolved Shielding Concerns."

J.7-25 Burns and Roe Technical Memorandum, TM-1295, "Bioshield Wall Penetration Shielding Requirements," dated April 6, 1983.

J.7-26 Calculation 1140-006-CLIST, "C1E/SRM Containment List."

J.7-27 Letter EDSWP-81-015, dated February 18, 1981, "SGTS Filter Modeling Assumption."

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Attachment J.A

UNISOLATED LEAKING BUILDING PATH REPORT

A basic assumption to the plant shielding analysis is that the reactor isolates such that there is no radiation leakage path to the outside. A leakage path investigation was done verifying the above assumption. While performing this investigation, the total number of lines (69) penetrating the RB boundary, the associated system components and interface systems were reviewed.

The assumption eliminating the consideration of leakage is consistent with NUREG-0737, Clarification 2. This investigation assumed that containment isolation occurred prior to the egress of highly radioactive fluids. Additionally, it assumed that all safety-related equipment was available, and that all safety systems were pressurized. Therefore, at any interface, such as a heat exchanger, no potential leakage was considered if the nonradioactive system was at a higher pressure than the radioactive system. This investigation has not considered leakage from equipment seals, closed valves, or pipe rupture, except in the evaluation of the equipment and floor drain systems. The systems considered are tabulated by drawing number in Table J.A-1.

TABLE J.A-1

SYSTEM FLOW DIAGRAMS EMPLOYED
TO PERFORM THE REVIEW

Drawing Number	Revision	Drawing Number	Revision
M501	10	M536	12
M502	17	M537	25
M503	5	M538	9
M504	25	M539	28
M505	14	M540	15
M506	23	M541	13
M507	27	M542	4
M508	25	M543	17
M509	10	M544	10
M510	30	M545	15
M511	15	M546	10
M512	8	M547	9
M513	33	M548	14
M514	13B	M549	14A
M515	17C	M550	9
M516	20	M551	8
M517	25	M552	12
M518	14	M553	10
M519	18	M554	11
M520	15	M555	7
M521	20	M556	10
M522	6	M557	4
M523	29	M607 Sheet 1	7
M524	19	M607 Sheet 2	5
M525	19	M607 Sheet 3	3
M526	25		
M527	18		
M528	15		
M529	21		
M530	18		
M531	24		
M532	20		
M533 Sheet 1	1		
M533 Sheet 2	1		
M533 Sheet 3	1		
M534	16		
M535 Sheet 1	26		
M535 Sheet 2	21		

Attachment J.B

SOURCE TERM DEVELOPMENT AND PARAMETRIC STUDIES FOR SECONDARY CONTAINMENT

The major tools used in the development of source terms and parametric studies inside secondary containment were the ORIGEN and QAD-P5A computer codes. Descriptions of the codes are in References J.7-11 and J.7-10. ORIGEN was used to compute the activities and energies of fission products released from the reactor core. The output of ORIGEN [the time-dependent energies and activity of radioactive fission products following loss-of-coolant accident (LOCA)] was used as input to QAD-P5A to calculate the airborne, shine, and direct doses for standard geometrics as well as the basis of direct dose parametric studies.

J.B.1 RADIOACTIVE SOURCE TERMS IN SECONDARY CONTAINMENT

The ORIGEN computer code (Reference J.7-11) was used to calculate the radioactive source terms inside secondary containment for liquid-containing and gas-containing systems. The fission products at the end of fuel life were assumed to be available for release immediately following the accident. The concentrations of noble gases, halogens, and other fission products released to the gaseous and liquid sources were computed. Subsequent fission product decay and daughter product generation were then calculated for 20 time periods, covering a total period of 1 year.

The assumptions used in determining the initial distribution and leakage of radioactivity in the primary containment air and liquid space are as follows:

a. 100% of the noble gases and 50% of the halogens are distributed homogeneously within the primary containment free volume immediately following the postulated accident;

b. 50% of the halogens and 1% of the remaining fission products in the core are mixed instantaneously and homogeneously with the primary containment liquid space. The primary containment liquid space is defined as the sum of the suppression pool liquid and the reactor coolant system (RCS) liquid; and

c. The fission products available for release are defined as the total inventory generated in the equilibrium core after 1000 days at reactor power of 3556 MWt.

Assumptions a and b are NRC recommended assumptions for defining radioactivity release fractions for the qualification of safety-related equipment (Reference J.7-2) and are detailed in References J.7-32 and J.7-34.

Assumption c represents the maximum burnup level in the core and the fission products at the end of fuel life prior to radioactivity release and is conservative.

Table J.B-1 shows the gamma activity concentration at selected time periods for the liquid-containing system. The results of Table J.B-1 were used as input in the dose parametric study. Due to rapid decay of the high-energy isotopes, the average gamma energy for the gas-containing system varies from 0.8 MeV at the beginning of the accident to 0.3 MeV at 1 year after the accident.

J.B.2 AIRBORNE DOSE IN SECONDARY CONTAINMENT

The time-dependent post-LOCA activity levels as calculated by the ORIGEN computer code were used as input in the calculation of the airborne beta and gamma dose rates and integrated doses inside the cubicles in the secondary containment. The assumptions used in this analysis are as follows:

a. Activity that leaks into the secondary containment is homogeneously mixed with the secondary containment atmosphere prior to its removal from the atmosphere through the standby gas treatment system (SGTS). This is consistent with the NRC-recommended assumptions used for calculation of doses inside primary containment (Reference J.7-2 and J.7-34);

b. An SGTS flow rate of 2430 scfm was assumed to be the flow rate of the effluent air. This is the designed minimum accident flow rate (Reference J.7-35) based on one reactor building airchange per day;

c. Air that leaks out of the primary containment flows directly and totally into the secondary containment. Bypass leakage is not considered. This is conservative when considering dose in the secondary containment, since it maximizes the buildup of radioactivity in the secondary containment;

d. Geometric factors are used to convert the semi-infinite cloud gamma dose to a finite gamma dose. This assumption is used in Reference J.7-28, and is based on an average gamma ray energy of 0.733 MeV. The effect of time dependence of average gamma ray energies has been proven to be negligible; and

e. Primary containment activity leakage rate is 0.5%/day. This is consistent with the assumptions established in Reference J.7-29.

A model of the primary and secondary containment atmosphere is shown in Figure J.B-1. The activity concentration of a certain isotope inside the containment is changing due to the following three mechanisms:

a. Transport of activity due to air leakage,

b. Depletion of activity due to radioactive decay and plateout of elemental halogens inside primary containment, and

c. Increases in activity levels due to daughter product generation from fission product decay.

According to References J.7-2 and J.7-34, plateout may be modeled by an expotential removal process:

$$A(t) = A(0)\exp(-\lambda_p t)$$

Where λ_p is the removal constant due to plateout.

The first step in this calculation is to model the decay and transport of the airborne radionuclides.

General airborne activity balance in containment:

$$\frac{d}{dt}(C_{1i}V_1) = \underbrace{-Q_1C_{1_i}}_{\text{leakage}} \quad \underbrace{-\lambda_iC_{1i}V_1}_{\text{decay}} \quad \underbrace{-\lambda_{pi}C_{1i}V_1}_{\text{plateout}} + \quad \underbrace{\Sigma_j\lambda_jC_{1j}V_1}_{\text{growth}} \qquad \text{(J.B-1)}$$

where

C_{1i}	=	concentration of isotope "i"
Q_1	=	leakage rate from primary containment
V_1	=	volume of primary containment
λ_i	=	radioactive decay constant of isotope "i"
λ_{pi}	=	plateout removal constant of isotope "i"

The term $\Sigma_j\lambda_jC_{1i}V_1$ reflects the growth of a given nuclide as the result of decay of parent nuclides.

The original release of nuclides consists only of halogens and noble gases. Since fission products are neutron-rich, decay of fission products proceeds toward higher atomic numbers.

In this manner, halogens will decay into noble gases, and then to higher atomic-numbered elements. Since the decay chain reaches a stable isotope after only a few decays, it can be seen that upon release of these airborne nuclides, the halogens have no significant airborne parent nuclides. This term may be neglected in the case of halogens.

Case 1 - Containment Halogens

Elemental iodine undergo plateout (Reference J.7-34) so equation (J.B-1) becomes:

$$\frac{d}{dt}(C_{1i}V_1) = -Q_1 C_{1i} - \lambda_i C_{1i} V_1 - \lambda_{pi} C_{1i} V_1 \qquad \text{(J.B-2)}$$

Solving (J.B-2) with the initial condition;

at t = 0,

$C_{1i} = C_{1i}(0)$,

$$C_{1i}(t) = C_{1i}(0) \exp\left(-\left(\frac{Q_1}{V_1} + \lambda_i + \lambda_{pi}\right)t\right) \qquad \text{(J.B-3)}$$

Particulate and organic iodine are assumed unaffected by plateout (Reference J.7-34).

Equations (J.B-3) for particulate and organic iodine may then be shown to be

$$C_{1i}(t) = C_{1i}(0) \exp\left(-\left(\frac{Q_1}{V_1} + \lambda_i\right)t\right) \qquad \text{(J.B-4)}$$

One can note, at this point, that all three iodine species have factors of

$C_{1i}(0) \exp(-\lambda_i t)$

in the equations. This term may be defined as

$$S_i(t) = C_{1i}(0) \exp(-\lambda_i t) \quad V_1 \qquad \text{(J.B-5)}$$

$S_i(t)$ is seen to be the total activity released into the system as a result of decay. $S_i(t)$ is independent of the transport of the nuclides. The following definitions will be made.

f_e = fraction of total iodine that are elemental
f_p = fraction of total iodine that are particulate
f_o = fraction of total iodine that are organic

Equations (J.B-3) and (J.B-4) can be combined to get

$$C_{1iH}(t) = \left[f_e \exp(-\lambda_p t) + (f_o + f_p)\right] \exp\left[-Q_1 t / V_1 \frac{S_{iH}(t)}{V_1}\right] \quad \text{(J.B-6)}$$

where

$C_{1iH}(t)$ = total iodine concentration in primary containment
$S_{iH}(t)$ = total iodine activity
λ_p = plateout constant for elemental iodine

At this point, Reference J.7-2 allows only a factor of 200 reduction for elemental iodine plateout effects.

So when

$$\exp(-\lambda_p t) = \frac{1}{200}, \text{ then } \lambda_p \text{ becomes zero.} \quad \text{(J.B-7)}$$

Defining: $t_p = \dfrac{\mathrm{Ln}\,(200)}{\lambda_p}$

Equation (J.B-6) may be rewritten as

$$C_{1iH}(t) = \frac{S_{iH}(t)}{V_1} \exp\left[-Q_1 t / V_1\right] f_H(t) \quad \text{(J.B-8)}$$

Where $f_H(t)$ is defined as

(a) $f_H(t) = f_e \exp(-\lambda_p t) + f_p + f_o \qquad t \le t_p$ (J.B-9)

(b) $f_H(t) = (f_e / 200) + f_p + f_o \qquad t \ge t_p$

Case 2 - Containment Noble Gases

Noble gases do not undergo plateout. Daughter products are also conservatively assumed to act as noble gases. Equation (J.B-1) for noble gases becomes

$$\frac{d}{dt}(C_{1i}V_1) = -Q_1C_{1i} - \lambda_iC_{1i}V_1 + \Sigma_j\lambda_jC_{1j}V_1 \qquad \text{(J.B-10)}$$

Integrating equation (J.B-10) gives

$$C_{1i}(t) = \exp\left[-Q_1 t/V_1\right] \exp\left[-\lambda_i t\right] (B + f_i(t)) \qquad \text{(J.B-11)}$$

where

$$f_i(t) = \int \Sigma_j\lambda_jC_{ij} \exp-\left[Q_1/V_1 + \lambda i\right] dt \qquad \text{(J.B-12)}$$

and B is a constant to be determined.

All daughter products of plated-out iodine are conservatively assumed to be re-released into the containment atmosphere as if the iodine were airborne. For the first isotope in a series (no parent nuclide), $j = 0$ and $f_o(t) = 0$.

Since $C_{1j}(t)$ has the same form as $C_{1i}(t)$, equation (J.B-12) becomes

$$f_i(t) = \int \Sigma_j \lambda_j (B + f_j(t)) e^{(\lambda_i - \lambda_j)t} dt \qquad \text{(J.B-13)}$$

Equation (J.B-13) shows that the only dependence on Q_1/V_1 is that carried over from the parent isotope is $f_n(t)$. Since $f_o(t)$ is independent of Q_1/V_1, $f_i(t)$ is independent of Q_1/V_1. Equation (J.B-11) can thus be rewritten as

$$C_{1i}(t) = e^{-(Q_1/V_1)t} S_i(t)/V_1 \qquad \text{(J.B-14)}$$

where

$$S_i(t) = \exp\left[-\lambda_i t\right] (B + f_i(t))V_1 \qquad \text{(J.B-15)}$$

It can be seen that $S_i(t)$ is the solution to equation (J.B-10) without the leakage term. $S_i(t)$ is the activity for the total inventory of nuclides released from the reactor core. $S_i(t)$ values are determined by the use of ORIGEN. $S_i(t)$ includes radioactive decay and daughter product growth.

For a general airborne activity balance in the reactor building (secondary containment):

$$\frac{d}{dt}(C_{2i}V_2) = \underset{\text{leakage in}}{+\,Q_iC_{1i}} \;\; \underset{\text{leakage out}}{-\,Q_2C_{2i}} \;\; \underset{\text{decay}}{-\,\lambda_iC_{2i}V_2} \;\; \underset{\text{growth}}{+\,\Sigma_j\lambda_jC_{2j}V_2} \qquad \text{(J.B-16)}$$

where

C_{2i} = concentration of isotope "i" in the reactor building
Q_2 = leakage rate from reactor building
V_2 = volume of the reactor building

Plateout inside secondary containment is conservatively neglected.

Case 3 - Iodine Inside the Reactor Building

As in Case 1, the growth term of equation (J.B-16) is negligible. Equation (J.B-16) can be integrated to give

$$C_{2i}\ (t) = e^{-(Q_2/V_2+\lambda_i)t}\left[B + \frac{Q_1}{V_2}\int e^{(Q_2/V_2+\lambda_i)t}\, C_{1i}(t)\ dt\right] \qquad \text{(J.B-17)}$$

From equation (J.B-8), $C_{1i}(t)$ is substituted into (J.B-17)

$$C_{2i}\ (t) = Be^{(Q_2/V_2+\lambda_i)t} + \frac{Q_1}{V_2}\ e^{-(Q_2/V_2+\lambda_i)t}\int \exp\ (Q_2/V_2 + \lambda_i)t$$

$$(\frac{S_{iH}(t)}{V_1}\ e^{-Q_1t/V_1}\ f_H(t))\ dt \qquad \text{(J.B-18)}$$

Substituting equation (J.B-5) into (J.B-18) results in

$$C_{2i}\ (t) = B\exp\left[-(Q_2/V_2 + \lambda_i)t\right] + \frac{Q_1}{V_2}\ C_{1i}\ (0)\ \exp \qquad \text{(J.B-19)}$$

$$-(Q_2/V_2 + \lambda_i)t$$

$$\int \exp\left[(Q_2/V_2 - Q_1/V_1)t\right]\ f_H(t)\ dt$$

$f_H(t)$ is a complex function of time (equation J.B-9). $C_{2i}(t)$ must be solved in a series of solutions to equation (J.B-19).

For simplification, the following factors are defined

$$x = \frac{Q_2}{V_2} - \frac{Q_1}{V_1}$$

$$y = x - \lambda_p$$

Equation (J.B-19) becomes

$$C_{2i}(t) = B\exp -(Q_2/V_2 + \lambda_i)t + \frac{Q_1}{V_2 V_1} S_{iH}(t) \exp -(Q_2/V_2 + \lambda_i)t \int e^{xt} f_H^{(t)}\, dt \qquad \text{(J.B-20)}$$

Integrating (J.B-20) for $0 \le t \le t_p$ with the initial condition; $C_{2i}(0) = 0$ gives

(For $S_{iH}(t) = S_{iH}(0)\, e^{-\lambda_i t}$):

$$C_{2i}(t) = \frac{Q_1}{V_1 V_2} S_{iH}(t) \left(\exp[-Q_1 t/V_1] \left(\frac{f_c}{y} \exp[-\lambda_p t] + \frac{f_p + f_o}{x}\right) - e^{-Q_2 t/V_2} \left(\frac{f_c}{y} + \frac{f_p + f_o}{x}\right)\right) \qquad \text{(J.B-21)}$$

Defining

$K_1 = \left(\frac{-f_c}{y} + \frac{f_p + f_o}{x}\right)$; (J.B-21) becomes (for $0 \le t \le t_p$): (J.B-22)

$$C_{2i}(t) = \frac{Q_1}{V_1 V_2} S_{iH}(t) \left(\left(\frac{f_c}{y} \exp[-\lambda_p t] + \frac{f_p + f_o}{x}\right) \exp[-Q_1 t/V_1] + K_1 \exp[-Q_2 t/V_2]\right)$$

And (for $t^3 t_p$): (J.B-23)

$$C_{2i}(t) = B\exp[-(Q_2/V_2 + \lambda_i)t] + \frac{Q_1}{V_1 V_2} S_{iH}(t) \exp[-Q_2/V_2 t] \int e^{xt} \left(\frac{f_c}{200} + f_p + f_o\right) dt$$

Solving (J.B-23) gives (J.B-24)

$$C_{2i}(t) = B\exp\left[-(Q_2/V_2 + \lambda_i)t\right] + \frac{Q_1}{V_1V_2}S_{iH}(t)\exp\left[-Q_2/V_2t\right]$$
$$\left(\frac{f_e/200 + f_o + f_p}{x}\right)e^{xt}$$

At t = tp (from J.B-22)): (J.B-25)

$$C_{2i}(t_p) = \frac{Q_1}{V_1\ V_2}S_{iH}(t_p)\left[\begin{array}{l}K_1\exp\left[-(Q_2/V_2)t_p\right] + \left(\frac{f_e}{y}e^{-\lambda_p t_p}\right. \\ \left. + \left(\frac{f_o + f_p}{x}\right)\right)\exp\left[-Q_1t_p/V_1\right]\end{array}\right]$$

By definition of t_p [eq. (J.B-7)]: $\exp\left[-\lambda_p t_p\right] = \frac{1}{200}$

Combining (J.B-24) and (J.B-25) at $t = t_p$ gives (J.B-26)

$$B\exp\left[-(Q_2/V_2 + \lambda_i)t_p\right] = \frac{Q_1}{V_1V_2}S_{iH}(t_p)\exp\left[-(Q_2/V_2)t_p\right]$$
$$\left(K_1 + \frac{f_e}{200}\left(\frac{1}{y} - \frac{1}{x}\right)e^{xt}p\right)$$

and

$$B = \frac{Q_1}{V_1V_2}S_{iH}(0)K_2 \qquad \text{(J.B-27)}$$

where

$$K_2 = K_1 + \frac{f_e}{200}\left(\frac{1}{y} - \frac{1}{x}\right)e^{xt}\ p \qquad \text{(J.B-28)}$$

So (J.B-24) becomes (for $t_p \leq t$)

$$C_{2i}(t) = \frac{Q_1}{V_1V_2}S_{iH}(t)\ \left(K_2e^{-Q_2t/V_2} + \left(\frac{f_e/200 + f_o + f_p}{x}\right)e^{-Q_1t/V_1}\right. \qquad \text{(J.B-29)}$$

Equations (J.B-22) and (J.B-29) may be combined to form a general solution as follows:

$$C_{2i}(t) = S_{iH}(t)\ \ F_{2H}(t)/V_2 \qquad \text{(J.B-30)}$$

where (for $0 \le t \le t_p$)

$$F_{2H}(t) = \frac{Q_1}{V_1}\left(K_1 \exp\left[-Q_2 t/V_2\right] + \left(\frac{f_c}{y}\exp\left[-\lambda_p t\right] + \frac{f_p + f_o}{x}\right)\exp\left[-Q_1 t/V_1\right]\right)$$

for ($t \ge t_p$) (J.B-31)

$$F_{2H}(t) = \frac{Q_1}{V_1}\left(K_2 \exp\left[-Q_2 t/V_2\right] + \left(\frac{f_c/200 + f_o + f_p}{x}\right)\exp\left[-Q_1 t/V_1\right]\right)$$

Case 4: Noble Gases Inside the Reactor Building

Equation (J.B-16) for noble gases may be rewritten as

$$\frac{d}{dt}(C_{2i}) - (Q_1/V_2)\ C_{1i} - (Q_2/V_2 + \lambda_i)\ C_{2i} + \Sigma_j \lambda_j C_{2j} \qquad \text{(J.B-32)}$$

Integrating (J.B-32) gives (J.B-33)

$$C_{2i}(t)\exp\left[(Q_2/V_2 + \lambda_i)t\right] = B + \int \exp\left[(Q_2/V_2 + \lambda_i)t\right]\left(\frac{Q_1}{V_2}C_{1i}(t) + \Sigma_j \lambda_j C_{2j}(t)\right)dt$$

$C_{1i}(t)$ is found from equation (J.B-14) to be

$$C_{1i}(t) = \exp\left[-(Q_1/V_1)t\right] S_i(t)/V_1$$

$S_i(t)$ cannot be found analytically; hence equation (J.B-33) cannot be found analytically through this method. However, in deriving equation (J.B-14), it was shown that if all parent nuclides are transported identically, then the solution of equations consisting of transport and radioactive decay can be separated. Since the halogens are not transported in the same manner as noble gases, this is not strictly true. However, the assumption of daughter growth as if the halogens were transported will be conservative, due to the nonconsideration of the physical holdup in primary to secondary leakage of daughters of halogens.

Equation (J.B-14) may be rewritten as

$$V_1 C_{1i}(t) = S_{iN}(t)\ F_{1N}(t) \qquad \text{(J.B-34)}$$

where

$$F_{IN}(t) = \exp\left[-Q_1 t / V_1\right] \qquad \text{(J.B-35)}$$

$S_{iN}(t)$ is the noble gas total activity term, as before. $F_{1N}(t)$ is the fraction of that activity remaining in primary containment.

Equation (J.B-16) may be modified to show the fractions of activity, rather than total isotopic activity, in secondary containment to give

$$\frac{d}{dt}(F_{2N}) = \frac{Q_1}{V_1} F_{IN} - \frac{Q_2}{V_2} F_{2N} \qquad \text{(J.B-36)}$$

Integrating equation (J.B-36) with initial conditions:

at $t=0$, $F_{2N} = 0$; gives

$$F_{2N}(t) = \frac{Q_1}{V_1 x}\left(\exp\left[-Q_1 t/V_1\right] - \exp\left[-Q_2 t/V_2\right]\right) \qquad \text{(J.B-37)}$$

$C_{2i}(t)$ is then found from

$$C_{2i}(t) = S_{iN}(t)\, F_{2N}(t)/V_2 \qquad \text{(J.B-38)}$$

λ_p is found in Reference J.7-2 to be determined

$$\lambda_p = K_g A_1/V_1 \qquad \text{(J.B-39)}$$

K_g is conservatively assumed to be equal to 0.05 cm/sec (Reference J.7-34).

A_1 is the surface area inside the drywell = $3.2 \times 10^7 cm^2$ (Reference J.7-33).

$V_1 = 5.68 \times 10^9 cm^3$ (Reference J.7-36)

$\lambda_p = 1.01\ hr^{-1}$

To calculate the airborne gamma dose rate inside the secondary containment, the method as described in Reference J.7-28 is used:

$$D_{\gamma\infty} = \sum_{i=1}^{n} 0.25 \overline{E}_\gamma i \left(C_{2i}\ \text{noble gas} + C_{2i}\ \text{halogen}\right) \qquad \text{(J.B-40)}$$

$$D_\gamma = \frac{D\gamma\infty}{GF} \qquad \text{(J.B-41)}$$

$$GF = \frac{1173}{V^{0.338}} \qquad \text{(J.B-42)}$$

where

$D_{\gamma\infty}$ = semi-infinite gamma cloud dose rate (rads/sec)

$\bar{E}\gamma_i$ = average gamma energy of the isotope (MeV)

C_{2i} = activity concentration inside secondary containment (Ci/m^3)

GF = geometric factor used to scale the semi-infinite gamma cloud dose to a finite cloud dose

V = volume of the finite cloud (ft^3)

By taking $S_i(t)$ from ORIGEN output and using equations (J.B-31) and (J.B-37) to calculate $F_2(t)$, the total gamma dose in secondary containment can be computed by using equations (J.B-40) through (J.B-42).

The airborne semi-infinite cloud gamma dose rates are shown in Figure J.B-2. As can be observed from the figures, the gamma doses inside secondary containment reach their peaks at around three days after the accident, and decay slowly thereafter due to the depletion of radioactivity by radioactive decay and removal through the SGTS.

The geometric factor in equation (J.B-42) is developed in Reference J.7-28 for average gamma energies of 0.733 MeV. There has been a concern that this geometric factor may vary appreciably with time due to the faster decay rate of the high energy isotopes. The average gamma energy during various time periods following the accident were computed and the results show that the average gamma energy varies from 0.3 MeV to 0.8 MeV. As discussed in Reference J.7-31, the geometric factor changes by less than 5% within that energy range. It is therefore concluded that the change in the geometric factors with time is negligible, and that equation (J.B-42) can be used to calculate the finite cloud gamma dose inside the secondary containment.

J.B.3 PARAMETRIC STUDIES FOR DIRECT PIPING DOSE

The purpose of the parametric study was to identify the parameters which have a significant affect on the radiation dose rates. The computer code QAD-P5A was used to develop a

correlation scheme for the significant parameters such that a simplified procedure for calculating radiation dose rates for complex source and receptor geometries can be developed. The dose rate at a target distance of 8 ft radially outwards from the centerline of an 8-in. schedule 40 pipe, infinitely long (standard pipe) was first calculated and defined as the standard dose rate. A parametric study was then performed to investigate the effects of the variation of parameters such as pipe length, pipe diameter, shield thickness, and target locations on the dose rate. The results of this parametric study were then correlated as a set of correction factors to the standard dose rate. A simplified procedure was developed to calculate the dose rates and cumulate doses for the multitude of source-target configurations by using these correction factors.

J.B.3.1 Functional Dependence of Various Parameters on Secondary Containment Dose Rates

The gamma ray energy flux from a line source "S_L" to a detector point "P" (see Figure J.B-3) is shown in Reference J.7-30 as

$$\phi = \frac{BS_L}{4\pi r} \; {}_0\!\int^{\theta 1} \exp - b_1 \operatorname{Sec} \theta_{d\theta} - \int^{\theta 2} \exp - b_1 \operatorname{Sec} \theta_{d\theta} \qquad \text{(J.B-43)}$$

where

ϕ = uncollided gamma ray flux (photons/cm^2 - sec)
b_1 = total attentuation through shield
S_L = source strength of line source (photons/cm sec)
B = buildup factor
θ = angle subtended by the length of the line source (see Figure J.B-3)

The source strength "S_L" is a function of the volume of liquid inside the pipe segments, which is also a function of the diameter and volume of the pipe. The angles "$\theta 1$" and "$\theta 2$" are also functions of "a/r" and "b/r," respectively (see Figure J.B-18 for definition of "a/r" and "b/r" respectively). Therefore, the functional dependence of gamma ray dose rates on the various parameters can be represented by the following equation:

$$\phi = \phi_o * F_D * F_R * F_L \left[(a/r, b_1) + F_L (b/r, b_1)\right] \qquad \text{(JB-44)}$$

where

ϕ_o = base gamma ray flux for standard pipe
F_D = pipe diameter correction factor
F_R = radial distance correction factor
F_L = $(a/r, b_1)$ = pipe length correction factor

J.B.3.2 Parametric Study Procedures

The procedure for performing this parametric study is documented as follows:

a. Calculate the dose rate at a target distance of 8 ft from the centerline of an 8-in. schedule 40 pipe infinitely long (standard pipe);

b. Perform parametric studies on the variation of dose rates with

   1. Radial distance from the pipe centerline,
   2. Length of the pipe,
   3. Nominal pipe diameter,
   4. Time, and
   5. Axial position along the pipe;

c. Correlate the results of the parametric study by a set of geometric correction factors;

d. Develop a procedure for calculating dose rates by using the correction factors; and

e. Verify the correlation scheme by calculating the dose rates at different target locations due to source piping of varied geometries through the use of QAD-P5A computer code, and compare the results to those obtained by using the procedure developed in step d.

J.B.3.3 Direct Dose Parametric Study Results Inside Secondary Containment

The standard pipe gamma dose rate and integrated dose curves for the different systems having different source term assumptions (defined in Section J.5.3.2) are shown in Figures J.B-4 through J.B-11. The various correction factors were calculated by the following correlation.

$$F_R(r) = \frac{\text{Dose rate at a radial distance "r" from an infinitely long 8-in. sch 40 pipe}}{\text{Dose rate at a radial distance of 8 ft from an infinitely long 8-in. sch 40 pipe}}$$

$$F_L(\ell) = \frac{\text{Dose rate at a radial distance of 8 ft from an 8-in. sch 40 pipe of length "}2\ell\text{"}}{\text{Dose rate at a radial distance of 8 ft from an infinitely long 8-in. sch 40 pipe}}$$

$$F_D(d) = \frac{\text{Dose rate at a radial distance of 8 ft from an infinitely long sch 40 pipe of nominal diameter "d"}}{\text{Dose rate at a radial distance of 8 ft from an infinitely long 8-in. sch 40 pipe}}$$

The above mentioned correction factors for liquid system source terms are shown in Figures J.B-12, J.B-13, and J.B-14. The correction factor curves for gaseous source terms are shown in Figures J.B-15, J.B-16, and J.B-17.

J.B.3.4 Correction Factor Method of Determining Direct Doses in Secondary Containment

Using the parametric curves from Section J.B.3.3, one obtains dose rates at varied radial distances (between 2 ft to 40 ft) from varied pipe diameters (between 2 in. to 24 in.) of varied lengths (between 2 ft to infinity) at any given time period within 1 year. The step-by-step procedure for calculating direct dose is as follows:

a. Identify a/r, b/r parameters and obtain pipe length correction factor F_L from Figure J.B-13 or J.B-16, depending on the system being considered. (See Figure J.B-18 for definition of "a/r" and "b/r");

b. Obtain the standard dose rate from the standard dose rate curve for time "t" desired;

c. Obtain the pipe diameter correction factor $F_D(d)$;

d. Obtain radial distance correction factor $F_R(r)$; and

e. The dose rate for the given pipe segment can be computed by

Dose Rate = (Standard Dose Rate) $(F_R)(F_D)(F_L)$.

Table J.B-2 compares the results for dose rate of 17 different pipe geometry and target locations as calculated using the correction factor method to those calculated by using the computer code QAD-P5A. It was observed that the biggest difference in results between the two methods is less than 10%. It is concluded that the correction factor method is adequate for calculating direct dose.

TABLE J.B-1

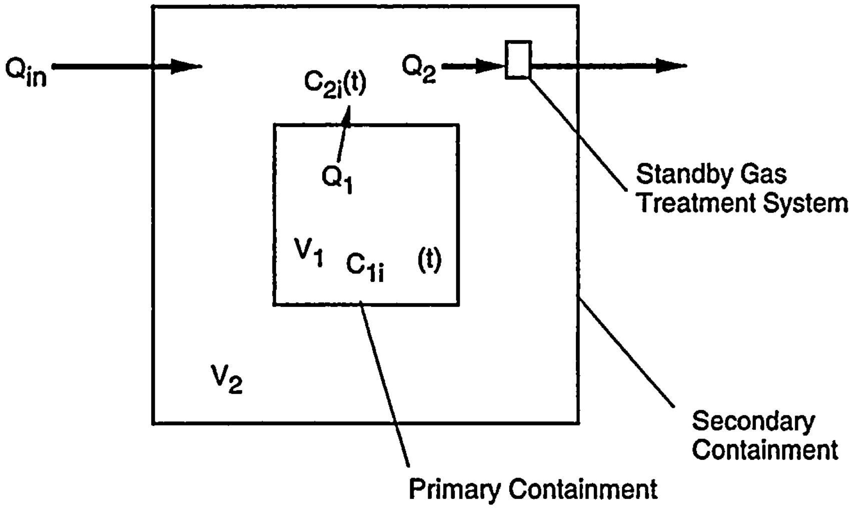
GAMMA ENERGY CONCENTRATION (photons/sec-cm^3) IN LIQUID-CONTAINING SYSTEMS

	Gamma Energy (MeV)											
Time	0.30	0.63	1.10	1.55	1.99	2.38	2.75	3.25	3.70	4.22	4.70	5.25
0 min	1.32E+09	7.25E+09	2.33E+09	1.63E+09	1.28E+08	1.00E+08	1.33E+08	3.61E+07	1.90E+07	2.82E+07	4.58E+07	3.39E+05
2 min	1.17E+09	7.17E+09	2.03E+09	6.17E+08	1.25E+08	4.54E+07	4.88E+07	2.42E+07	1.03E+07	7.17E+06	1.02E+07	2.10E+05
6 min	1.06E+09	6.92E+09	1.85E+09	5.63E+08	1.22E+08	1.99E+07	1.55E+07	1.62E+07	7.34E+06	8.50E+05	5.84E+05	8.09E+04
20 min	9.71E+08	6.21E+09	1.69E+09	5.00E+08	1.14E+08	1.30E+07	8.21E+06	9.17E+06	5.25E+06	2.03E+04	3.55E+03	2.86E+03
1 hr	8.84E+08	4.75E+09	1.41E+09	3.84E+08	1.01E+08	7.71E+06	3.36E+06	2.60E+06	2.17E+06	1.43E+00	3.66E-01	2.01E-01
3 hr	8.50E+08	2.65E+09	9.92E+08	2.28E+08	7.75E+07	2.77E+06	3.61E+05	3.74E+05	1.58E+05	3.26E-03	1.55E-03	9.71E-04
9 hr	9.04E+08	1.29E+09	5.00E+08	1.05E+08	3.88E+07	7.71E+05	9.04E+03	2.35E+04	6.17E+01	3.26E-03	1.55E-03	9.71E-04
1 day	8.09E+08	7.17E+08	1.39E+08	3.73E+07	8.84E+06	6.17E+05	1.30E+03	6.29E+01	5.17E-03	3.26E-03	1.54E-03	9.71E-04
3 days	5.54E+08	2.71E+08	1.79E+07	1.91E+07	9.34E+05	5.71E+05	1.10E+03	3.56E+01	5.17E-03	3.26E-03	1.54E-03	9.67E-04
9 days	3.16E+08	1.22E+08	4.58E+06	1.36E+07	5.71E+05	4.29E+05	1.09E+03	3.46E+01	5.13E-03	3.22E-03	1.53E-03	9.59E-04
30 days	5.42E+07	6.46E+07	1.73E+06	4.38E+06	2.67E+05	1.48E+05	1.05E+03	3.31E+01	4.96E-03	3.12E-03	1.48E-03	9.29E-04
60 days	8.17E+06	4.42E+07	9.29E+05	1.03E+06	1.49E+05	3.94E+04	9.92E+02	3.13E+01	4.71E-03	2.98E-03	1.41E-03	8.88E-04
90 days	3.99E+06	3.45E+07	7.13E+05	3.60E+05	1.14E+05	1.75E+04	9.38E+02	2.96E+01	4.54E-03	2.86E-03	1.35E-03	8.50E-04
120 days	3.25E+06	2.77E+07	6.25E+05	2.19E+05	1.00E+05	1.26E+04	8.88E+02	2.80E+01	4.38E-03	2.75E-03	1.30E-03	8.17E-04
150 days	2.90E+06	2.27E+07	5.79E+05	1.83E+05	9.17E+04	1.11E+04	8.38E+02	2.64E+01	4.21E-03	2.66E-03	1.26E-03	7.92E-04
180 days	2.64E+06	1.89E+07	5.42E+05	1.69E+05	8.50E+04	1.04E+04	7.92E+02	2.50E+01	4.08E-03	2.57E-03	1.22E-03	7.67E-04

TABLE J.B-2

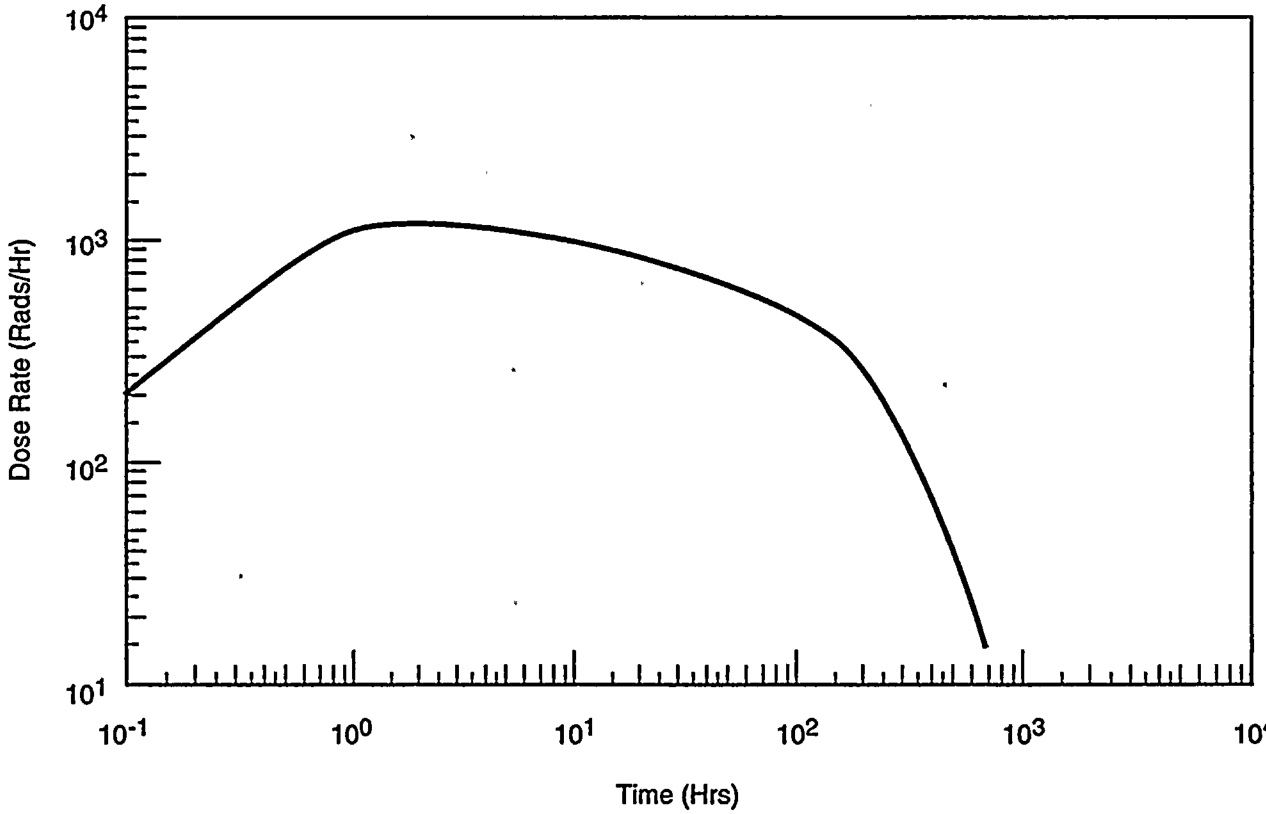
COMPARISON OF DIRECT DOSE RATE RESULTS

Target Location and Pipe Geometry					Dose Rate Results			
Pipe Diameter (cm)	Pipe Length (cm)	Target Location r (cm)	Target Location a (cm)	Target Location b (cm)	Time After Accident (hr)	Correction Factor Method (rad/hr)	Computer Results (rad/hr)	Difference (%)
6	800	548.6	570	230	24	52.7	53.3	-1.1
6	800	91.4	720	80	24	484	479	+1.0
6	800	1006.8	650	150	24	15.3	16.1	+5.0
8	800	548.6	570	230	24	77.0	80.4	-4.23
8	800	391.4	720	80	24	105.0	110.0	-4.5
8	800	1066.8	650	150	24	22.4	24.4	-8.2
2	700	100.0	600	100	720	5.36	5.32	0.75
2	700	1066.8	600	100	720	0.159	0.146	8.9
2	700	100	-900	1600	720	0.0126	0.0123	2.3
2	700	1066.8	200	900	720	0.128	0.124	3.2
12	400	1066.8	-400	800	720	1.14	1.21	-5.8
12	400	100	350	50	720	72.5	71.4	1.5
12	400	609.6	350	50	720	4.66	4.93	-5.5
12	400	1066.8	350	50	720	1.57	1.73	-9.3
10	600	304.8	-243.8	548.6	0.0333	554	539	2.7
10	600	121.9	450	150	0.0333	7617	7396	-3.0
10	600	1005.8	450	150	0.0333	258	280	-7.9



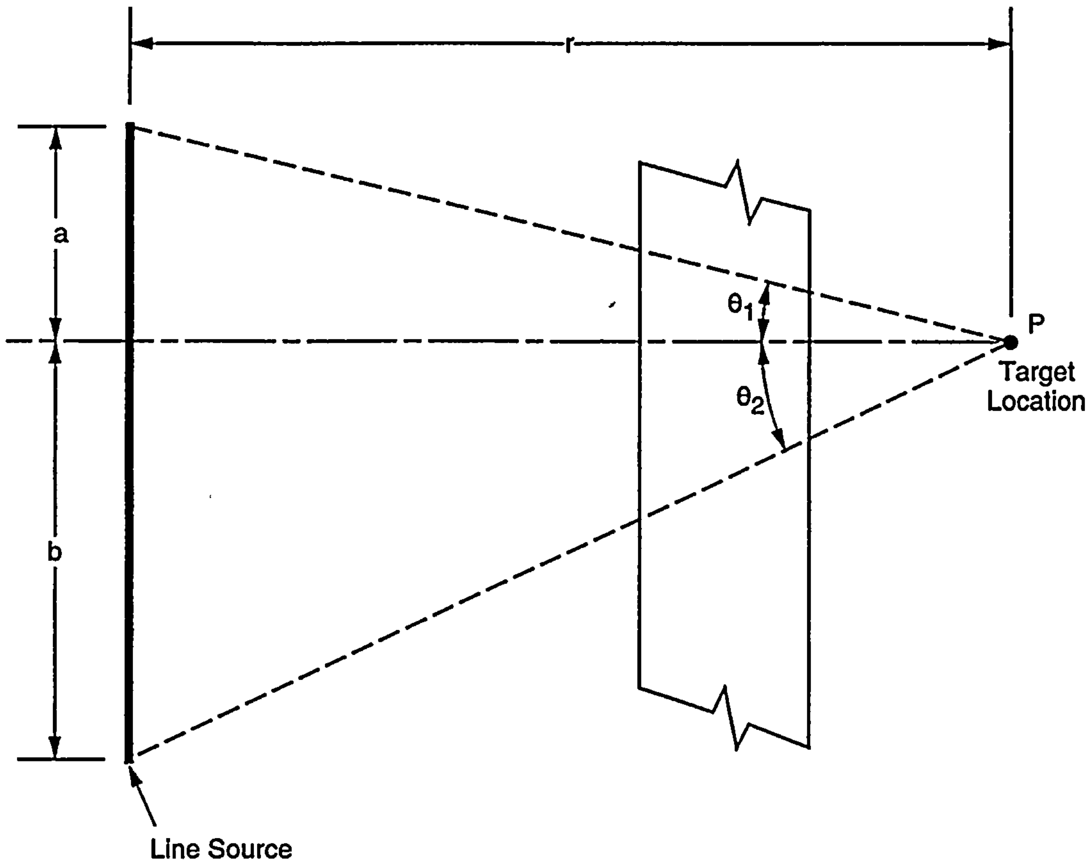
Q_2 = Air Leakage Rate from Secondary Containment (m^3/sec)
Q_1 = Air In-leakage Rate from Primary Containment (m^3/sec)
V_2 = Volume of Secondary Containment (m^3)
V_1 = Volume of Primary Containment (m^3)
i = Nuclide Index
$C_{2i}(t)$ = Activity Concentration in Secondary Containment (Ci/m^3)
$C_{1i}(t)$ = Activity Concentration in Primary Containment (Ci/m^3)
Q_{in} = Clean Air In-leakage Rate (m^3/sec)

Model of the Primary and Secondary Containment



0.5%/Day Primary Containment Leakage Rate

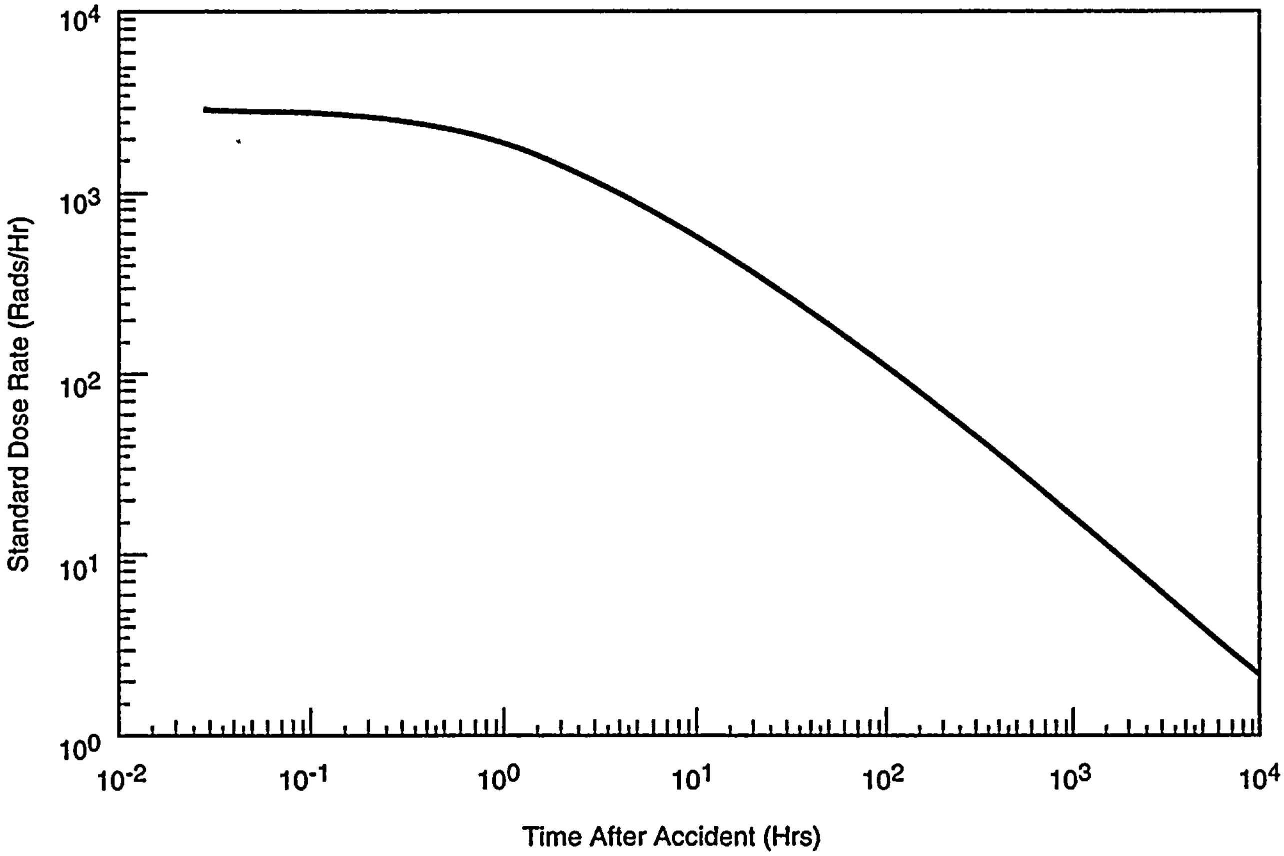
Time-Dependent Gamma Dose Rate for a Semi-Infinite Cloud of Fission Products at Secondary Containment Concentrations



$$b_i = \sum_i \mu_i t_i$$

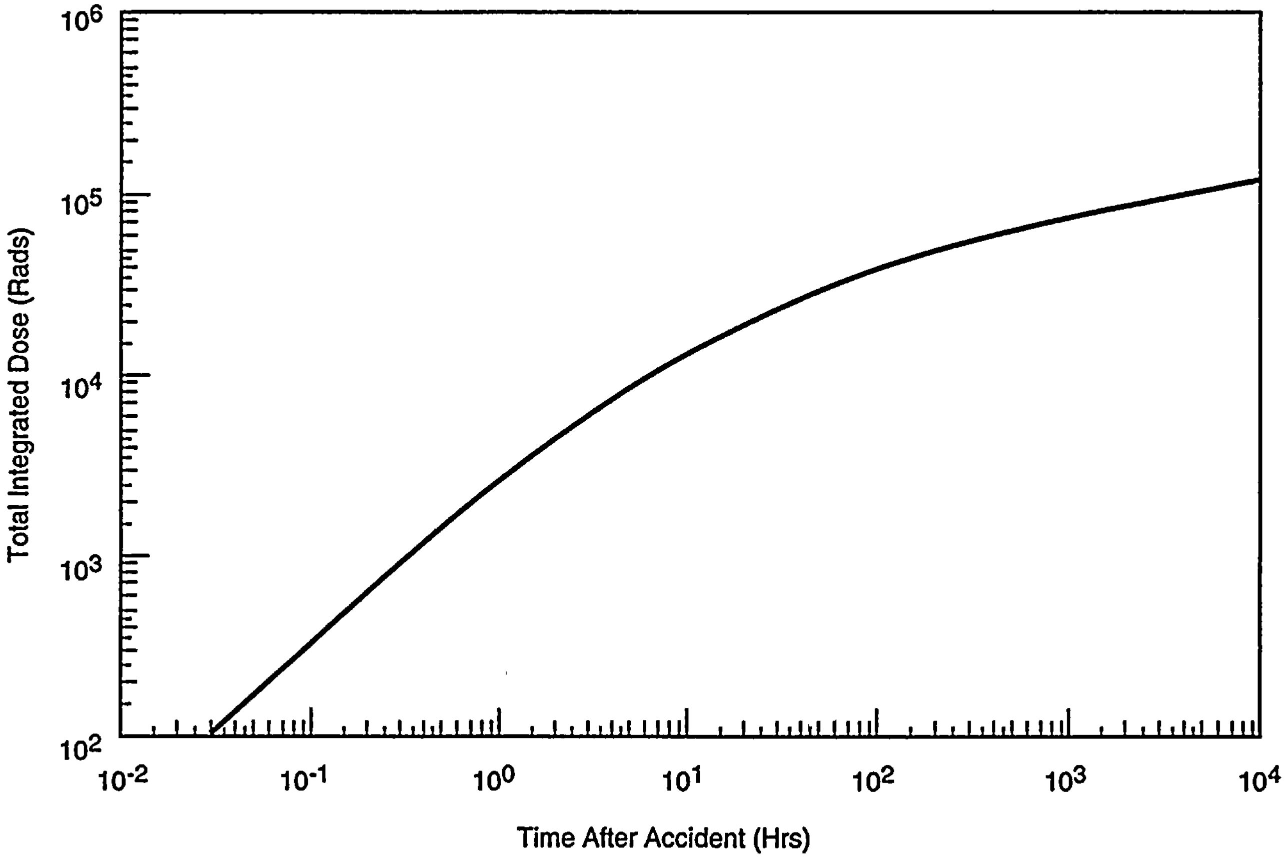
Illustration of Parameters Used in the Shielding Equation

Draw. No. 970187.26	Rev.	Figure J.B-3



Standard Gamma Dose Rate Curve for Liquid Containing Systems (RCIC Liquid System and RHR System)

Draw. No. 970187.27	Rev.	Figure J.B-4



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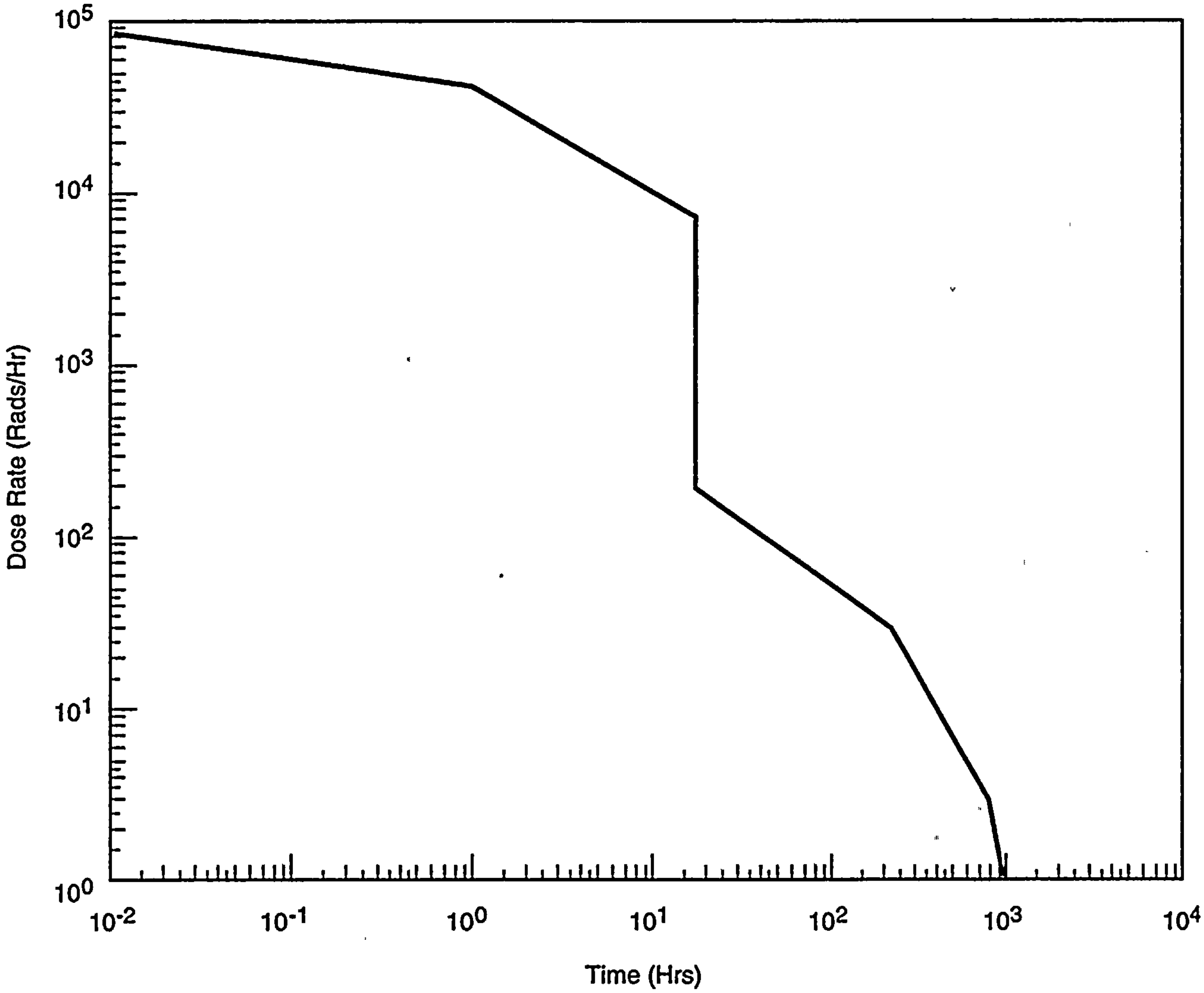
Standard Integrated Gamma Dose Rate Curve for Pipes in Liquid Containing Systems (RCIC Liquid System and RHR System)

Draw. No. 970187.28	Rev.	Figure J.B-5



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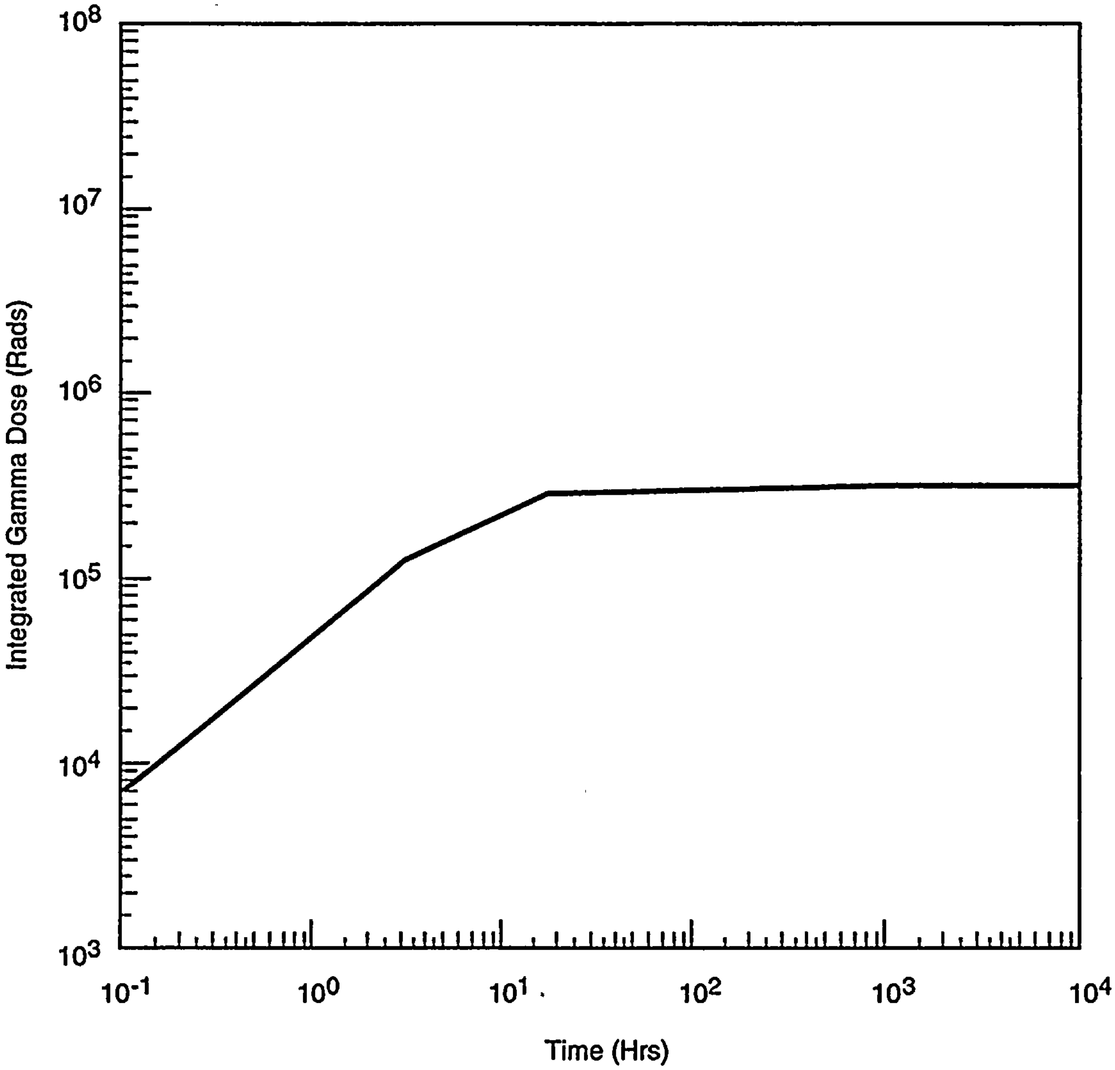
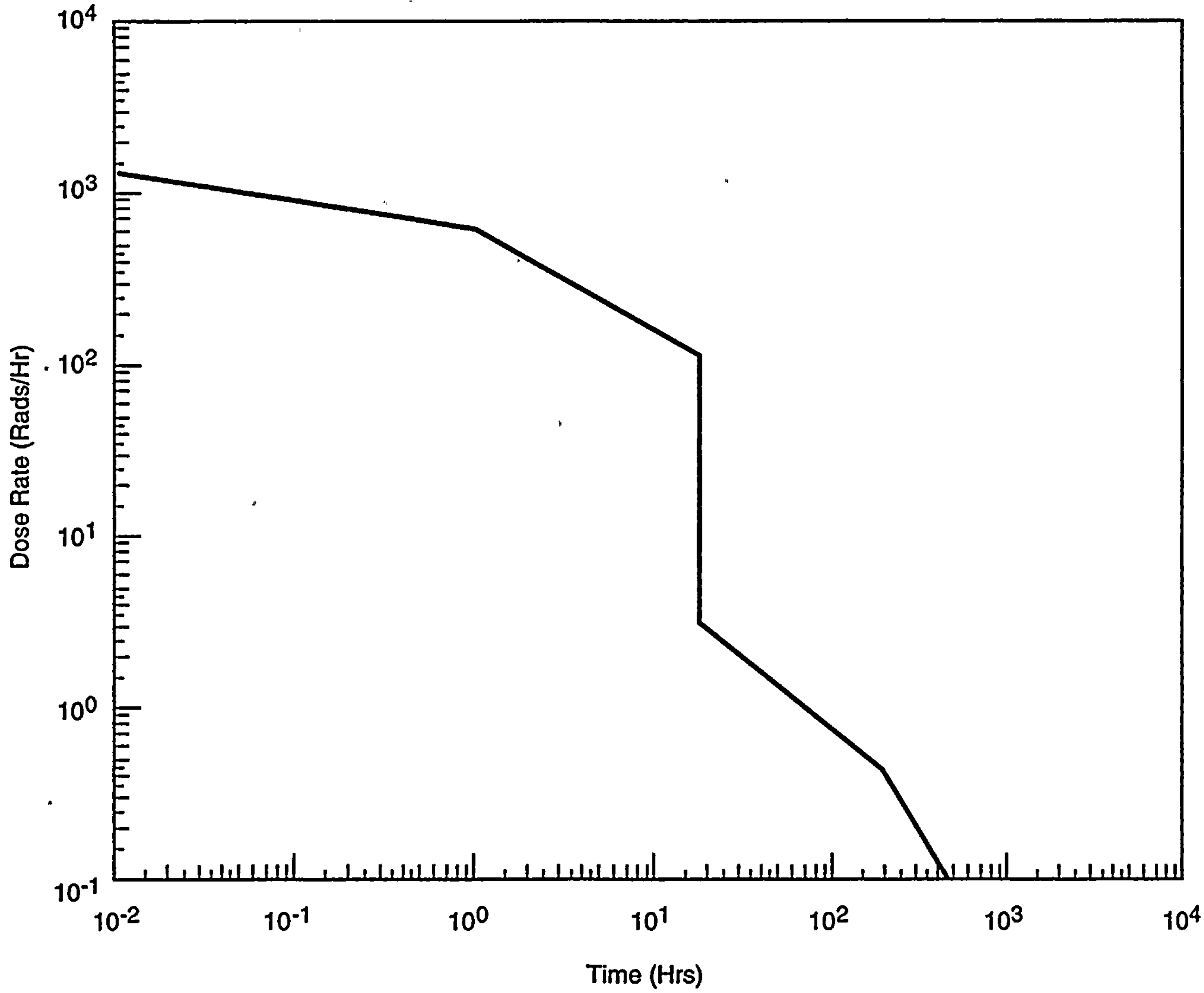
NUCLEAR PLANT 2 FSAR

Standard Gamma Dose Rate Curve for Pipes in the RCIC Steam System and MSIV-LCS Steam System Before the Header

Draw. No. 970187.29	Rev.	Figure J.B-6



Standard Integrated Gamma Dose Curve for Pipes in the RCIC Steam System and MSIV-LCS Steam System Before the Header



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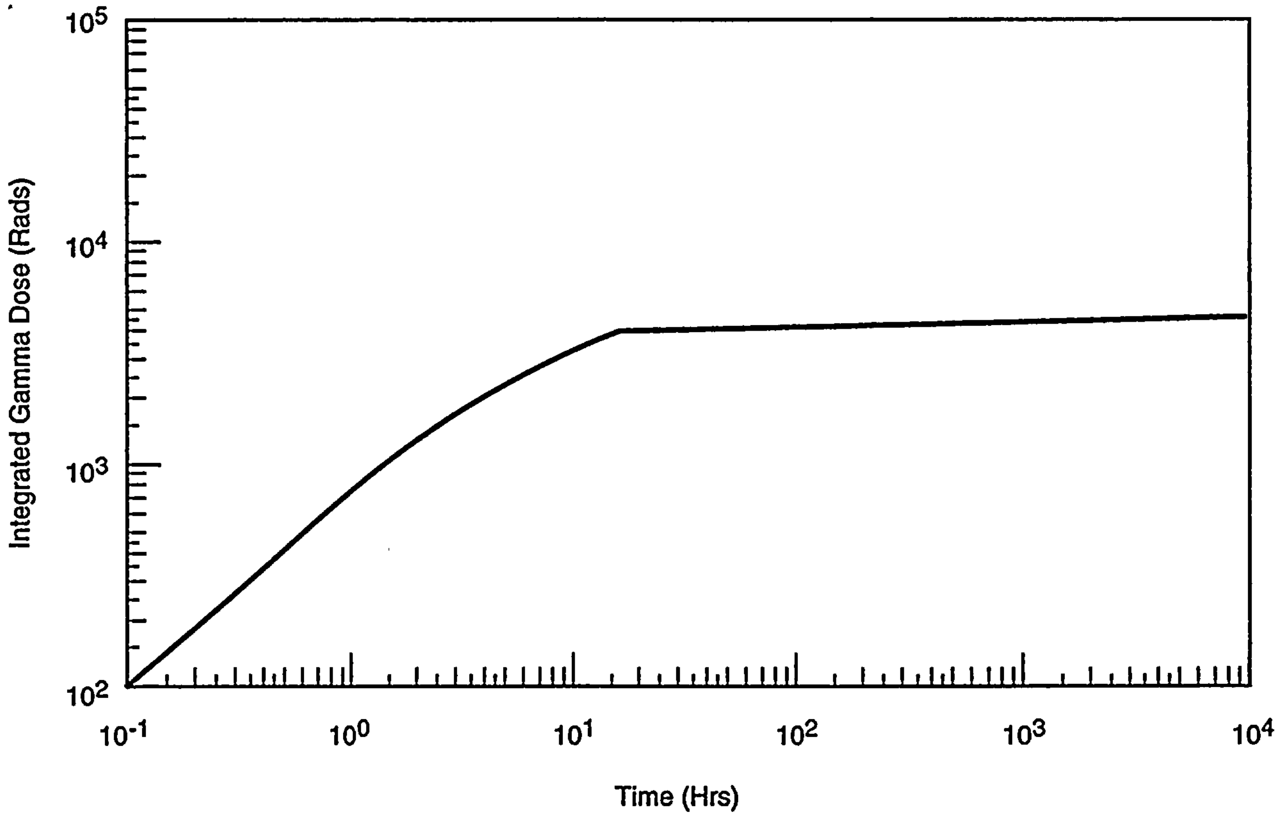
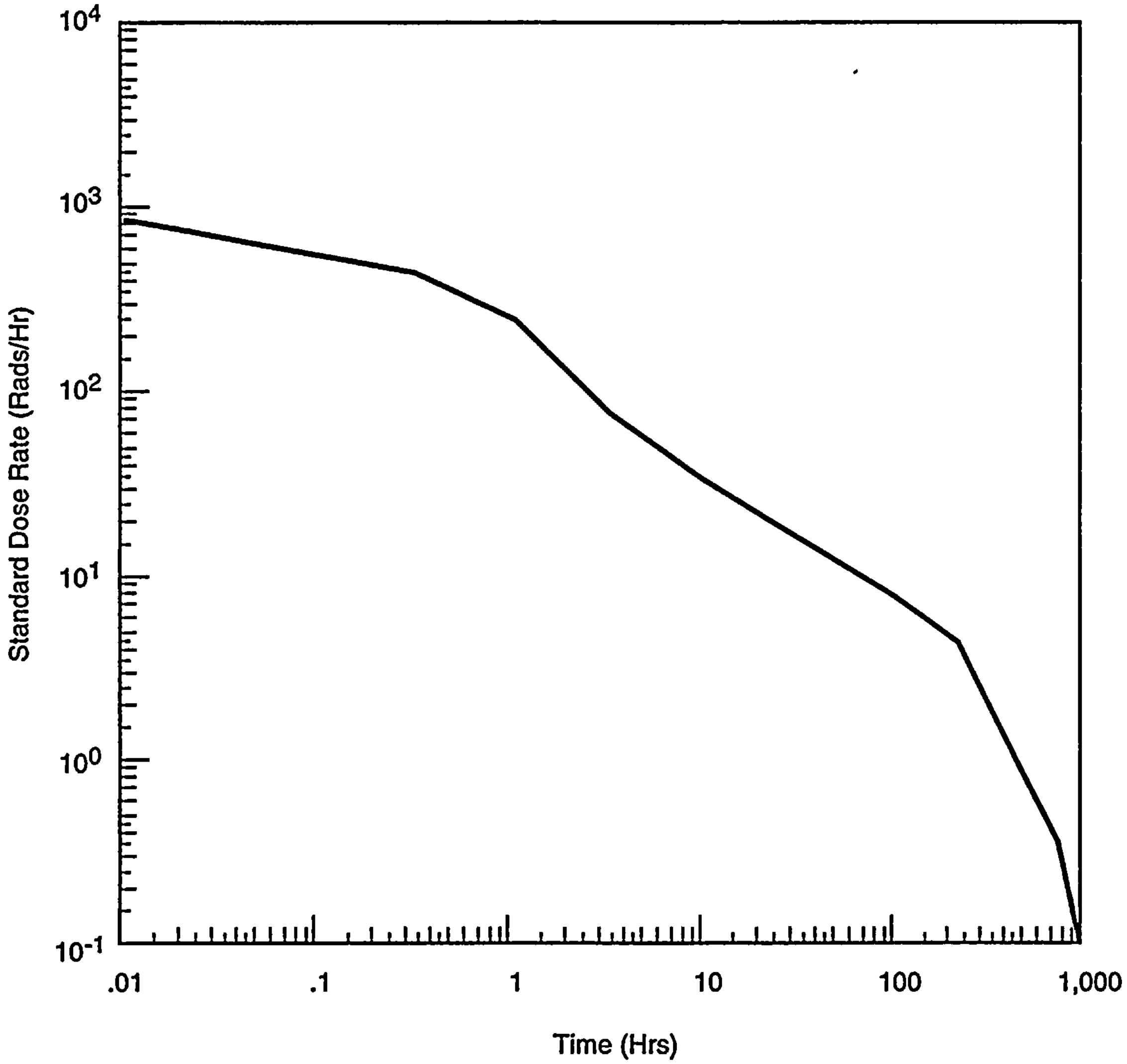
Standard Gamma Dose Rate Curve for Pipes in the MSIV-LCS Steam System After the Header

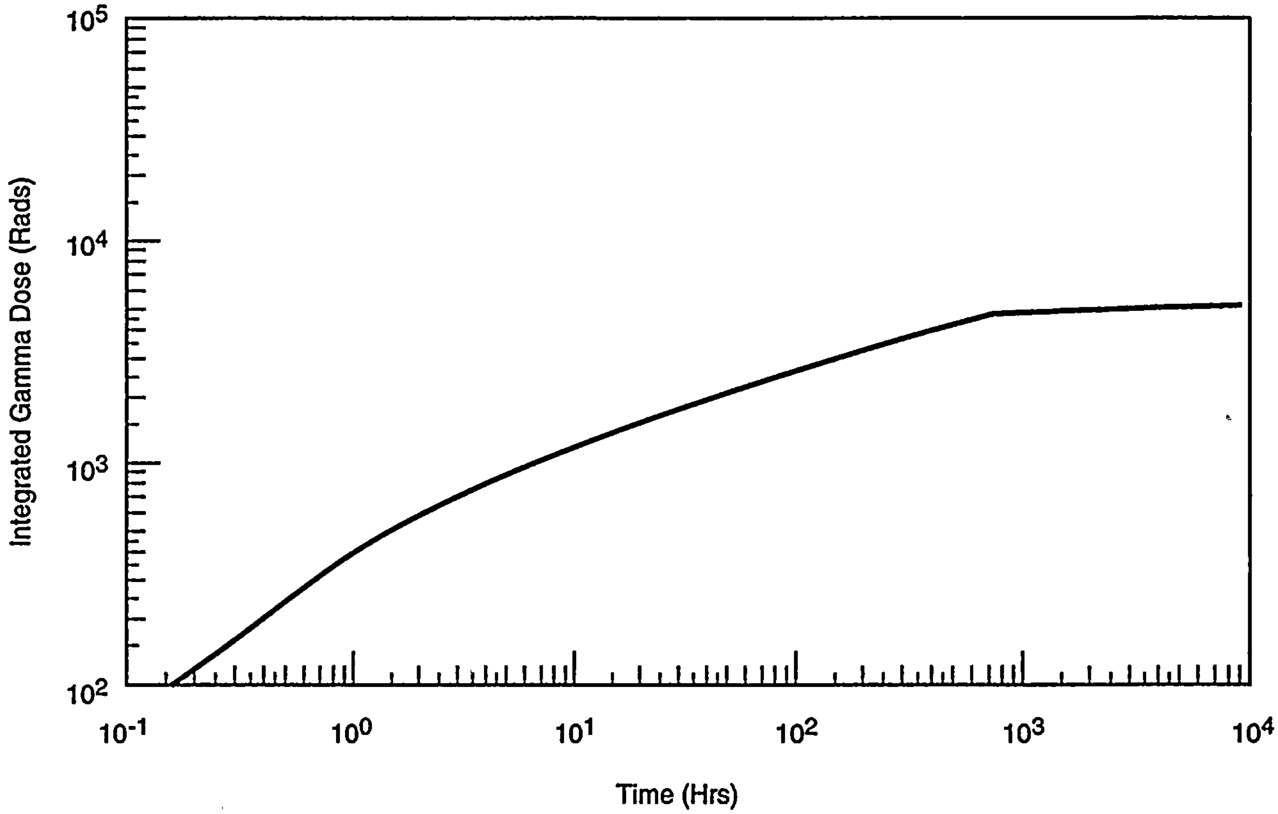
Draw. No. 970187.31	Rev.	Figure J.B-8



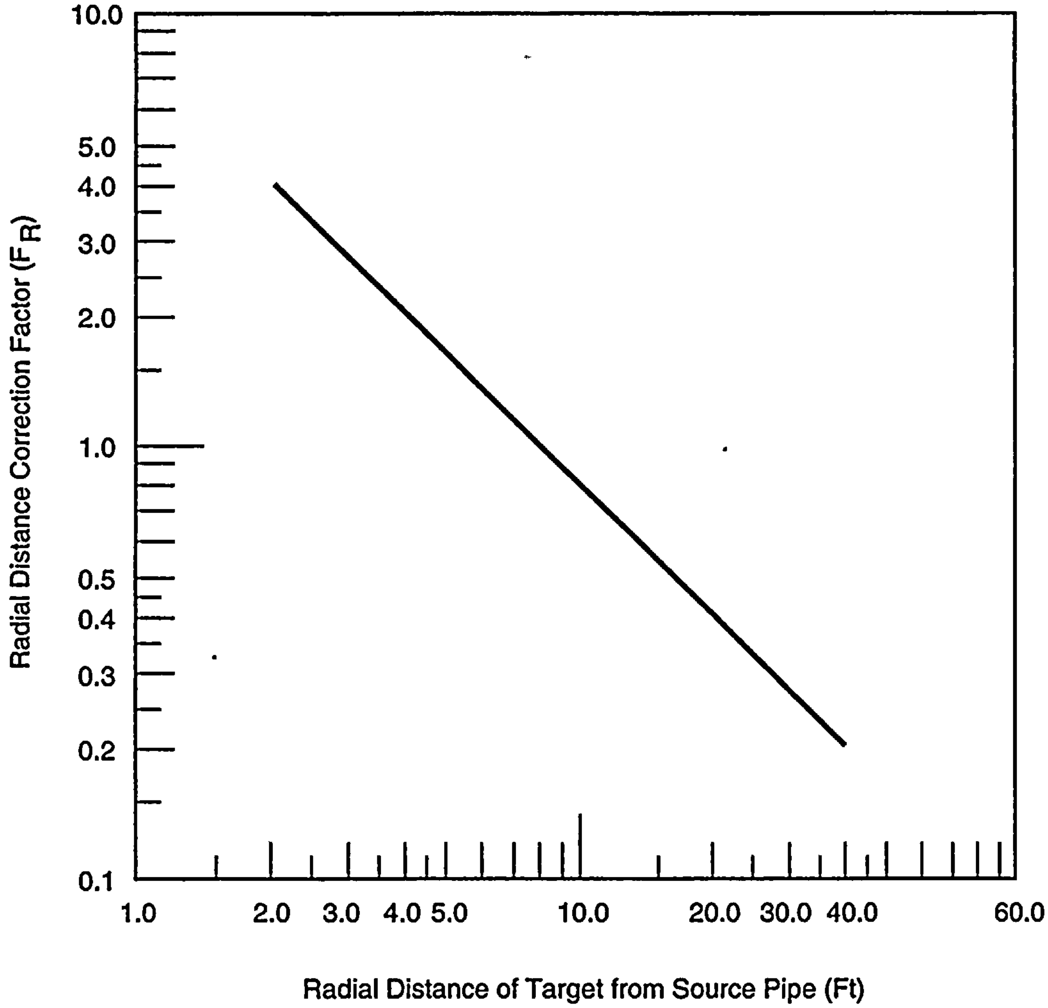
Standard Integrated Gamma Dose Curve for Pipes in the MSIV-LCS Steam System After the Header

Draw. No. 970187.32	Rev.	Figure J.B-9

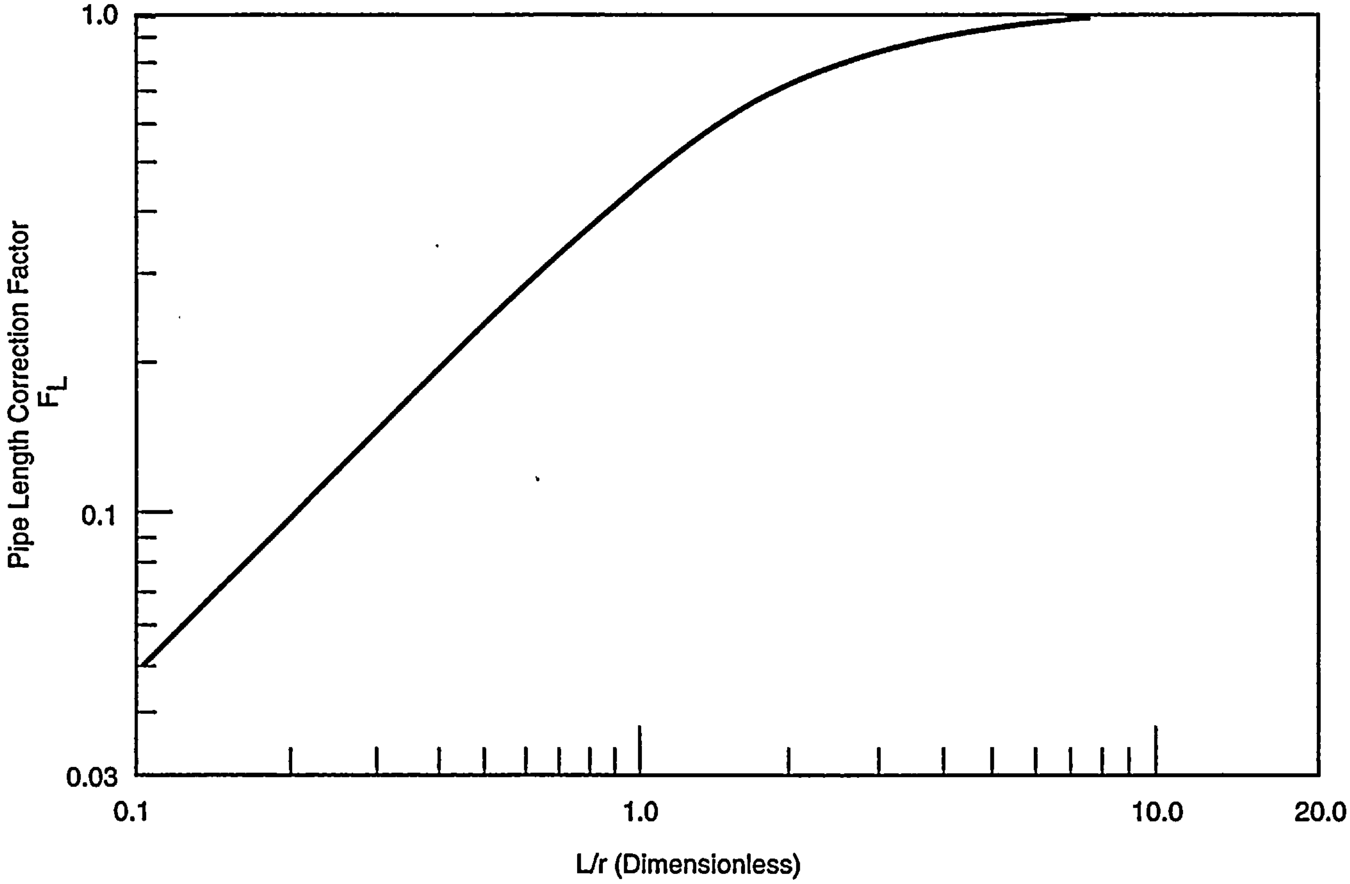

10^4
10^3
10^2
10^1
10^0
10^-1
Standard Dose Rate (Rads/Hr)
.01
.1
1
10
100
1,000
Time (Hrs)



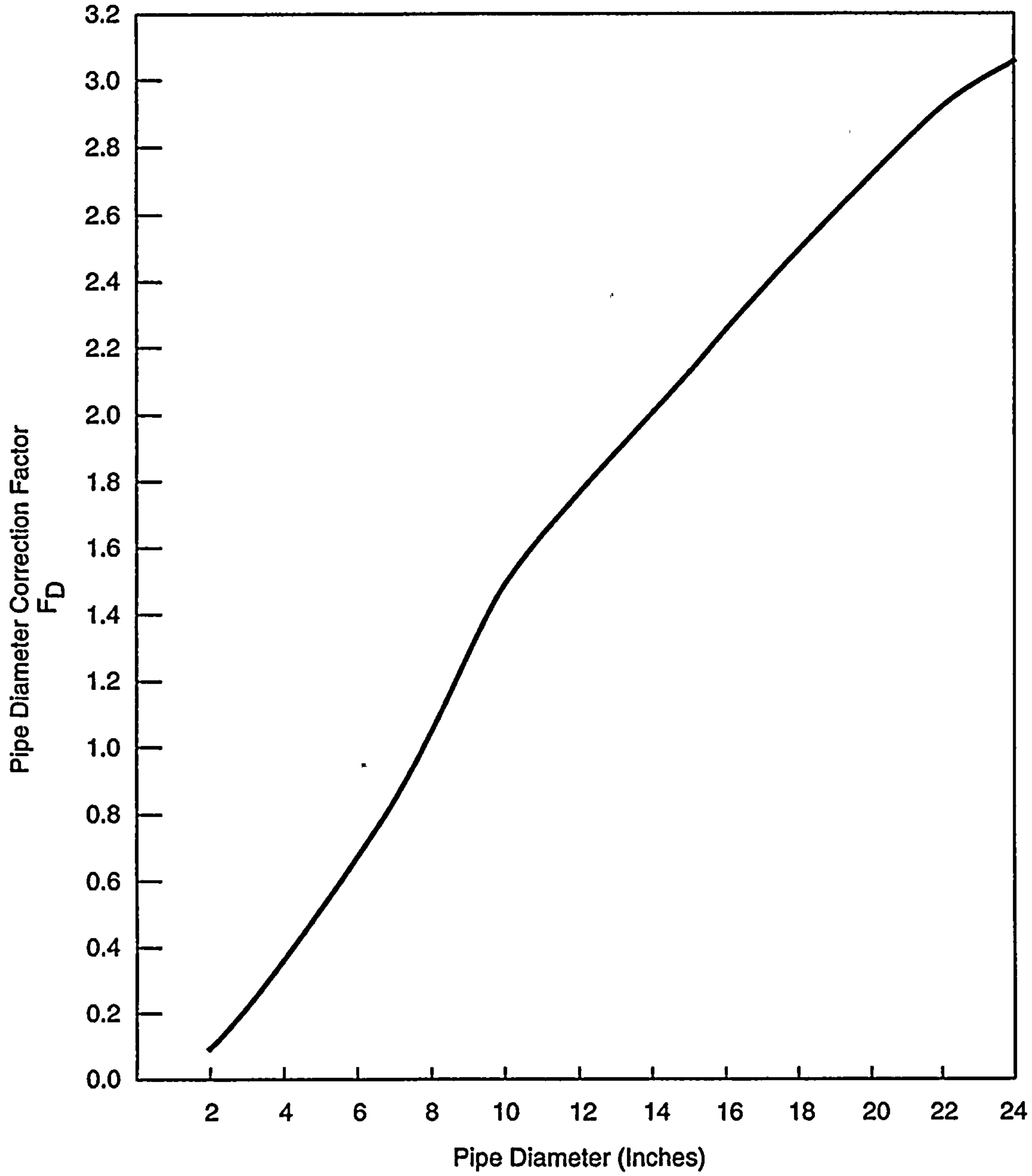
Standard Integrated Gamma Dose Curve for CAC System Gas Lines



Radial Distance Correction Factor for Liquid Sources



Pipe Length Correction Factor for Liquid Sources



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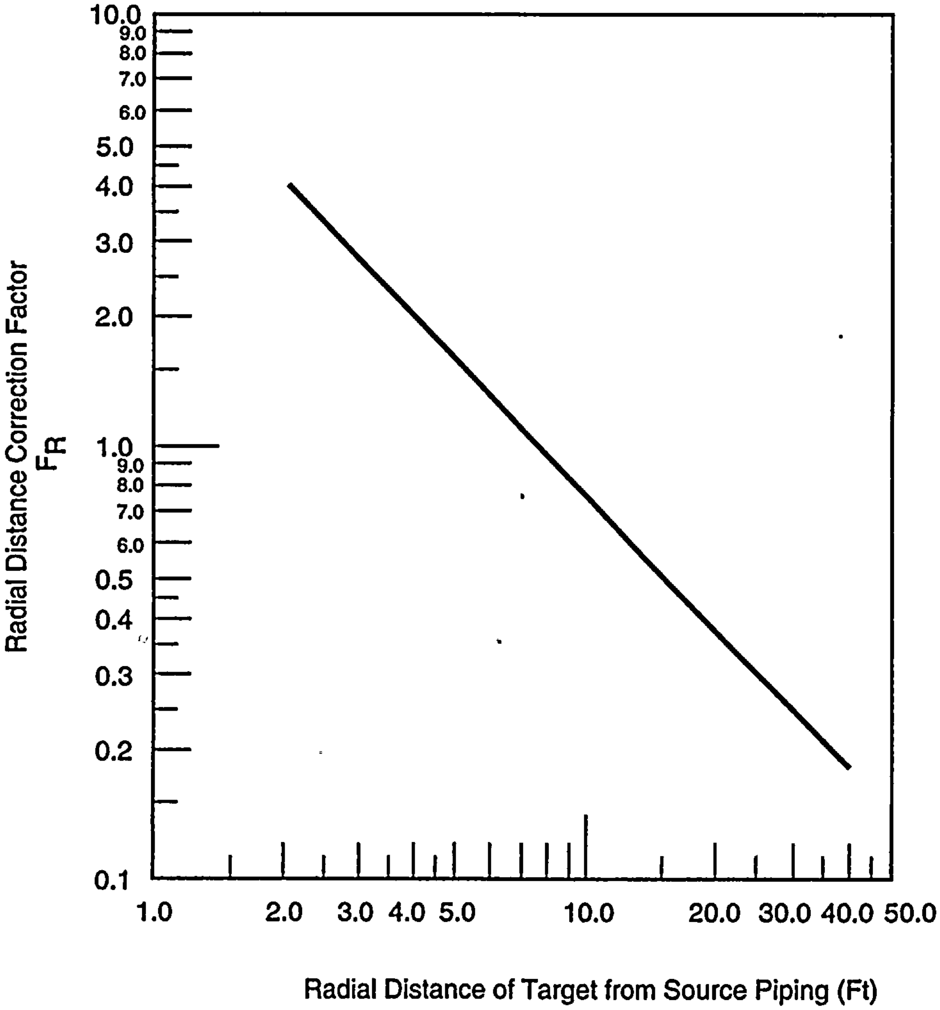
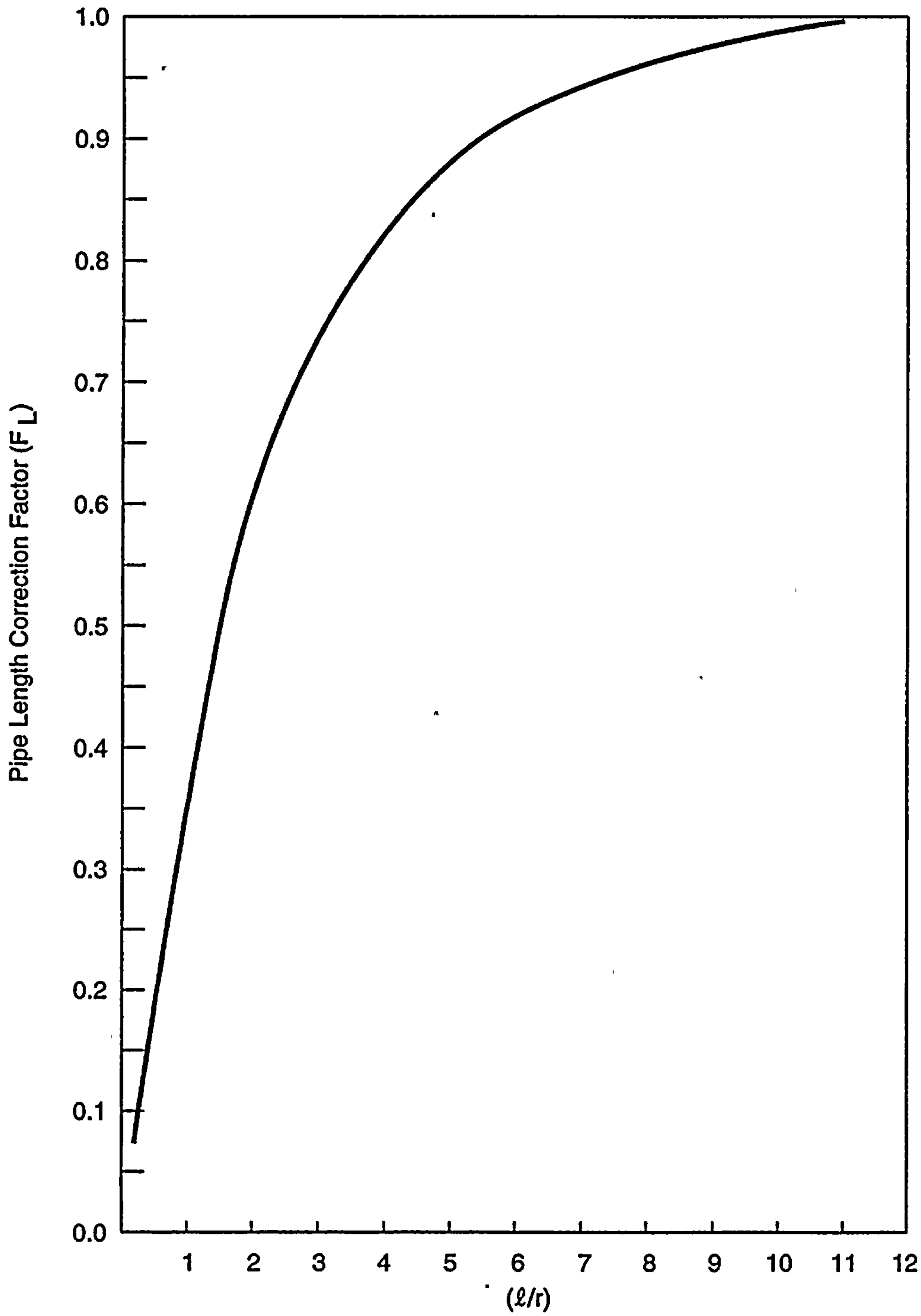
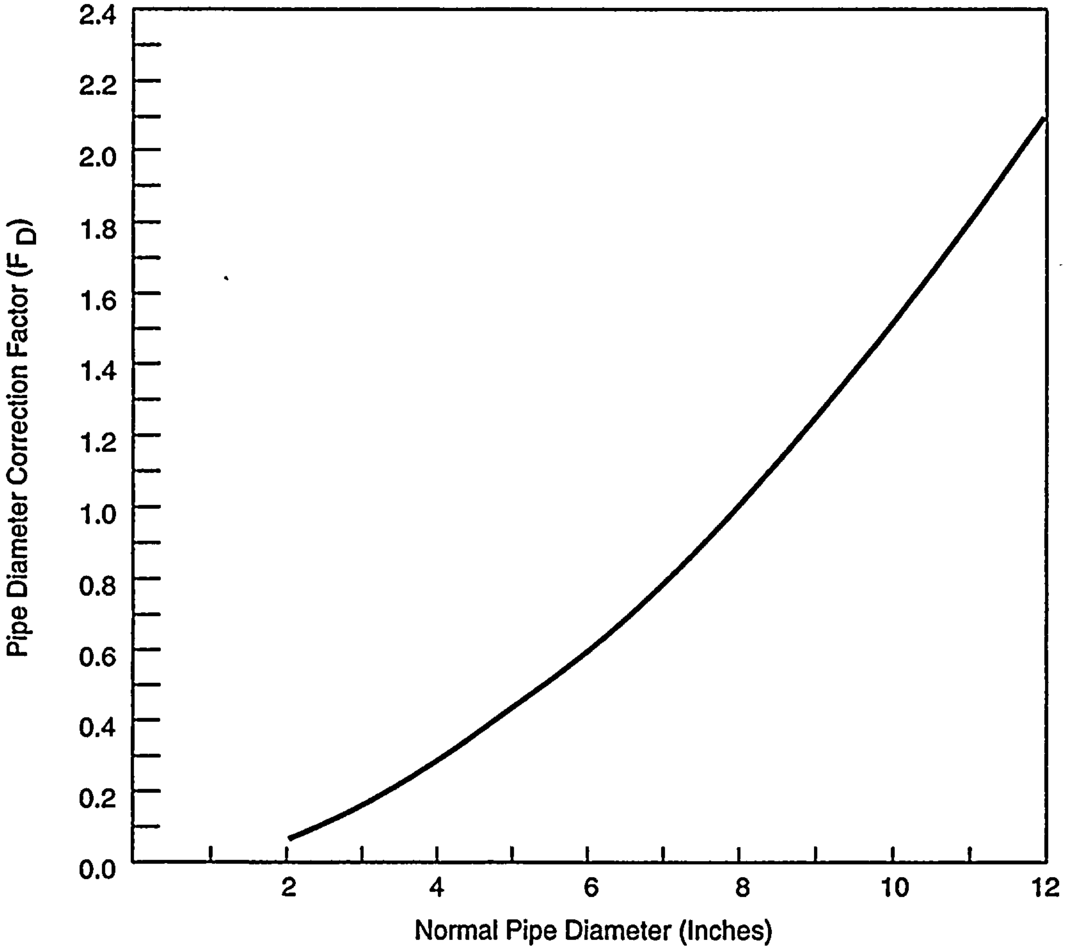
Pipe Diameter Correction Factor for Liquid Sources

Draw. No. 970187.37	Rev.	Figure J.B-14


10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
9.0
8.0
7.0
6.0
0.5
0.4
0.3
0.2
0.1
Radial Distance Correction Factor
F_R
1.0
2.0
3.0
4.0
5.0
10.0
20.0
30.0
40.0
50.0
Radial Distance of Target from Source Piping (Ft)



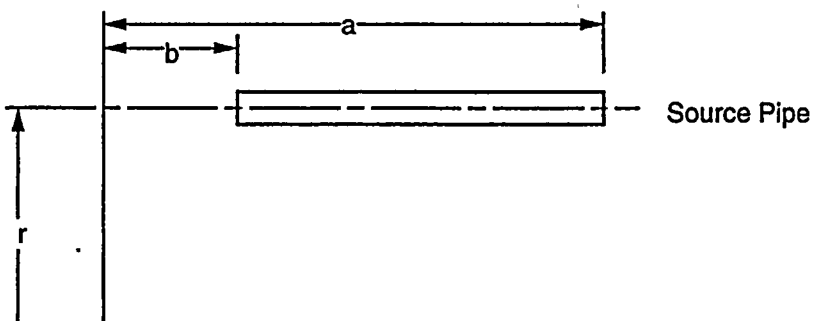
Pipe Length Correction Factor for Gaseous Sources



Pipe Diameter Correction Factor for Gaseous Sources

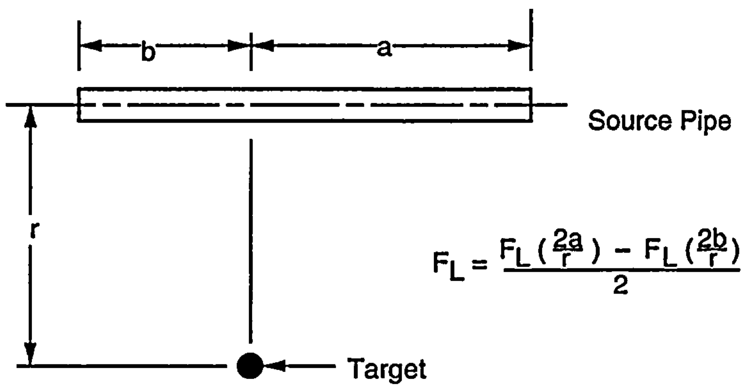
Draw. No. 970187.40	Rev.	Figure J.B-17

Configuration 1



$$F_L = \frac{F_L\left(\frac{2a}{r}\right) - F_L\left(\frac{2b}{r}\right)}{2}$$

Configuration 2



$$F_L = \frac{F_L\left(\frac{2a}{r}\right) - F_L\left(\frac{2b}{r}\right)}{2}$$

Parameters Used for the Calculation of Length Correction Factor

Attachment J.C

PROCEDURE FOR THE CALCULATION OF SECONDARY CONTAINMENT RADIATION ZONE GAMMA DOSES

J.C.1 INTRODUCTION

Three Mile Island Lessons Learned Short Term Recommendations (NUREG-0578) Section 2.1.6.b, requires all nuclear power plant licensees to calculate post-loss-of-coolant accident (LOCA) environmental conditions for all safety-related equipment. This procedure is specifically concerned with the definition of the postaccident radiological environments in the secondary containment of WNP-2, a BWR.

The assumptions used in this procedure are based on a nonmechanistic LOCA scenario in which core damage is experienced at the beginning of the accident and primary containment isolation is achieved prior to radiation transport.

The radiation level at a given location inside the secondary containment of WNP-2 during and following such an accident is defined by the following major source contributors.

Airborne gamma dose	Gamma ray dose from airborne radioactive sources inside secondary containment
Containment shine dose	Gamma ray dose from radioactive sources suspended in the drywell and the wetwell inside primary containment
Direct gamma dose	Gamma ray dose from piping containing recirculating radioactive fluids
Bioshield penetration streaming dose	Gamma ray dose from liquid piping and airborne radioactive sources inside primary containment which stream through bioshield wall penetrations into secondary containment

The methods presented in this procedure make it possible to calculate the worst-case gamma ray dose due to the above mentioned source of contributors inside radiation zones (see Section J.C.2 for the definition of radiation zones) of the secondary containment of WNP-2. The radiation zone dose calculated by using this procedure is applicable solely for the purpose of environmental qualification of safety-related equipment.

The following sections of this procedure describe the nomenclature, assumptions, and methods used in calculating radiation dose rates and cumulative doses. Section J.C.2 defines the terms and nomenclature found in this procedure. The assumptions and approximation used in

developing the dose rate calculation method, as well as limitations to this method, are stated in Section J.C.3. Section J.C.4 provides a step-by-step procedure for determining the worst-case gamma dose rate and cumulative dose inside a particular radiation zone. The calculation of airborne beta dose is defined in a separate calculation procedure and is not included in this procedure (see Attachment J.E).

J.C.2 DEFINITION OF TERMS

This section contains the definition of the terms and symbols as used in this procedure:

CIND: (rads) — Cumulative integrated dose
Cumulative dose due to exposure to the decaying radioactive sources.

D_a: (rads/hr) — Airborne gamma dose rate
Gamma dose rate resulting from radioisotopes suspended in the atmosphere of the secondary containment.

D_d: (rads/hr) — Direct dose rate
Gamma dose rate resulting from the radioactive fluid contained inside recirculating pipes.

D_s: (rads/hr) — Shine dose rate
Gamma dose rate in the secondary containment resulting from radioisotopes suspended and deposited inside primary containment.

D_B: (rads/hr) — Bioshield penetration streaming dose
Gamma dose rate contributed by the liquid piping and airborne radioactive sources inside primary containment which stream through the bioshield wall.

D_t: (rads/hr) — Total gamma dose rate
Gamma dose rate contributed by the sum of airborne, direct, and shine from penetrations into secondary containment.

$$D_t = D_a + D_d + D_s + D_B$$

GF: — Geometric factor
Scaling factor used to convert semi-infinite airborne gamma dose to finite dose inside enclosed air spaces.

$$D_a = \frac{D_{a,\infty}}{GF}$$

$$GF = \frac{1173}{V^{0.338}}$$ (Reference J.7-39)

F_L: Length conversion factor
A scaling factor dependent on the source pipe segment length and spatial orientation relative to a target (see Figure J.C-1 for the calculation of this factor). F_L is used to convert the standard dose to the dose emitted by a pipe segment of finite length.

F_D: Diameter conversion factor
A scaling factor dependent on the source pipe diameter. F_D is used to convert the standard dose to the dose emitted by a pipe of specified diameter.

F_R: Radial distance conversion factor
A scaling factor dependent on the radial distance of the target from the source piping. F_R is used to convert the standard dose to the dose at a target of specified radial distance from the source piping.

F_t: Total dose contribution correction factor
A scaling factor used to convert the standard dose to the dose at a target from a pipe segment of specified geometry and orientation.

$$F_t = F_D * F_R * F_L$$

F_s: Sum of dose contribution correction factor
A scaling factor used to convert the standard dose to the radiation zone dose due to all the significant pipe sources in the zone.

$$F_s = \sum_{i=1}^{n} F_{ti}$$

Radiation zone: A region in the secondary containment defined to be such that gamma radiation calculated in the zone bounds the magnitude of dose received by the pieces of safety-related equipment located in that zone.

Source term: The total radiated gamma energy associated with a specified quantity of radioactive material released from the reactor as the result of a postulated accident.

Special sources: Radioactive source of such geometry or concentration that cannot be approximated by pipe segments of diameters 2 in. through 24 in. and containing contaminated liquid of activity concentration established in Section J.C.3.1. This can be a heat exchanger, standby gas treatment filter, pump, etc.

Standard dose: Gamma dose at a target having a radial distance of 8 ft from the centerline of an infinitely long, 8-in.- diameter schedule 40 pipe.

Target: The point in space chosen to represent the location of an object for which a dose rate and/or cumulative dose is being calculated.

Worst case target: Location of the piece of safety-related equipment inside a radiation zone which will experience the highest gamma dose among all the pieces of safety-related equipment in that zone.

J.C.3 ASSUMPTIONS, APPROXIMATIONS, AND LIMITATIONS

J.C.3.1 Basic Assumptions to be Used in the Analysis

Gamma doses and dose rates inside radiation zones will be determined for four types of radioactive source distribution:

Major Source	Contributors
Airborne gamma dose	Isotopes suspended in the atmosphere of the secondary containment
Shine dose	Gamma irradiation from the primary containment
Direct dose	Direct gamma irradiation from the radioactive fluid contained inside recirculating pipes
Streaming dose	Gamma irradiation from liquid piping sources inside primary containment and primary containment atmosphere streaming through bioshield wall penetrations

The dose contributed by each of these sources is determined by the location of the equipment, the time dependent distribution of the source, and the effects of shielding.

The assumptions used in determining the initial distribution and leakage of radioactivity in the primary containment are as follows:

a. 100% of the noble gases and 50% of the halogens initially in the reactor core will be distributed homogeneously within the primary containment free volume immediately following the postulated accident. Plateout of 95% of the elemental iodines is allowed to occur in accordance with Reference J.7-34;

b. 50% of the halogens and 1% of the remaining fission products in the core will be mixed homogeneously with the primary containment liquid space instantaneously. The primary containment liquid space is defined as the sum of the suppression pool liquid and the reactor coolant system (RCS) liquid. Assumptions a and b are NRC-recommended assumptions for defining radioactivity release fractions for the qualification of safety-related equipment (Reference J.7-2) and are consistent with the accident analysis (Reference J.7-13);

c. The core fission product source term is defined as the total product generated in the core after 1000 days at a reactor power of 3556 MWt. This represents the maximum burnup level in the core prior to radioactivity release and is conservative; and

d. Primary containment leakage of 0.50% volume/day was considered and is consistent with the assumptions established in Reference J.7-13.

J.C.3.1.1 Assumptions Used in the Calculation of Airborne Dose Rate Inside Secondary Containment

a. Activity that leaks into the secondary containment is homogeneously mixed with the secondary containment atmosphere prior to its removal from the atmosphere by the standby gas treatment system (SGTS) exhaust fans. This is consistent with the NRC-recommended assumptions used for calculation of doses inside primary containment (Reference J.7-2);

b. The SGTS flow rate of 2430 scfm is assumed to be the flow rate of the effluent air and is based on one reactor building air change per day;

c. Air that leaks out of the primary containment flows directly into the secondary containment. Bypass leakage is not considered. This is conservative when considering dosage in the secondary containment, since it maximizes the buildup of radioactivity in the secondary containment; and

d. Geometric factors provide a good approximation to convert the semi-infinite cloud dose to a finite cloud dose and is based on the results presented in Reference J.7-28 and based on average gamma ray energy of 0.733 MeV. The effect of variation of this parameter due to difference in gamma ray energies have been proven to be negligible (see Attachment J.B for justification).

J.C.3.1.2 Assumptions Used for the Calculation of Shine or Streaming Dose From Primary Containment

a. No depletion of activity due to leakage is assumed to maximize the source activity and is conservative;

b. The airborne source is assumed to be uniformly distributed in the drywell and in the wetwell air space. The effect of the plateout of iodine is not considered in secondary containment;

c. Activity in the wetwell water volume is assumed to be uniformly distributed in the sump water. Assumptions b and c are based on the plateout modeling and source term assumption contained within References J.7-2 and J.7-34;

d. The dosage at a point inside the region closest to the source is considered to be representative of the gamma dose in the region which maximizes the gamma ray dose at the region and is conservative; and

e. The liquid piping sources inside primary containment are assumed to be uniformly distributed in the RCS for the first 17 hr post-LOCA. The liquid piping sources inside primary containment are assumed to be uniformly distributed in the RCS plus the suppression pool after the first 17 hr post-LOCA. This is consistent with the WNP-2 operations procedure to depressurize and utilize the alternate shutdown cooling mode within 17 hr post-LOCA once a degraded core condition is identified.

J.C.3.1.3 Assumptions and Approximations Used in the Calculation of Direct Doses

a. No valve leakage is assumed, which is consistent with Reference J.7-5, Item II.B.2, Clarification (2);

b. Schedule 40 piping is assumed, which is a conservative simplification of the calculation process. Because the majority of the pipe segments considered are schedule 40 piping, and because increases in pipe schedule can only decrease the dose rate at the targets, this approximation is considered to be conservative and appropriate;

c. Heat exchangers and pumps can be approximated as pipe systems. The volume of radioactive liquid in the component and its length are used to determine an equivalent volume of liquid. This is a crude approximation for dose rates contributed by complex geometries. Because the pump and heat exchanger walls are thicker than the pipe walls of schedule 40 piping, this assumption is conservative; and

d. Radioactive piping with diameters 2-1/2 in. or less was not modeled unless it was determined that such a pipe was a major source contributor. A major source contributor is defined as the only radioactive pipe in a target area or the radioactive pipe of closest proximity to the target. This is made because the dose contributions due to pipe segments of diameter less than 2-1/2 in. are generally negligible, unless they are major source contributors.

J.C.3.2 Limitations

The following limitations apply to the use of this procedure for the calculation of radiation zone doses.

a. This procedure is only applicable to the calculation of radiation zone gamma doses in the secondary containment of WNP-2;

b. The assumptions stated in Section J.C.3.1 are basic to the methodology used in this procedure. Changes in any of the assumptions will affect the accuracy of the results generated using this procedure;

c. The calculation of direct doses using the generic curves in this procedure is limited to liquid sources in schedule 40 pipe segments or equivalent pipe segments with nominal pipe diameters ranging from 2 in. to 24 in. Any deviation from these pipe geometries should be modeled as special cases. Note: Schedule 40 piping is used because the majority of the pipe segments to be considered are standard pipes (schedule 40). Increases in the pipe schedule only introduces conservatism in the results;

d. The results for direct dose calculated using the generic curves were found to be accurate to within 10% (see Reference J.7-39 for error study); and

e. Source piping located 40 ft or further from the target is generally an insignificant dose contributor. If its contribution is not found to be negligible, it should be considered as a special source.

J.C.4 PROCEDURES FOR THE CALCULATION OF SECONDARY CONTAINMENT RADIATION ZONE DOSES

This procedure describes the method used in calculating the gamma radiation doses inside radiation zones. For equipment located inside a zone, the following four sources contribute to the total dose level.

a. Airborne dose (gamma),
b. Direct gamma dose from sources within pipes,
c. Direct gamma shine dose from drywell and wetwell, and
d. Gamma streaming dose from drywell and wetwell.

A step-by-step procedure is discussed in the following sections for the calculation of the maximum total gamma dose and dose rates for each zone.

J.C.4.1 Procedure A: Radiation Zone Dose Calculation

The first step in preparing a zone dose calculation is to identify all the parameters to be used. This includes the identification of all the potential sources and targets, both inside and outside the zone, and the identification of the dimensions of the zone. Figure J.C-2 is a step-by-step flowchart of the calculation procedure. When identifying sources outside the zone, sources at the upper and lower elevations in the review process are included. A conservative dose estimate is used to determine whether a source outside a zone is a significant contributor. For example, if the closest pipe segment in the zone is a few feet away from a target, then the dose estimate will show that a pipe segment outside the room at 30 ft is insignificant by comparison. Conversely, if a target is located near a wall with several pipes on the other side of a wall, then those pipes may become significant source contributors and are included in the final evaluation for the target.

J.C.4.2 Procedure B: Airborne Dose Calculation in Secondary Containment

Because the semi-infinite airborne dose and dose rates are already calculated and shown in Figures J.C-6 and J.C-7, the only calculation involved in determining the airborne dose is the conversion of the semi-infinite cloud dose at reactor building concentrations to a finite cloud dose inside the cubicles in which the radiation zones are defined. The first step in this calculation is to determine the volume which defines the air space (or zone) of interest. An enclosed air space is defined as a cubicle, at least 95% shielded by concrete (or equivalent shielding) at least 1 ft thick.

To convert a semi-infinite cloud dose (calculated in Reference J.7-38) to a finite cloud dose, a geometric factor is used.

$$D_a(t) = \frac{D_{a,\infty}(t)}{GF} \qquad (J.4\text{-}1)$$

where $GF = \frac{1173}{V^{0.338}}$ (Reference J.7-39) (J.4-2)

GF	=	geometric factor (dimensionless)
V	=	volume of the enclosed air space (ft^3)

Similarly,

$$CIND_a(t) = \frac{CIND_{a,\infty}(t)}{GF} \qquad (J.4\text{-}3)$$

Figure J.C-3 is a step-by-step flowchart of the procedure for calculating airborne gamma doses.

J.C.4.3 Procedure C: Primary Containment Shine Dose Calculation

Containment shine doses are calculated using the QAD-P5A computer code. Guidelines for preparing input parameters are documented in Procedure E and Reference J.7-10. The modeling procedure and the accuracy of the results are highly dependent on the geometry to be modeled, specification of the source volume, and the selection of a buildup factor. Figure J.C-4 is a step-by-step procedure for calculating containment shine doses.

J.C.4.4 Procedure D: Direct Dose Calculation

The first step in the direct dose calculation (from Reference J.7-39) is the identification of the "worst-case" target. Normally, the worst-case target is the piece of equipment that is closest to the major source piping and can be selected by inspection. However, if situations arise such that the worst-case target cannot be chosen by simple inspection, order-of-magnitude calculations are performed for each potential worst-case target in the zone. These calculations are illustrated in Steps 3a through 3c of Figure J.C-5.

The next step is to identify special sources. Special sources are defined as source geometries that cannot be represented by liquid pipe segments between 2 and 24 in. in diameter. Example special sources are SGTS filters, reactor core isolation cooling (RCIC) steam pipe, turbines, and heat exchangers larger than 24-in. diameter. Other components such as pumps and small heat exchangers should be modeled as pipes. The pipe cross-sectional area is calculated by dividing the total fluid volume by the effective length of the component.

The contribution due to sources with shield walls is investigated next. Figure J.C-13 is used for this evaluation. If these sources are determined to be significant contributors, special QAD-P5A modeling procedures as described in Procedure E are followed.

It is unlikely that all sources under consideration will contribute significantly to the dose at a specific target. If all source contributions were to be calculated, the time involved in performing the calculation would be unnecessarily long without making a substantial improvement in the accuracy of the results.

Hence, as the sources are being identified, good judgment is used to distinguish between sources which contribute significantly to the target dose and those sources which do not.

An insignificant source is determined by comparing its dose contribution to the source making the largest dose contribution. The comparison is facilitated by arranging sources in decreasing order of importance and assigning rank numbers to the sources. The largest dose contributor is given a ranking number of 1. The largest dose contributor is determined by inspection of the sketches and drawings being used. The largest dose contributor is generally the longest segment with the largest pipe diameter and the least amount of intervening shielding between the target and source. All sources which are in the radiation zone and have been assumed to be insignificant contributors are listed as such to indicate that those sources have been considered.

Equations Used in the Calculation of Dose Rates

The following procedure is followed for the calculation of correction of dose rates factors of dose rates (Step 9 through Step 12 of Figure J.C-5):

a. Identify the radial distance of the pipe segment from the target; read F_R from Figure J.C-11.

   If the target is in contact with the source piping, read F_D from Table J.C-1 and set F_R and F_L equal to 1.

   (Note: dose rate is not a function of pipe length and radial distance.)

   If the target is geometrically in line with the source pipe segment, as shown in configuration 3 of Figure J.C-1, set $F_L=1$ and read F_D and F_R from Figures J.C-14 and J.C-15, respectively.

   (Note: F_L is defined here because dose rate is not sensitive to pipe length variation.)

b. Identify the pipe diameter; read F_D from Figure J.C-10.

c. Determine F_L from Figure J.C-12; use equations in Figure J.C-1 to calculate this factor.

d. The total dose contribution factor for a given pipe segment (I) is given as

$$F_t(I) = F_D(I) * F_R(I) * F_L(I)$$

e. When all the significant contributions have been calculated, sum the total dose contribution factors.

$$F_s = \sum_{n=1}^{n} F_t(I)$$

f. To determine if a source is negligible, the following test should be performed:

When N source segments are being considered and the dose contribution of ranking I is less than 1/10 of the dose rate calculated from the largest source divided by (N-I), the sources remaining should not contribute more than 10% to the total source contribution. This level of accuracy should be adequate for most calculations.

The total integrated direct dose and dose rate can be calculated.

$$D_D(t) = D_{Do}(t) \cdot F_s + D_D(t) \qquad \text{(Special Sources)}$$

$$CIND_D(t) = CIND_{Do}(t) \cdot F_s + D_D(t) \qquad \text{(Special Sources)}$$

where $D_{Do}(t)$ and $CIND_{Do}(t)$ are dose rates and cumulative doses for standard pipe segments and are found on Figures J.C-8 and J.C-9.

J.C.4.5 Procedure E: QAD-P5A Modeling Procedure

Direct dose contribution due to special sources and/or sources with shield walls should be calculated using the QAD-P5A computer code. This computer code is three-dimensional and calculates dose rates at specified target locations from radioactive volume, line, and point sources. Attenuation due to shield materials, if applicable, is also applied.

The accuracy of the results is highly affected by the manner by which the source volume is divided, and the position of the target relative to the source point. Therefore, a sensitivity study on the specification of the source volume should be performed. This can be achieved by

increasing the number of source volume divisions until the dose rate results converge to within 5%.

Another factor to be considered is the specification of the buildup factor. As a general rule, aluminum buildup factor should be used when concrete shield is encountered, and iron energy buildup factor should be used when considering attenuation through steel shield.

J.C.4.6 Procedure F: Streaming Dose Calculation

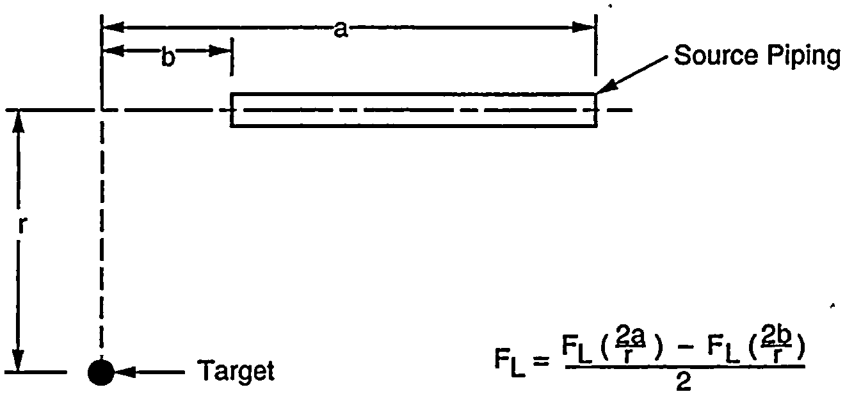
Containment streaming doses through the bioshield wall penetrations are calculated using the SCAP-BR and QAD-CG computer codes. The modeling procedure and the accuracy of the results are highly dependent on the geometry to be modeled, specification of the source volume, and the selection of a buildup factor.

TABLE J.C-1

DIAMETER CORRECTION FACTOR (F_D) FOR TARGETS IN CONTACT WITH THE SOURCE PIPING

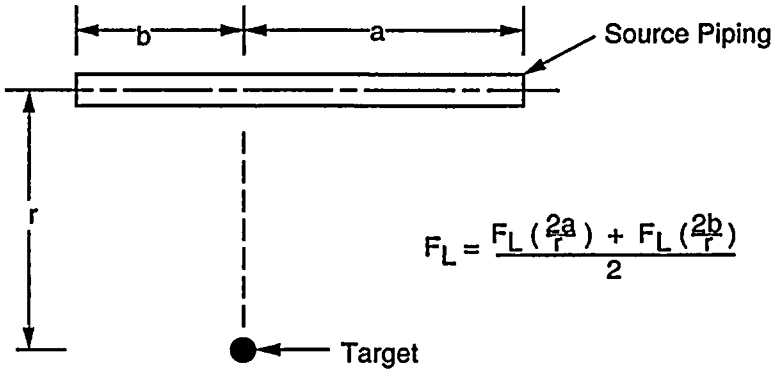
Nominal Pipe Diameter (in.)	Pipe Diameter Correction Factor (F_D)
2	18.4
4	24.4
6	54.6
8	33.3
10	35.3
12	35.3
14	35.5
16	33.7
20	32.0
24	29.6

Configuration 1



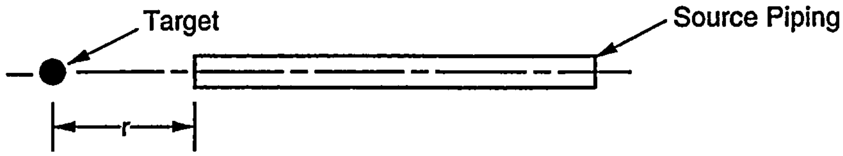
$$F_L = \frac{F_L\left(\frac{2a}{r}\right) - F_L\left(\frac{2b}{r}\right)}{2}$$

Configuration 2



$$F_L = \frac{F_L\left(\frac{2a}{r}\right) + F_L\left(\frac{2b}{r}\right)}{2}$$

Configuration 3



$$F_L = 1$$

Start

↓

Step 1 — Identify Dimensions of Zone

↓

Step 2 — Locate Targets Inside Zone on the Zone Sketch

↓

Step 3 — Identify All Dose Contributing Sources Inside Zone and Locate on Zone Sketch

↓

Step 4 — Identify All Possible Dose Contributing Sources Outside Zone

↓

Step 5 — Calculate Airborne Gamma Dose Rate and Integrated Dose (Refer to Procedure B)

↓

Step 6 — Calculated Shine and Streaming Gamma Dose Rate and Integrated Dose (Refer to Procedure C)

↓

Step 7 — Calculate Direct Dose Gamma Dose Rate and Integrated Dose (Procedure D)

↓

Step 8 — Calculate Total Gamma Dose and Dose Rate

$$D_t = D_a + D_d + D_s + D_B$$

$$CIND_t = CIND_a + CIND_d + CIND_s + CIND_B$$

↓

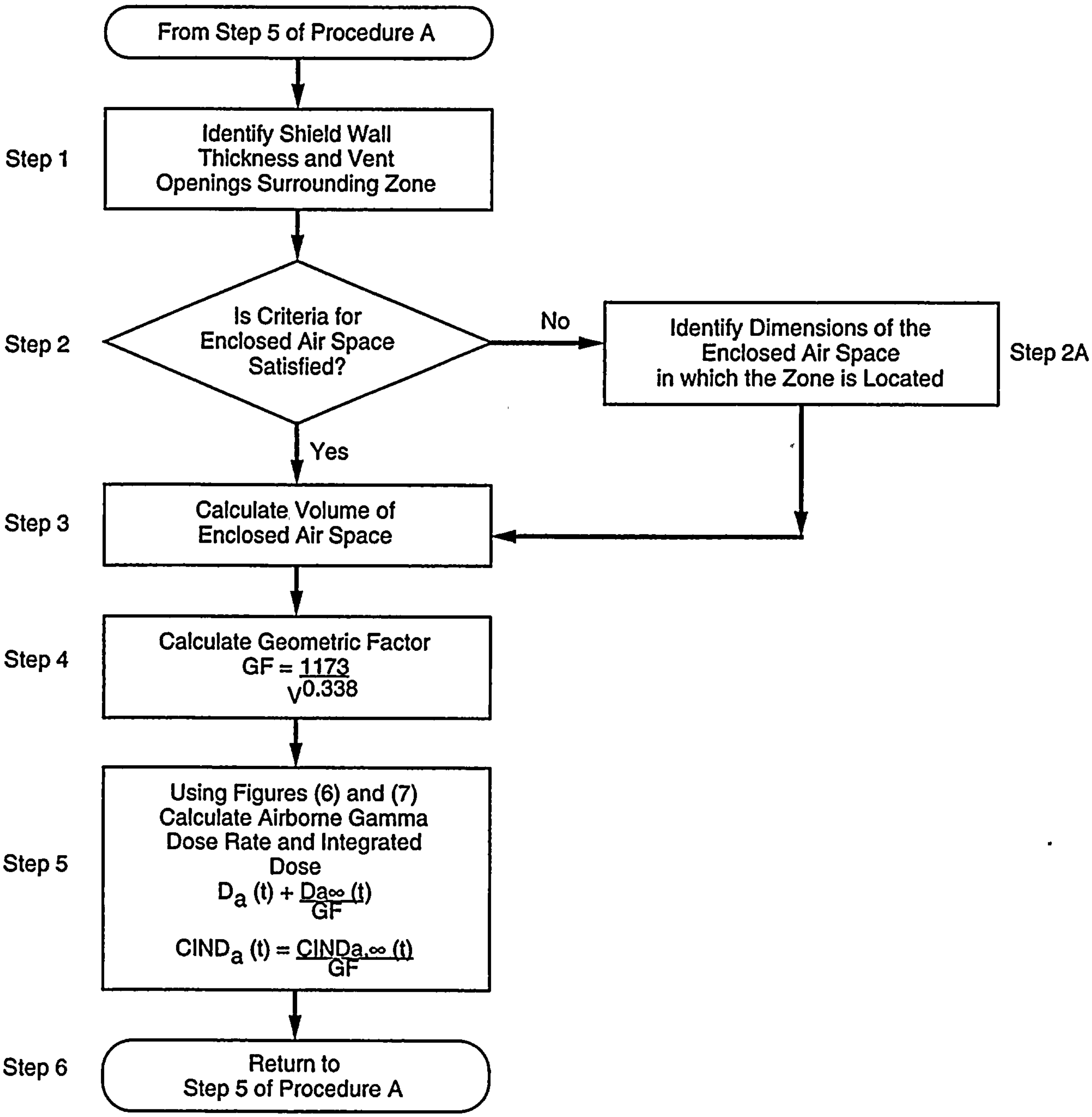
Step 9 — Complete Table 1

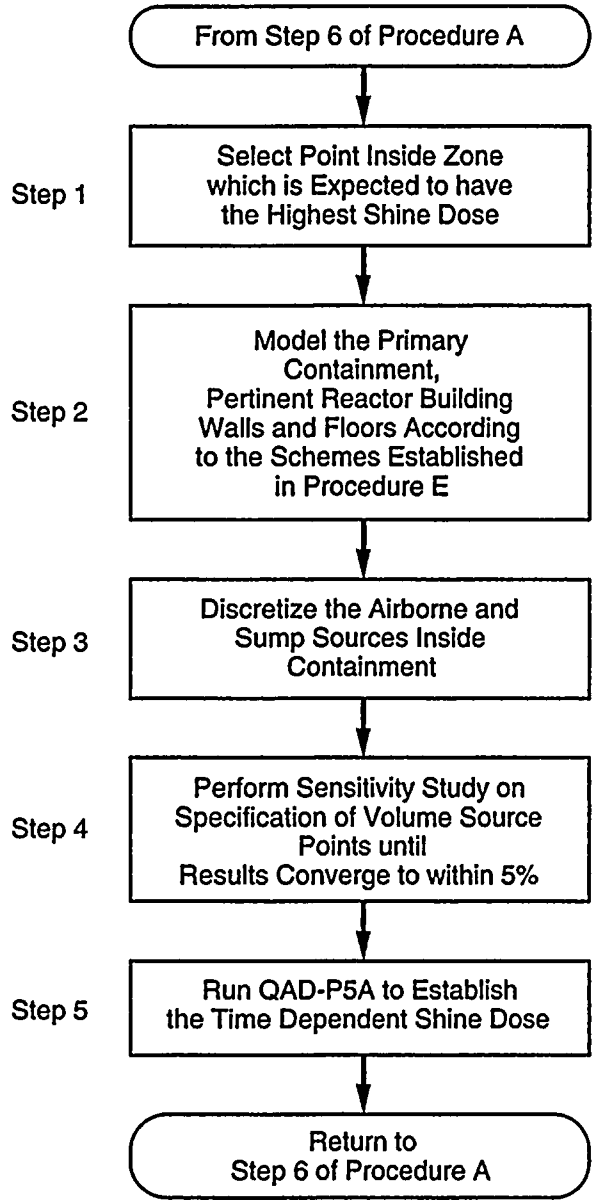
↓

Step 10 — PLCT Total Dose Rate and Integrated Dose

↓

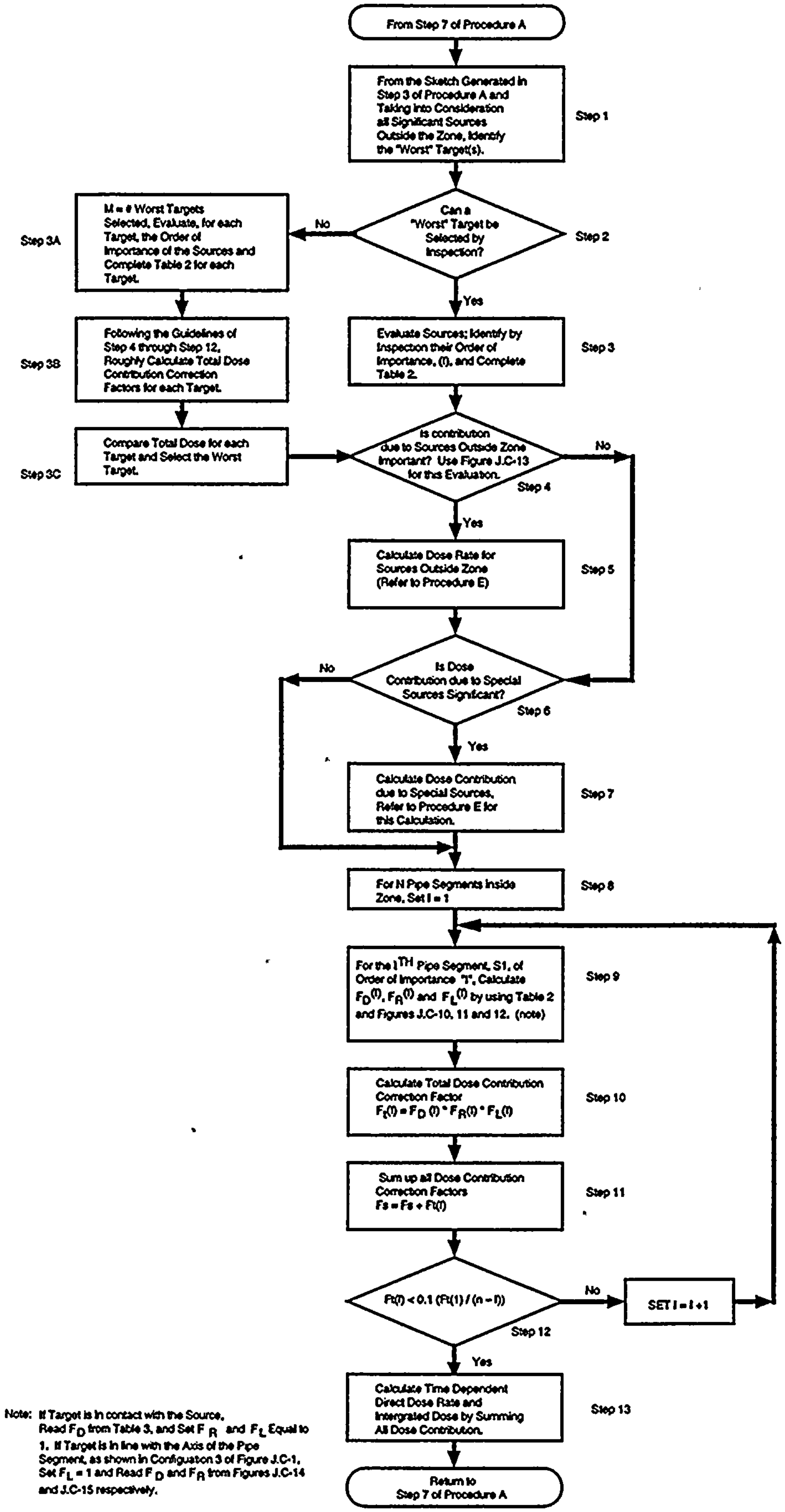
Problem Completed


From Step 5 of Procedure A
Step 1
Identify Shield Wall Thickness and Vent Openings Surrounding Zone
Step 2
Is Criteria for Enclosed Air Space Satisfied?
No
Identify Dimensions of the Enclosed Air Space in which the Zone is Located
Step 2A
Yes
Step 3
Calculate Volume of Enclosed Air Space
Step 4
Calculate Geometric Factor
$GF = \frac{1173}{V^{0.338}}$
Step 5
Using Figures (6) and (7) Calculate Airborne Gamma Dose Rate and Integrated Dose
$D_a(t) + \frac{D_{a\infty}(t)}{GF}$
$CIND_a(t) = \frac{CIND_{a,\infty}(t)}{GF}$
Step 6
Return to Step 5 of Procedure A



Procedure C: Procedure for Calculation of Containment Shine Dose

Amendment 53
November 1998



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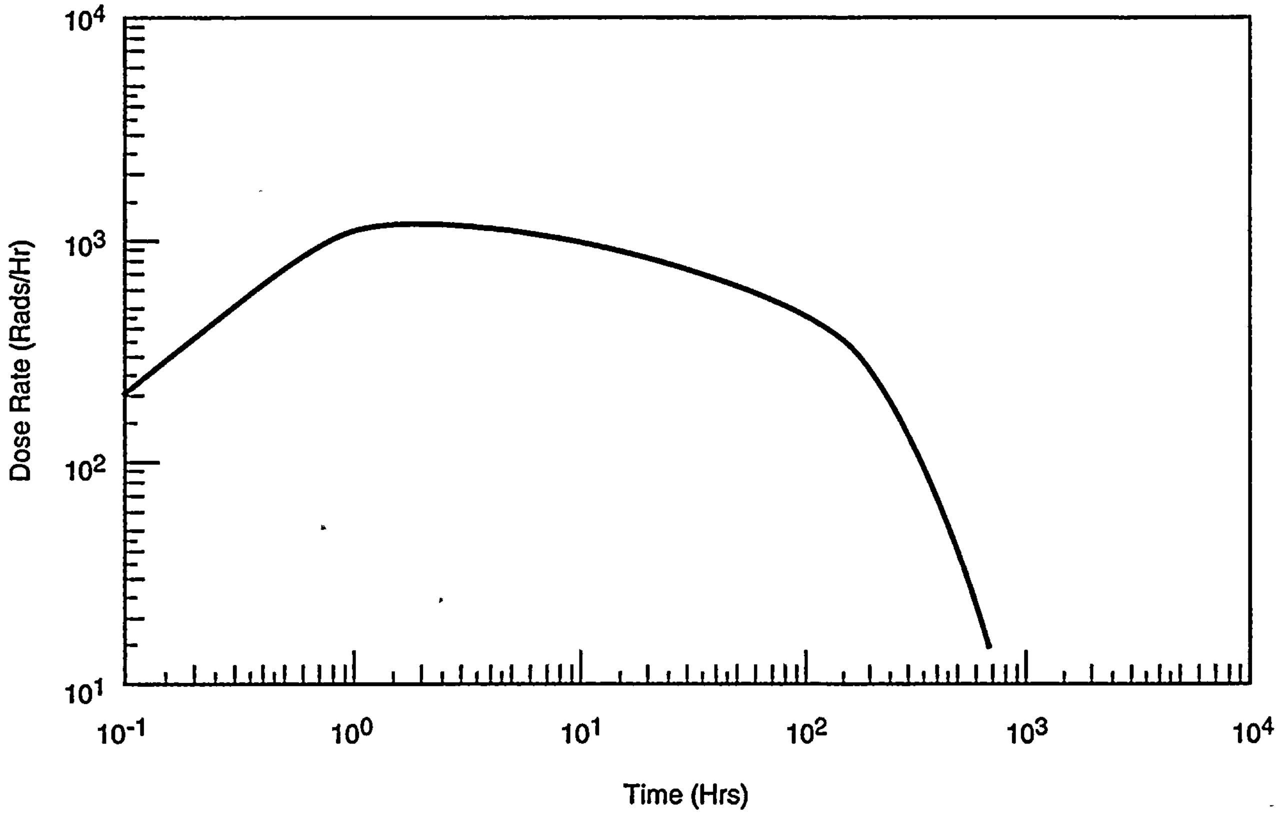
Procedure D: Procedure for Calculation of Direct Dose Rate and Integrated Dose

Draw. No. 970187.55	Rev.	Figure J.C-5

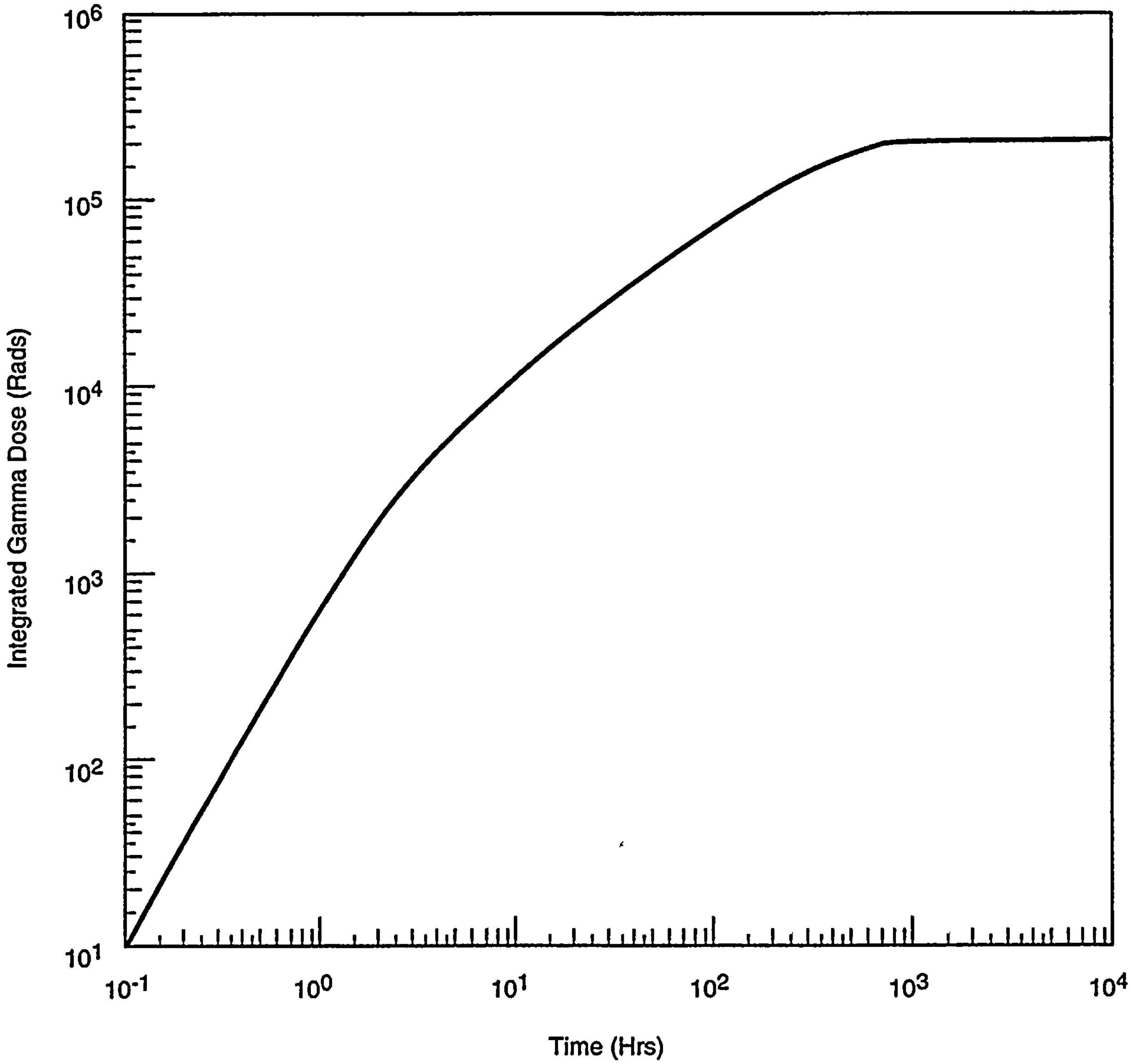
Form No. 960690



0.5%/Day Primary Containment Leakage Rate

Time-Dependent Gamma Dose Rate for a Semi-Infinite Cloud of Fission Products at Secondary Containment Concentrations

Draw. No. 970187.56	Rev.	Figure J.C-6



0.5%/Day Primary Containment Leakage Rate

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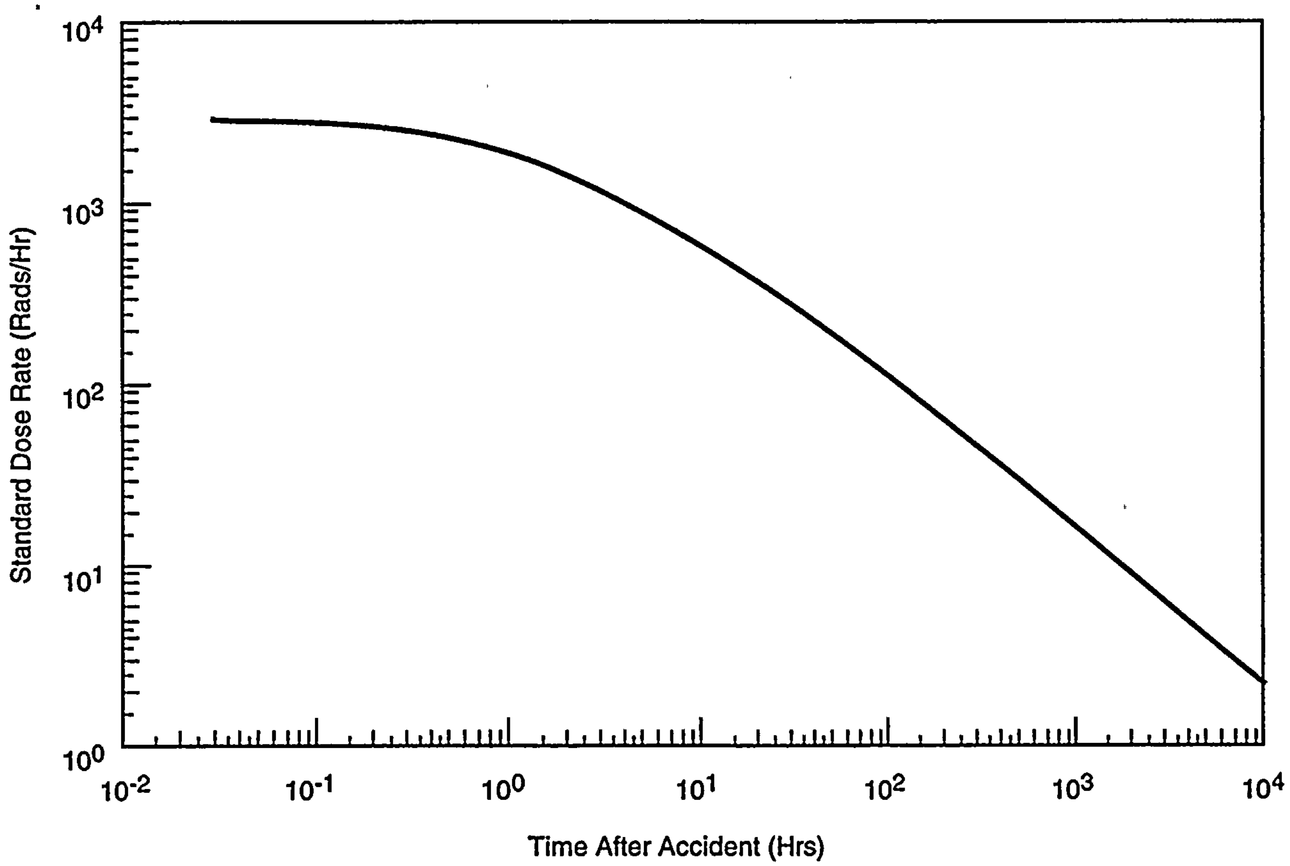
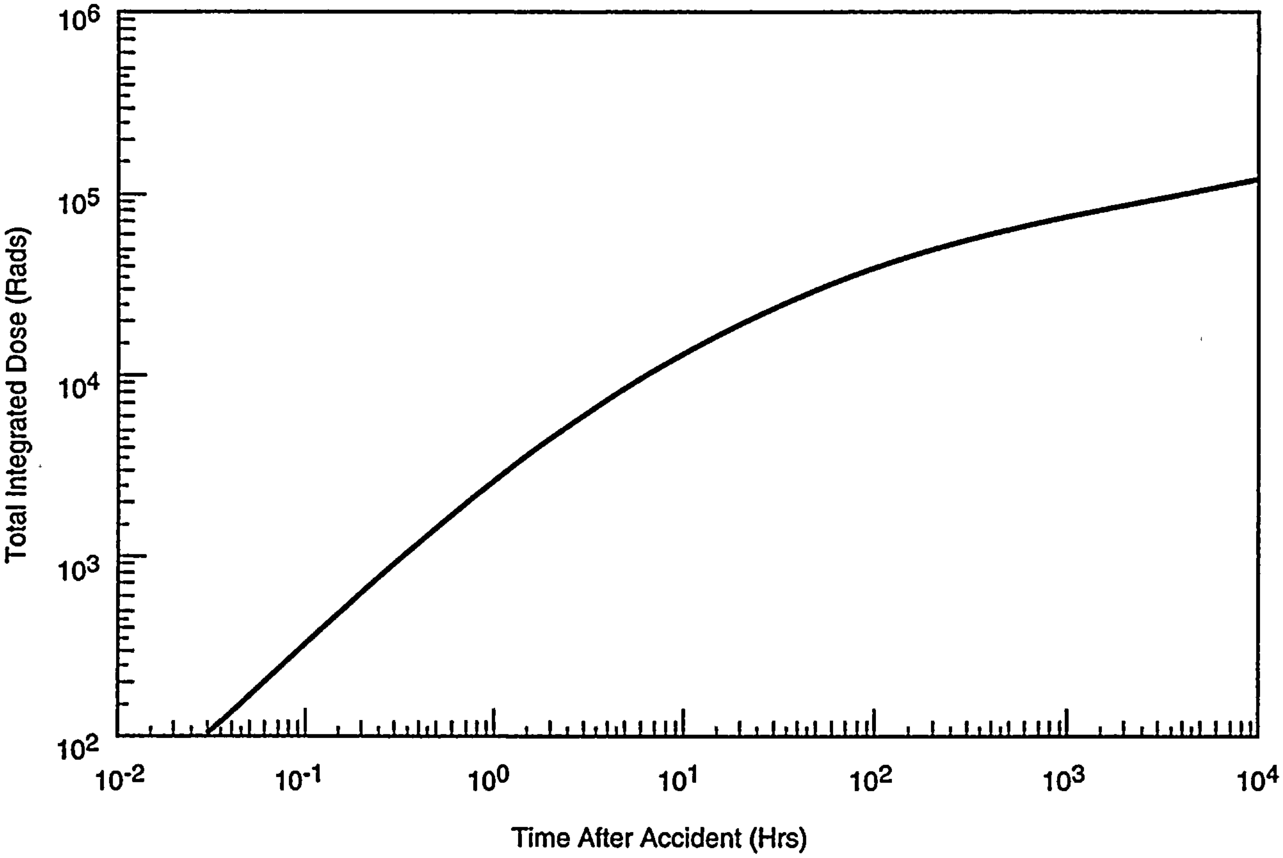
Time-Dependent. Integrated Gamma Dose Rate for a Semi-Infinite Cloud of Fission Products at Secondary Containment Concentrations

Draw. No. 970187.57	Rev.	Figure J.C-7



Gamma Dose Rate at Target 8 ft Away from Standard Pipe



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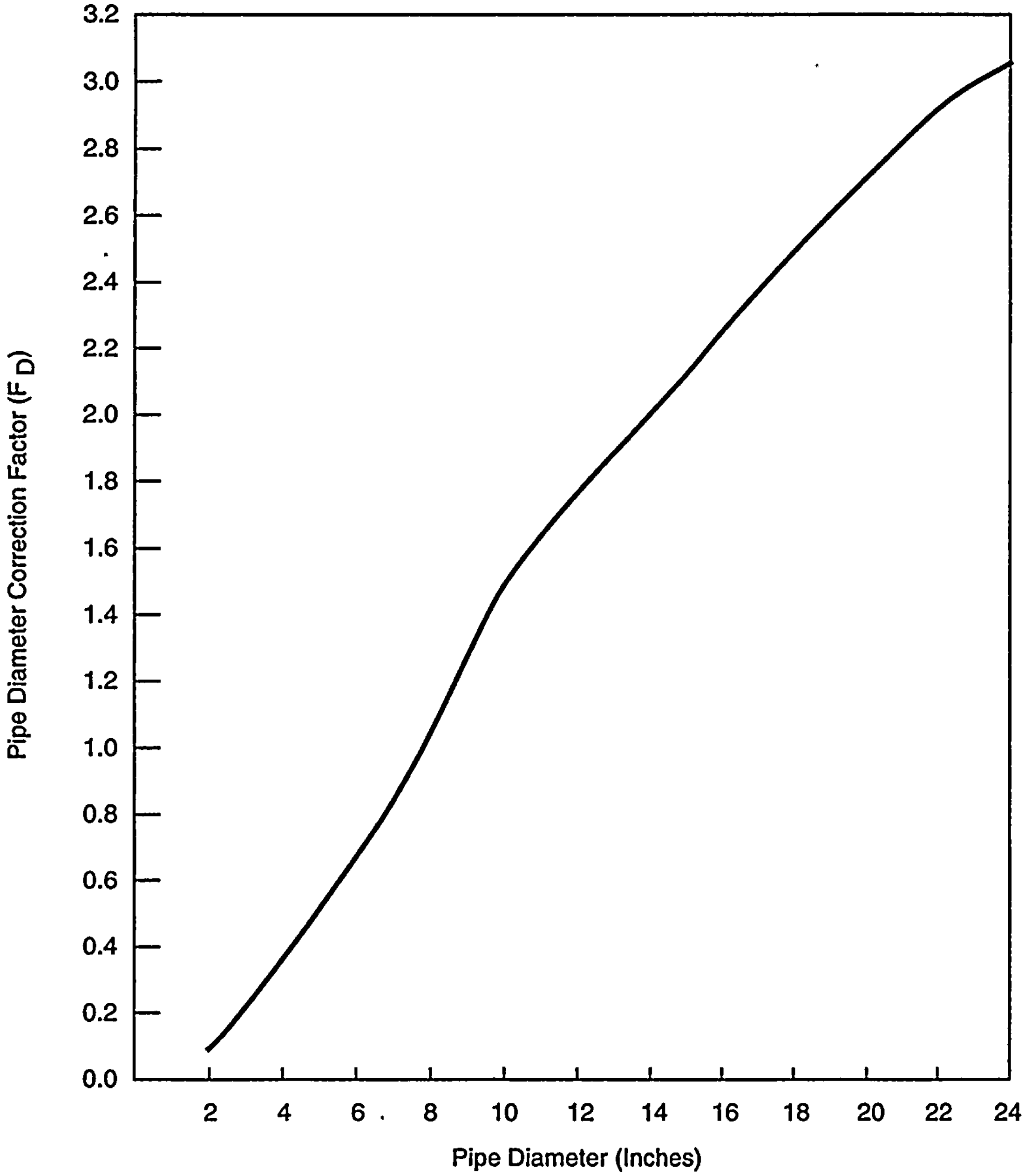
Gamma Integrated Dose at a Target 8 ft Away from Standard Pipe

Draw. No. 970187.59	Rev.	Figure J.C-9



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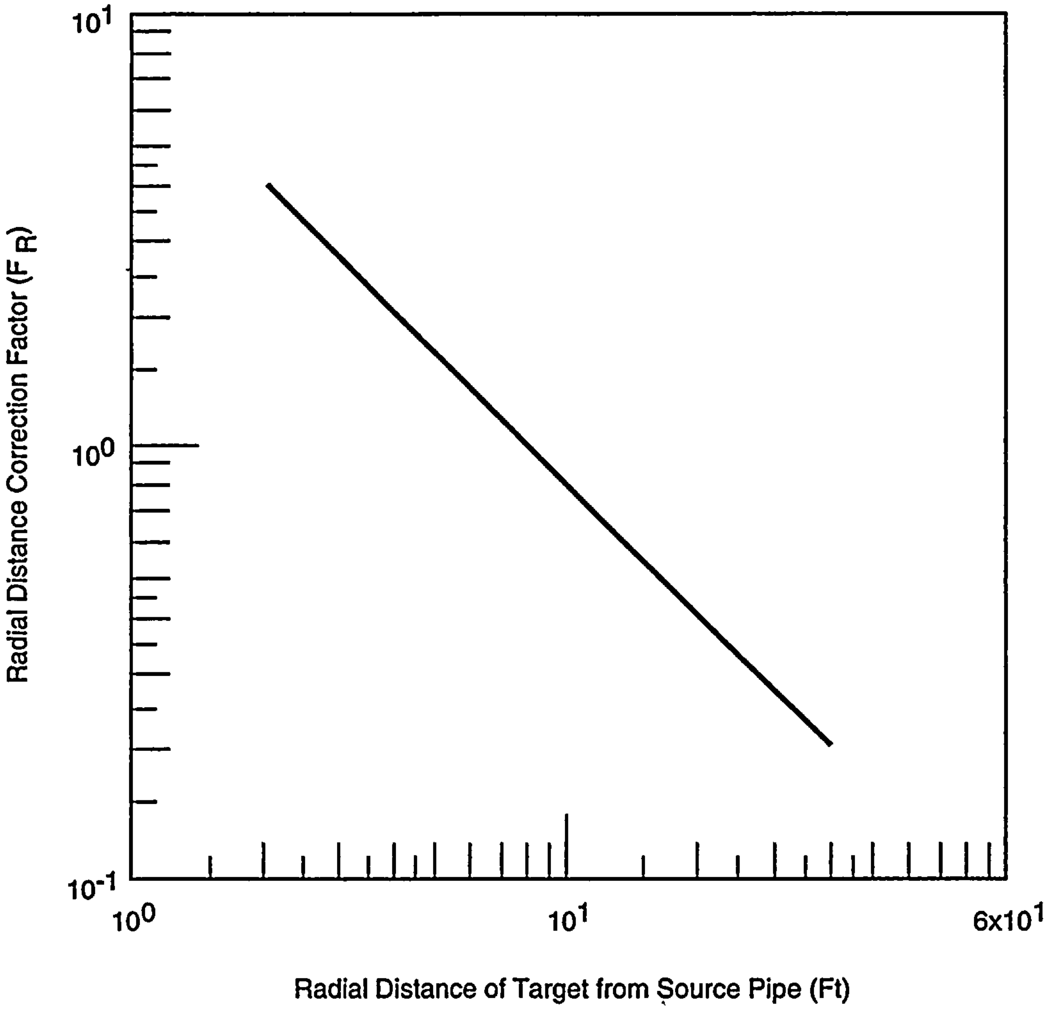
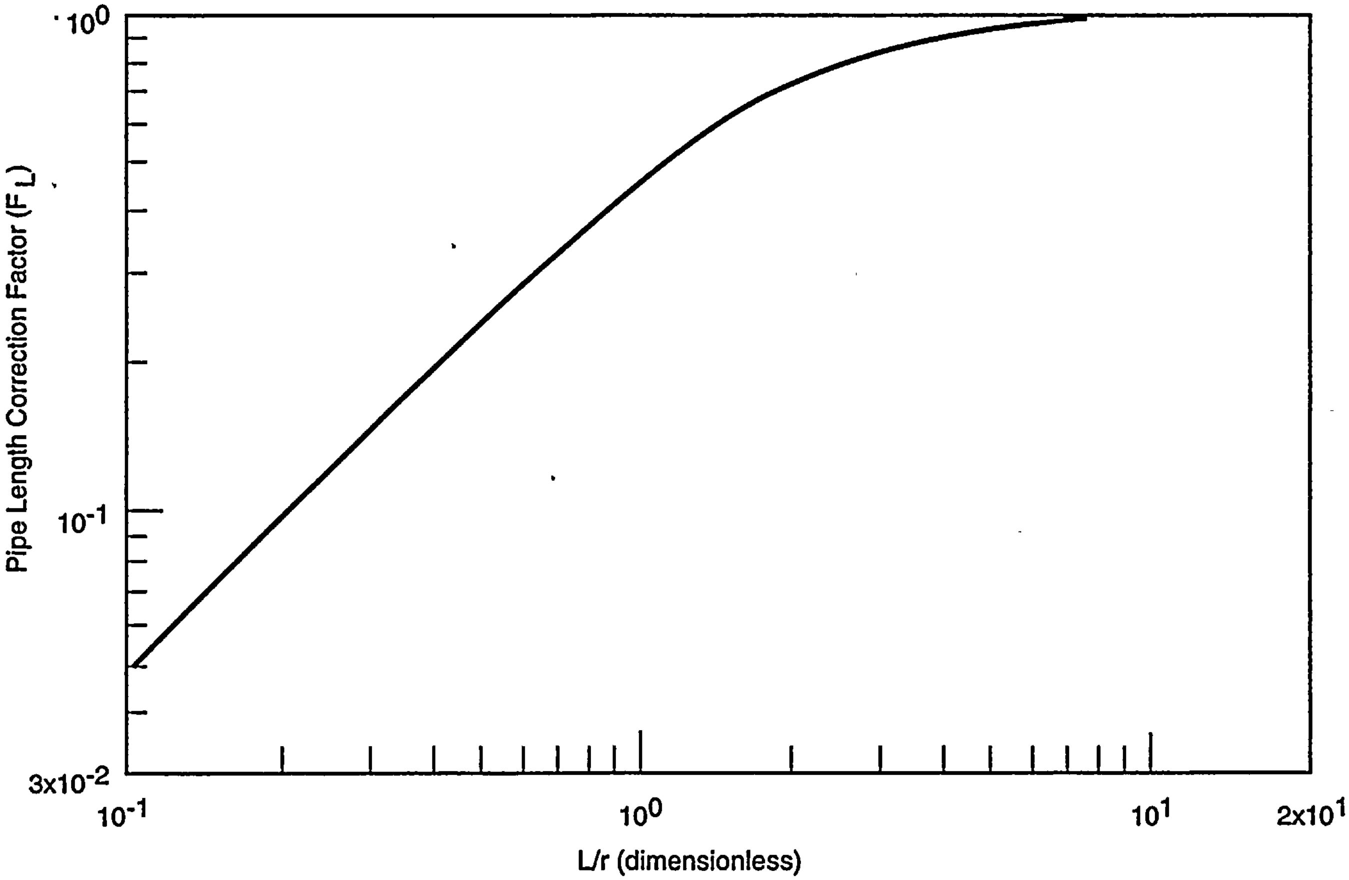
Pipe Diameter Correction Factor

Draw. No. 970187.60	Rev.	Figure J.C-10



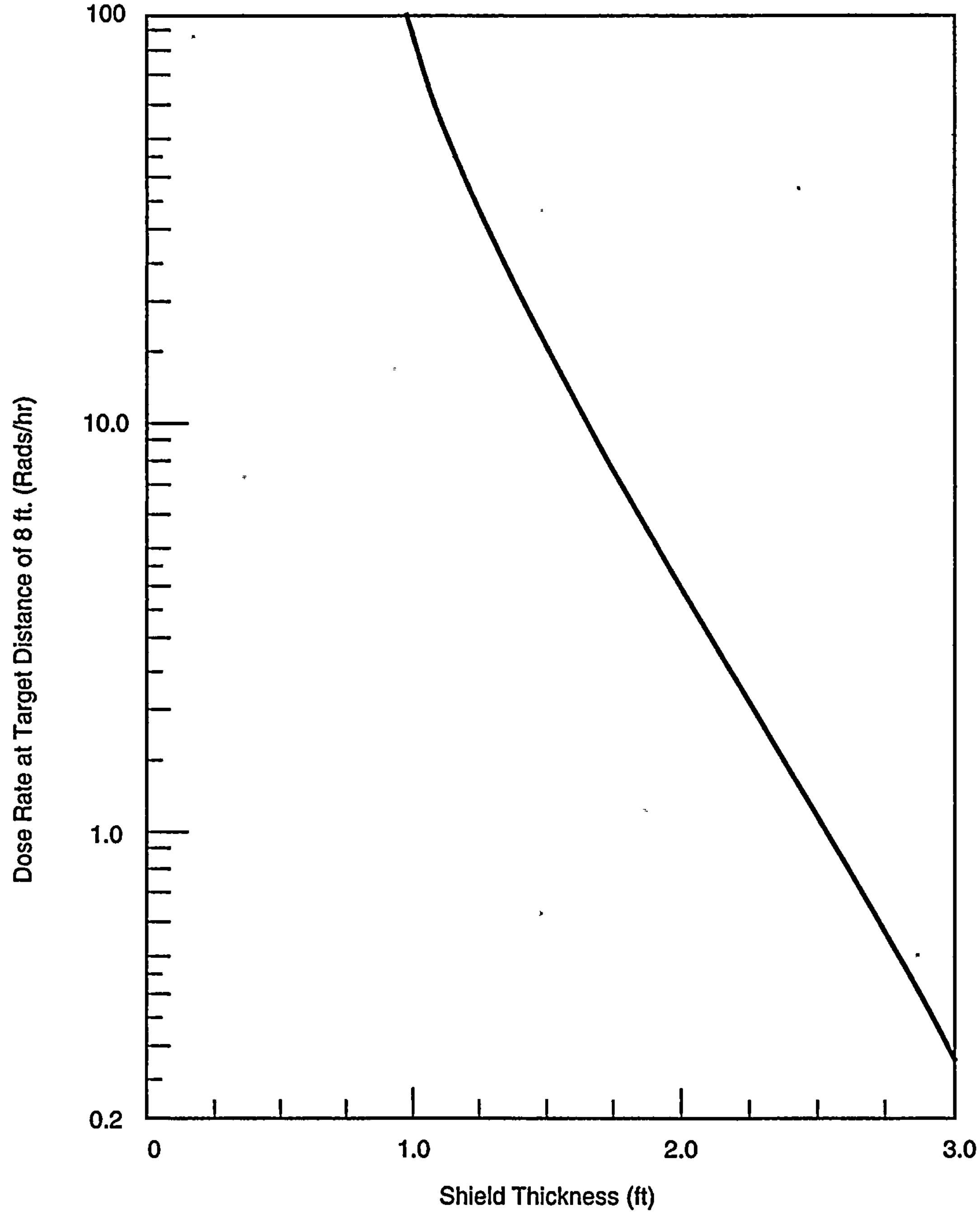
Radial Distance Correction Factor

Draw. No. 970187.61	Rev.	Figure J.C-11



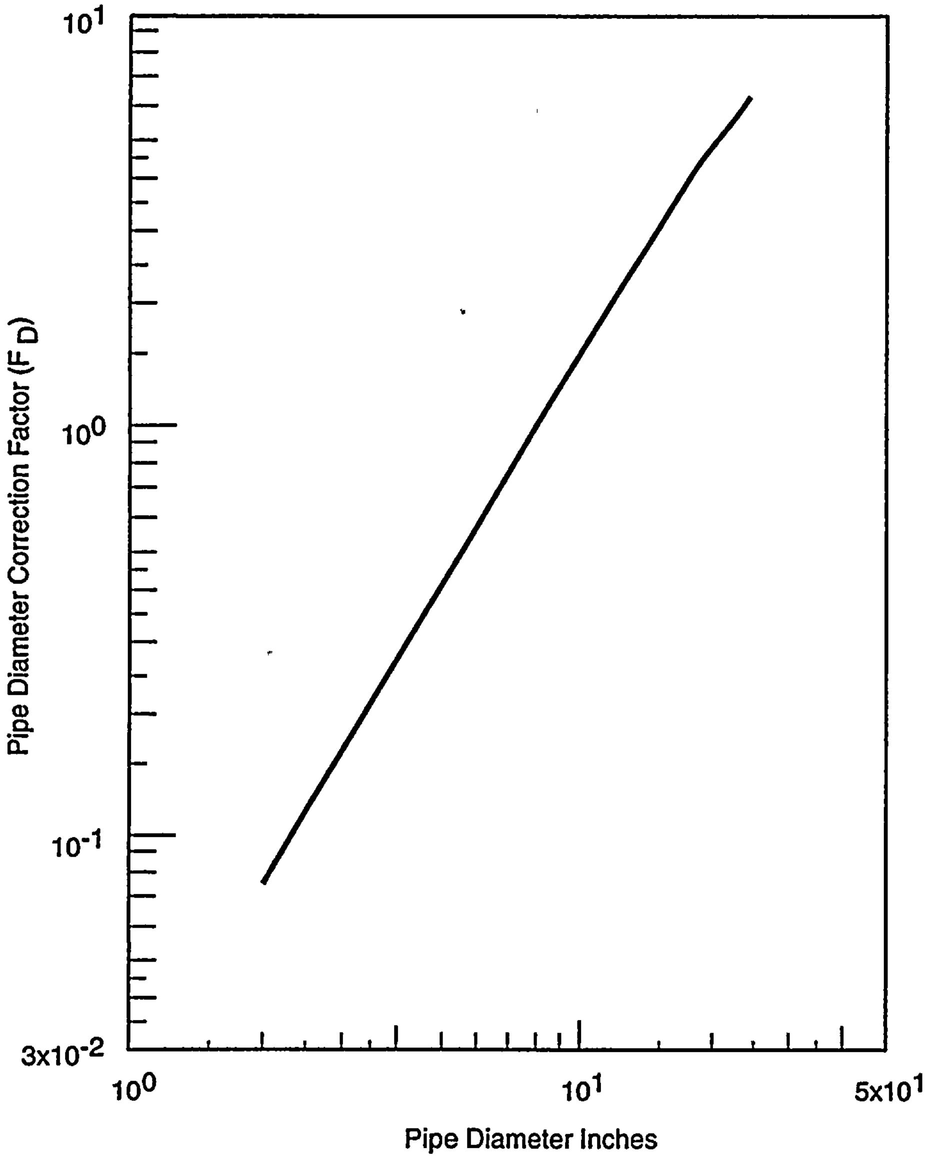
Pipe Length Correction Factor

Draw. No. 970187.62 | Rev. | Figure J.C-12

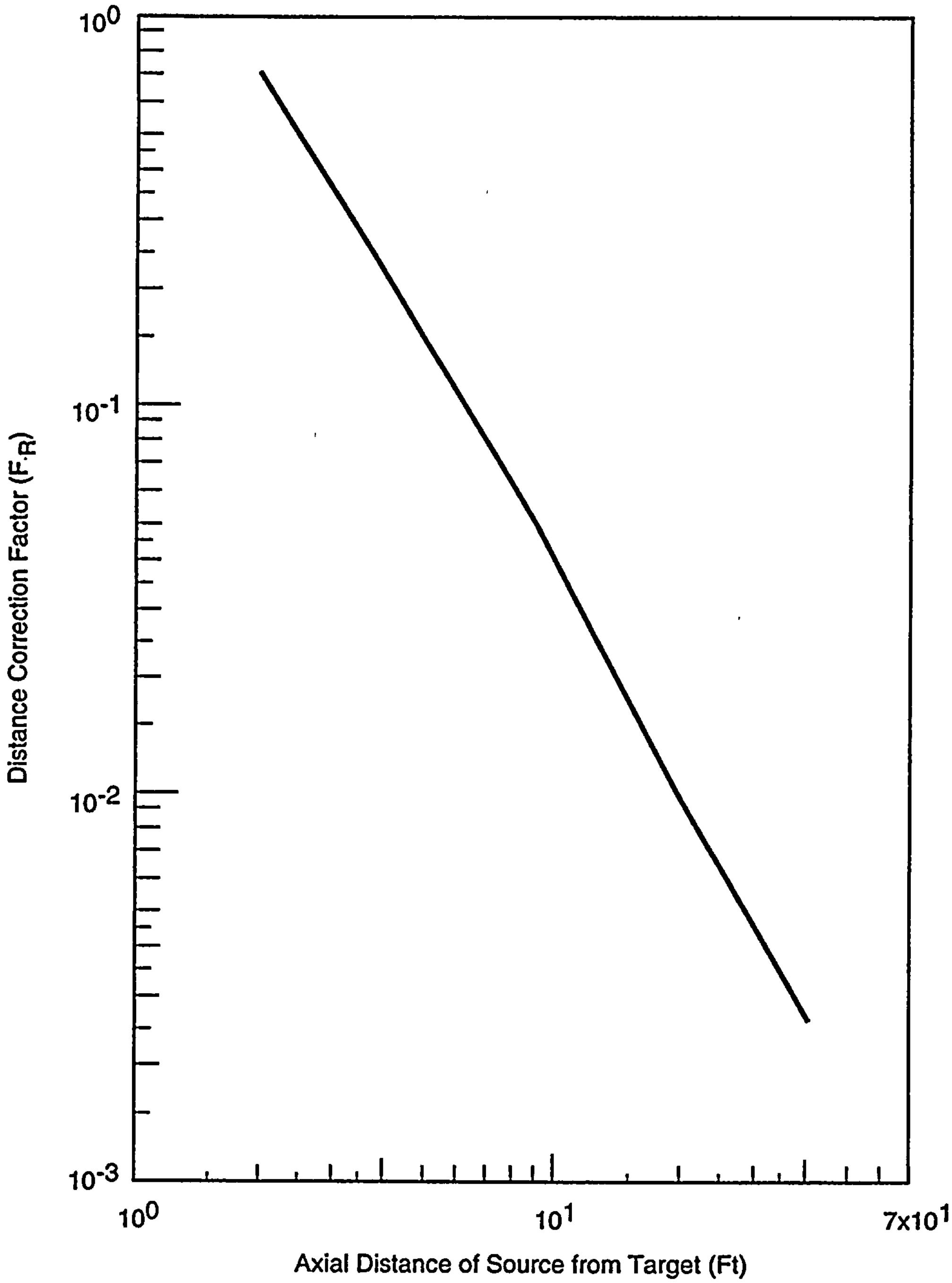


Note: This Figure is to be used for estimation purposes only.
Refer to Procedure E for calculating Dose rates outside shield walls

Dose Rate Versus Concrete Shield-Thickness for Standard Pipe (8 in. Sch 40)



Configuration 3 of Figure J.C-1



Configuration 3 of Figure J.C-1

Distance Correction Factor for Targets Located Axially in Line with Source Piping

Attachment J.D

CALCULATION OF THE RADIATION

The standby gas treatment system (SGTS) filters are located in the reactor building (el. 572 ft) and function to process the radioactive contaminated gaseous effluent from the primary and secondary containment. In the event of a loss-of-coolant accident (LOCA) in the primary containment the SGTS will be actuated. The gaseous contaminants that leak out of the primary containment will be filtered by the SGTS. It will adsorb the iodines in the charcoal filters and the particulates in the prefilters and high-efficiency particulate air (HEPA) filters. Plateout in the primary containment of the iodines released from the core was considered in the radiation assessment of the SGTS. Depending on the radioactive source distribution and the primary containment leakage rate, the radioactive iodine concentration in the filters will be increasing with time as more and more is deposited on the filters. Main steam isolation valve (MSIV) leakage is also considered in the radiation dose calculations.

The purpose of this study was to evaluate the time dependent gamma radiation level for safety-related equipment located near the SGTS filters and in adjacent rooms post-LOCA.

The time-dependent activity concentration in each of the filters is first calculated. The time and energy-dependent gamma activity levels on the SGTS filters is developed by a combination of computer runs and hand calculations and is used as input to the QAD-P5A computer code to calculate the gamma radiation levels for the pieces of safety-related equipment located in the room. A discussion of the analysis follows.

J.D.1 DESCRIPTION OF THE STANDBY GAS TREATMENT SYSTEM FILTERS

Figure J.D-1 is a drawing of the SGTS filter train. The SGTS consists of two fully redundant filter trains, each of which consists of the following components in series:

a. A demister to remove entrained water particles in the incoming air stream;

b. Two banks of electrical coil heaters designed to limit the humidity of the incoming air to 70% at design flow during post-LOCA conditions;

c. A bank of prefilters to remove large particles from the airstream (Figure J.D-2);

d. A bank of HEPA filters to remove the remaining particulates from the airstream (Figure J.D-2);

e. Two 4-in. deep beds of charcoal adsorber filters, arranged as shown in Figure J.D-1, are designed to capture the elemental and organic halogens from the airstream. The dimensions of the charcoal filters are shown in Figure J.D-3; and

f. A second bank of HEPA filters, identical to that described in item d above. The function of this second HEPA filter bank is to capture contaminated charcoal dust which may escape from the charcoal filters.

Both SGTS filter units are located in reactor building el. 572 and are automatically actuated and become fully operational within 34 sec of the event of any of the following three isolation signals:

a. High radiation in the reactor building ventilation exhaust duct,
b. High drywell pressure, and
c. Low water level in the reactor vessel.

J.D.2 CALCULATION OF TIME-DEPENDENT FILTER ACTIVITY CONCENTRATION

The analysis of the time-dependent transport of the radioactivity from the primary containment to the SGTS filters and the activity concentration on each filter is based on the following assumptions:

a. The SGTS filters are assumed to be loaded by iodine at a rate based on atmospheric leakage from primary containment of 0.67 wt %/day. This is composed of 0.5% direct from primary containment leakage and 0.17% via the MSIV. This is based on the primary containment rated leakage flow rate and the calculated MSIV leakage (Reference J.7-40). The containment rated leakage flow rate is 0.5%/day. The MSIV leakage was originally determined to be 0.23%/day, but a reevaluation has resulted in a revision of the MSIV leakage to 0.17%/day as referenced in J.7-40. Since the revision resulted in a lower value the original analysis with MSIV leakage of 0.23%/day is conservative. Thus, the radiation zone calculations were not revised to reflect the MSIV leakage of 0.17%/day since the original analysis was conservative;

b. Straight exhaust through the filters, with no mixing or holdup in the secondary containment atmosphere, is assumed based on an NRC recommended assumption for the analysis for fission product control systems (Reference J.7-41);

c. The elemental iodine in primary containment plateout on primary containment surfaces until one part in 200 of the elemental iodine remain airborne (0.5% of the total iodine). This is consistent with Reference J.7-14;

d. The released halogen fraction is 50% of the core inventory. This halogen fraction is assumed to be composed of 95.5% elemental, 2% organic, and 2.5% particulate iodines. This is consistent with Reference J.7-14;

e. The particulate halogens will be homogeneously distributed within the prefilters and the HEPA filters, while the elemental and organic iodines will be homogeneously distributed within the two charcoal filters of the filter train. This is conservative and necessary because the time-dependent collection of iodines in the filters has not been defined. The homogenous assumption is reasonable; and

f. Leakage past the MSIVs discharges directly to the inlet of the operating SGTS filter unit. Therefore, it bypasses the secondary containment volume. This is conservative and necessary because the time dependent collection of iodines in the filters has not been defined. The homogenous assumption is reasonable.

The time- and energy-dependent gamma activity concentration in the SGTS filters was first investigated as discussed in Section J.5.3.3. This analysis was performed by a combination of computer analysis and hand calculations. The activity concentration of a halogen isotope inside a SGTS filter is changing with time due to the following three mechanisms:

a. Transport of activity from the primary containment and deposition of the filters due to air leakage,

b. Depletion of activity due to radioactive decay and plateout of elemental halogens inside primary containment, and

c. Increases in activity levels due to daughter fission product generation from radioactive decay of other isotopes.

The activity balance on the SGTS filters can be described by (from equation J.B-16, Attachment J.B)

$$\frac{d}{dt}(A_i) = \underbrace{Q_l C_{li}(t)}_{\text{leakage in}} - \underbrace{{}_i A_i}_{\text{decay}} + \underbrace{{}_j\,{}_j A_j}_{\text{growth}} \qquad \text{(J.D-1)}$$

where

A_i	=	activity (iodine) deposited on the SGT filters
$C_{1i}(t)$	=	airborne concentration of iodine isotope "i"
Q_1	=	flow rate (volume) from the primary containment

As in Attachment J.B (equation J.B-1, J.B-2) the growth term is negligible.

$C_{1i}(t)$ is given by equation J.B-8 of Attachment J.B as

$$C_{1i}(t) = (S_{iH}(t)/V_1)\, f_H(t) \exp(-Q_1 t/V_1) \qquad \text{(J.D-2)}$$

V_1 is the volume of primary containment

$f_H(t)$ is defined by

$$f_H(t) = f_e\, e^{-\lambda_p t} + f_p + f_o \quad \text{where } t \le t_p \qquad \text{(J.D-3)}$$

$$f_H(t) = \left(\frac{f_e}{200}\right) + f_p + f_o \quad \text{where } t \ge t_p$$

Integrating (J.D-2) gives the following, where B is a constant to be determined:

$$A_i(t) = Be^{-\lambda_i t} + e^{-\lambda_i t} \int e^{\lambda_i t}\, Q_1 C_{1i}(t)\, dt \qquad \text{(J.D-4)}$$

$C_{1i}(t)$ is substituted into (J.D-4) from (J.D-2) to give

$$A_i(t) = Be^{-\lambda_i t} + \frac{e^{-\lambda_i t}}{V_1} \int Q_1\, S_{iH}(t)\, f_H(t)\, e^{(\lambda_i - Q_1/V_1)t} dt \qquad \text{(J.D-5)}$$

Substituting the definition of $S_{iH}(t)$ from equation J.B-5 of Attachment J.B, where $A_{1i}(0)$ is the original activity in primary containment

$$(S_{iH}(t)) = C_{1i}(0)\, e^{-\lambda_i t}\, V_1 = A_{1i}(0)\, e^{-\lambda_i t}$$

$$A_i(t) = Be^{-\lambda_i t} + A_{1i}(0)\, e^{-\lambda_i t} \int \frac{Q_1}{V_1} f_H(t) \exp\left[-(Q_1/V_1)^t\right] dt \qquad \text{(J.D-6)}$$

$f_H(t)$ consists of three chemical species: organic, particulate, and elemental iodine.
Equation (J.D-6) must be solved for each species, so the species will be separated at this point:

$$\theta_o(t) = f_o$$

$$\theta_p(t) = f_p \quad \text{(J.D-7)}$$

$$\theta_e(t) = f_e \; e^{-\lambda_p t} \quad 0 \leq t \leq tp$$

$$\theta_e(t) = \frac{f_e}{200} \quad \text{where } t_p \leq t$$

$$f_H(t) = \theta_o(t) + \theta_p(t) + \theta_e(t)$$

To clarify the solution of (J.D-6), the following definitions are made:

$$X = ^{-\lambda}p^{-q}$$

$$q = \frac{Q_1}{V_1}$$

Since $\theta_e(t)$ has step-function changes, solutions to (J.D-6) require a series solution - one for both of the time bands:

$$0 \leq t_p \leq \infty$$

<u>Organic Iodines</u>

Equation (J.D-6) for all times t becomes

$$A_i(t) = Be^{-\lambda}i^t + A_{Ii}\,(0)\; q\; f_o e^{-\lambda}i^t \frac{e^{-qt}}{-q} \quad \text{(J.D-8)}$$

At t=0, A_i=0, so

$$A_i(t) = + \; f_o \; A_{Ii}\;(0)\; e^{-\lambda}i^t \left[\, 1 - e^{-qt} \,\right] \quad \text{(J.D-9)}$$

Since

$$A_{Ii}(0)e^{-\lambda}i^t = S_{iH}(t)$$

from equation J.B-5 (from Attachment J.B), we define

$$A_i(t) = S_{iH}(t) \quad \phi_o(t) \quad \text{(J.D-10)}$$

where

$$\phi_o(t) = + f_o\ (1 - e^{-qt})$$

$$\phi_o(t) = \text{fraction of organic halogens on the SGTS filters}$$

Particulate Iodines

Particulate halogens are obtained in the same manner as organic halogens. The only difference is that f_o is replaced by f_p.

Elemental Iodines

For $0 \le t \le t_p$, equation (J.D-6) becomes

$$A_i(t) = Be^{-\lambda_i t} + A_{li}\ (0)\ e^{-\lambda_i t}\ q\ (e^{-\lambda_p t}\ f_e)\ \ e^{-qt}\ dt \qquad \text{(J.D-11)}$$

since at $t = 0$, $A_i = 0$

$$A_i(t) = q\ \frac{f_e}{x}\ A_{li}(0)\ \ e^{-\lambda_i t}\ (e^{xt} - 1) \qquad \text{(J.D-12)}$$

For $t_p \le t$, equation (J.D-6) becomes

$$A_i(t) = Be^{-\lambda_i t} + A_{li}\ (0)\ e^{-\lambda_i t} \int q\ (\frac{f_e}{200})\ \ e^{-qt}\ dt \qquad \text{(J.D-13)}$$

Integrating, with initial condition of $t = t_p$

$$A_i = \frac{qf_e}{x}\ A_{li}\ (0)e^{-\lambda_i t}\ p\ (e^{xt_p} - 1)$$

$$A_i(t) = f_e\ \ A_{li}\ (0)\ \exp - \lambda_i t\ \frac{q}{x} \left[(e^{xt}[tp] - 1) + \frac{x}{200q}\ (e^{-qt}[tp] - e^{-qt}) \right] \qquad \text{(J.D-14)}$$

The activity on the SGTS filter may then be generally described by

$$A_i(t) = S_{iH}(t)\ \ \phi(t) \qquad \text{(J.D-15)}$$

where $\phi(t)$ is the fraction of released iodines located on the filters and is defined by

$$\phi(t) = \phi_o(t) + \phi_p(t) + \phi_e(t) \qquad \text{(J.D-16)}$$

where

$$\phi_o(t) = f_o\,(1 - e^{-qt})$$
$$\phi_p(t) = f_p\,(1 - e^{-qt})$$

$$e(t) = \begin{cases} F_o \dfrac{q}{x}\,(e^{xt} - 1) & (\text{For } 0 \le t \le t_p) \\ F_o \dfrac{q}{x} \left[(e^{xt} p_{-1}) + \dfrac{x}{200\,q}\,(e^{-qt} p_{-o}^{-qt}) \right] & (\text{For } t_p \le t) \end{cases}$$

J.D.3 CALCULATION OF RADIATION DOSE FROM THE STANDBY GAS TREATMENT SYSTEM FILTER

After the activity concentration in each filter segment is determined, the gamma radiation dose for safety-related equipment located in the SGTS filter room is determined by the use of computer code QAD-P5A (Reference J.7-10). The QAD-P5A modeling procedure as described in Attachment J.C is followed for this analysis. The following modeling assumptions were used:

a. Self-shielding of the filters is conservatively neglected because the density of the charcoal dust or the wire mesh (prefilter and HEPA filters) in the filters is low. Neglecting the self-shielding effect of the filters will not add too much conservatism to the results; and

b. Shielding due to the sheet metal filter housing is conservatively neglected due to computer code stability considerations. The shielding effect of the thin sheet metal filter housing is negligible.

One zone and four subzones were evaluated for the SGTS system and the five C1E/SRM components evaluated are

a. SGT-DV-1A3,
b. FPC-LIS-1A,
c. SGT-EHO-1B1,
d. SGT-MO-5B1, and
e. SGT-TE-6A1/7A1.

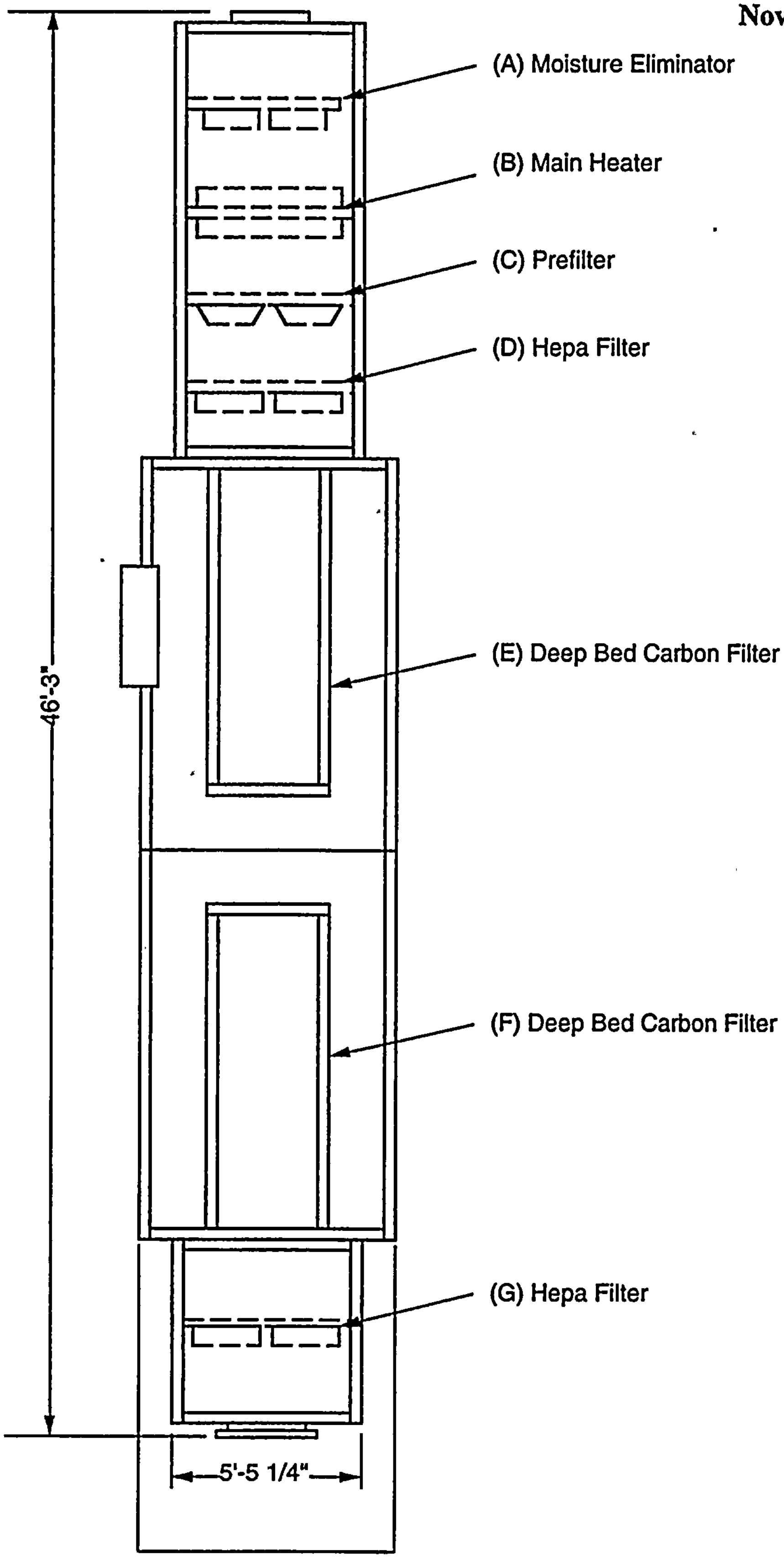
These targets are evaluated according to their proximity to the SGTS filters.

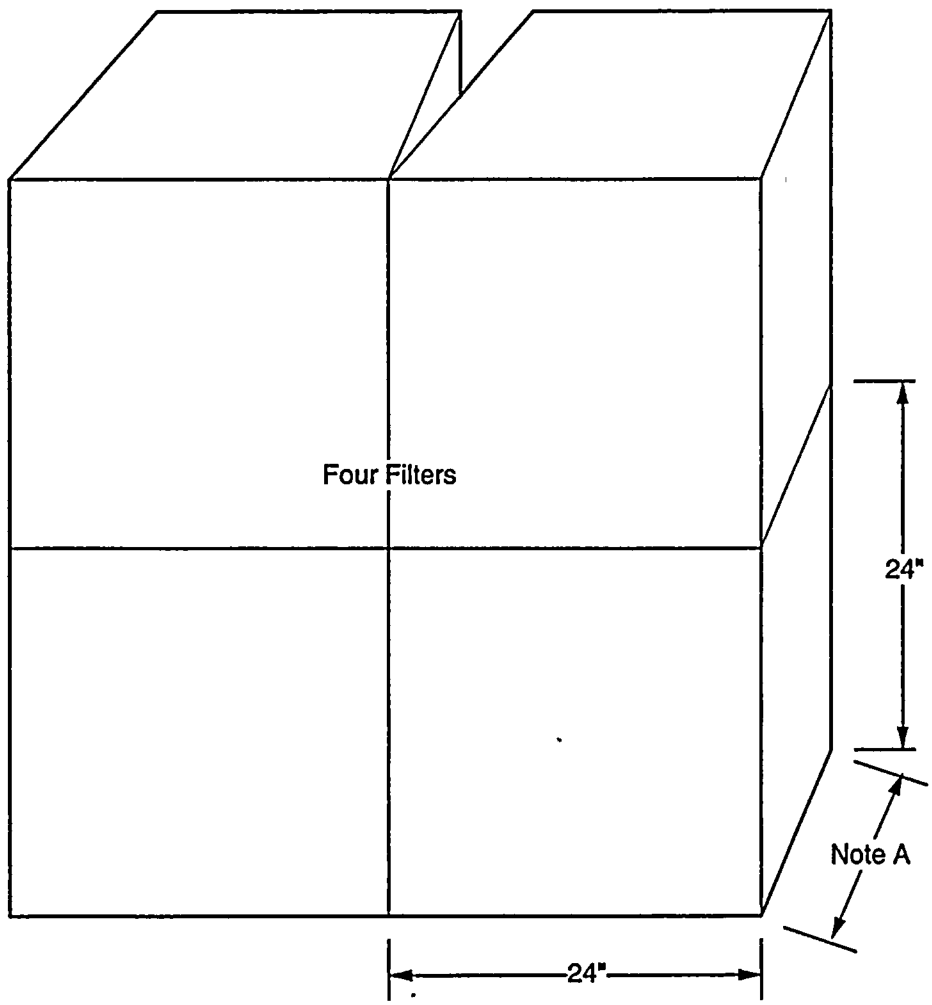
The time-dependent, gamma ray activity concentration as calculated using the method described in Section J.D.2 was used as input to the QAD-P5A model described in Attachment J.C. The dose rate results of this analysis were integrated numerically to give time-dependent, integrated doses. Table J.D-1 shows the direct gamma dose rate and integrated results for each of the five targets.

TABLE J.D-1

DIRECT GAMMA DOSE RATE AND INTEGRATED DOSE RESULTS
FOR TARGETS IN THE STANDBY GAS TREATMENT SYSTEM ROOM

	FPC-LIS-1A			SGT-EHO-1B1			SGT-MO-5B1			SGT-TE-6A1/7A1	
Time (hr)	Dose Rate (rad/hr)	Integrated Dose (rad)		Dose Rate (rad/hr)	Integrated Dose (rad)		Dose Rate (rad/hr)	Integrated Dose (rad)		Dose Rate (rad/hr)	Integrated Dose (rad)
0	8.6E+02	4.3E+01		2.7E+02	1.4E+01		9.9E+02	5.0E+01		4.8E+04	2.5E+03
1	4.1E+03	2.3E+03		1.3E+03	7.3E+02		4.7E+03	2.6E+03		2.3E+05	1.4E+05
3	3.8E+03	1.0E+04		1.2E+03	3.3E+03		4.4E+03	1.2E+04		2.1E+05	5.8E+05
9	2.3E+03	2.9E+04		7.6E+02	9.3E+03		2.6E+03	3.3E+04		1.2E+05	1.6E+06
24	1.6E+03	5.8E+04		5.1E+02	1.9E+04		1.7E+03	6.6E+04		7.7E+04	3.1E+06
72	1.2E+03	1.2E+05		3.8E+02	4.0E+04		1.3E+03	1.4E+05		5.4E+04	6.3E+06
216	1.2E+03	3.0E+05		3.9E+02	9.5E+04		1.3E+03	3.3E+05		5.5E+04	1.4E+07
720	5.7E+02	7.5E+05		1.7E+02	2.4E+05		6.1E+02	8.1E+05		2.5E+04	3.4E+07
1440	7.6E+01	9.8E+05		2.3E+01	3.1E+05		8.1E+01	1.1E+06		3.3E+03	4.4E+07
2160	7.7E+00	1.0E+06		2.5E+00	3.2E+05		8.2E+00	1.1E+06		3.3E+02	4.6E+07
4320	1.0E-02	1.0E+06		6.4E-03	3.2E+05		1.0E-02	1.1E+06		2.3E-01	4.6E+07


(A) Moisture Eliminator
(B) Main Heater
(C) Prefilter
(D) Hepa Filter
(E) Deep Bed Carbon Filter
(F) Deep Bed Carbon Filter
(G) Hepa Filter
46'-3"
5'-5 1/4"



Note A: Prefilter 8"
HEPA Filter 11 1/2 "

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Geometry of Prefilters and HEPA Filters

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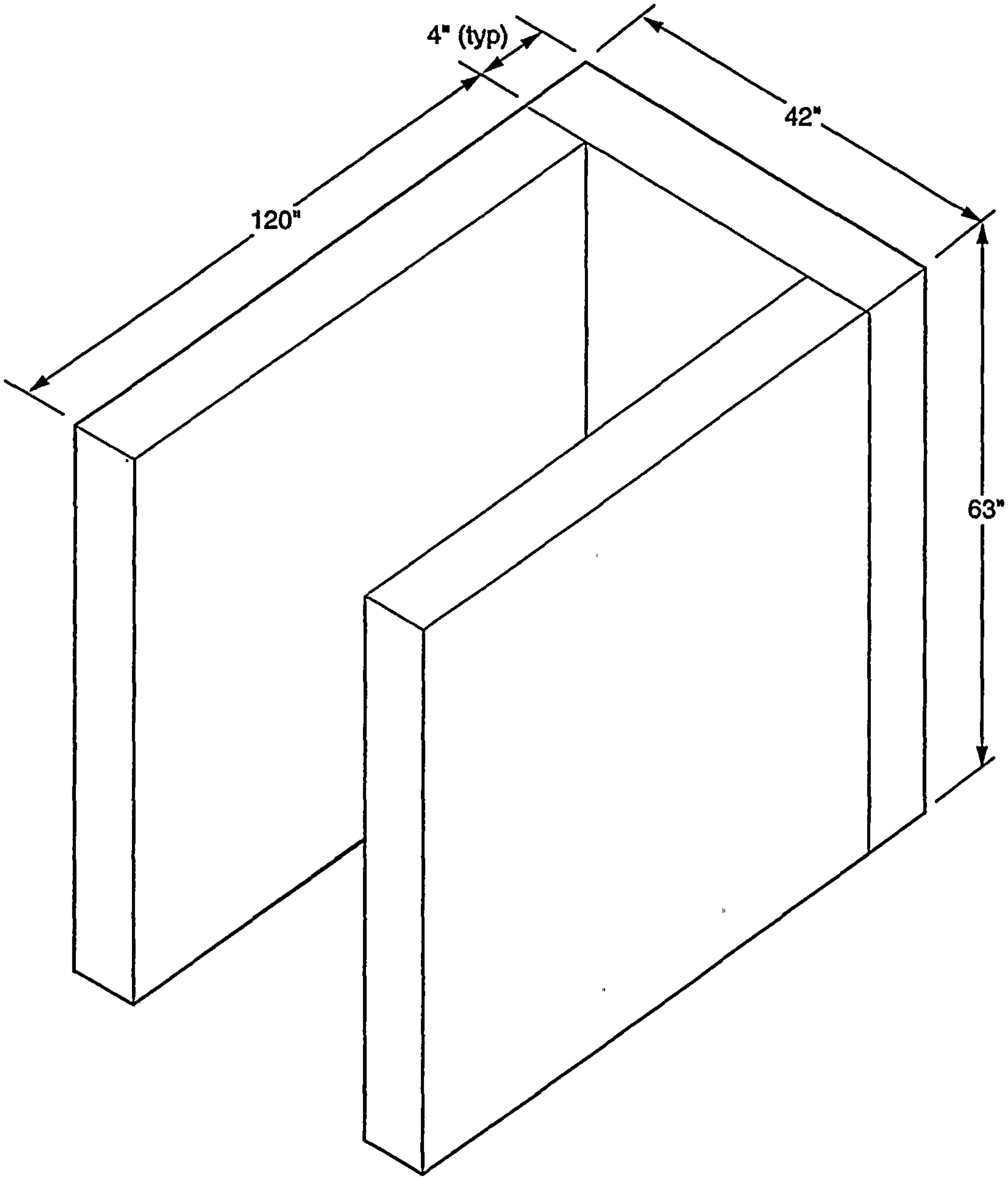


Not to Scale

Geometry of Charcoal Filters

Attachment J.E

BETA DOSE CALCULATION METHOD

The source volume used for the beta dose analysis in secondary containment is a sphere surrounded by a shell of sufficient thickness to stop all outside beta particles from entering the source volume. This spherical source volume is conservative for any generalized source volume shape. The dose at the center of the sphere is higher than the dose at any point of any generalized source of equal total volume.

The assumptions used in this analysis are as follows:

a. Atmosphere inside the equipment casing is identical to the atmosphere in the reactor building which is conservative because there will be some actual delay in transport of the gaseous fission products into the equipment;

b. The initial beta source term used was 100% of core noble gases and 50% of core halogens based on NUREG-0588, Revision 1 and NUREG-CR/0009 (References J.7-29 and J.7-34);

c. Daughter products of the airborne noble gases and halogens are included in the calculation of the airborne dose. This is conservative and was required by the use of ORIGEN2 as a source code (Reference J.7-8);

d. Plateout of halogens inside primary containment was utilized as allowed in accordance with Reference J.7-34. The dose contribution of fission products plated out on equipment casings was neglected. This is based on the NRC recommended assumptions (Reference J.7-34). The deletion of dose contributions from fission products plated out on equipment casings is acceptable, since equipment surface areas are small relative to the available containment surface area. In addition, the beta radiation emitted from plated out fission products would be absorbed in the equipment casing and, hence, would not affect internal components;

e. The primary to secondary leak rate is 0.5% of primary containment, wt %/day is consistent with the assumptions established in Reference J.7-2;

f. The standby gas treatment system (SGTS) operates at the minimum flow of 2430 scfm based on the SGTS flow rate assumption of one reactor building air change per day;

g. Primary to secondary leakage is homogeneously mixed in the secondary containment atmosphere consistent with the NRC-recommended assumptions used for the calculation of doses inside primary containment (Reference J.7-2);

h. No halogen plateout in the secondary containment was assumed; and

i. A spherical volume and equipment casing will be used which is conservative.

The beta dose to equipment is dependent on the internal volume size of the piece of equipment. The beta dose is determined through the use of any energy dependent geometry factor and a ratio of the internal equipment volume to an infinite cloud. The beta dose contribution is excluded from the total integrated radiation doses shown on the radiation zone maps and tables for the C1E* equipment in the reactor building. If determination of a beta dose contribution to a C1E* component is required then a calculation to determine the internal volume size and perhaps the angle of incidence of the beta cloud to the sensitive component is performed. The results of the beta calculation are then included in the equipment qualification files for that beta sensitive equipment.

The beta calculation is determined by the airborne dose at the center of the spherical source as a function of the volume of the sphere.

The variation of beta dose rate from a typical beta energy distribution in a one-dimensional absorbing medium can be approximated by the formula:

$$D(X) = A \exp(-\mu_E X) \qquad \text{(J.E-1)}$$

where

D(X)	=	dose at a point X
A	=	constant
X	=	position in the material
μ_E	=	a parameter that depends on beta energy

This relationship holds approximately up to the point where all beta particles are absorbed. This point is called the range of the beta particles. The range of a beta particle is dependent upon the energy of the beta particle and is denoted r_E.

Both of the parameters μ_E and r_E may be determined by empirical formulas given below, based on the maximum energy of the beta particles, and approximately independent of the absorbing medium.

* Environmental qualification (EQ) of safety-related mechanical equipment has been eliminated from the overall WNP-2 EQ program (SRM).

$$\mu_E = 17\rho\,(E_{max})^{-1.14} \quad \text{(J.E-2)}$$

$$r_E = (0.412/\rho)\,E^n \text{ for } 0.01 \le E \le 3 \quad \text{(J.E-3)}$$

$$= (0.530E - 0.106)/\rho \text{ for } 2.3 \le E \le 20 \quad \text{(J.E-4)}$$

ρ is material density (in g/cm^3)
E is energy of beta particle (in MeV)
μE is in cm^{-1}
r_E is in cm
n is 1.265 - .0954 LnE

The dose at a given point from a single beta source is now transformed into a dose from a uniform concentration of airborne sources which extend from radius zero to radius r. K is a constant.

$$D(r) = K(1 - \exp(\mu_E r)) \quad \text{(J.E-5)}$$

This relationship is valid for $r \le r_E$. At $r \le r_E$, none of the beta particles originating beyond r_E reach the target point. Hence, at this radius, an effective infinite medium for airborne beta radiation has been reached. The dose from a volume such that $r \ge r_E$ is equal to the dose from an infinite volume, which is denoted $D\infty$.

The dose as a function of volume radius is thus found to be given by the dual relation:

$$D(r) = D\infty \frac{(1 - \exp(-\mu_E r))}{(1 - \exp(-\mu_E r_E))} \qquad 0 \le r \le r_E \quad \text{(J.E-6)}$$

This relation may be transformed to a function of volume by noting that $V = 4\,\pi r^3/3$.

Since μ_E and r_E vary for each beta energy, this equation cannot be solved analytically for the case of a mixture of many beta energies - which is the case at hand. However, since $D\infty$ for each beta energy is known (from the calculation of the semi-infinite source), $D_{E(v)}$ for each beta energy at a given volume may be determined. All contributions to the total dose at a given volume are then added together.

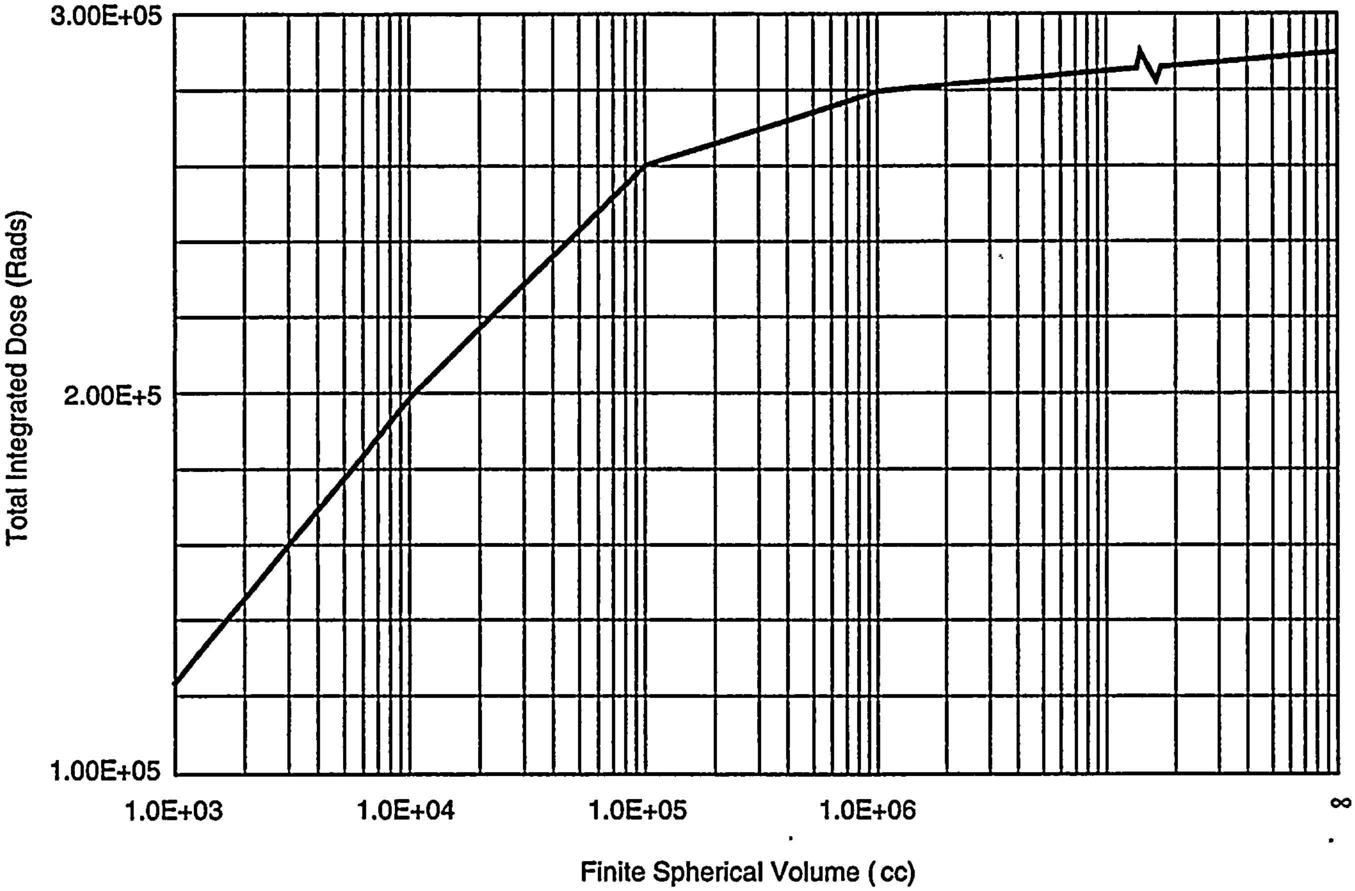
The volumes evaluated in this analysis were 10^3, 10^4, 10^5, and 10^6 cm^3. Table J.E-1 summarizes the semi-infinite volume for each beta energy group. Table J.E-1 also indicates the beta dose reduction factor for each of the beta energy groups at the finite beta volumes of interest. A plot of the integrated 6-month doses for these finite beta volumes is shown in Figure J.E-1. These results reflect the reduction in beta air dose from the semi-infinite

medium air dose to a finite volume medium air dose. The integrated beta infinite airborne dose for the reactor building as a function of time post-loss-of-coolant accident (LOCA) is shown in Figure J.E-2.

TABLE J.E-1

DOSE RATE REDUCTION FACTORS FOR THE POST-LOSS-OF-COOLANT ACCIDENT BETA ENERGY GROUPS AT FINITE VOLUMES

Energy Group (MeV)	V_E (cm^3)	$\frac{D(V)}{D_\infty}$ for Volumes			
		10^3 cm^3	10^4 cm^3	10^5 cm^3	10^6 cm^3
0.02 - 0.10	120.0	1.0	1.0	1.0	1.0
0.10 - 0.20	4.08×10^5	0.486	0.763	0.960	1.0
0.20 - 0.40	8.58×10^6	0.260	0.478	0.755	0.955
0.40 - 0.70	1.36×10^8	0.127	0.254	0.468	0.744
0.70 - 1.0	1.04×10^9	0.0695	0.144	0.284	0.513
1.0 - 1.3	3.46×10^9	0.0467	0.0979	0.199	0.380
1.3 - 1.6	8.18×10^9	0.0348	0.0735	0.152	0.299
1.6 - 2.0	1.59×10^{10}	0.0276	0.0585	0.122	0.244
2.0 - 2.5	3.20×10^{10}	0.0215	0.0457	0.0960	0.195
2.5 - 3.0	6.47×10^{10}	0.0167	0.0356	0.0752	0.155



Total Integrated Beta Cloud Airborne Dose as a Function of Size

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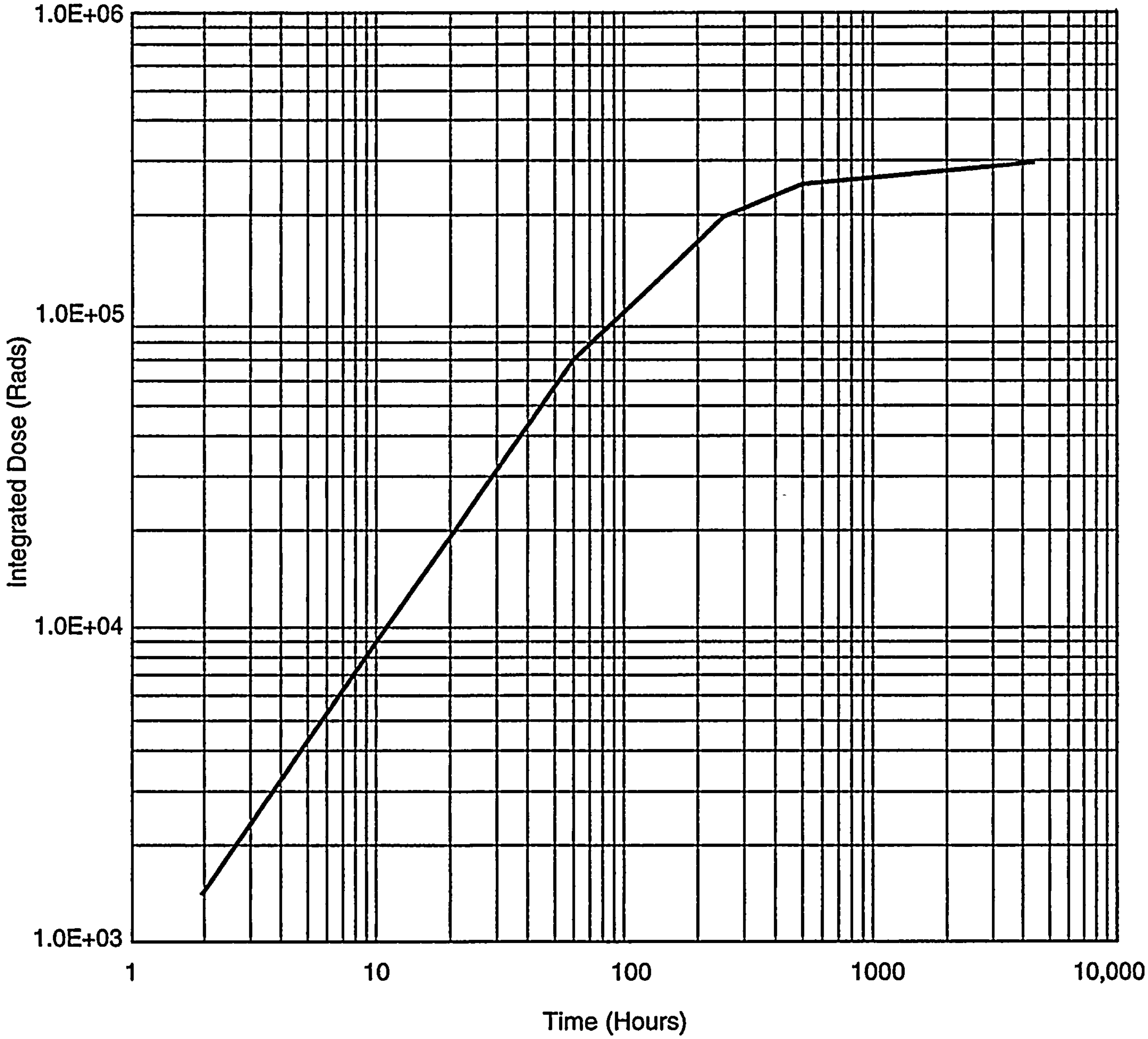


Integrated Beta Infinite Airborne Dose for the Reactor Building

Attachment J.F

PRIMARY CONTAINMENT ANALYSES

J.F.1 STATEMENT OF PROBLEM

It is required by NRC regulations (NUREG-0737 and NUREG-0588, References J.7-5 and J.7-2) that safety-related equipment be qualified to withstand the radiation environment in which they are located for the 40 years of normal plant operation plus for the 6 months following a postulated design basis loss-of-coolant accident (LOCA). This attachment presents a summary of the evaluation of the radiation environment inside the primary containment of WNP-2 during normal plant operation and for the 6 months following the postulated LOCA. This attachment also calculates the maximum integrated dose due to those radiation sources.

J.F.2 BASIC APPROACH

NUREG-0737 offers two approaches for evaluating the qualification of equipment within primary containment; pressurized versus depressurized reactor coolant system, with the more conservative to be considered the base case. Both cases assume the same source (100% noble gas, 50% halogens, and 1% particulates of the core inventory). The difference between the two is that in the pressurized case, the source is assumed to remain in the reactor coolant system for the first 17 hr (Reference J.7-44) after the accident and then is assumed to be released into the primary containment. In the depressurized case, there is assumed to be an instantaneous release of 100% of the core noble gases and 50% of the core halogens to the free volume of the primary containment (Reference J.7-45). It is also assumed that 50% of the core halogens and 1% of the core solids are released to the reactor coolant and the suppression pool. This causes some double counting of halogens and hence some conservatism, since only 50% of the core halogens need ever be considered for release after a LOCA.

Both scenarios, the pressurized and depressurized were evaluated and it was determined that for WNP-2 the depressurized case results in higher integrated doses (References J.7-46, J.7-50, and J.7-54). Therefore, it was considered to be the base case.

Due to the large number of C1E* components inside primary containment, it was deemed impractical (from both scheduling and cost considerations) to calculate the integrated dose to each piece of equipment. Therefore, it was decided to calculate the worst point dose from each of the major sources in the drywell and wetwell, and then to sum these for a conservative estimate of the total integrated dose. This methodology for determining a worst-case dose for equipment in the drywell is not valid for the region inside the sacrificial shield wall or under

* Environmental qualification (EQ) of safety-related mechanical equipment has been eliminated from the overall WNP-2 EQ program (SRM).

the reactor pressure vessel. A point-specific radiation dose calculation is required for all components present in either of these two regions.

J.F.3 DRYWELL

The integrated dose from each of the major sources to the drywell is tabulated in Table J.F-1. All values are the maximum dose for each source considered. Since the maximum dose does not occur at the same location or the same time from all sources, it is not appropriate to sum them to obtain the total integrated dose. All of the maximum doses calculated cannot be present for a particular accident. The highest dose (7.4×10^7) is calculated for a depressurized reactor coolant system.

This dose is conservative since all of the source contributors summed do not have the maximum dose at the same location. If it were determined that certain pieces of equipment could not withstand the maximum dose, a more detailed calculation would unquestionably result in an integrated dose of lower than 7.4×10^7 rads. A lower bound for the more detailed calculation would be about 10^7 rads.

One major factor regarding the airborne contribution needs to be addressed here to understand the results in Tables J.F-1 and J.F-2. Of the total airborne contribution (3.5×10^7 rads) slightly over 50% of it is due to photons which have an energy of less than 0.045 MeV. These photons are readily attenuated. As such, virtually any amount of shielding will result in a reduction by a factor of approximately two in the total airborne dose. Such an example is the smallest size conduit used in containment which has a wall thickness of 0.179 in.

This is not the only conservatism in the calculation; however, it is the most noteworthy. The following section addresses the individual contributors, assumptions, sources, models, etc., used to calculate the integrated dose.

J.F.3.1 Sources

There are six major radiation sources to the equipment in the drywell. Two of these sources are present during normal operation and four sources are present after a LOCA. They are

	Normal Ops	Sources
Rx Core	Normal Ops	Neutrons emanating directly from the reactor core and the resultant capture gammas.

Systems	Normal Ops	The following systems are the main sources of radiation during normal plant operation: a. Residual heat removal (RHR) system, b. Reactor water cleanup (RWCU) system, c. Main steam (MS) system, and d. Reactor recirculation (RRC) system.
Systems	Post-LOCA	In addition to the systems considered under normal operation, (except for the MS) the following systems were also considered post-LOCA: a. High-pressure core spray (HPCS), b. Low-pressure core spray (LPCS), and c. Reactor core isolation cooling (RCIC).
Airborne	Post-LOCA	Airborne radiation from radionuclides (noble gases and halogens) which are postulated to be released into the primary containment atmosphere following a LOCA.
Plateout	Post-LOCA	Plateout on surfaces within containment. This consists of radioactive iodines which are initially airborne and subsequently plateout (Reference J.7-34).
Wetwell	Post-LOCA	The radionuclides contained within the wetwell as a result of the blowdown after the accident.

J.F.3.1.1 Reactor (Normal Operation - Drywell)

There exists a general radiation field inside primary containment due to normal plant operation. Part of this field is due to neutron leakage from the reactor core. A fraction of those neutrons penetrate the reactor vessel into the reactor cavity. Some will traverse vertically while others will penetrate the sacrificial shield wall. In addition, secondary gammas will be generated from neutron interaction with materials along their path.

ANISN, a one-dimensional discrete ordinates computer code was used to calculate the transport of these neutrons, and the generation of secondary gamma rays (Reference J.7-55).

The total neutron and gamma dose rates outside the sacrificial shield wall at core mid-plane are calculated to be

a. 5.7 rad/hr neutron, and
b. 50 rad/hr gamma

An estimate was made to determine the axial variation of the dose rate based on geometric and material attenuation factors. The approximate dose rate reduction factors are shown in Table J.F-3 as a function of distance from the core mid-plane.

J.F.3.1.2 Systems (Normal Operation - Drywell)

During normal operation, a radiation field exists within containment due in part to radioactivity contained within the piping inside primary containment.

The single major source within the piping is ^{16}N [produced by the (n,p) ^{16}O ^{16}N reaction within the core]. The dose from other sources such as fission products, corrosion products, etc., are too small compared to ^{16}N to be considered.

Calculations were done to determine the dose rate to which equipment was exposed. The results indicated that the dose rate ranged from a high of 35 rad/hr to a low of 0.36 rad/hr. These calculations were performed with KAP-V and QAD-BR. They took into account the following systems: RHR, RWCU, MS, and RRC (References J.7-47, J.7-48, and J.7-49). The ^{16}N source used was 40 µCi/g (FSAR Table 11.1-4) maximum. This is the source strength of the ^{16}N in the coolant exiting the reactor. Based on this initial source, the source strength for the pipes of the systems considered was evaluated, and the dose calculations were then performed.

J.F.3.1.3 System (Post-Loss-of-Coolant Accident) - Drywell

The dose rate calculations for systems post-LOCA were performed using a method similar to that used for the systems under normal operation with two exceptions. The first was that in addition to the RHR, RWCU, and RRC systems, the HPCS, LPCS, and RCIC systems were also included. The second exception was that a different source was used (References J.7-48 and J.7-49). After a LOCA, the predominant source past the first minute or so is the assumed fission product release from the core. The ^{16}N inventory, with a 7.1-sec half-life decays away in less than a minute once the (n,p) ^{16}O ^{16}N reaction stops occurring (after the reactor shuts down).

For the base case, i.e., the depressurized case, it was assumed that 50% of the core halogens and 1% of the core solids were released and distributed within the suppression pool and the reactor coolant systems (References J.7-51, J.7-52, and J.7-53). As noble gases were produced by the radioactive decay of the halogens, they were discounted on the premise that

they would be released from the liquid to the gas rapidly. The released inventory is then decayed for 37 discrete time intervals out to 6 months (these are given in Table J.F-7). An average source strength is then calculated for the 6-month period. The source strength is given in Table J.F-4.

J.F.3.1.4 Airborne - Drywell

A nonmechanistic accident scenario was postulated in calculating the airborne source. It was assumed that after 1000 days of operation at 3556 MWt (105% of core power), 100% of the noble gases and 50% of the halogens contained within the reactor core are instantaneously released. After the release, no additional contribution of either noble gases or halogens is considered. Also, plateout of halogens is considered (see Section J.F.3.1.5). (The average airborne source strength is given in Table J.F-5.)

The above source is calculated via the ORIGEN2 computer code. After the source strength was determined, the dose rate was calculated using the QAD-CG computer code. Details of the model and the calculation are discussed in Section J.F.5. The value for the airborne contribution presented in Table J.F-1 represents the dose rate at a point within the drywell which is predominantly surrounded by air. This point was chosen because of the absence of structural steel, piping, etc., surrounding the dose point. This would result in an upper limit dose rate which could be expected to occur in the drywell.

The effect of the shielding afforded by the structural steel, piping, etc. (i.e., "shadow shielding"), within containment was considered. Advantage was taken of "shadow shielding" when considering the contribution of the more distant airborne sources (References J.7-48 and J.7-49). This significantly reduces the dose rate compared to the case where "shadow shielding" is not employed. (See Section J.F.5 for modeling of "shadow shielding.")

J.F.3.1.5 Plateout - Drywell

The basis for determining the plateout source is 50% iodine inventory released after 1000 days irradiation at a power level of 3556 MWt. However, the plateout source is only those iodines which are removed from the airborne source and assumed to plateout on the surfaces within containment. As such, plateout removes sources from the airborne source, and this was accounted for in the calculations. It was assumed, however, that the noble gases generated by the decay of the plated out halogens (I → Xe and BR → KR) are instantaneously released and are mixed within the free volume of the drywell. In this manner, both the airborne and plateout sources are determined with no "double counting" of nuclides. The plateout source is given in Table J.F-6.

When the halogens are initially released, not all of them are considered available to plateout. Of the halogens released, 2.0% are in the form of organic compounds, and 2.5% are in the form of particulates (Reference J.7-2); and both of these forms are assumed not to plateout.

The remaining 95.5% are considered to be in an elemental state of which one-two hundredth remain airborne and the rest plateout. Therefore, no more than 95% of the released halogens can ever plateout. The plateout was assumed to occur with an effective deposition velocity of 0.05 cm/sec. This translated into an effective half-life of 1.01 hr^{-1} (References J.7-34 and J.7-45). Given this half-life, the limit of a reduction of a factor of 200 is attained in slightly over 5 hr. After that time, the percentage of plated out halogens remains constant at 95%.

The dose calculations were performed with the computer code QAD-CG, incorporating a model similar to that used for the airborne dose. (See Section J.F.5 for discussion of model and calculations.)

Initial calculations were performed with the total plateout being distributed over: (1) the drywell lateral surface, top, and bottom; (2) inner, outer and top surfaces of the sacrificial shield wall; and (3) heat reflector of pressure vessel surface. Given this distribution area, the maximum dose rate calculated was 7.04×10^3 rad/hr. However, when the remaining surface areas within containment (i.e., equipment, piping, structural steel, etc.) were considered, the area over which the source would be plated out increased sevenfold. A counter-balancing effect to this reduction in plated out concentration was that the source would be more universally distributed around any given receiver. It was estimated that the net effect would reduce the calculated maximum dose rate by a factor of approximately three.

It is noted that the energy spectrum for the plateout source is significantly harder than that of the airborne. As such, the comments in Section J.F.3 regarding low energy photons are not completely applicable.

J.F.3.1.6 Wetwell - Drywell

The wetwell was also considered as a source to the drywell. However, due to distance, self-attenuation, and the available shielding from the 2-ft-thick diaphragm floor, its contribution to the drywell was negligible.

It was assumed that 50% of the halogens and 1% of the particulates from the core were entrained in the water in the suppression pool. This is the same source used for the systems post-LOCA. The air space volume above the suppression pool was assumed to have the same volumetric source strength as the drywell air space. These are conservative premises since only a total of 50% of the core halogens are assumed to be released after the accident.

J.F.4 WETWELL

The results for the wetwell are given in Table J.F-2. Doses were calculated for detector points both within the suppression pool as well as in the free volume above it using QAD-CG, applying the same modeling techniques as was used in the drywell.

With regard to the airborne contribution, the volumetric source strength is the same as the drywell airborne source and the comments in Section J.F.3.1 regarding the low-energy photons applicability to the wetwell.

There does exist some double counting of nuclides in the wetwell analysis. The airborne source is 100% noble gases and 50% halogens, released into the containment (wetwell and drywell) free volume. For the suppression pools the source is 50% halogens and 1% particulates. Since only 50% of the total core halogens are assumed to be released after an accident, they are double counted. (The effect is small, however, because of the shielding offered by the suppression pool water.) Another conservatism in the airborne source in the wetwell is that, since the path for the wetwell airborne sources is via the downcomers and then up through the suppression pool, some halogens are expected to be entrained in the water during this transfer. (This was not considered in the calculation.) The result would have been a smaller airborne source and in turn a smaller dose.

J.F.4.1 Sources

There are three sources of radiation to the equipment in the wetwell, all of which are present only after an accident.

a. Airborne

   The airborne source is present as a result of the initial blowdown into the suppression pool via the downcomers,

b. Plateout

   Plateout of halogens onto the surfaces in the wetwell (i.e., containment, downcomers, etc.), and

c. Suppression Pool

   The radionuclides contained within the suppression pool as a result of the blowdown after the accident.

J.F.4.1.1 Airborne - Wetwell

The airborne source, on a specific volume basis, is equal to the airborne source in the drywell (i.e., 100% noble gas and 50% halogen released into the total primary containment immediately following a LOCA). However, the amount of "shadow shielding" within the wetwell is much less than in the drywell. Hence, the contribution from sources further away is greater. This factor accounts for the increased dose rate in the wetwell with respect to the

drywell (due to airborne sources). Dose calculations in the wetwell were done in similar manner as for the drywell (i.e., using QAD-CG).

J.F.4.1.2 Plateout - Wetwell

As in the drywell, the source of the plateout in the wetwell is the halogens. However, the area available for plateout is smaller in the wetwell than the drywell. This results in a dose rate in the wetwell slightly more than double that in the drywell.

J.F.4.1.3 Suppression Pool - Wetwell

The source in the suppression pool was assumed to be 50% of the halogens and 1% of the particulates instantaneously released from the core into the pool and the reactor coolant system. It is further assumed that as noble gases are produced by the decay of the halogens (I→Xe and Bγ→Kγ), they "bubble out" of the pool, hence they are not considered a source term. Dose rates both in the suppression pool as well as in the wetwell free volume were calculated using QAD-CG.

J.F.5 QAD-CG MODEL

The QAD-CG computer program was used to calculate dose rates for both the airborne source as well as the plateout. In both cases, i.e., airborne and plateout, similar modeling techniques were used. This section defines the modeling used in both calculations (with only the drywell used for illustrative purposes).

The QAD-CG computer code makes use of a geometry package, which allows the user to model a calculation with the use of predetermined geometric bodies. The user defines a set of geometric "bodies" (boxes, truncated cones, spheres, cylinders, etc.) and using these "bodies," the user defines "zones" by intersection or forming unions of them to build the shapes desired in a manner analogous to "intersections" and "unions" when one deals with sets. The model is done three-dimensionally thereby allowing the user considerable flexibility. These "zones" are then what constitute the computer model. (The parts of "bodies" that are not used have no effect on the model.)

As an example, a dumbbell could be defined as the union of three "bodies": two spheres and a long, thin cylinder between them (see Figure J.F-1). Likewise, a hemisphere could be formed by intersection of a sphere with a box (see Figure J.F-1). In this manner, a complex model can be defined.

In our case, the basic model was defined as a truncated cone (approximating the containment shell) and two cylinders (approximating the sacrificial shield wall and the reactor vessel). Figure J.F-2 illustrates this in a sectional view. The free volume of the drywell was compartmentalized into cubes, 7 ft on a side. These cubes were formed by intersection of a

series of tall rectangles, which are 7 ft on a side in cross-section, with cylinders at 7-ft high intervals. (Each 7-ft high cylinder constitutes the elevational boundaries of what is referred to as a "layer" below.) Combining these "bodies" appropriately one winds up with a truncated cone (containment) with two cylinders (i.e., sacrificial wall and reactor vessel) and the remainder of the volume forced with cubes (except on the boundary of the cone or cylinders). Figure J.F-3 illustrates this model, while Figure J.F-4 illustrates how the layer from el. 513 ft 6 in. to el. 520 ft 6 in. is modeled.

All major structures, pipes (6 in. and above), hangers, etc., within the drywell were then located, and the mass of steel in each cubicle determined. These were translated into average densities such that each cube had an average density assigned to it. These are illustrated on Figures J.F-5 to J.F-9 for the lower five layers. (For the purpose of clarity, the densities shown are much cruder than the 41 used in the code.) In those cubicles which are noted to have zero density, the density of air was assumed.

In Figures J.F-7 to J.F-9 a large void (air only) exists in the southwest (fourth) quadrant in layers 3 and 4. It was in this region that the airborne dose rate was calculated. This region provides us with a volume which is large enough so that the "shadow shielding" (smearing discrete shielding within a cubicle into an average density in the cubicle) beyond its boundary is justified.

Several runs were made using this model with various source volumes. Three runs were made placing the source terms within the elevational boundaries of layers 3, 4, and 5, respectively, and another run was made by placing the source from the lower elevational boundary of layer 1 up to the upper elevational boundary of layer 2. It was noted that >95% of the total dose contribution from these five layers came equally from layers 3 and 4. In other words, the further away the source layer, the smaller the contribution. Also, shadowing shielding in layers 1 and 2 provided sufficient attenuation as to make the contribution to the total dose negligible. The same is true also for all layers above layer 5.

Plateout was calculated in a similar manner, increasing the source until successive contributions became negligible. For the plateout, the dose point was taken near the sacrificial shield wall. Other points were also considered, but the dose rate near the sacrificial shield wall was found to be the maximum. Again, the dose point was taken between layers 3 and 4 to maximize the dose rate.

J.F.6 CODES

J.F.6.1 FSPROD

FSPROD is a computer program which calculates the inventory and activity of radioactive fission products, produced from the thermal fission of ^{235}U, as a function of fission rate and decay time after fission. The program is used in establishing the gross and specific gamma

and beta activity of those fission products. The calculation incorporates 123 fission product nuclides and is based on Perkins and King data.

J.F.6.2 ORIGEN2

ORIGEN2 is a point depletion and decay computer code for use in simulating nuclear fuel cycles and calculating the nuclide composition of materials contained therein. The code represents a revision and update of the original ORIGEN computer code. The general function of the ORIGEN2 computer code is to calculate the nuclides present in various nuclear materials by determining the buildup and depletion of nuclides during irradiation and decay. The code can also account for reprocessing (i.e., chemical separation) and continuous feed, removal, and accumulation of nuclear materials.

J.F.6.3 QAD-BR

QAD-BR is a point kernal computer code designed to evaluate gamma penetration of various shield configurations. It is a modification of QAD-P5A; i.e., it has no capability for neutron calculations. The program provides an estimate of the uncollided and collided gamma flux, dose rate, energy deposition, and other quantities which result from a point-by-point representation of volume-distribution source of radiation.

J.F.6.4 QAD-CG

QAD-CG is also a modification of the QAD-P5A computer program. It is similar to QAD-BR in application with the major difference being in the geometry description. QAD-CG makes use of a combinatorial geometry package originally developed for MORSE. It is one of the more versatile geometry packages to be available in the QAD family of computer codes.

J.F.6.5 KAP-V

KAP-V is a hybrid of the QAD computer code. Analytically, it is identical to QAD as it is a point kernal code. The major differences are changes in input allowing more flexibility in running successive cases. It also has internal libraries for attenuation and buildup data which can be used by default for convenience.

J.F.6.6 ANISN

ANISN is a one-dimensional Sn transport code with anisotropic scattering. It allows for the solution of the transport equation for neutrons and photons using the discrete ordinate method.

TABLE J.F-1[a]

INTEGRATED DOSE IN DRYWELL[b]

Source	Maximum Average Dose Rate[c] (rad/hr)	Exposure Time	Dose[c] (rad)
Reactor	5.6×10^1	32 years[d]	1.6×10^7
Systems - normal	3.5×10^1	32 years[d]	9.9×10^6
Systems - LOCA	---	6 months	3.2×10^6
Airborne	---	6 months	3.7×10^7
Plateout	---	6 months	1.0×10^7
Suppression pool	---	6 months	$<4.5 \times 10^4$

[a] Not valid for regions inside the sacrificial shield wall or under the reactor pressure vessel (a point specific radiation calculation is required for components in these two regions).

[b] Also see Figure J.F-10.

[c] Maximum dose rate from individual contributors does not necessarily occur at the same location or for the same accident.

[d] (40-year plant life) x (0.8) availability to account for down time.

TABLE J.F-2

INTEGRATED DOSE IN WETWELL

Source	Maximum Average Dose Rate[a] (rad/hr)	Exposure Time	Dose[a] (rad)
Dose above suppression pool			
Airborne	1.8×10^4	6 months	8.2×10^7
Suppression pool	2.0×10^2	6 months	9.1×10^5
Plateout	2.7×10^3	6 months	1.2×10^7
Dose within suppression pool			
Airborne	2.9×10^2	6 months	1.4×10^6
Suppression pool	5.5×10^2	6 months	2.5×10^6

[a] Maximum dose rate from individual contributors does not necessarily occur at the same location.

TABLE J.F-3

APPROXIMATE DOSE RATE REDUCTION FACTOR
VERSUS DISTANCE FROM CORE MID-PLANE
FOR REACTOR INTEGRATED DOSE

Distance (ft)	Reduction Factor
0	1.0
5	0.5
10	0.02
15	1×10^{-5}

TABLE J.F-4

SUPPRESSION POOL AND SYSTEM
(LOSS-OF-COOLANT ACCIDENT) LIQUID SOURCE TERMS
0-6 MONTH AVERAGE AFTER LOSS-OF-COOLANT ACCIDENT

MeV	MeV/sec	MeV/cm^3-sec[a]
0.015	1.8E+14	4.4E+4
0.025	3.5E+14	8.5E+4
0.0375	4.8E+14	1.2E+5
0.0575	1.4E+14	3.5E+4
0.085	5.8E+14	1.4E+5
0.125	2.2E+15	5.3E+5
0.225	4.0E+15	9.6E+5
0.375	4.8E+16	1.2E+7
0.575	5.5E+16	1.3E+7
0.85	7.2E+16	1.7E+7
1.25	1.5E+16	3.7E+6
1.75	1.8E+16	4.3E+6
2.25	2.1E+15	5.1E+5
2.75	9.1E+14	2.2E+5
3.5	1.1E+14	2.6E+4
5.0	7.4E+13	1.8E+4

[a] Volume considered was that of the suppression pool plus that of the reactor coolant system.

TABLE J.F-5

AIRBORNE SOURCE TERMS
0-6 MONTH AVERAGE AFTER LOSS-OF-COOLANT ACCIDENT

MeV	MeV/sec	MeV/cm^3-sec[a]
0.015	2.5E+14	2.5E+4
0.025	2.1E+14	2.1E+4
0.0375	6.9E+15	7.1E+5
0.0575	3.0E+13	3.0E+3
0.085	1.4E+16	1.4E+6
0.125	3.7E+13	3.8E+3
0.225	4.4E+15	4.5E+5
0.375	3.0E+15	3.1E+5
0.575	4.0E+15	4.1E+5
0.85	3.2E+15	3.2E+5
1.25	3.4E+15	3.5E+5
1.75	2.6E+15	2.7E+5
2.25	3.9E+15	4.0E+5
2.75	6.7E+14	6.9E+4
3.5	2.1E+14	2.2E+4
5.0	9.5E+13	9.7E+3

[a] Volume considered was total; i.e., drywell plus wetwell free volume.

TABLE J.F-6

DRYWELL PLATEOUT SOURCE TERMS
0-6 MONTH AVERAGE AFTER LOSS-OF-COOLANT ACCIDENT

MeV	MeV/sec	MeV/cm^3-sec[a]
0.015	3.6E+13	6.3E+5
0.025	1.8E+14	3.2E+6
0.0375	5.4E+13	9.5E+5
0.0575	2.0E+13	3.6E+5
0.085	3.2E+14	5.7E+6
0.125	1.9E+13	3.4E+5
0.225	2.8E+15	4.9E+7
0.375	4.4E+16	7.7E+8
0.575	2.4E+16	4.2E+8
0.85	7.6E+15	1.3E+8
1.25	9.6E+15	1.7E+8
1.75	3.4E+15	5.9E+7
2.25	5.2E+14	9.2E+6
2.75	7.3E+12	1.3E+5
3.5	1.3E+13	2.3E+5
5.0	2.9E+11	5.1E+3

[a] These values should be reduced by a factor of seven when all structural, component and equipment surfaces in containment are considered.

TABLE J.F-7

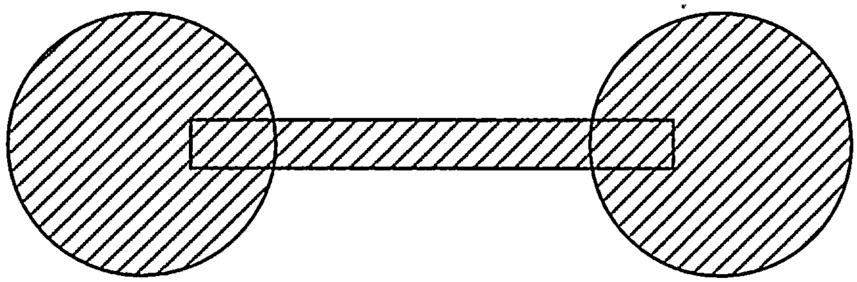
TIME MESH SPACING USED IN SOURCE CALCULATIONS
(MINUTES)

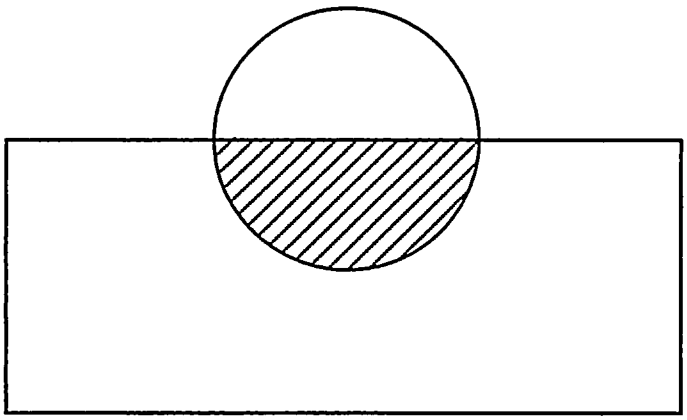
0	640	28800
20	800	36000
40	960	43200
60	1120	57600
80	1280	72000
100	1440	86400
120	2160	108000
180	2880	129600
240	3600	151200
300	4320	172800
360	5040	216000
420	5740	259200
480	14400	

TABLE J.F-8

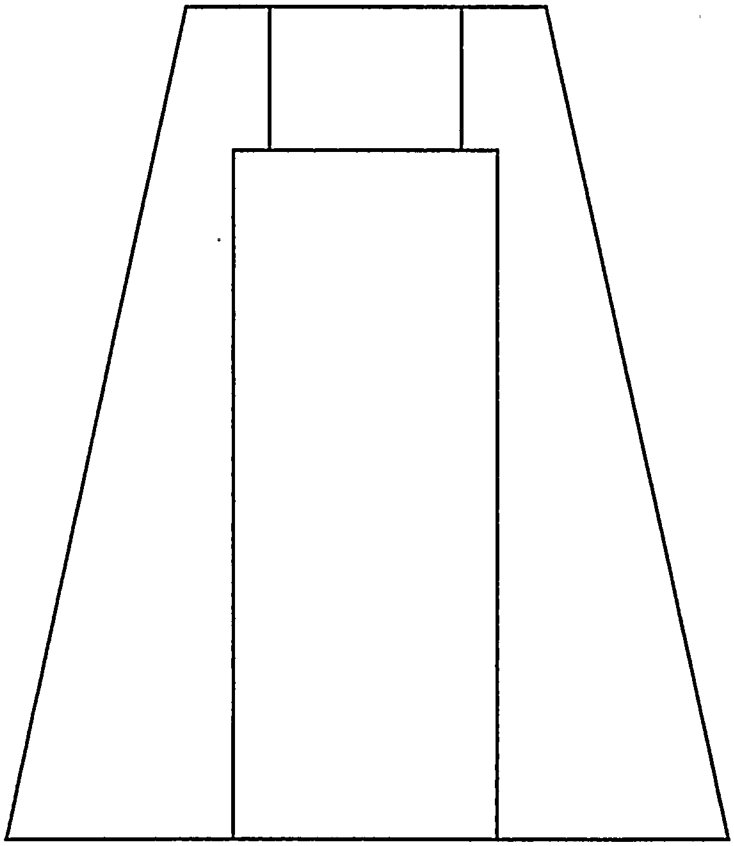
SOURCE ENERGY GROUP STRUCTURE

Lower Boundary (MeV)	Upper Boundary (MeV)	Average Energy (MeV)
0.00	0.02	0.015
0.02	0.03	0.025
0.03	0.045	0.0375
0.045	0.07	0.0575
0.07	0.10	0.085
0.10	0.15	0.125
0.15	0.30	0.225
0.30	0.45	0.375
0.45	0.70	0.575
0.70	1.0	0.85
1.0	1.5	1.25
1.5	2.0	1.75
2.0	2.5	2.25
2.5	3.0	2.75
3.0	4.0	3.5
4.0	6.0	5.0



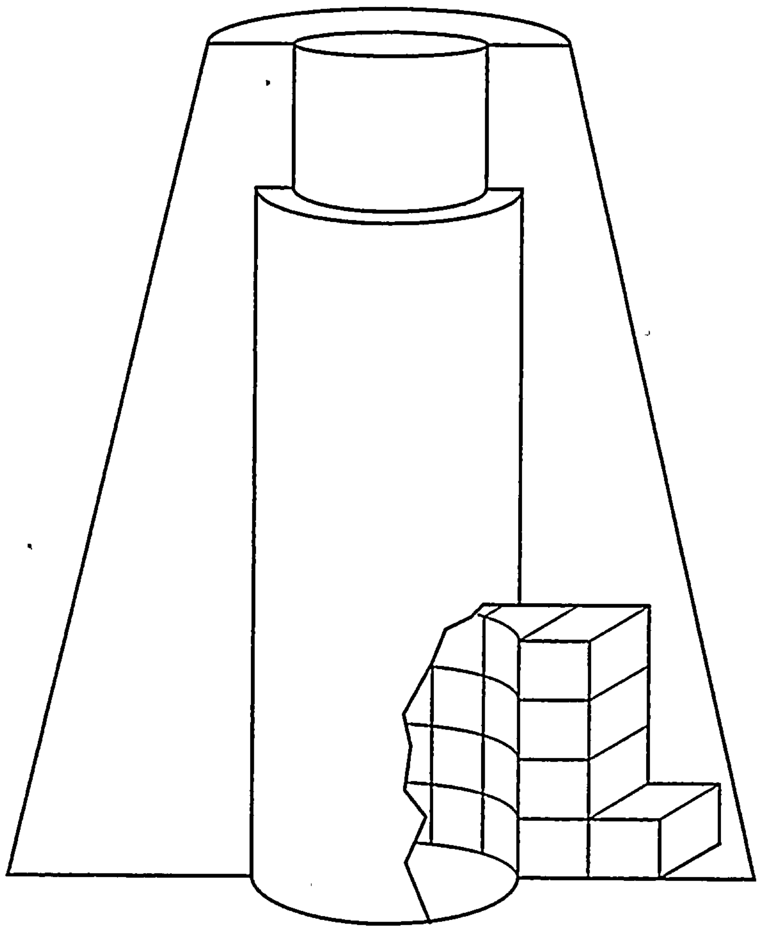


Geometry Examples



Basic QAD-CG Drywell Model

Draw. No. 970187.70	Rev.	Figure J.F-2

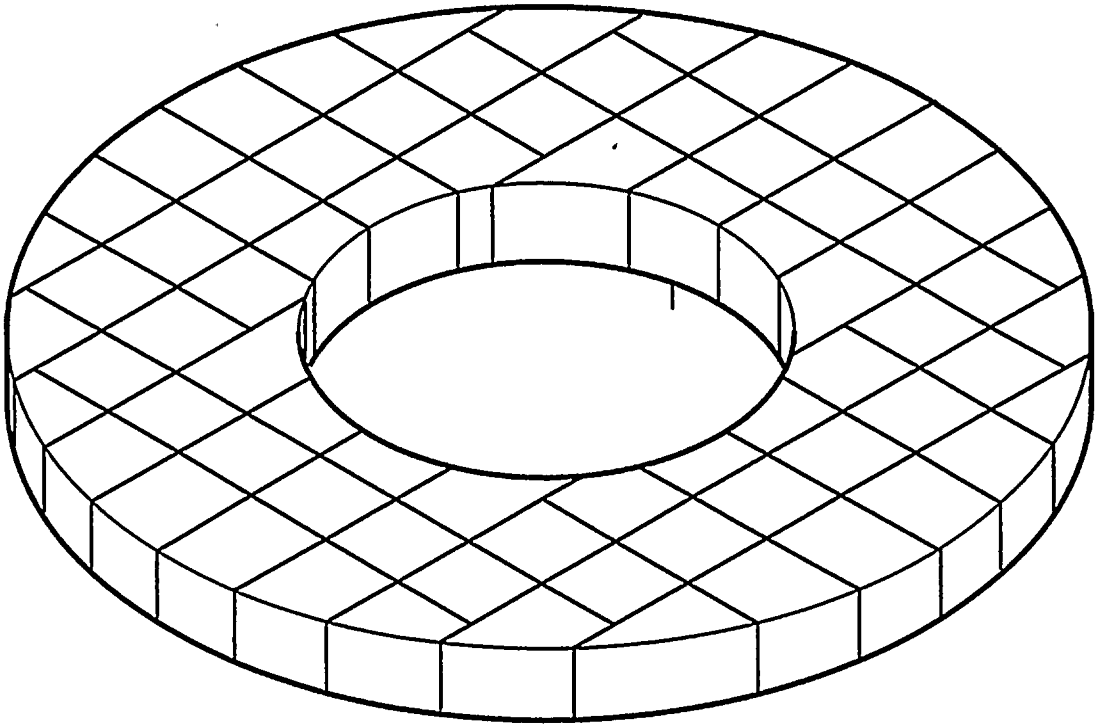


WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Isometric of Drywell Model

Draw. No. 970187.71	Rev.	Figure J.F-3

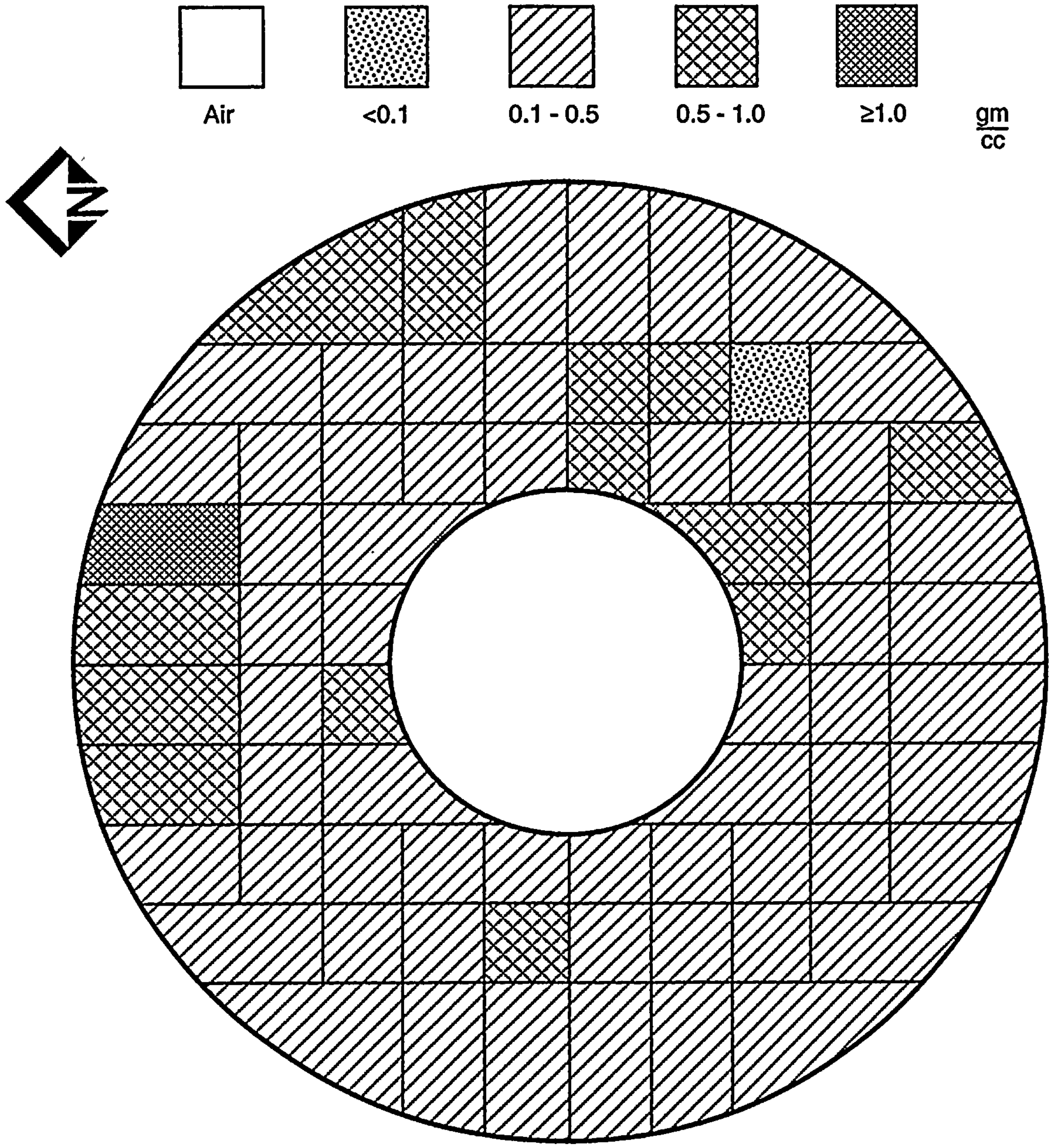
Form No. 960690



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

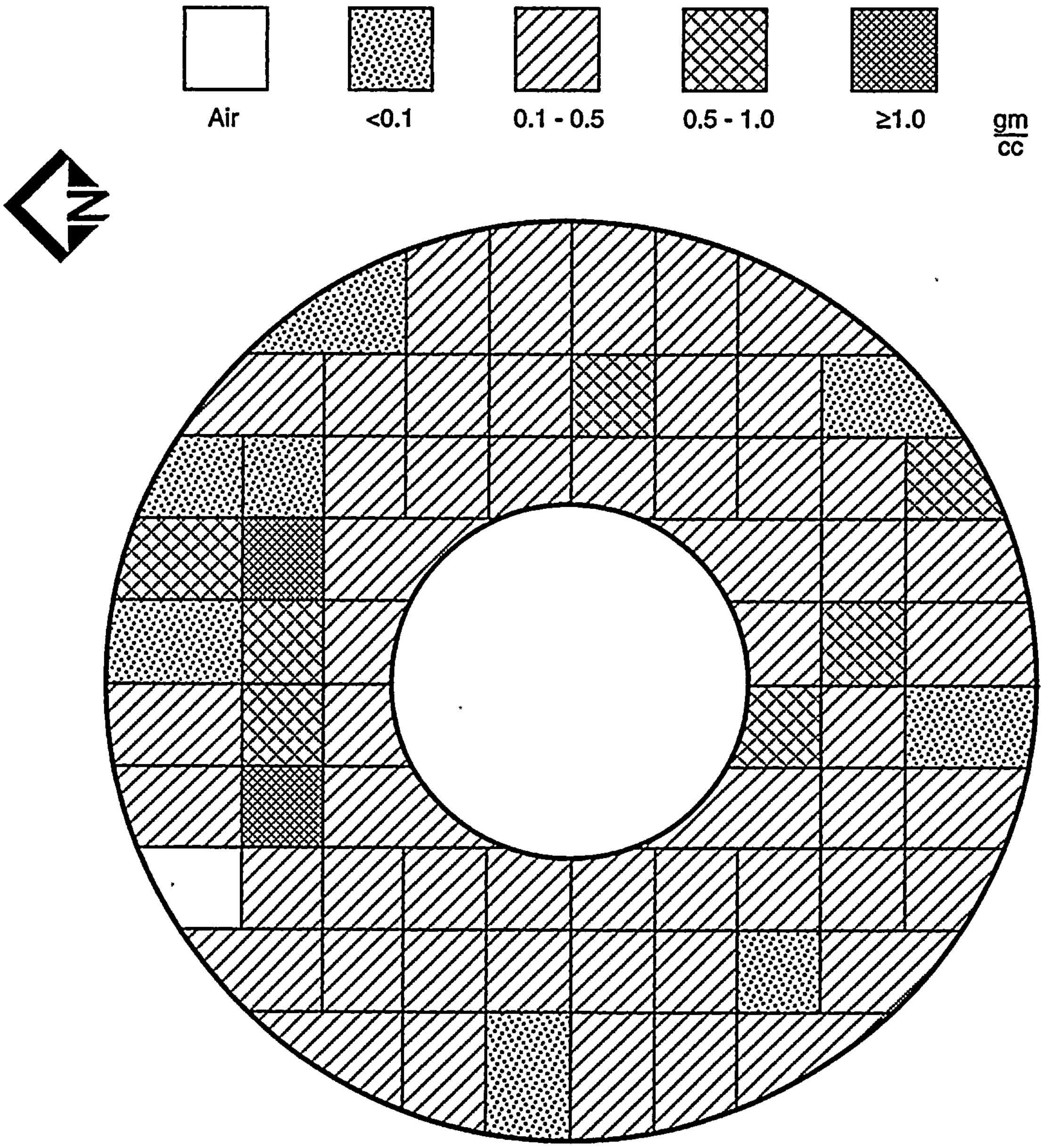
Isometric of El. 513 ft 6 in. to 520 ft 6 in.

Draw. No. 970187.72 | Rev. | Figure J.F-4



Illustrative Only - Code Used 41 Density Groups

Amendment 53
November 1998



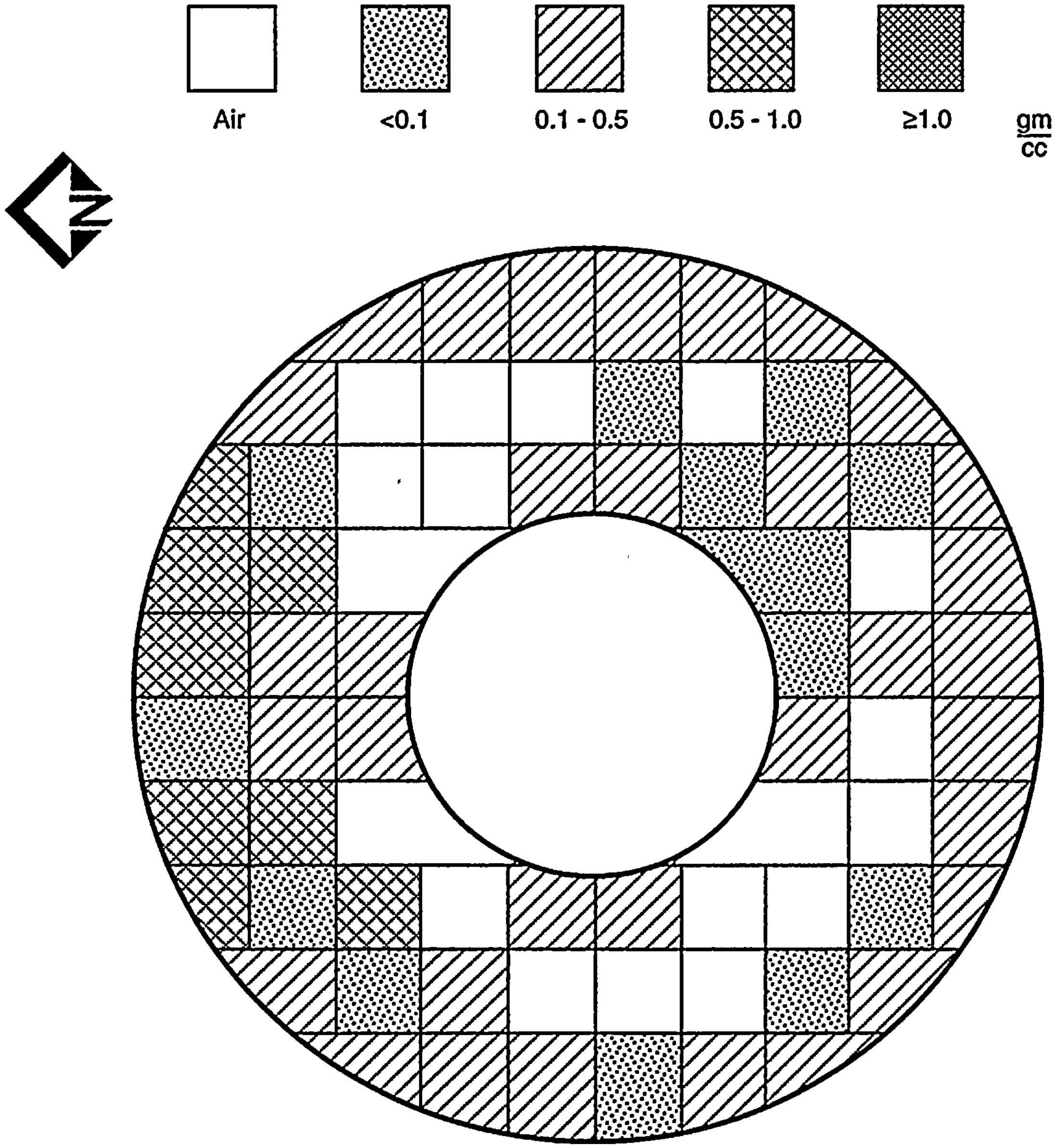
Illustrative Only - Code Used 41 Density Groups

WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Plan at El. 506 ft 6 in.

Draw. No. 970187.74 | Rev. | Figure J.F-6

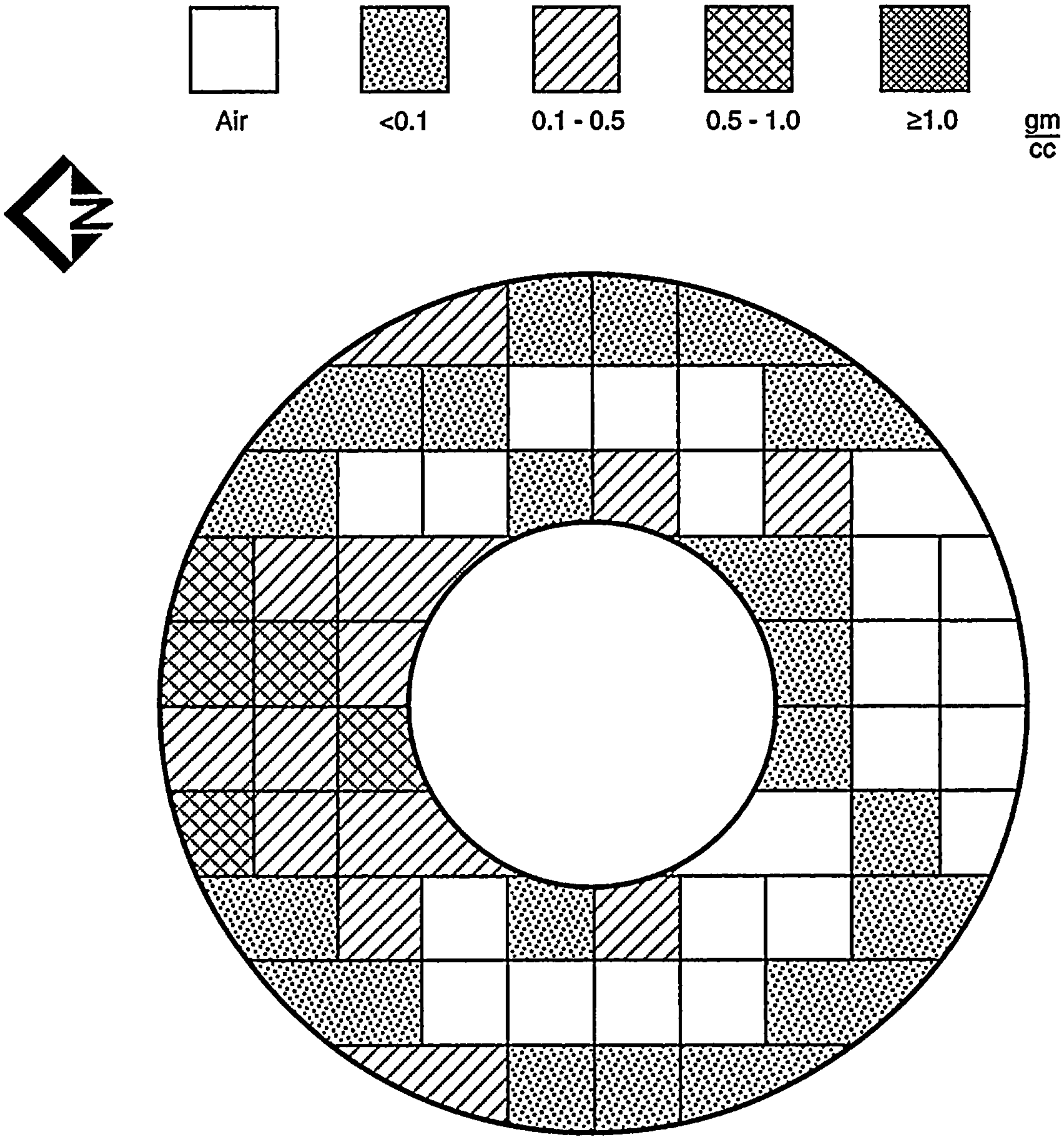
Form No. 960690



Illustrative Only - Code Used 41 Density Groups

Plan at El. 513 ft 6 in.

Draw. No. 970187.75 | Rev. | Figure J.F-7



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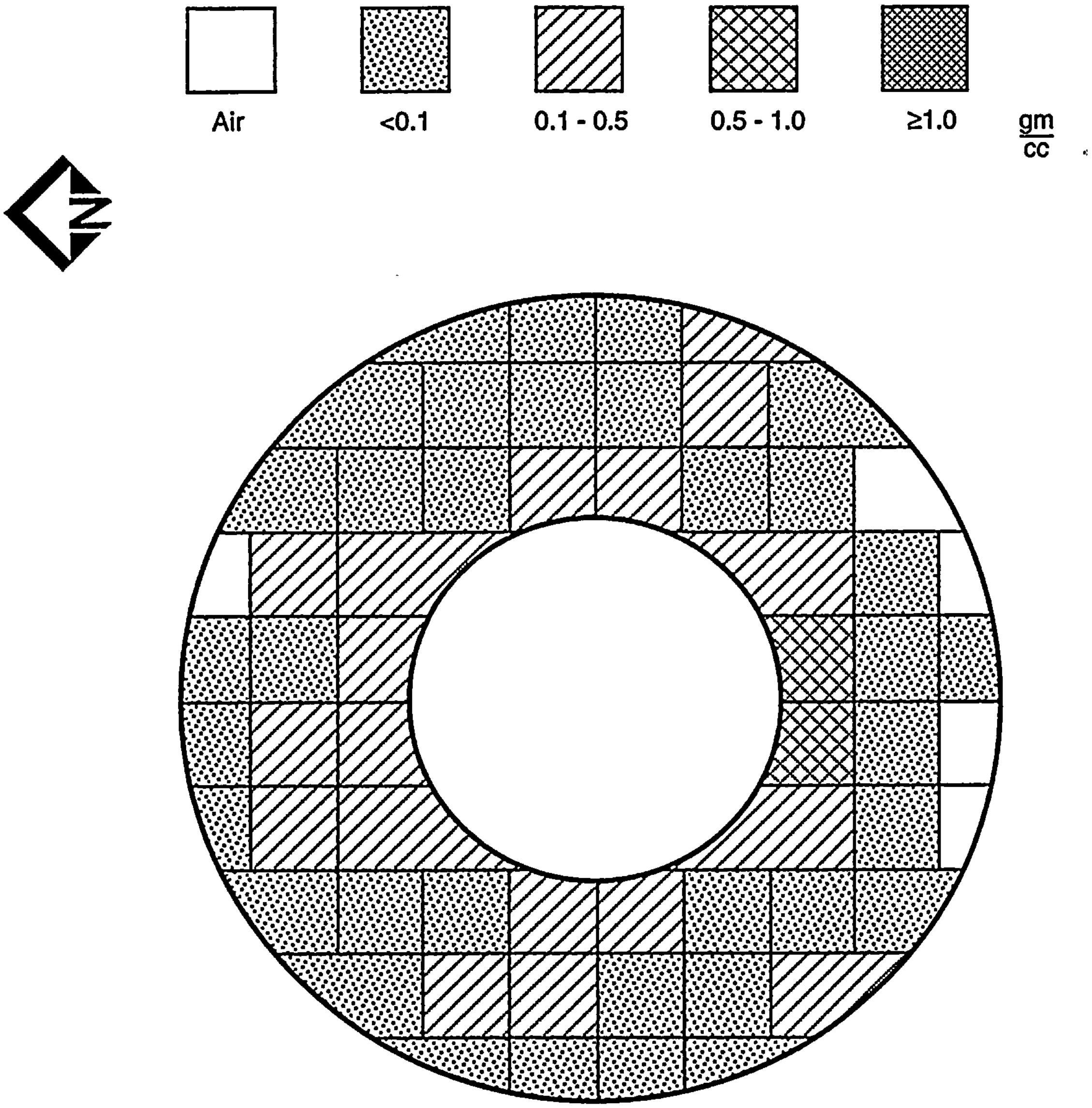


Illustrative Only - Code Used 41 Density Groups

Attachment J.G

BETA DOSE CONTRIBUTION IN PRIMARY CONTAINMENT

The source volume used for the beta dose analysis in primary containment is a sphere surrounded by a shell of sufficient thickness to stop all outside beta particles from entering the source volume. This spherical source volume is conservative for any generalized source volume shape (the dose at the center of the sphere is higher than the dose at any point of any generalized source of equal total volume).

The assumptions used in the analysis are as follows:

a. Atmosphere inside the equipment casing is identical to the atmosphere in primary containment. This is conservative because there will actually be some delay in transport of the gaseous fission products into the equipment;

b. The initial beta source term used was 100% of core noble gases and 50% of core halogens (References J.7-2 and J.7-34);

c. Daughter products of the airborne noble gases and halogens are included in the calculation of the airborne dose which is conservative and was required by the use of ORIGEN2 as a source code (Reference J.7-8);

d. Plateout of halogens inside primary containment was utilized as allowed per Reference J.7-34. The dose contribution of fission products plated out on equipment casings was neglected. The deletion of dose contributions from fission products plated out on equipment casings is acceptable, since equipment surface areas are small relative to the available containment surface area. In addition, the betas emitted from plated out fission products would be absorbed in the equipment casing and, hence, would not affect internal components;

e. No primary to secondary containment leakage is assumed since it maximizes the beta source concentration in primary containment;

f. Activity is assumed to be uniformly distributed throughout the containment free volume which is reasonable, considering the mixing effects of the loss-of-coolant accident (LOCA) blowdown and the operation of the drywell fan coolers; and

g. A spherical volume representing the equipment casing will be used.

The beta dose to equipment is dependent on the internal volume size of the piece of equipment. The beta dose is determined through the use of an energy dependent geometry factor and a

ratio of the internal equipment volume to an infinite cloud. The beta dose contribution is excluded from the worst case total integrated gamma doses of primary containment shown in Section J.6.1 and Tables J.F-1 and J.F-2. The beta dose contribution is also excluded from the value, pump, and fan tables for C1E/SRM equipment in a primary containment environment.

The discussion and development of beta dose rate variation due to beta energy distribution in a one-dimensional absorbing medium is also valid for primary containment analysis.

Thus, the dose as a function of volume radius is given by the dual relation:

$$D(r) = D\infty \frac{[1-\exp(-\mu_E r)]}{[1-\exp(-\mu_E r_E)]} \qquad 0 \le r \le r_E$$

This relation may be transformed to a function of volume by noting that $V = 4\pi r^3/3$.

Since μ_E and r_E vary for each beta energy, this equation cannot be solved analytically from the case of a mixture of many beta energies, which is the case at hand. However, since D_∞ for each beta energy is known (from the calculation of the semi-infinite source), $D_{E(v)}$ for each beta energy at a given volume may be determined. All contributions to the total dose at a given volume are then added together.

The volumes evaluated in this analysis were 10^3, 10^4, 10^5, and 10^6 cm^3. Table J.G-1 summarizes the semi-infinite volume for each beta energy group. Table J.G-1 also indicates the beta dose reduction factor for each of the beta energy groups at the finite beta volumes of interest. A plot of the integrated post-LOCA doses for these finite beta volumes is shown in Figure J.G-1. These results reflect the reduction in beta air dose from the semi-infinite medium air dose to a finite volume air dose.

The integrated beta infinite airborne dose for the primary containment as a function of time post-LOCA is shown in Figure J.G-2.

The absorbed beta dose within a physical target is not always equal to the beta dose at a mathematical point in air at the surface of that piece of equipment. The beta ionization energy (dose) deposited on the surface of a solid object is distributed in a thin surface layer to a depth equal to the beta range in the material. The relative material penetration of the different beta energy groups is used to provide a total integrated LOCA dose as a function of material depth.

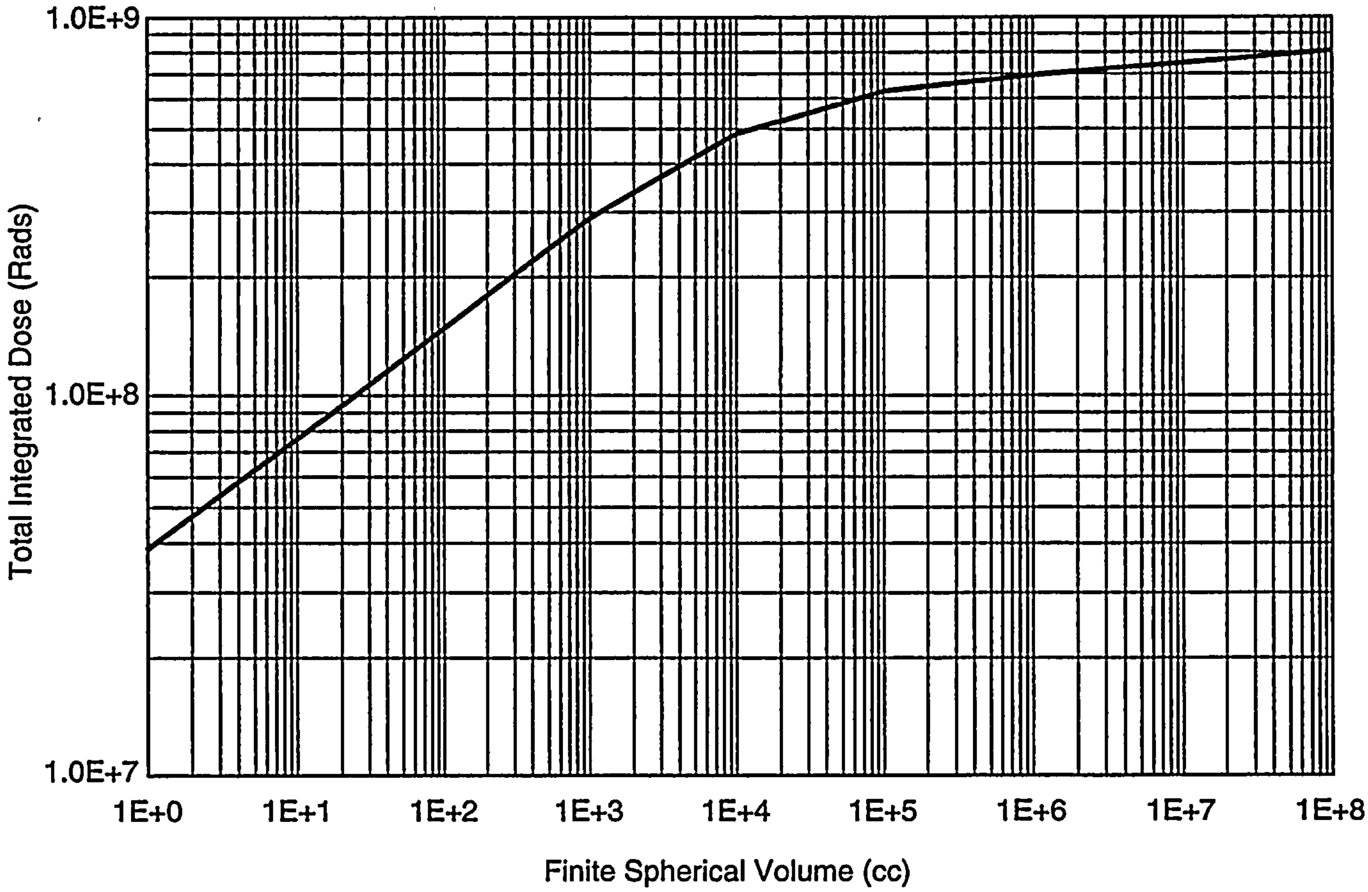
Finite volume beta dose reduction factors were determined for each of the 10 beta energy groups. These factors are used to provide total integrated LOCA dose as a function of material penetration to reduce volume exposure.

Thus, the integrated dose values (Figure J.G-1) can be used as the absorbed material dose with a standard order of magnitude for reduction for material beyond 0.030-in. thickness or a dose reduction versus thickness based on the range of beta penetration within the material can be calculated.

TABLE J.G-1

DOSE RATE REDUCTION FACTORS FOR THE
POST-LOSS-OF-COOLANT ACCIDENT
BETA ENERGY GROUPS AT FINITE VOLUMES

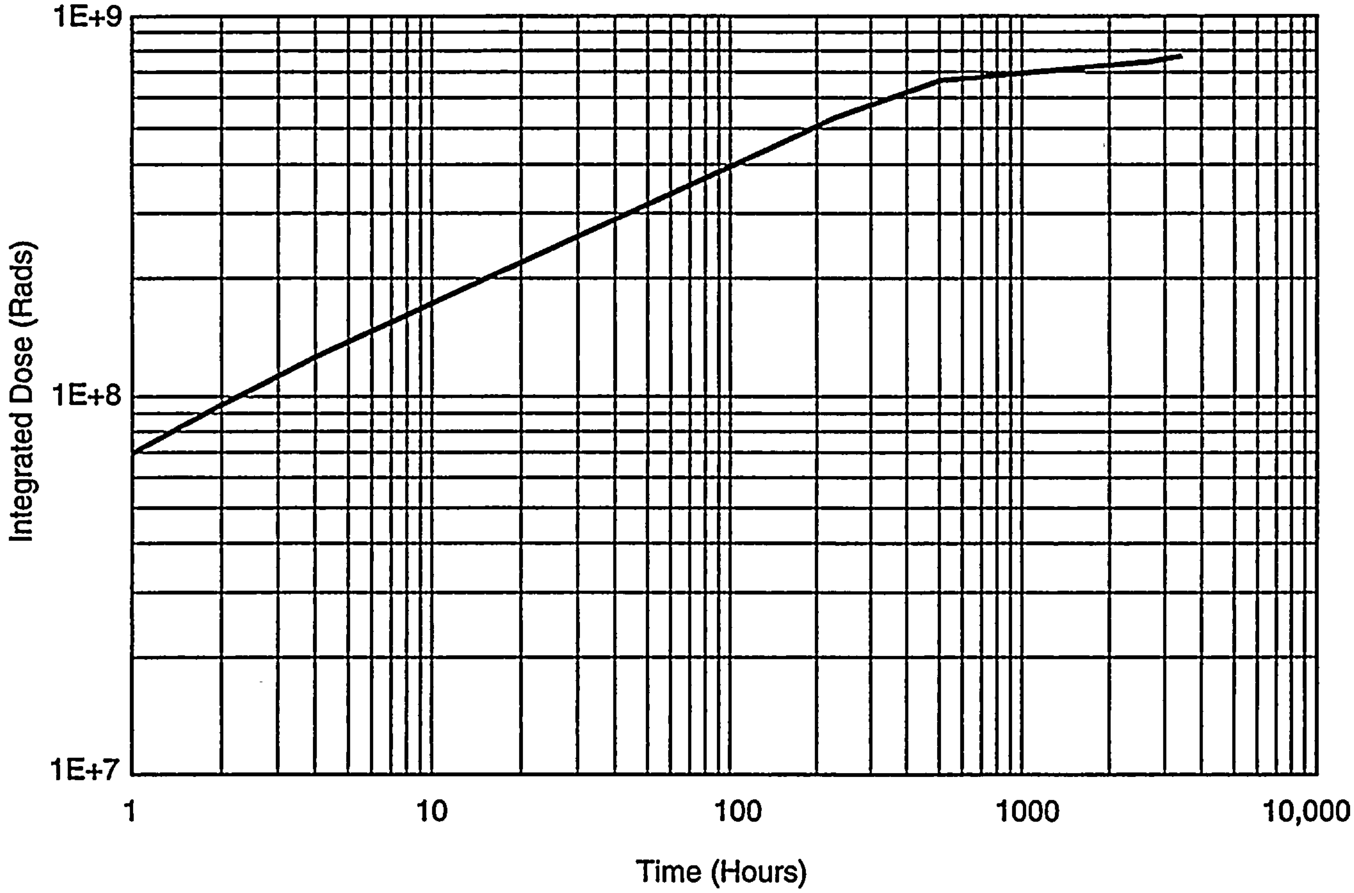
		$\frac{D(V)}{D_\infty}$ for Volumes			
Energy Group (MeV)	V_E (cm^3)	10^3 cm^3	10^4 cm^3	10^5 cm^3	10^6 cm^3
0.02 - 0.10	120.0	1.0	1.0	1.0	1.0
0.10 - 0.20	4.08×10^5	0.486	0.763	0.960	1.0
0.20 - 0.40	8.58×10^6	0.260	0.478	0.755	0.955
0.40 - 0.70	1.36×10^8	0.127	0.254	0.468	0.744
0.70 - 1.0	1.04×10^9	0.0695	0.144	0.284	0.513
1.0 - 1.3	3.46×10^9	0.0467	0.0979	0.199	0.380
1.3 - 1.6	8.18×10^9	0.0348	0.0735	0.152	0.299
1.6 - 2.0	1.59×10^{10}	0.0276	0.0585	0.122	0.244
2.0 - 2.5	3.20×10^{10}	0.0215	0.0457	0.0960	0.195
2.5 - 3.0	6.47×10^{10}	0.0167	0.0356	0.0752	0.155



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Total Integrated Beta Cloud Airborne Dose in Primary Containment as a Function of Size

Draw. No. 960222.58 | Rev. | Figure J.G-1



WASHINGTON PUBLIC POWER
SUPPLY SYSTEM
NUCLEAR PLANT 2 FSAR

Integrated Beta Infinite Airborne Dose for WNP-2 Primary Containment

Draw. No. 960222.60	Rev.	Figure J.G-2

Attachment J.H

VITAL AREAS AND ACCESS ROUTES ANALYZED FOR
POST-LOSS-OF-COOLANT-ACCIDENT OPERATIONS

This attachment represents the methodology and assumptions used to determine the integrated dose to equipment and personnel for vital areas and access routes outside the reactor building during post-loss-of-coolant accident (LOCA) operations. The source term is the reactor building elevated vent with gaseous effluents being filtered by the standby gas treatment system (SGTS) prior to discharge to the atmosphere.

J.H.1 SOURCE OF RADIOACTIVITY TO THE REACTOR BUILDING ELEVATED VENT

Two contributions were considered as the source of the radioactivity to the reactor building elevated vent:

a. Leakage from the drywell to the reactor building and discharged via the SGTS to the reactor building elevated vent was assumed at a rate of

   0.5%/day = 2.1E-4/hr, and

b. Leakage from the assumed leaks on the main steam isolation valves (MSIVs) in the main steam tunnel was assumed at a rate of

   0.17%/day = 7.1E-5/hr (Reference J.7-56)

   Thus, the total leakage rate of activity from the primary system is assumed to be

   0.67%/day = 2.8E-4/hr.

J.H.1.1 Reactor Building Air Discharge Rate

All radioactivity considered outside the reactor building is assumed to discharge via the reactor building elevated vent.

The removal rate of the reactor building ventilation can be determined as follows:

$$\text{Removal rate} = \frac{\text{SGTS discharge rate}}{\text{Reactor building volume}}$$

SGTS discharge flow = 2430 ft^3/minute

Reactor building volume = 3.5E+6 ft^3

Thus, the removal rate is as follows representing one volume change per day:

$$\text{Removal rate} = \frac{(2430\,\text{ft}^3/\text{min})\,(60\,\text{min/hr})}{3.5\text{E}+6\,\text{ft}^3}$$

Removal rate = 4.2E-2/hr

This removal rate was used in the determination of radiation levels outside the reactor building.

J.H.2 POSTACCIDENT DESIGN DOSE (PADD)

A small computer program (PADD) was written to complete the calculations for the 18 nuclides over various time periods and sum the results. The equation used to determine the dose is as follows:

$$\text{Dose(rad)} = \text{DF(j)}\left(\frac{\chi}{Q_1} * \text{TF} * \frac{Q1_j + Q2_j}{3600}\right) \qquad \text{(J.H-1)}$$

where

$Dose_{ji}$ = Rads from jth nuclide for the ith time period.

DF_j = Gamma dose factors for semi-infinite cloud $\frac{Rad * m^3}{Ci * hr}$ for jth nuclide.

χ/Q_1 = sec/m^3 for gaseous releases from the reactor building vent to the atmosphere for the ith time period.

RF = Removal fraction of activity via the standby gas treatment.

TF = 0.01 for particulates and iodines (99% efficiency or RF).

TF = 1.0 for noble gases (WNP-2 FSAR Section 6.5).

$Q1_j$ = Integrated activity of jth nuclide over ith time period that was released via leaks in the MSIVs (curies/hour).

$Q2_j$ = Integrated activity of jth nuclide over the ith time period that was released via leakage from the primary to secondary containment (curies/hour).

3600 = Conversion from hours to seconds.

J.H.2.1 Assumptions Used in χ/Q Calculation Methodology

The following equation from "Meteorology and Atomic Energy" (Reference J.7-31) was used to determine the χ/Q values shown in Table J.H-1.

$$\text{Dilution} = 2.22(M)\left(3.16 + 0.1\frac{S}{(Aex)^{1/2}}\right)^2 \frac{V_{mean}}{V_{ex}} \qquad \text{(J.H-2)}$$

= F_B (building wake factor)

M = 1 if intake and exhaust same elevation

M = 2 if intake and exhaust separated by one floor

M = 4 if intake is in building wake cavity

S = shortest intake exhaust arc length

Aex = exhaust area

V_{mean} = mean approach flow

V_{ex} = mean exhaust flow

The intake was assumed to be for category F weather conditions with a V_{mean} = 1 meter/sec.

Then $\chi/Q = \dfrac{1}{F_B \;\; R_R}$

F_B = building wake factor

R_R = release rate from reactor building vent (m^3/sec)

Concentration in reactor vent

$C_V = Q/R_R$

where

Q = curies/sec released

Concentration at intake $C_I = C_V/F_B$

C_I also $= Q(\chi/Q)$

Therefore:

$$C_i = \frac{C_V}{F_B} = Q(\chi / Q) = (\frac{Q}{F_B \quad R_R})$$

$$(\chi / Q) = \frac{1}{(F_B)(R_R)} = \text{total dilution factor } (D_F).$$

An F class stability was assumed for atmosphere conditions and 5% meteorology was then applied for time periods from 0 to 180 days. The dilution factors decrease by the following ratios for the time periods indicated.

Time (hr)	0-2	2-8	8-24	24-96	96-4320
Ratio	1.0	0.35	0.04	0.02	0.01

The dilution factors were multiplied by the 5% meteorology ratios to determine the actual χ/Q values used in these computations as presented in Table J.H-1.

J.H.2.2 Integrated Activity Equations Used in this Analysis

The time dependent activity of each nuclide being released from the MSIV was analyzed as follows:

$$\frac{dA1}{dt} = PA_o e\,(-\lambda + \frac{0.0067}{24})\,t \qquad \text{(J.H-3)}$$

where

P = Fractional leak from MSIV per hour (7.1 E-5/hr)

A_o = Initial activity of jth nuclide in primary containment at t = 0 hr

Thus, the activity concentration over a time period of t_1 to t_2 is

$$Q_1 = \int_{t_1}^{t_2} PA_o\, e\left[-(\lambda + 2.8E-4)t\right]$$

or

$$Q_1 = \frac{PA_o}{(\lambda + 2.8E\text{-}4)} \left[e^{-(\lambda + 2.8E\text{-}4)\, t1} - e^{-(\lambda + 2.8E\text{-}4)\, t2} \right] \qquad \text{(J.H-4)}$$

The integrated activity concentration from the primary to secondary containment leakage, Q2, was calculated as follows:

$$\frac{dA_2}{dt} = KA_1 - L_2C_2 - \lambda A_2 \qquad \text{(J.H-5)}$$

where

K	=	Fractional leak rate from primary containment
	=	$\frac{0.005}{24hr} = 2.1E-4\ hr-1$
A_0	=	Activity in primary containment
	=	$A_o \exp\left[-(\lambda + \frac{0.0067}{24})t\right]$
A_1	=	Initial activity (Ci) at t = 0
$\frac{0.0067}{24}$	=	Leakage removal rate from primary containment per hour
	=	2.8E-4 hr^{-1}
L2	=	Discharge rate from reactor building vent via standby gas treatment
	=	2430 ft^3/min (60 min/hr)
	=	1.46E+5 ft^3/hr
C2	=	Activity concentration in secondary containment
A2	=	Curies in secondary containment
V2	=	Volume in secondary containment

Rearranging

$$\frac{dA2}{dt} = kA_o \exp\left[-(\lambda + 2.8E\text{-}4)t\right] - \frac{L2}{V2} A2 - \lambda A2$$

or (J.H-5A)

$$dA2 = kA_o e^{-F_1 t} - (\frac{L2}{V2} + \lambda) A2$$

$$dA2 = \left[kA_o e^{-F_1 t} - F_2 A2\right] dt$$

where

$$F_2 = \lambda + \frac{L2}{V2}$$

$$F_1 = (\lambda + 2.8E\text{-}4)$$

$$A2' = kA_1 - F_2 A2$$

$$A2' + F_2 A_2 = r(t)$$

$$r(t) = kA_o e^{-F_1 t} \qquad \text{(J.H-6)}$$

solving

$$A2 = e^{-F_2 t}\left[\left(\frac{kA_o}{F_2 - F_1}\right)\right] e^{(F_2 - F_1)t} + C$$

$$\text{at } t=o,\ A2 = o \qquad \text{(J.H-7)}$$

$$c = -0.005\, A_o$$

Thus,

$$A_2(t) = 0.005\, A_o e^{-\lambda t}\,(1 - e^{-(.0042)t})$$

$$Q2 = \frac{L2\, A_2(t)}{V2} \text{ or} \qquad \text{(J.H-8)}$$

$$Q2 = \frac{1.45\,E{+}5\,ft^3/hr}{3.5\,E{+}6\,ft^3}\left[0.005\, A_o e^{-\lambda j t}\,(1 - e^{-C2t})\right]$$

where C2 = 0.042 (J.H-9)

thus,

$$Q2 = 2.11E\text{-}4 \; A_o e^{-\lambda_j t} \; (1 - e^{-C2t})$$

To determine the integrated concentration:

$$Q2(t) = 2.1E\text{-}4 A_o \; {}_{t_1}\int^{t_2} [e^{-\lambda t} - e^{-(\lambda + C2)t}] \, dt$$

Solving,

$$Q2 = 2.1E\text{-}4 A_o \left[e^{-\lambda t_1} - e^{-\lambda t_2}\right] \frac{(e^{-C2t_1} - e^{-C_2 t_2})}{\lambda + C2} \qquad \text{(J.H-11)}$$

The values of Q1 and Q2 are substituted in for each nuclide and each time period. Then using equation (J.H-1), the dose commitment for each nuclide and each time period may be calculated. These results are presented in Section J.6.3.

TABLE J.H-1

POST-LOSS-OF-COOLANT ACCIDENT χ/Q VALUES[a] USED FOR CALCULATIONS OF INTEGRATED DOSES OUTSIDE THE REACTOR BUILDING

	Time (hr)				
Area	0-2	2-8	8-24	24-96	96-4320 (180 days)
Security center	2.1E-4[b]	7.35E-5	8.4E-6	4.2E-6	2.1E-6
Auxiliary security center	1.2E-4	4.2E-5	4.8E-6	2.4E-6	1.2E-6
Sample analysis area (end of cycle)	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Nitrogen supply to accumulators	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Standby service water pump valves	1.2E-4	4.2E-5	4.8E-6	2.4E-6	1.2E-6
Remote shutdown room	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Switchgear room 1	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Switchgear room 2	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Radwaste control room	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Battery racks Direct current battery charger Motor control center	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Three motor control centers/ Three switchgears Direct current battery charger and rack	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Diesel oil tanks	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Solid radwaste control panel	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Sample of elevated release duct	8.0E-4	2.8E-4	3.2E-5	1.6E-5	8.0E-6

The standby service water pump valves are approximately 700 ft from the release point. This distance is too great to calculate a dilution based solely on a building wake factor. However, the conservative assumption will be made that the dilution at the valves is the same as at the auxiliary guard house which is only 420 ft.

[a] These values are based on an MSIV leak rate of 0.22%/day not the 0.17%/day previously listed. The results are acceptable and conservative for a leak rate of 0.17%/day.

[b] Read as 2.1×10^{-4} etc.