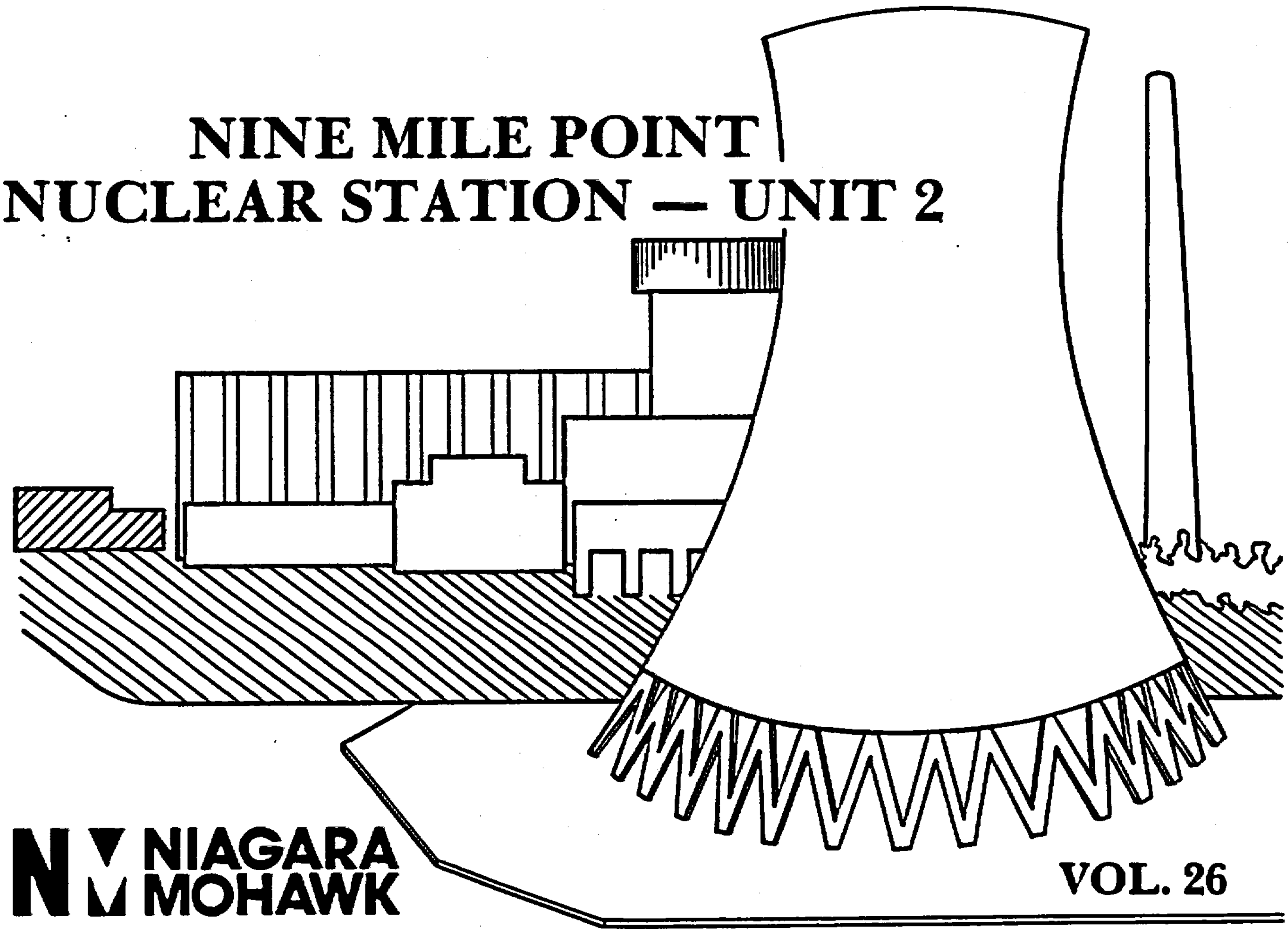
UPDATED SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2



NIAGARA MOHAWK

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12.4 DOSE ASSESSMENT

Radiation exposures in the plant are primarily from components and equipment containing radioactive fluids, and to a lesser extent from the presence of airborne radionuclides. In-plant radiation exposures during normal operation, refueling, and anticipated operational occurrences are discussed in Section 12.4.2. Radiation exposures at onsite locations outside the plant are discussed in Section 12.4.3.

12.4.1 Design Criteria

The criteria for doses to plant personnel during normal operation and anticipated operational occurrences, including refueling, are based on the requirements discussed in 10CFR20. Zone I plant areas during normal operation, refueling, and anticipated occupational occurrences are shown on Figures 12.3-34 through 12.3-66.

Radiation exposures to operating personnel are within 10CFR20 limits. Radiation protection design features (Section 12.3) and the radiation protection program (Section 12.5) assure that the occupational radiation exposures (ORE) to operating personnel during normal operation, refueling, and anticipated operational occurrences are ALARA.

12.4.2 Exposures Within the Plant

12.4.2.1 Man-Rem Evaluation

The occupational radiation dose assessment for Unit 2 was performed using the guidelines of RG 8.19[1]. The bases for the annual man-rem estimates are operating data from Unit 1, which are modified to account for differences and improvements in Unit 2. The projected radiation dose rates throughout the plant facilities are based on assumed radiation conditions after 5 yr of plant operation and expected radiation dose rates. Table 12.4-12 presents operational data from several BWRs[2] and shows the average annual man-rem per unit over several operating years to be 948 man-rem per year. These data indicate that, in recent years, OREs have been much larger than the radiation exposures reported for operating BWR plants in the mid-1970s. The primary reason for the increase in radiation exposure has been the increase in manpower necessary to support the expanding number of special maintenance activities.

Table 12.4-13 shows the distribution of annual OREs suggested in RG 8.19[1] work functions for all BWRs over several years. The average values indicate that operating BWR plants have approximately 76 percent annual occupational exposure attributed to routine (40 percent) and special (36 percent) maintenance. In recent years, plant modifications attributed to feedwater sparger repairs, inspection, repair and replacement of recirculation piping, Three Mile Island (TMI) lessons-learned modifications, and increased snubber and pipe hanger inspections have contributed to the growing amount of OREs associated with special maintenance work functions. Design features described in Sections 12.1 and 12.3 for the Unit 2 BWR 5 plant should minimize the special maintenance work experienced at earlier-designed operating BWR plants.

Design improvements for Unit 2 that are expected to reduce the OREs include the following:

a. Incorporation of flush connections on the control rod drive (CRD) scram discharge volume (SDV) header permits condensate flushing of piping to minimize corrosion product holdup in a high personnel access area.

b. Use of filtered condensate water for CRD hydraulic fluid and the reactor recirculation pump seal purge provides a clean water source that should extend pump seal life.

c. Installation of permanent hoisting systems and access platforms for the recirculation pumps, main steam isolation valves (MSIVs), and safety relief valves (SRVs) minimizes maintenance time in the drywell.

d. Improved refueling platform makes fuel handling activities more efficient and reduces time spent on the platform.

e. A multistud tensioner reduces the amount of man-hours necessary to handle the reactor vessel head studs.

f. A new handling tool and platform for the removal of CRDs from beneath the reactor vessel reduces crew size and time spent in the high radiation area.

g. Improved fuel design minimizes the buildup of radiation levels near reactor coolant systems and reduces the amount of fuel assembly sipping activities.

h. Improved piping material for the recirculation system eliminates the special maintenance which was required on older BWR recirculation piping due to stress corrosion cracking.

i. ISI access is improved by remote equipment development and access doors for reactor vessel and nozzle weld inspection.

j. Decontamination methods are provided to decontaminate the walls of the reactor cavity pit and internals pool to minimize contribution from this source.

k. Use of separate shielded cubicles for locating redundant and highly-radioactive components minimizes radiation exposures during maintenance activities.

l. Compared to hydraulic-operated snubbers available during the original design of the plant, use of mechanical snubbers should reduce the frequency of necessary inspection.

m. Installation of a CRD flush tank removes highly-radioactive corrosion and fission products from the CRD internals prior to rebuilding.

n. Use of sealed hydraulic snubbers (improved design) that are less susceptible to failure than mechanical snubbers.

The ORE for Unit 2 is determined for each of the RG 8.19[1] work function categories by identifying specific tasks within each of the seven work function categories and determining the time and manpower requirements for those tasks. This information is used with the expected dose rates in the areas where work is performed to determine radiation exposure from each activity. Tables 12.4-5 through 12.4-11 provide the estimates of occupational exposures based on the identification of specific tasks within each of the seven work function categories: routine operations and surveillance, nonroutine operation and surveillance, routine maintenance, radwaste processing, refueling, ISI, and special maintenance. Table 12.4-4 summarizes the occupational dose estimates for the seven work functions. A comparison between Tables 12.4-4 and 12.4-12 shows that Unit 2 occupational exposure is consistent with the data for operating plants for the period 1974-1979 (before the TMI accident). The higher occupational exposures for the period 1980-1982 are not expected at Unit 2 because the plant modifications that caused the increases have been incorporated into the original design of Unit 2.

12.4.2.2 Estimates of Inhalation Thyroid Doses

Inhalation doses during full-power operations will be negligible in every area except the reactor, turbine, and radwaste building areas. Potential airborne activities for these areas are given in Section 12.2.2. These concentrations are based upon data given in NUREG-0016 and EPRI-495. The inhalation thyroid doses that result are given in Table 12.4-2.

Thyroid dose rates in Table 12.4-2 are calculated according to:

$$D_t = \Sigma_i \text{ (B.R.) } (A_i) \text{ (C) } (K_i)$$

Where:

D_t = thyroid dose rate (mRem/hr)

K_i = thyroid dose conversion factor (from TID 14844, March 1962) (Rem/Ci)

B.R. = breathing rate, m^3/sec

A_i = building airborne concentration, Table 12.2-15 of the ith isotope (uCi/cm^3)

C = conversion factor = (10^3 mRem/Rem) (3.6 x 10^3 sec/hr) (10^6 cm^3/m^3) (1 Ci/10^6 uCi)

12.4.3 Exposures at Locations Outside the Plant Structures

Radiation exposures at locations outside the plant arise from:

1. Direct and air-scatter (skyshine) contributions due to the presence of N-16 in the plant buildings.
2. Release of gaseous effluents from the plant.
3. Contributions due to the operation of Unit 1 and the James A. FitzPatrick plant.

Estimated doses at the restricted area boundary (RAB) directly north of Unit 2 are summarized in Table 12.4-1 and are based on 300 hr/yr expected occupancy. These estimates meet the dose guidelines of 10CFR20 and 40CFR190.

12.4.3.1 N-16 Dose Contributions

Dose contributions due to N-16 are evaluated for both direct and skyshine components. Skyshine doses are due to air scattering of the high-energy gammas emitted by decaying N-16 present in reactor steam in the steam lines, turbines, and moisture separators. The layout of the turbine building walls and floors used in the dose evaluation is given on Figures 12.3-13 through 12.3-18. Data regarding the source term and the major shields providing skyshine shielding are as follows.

<u>Source Term</u>

The N-16 activity at the RPV nozzle is 50 uCi/gm. The N-16 activity in the turbine building equipment is 50 uCi/gm decayed for the transit time from the RPV to the entrance of each specific component.

<u>Major Shielding</u>

The shield walls surrounding the turbine operating floor are sufficiently thick to reduce direct radiation levels. Air-scattered radiation is reduced by enclosure of the most intense sources (i.e., the moisture separator reheaters and

12.5 RADIATION PROTECTION PROGRAM

12.5.1 Organization

12.5.1.1 Program Objectives

The Radiation Protection Program is designed to provide for the protection of all permanent and temporary personnel and all visitors from radiation and radioactive materials in a manner consistent with federal and state regulations during all phases of plant operation.

12.5.1.2 Personnel Experience and Qualifications

The Radiation Protection Program is developed and administered by the Manager Radiation Protection. The Manager Radiation Protection is responsible for the handling and monitoring of radioactive materials including source and by-product material. New fuel receipt, inspection, and initial storage into the fuel vault will be performed by maintenance and radiation protection personnel under the direction of the Manager Maintenance and the Manager Radiation Protection. The responsibility for directing fuel movement will rest with reactor engineering personnel and radiologic monitoring with radiation protection personnel. The physical movement of fuel within the reactor and spent fuel pool will be performed by qualified personnel under the supervision of a licensed Senior Reactor Operator (SRO) or SRO limited to fuel handling. The Station Shift Supervisor is responsible for all fuel movements within the Station. The experience and qualifications of all the above responsible individuals are given in Sections 13.1.2 and 13.1.3.

12.5.2 Equipment, Instrumentation, and Facilities

This section describes the radiation protection facilities provided at Unit 2 for measuring and maintaining personnel radiation exposure ALARA.

12.5.2.1 Location of Equipment, Instrumentation, and Facilities

12.5.2.1.1 Radiation Protection Office

The Radiation Protection Office, which is the center for directing the radiation protection technical staff and RWP coordination, is located in the access control building at el 261 ft. The office is equipped with desks and tables for work space and file cabinets and bookshelves for current survey data and reference material.

12.5.2.1.2 Counting Room

The counting room where radioactive samples are analyzed for radioisotopic content and activity level is located in the access control building linkway at el 261 ft. Counting room equipment is discussed in Section 12.5.2.2.1.

12.5.2.1.3 Chemistry and Radiochemistry Laboratory

The chemistry and radiochemistry laboratories where radioactive samples are chemically analyzed and/or prepared for radiochemical analysis are located in the Unit 1 turbine building at el 261 ft, and in the Unit 2 decontamination area. The laboratories are equipped with fume hoods with filters, an emergency shower, an eyewash, and miscellaneous chemistry laboratory equipment for chemical analysis. The laboratories support routine chemistry and radiochemistry analysis.

12.5.2.1.4 Personnel Decontamination Facility

A personnel decontamination facility is located in the turbine building at el 306 ft, and two additional facilities, one for women and one for men, are located in the auxiliary service building south at el 261 ft. These facilities are equipped with dressing areas, sinks, and showers.

12.5.2.1.5 Locker Rooms and Toilet Facilities

Locker rooms and toilet facilities for men and women are located in the maintenance building.

12.5.2.1.6 This section deleted.

12.5.2.1.7 Instrument Storage

The instrument storage room used for storage of portable survey instrumentation, respiratory equipment, and radiation protection supplies is located in the access control building linkway at el 261 ft.

12.5.2.1.8 Instrument Calibration and Repair Facility

Radiation-measuring instrumentation is normally calibrated and repaired at the instrument calibration facility located in the auxiliary service building south at el 261 ft.

12.5.2.1.9 Respiratory Equipment Repair, Assembly, and Testing

Respiratory equipment repair, assembly, and testing facilities are located at Unit 1. Respiratory equipment storage is discussed in Section 12.5.2.1.7.

12.5.2.1.10 Personnel Monitoring Stations

All personnel exiting the radiologically-controlled area are required to monitor/frisk themselves for contamination as directed by Station procedures. Monitor/frisk stations are provided as necessary.

In addition to local monitoring, a portal monitor is installed at the exit from the protected/restricted area to alarm in the case of contamination on person or clothing.

12.5.2.2 Radiation Protection Instrumentation

Although the following instrumentation is intended to be purchased and is fully acceptable, should new instrumentation become available or regulatory measuring and reporting requirements change, the new instrumentation may be purchased in lieu of that listed.

12.5.2.2.1 Counting Room Instrumentation

Radiation-measuring instrumentation located in the counting room is used by radiation protection personnel to analyze samples for radioactivity and/or radioisotopic content. Typical samples include contamination survey media, airborne survey media, and process samples.

Counting room instrumentation is listed in Table 12.5-1. The criteria for selection of these instruments are reliability, efficiency, and sensitivity to count and/or analyze sample media. Each instrument is checked and calibrated at routine intervals with standard radioactive sources traceable to a NIST source. Calibration of an instrument is also performed after repair and prior to use if the period since the last calibration is greater than the regular interval. Radiation protection personnel perform instrument calibrations and check counting efficiency, background count rates, and high voltage settings according to Station procedures.

12.5.2.2.2 Portable Survey Instrumentation

Portable survey equipment allows Station personnel to perform surveys for direct radiation, airborne radioactivity, and surface contamination. Portable survey instrumentation is listed in Table 12.5-2.

The criteria for selection of portable survey equipment are based on accuracy, dependability, and simplicity of operation, calibration, and maintenance. The instrument can be easily serviced and can cover the entire spectrum of radiation measurements expected during normal or accident conditions.

Portable survey instruments used for establishing beta and gamma dose rates are calibrated semiannually, with deviations not exceeding annually allowed based on documented instrument reliability. Instruments are also calibrated by radiation protection personnel after repair and before use when the period since the last calibration is greater than the regular interval. All portable survey instruments are source checked prior to use to verify proper operation according to Station procedures.

12.5.2.2.3 Personnel Monitoring Instrumentation

Monitoring of personnel is accomplished by the use of TLDs, direct-reading pocket dosimeters, and neutron TLD badges. Personnel entering the radiologically-controlled area (RCA) are issued TLDs and pocket dosimeters in accordance with 10CFR20 and Station procedures.

The TLD readings are normally used as the official record. The TLD has four thermoluminescent chips and suitable filters to differentiate between penetrating and nonpenetrating radiations.

TLDs are normally processed quarterly or more frequently if warranted. If a TLD should be lost or damaged, an individual's exposure is estimated using appropriate methods and documented.

Direct-reading pocket dosimeters are worn by plant personnel for a day-to-day or job-to-job estimate of personnel exposure. Direct-reading pocket dosimeters are provided in various ranges and are calibrated semiannually or when damage is suspected.

Table 12.5-3 lists personnel monitoring instrumentation with various ranges and sensitivities.

12.5.2.2.4 Radiation Protection Equipment

Portable air samplers are used to collect samples for determination of airborne radioactive material concentrations. Samples may be analyzed for radioactive particulate, radioiodine, and airborne gaseous activities. Portable air samplers are calibrated semiannually.

To monitor a specific work area or field location, portable air samplers are used. Continuous air monitors with visual and audible alarms may also be used.

The ARMS is installed in areas where it is desirable to have continuous radiation level information. These monitors provide radiation level indication locally and in the control room. If radiation levels reach a preset level, an audible and visual alarm is provided locally and in the control room.

In areas where it is desirable to monitor dose rates and there is no area monitor in close proximity, a portable alarming dose rate instrument is used. If the radiation dose rate is high, the instrument provides a local audible and visual alarm. Table 12.5-4 lists other radiation protection instrumentation.

5. Special access control procedures are used for entry to areas where significant exposure might be received.

6. Protective clothing and equipment are provided.

7. An ARMS is installed and provides indication of radiation levels with local alarms, where appropriate.

8. The ventilation system is designed to minimize the spread of airborne contamination.

9. Shielding effectiveness is verified by an initial startup survey for gamma and neutron radiation.

12.5.3.2.6 Routine and Nonroutine Maintenance (Repair)

Examples of procedures and methods used during routine maintenance to maintain personnel radiation exposure ALARA are as follows:

1. Maintenance work involving systems that collect, store, contain, or transport radioactive materials must be covered by an approved RWP.

2. Training is provided, as required, to accomplish assigned tasks in controlled areas.

3. Maintenance procedures incorporate appropriate precautions and radiological considerations.

4. Equipment is moved to areas with lower radiation and contamination levels for maintenance when practical.

5. Special tools are used when practical.

6. Portable shielding is used when practical.

7. Periodic monitoring by radiation protection technicians, as radiological conditions warrant, is provided.

8. Post-job debriefings are utilized for high-exposure jobs to obtain input from personnel actually performing the work. This is utilized in revising procedures and instructions as appropriate for ALARA considerations.

12.5.3.2.7 Sampling

Procedures and methods of maintaining personnel radiation exposure ALARA during sampling include the following:

1. Sampling of radioactive systems may be performed from inside sample hoods or locally.

2. Procedures specify the protective clothing and sampling techniques to be used.

3. Radiation levels of the sample container and of the work area during sampling are monitored.

4. Personnel are trained in the proper handling of sample containers after samples are collected.

5. Personnel are trained in the proper storage and disposal of radioactive samples.

12.5.3.2.8 Calibration

Procedures and methods of maintaining radiation exposure of personnel ALARA during calibration include the following:

1. Detailed procedures are followed for each calibrator use.

2. The instrument calibrator is properly shielded.

3. An interlock is provided to prevent opening the calibrator door while the source is exposed.

4. Portable sources used to calibrate fixed instruments are transported and maintained in shielded containers.

5. The RWP system is used to provide positive radiological controls over calibration.

6. Where possible fixed instruments are situated in low radiation areas so that necessary test signals can be inserted with the instrument in place.

12.5.3.3 Control of Personnel Radiation Exposure

Occupational radiation exposures are kept ALARA by a combination of shielding, access control, contamination control, radiation protective equipment, and radiation protection policies. As plant operation progresses, if it is found that shielding in given locations is insufficient or that the level of contamination is unacceptable, measures will be taken to reduce radiation levels by providing additional shielding, decreasing the amount of contamination, or limiting personnel access.

12.5.3.3.1 Access Control

Access control can be accomplished by a locked barrier such as a door or gate or a posted guard. Access control within the fenced area of the site for radiological purposes is determined by the radiation level, contamination level, or the presence of radioactive materials. Areas are posted as required by 10CFR20. Posted areas include the following:

TABLE 12.5-3

PERSONNEL MONITORING INSTRUMENTATION

Quantity*	Instrument	Range	Sensitivity	Remarks
As required	Film dosimetry badge	20-100,000 mR	10 mR	If Used
As required	TLD	10-200,000 mR	10 mR	
As required	Direct-reading dosimeter	0-500 mR	10 mR	Direct-reading ion chamber
25	Direct-reading dosimeter	0-1 R	50 mR	Direct-reading ion chamber
25	Direct-reading dosimeter	0-5 R	200 mR	Direct-reading ion chamber
10	Direct-reading dosimeter	0-50 R	2 R	Direct-reading ion chamber
1	Whole-body counter	0-several body burdens	1% of most nuclide body burdens	To determine internal exposure
10	Dosimeter chargers			
As required	Electronic dosimeter	0-999 R	10%	Solid state or GM dosimeter
As required	Electronic dosimeter reader	NA	NA	

* Quantity is minimum required.

CHAPTER 13

CONDUCT OF OPERATIONS

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CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE OF APPLICANT

The following sections describe the organizational structure of Niagara Mohawk Power Corporation (NMPC) and delineate the line of responsibility for the operation of Nine Mile Point Nuclear Station - Unit 2 (Unit 2) in accordance with established administrative and quality standards. The organizational structure associated with the quality assurance (QA) program for plant operation is described in Appendix B.

The use of generic position descriptions permits the efficient implementation of administrative changes in organizational structure or nomenclature without the use of extensive resources or activities which do not directly support safe operation. For example, the function of the generic position description of manager quality assurance can be filled by an individual having a specific title such as Manager, Vice President, or Director. These specific titles are indicated by use of capitalization in the USAR.

13.1.1 Management and Technical Support Organization

13.1.1.1 Design and Operating Responsibilities

13.1.1.1.1 Design and Construction Activities

1. Principal site-related work, such as meteorology, seismology, hydrology, demography, and environmental effects, has been completed and is described in Chapter 2. Post-operational environmental evaluations are described in the Environmental Report-Operating License Stage (ER-OLS).

2. The design of the Unit 2 plant and auxiliary systems is described in Chapters 3 and 9.

3. The review and approval of plant design features were completed as an integral part of the design review process.

4. Site layout with respect to environmental effects is described in Chapter 2. Section 13.6 discusses the security plan with respect to site layout.

5. Most of the Final Safety Analysis Report (FSAR) was prepared through the combined efforts of NMPC, General Electric Company (GE), and Stone & Webster Engineering Corporation (SWEC). Some portions were prepared by

Dames and Moore; Lawler, Matusky, and Skelly; and Meteorological Evaluation Services.

6. Management control and review of construction activities are currently and have been exercised routinely during construction of the plant.

13.1.1.1.2 Nuclear Engineering

A number of Engineers from this organization have actively engaged in technical aspects of the Unit 2 design. This organization presently consists of Engineers and technical personnel with a variety of disciplines and backgrounds in power plant technology. Support in Plant Chemistry, Health Physics, Fueling and Refueling Operations, and Maintenance Support as required in nuclear, mechanical, structural, electrical, thermal-hydraulic, and instrument and control engineering, is provided. (Specific headquarters support group descriptions are provided in Section 13.1.1.2). Qualifications of engineering support personnel are described in job descriptions.

Most design-related requests are relayed from the Plant Manager through the Manager Engineering, who assigns appropriate engineering support groups the design responsibility and/or hires a vendor or contractor to perform the work. Conceptual designs are formulated and sent to the site for approval after engineering approval. Conceptual site approval is made by the Plant Manager after review by the appropriate site discipline. Final design is provided by engineering for review and approval by the appropriate site disciplines, the Plant Manager, and Station Operations Review Committee (SORC). Written safety evaluations are prepared in accordance with 10CFR50.59, reviewed by the SORC, approved by the Plant Manager, and reviewed by the Safety Review and Audit Board (SRAB) as described in Section 13.4.

13.1.1.1.3 Nuclear Construction

The Senior Vice President had the overall responsibility for project management of Unit 2. The project management efforts included management of construction, design, support for preoperational and startup testing, and turnover of plant equipment and systems to Nuclear Generation for operation. These activities were governed by the Project Manual and procedures for Unit 2.

The technical staff were used in the initial test program to the extent practical. Participants in the test program (i.e., Test Engineers) received training in plant specifics, systems, and indoctrination in administrative controls of the test program.

The Test Engineers participated in preliminary and preoperational test phases. In the preliminary test phase, they wrote the preliminary test and helped to direct the testing. In the preoperational test phase, they helped to write the preoperational test and participated in the actual testing.

After commercial operation, the construction organization was assimilated into other areas of the corporation, such as Quality Assurance, Nuclear and Nonnuclear Engineering, and Operations. The Construction Engineers provide coordination support for contractors engaged in the installation and checkout of plant modifications. Support to contractors will include the provision of equipment, such as welding machines, trailers, and special tools that may be required by the contractor personnel during the performance of the contracted services.

13.1.1.1.4 Technical Support for Operations - Testing Calibration and Inservice Inspection Support, and Laboratory Services

Technical support for operations (after commercial operation), including testing, calibration, and inservice inspection (ISI) support, laboratory services, and fire protection, are coordinated onsite. The personnel assigned responsibility and authority to perform these functions are described in Section 13.1.2.

This support consists of:

1. Electrical and mechanical testing of the unit.

2. Certification of test and maintenance equipment, calibration of equipment, meters, etc.

3. Expertise and service for nondestructive testing including radiography, ultrasonic, magnetic particle, penetrant examinations, etc. Baseline inspection and ISI overseeing and support.

4. Laboratory services for water chemistry, radiology, metallurgy, etc., and troubleshooting support as requested by the Plant Manager.

13.1.1.2 Organizational Arrangement

13.1.1.2.1 Nuclear Division

The upper level Nuclear Organization Management is depicted on Figure 13.1-1. The Chief Nuclear Officer reports to the NMPC Chief Executive Officer and has overall responsibility for the administration and operation of the Nuclear Division, including: the plant Generation, Engineering, and Quality Assurance functions; Business Management; Human Resource Development; and Nuclear Communications and Public Affairs.

Vice President Nuclear Generation

The Vice President Nuclear Generation reports to the Chief Nuclear Officer and has oversight responsibility to assure safe, orderly, and efficient plant operation is achieved. The Vice President Nuclear Generation is responsible for Operations, Radiation Protection, Maintenance, Chemistry, Technical Support, Outage Management for both units, and Training. Additionally, the Vice President Nuclear Generation has oversight responsibility for the Assessment and Corrective Action Group. The Plant Managers, the Manager Training, and the Director Assessment and Corrective Action report directly to the Vice President Nuclear Generation.

The Nuclear Generation Organization is described in Section 13.1.2 and is depicted on Figure 13.1-2. This figure shows the relationship between the Vice President Nuclear Generation, his staff, and the staff of Unit 2.

Staffing levels of site personnel for Nine Mile Point Nuclear Station - Unit 1 (Unit 1) and Unit 2 are provided on Figure 13.1-4.

Vice President Nuclear Engineering

The Vice President Nuclear Engineering is responsible for the administration of Engineering, Engineering Services, and Procurement functions. He has single-point accountability for design basis concerns and responses. The Engineering organization chart is provided on Figure 13.1-3.

1. The Manager Unit 2 Engineering is responsible for providing engineering services for the safe, reliable and economic operation of Unit 2, including adherence to applicable regulatory requirements. Responsibilities include:

    a. Design

    b. Plant Support

    c. Maintenance and System Engineering Support for Unit 1 and Unit 2 Plant Process Computers

2. The Manager Engineering Services is responsible for:

    a. Nuclear Fuel

    b. Engineering Programs

    c. Engineering Assurance

    d. Analysis Services

e. ASME Section XI Programs

3. The Manager Procurement is responsible for ensuring that procurement and warehouse activities are properly performed in accordance with applicable rules, regulations, approved procedures, codes and standards. This manager maintains a branch that provides the following functions:

   a. Procurement

   b. Inventory Management

   c. Material Receipt, Test and Inspection

   d. Warehouse and Storeroom Operations

   e. Purchasing

4. The Manager Project Management manages large, complex, or costly projects for Unit 1 and Unit 2 as assigned by the Vice President Engineering.

5. The Manager Nuclear Security has overall responsibility for ensuring effective implementation of security plan requirements. The Nuclear Security organization and responsibilities of supervisory personnel under direction of the Manager Nuclear Security are described in the security plans.

6. The Manager Licensing is responsible for Site Licensing, Licensing Support, interfacing and communicating with the NRC and outside agencies, UFSAR updates, Nuclear Commitment Tracking; and implementation of the Environmental Monitoring Program, including control of hazardous and industrial wastes, and assessing effects of radioactive effluent.

<u>Vice President Nuclear Safety Assessment and Support</u>

The Vice President Nuclear Safety Assessment and Support is responsible for the Independent Safety Engineering Group (Unit 2 only). The Director Independent Safety Engineering Group reports directly to the Vice President Nuclear Safety Assessment and Support.

The Director Independent Safety Engineering Group (ISEG) is responsible for providing independent review of Unit 2 activities, including maintenance, modifications, and operational concerns, performing analysis, and providing recommendations of the activities reviewed.

Vice President Quality Assurance - Nuclear

The Vice President Quality Assurance - Nuclear reports directly to the Chief Nuclear Officer and is responsible for the Quality Assurance program. The Supervisor Quality Assessment, Supervisor Procurement Quality Assurance, Supervisor Inspection, and Supervisors Quality Services report directly to this Vice President.

Director Nuclear Communications and Public Affairs

The Director Nuclear Communications and Public Affairs is responsible for all internal/external nuclear communications programs in support of the corporation and the Nuclear Division; principle nuclear communications liaison with media, public customers, corporation, industry groups, government organizations and other utilities; and all activities associated with the programs, staffing, maintenance and operation of the Energy Center.

Director Human Resource Development

The Director Human Resource Development is responsible for Employee/Labor Relations, Leadership/Career Development, Occupational Safety and Health, Quality First Program (Q1P) administrative issues, and the Fitness-for-Duty Program.

General Manager Business Management

The General Manager Business Management reports directly to the Chief Nuclear Officer and has overall responsibility for finance and accounting, business computers, office administration, and integrated planning.

13.1.1.2.2 Corporate Support Departments

1. The Executive Director System Electric Operations reports to the Executive Vice President Energy Delivery, and is responsible for formulating, establishing and directing offsite Meter and Laboratory Facilities department activities.

    a. The Director System Meter and Laboratory Facilities reports to the Executive Director System Electric Operations. The staff includes the Supervisor Standards Laboratory, who is responsible for maintaining a facility for calibrating reference standards and for calibration and maintenance of portable measuring and testing equipment (M&TE).

2. The Director Risk Management reports to the Vice President - Treasurer, who in turn reports to the Senior Vice President Finance and Chief Financial

Officer. He has responsibility for assuring adequate fire protection for company facilities and fire personnel training; to verify appropriate measures are taken to prevent or limit losses from any perils resulting from Nuclear Operations; and for all matters relating to insurance of NMPC facilities.

13.1.1.3 Qualifications of Support Personnel

General responsibilities and activities of management and technical support personnel are described in appropriate documents including administrative procedures and engineering procedures. Contract support for Unit 2 is utilized in the same general manner as contract support at Unit 1.

The Nuclear Division support organization department heads are generally employees with 8 to 25 yr experience who have operations-related experience from the more than 20 yr of NMPC's nuclear power generation, construction, and design.

13.1.2 Operating Organization

This section describes the structure, function, and responsibilities of the onsite organizations established to operate and maintain the plant. The onsite and offsite independent review committees are described in Section 13.4. Unit 1 and Unit 2 operations are independent of each other, including backshift operation.

13.1.2.1 Site Organization

An organization chart showing the title of each position is shown on Figure 13.1-2. The description of these positions is provided in the administrative procedures and Section 13.1.2.2 below. The interface between site and offsite personnel is from the Plant Manager to the Vice President Nuclear Engineering or any other technical support function. The lines of authority are described in administrative procedures.

13.1.2.2 Plant Personnel Responsibilities and Authorities

13.1.2.2.1 Plant Manager

The Plant Manager reports directly to the Vice President Nuclear Generation and is responsible for the safe, orderly and efficient functional operation of his Station. He is the Chairman of the SORC. The Plant Manager has under his direction the Managers of Operations, Maintenance, Technical Support, Chemistry, Radiation Protection, and Work Control/Outage. The Unit 2 Manager Engineering reports functionally to the Plant Manager for the purpose of providing maintenance and system engineering functions for plant process computers.

The authority for writing and issuing special orders or standing orders rests with the Plant Manager.

13.1.2.2.1.1 Manager Operations

The Manager Operations is responsible for safe operation of the Station in accordance with approved procedures and regulatory requirements. He maintains a branch comprised of the following functional sections:

1. Station Operations

2. Reactor Engineering

3. Operations Support

<u>General Supervisor Operations</u>

The General Supervisor Operations is responsible for daily operation of the unit including direct supervision of Station Shift Supervisors (SSS) and Supervisors Operations. He maintains a current Senior Reactor Operator (SRO) License.

1. The SSS is in charge of all operations on his assigned shift. Under the general direction of the General Supervisor Operations, his functions include direction of shift activities, authorization of equipment releases for maintenance, ensuring that the plant is operated safely and within the license and Technical Specifications, and ensuring that plant operations are conducted in accordance with approved procedures. As overall supervisor of operations for his shift, the SSS should avoid becoming personally involved in the manipulative tasks or details of operation of any one portion of the plant so that he may retain a comprehensive perspective of general Station conditions at all times. In an emergency situation, however, should the Shift Supervisor choose to perform manipulative functions to ensure that the plant is in a safe condition, he shall coordinate his actions with the Chief Shift Operator (CSO). Whenever he determines that the safety of the reactor is in immediate jeopardy, or when operating parameters exceed any of the reactor protection circuit setpoints and automatic shutdown should but does not occur, he has the responsibility and the authority to order shutdown of the reactor, or to personally effect the shutdown.

   The Shift Supervisor shall hold a NRC SRO License. He shall be continuously present at the plant for the duration of his assigned shift until properly relieved by the oncoming Shift Supervisor. It is his responsibility to provide direction for returning the reactor to power following a trip or an unscheduled power reduction.

During (normal operations) periods when the SSS is out of the control room, he will designate to another SRO the control room command function, as specified by administrative procedures. The SSS or designated replacement shall remain in the control room to ensure the maintenance of visual and aural contact with all control room boards.

During emergencies, accidents or incidents requiring special procedures, the Shift Supervisor shall remain continuously in the control room until relieved by the oncoming Shift Supervisor, or a Senior Licensed Operator designated by the General Supervisor Operations or higher authority. From the control room he shall continuously assess the condition of the Station and provide general direction for all operating actions.

The duties, responsibilities, and authority of the SSS meet the requirements of Three Mile Island (TMI) Item I.A.1.2, as described in Section 1.10.

2. The Assistant Station Shift Supervisor (ASSS) may be assigned to either of two duties at the direction of the General Supervisor Operations and depending upon his qualifications: 1) Shift Technical Advisor (STA) or 2) Control Room Supervisor.

The ASSS, if qualified, may perform the STA function if a dedicated STA is not available, subject to the conditions outlined in the Technical Specifications (see also Section 1.10, TMI Item I.A.1.1). When acting in the STA role when the Emergency Plan is activated, he shall perform no duties unrelated to assessment or diagnosis.

When assigned as Control Room Supervisor, the ASSS shall hold a SRO License and may have charge of Station operations subject to the general supervision of the SSS, provided the ASSS is not in the STA function.

As Control Room Supervisor, the ASSS has the duty and responsibility to ensure that operations are conducted in accordance with approved procedures, that whenever the safety of the reactor is in immediate jeopardy, or when operating parameters exceed any of the reactor protection setpoints and automatic shutdown should but does not occur, he has the responsibility and authority to order shutdown of the reactor, or to personally effect the shutdown. Normally he should not personally perform manipulative tasks or become involved in details of operation of one portion of the plant to the exclusion of others.

3. The CSO is in charge of the operation of the control room subject to the general supervision of the Control Room Supervisor or SSS. He exercises direct supervision over the assigned Operators on shift. From his position, he is able to control the starting and stopping of all major pieces of equipment and the control of the reactor and turbine. He also has the ability to open and close the major powerboard breakers in the plant, as well as the line breakers in the switchyard. He is the key man in determining that engineered safeguards perform as required in the event of a loss-of-coolant accident (LOCA) or other abnormal incidents.

   As principal Reactor Operator, the CSO has the responsibility and the authority to shut down the reactor whenever he determines that the safety of the reactor is in immediate jeopardy, or when operating parameters exceed any of the reactor protection circuit setpoints and automatic shutdown should but does not occur. In this connection, he has the responsibility to believe and respond conservatively to instrument indications unless they may be otherwise proven to be incorrect. He shall at all times operate in accordance with approved procedures unless immediate and unforeseen action is required to ensure the safety of the reactor, the plant, plant personnel and the general public. The CSO shall hold a NRC Reactor Operator (RO) License.

4. The Nuclear Auxiliary Operator E on shift provides operational attendance to the plant equipment. He shall perform all evolutions with the concurrence of or at the direction of the CSO. In addition, as required, he is responsible for the operation of the main turbine generator unit and related equipment from the control room, and performs switching in the switchyard. He shall hold a NRC RO License. When acting for the CSO as principal RO, he shall assume the shutdown and safe operation authority and responsibilities outlined for the CSO. He shall at all times perform his duties in accordance with approved procedures unless immediate and unforeseen action is required to ensure the safety of the reactor, the Station personnel and the general public.

<u>Supervisor Reactor Engineering</u>

The Supervisor Reactor Engineering is responsible to provide core management and reactor engineering support, to provide accountability for special nuclear material, and to supervise STAs who perform routine reactor engineering functions on shift.

1. The STA will normally be a dedicated position. If, however, a dedicated STA cannot be provided on a shift, then the ASSS will function in a dual role (SRO/STA) and assume the duties of the STA when the Emergency Plan is activated during normal operation, startup, and hot shutdown conditions (see also Section 1.10, TMI Item I.A.1.1). The STA provides advisory technical support to the SSS in the areas of thermal-hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. He reviews and evaluates operating experience reports, including engineering aspects of ensuring safe operations. During off-normal events, he provides the SSS with an assessment of Station conditions and advises action to terminate or mitigate the consequences of off-normal conditions. During this time he shall perform no duties unrelated to assessment or diagnosis.

   The STA also performs routine reactor engineering functions on shift.

General Supervisor Operations Support

The General Supervisor Operations Support is responsible for ensuring that routine administrative functions of the Operations Branch are performed accurately and in a timely manner, and that appropriate levels of technical and engineering support are provided to the Operations Branch.

13.1.2.2.1.2 Manager Maintenance

The Manager Maintenance is responsible for ensuring that modifications, housekeeping, decontamination, surveillance, maintenance, preventative maintenance, site relay and control testing, and M&TE calibrations are properly performed in accordance with applicable rules, regulations, approved procedures, codes and standards. He maintains a branch comprised of functional sections. The number and description of the functional sections may vary. It is typically comprised of functional sections such as:

1. Instrument and Control Maintenance

2. Mechanical Maintenance

3. Electrical Maintenance

4. Fix It Now

5. Valves

6. Outage

7. Maintenance Support

13.1.2.2.1.3 Manager Technical Support

The Manager Technical Support is responsible for ensuring that system engineering, performance monitoring, plant modifications, and in-service testing are properly performed in accordance with applicable rules, regulations, approved procedures, codes and standards. He maintains a branch comprised of the following functional sections:

1. System Engineering (with the exception of Plant Process Computers)

2. Plant Performance

3. Administrative Support (SORC, Technical Review, and Modification Coordination)

4. Other direct reports responsible for tasks and assigned programs (e.g., Maintenance Rule, EPIX)

13.1.2.2.1.4 Manager Radiation Protection

The Manager Radiation Protection develops, implements, and administers the radiation protection and as low as reasonably achievable (ALARA) programs. The Manager Radiation Protection is responsible for the technical quality and implementation of the ALARA and radiation protection programs. He acts as Manager Radiation Protection as specified in Technical Specification 6.3. The Manager Radiation Protection has authority to require plant shutdown if unsafe radiological conditions exist, and has direct access to appropriate levels of corporate management to resolve radiation protection concerns. He maintains a branch comprised of the following functional sections:

1. ALARA/Radiological Engineering

2. Radiological Instrument Calibration

3. Radiation Protection Operations

4. Radwaste Operations

The Radiation Protection organization and responsibilities are further described in Section 12.1.1.

13.1.2.2.1.5 Manager Chemistry

The Manager Chemistry is responsible for managing chemistry and radiochemistry monitoring and control programs, including personnel, procedures and qualifications, to ensure compliance with federal and Technical Specification requirements related to primary and secondary system chemistry and radiochemistry, radioactive effluent, chemistry control, post-accident assessment and solid radioactive waste measurements. He maintains a branch comprised of the following functional sections:

1. Chemistry Operations

2. Chemistry Support Staff

13.1.2.2.1.6 Manager Work Control/Outage

The Manager Work Control/Outage oversees the entire planning/scheduling function for daily and outage work and ensures coordination with site groups. During plant outage, assumes role of Plant Manager for direction of day-to-day operations and maintenance. He maintains a branch comprised of the following functional sections:

1. Work Control

2. Outage Scheduling

The Work Control Center functional section is under the direction of the Unit 1 Manager Work Control/Outage.

13.1.2.2.2 Supervisor Quality Inspection

The Supervisor Quality Inspection, under the general direction of the Manager Quality Assurance, is responsible for nondestructive examination, testing, and documentation including implementation of the ISI Program.

13.1.2.3 Operating Shift Crews

Table 13.1-1 shows the position titles, applicable operating licensing requirements, and minimum numbers of personnel planned for each shift for the various reactor operating modes. Unique requirements for additional personnel for the refueling modes are also listed in Table 13.1-1. Round-the-clock chemistry and radiation protection coverage is met by qualified Technicians. Technicians are qualified in accordance with the requirements of ANSI/ANS-3.1-1978 as outlined in Section 13.2. Round-the-clock Fire Brigade coverage is provided by shift Fire Brigades. Fire Brigades are qualified in accordance with 10CFR50 Appendix R as described in Section 13.2.

There are six operating shift crews.

13.1.2.4 Director Assessment and Corrective Action

The Director Assessment and Corrective Action reports directly to the Vice President Nuclear Generation and has responsibility for the administration, conduct, and management of the Assessment and

Corrective Action Group. The oversight and signature authority of the Director Assessment and Corrective Action is equivalent to that of the Branch Managers within the Nuclear Generation Branch. The Director Assessment and Corrective Action is responsible to coach, assist and ensure consistency in approach and application of the DER program, OE program, and Branch self-assessments.

13.1.3 Qualifications of Personnel

13.1.3.1 Supervisory Personnel

The essential technical qualifications required for each position in the onsite Supervisory staff meet the intent of the requirements of ANSI/ANS-3.1-1978 and Regulatory Guide (RG) 1.8. Table 13.1-2 shows the qualifications of site personnel in accordance with ANSI/ANS-3.1-1978. Typical resumes for Management and Supervisory personnel performing operational and technical support functions were provided in FSAR Appendix 13A as part of the Operating License application. The qualification summaries of personnel currently filling these or equivalent positions are maintained in personnel files and are available for review by the NRC.

13.1.4 Other Functions Reporting to the Vice President Nuclear Generation

13.1.4.1 Manager Training

The Manager Training has overall Nuclear Division responsibility for the administration and coordination of training programs. This Manager maintains a branch comprised of the following functional sections:

1. Operations Training
2. Technical Training
3. Training Services and Engineering Training
4. Emergency Preparedness

The Director Emergency Preparedness is responsible for the administration and maintenance of the Site Emergency Plan and associated procedures, maintaining the emergency plan monitoring equipment, scheduling, operation and analysis of drills and other exercises of the Emergency Plan and Procedures, and for the implementation of the Meteorological Monitoring Program.

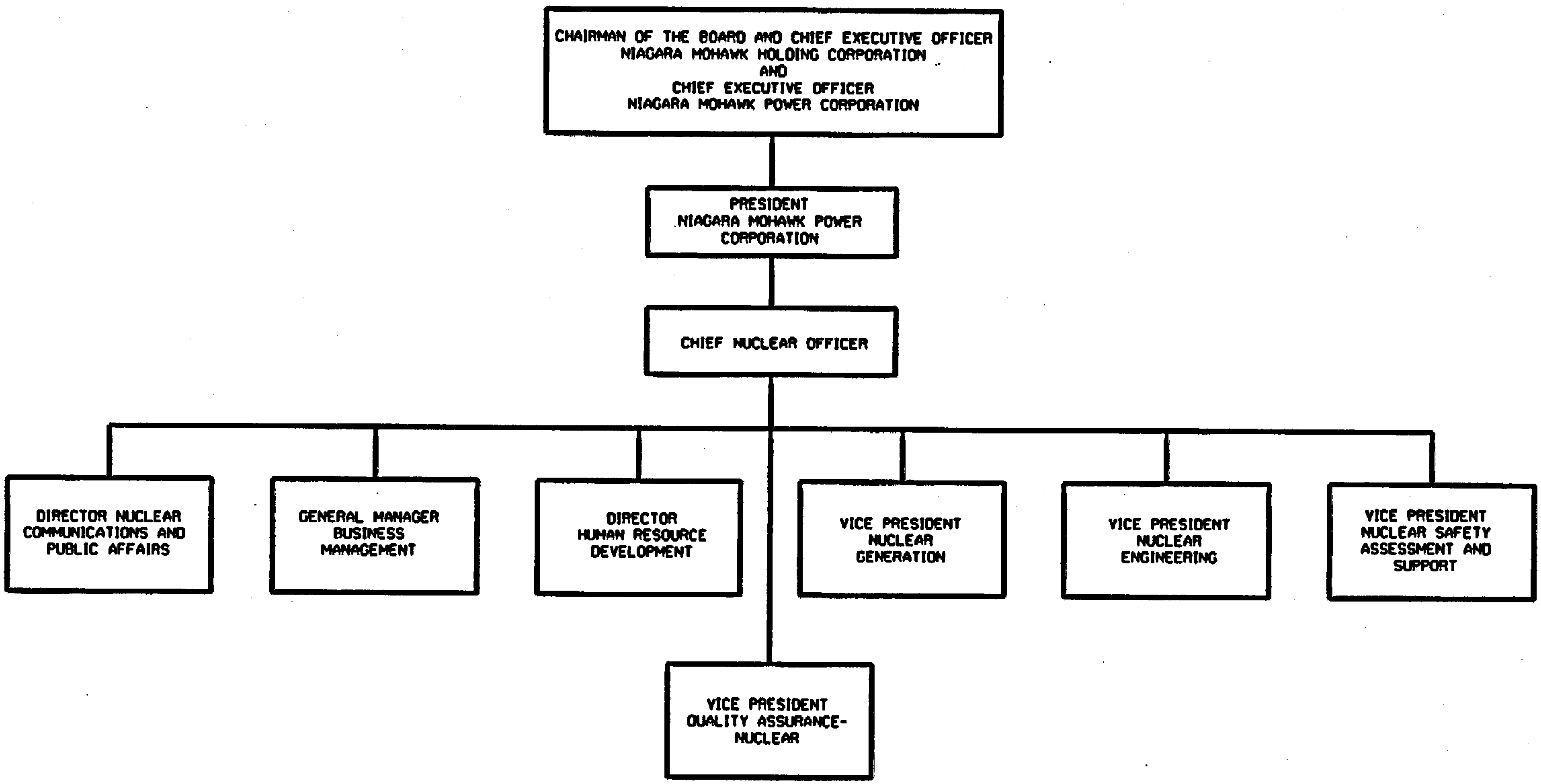
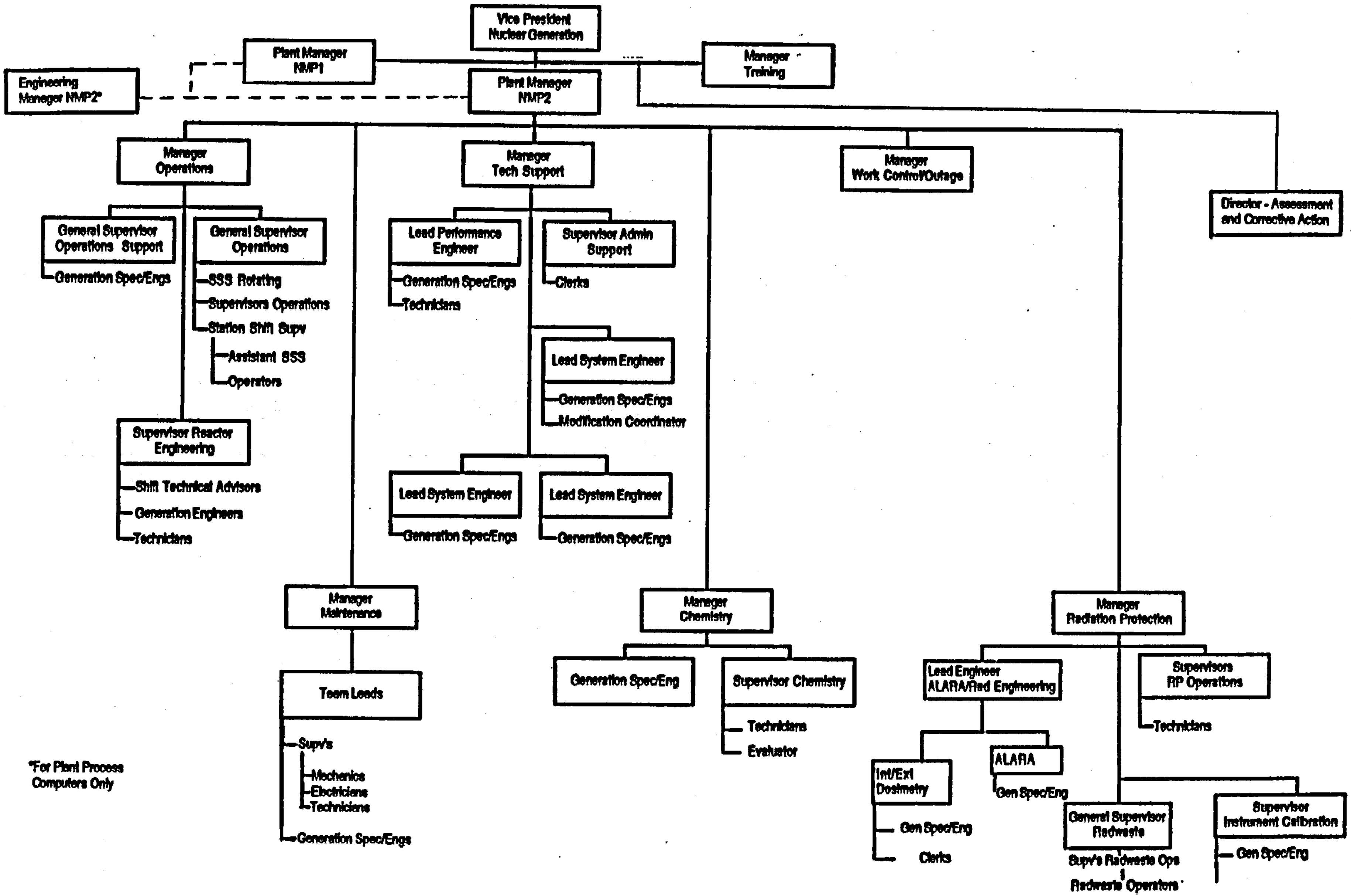


FIGURE 13.1-1

NMPC UPPER MANAGEMENT NUCLEAR ORGANIZATION

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

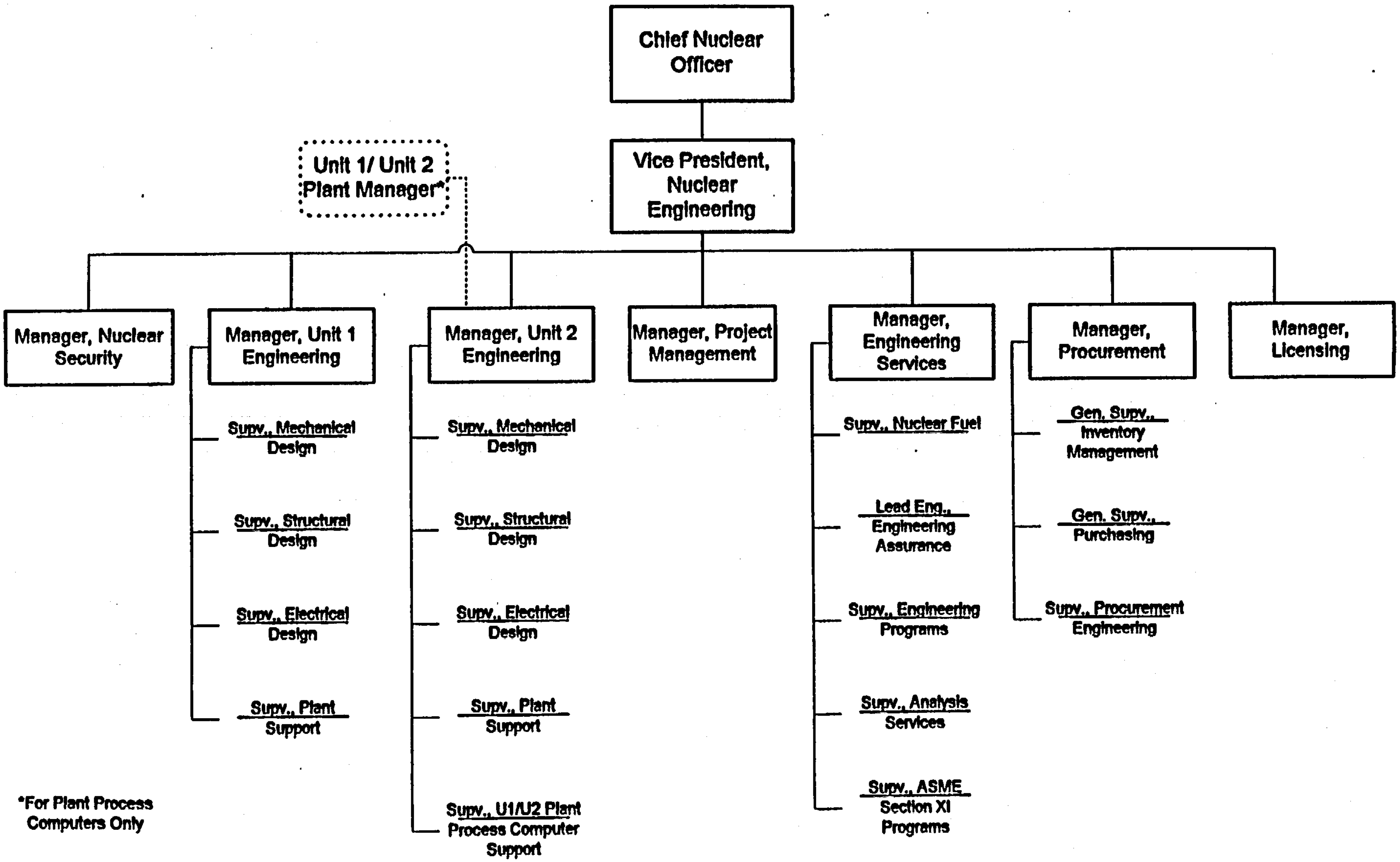
NINE MILE POINT NUCLEAR SITE ORGANIZATION



SOURCE: GAP-POL-01 REV. 23

FIGURE 13.1-2
USAR REV. 13 OCTOBER 2000

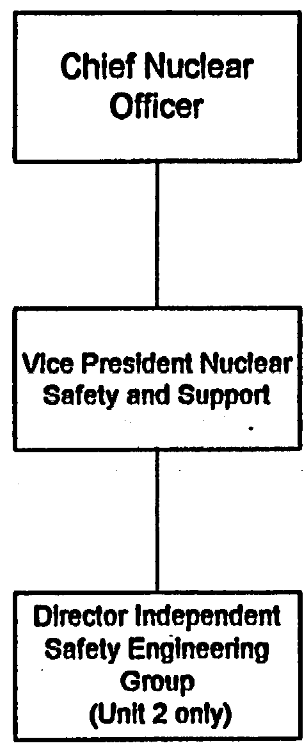
NUCLEAR ENGINEERING ORGANIZATION



SOURCE: NEP-POL-01 REV. 08

FIGURE 13.1-3
USAR REV. 13 OCTOBER 2000

NUCLEAR SAFETY ASSESSMENT AND SUPPORT ORGANIZATION



SOURCE: NSAS-POL-01 REV. 12

FIGURE 13.1-5

13.2 TRAINING

13.2.1 Unit 2 Station Staff Training Program

The objectives of this program are to:

1. Train sufficient personnel to operate and maintain the plant in a safe and reliable manner.

2. Prepare the Technical Support/Services Groups for their functions necessary for the support and safety of plant operation.

3. Prepare shift supervisory personnel, main control room personnel, and other licensed personnel for NRC licensing examinations.

4. Provide training for replacement of personnel due to vacancies.

5. Provide requalification training, as required by NRC regulations, to maintain a high level of proficiency throughout the plant staff.

The overall training program for the plant staff is the responsibility of the Vice President Nuclear Generation. The details of the training program and its administration are the responsibility of the Manager Training.

The Manager Training designates, as necessary, qualified individuals to prepare lesson plans, give lectures, tests and examinations, provide performance evaluations, and document various aspects of the training programs.

13.2.1.1 Program Objectives

The training program for Unit 2 is designed to provide plant staff training, requalification training, and replacement training at all levels of the plant organization.

The training programs incorporate the guidelines set forth in RG 1.8. They are designed to allow placement of personnel into specific programs based on the employee's previous experience and intended position.

Pursuant to ANSI 3.1, differences in the training programs based on the extent of an individual's previous nuclear power plant experience may be used to establish eligibility for hot license examinations as follows:

1. Individuals who have had nuclear experience at facilities not subject to licensing (e.g., U.S. Navy) are evaluated on a case-by-case basis to determine the training required.

2. Individuals certified to have completed a NRC-approved training program using a nuclear power plant simulator or having completed a NRC-administered written examination and operating test at a comparable licensed reactor facility with or without issuance of a RO or SRO License, will attend the Unit 2 Licensed Operator Candidate Course. Additional training is specified on a case basis commensurate with the individual's needs.

3. Individuals with no previous nuclear experience will attend the Nuclear Auxiliary Operator Training Course before attending the Licensed Operator Candidate Course.

Other personnel attend lectures in courses on systems related to their disciplines which satisfy NRC requirements.

In the following sections each course is described to include: 1) a general course description, 2) the organization responsible for teaching the course or supervising the instruction, and 3) a listing of personnel who will be scheduled to attend.

13.2.1.2 Responsibilities

All instructors teaching the licensed training and retraining programs shall demonstrate SRO qualifications and participate in appropriate requalification programs. Other members of the permanent or nonpermanent training staff who are responsible for teaching technical subjects are exempt from the SRO criterion. Guest lecturers who are considered subject matter experts and are used on a limited basis also are exempt from the SRO criterion; however, they shall be monitored by a qualified instructor.

13.2.1.3 Training Program Description

The overall training program was developed consistent with Institute of Nuclear Power Operations (INPO) accreditation objectives and criteria.

The Training System Development (TSD) process developed by INPO and its members is a systematic approach for establishing and maintaining a performance-based training program.

The process of maintaining an INPO-accredited training program is controlled internally through the use of training procedures.

13.2.1.4 Training System Development

The TSD systematic process was used for all accredited program development. This process contains five phases:

1. Analysis This phase begins with a determination of the training needed for specified job positions. These needs are then analyzed using job and task analysis.

The course is taught by members of the Nine Mile Point Nuclear Training Staff or by qualified vendors under the supervision of the Manager Training.

13.2.2.1 Program

13.2.2.1.1 Technical Training for Auxiliary Operators

Operating personnel who are not license candidates may be scheduled for training sessions on topics which may include:

1. Nuclear power plant fundamentals.

2. Mathematics.

3. The physical sciences, including but not limited to:

   a. Mechanics

   b. Heat and heat transfer

   c. Electrical fundamentals

   d. Atomic properties

   e. Structure and properties of materials

   f. Nuclear physics.

13.2.2.1.2 Systems Training

1. Nuclear steam supply system (NSSS).

2. Neutron monitoring system (NMS).

3. Containment and emergency systems.

4. Turbine, generator, and electrical systems.

5. Balance-of-plant (BOP) and auxiliary systems.

13.2.2.1.3 Individual Reading Assignments as Necessary

13.2.2.1.4 Offsite Facilities Training

Visits to offsite training facilities may be used to substitute for or supplement the on-the-job training (OJT) and technical training specified in Sections 13.2.2.1.1, 13.2.2.1.2, and 13.2.2.1.5.

13.2.2.1.5 On-the-Job Training

OJT is variable in duration until such time as the unlicensed Operators meet the experience eligibility requirements of 10CFR55 to become Licensed Operator candidates.

1. Operators shall participate in shift operations, including control of equipment, when practical.

2. Training manuals similar to those provided for licensed candidates and Licensed Operators shall be maintained by all operating personnel assigned to a shift. These manuals shall contain checklists of plant evolutions.

3. Each individual shall be responsible for maintaining his/her own records as specified in the training manuals.

13.2.3 Training of Licensed Operator Candidates

This course establishes the procedures, responsibilities, and requirements for initial training and qualification of persons designated as NRC Licensed Reactor Operator and Senior Reactor Operator candidates.

This program is consistent with INPO ACAD 91-012, "Guidelines for Training and Qualification of Licensed Operators," administered in accordance with 10CFR55, "Operator Licenses," and meets or exceeds the requirements of Sections 4.3.1, 4.5.1, and 5.2 of ANSI/ANS 3.1-1978, "Selection and Training of Nuclear Power Plant Personnel," and Section A of Enclosure 1 of the March 28, 1980, NRC letter to all licensees. The program is based on a systems approach to training (SAT) and uses a simulation facility acceptable to the NRC under 10CFR55.45(b). The program is also accredited by the National Nuclear Accrediting Board, with initial accreditation awarded on May 6, 1987, and communicated to the NRC in letter NMP1L 0749, dated March 24, 1993.

13.2.4 Licensed NRC Operator Requalification Training

This course establishes the procedures, responsibilities, and requirements for requalification of NRC-licensed ROs and SROs.

This program is consistent with INPO ACAD 86-025, "Guidelines for Continuing Training of Licensing Personnel," administered in accordance with 10CFR55, "Operator Licenses," and meets or exceeds the requirements of Section 5.5 of ANSI/ANS 3.1-1978, "Selection and Training of Nuclear Power Plant Personnel." The program is accredited by the National Nuclear Accrediting Board, with initial accreditation awarded on May 6, 1987.

13.2.5 Radwaste Operator Training

This program is structured to provide basic knowledge in radwaste systems and procedures for waste handling. Included in this program is a practical section to enhance Operator skills and development.

This program will be taught by members of the Nine Mile Point Training Staff or by a qualified vendor under either the supervision of the General Supervisor Operations Training or the General Supervisor Technical Training.

13.2.5.1 Programs

Technical training for Radwaste Operators shall consist of scheduled classroom sessions and/or laboratory time, offsite training, vendor training, and assigned reading to cover the following subjects.

13.2.5.1.1 Initial Qualification

Persons employed as Radwaste Operators at the entry level shall receive classroom training in the following areas:

1. Nuclear power plant fundamentals.

2. Mathematics.

3. Classical physics.

4. Plant-specific training.

5. Radwaste systems training, which includes an overview of waste handling procedures and radwaste-related regulations for shipping and burying radwaste materials.

6. Print reading.

7. Specific operating procedures.

13.2.5.1.2 On-the-Job Training

1. Radwaste Operators will be provided with sign-off sheets for each task selected for OJT.

2. Trainees are trained and evaluated in accordance with the task qualification procedure.

3. The Supervisor Radwaste or his designee will sign off each task after satisfactory ability has been demonstrated.

4. The Supervisor Radwaste may certify a qualified Operator to be his designated evaluator.

13.2.5.1.3 Continuing Training

Continuing training will be conducted as needed to keep Radwaste Operators up-to-date on changes to procedures, regulations, equipment modifications, and significant Licensee Event Reports (LERs).

13.2.6 General Employee Training

These courses are structured to provide a basic knowledge of radiation protection and plant access training topics required for work at Unit 2.

The program will be taught by members of the Nine Mile Point Training Staff or by a qualified vendor under the supervision of the Manager Training.

13.2.6.1 Plant Access Training (PAT) Program

This program is required upon initial assignment to the Unit 2 site, with annual refresher training thereafter, for all individuals desiring unescorted access to the protected area and for personnel outside the protected area as directed by Station procedures. Training content includes topics described in the INPO "Guidelines for General Employee Training."

13.2.6.2 Radiation Worker Training (RWT) Program

This program is required upon initial assignment to the Unit 2 site, with annual refresher training thereafter, for all individuals desiring unescorted access to the radiologically-controlled area (RCA). Training content includes topics described in the INPO "Guidelines for General Employee Training."

13.2.6.2.1 Radiation-Controlled Area Escorted Access Training (Visitor Orientation Program)

Individuals who have not completed radiation worker training shall receive a radiation protection orientation prior to entering the RCAs of the Station buildings, unless specifically exempted by radiation protection supervision.

13.2.6.2.2 Regulatory and Industry Auditors Training

This training is required for NRC Inspectors and INPO observation team members prior to being granted unescorted access. The training consists of selected objectives from the PAT and RWT Programs as deemed necessary by the Manager Radiation Protection.

13.2.6.3 Radiological Respiratory Protection Training Program

This training must be completed prior to wearing respiratory protection at Unit 2 site and annually thereafter for individuals requiring respiratory protection. Training content includes topics described in the INPO "Guidelines for General Employee Training."

13.2.6.3.1 Radiological Respiratory Protection Orientation Training

Individuals not qualified in respiratory protection shall receive a respiratory protection orientation prior to wearing respiratory protective devices for protection against airborne radioactivity, unless exempted as in Section 13.2.6.2.1.

13.2.6.4 Self-Contained Breathing Apparatus Training

This training is required initially and annually thereafter to be qualified to wear a self-contained breathing apparatus (SCBA). Requalification is accomplished through classroom training or challenge session.

13.2.7 Emergency Preparedness Training

This program describes the training requirements for site personnel and nonsite personnel who have response and functional group duties in accordance with the Nine Mile Point Site Emergency Plan. Training and retraining of emergency personnel is defined in Section 8.1 and on Figure 8.2 of the Site Emergency Plan.

This program is taught by members of the Nine Mile Point Training Staff or by a qualified vendor under the supervision of the Manager Training/designee.

13.2.8 Instrument and Control Technician - Nuclear Training Program

13.2.8.1 Technical Training

Training for Technicians-Instrument and Control - Nuclear shall consist of classroom training and/or laboratory sessions.

13.2.8.1.1 Initial Training

General technical training provides the Technician with generic technical knowledge as follows:

1. Math.
2. Physics.
3. Electricity and electronics.

4. Tools and test equipment.

5. Boiling water reactor (BWR) technology.

6. Print reading.

7. Instrumentation - measurement concepts.

8. Instrumentation - control methods.

9. Instrumentation automatic - control theory.

13.2.8.1.2 Advanced Training

1. Signal processing/conditioning (module operation).

2. Microprocessors and computer interface.

3. Reactor plant system training.

13.2.8.2 On-the-Job Training

The Instrument and Control (I&C) Department OJT Program ensures that I&C Technicians - Nuclear possess the required job-related knowledge and skills.

There are four effective elements used in the I&C OJT Program. They are:

1. Objectives.

2. Standards.

3. Trainer/evaluator.

4. Documentation.

Appropriate objectives and standards are established for each task. Training and evaluation are conducted on selected tasks. The results then are documented and maintained in training records.

13.2.8.3 Examinations and Quizzes

1. Examinations and quizzes shall be used to evaluate the effectiveness of the I&C Technician Training Program.

2. Demonstration of competency of an individual shall be accomplished by satisfactory completion of the I&C Technician Training Program with a minimum grade of 80 percent in each subject.

13.2.8.4 Exemptions

Exemptions from attending specific presentations will be approved by the Manager Maintenance if the individual demonstrates expertise in that area by academic performance or on-the-job performance.

The General Supervisor I&C Maintenance shall approve all technical training lesson plans and the Station practical training program.

13.2.8.5 Continued Training Program

The I&C Technician Continued Training Program shall be regularly scheduled. Lectures and/or laboratory exercises may be used.

13.2.8.6 Records

An individual training record will be maintained for each I&C Technician.

13.2.9 Training and Continuing Training for Chemistry Technicians

This program is structured to provide a comprehensive technical and practical program for chemistry and radiochemistry training and continuing training. This program will be taught by members of the Nine Mile Point Training Staff or by a qualified vendor under the supervision of the General Supervisor Technical Training.

13.2.9.1 Chemistry Technician Training Program

13.2.9.1.1 Scope

This training program will consist of annual training, technical training, OJT, and task qualification.

13.2.9.1.2 Annual Training (±3 Months)

Chemistry and Radiochemistry Technicians will attend the following training:

1. General employee training and radiation protection training.

2. Site Emergency Plan procedures training.

13.2.9.1.3 Technical Training

Technical training for Chemistry and Radiochemistry Technicians will consist of the following classroom training and/or laboratory sessions and, in addition, will include the following:

1. Technical Specifications and administrative procedures.
2. Chemistry and radiochemistry procedures.
3. Technical fundamentals.
4. Advanced training.

13.2.9.1.4 Station On-the-Job Training and Task Qualification

Station OJT and task qualification for Chemistry and Radiochemistry Technicians will consist of a systematic OJT and task qualification module program.

13.2.9.1.5 Examinations and Quizzes

Examinations and quizzes will be used to evaluate the effectiveness of the Chemistry and Radiochemistry Technician Training Program.

Demonstration of competency of an individual will be accomplished by satisfactory completion of the Chemistry and Radiochemistry Technician Training Program with a minimum grade of 80 percent in each subject.

13.2.9.1.6 Exemptions

Exemptions from attending specific training will be approved by the Manager Chemistry if the individual demonstrates expertise in that area by academic or on-the-job performance.

The Manager Chemistry will approve all technical training lesson plans and the Station OJT and task qualification program.

13.2.9.2 Chemistry Technician Continuing Training Program

The Chemistry Technician Continuing Training Program is essentially a twofold program. Requalification training is conducted over a 2-yr cycle in order to maintain and upgrade the Technician's level of knowledge and skills. Special requalification training is conducted as necessary to correct observed weaknesses in knowledge or performance and to address special training needs.

13.2.9.3 Technician Training Record

An individual training record will be maintained for each Chemistry and Radiochemistry Technician.

13.2.9A Training and Continuing Training of Radiation Protection Technicians

This program is structured to provide a comprehensive technical and practical program for Radiation Protection Technician

Training and Continued Training. This program will be taught by members of the Nine Mile Point Training Staff or by a qualified vendor under the supervision of the General Supervisor Technical Training.

13.2.9A.1 Radiation Protection Technician Training Program

13.2.9A.1.1 Scope

This training program will consist of annual training, technical training, OJT, and task qualification.

13.2.9A.1.2 Annual Training (±3 Months)

Radiation Protection Technicians will attend the following training:

1. General employee training and radiation protection.

2. Site Emergency Plan procedures training.

13.2.9A.1.3 Technical Training

Technical training for Radiation Protection Technicians will consist of classroom training and/or laboratory sessions and will include the following:

1. Technical Specifications and administrative procedures.

2. Radiation protection procedures.

3. Technical fundamentals.

4. Advance training.

13.2.9A.1.4 Station On-the-Job Training and Task Qualification

Station OJT and task qualification for Radiation Protection Technicians will consist of a systematic OJT and task qualification module program.

13.2.9A.1.5 Examinations and Quizzes

Examinations, quizzes and industry-approved evaluation methods will be used to evaluate the effectiveness of the Radiation Protection Technician Training Program.

13.2.9A.1.6 Exemptions

Exemptions from specific training will be approved by the Manager Radiation Protection if the individual demonstrates expertise in that area by academic performance or OJT and task qualification program.

13.2.9A.2 Radiation Protection Technician Continuing Training Program

The Radiation Protection Technician Continuing Training Program is essentially a twofold program. Refresher training is conducted over a 2-yr cycle in order to maintain and upgrade the Technician's level of knowledge and skills. Special requalification training is conducted as necessary to correct observed weaknesses in knowledge or performance and to address special training needs.

13.2.9A.3 Technician Training Record

An individual training record will be maintained for each Radiation Protection Technician.

13.2.10 Training of Maintenance Mechanics

This course is structured to provide a comprehensive technical and practical program for mechanical maintenance training. This course will be taught by members of the Nine Mile Point Training Staff or by a qualified vendor under the supervision of the General Supervisor Technical Training.

13.2.10.1 Mechanical Maintenance Training

Mechanical maintenance training is divided into three categories:

1. Initial training
    a. Mechanic Helper School
    b. Mechanic "A" School
    c. Mechanic "B" School
2. Continuing training
    a. Routine training
    b. Nonroutine training
3. On-the-job training

Any or all of these categories may involve the use of:

1. Classroom training
    a. Lecture
    b. Videotape
    c. Work booklets

d. Demonstrations

e. Assigned reading

2. Shop/lab practicals

a. Hands-on pass/fail practicals

b. Checkoff sheets

c. Written examinations

3. On-the-job training

a. In the plant

13.2.10.1.1 Initial Training Program

1. Mechanic Helper School

a. Part I

b. Part II

2. Mechanic "A" School

3. Mechanic "B" School

13.2.10.1.2 Continuing Training

The Continuing Training Program is established to ensure that essential job-related knowledge and skills are maintained and improved.

Methods of implementing the Continuing Training Program may consist of any combination of the following:

1.	Classroom	Lectures, self study, demonstrations, written examinations, or oral examinations.
2.	Shop Practice	Hands-on pass/fail practicals, written examinations, or checkoff sheets.

13.2.10.1.3 On-the-Job Training

OJT is conducted in conjunction with Mechanic Helper School, "A" School, and "B" School, as appropriate.

The Maintenance Branch designates the evaluators, and the Training Branch trains the evaluators.

The Maintenance Branch has the overall responsibility for implementing the OJT Program, with the Training Branch assuming the responsibility of documenting the completed OJT tasks.

13.2.10.2 Mechanical Maintenance Evaluator

Examinations are given to evaluate trainee performance. Examinations may include written and/or practical segments. A mechanic must achieve a score of at least 80 percent on any examination. Examinations, both written and practical, become part of the individual's training record. Remediation training is scheduled for any mechanic whose average score is below 80 percent.

13.2.11 Training of Maintenance Electricians

This course is structured to provide a comprehensive technical and practical program for electrical maintenance training. This program will be taught by members of the Nine Mile Point Training Staff or by a qualified vendor under the supervision of the General Supervisor Technical Training.

13.2.11.1 Electrical Maintenance Training

Electrical maintenance training is divided into three categories:

1. Initial training
   a. Electrician Helper School
   b. Electrician "A" School
   c. Electrician "B" School
2. Continuing training
   a. Routine training
   b. Nonroutine training
3. On-the-job training

Any or all of these categories may involve use of the following:

1. Classroom training
   a. Lecture
   b. Videotape
   c. Work booklets
   d. Demonstrations

e. Assigned reading

2. Shop/lab practicals

a. Hands-on pass/fail practicals

b. Checkoff sheets

c. Written examinations

3. On-the-job training

a. In the plant

13.2.11.1.1 Initial Training Program

1. Electrician Helper School

a. Part I

b. Part II

2. Electrician "A" School

3. Electrician "B" School

13.2.11.1.2 Continuing Training

The Continuing Training Program is established to ensure that essential job-related knowledge and skills are maintained and improved.

Methods of implementing the Continuing Training Program consist of any combination of the following:

1.	Classroom	Lectures, self study, demonstrations, written examinations, or oral examinations.
2.	Shop Practice	Hands-on pass/fail practicals, written examinations, or checkoff sheets.

13.2.11.1.3 On-the-Job Training

OJT is conducted in conjunction with Mechanic Helper School, "A" School, and "B" School, as appropriate.

The Maintenance Branch designates the evaluators, and the Training Branch trains the evaluators.

The Maintenance Branch has the overall responsibility for implementing the OJT Program, with the Training Branch assuming the responsibility of documenting the completed OJT tasks.

13.2.11.2 Electrical Evaluations

Examinations are given to evaluate trainee performance. Examinations may include written and/or practical segments. An Electrician must achieve a scope of at least 80 percent on any examination. Examinations, both written and practical, become part of the individual's training record. Remediation training is scheduled for any electrician whose average score is below 80 percent.

13.2.12 Fire Brigade Training

Fire Brigade members are trained in accordance with approved training procedures to familiarize the individuals with fire protection systems and equipment, plant fire hazards and emergency response. This training program is also intended to ensure that the Brigade leader and at least two members have sufficient training and a knowledge of plant safety-related systems to understand the effects of fire and fire suppression on safe shutdown capability.

This training program for the Brigade members consists of a combination of classroom sessions and in-plant inspection of site-specific applications of classroom sessions.

Members of the Fire Brigade attend the Niagara Mohawk Fire School annually to provide Fire Brigade work experience in actual fire extinguishment and the use of emergency breathing apparatus under strenuous conditions.

Local Fire Department personnel are periodically trained in the operational precautions of fighting fires at nuclear power plant sites. In addition, orientation is provided regarding radiation protection at the nuclear station.

13.2.12.1 Practice

Practice sessions will be held for each shift Fire Brigade on the proper method of fighting fires that could occur in a nuclear power plant. These sessions will provide Brigade members with experience in actual fire extinguishment and the use of emergency breathing apparatus under conditions encountered in firefighting. These practice sessions will be provided once each year for each Fire Brigade member.

13.2.12.2 Fire Drills

Fire drills are conducted on a quarterly basis to ensure that members work together as a team to address a simulated fire event. These drills are evaluated by supervisory personnel to assess leadership effectiveness, knowledge of responsibilities and of equipment. The drills are critiqued following completion to determine any necessary corrective actions which may be warranted.

Local Fire Departments will be provided training in operational precautions when fighting fires at nuclear power plant sites and will be made aware of the need for radiological protection of personnel and special hazards associated with a nuclear power plant site.

13.2.12.3 Records

Individual records of training provided to each Fire Brigade member and drill critiques will be maintained for at least 3 yr to ensure that each member receives training in the program. These records of training will be available for NRC review. Retraining for firefighting will be scheduled for those Brigade members whose performance records show deficiencies.

13.2.12.4 Other Station Employees

<u>Instruction</u>

1. Instruction will be provided once a year for site employees and those authorized unescorted access. It will be repeated on an annual basis. The instruction will include, as appropriate, information concerning the procedure for reporting a fire.

2. Instruction will be provided to all shift personnel who complement the Fire Brigade.

<u>Drills</u>

Generally, site employees will participate in an annual evacuation drill.

13.2.12.5 Fire Protection Staff

Training for Fire Protection supervisory staff members and Training personnel (involved with fire training) will include courses in:

1. Design and maintenance of fire detection, suppression, and extinguishing systems.

2. Fire prevention techniques and procedures.

3. Training and manual firefighting techniques and procedures for plant personnel and the Fire Brigade.

13.2.13 Training of Unlicensed Managerial Personnel

This program describes the responsibilities for training of professional personnel assigned to Unit 2. Specific programs will be taught by members of the Nine Mile Point Training Staff or by subject matter experts.

13.2.13.1 Professional Personnel

It shall be the responsibility of each individual management or professional person assigned to the plant/Station or site to maintain an up-to-date resume of his professional training and experience.

13.2.13.2 Survey

Training program needs are assessed by survey of the supervisory and professional personnel assigned to Unit 2.

13.2.13.3 Records

1. A training record shall be maintained for each individual assigned as professional personnel. This record shall contain a list of formal training sessions attended and a resume of the individual's technical competence.

2. A record of attendance at General Employee Training shall be included in each individual's training record.

13.2.13.4 Quality Assurance Personnel

The manager quality assurance is responsible for the training and proficiency of those NMPC QA personnel active onsite.

13.2.13.5 Quality Assurance Duties of Station Personnel

Each supervisor shall be responsible that all personnel assigned to him who perform specific QA functions, such as nondestructive testing (NDT) examinations, shall be properly trained and certified for the performance of these functions.

13.2.14 Training Program Records

An individual training record shall be maintained for each individual.

13.2.15 Applicable NRC Regulations

The following NRC documents are applicable to training:

10CFR50	Licensing of Production and Utilization Facilities
10CFR50	Appendix R, Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979
10CFR55	Operator License

10CFR55.59	Requalification Program for Licensed Operators
10CFR55.57	Renewal of Licenses, Technical Specifications, 6.4.1
RG 1.8	Personnel Selection and Training

13.3 SITE EMERGENCY PLAN

The Nine Mile Point Nuclear Station Site Emergency Plan describes the total preparedness program established, implemented, and coordinated by NMPC to assure capability and readiness for coping with and mitigating both onsite and offsite consequences of radiological and nonradiological emergencies. For emergency planning purposes, the Site Emergency Plan treats Unit 1 and Unit 2 as one site; therefore, the previously reviewed and approved Site Emergency Plan will be implemented at Unit 2 with appropriate modifications to incorporate Unit 2 plant-specific parameters. The Site Emergency Plan covers the spectrum of emergencies from minor, localized incidents to major emergencies requiring protective measures by offsite response organizations. Included are guidelines for immediate response, assessment of emergency situations, defined action criteria, and delineation of support functions. The Site Emergency Plan Implementing Procedures provide detailed information for individuals involved with specific emergency response functions.

The Site Emergency Plan also provides for a graded scale of response for distinct classifications of emergency conditions, action within those classifications, and criteria for escalation to more severe classifications. This classification system was developed in accordance with RG 1.101 and is identical to that used by the State of New York and the Oswego County Emergency Management Office. The plans have four emergency categories in ascending order of severity: Unusual Event, Alert, Site Area Emergency, and General Emergency. In addition to notifying the offsite agencies of the existing emergency classification, provisions are made in the Implementing Procedures for the Station to advise the state and county of appropriate protective actions. Organization for the control of emergencies begins with the shift organization and contains provisions for augmentation and extension to include other Station personnel, NMPC corporate personnel, and outside emergency response organizations.

Nine Mile Point Station personnel and NMPC corporate support personnel are responsible for onsite emergency actions and limited offsite activities such as offsite radiological surveillance.

The total emergency program includes support from local, state, and federal emergency organizations. Detailed provisions are made for implementing protective measures against direct radiation exposure and inhalation of radioactive material for members of the public within a radius of at least 10 mi from the site. Additional preventive measures may be taken beyond that distance to preclude ingestion pathway exposures.

Specific arrangements and agreements have been made with local offsite support organizations to provide:

1. Fire and rescue.

2. Emergency medical transportation.

3. Hospital medical treatment.

4. Law enforcement and traffic control.

County, state, and federal agencies having lead responsibilities specifically related to the Site Emergency Plan are:

1. New York State Department of Health (NYDOH) The lead state emergency response coordinating agency responsible for notifying and advising other agencies.

2. Oswego County Emergency Management Office (OCEMO) The OCEMO is designated by local laws and executive orders to coordinate the county's emergency response.

3. U.S. Nuclear Regulatory Commission (NRC) The federal agency responsible for verifying that appropriate emergency plans have been implemented and for conducting investigative activities associated with a radiological emergency.

4. U.S. Department of Energy (DOE) The federal agency responsible for providing assistance essential for the control for immediate hazards to public health and safety.

The Site Emergency Plan and Implementing Procedures have been submitted to the NRC under separate cover.

The current version of the Site Emergency Plan is Revision 40.

13.4 OPERATION REVIEW AND AUDIT

13.4.1 Administrative Controls

Administrative controls are written rules, orders, instructions, procedures, policies, practices, and designation of authority and responsibility by management to ensure safety and quality of operation and maintenance of Unit 1 and Unit 2. The Site Administrative Procedures describe the controls over all Station procedures.

The Chief Nuclear Officer retains the overall corporate responsibility for plant nuclear safety. The Vice President Nuclear Generation has oversight responsibility to assure safe, orderly, and efficient operation of both units on site. The functional operation of each Station is the responsibility of the respective Plant Manager. In addition, the Plant Manager is charged with the responsibility for keeping the Vice President Nuclear Generation fully informed on all significant matters of Station operation.

13.4.2 Safety Review and Audit of Operations

The Station Operations Review Committee (SORC) and Safety Review and Audit Board (SRAB) function for Unit 2. These organizations are shown on Figure 13.4-1. The SORC and SRAB committees' methods, procedures, and practices comply with Sections 4.4 and 4.3 of ANSI N18.7-1976, respectively. Functions served by both of these committees are the same as those performed by committees for Unit 1 and are shown in Tables 13.4-1 and 13.4-2. Technical review and control criteria are shown in Table 13.4-3.

13.4.2.1 Station Operations Review Committee

Members of the SORC are managers or supervisors in the site organization. Qualifications for these positions relate to the discipline or position held by the members in the organization and are described in Section 13.1.3. Records and minutes of meetings are kept on file at the site and are available upon request. Recommendations for changes to licenses, as well as reports of abnormal operation or requests for technical assistance, are forwarded to the SRAB for review as appropriate. SORC procedures are described in the Site Administrative Procedures.

The SORC meetings include a review of in-house and industry operating experience at the discretion of the Plant Manager.

13.4.2.1.1 Review of Operating Experience

Internal and external operating experience is reviewed and assessed via the DER process to ensure that information pertinent to plant safety is supplied to Operators and other appropriate personnel, and is used for effecting design and procedural changes to correct generic or specific deficiencies and to enhance plant safety when warranted.

An initial applicability review of externally-generated operating experience shall be performed primarily by individuals in the Assessment and Corrective Action group. These reviews include, but are not limited to, NRC issuances such as Generic Letters, Information Notices (IN), Bulletins, and Administrative Letters; INPO issuances such as Significant Operating Experience Reports (SOER), Significant Event Reports, Significant Event Notifications (SEN), Significant by Others (SO), and Operations and Maintenance Reminders (O&MR); Vendor issuances such as General Electric (GE) Service Information Letters (SIL), Rapid Information Communication Service Information Letters (RICSIL), Technical Information Letters (TIL), Service Advisory Letters (SAL); and potential 10CFR21 notifications.

External operating experiences that require further evaluation are assigned to responsible Nuclear Division organizations via the DER process, as appropriate, for evaluation and corrective and preventive action. The evaluations and dispositions are reviewed by the applicable Branch Manager. Hardware and software modifications, procedure revisions, design changes, etc., resulting from the reviews are then implemented by the responsible groups within the Nuclear Division. The evaluations and dispositions are reviewed by the SORC as required by the Plant Manager.

In-house operating experience such as significant equipment malfunction, adverse trends developed from testing and operations surveillance, reactor core operating trends, operability problems, and/or organizational and programmatic problems that may impact plant safety and reliability, will be treated as an event/deviation and processed accordingly. Processing shall be accomplished by the appropriate Branch Manager allowing the Plant Manager to designate SORC review as appropriate.

13.4.2.2 Safety Review and Audit Board

The SRAB is composed of engineers with extensive experience in the design of generating plants and knowledge in various disciplines affecting plant safety. They do not have responsibility for day-to-day operation. The Plant Manager is included as a board member, providing liaison and direct information to board members, and ensuring that board recommendations are implemented.

The SRAB is charged with the responsibility for reviewing change requests originating in the SORC and recommending action where appropriate. When a license change is required, the SRAB reviews necessary documents for submission to the NRC. The SRAB also reviews all abnormal situations that may arise in plant operation. Periodic audits of operation are made by board members knowledgeable in the operating process, but without responsibility for daily plant operation. Functions served by these committees are shown on Figure 13.4-1 and Table 13.4-2. Education and experience qualifications required for members of the SRAB are as follows:

<u>Staff Engineer, Manager, or Vice President - Chairman</u>

Education: Four-yr college graduate or equivalent.

Experience: Ten yr of electric utility experience, with 5 yr of experience in a responsible engineering management position which includes 4 yr of nuclear plant engineering, design, construction, or operation.

<u>Plant Manager</u>

The Plant Manager qualifications are described in Section 13.1.3.1.

<u>Staff Engineer - Nuclear</u>

Education: Four-yr college graduate in engineering or operations of nuclear facilities with at least 3 yr of experience in nuclear engineering.

<u>Staff Engineer - Mechanical and Electrical</u>

Education: Four-yr college graduate, engineering or equivalent.

Experience: Five yr of experience in mechanical or electrical engineering components and control systems for thermal power stations or similar facilities.

<u>Consultants</u>

Consultants shall be utilized as determined by the SRAB Chairman.

13.4.3 Audit Program

The SRAB provides independent review and audit of various operating activities, administrative controls and compliance to NRC regulations, Technical Specifications, and quality assurance. The following audits are conducted by SRAB in accordance with the Technical Specifications.

1. Conformance to Technical Specifications and license conditions.

2. Training and qualifications of the operating staff.

3. Actions to correct deficiencies.

4. Quality assurance.

5. Emergency Plan and procedures.

6. Security Plan and procedures.

7. Radiological Environmental Monitoring Program.

8. Offsite Dose Calculation Manual and procedures.

9. Process Control Program and procedures.

10. Other audits directed by the Chairman of the SRAB or Vice President Nuclear Generation.

11. Fire Protection Program and procedures.

Additional audits are performed by the Quality Assurance Department as described in Chapter 17.

descriptive title for each procedure within the classification. Refer to Section 1.10 for a description of the commitment to NUREG-0737, Supplement 1, Items I.C.7 and I.C.8.

13.5.2.1.1 General Plant and System Operating Procedures

General plant and system operating procedures are developed for Unit 2. They are in three categories: operating procedures (Table 13.5-6), special operating procedures (Table 13.5-7) and fuel handling procedures. Fuel handling procedures deal specifically with refueling, core alterations, and refueling equipment operation (RG 1.33, Revision 2, February 1978, Appendix A, Sections 2.k and 2.1, and ANSI/ANS-3.2-1982, Appendix, Sections A5.k and A5.1).

Special operating procedures cover off-normal situations not meeting the requirement for inclusion in an EOP. These procedures are written in an event-based format using the guidance of Section 5.3.9 of ANSI/ANS-3.2-1982. These procedures cover the scope of events identified in Appendix A of RG 1.33, Revision 2 (Table 13.5-7), except for a few events which are more appropriately covered by EOPs or other procedures.

The operating procedures contain the following sections (as applicable):

1. Title

2. Technical Specification requirements

3. System description

4. Plant operating requirements

5. Startup

6. Normal operation

7. Shutdown

8. Off-normal procedures

9. Procedures for correcting alarm conditions

10. Attachments (as required)

13.5.2.1.2 Emergency Operating Procedures

EOPs were developed based on GE BWR Owners' Group Emergency Procedure Guidelines (BWROG EPG)/Severe Accident Guidelines (SAG), Revision 4. Later revisions to the BWROG EPG will be considered as required.

13.5.2.1.3 Annunciator Response Procedures

Instructions for annunciator response are incorporated in the Station operating procedures or in individual annunciator response procedures. Annunciators in the control room are identified individually by a succinct designation. The general format of the annunciator response instructions is shown in Table 13.5-5.

13.5.2.1.4 Temporary Procedures

Temporary procedures are described in Section 13.5.1.3.7.

13.5.2.2 Other Operating and Maintenance Procedures

This section classifies other operating and maintenance procedures, group responsibility, and general objectives and character of each class.

13.5.2.2.1 Plant Radiation Protection Procedures

These procedures are described in Chapter 12. These procedures are prepared by the Manager Radiation Protection and are used, as applicable, by all site departments.

13.5.2.2.2 Emergency Preparedness Procedures

These procedures are described generally in Section 13.3 and fully in the Unit 1 and Unit 2 Emergency Plan and Procedures. These procedures are prepared by the Director Emergency Preparedness and all site personnel are required to follow these procedures as warranted.

13.5.2.2.3 Instrument Calibration and Test Procedures

The Instrumentation Procedures govern the operation of instrumentation checkout and calibration. These procedures apply to nuclear, process, area radiation monitoring, reactor protection, and rod worth minimizer instrumentation. Checkoff lists are provided for more complex operations.

13.5.2.2.4 Chemistry/Radiochemistry Control Procedures

The operating procedures and chemistry/radiochemistry procedures state the operating limits or ranges for chemistry and radiochemistry control and prescribe corrective action and personnel to be notified if these limits are approached. Chemistry personnel are provided with a schedule describing the types of analyses to be performed and frequency of samples to be taken.

13.6 SECURITY

A detailed Nine Mile Point Nuclear Station Physical Security and Safeguards Contingency Plan, identified as Safeguards Information and withheld from public disclosure in accordance with 10CFR73.21, as well as a Nuclear Security Training and Qualification Plan, have been submitted to the NRC.

The security plans described above detail the measures taken to provide adequate site and Station security, and conform to 10CFR73.55.

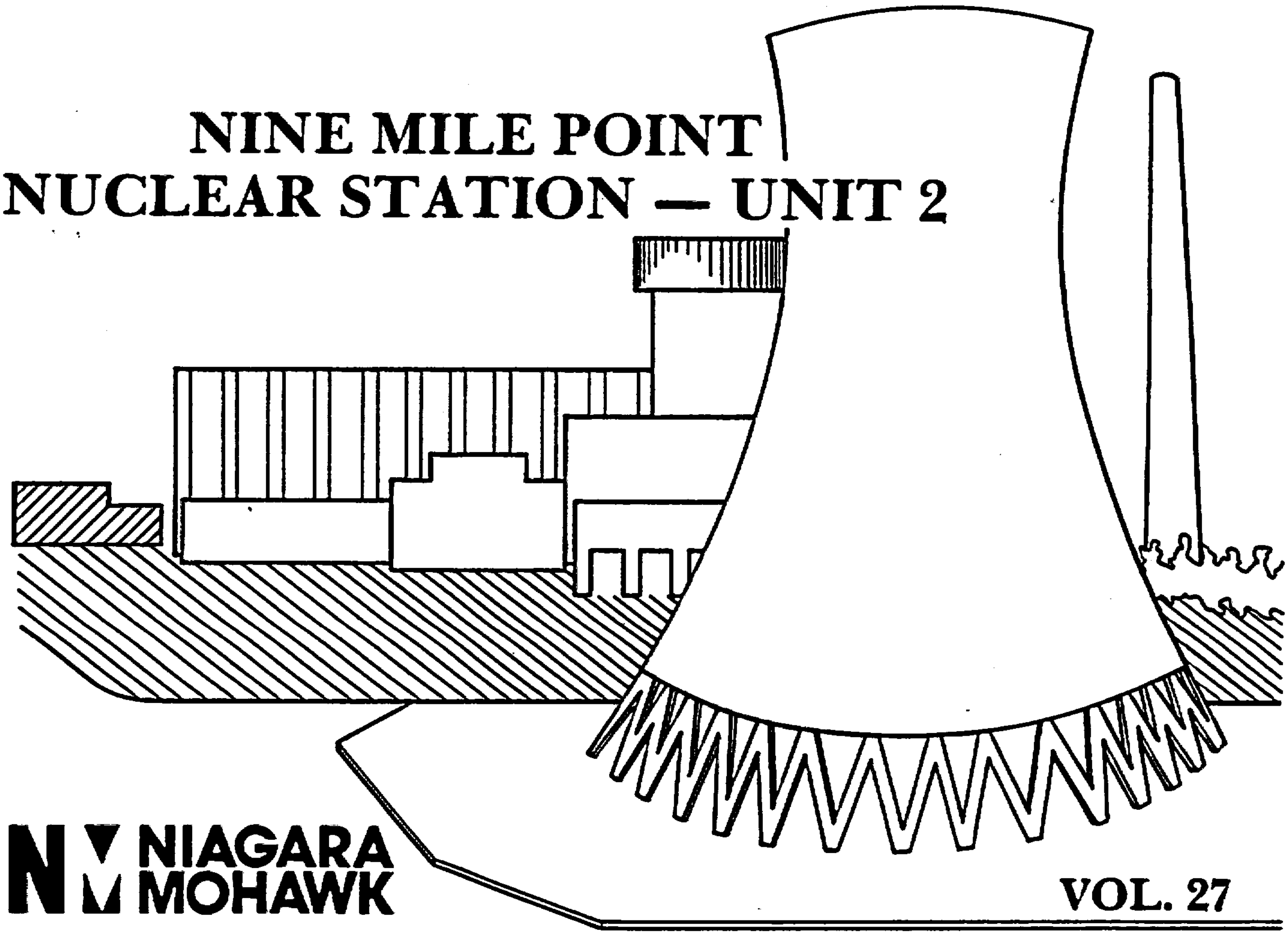
The current versions of the plans are as follows:

1. Physical Security and Safeguards Contingency Plan - Issue 5, Revision 2.

2. Nuclear Security Training and Qualification Plan - Issue 3, Revision 1.

UPDATED SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2



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15.2 INCREASE IN REACTOR PRESSURE

Cycle-specific reload analyses are discussed in Appendix A, Section A.15.2.

15.2.1 Pressure Regulator Failure - Closed

The analysis of this event was initially performed at 3,467 MWt (104.3 percent of original rated power), and was not reanalyzed for rated 3,467 MWt operation. This event does not set reactor operating limits and is not reanalyzed for each reload cycle.

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 just 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 output of both regulators feeds into a high value gate. The regulator with the highest output controls the main TCVs. The lowest pressure setpoint gives the largest pressure error and thereby the largest regulator output. The backup regulator is set approximately 5 psi higher giving a slightly smaller error and a slightly smaller 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, the backup regulator takes control.

15.2.1.1.2 Frequency Classification

This event is treated as a moderate frequency event.

15.2.1.2 Sequence of Events and System Operation

15.2.1.2.1 Sequence of Events

Postulating a failure of the primary or controlling pressure regulator in the closed mode (Section 15.2.1.1.1) causes the TCVs start to close. The pressure increases because the reactor is still generating the initial steam flow. The backup regulator reopens the valves and reestablishes steady-state operation above the initial pressure equal to the setpoint difference of approximately 5 psi.

No Operator action is required.

15.2.1.2.2 Systems Operation

One Pressure Regulator Failure - Closed

Normal plant instrumentation and controls are assumed to function. This event requires no protection system or safeguard systems operation.

15.2.1.2.3 The Effect of Single Failures and Operator Errors

The nature of 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, the second assumed failure, the control valves start to close, raising reactor pressure to the point where a flux scram trip is initiated to shut down the reactor. At 100-percent power, this event is less severe than the turbine trip where stop valve closure occurs (Event 15.2.3) and shuts off steam flow at a faster rate. At less than 100-percent power, an interim evaluation has been performed for Cycle 8.[5]

15.2.1.3 Core and System Performance

The disturbance is mild, similar to a pressure setpoint change, and no significant reductions in fuel thermal margins occur. This transient is much less severe than the generator and turbine trip transients described in Sections 15.2.2 and 15.2.3.

15.2.1.3.1 Mathematical Model

Qualitative evaluation only is provided.

15.2.1.3.2 Input Parameters and Initial Conditions

Qualitative evaluation only is provided.

15.2.1.3.3 Results

The response of the reactor during this regulator failure is such that pressure at the turbine inlet increases in 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 utilized for protection in this event were assumed to have the most conservative allowable response (e.g., relief setpoints, scram stroke time, and control rod worth characteristics). Plant behavior is therefore expected to reduce the actual severity of the transient.

15.2.3 Turbine Trip

The analysis of this event was initially performed at 3,467 MWt (104.3 percent of original rated power). Evaluation of this event for operation at uprated (3,467 MWt) conditions confirmed that turbine trip events are similar to but bounded by the generator load rejection event.[3] The turbine trip event does not set reactor operating limits and is not reanalyzed for each reload cycle. For reload cores, an evaluation is performed to determine if the turbine trip with bypass failure could potentially alter the previous cycle MCPR operating limit. If it does, the results will be reported in the supplemental reload licensing report.

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 initiate a turbine trip. Some examples are moisture separator high level, turbine vibrations, Operator lockout, loss of EHC fluid pressure, low condenser vacuum, and reactor high water level.

15.2.3.1.2 Frequency Classification

<u>Turbine Trip</u>

This transient is categorized as an incident of moderate frequency. In defining the frequency of this event, turbine trips that 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 that cause an unnecessary turbine trip are included in defining the frequency. To get an accurate event-by-event frequency breakdown, this type of division of initiating causes is required.

<u>Turbine Trip with Bypass Failure</u>

This transient disturbance is categorized as an infrequent incident. Frequency is expected to be as follows:

Frequency	0.0064/plant year
MTBE	156 yr

<u>Frequency Basis</u> As discussed in Section 15.2.2.1.2, the failure rate of the bypass is 0.0048. Combining this with the turbine trip frequency of 1.33 events/plant year yields the frequency of 0.0064/plant year, or a MTBE of 156 yr. Although this event is classified as infrequent, it has been considered in the evaluation of operating CPR limits in Table 15.0-2 and on Figure 15.0-1.

15.2.3.2 Sequence of Events and Systems Operation

15.2.3.2.1 Sequence of Events

Turbine Trip

Turbine trip at high power produces the sequence of events listed in Table 15.2-3. The analysis assumes the availability of feedwater pump motors after successful fast transfer. Thereafter, the feedwater pump motor trips at Level 8. Even if the feedwater pump motor were to trip immediately after turbine trip, the analysis is still bounding. The timing of scram and RPT would remain unchanged and the subsequent HPCS and RCIC operation due to loss of feedwater would have no effect on all key transient parameters.

Turbine Trip with Bypass Failure

Turbine trip at high power with bypass failure produces the sequence of events listed in Table 15.2-4.

Identification of Operator Actions

The Operator should verify automatic functions and monitor all parameters.

No Operator action is required.

15.2.3.2.2 Systems Operation

Turbine Trip

All plant control systems maintain normal operation unless specifically designated to the contrary.

Turbine stop valve closure initiates a reactor scram trip via position signals to the protection system. Credit is taken for successful operation of the RPS.

Turbine stop valve closure initiates a 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.

It should be noted that below approximately 30 percent 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 when steam flow is within bypass valve capacity. All other protection system functions remain operational, and credit is taken for those protection system trips.

K-factor of 240.2 Btu/sec-°F, and a service water temperature of 82°F (see Table 6A.10-2).

Figures 15.2-18 and 15.2-19 show the reactor vessel pressure and temperature responses for Case 2' past the time of cold shutdown. Figure 15.2-20 shows the corresponding long-term suppression pool temperature response. The peak bulk pool temperature obtained for Case 2' of Section 6A.10 is 211°F, which is less than the design value of 212°F and significantly less than the original value of 222°F shown on Figure 15.2-17. The analysis for Case 2' produces a time to cold shutdown of 46 hr. This is 8 hr less than the time (54 hr) given in the notes to Figure 15.2-11 for the same alternate shutdown cooldown mode.

15.2.9.4 Barrier Performance

As noted previously, 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 the containment occurs via SRV actuation. Release of radiation to the environment is described in the following section.

15.2.9.5 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 via SRV operation (Section 15.1.2.5).

15.2.10 References

1. Fukushima, T. Y. HEX01 User Manual, July 1976 (NEDE-23014).

2. Bilanin, W. I.; Bodily, R. J.; and Cruz, G. A. The General Electric Mark III Pressure Suppression Containment System Analytical Model (Supplement 1), September 1975 (NEDO-20533, Supplement 1).

3. Letter from R. S. Boyd to I. F. Stuart dated November 12, 1975. Subject: Requirements Delineated for RHRS - Shutdown Cooling System--Single Failure Analysis.

4. Licensing Topical Report, Power Uprate Licensing Evaluation for Nine Mile Point Nuclear Power Station Unit 2, NEDC-31994P, Revision 1, May 1993.

5. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

TABLE 15.2-3

TURBINE TRIP
SEQUENCE OF EVENTS FOR FIGURE 15.2-3

Note: These results are for Cycle 1. This event does not set reactor operating limits and is not reanalyzed for power uprate or for each reload cycle.

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 percent open position and initiate reactor scram trip and a RPT.
0.10	Turbine stop valves closed.
0.10	Turbine bypass valves start to open to regulate pressure.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
1.5	Group 1 relief valves actuated.
1.7	Group 2 relief valves actuated.
1.8	Group 3 relief valves actuated.
1.9	Group 4 relief valves actuated.
2.1	Group 5 relief valves actuated.
4.6	Feedwater pump motors trip on L8 high water level.
5.1	Group 5 relief valves start to close.

TABLE 15.2-4

TURBINE TRIP WITH BYPASS FAILURE
SEQUENCE OF EVENTS FOR FIGURE 15.2-4

Note: These results are for Cycle 1. For reload cores, an evaluation is performed to determine if this AOO could potentially alter the previous cycle MCPR operating limit. If it does, the results will be reported in the supplemental reload licensing report.

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 percent open position and initiate reactor scram trip and RPT.
0.10	Turbine stop valves close.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
1.25	Group 1 relief valves actuated.
1.34	Group 2 relief valves actuated.
1.42	Group 3 relief valves actuated.
1.51	Group 4 relief valves actuated.
1.60	Group 5 relief valves actuated.
7.0	Group 5 relief valves start to close.
9.0	All relief groups closed.

rate of 11 percent/sec. It is similar to the fast opening of one recirculation valve. Flux scram occurs at approximately 1.2 sec, peaking at 241 percent of NBR while the average surface heat flux reaches 74.1 percent of NBR at approximately 2.2 sec. MCPR remains considerably above the safety limit, and fuel center temperature increases 330°F.

As indicated above, this is the most severe set of conditions under which this transient may occur. The results expected from an actual occurrence of this transient are less severe than those calculated.

15.4.5.3.4 Considerations of Uncertainties

Void reactivity characteristics, scram time, and worth are expected to be more favorable and, therefore, lead to reducing the actual severity from that which is discussed above.

15.4.5.4 Barrier Performance

15.4.5.4.1 Fast Opening of One Recirculation Valve

This transient results in a very slight increase in reactor vessel pressure as shown on Figure 15.4-7 and, therefore, represents no threat to the RCPB.

15.4.5.4.2 Fast Opening of Two Recirculation Valves

This transient results in a very slight increase in reactor vessel pressure as shown on Figure 15.4-8 and, therefore, represents no threat to 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 from the fuel.

15.4.6 Chemical and Volume Control System Malfunctions

Not applicable to BWRs. This is a pressurized water reactor (PWR) event.

15.4.7 Misplaced Bundle Accident

The analysis of this event was initially performed at 3,467 MWt (104.3 percent of original rated power), and was not reanalyzed for rated 3,467 MWt operation. Analysis of the mislocated bundle accident is performed for reload cores where the resultant CPR response may establish the operating limit MCPR.

15.4.7.1 Identification of Causes and Frequency Classification

15.4.7.1.1 Identification of Causes

This event 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 loaded into a wrong location in the core. Second, the bundle that should have been loaded where the mislocation occurred would have to be overlooked and also put into an incorrect location. Third, the misplaced bundles would have to be overlooked during the core verification performed following initial 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 an expected frequency of 0.004 events/operating cycle.

The above number is based upon past experience. The only misloading events that have occurred in the past were in reload cores where only two errors are necessary. Therefore, the frequency of occurrence for initial cores is even lower since three errors must occur concurrently.

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 15.4-6. 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; therefore, no corrective Operator action or automatic protection system functioning occurs.

This analysis represents the worst case (i.e., operation of a misplaced bundle with three SEFs or SOEs).

15.4.7.3 Core and System Performance

This event is discussed in Section S.2.5.4 of GESTAR II[2].

15.4.7.3.1 Analysis

The initial core consists of three bundle types with average enrichments that are high, medium, or low with correspondingly different gadolinia concentrations. The fuel bundle loading error involves interchanging a bundle of one enrichment with another bundle of a different enrichment. The following fuel loading errors are possible in an initial core.

TABLE 15.4-5

SEQUENCE OF EVENTS FOR FAST OPENING OF TWO RECIRCULATION VALVES (FIGURE 15.4-8)

Note: These results are for Cycle 1. This event does not set reactor operating limits and is not reanalyzed for power uprate or for each reload cycle.

Time (sec)	Event
0	Initiate failure of master controller.
1.2	Reactor APRM high flux scram trip initiated.
4.5	TCVs start to close upon falling turbine pressure.
21	Feedwater decreases upon rising water level.
29	TCVs closed; turbine pressure below pressure regulator setpoints.
50+	Reactor variables settle into new steady state.

TABLE 15.4-6

SEQUENCE OF EVENTS FOR MISPLACED BUNDLE ACCIDENT

Note: These results are for Cycle 1. Analysis of the mislocated bundle accident is performed for reload cores where the resultant CPR response may establish the operating limit MCPR.

1. During core loading operation, a bundle is placed in the wrong location.
2. Subsequently, the bundle intended for this location is placed in the location of the previous bundle.
3. During core verification procedure, the two errors are not observed.
4. Plant is brought to full power operation without detecting misplaced bundle.
5. Plant continues to operate.

TABLE 15.4-7

INPUT PARAMETERS AND INITIAL CONDITIONS FOR
FUEL BUNDLE LOADING ERROR - CYCLE 1

Input Parameters	Initial Conditions
1. Power, % rated	100
2. Flow, % rated	100
3. MCPR operating limit	1.24
4. MLHGR operating limit, kW/ft	13.4
5. Average core exposure, MWD/t	EOC
6. Control rod pattern	All rods out

NOTES:

1. Core conditions are assumed to be normal for a hot operating core at EOC.
2. Analysis of the mislocated bundle accident is performed for reload cores where the resultant CPR response may establish the operating limit MCPR.

TABLE 15.4-8

RESULTS OF FUEL LOADING ERROR ANALYSIS - CYCLE 1

Note: Analysis of the mislocated bundle accident is performed for reload cores where the resultant CPR response may establish the operating limit MCPR.

1.	MCPR limit	1.24
2.	MCPR with misplaced bundle	1.13
3.	ΔCPR for event	0.11
4.	ΔLHGR limit, kW/ft	13.4
5.	LHGR with misplaced bundle, kW/ft	14.7
6.	LHGR for event, kW/ft	1.3

5. The Moody critical blowdown flow model is applicable, and flow is critical at the orifice[1].

The total integrated mass of fluid released into the reactor building via the break is 19,800 lb. Of this total, 7,583 lb flash to steam.

15.6.2.4.2 Containment Effects

The energy released by this coolant loss would cause the reactor building's siding pressure to be exceeded. No benefit from the secondary containment or the standby gas treatment system is to be assumed.

15.6.2.5 Radiological Consequences

15.6.2.5.1 Design Basis Analysis

While the NRC has developed a standard review plan for this event, a specific regulatory guide calculation method has not been issued to specify unique design basis assumptions. For this reason, only the realistic bases will be provided.

15.6.2.5.2 Realistic Analysis

The realistic analysis is based on a realistic, but still conservative, assessment of this accident. Specific values of parameters used in the evaluation are presented in Table 15.6-1.

Several Chapter 15 accident sections include both a design basis and a realistic basis analysis. The realistic basis analysis for such SAR sections is not updated beyond FSAR Amendment 28. However, because the only instrument line break analysis presented is a realistic analysis, it is and will continue to be updated as necessary.

Fission Product Release from Fuel

The iodine activity in the coolant is assumed to be at the maximum Technical Specification limit for continued operation. No iodine spike occurs because the reactor remains at normal temperature and pressure throughout the accident.

All of the iodine in the released coolant that flashes to steam becomes airborne and available for release to the environment. All other activity which may become airborne is negligible when compared to the iodine concentration. Table 15.6-2 lists the iodine activities before the accident.

Fission Product Release to the Environment

No credit is taken for operation of the SGTS, and an instantaneous, ground level release is assumed. Table 15.6-3 presents the activity released to the environment.

Results

The calculated exposures for the realistic analysis are presented in Table 15.6-4, and are a small fraction of the guidelines of 10CFR100. Control room doses for exposures for and beyond the 2-hr release duration are a small fraction of the GDC 19 limit.

15.6.3 Steam Generator Tube Failure

This section is not applicable to the direct-cycle BWR, but is a PWR-related event.

15.6.4 Steam System Piping Break Outside Containment

This event involves the postulation of a main steam line pipe break outside primary containment. It is assumed that the largest steam line instantaneously and circumferentially breaks at a location downstream of the outside isolation valve. The plant is designed to detect such an occurrence immediately, initiate isolation of the main steam lines, and actuate the necessary protective features. This postulated event represents the envelope evaluation of steam line failures outside primary containment.

The analysis of this event was initially performed at 3,467 MWt (104.3 percent of original rated power) and was not reanalyzed for rated 3,467 MWt operation. This event does not set reactor operating limits and is not reanalyzed for each reload cycle. However, the postaccident radiological consequences have been recalculated based on operation at 102 percent of the uprated power (3,536 MWt).

15.6.4.1 Identification of Causes and Frequency Classification

15.6.4.1.1 Causes

A main steam line break is postulated without the cause being identified. These lines are designed to high-quality engineering codes and standards, and to restrictive 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 primary containment are the result of postulated breaches in the RCPB or the steam power conversion

15.6.4.5.6 Results

Calculated exposures for this event are presented in Table 15.6-12. As noted, these values are a small fraction of 10CFR100.

15.6.5 Loss-of-Coolant Accidents (Resulting from Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary) Inside Primary 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 also assumed to be coincident with a safe shutdown earthquake (SSE). The occurrence of this event while SGTS is operating in the pressure control mode is also postulated.

The event has been analyzed quantitatively in Sections 6.2, 6.3, 7.1, 7.3, and 8.3. Therefore, the following discussion provides information not presented in the subject sections. All other information is covered by cross-referencing.

The postulated event represents the envelope evaluation for liquid or steam line failures inside containment.

The LOCA analysis was initially performed at 3,467 MWt (104.3 percent of original rated power and 105 percent steam flow). The full spectrum LOCA analysis was performed for operation at 102 percent of the uprated power (3,536 MWt) using the GE SAFER/GESTR-LOCA methodology.[13] The results of the analysis confirmed that all LOCA-ECCS performance requirements are met. The results, as stated in 15.6.5.3, are given in detail in Section 6.3. The postaccident radiological consequences have also been recalculated based on operation at 102 percent of the uprated power.

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 LOCA coincident with SSE plus SACF criteria requirements. The subject piping is designed to high quality and strict industry code and standard criteria and 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 Table 6.3-2 for core system performance, and Table 6.2-8 for barrier (containment) performance.

Following the pipe break and scram, the low-low water level signal initiates HPCS and RCIC systems, and high drywell pressure initiates HPCS system, at time 0, plus approximately 30 sec.

The low-low-low water level or high drywell pressure signal initiates both the low-pressure core spray (LPCS) and LPCI systems at time 0, plus approximately 40 sec, and low-low-low water level initiates MSIV closure at time 0.

Since automatic actuation and operation of the ECCS is a system design basis, no Operator actions are required for the accident.

15.6.5.2.2 Systems Operations

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. Possibilities for all pipe break sizes and locations are examined in Sections 6.2 and 6.3, including the severance of small process system lines, the main steam lines upstream of the flow restrictors, and the recirculation loop pipelines. 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 loop pipelines. The minimum required functions of any reactor and plant protection system are discussed in Sections 6.2, 6.3, 7.3, 7.6, and 8.3, and Appendix 15A.

15.6.5.2.3 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 failures are shown to be fully accommodated without the loss of any required safety function (see Appendix 15A for further details).

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 provide conservative assessment of the expected consequences of this very improbable event. The details of these calculations, their justification, and bases for the models are developed in Sections 6.3, 7.3, 7.6, 8.3, and Appendix 15A.

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 6.3-1.

15.6.5.3.3 Results

Results of this event are given in detail in Section 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. Postaccident tracking instrumentation and control is assured. Continued long-term core cooling is demonstrated. Radiological input is minimized and within limits. Continued Operator control and surveillance is examined and guaranteed.

15.6.5.3.4 Consideration of Uncertainties

This event was conservatively analyzed (see Sections 6.3, 7.3, 7.6, 8.3, and Appendix 15A for details).

15.6.5.4 Barrier Performance

The design basis for the containment is to maintain its integrity, and experience acceptable stresses after the instantaneous rupture of the largest single primary system piping within the structure, while also accommodating the dynamic effects of the pipe break at the same time a SSE is also occurring. Therefore, any postulated LOCA does not result in exceeding the containment design limit. For details and results of the analyses, see Sections 3.8, 3.9, and 6.2.

15.6.5.5 Radiological Consequences

Two separate radiological analyses are provided for this accident:

1. The first analysis applies the isentropic flow model (see Section 6.2.3.2) to the design basis analysis. The results are used in determining the adequacy of the plant design to meet 10CFR100 and 10CFR50 Appendix A, GDC 19 guidelines.

2. The second is based on assumptions considered to provide a realistic estimate of radiological consequences. This analysis is referred to as the realistic analysis.

15.6.5.5.1 Design Basis Analyses

The methods, assumptions, and conditions used to evaluate this accident are in accordance with those guidelines set forth in the NRC SRP 15.6.5, Revision 2, and RG 1.3 and 1.7. The containment leakage and TIP releases during the secondary containment drawdown or pressurization period are evaluated using a suppression pool decontamination or "scrubbing" factor. Use of the suppression pool as a fission product cleanup system is allowed by SRP 6.5.5, Rev. 0, which replaces Regulatory Position C.1.f of RG 1.3 which states, "No credit should be given for retention of iodine in the suppression pool." Specific values of parameters used in this evaluation are presented in Table 15.6-13. Compliance with the dose guidelines set forth in 10CFR100 and Appendix A to 10CFR50, GDC 19, takes credit for the capability of the control room Operators to select the less contaminated of the control room east and west air intakes, and isolate the more contaminated intake within the first 8 hr of the LOCA, as detailed in Technical Specification Amendment No. 67. Alternative lower MSIV leak rates may be applied as a means of eliminating the control room outside air intake operating restrictions as detailed in Technical Specification Amendment No. 67.

15.6.5.5.2 Fission Product Release from Fuel

It is assumed that the reactor is operating at a power level of 3,536 MWt for 1,000 days prior to the accident. The airborne source immediately available for release from primary containment contains 100 percent of the core noble gas inventory and 25 percent of the core halogen inventory. These release assumptions are applied to all transport pathways except the containment leakage and traversing in-core probe (TIP) leakage releases during the secondary containment drawdown period. For the drawdown period containment and TIP leakage releases, a suppression pool decontamination factor is included in determining the activity available for release from primary containment. The suppression pool source contains no noble gases and 50 percent of the core halogen inventory. While not specifically stated in RG 1.3 or SRP 15.6.5, the assumed release of 100 percent of the core noble gas activity and 50 percent of the halogen activity implies fuel damage approaching melt conditions. Even though this condition is inconsistent with operation of the ECCS system (Section 6.3), it is assumed applicable for the evaluation of this accident. The airborne activity available for release from the primary containment at T=0 hr post-LOCA is presented in Table 15.6-14.

15.6.5.5.3 Fission Product Transport to the Environment

The transport pathways consist of leakage from the primary containment to the environment through several different mechanisms. Where applicable, the SGTS filter efficiency for halogen removal is assessed as 99 percent. The mechanisms for leakage from the primary containment are discussed in the following paragraphs:

1. Containment leakage - The Technical Specification leak rate of the primary containment and its penetrations (excluding the bypass leakage paths) is 1.1 percent per

TABLE 15.6-13 (Cont'd.)

	Design Basis Assumptions		Realistic Basis Assumptions
b. Radwaste/reactor building vent[8]			
0-2 hr EAB	1.90-4		2.19-5
0-8 hr LPZ	1.78-5		6.48-6
8-24 hr LPZ	1.19-5		N/A
24-96 hr LPZ	4.93-6		N/A
96-720 hr LPZ	1.40-6		N/A
	East Intake	West Intake	
0-8 hr control room	2.05-4	1.90-4	2.13-4
8-24 hr control room	1.56-4	1.50-4	N/A
24-96 hr control room	5.19-5	5.32-5	N/A
96-720 hr control room	1.48-5	1.68-5	N/A
c. Main steam tunnel			
0-2 hr EAB	1.90-4		N/A
0-8 hr LPZ	1.78-5		N/A
8-24 hr LPZ	1.19-5		N/A
24-96 hr LPZ	4.93-6		N/A
96-720 hr LPZ	1.40-6		N/A
	East Intake	West Intake	
0-8 hr control room	1.29-3	7.62-4	N/A
8-24 hr control room	9.90-4	5.99-4	N/A
24-96 hr control room	3.37-4	2.14-4	N/A
96-720 hr control room	9.92-5	6.76-5	N/A
d. Radwaste tunnel (PASS area)			
0-2 hr EAB	1.90-4		N/A
0-8 hr LPZ	1.78-5		N/A
8-24 hr LPZ	1.19-5		N/A
24-96 hr LPZ	4.93-6		N/A
96-720 hr LPZ	1.40-6		N/A
	East Intake	West Intake	
0-8 hr control room	1.83-4	1.60-4	N/A
8-24 hr control room	1.41-4	1.21-4	N/A
24-96 hr control room	4.81-5	3.95-5	N/A
96-720 hr control room	1.42-5	1.10-5	N/A

15.7.3.1.1 Identification of Causes and Frequency Classification

Postulated events that could cause the release of the radioactive inventory of the CSTs are cracks in the vessels and Operator error.

The possibility of cracks and consequent low-level release rates receives primary consideration in system and component design, so the possibility of a failure is considered small.

A CST release caused by Operator error is also considered a remote possibility because operating techniques and administrative procedures emphasize detailed system and equipment operating instructions.

The probability of a complete rupture or malfunction accident is considered even lower than that for small cracks and Operator error. Although not analyzed for the requirements of Category I equipment, the CSTs are constructed in accordance with sound engineering principles. This accident is, therefore, expected to occur with the frequency of a limiting fault.

15.7.3.1.2 Sequence of Events and Systems Operation

1. Event begins; CSTs fail, and the contents are released into the condensate storage building.

2. Level alarms in the CSTs alert personnel.

3. Operator actions begin.

The rupture of the CSTs would leave little recourse to the Operator. No method of containing the discharge is available.

No credit for any Operator action has been taken in evaluating this event.

15.7.3.1.3 Core and System Performance

The failure of the CSTs does not directly affect the NSSS.

15.7.3.1.4 Barrier Performance

This event does not involve any containment barrier integrity.

15.7.3.1.5 Radiological Consequences

The radiological analysis provided for this accident is based on realistic conservative assumptions considered to be acceptable to the NRC for the purpose of determining adequacy of the plant design to meet 10CFR100 guidelines.

The analysis is based on SRP 15.7.3, Revision 2, although no specific regulatory guideline requirements are established.

Specific values of parameters used in the evaluation are presented in Table 15.7-6.

Several Chapter 15 accident sections include both a design basis and a realistic basis analysis. The realistic basis analysis for such SAR sections is not updated beyond FSAR Amendment 28. However, because the only CSTs rupture analysis presented is a realistic analysis, it is and will continue to be updated as necessary.

Fission Product Release

It is assumed that the CSTs contain the inventory of radioactive material presented in Table 15.7-7. This is consistent with an offgas release rate of 50,000 uCi/sec at 30-min decay. The CSTs are assumed to fail simultaneously, releasing the entire contents of both tanks to the CST building. (This is conservative with respect to the SRP 15.7.3 assumption that 80 percent of the tanks' liquid volume is released.) The spillage proceeds, as surface water, directly to Lake Ontario.

Fission Product Transport to the Environment

The travel time to the Oswego & Metropolitan Water Board Intake is 29.6 hr, and the dilution factor at this intake is 45.3. Table 15.7-8 presents the fixed concentrations at the water intake and the fraction of maximum permissible concentration (MPC).

15.7.4 Fuel Handling Accident

The analysis of this event was initially performed at 3,467 MWt (104.3 percent of originally rated power) and the design basis radiological consequences have been recalculated for 3,536 MWt (uprated power, 3,467 MWt + 2 percent for instrument error) power conditions. This event does not set reactor operating limits and is not reanalyzed for each reload cycle.

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 stored fuel bundles. A variety of events that qualify for the class of accidents has been investigated. The accident which produces the largest number of failed spent fuel rods is the drop of a spent fuel bundle onto the reactor core when the reactor vessel head is off.

15.7.4.1.2 Frequency Classification

This event has been categorized as a limiting fault.

and the number of failures in the impacted assemblies is:

$$N_F = \frac{2278\,ft\text{-}lb}{250\,ft\text{-}lb} = 9 \qquad (15.7\text{-}4)$$

Thus, during the second impact the fuel rod failures are as follows:

Struck assemblies	9 rods (compression)
	9 failed rods

Total Failures The total number of failed rods resulting from the accident is as follows:

First impact	95 rods
Second impact	9 rods
	104 total failed rods

15.7.4.3.4 Input Parameters and Initial Conditions for GE 9 (8x8 Array) and GE 11 (9x9 Array) Using GESTAR II, NEDE-24011-P-A-11-US, Methodology

An analysis for the GE 9 fuel using the parameters and initial conditions in Section 15.7.4.3.2, with the exception that the weights associated with the new design of the refueling mast with grapple head (NF-500 with total maximum wet weight of 619 lb) were used, resulted in 117 failed rods instead of 104 failed rods. Therefore, the design basis analysis using the specific values of parameters as presented in Table 15.7-9 is bounding.

GESTAR II, NEDE-24011-P-A-11-US, analyzed the GE 11 fuel that is currently used at Unit 2 using the same methodology as in the analysis of the GE 9 fuel, with the following changes to the input parameters and initial conditions:

1. A more conservative threshold value before cladding failure (200 ft-lb).

2. NF-500 refueling mast with grapple head.

3. A drop height of 34 ft.

4. The fraction of energy available for clad deformation 0.510.

This resulted in a total of 140 failed fuel rods.

15.7.4.4 Barrier Performance

The RCPB and primary containment are assumed to be open. The transport of fission products from the reactor building is discussed in Section 15.7.4.5.2.

15.7.4.5 Radiological Consequences

Two separate radiological analyses are provided for this accident:

1. The first, referred to as the design basis analysis, is based on conservative assumptions considered to be acceptable to the NRC for the purpose of determining adequacy of the plant design to meet 10CFR100 guidelines.

2. The second, referred to as the realistic analysis, is based on assumptions considered to provide a realistic conservative estimate of radiological consequences.

The fission product inventory in the fuel rods assumed to be damaged is based on 1,000 days of continuous operation at 3,489 MWt for the realistic analysis and 3,536 MWt for the design basis analysis. A 24-hr period for decay from the above power condition is assumed because it is not expected that fuel handling can begin within 24 hr following initiation of reactor shutdown.

15.7.4.5.1 Design Basis Analysis

The design basis analysis is based on SRP 15.7.4, Revision 1, and RG 1.25. Specific values of parameters used in the evaluation are presented in Table 15.7-9. The design basis parameters listed in Table 15.7-9, the activity released to the reactor building listed in Table 15.7-10, the activity released to the environment listed in Table 15.7-11, and the doses presented in Table 15.7-12 are based on a design basis accident with fuel assemblies in an 8x8 fuel rod array. The radiological consequences given in those tables bound the fuel handling accident in which 140 fuel rods of 9x9 fuel are damaged due to the fact that the activity in 140 fuel rods of 9x9 fuel is only 95 percent of activity which is in 124 fuel rods of 8x8 fuel.

Fission Product Release from Fuel

The fission product inventory of a core average rod is adjusted by a peaking factor of 1.5 to establish the inventory of each damaged rod. Ten percent of the noble gas inventory (30 percent for Kr-85) and 10 percent of the halogen inventory (12 percent for I-131) are assumed to be released to the fuel pool.

Fission Product Transport to the Environment

All of the noble gases and 1 percent of the halogen inventory released from the fuel and mixing in the fuel pool are assumed to migrate from the pool and become airborne in the reactor building. The activity released to the fuel pool is presented in Table 15.7-10. The transport pathway to the environment consists of an instantaneous release to secondary containment, mixing in a cylindrical volume above the reactor vessel, and exhaust from the cylindrical volume via four exhaust ducts above the vessel area. The release rate, based on the volumetric flow rate of the four exhaust ducts, is equivalent to 74 air changes during the 2-hr release period. Although the reactor building ventilation system would isolate on a high radiation signal, no credit for SGTS filtration/elevated release is taken. The activity released to the environment is presented in Table 15.7-11.

Results

The calculated exposures for the design basis analysis are presented in Table 15.7-12 and are a small fraction of the guidelines of 10CFR100. Control room doses for exposure for and beyond the 2-hr release duration are less than the GDC 19 limit.

15.7.4.5.2 Realistic Analysis

The realistic fuel handling accident analysis is provided to illustrate the conservatism of the design basis analysis. The realistic analysis is presented here as it appeared in Amendment 28 of the FSAR and will not be updated.

The realistic analysis is based on a realistic but still conservative assessment of this accident. Specific values of parameters used in the evaluation are presented in Table 15.7-9.

Fission Product Release from Fuel

Fission product release estimates for the fuel handling accident are based on the following assumptions:

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15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

15.8.1 Requirements

The issue of a postulated failure to scram the reactor following an anticipated transient, i.e., an ATWS, has been under consideration by the NRC. As a result of its assessment, the NRC has required additional plant modifications for the BWR in 10CFR50.62. The NRC has determined that the current risk from an ATWS event is acceptably small; therefore, any plant modifications would only be required for long-term resolution of the ATWS issue, and such modifications need not satisfy the requirements for a design basis event.

15.8.2 Plant Capabilities

The Unit 2 design uses diverse, redundant, and reliable scram systems which include the normal scram systems plus the electrically-diverse alternate rod insertion (ARI) system. Each of these systems is frequently tested and would insert the control rods even if multiple component failures should occur, thus making the probability of an ATWS event extremely remote.

The ATWS RPT feature prevents reactor vessel overpressure and possible short-term fuel damage for the most limiting postulated ATWS event. Subsequent to an ATWS event for which the ARI system fails to insert the control rods, the long-term shutdown of the reactor can be accomplished by either manual insertion of the control rods, or simultaneous two-pump injection of sodium pentaborate solution into the vessel.

Niagara Mohawk Power Corporation (NMPC) has incorporated in the Unit 2 plant the features described in Section 15.8.3. These features exceed the requirements of 10CFR50.62 and are consistent with the Alternate 3A features described in References 1 and 2 in Section 15.8.5.

For operation at power uprate conditions (3,467 MWt), the capability of the ATWS design features to mitigate the consequences of a postulated ATWS event has been confirmed. The limiting ATWS events were reanalyzed for uprated power conditions and with revised setpoints for pertinent functions. These analyses demonstrated that acceptable results are maintained for uprated power condition with the existing NMP2 design, as documented in References 6 and 7.

Adequacy of the ATWS design features has also been evaluated under applicable equipment OOS options. These case studies are documented in appendices as follows:

Appendix 15B	Recirculation System Single Loop Operation
Appendix 15C	Two Safety Relief Valves Out of Service

Appendix 15D One Main Steam Isolation Valve Out of Service

Appendix 15G Extended Load Line Limit Operation

15.8.3 Equipment Description

This section describes the equipment and control logic added or modified exclusively for ATWS prevention or mitigation. The description covers design and functional performance and provides references that contain more detailed information. The dynamic and environmental qualifications of the related equipment are described in Sections 3.9, 3.10, and 3.11.

15.8.3.1 Redundant Reactivity Control System

The redundant reactivity control system (RRCS) determines that a transient is underway that exceeds expected operating parameters and immediately activates ATWS prevention equipment. After deciding that a controlled shutdown is not occurring, the RRCS activates ATWS mitigation equipment. The RRCS uses transient detection sensors for high vessel dome pressure and low vessel water level to initiate ARI and RPT. The actuation logic also includes APRM neutron flux "not downscale" to initiate SLC injection and feedwater runback.

The RRCS consists of two completely redundant divisions. Each division is initiated automatically by the ATWS detection sensors, which are independent of the RPS sensors, or manually by switches that require the same type of Operator actions as manual scram.

Additional information on the RRCS is contained in Sections 7.1, 7.2, 7.4, 7.6, and 7.7.

15.8.3.2 Alternate Rod Injection

ARI is designed to provide a parallel path for actuation of the scram valves, which results in control rod insertion. ARI consists of the redundant valves on the scram valve pilot air headers that are actuated automatically by the RRCS logic or manually by the Operator in the main control room. The RRCS logic is designed so that successful ARI performance will avoid subsequent ATWS mitigation action (feedwater runback and SLCS initiation).

Additional information on the ARI system is contained in Sections 7.1 and 7.2.

15.8.3.3 Recirculation Pump Trip

The recirculation pump motors are tripped by the RRCS logic. The purpose of the RPT is to reduce core flow and create core voids to decrease power generation, thus limiting any power or pressure disturbance. The RPT function is single failureproof and is

15.8.5 References

1. Assessment of BWR Mitigation of ATWS. NUREG-0460 Alternate 3, Volume 4 (for comment). General Electric, 1979, NEDE-24222.

2. Design Analysis and SAR Inputs for ATWS Performance and Standby Liquid Control System. Nine Mile Point Unit 2 Plant, General Electric, 1982, NEDE-22013.

3. GE letter to NMPC, NMP2-6309, September 24, 1984.

4. GE letter to NMPC, NMP2-6769, April 26, 1985.

5. GE letter to NMPC, NMP2-6835, June 7, 1985.

6. Licensing Topical Report, Power Uprate Licensing Evaluation for Nine Mile Point Nuclear Power Station Unit 2, NEDC-31994P, Revision 1, May 1993.

7. Analysis of Anticipated Transients Without Scram at Uprated Power Conditions - Nine Mile Point 2, EAS-GENE-770-36-0492, April 1992.

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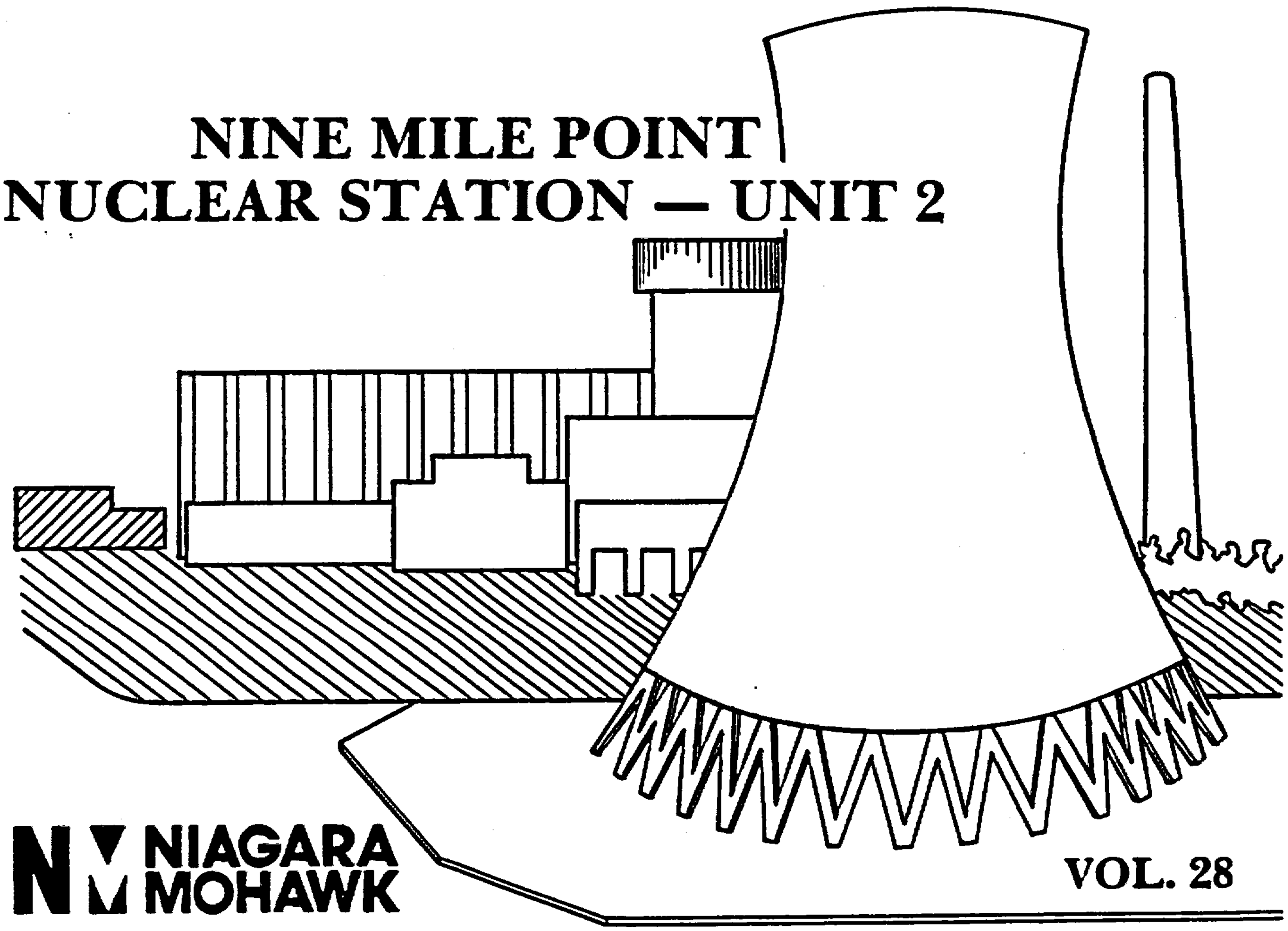
NINE MILE POINT NUCLEAR STATION — UNIT 2



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11. Rod worth control.

12. Primary containment and reactor building pressure and temperature control.

13. Spent fuel storage shielding, cooling, and reactivity control.

15A.6.3 Anticipated Operational Transients

15A.6.3.1 General

The safety requirements and protection sequences for anticipated operational transients are described in the following paragraphs for Events 7 through 29. The protection sequence block diagrams show the sequence of front-line safety-related systems (Figures 15A-13 through 15A-36). The auxiliaries for the safety-related systems are indicated in the auxiliary diagrams (Figures 15A-7 and 15A-8).

15A.6.3.2 Required Safety Actions/Related Unacceptable Consequences

The following list relates the safety actions for anticipated operational transients to mitigate or prevent the unacceptable safety consequences. Refer to Table 15A-7 for the unacceptable consequences criteria.

Safety Action	Criteria	Reason Action Required
Scram and/or recirculation pump trip (RPT)	2-2 2-3	To prevent fuel damage and to limit RPV system pressure rise.
Pressure relief	2-3	To prevent excessive RPV system pressure rise.
Core and primary containment cooling	2-1 2-2 2-4	To prevent fuel and primary containment damage in the event that normal cooling is interrupted.
Reactor vessel isolation	2-2	To prevent fuel damage by reducing the outflow of steam and water from the reactor vessel, thereby limiting the decrease in reactor vessel water level.
Restore ac power	2-2	To prevent fuel damage by restoring ac power to systems essential to other safety actions.

Safety Action	Criteria	Reason Action Required
Prohibit normal rod movement	2-2	To prevent exceeding fuel limits during transients.
Primary containment isolation	2-1 2-4	To minimize radiological effects.

15A.6.3.3 Event Definitions and Operational Safety Evaluations

Event 7 - Manual and Inadvertent Scram

The deliberate manual or inadvertent automatic scram due to SOE is an event that can occur under any operating condition. Although assumed to occur here for analysis purpose, multi-Operator error or action is necessary to initiate such an event.

While all the safety criteria apply, no unique safety actions are required to control the planned operation-like event after effects of the subject initiation actions. In all operating states, the safety criteria are, therefore, met through the basic design of the plant systems. Figure 15A-13 identifies the protection sequences for this event.

Event 8 - Loss of Plant Instrument or Service Air System

Loss of all plant instrument or service air system causes reactor shutdown and the closure of all isolation valves except MSIVs. After partial insertion of control rods in State D, the MSIVs would close on low pressure causing actuation of the reactor protection system (RPS). Although these actions occur, they are not required to prevent unacceptable consequences in themselves. Multi-equipment failures would be necessary in order to cause the deterioration of the subject system to the point that the components supplied with instrument or service air would cease to operate normally and/or fail-safe. The results are less severe than those of Event 14 described later.

Isolation of the main steam lines can result in a transient for which some degree of protection is required only in operating States C and D. In operating States A and B, the main steam lines are continuously isolated.

Isolation of all main steam lines in operating State D during power operation is the most severe and rapid transient.

Figures 15A-14, 15A-20, and 15A-21 show how scram is accomplished by loss of air and/or main steam isolation through the actions of the RPS and the CRD system. The nuclear system pressure relief system provides pressure relief. Pressure relief, combined with loss of feedwater flow, causes reactor vessel water level to fall. The high-pressure core cooling systems supply water to

TABLE 15A-5

SPECIAL EVENTS

NSOA Event No.	Event Description	NSOA Event Figure No.	FSAR Section No.	BWR Operating State			
				A	B	C	D
50	Shipping cask drop	15A-50	15.7.5	X	X	X	X
51	Reactor shutdown from ATWS	15A-51	15.8	X	X	X	X
52	Reactor shutdown from outside main control room	15A-52	7.5	X	X	X	X
53	Reactor shutdown without control rods	15A-53	9.3.5		X		X

15B.4 STABILITY ANALYSIS

15B.4.1 Phenomena

The primary contributing factors to the stability performance with one recirculation loop not in service are the power/flow ratio and the recirculation loop characteristics. At forced circulation with only one recirculation loop in operation, the reactor core stability is influenced by the inactive recirculation loop. As core flow increases in SLO, the inactive jet pump forward flow decreases because the driving head across the inactive jet pumps decreases with increasing core flow. The reduced flow in the inactive loop reduces the resistance that the recirculation loops impose on reactor core flow perturbations thereby adding a destabilizing effect. At the same time, the increased core flow results in a lower power/flow ratio which is a stabilizing effect. These two countering effects result in slightly decreased stability margin (higher decay ratio) initially as core flow is increased (from minimum) in SLO, and then an increase in stability margin (lower decay ratio) as core flow is increased further and reverse flow in the inactive loop is established.

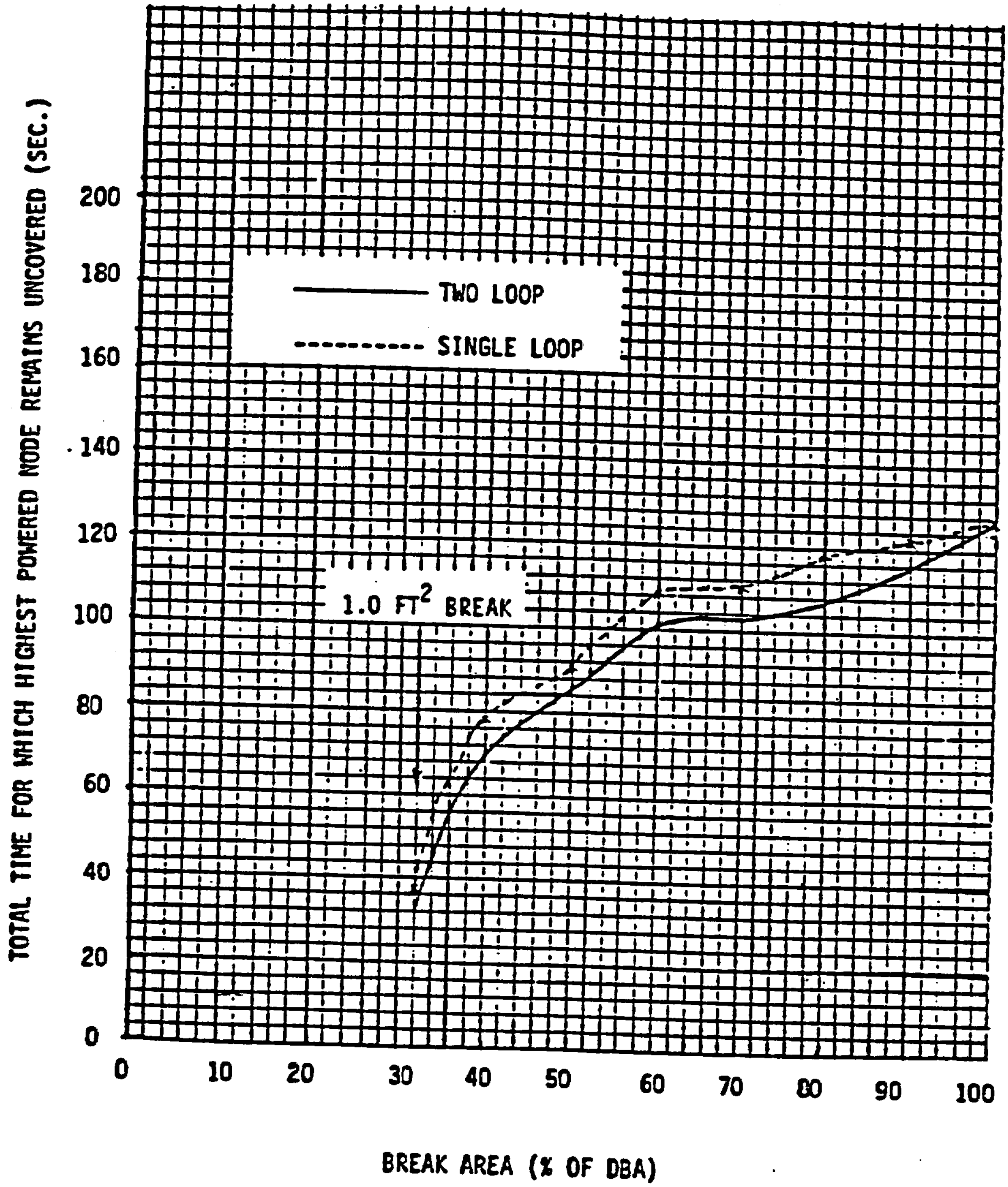
As core flow is increased further during SLO and substantial reverse flow is established in the inactive loop, an increase in jet pump flow, core flow and neutron noise is observed. A cross flow is established in the annular downcomer region near the jet pump suction entrance caused by the reverse flow of the inactive recirculation loop. This cross flow interacts with the jet pump suction flow of the active recirculation loop and increases the jet pump flow noise. This effect increases the total core flow noise which tends to drive the neutron flux noise.

To determine if the increased noise is being caused by reduced stability margin as SLO core flow was increased, an evaluation was performed which phenomenologically accounts for SLO effects on stability, as summarized in Reference 15B.8-4. The model predictions were initially compared with test data and showed very good agreement for both two-loop and single-loop test conditions. An evaluation was performed to determine the effect of reverse flow on stability during SLO. With increasing reverse flow, SLO exhibited slightly lower decay ratios than two-loop operation. However, at core flow conditions with no reverse flow, SLO was slightly less stable. This is consistent with observed behavior in stability tests at operating BWRs (Reference 15B.8-5).

In addition to the above analyses, the cross flow established during reverse flow conditions was simulated analytically and shown to cause an increase in the individual and total jet pump flow noise, which is consistent with test data (Reference 15B.8-4). The results of these analyses and tests indicate that the stability characteristics are not significantly different from two-loop operation. At low core flow, SLO may be slightly less stable than two-loop operation but as core flow is increased and reverse flow is established the stability performance is similar. At even higher core flow with substantial reverse flow in the inactive recirculation loop, the effect of cross flow on the flow noise results in an increase in system noise (jet pump, core flow and neutron flux noise).

15B.4.2 Compliance to Stability Criteria

Cycle-specific evaluation is covered in Appendix A, Section A.4.4.4.



NOTE: THIS FIGURE IS FROM ORIGINAL LOCA SLO ANALYSIS. SEE REFERENCES 15B.8-12 AND 13 FOR SAFER/GESTR RESULTS FOR LIMITING BREAK.

Niagara Mohawk Power Corp.	Uncovered Time vs. Break Area-Suction Break, LPCS Diesel Generator Failure	Figure 15.B.5-1

15B.8 REFERENCES

15B.8-1 "General Electric BWR Thermal Analysis Basis (GETAB); Data, Correlation, and Design Application," NEDO-10958-A, January 1977.

15B.8-2 "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," NEDO-24154, October 1978.

15B.8-3 R. B. Linford, "Analytical Methods of Plant Transients Evaluation for the General Electric Boiling Water Reactor," NEDO-10802, April 1973.

15B.8-4 Letter, H. C. Pfefferlen (GE) to C. O. Thomas (NRC), "Submittal of Response to Stability Action Item from NRC Concerning Single-Loop Operation," September 1983.

15B.8-5 S. F. Chen and R. O. Niemi, "Vermont Yankee Cycle 8 Stability and Recirculation Pump Trip Test Report," General Electric Company, August 1982 (NEDE-25445, Proprietary Information).

15B.8-6 Deleted.

15B.8-7 Deleted.

15B.8-8 Deleted.

15B.8-9 Deleted.

15B.8-10 "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K, Vol. III, Appendix A - One Recirculation Loop Out-of-Service," NEDO-20566-P-A, September 1986.

15B.8-11 GESTAR II, General Electric Standard Application for Reload Fuel, NEDE-24011-P-A-10-US, March 1991.

15B.8-12 Nine Mile Point Nuclear Power Station Unit 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, NEDC-31830P Rev. 1, November 1990.

15B.8-13 General Electric Company Report, Supplemental Reload Licensing Report for Nine Mile Point - Unit 2, Reload 3 Cycle 4, 23A7228 Rev. 1, November 1993.

15B.8-14 Licensing Topical Report, Power Uprate Licensing Evaluation for Nine Mile Point Nuclear Power Station Unit 2, NEDC-31994P, Revision 1, May 1993.

APPENDIX 15C

TWO SAFETY/RELIEF VALVES OUT OF SERVICE

15C.1 INTRODUCTION

Cycle-specific information is covered in Appendix A, Section A.15.

The current Technical Specification 3/4 4.2 requirement is that 16 of the total 18 safety/relief valves (SRVs) must be OPERABLE and, with one or more of the 16 SRVs inoperable, the action is to be in at least HOT SHUTDOWN within 12 hr and in COLD SHUTDOWN in the next 24 hr.

For the 7 SRVs which are part of the automatic depressurization system (ADS), Technical Specification 3/4 5.1, the requirement is, with up to two valves inoperable, restore the valve(s) to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within 12 hr and reduce reactor steam dome pressure to less than or equal to 100 psig within the next 24 hr.

This report contains technical justification to allow for extended plant operation with up to two SRVs out of service (OOS).

To justify extended plant operation with up to two SRVs OOS, a broad-based analysis of plant operating conditions is required. These analyses include the consideration of two SRVs OOS. The most limiting transient and overpressure protection events are evaluated with two SRVs OOS. This report covers the following areas:

1. Overpressure protection transient analysis,
2. Normal plant transient analysis, including operating critical power ratio (CPR) limit,
3. Anticipated transient without scram (ATWS) evaluation, and
4. Loss-of-coolant accident (LOCA) analysis.

15C.2 SUMMARY AND CONCLUSION

Based on the analyses described herein and in the reload analysis (Appendix A), it is concluded that extended plant operation at full power with up to two SRVs OOS meets all licensing requirements and, therefore, is acceptable for Nine Mile Point Nuclear Station - Unit 2 (Unit 2).

15C.3 OVERPRESSURE PROTECTION TRANSIENT ANALYSIS

Cycle-specific reload analyses are discussed in Appendix A, Section A.5.

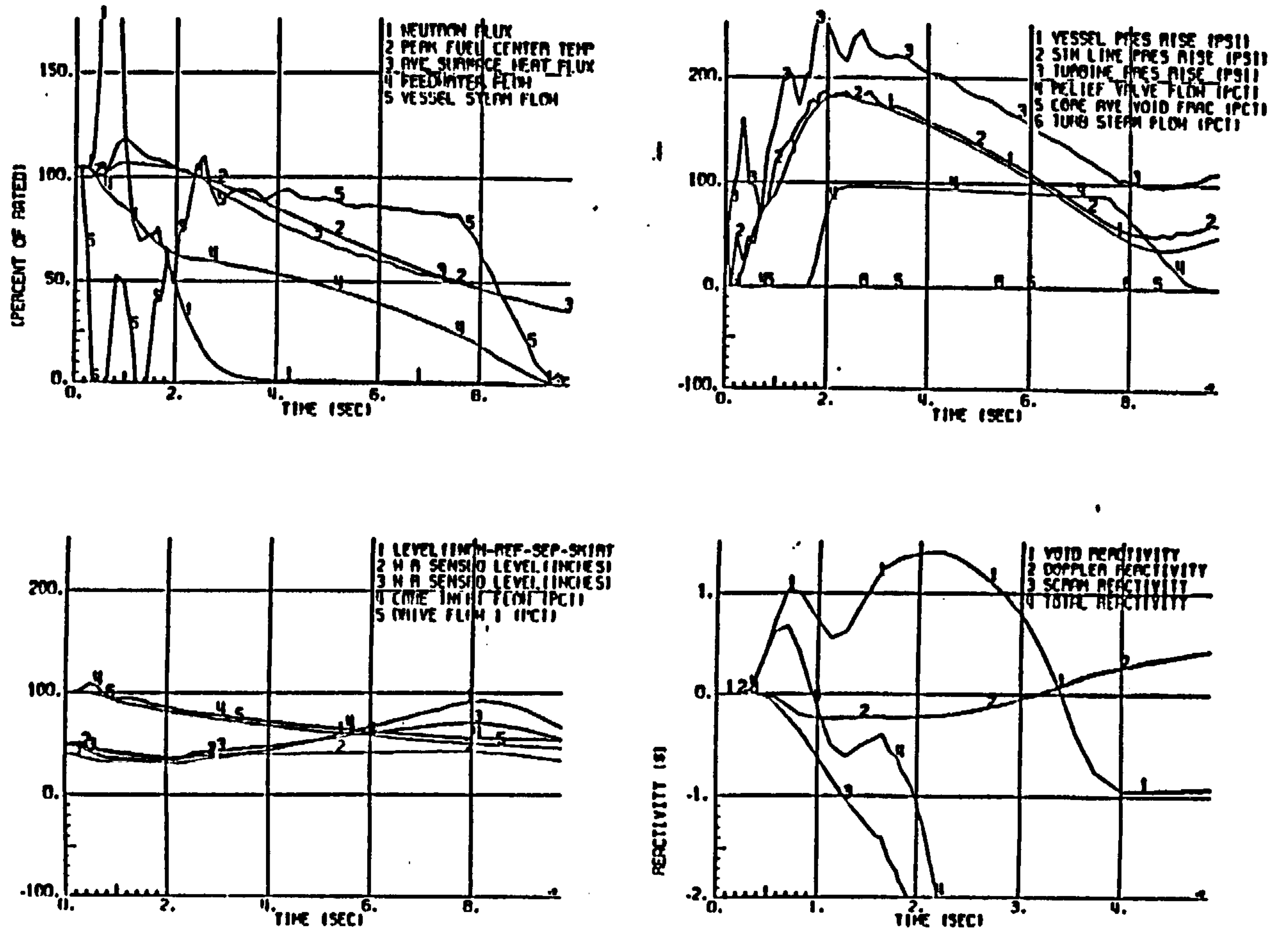
In order to confirm that the remaining operating SRVs can maintain the vessel pressure below the ASME Code allowable limit of 1375 psig, an analysis of the most limiting overpressure transient (i.e., 3-sec closure of all main steam line isolation valves and neglecting the direct scram) is performed. The results are summarized on Figure 15C-1. Figure 15C-1 shows the peak vessel bottom pressure as a function of number of operating SRVs. It shows the peak vessel pressure with 2 of the 18 SRVs temporarily out of service is well below the ASME Code limit. Therefore, it is acceptable to operate the plant with 2 SRVs out of service at full power from the consideration of overpressure protection.

15C.4 NORMAL PLANT TRANSIENT ANALYSIS

Cycle-specific reload analyses are discussed in Appendix A, Section A.15.

In order to determine if there is any impact on the operating CPR limit due to two SRVs out of service, an assessment of the limiting transients performed for the Final Safety Analysis Report (FSAR) (Reference 1) was made. In all cases minimum critical power ratio (MCPR) occurs well before the first SRV opens. Therefore, up to two SRVs out of service will have no impact on the operating CPR limit. The only impact of two SRVs out of service on transient responses is peak pressures. However, these peak pressures are bounded by the case discussed in Section 15C.3 for ASME overpressure protection. The most limiting transient (i.e., load rejection with bypass valve failure) was reanalyzed with two SRVs out of service (see Figure 15C-9). This analysis confirms the above conclusion that the MCPR during this transient is not impacted by two SRVs out of service. The peak pressures for the case with two SRVs out of service are only about 4 psi higher than those with no SRV out of service, while the peak neutron flux, peak heat flux and MCPR are identical for both cases. Therefore, it is acceptable from the transient performance standpoint that the plant is operating at full power with 2 SRVs out of service.

The SRV operation has no significant effect on reactor core isolation cooling (RCIC) flow because it is a flow-sensing/flow-controlling system and the reactor pressure at the time of RCIC operation is not changed significantly by any two SRVs out of service. It has no effect on high-pressure core spray (HPCS) flow during operational events because of the unchanged reactor pressure when HPCS is needed. A small effect is seen in LOCA evaluations if the two out-of-service valves are ADS valves. This effect is considered in the analysis discussed in Section 15C.6.



NOTE: Cycle-specific information is presented in Appendix A

FIGURE 15C-9

GENERATOR LOAD REJECTION WITH BYPASS FAILURE AND 2 SRV OUT-OF-SERVICE

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measures in this guideline are the verification of major steps and the independent QA check between the control rod insertion with bypass removed and the actual fuel loading. The entire reload is performed in batches, with the batch size equal to the number of available double blade guides. These guidelines are also applicable to initial core loading, with several exceptions. The unique features of an initial core loading are described in Section 15E.3.4.

After the refueling platform operation prerequisite checks, the control room Operator checks the operability of the SRMs, using a special movable neutron source, and verifies the use of the same worksheet with the bridge Operator. The next several steps involve the operation on one control cell, namely the installation of a double blade guide in this cell, the bypass removal of the rod position input to the refueling interlock, the activation of the HCU system for the control rod, control rod coupling check and, finally, the insertion of the control rod to the full-in position, followed by refueling interlock functional check. The guideline to perform bypass removal of individual rod position inputs is provided as a separate guideline (Section 15E.3.3.1). After the completion of these steps on one control rod, the same operation is repeated for the remaining control cells in the batch. After the above operations are completed for the whole batch, an independent QA check is performed to verify that within this batch all rod position refueling interlock bypasses are removed and all control rods are fully inserted. Fuel assemblies are then loaded into control cells of this batch, with the double blade guides moved to cell locations of the next batch as the fuel assemblies are loaded. This completes the reload procedure for one batch. Finally, the same reload procedure is repeated for the loading of the next batch, until the entire core is loaded.

The same number of operation staff members are required in the reload operation as in the offload operation. In the control room, both control room Operators will serve as verifiers. On the refueling bridge, there are the bridge Operator, the SRO, and the bridge checker, the latter two serving as verifiers. The staffing requirements at HCU station and refueling interlock bypass panel are the same as in the offload operation. An independent QA checker is to be designated to perform all the QA checks required by this guideline.

Similar to the offload guideline, the batch size can be any number from 2 to 15, depending on the total number of available double blade guides. As determined by the probability analysis to be discussed later, the above identified batch size range will not significantly affect the probability of creating inadvertent criticality events.

Instead of loading initially from the geometrical center of the core, the loading starts at a location near a SRM. By doing so, a SRM can be brought on scale as early as possible in the reload operation to continuously monitor the fueled region. Throughout the entire reload operation, there is at least one SRM which is continuously monitoring the fueled region (except for the loading of the first 4 bundles), with at least one additional SRM operable.

15E.3.3 Refueling Interlock Logic Bypass Guidelines

15E.3.3.1 Individual Rod Position Bypass Guideline

The individual rod position bypass procedure should provide step-by-step instructions for the bypass or bypass removal of the individual rod position input signals to the refuel interlock logic during core offload or reload operations. During offload operation, since all control rods are to be withdrawn, it is necessary to bypass the individual rod position input to the refueling interlock logic to bypass the "one-rod-out" rod block logic. The refueling interlock logic from all other control rods, however, shall remain in effect to prevent any erroneous rod withdrawals. During reload operation, the bypass of the rod position input must be removed before a control rod is fully inserted such that full position indication of the rod is available. This guideline is to be used in conjunction with the core offload or reload procedure guidelines.

The bypass of the rod position input to the refueling interlocks is to be performed during core offload operations. This guideline is called upon at the designated step in the core offload guideline. Before the bypassing, the control room Operator must verify that the control rod is fully withdrawn. As soon as the rod position inputs are temporarily disconnected from the bypassing panel, the control room Operator must verify a loss of indication on the four-rod display panel. The bypass is then performed by shorting the two pins which will simulate a "Full-In" position signal to the refueling interlock logic. The control room Operator then verifies that the light indication on the rod display panel has changed to a "Full-In" green. This light is then tagged to remind the control room Operator of the bypassing. A second control room Operator then verifies this step.

During core reload, the bypass of the rod position input to the refueling interlock logic is to be removed prior to the insertion of a control rod. This guideline is called upon at the designated step in the core reload guideline. The control room Operator first verifies that the correct rod is selected. He then removes the bypass tag and verifies the "Full-In" green light is displayed. The instrumentation Technician then removes the bypass from the designated connector. During and after the removal of the bypass from the two pins, the appropriate light indications are verified. The "Full-Out" red light shall be on after the bypass removal. A second control room Operator then verifies these steps. For both bypass and bypass removal operations, the control room Operator and shift supervisor shall

15G.3 VESSEL OVERPRESSURE PROTECTION ANALYSIS

Cycle-specific reload analyses are discussed in Appendix A, Section A.5.

For the ELLLA region operation, compliance with the ASME Code is demonstrated by analysis of the most limiting overpressure transient, a main steam isolation valve (MSIV) closure transient with a failure of the MSIV direct scram from the MSIV position switches. The transient is initiated by a simultaneous closure of all MSIVs. The assumed closure time for the valves is 3 sec. The trip of the APRM high neutron flux setpoint generates a reactor scram. The input parameters are listed in Table 15G-1. The results are summarized on Figure 15G-6 and in Table 15G-9. The peak vessel pressure for the ELLLA case is below the ASME Code limit for upset conditions, 1375 psig, and is bounded by the licensing basis overpressure analysis in Section 5.2.2.2.

The sequence of events for the ELLLA MSIV closure is shown in Table 15G-10. The event starts as the MSIVs close generating a pressure wave in the steam line that is quickly transmitted to the reactor vessel. The neutron flux increases rapidly, which results in a reactor scram, because of the void collapse resulting from the vessel pressure increase. The pressure increase is large enough to trip the ATWS RPT setpoint. As the pressure increase continues the safety relief valves (SRVs) open directing the steam to the suppression pool.

15G.4 STABILITY ANALYSIS

Cycle-specific evaluation is covered in Appendix A, Section A.4.4.4.

15G.5 EMERGENCY CORE COOLING SYSTEM PERFORMANCE

Cycle-specific reload analysis is discussed in Appendix A, Section A.6.

For 251-in diameter BWR/5 plants like Unit 2, the effect of low initial core flow on ECCS performance was found to be small. These plants reflood rapidly following a postulated break and have relatively large peak clad temperature (PCT) margins to the 2200°F limit.

The ECCS responses to loss-of-coolant accident (LOCA) at 102P, 100F, and 102P, 87F, are very similar for a BWR/5-251 plant. A LOCA starting at 87-percent core flow produces a slightly earlier (less than 0.1 sec) loss of nucleate boiling in the top part of the limiting fuel bundle. However, it does not affect the dryout time of the high-power node where the maximum PCT occurs. The reduced initial core flow also has little impact on the reflood phase following a LOCA. This period is dominated by the effect of "countercurrent flow limiting" at the top of the fuel bundles. Since both cases being considered have the same core power, the steam generation rate in the core and the liquid downflow rate through the fuel bundles will be similar for both cases. Thus, the effect of reduced initial core flow on the reflooding time is negligible.

In summary, the licensing basis ECCS-LOCA analysis in Section 6.3.3 is applicable to and bounds the plant operation in the ELLLA region. The maximum average planar linear heat generation rate (MAPLHGR) or PCTs calculated in this analysis remain applicable to the ELLLA region.

15G.6 CONTAINMENT SYSTEM RESPONSE

The analyses and evaluations described in this section were performed based on the original rated core thermal power of 3,323 MWt. The conclusions stated below continue to apply for rated 3,467 MWt operating conditions (see Reference 12).

The containment system response to a LOCA was evaluated for the effect of plant operation in the ELLLA region. The initial break flow is directly related to the reactor coolant subcooling. The increased subcooling during ELLLA operation can affect the containment thermal-hydraulic response and the containment dynamic loads following a LOCA.

The containment system response can be characterized by the following major parameters:

1. Containment pressure

2. Containment temperature

3. Drywell bypass leakage

15G.8 REFERENCES

1. General Electric Company, Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors, NEDO-24154A, August 1986.

2. General Electric Company, as amended General Electric Standard Application for Reactor Fuel (Supplement for United States), NEDE-24011-P-A-8-US, May 1986.

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7. P. F. Bird, et al, 4T Condensation Oscillation Test Program Final Report, General Electric Proprietary Report NEDE-24881-P, May 1980.

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9. G. A. Watford and G. Orr, Design Analysis and SAR Inputs for ATWS Performance and Standby Liquid Control System (Nine Mile Point 2 Plant), NEDE-22013, General Electric Company, June 1982.

10. General Electric Company, Class III, Assessment of BWR Mitigation of ATWS, Vol. I (May 1979) and Vol. II, NEDE-24222, December 1979.

11. Deleted.

12. Licensing Topical Report, Power Uprate Licensing Evaluation for Nine Mile Point Nuclear Power Station Unit 2, NEDC-31994P, Revision 1, May 1993.

design bases, control requirements, QA requirements, specifications, and drawings. Technical content of procurement documents is reviewed by appropriate NMPC personnel or their designated representative in accordance with appropriate procedures.

QA provisions in procurement documents for safety-related materials and services are to be reviewed for adequacy by the QA Department of NMPC or their designated representative, in accordance with prescribed procedures.

Any change to procurement documents will be reviewed in the same manner as the original document.

17.1.4.2 Contractors and Subcontractors

Procurement documents for safety-related materials and services shall require contractors and their subcontractors to provide appropriate QA programs and procedures to the extent necessary to comply with NMPC QA policies and Appendix B to 10CFR50. The contractor/subcontractor QA programs must be presented to and accepted by NMPC prior to material release in the case of manufactured items or start of work in the case of a service contract. Items/services will be procured only from qualified vendors. NMPC or their designated representative will qualify vendors in accordance with applicable regulatory requirements, codes, standards, and procedures.

All procurement documents will impose upon the principal contractors the responsibility to ensure that their subcontractors provide, to the extent necessary, QA tests, documentation, and access to their facilities by NMPC or their designated agents.

17.1.4.3 Review

The NMPC QA Department or a designated representative is responsible for assuring that reviews of procurement documents are performed properly.

17.1.5 Instructions, Procedures, and Drawings

17.1.5.1 General

The intent of this section is to assure that quality-related activities are prescribed by documented instructions, procedures, and drawings and are accomplished in accordance with these instructions, procedures, and drawings.

17.1.5.2 Quality Activities

The NMPC QA Department or their designated representative will verify that appropriate QA measures exist and are implemented in all quality-related activities. Quality measures include, but are not limited to, instructions, procedures, and drawings.

The NMPC design office, operations group, or designated representative, as applicable, is responsible for establishing appropriate quantitative and/or qualitative acceptance criteria for determining that quality-related activities are satisfactorily accomplished. In the case of equipment and components, these criteria are made a part of the design documents for procurement and/or installation of each piece of equipment, component, or order of material. In the case of operations, these criteria are set forth in the applicable operations and maintenance procedures.

The description of compliance to the requirements of 10CFR50.55a is described in various FSAR sections (such as conformance to ASME Section XI, described in FSAR Section 6). Procedures will be developed to address the implementation of plant modifications to ensure continuing conformance to 10CFR50.55a and QA procedures to assure conformance.

The description of compliance to regulatory guides is described in Section 1.8. Procedures will be developed to address the implementation of the regulatory guides listed in Table 17.0-1 and QA procedures to ensure conformance.

QA Department procedures for the preparation, review, and control of procedures requires that reviews be performed on a scheduled basis. All changes or revisions are reviewed, approved, and controlled in the same manner as the original procedure. The reviews are performed by the Corporate QA Section with input provided by the affected QAD sections. QA Department procedures are approved by the Vice President Quality Assurance and may be concurred with by other NMPC organizations whose responsibilities are affected by the QA procedure.

Assurance that similar procedures are established and implemented in other departments is obtained by audit and surveillance by the QA Department.

The QA Department reviews all engineering and site administrative procedures for QA-related aspects. Concurrence by the Quality Assurance Manager is required before implementation. Concurrence is indicated by signature and date on the title page of the procedure.

17.1.5.2.1 Document Procedures

Procedures for directing quality-related activities will be prepared to comply with each of the 18 criteria within 10CFR50 Appendix B.

QA procedures/instructions delineate the QA responsibilities for review of the calibration programs by monitoring, surveillance, and audit.

QA procedures/instructions will delineate the QA Department's own calibration control program.

17.1.12.1 Requirements of Control Program

Procedures are established for Unit 2 that provide for the following, as a minimum:

1. Positive identification of all M&TE. This includes measuring and test instruments, tools, gauges, fixtures, reference standards, transfer standards, and NDE equipment used in the measurement, inspection, and monitoring of safety-related components, systems, and structures.

2. Description of the calibration technique used for each type of equipment.

3. Establishment of frequency of calibration intervals for each type of measuring equipment consistent with the required accuracy, purpose, degree of usage, stability characteristics, and other conditions affecting the measurement.

4. Positive means to prevent the use of measuring or test equipment by inspection or production personnel unless it has been calibrated and properly adjusted in accordance with the approved procedure for that type of equipment.

5. Procedures to evaluate or recall and re-inspect material inspected during the period the test equipment was used preceding the calibration test which found test equipment to be out of calibration.

6. The use of recognized calibrating equipment whose calibration is traceable to the National Institute of Standards and Technology (NIST) or other recognized national standard group where such standards exist. System standards laboratory procedures require that calibrating standards have an accuracy greater than M&TE being calibrated. Provisions assure that calibration of M&TE be against standards that have an accuracy of at least four times the required accuracy of the equipment being calibrated or, when this is not possible, have an accuracy that assures the equipment being calibrated will be within required tolerance and that the basis of acceptance is documented and authorized by responsible management. The minimum ratio of accuracy from M&TE to plant equipment shall be

equal to or greater than 1 to 1, or the basis of acceptance will be documented and authorized by responsible management. The management authorized to perform this function is identified.

7. Determination of the allowable inaccuracies using the reference standards.

8. Establishment and maintenance of calibration records to provide objective evidence that all M&TE is being calibrated and maintained in accordance with approved procedures. These records are to provide traceability to the calibration data for each identified piece of testing and measuring equipment.

17.1.12.2 Tagging

Site administrative procedures provide the method of tagging or labeling of measuring or test equipment. Procedures require that each primary test device or portable measuring device will be identified by serial number, nameplate data, or individualized permanent tagging and will be incorporated in a log. In addition, each of these devices will bear a label denoting the latest calibration date, initials of calibrator, and date of next scheduled calibration.

The procedures also require that any test device which has exceeded its calibration tenure, or which displays erratic or inaccurate behavior, or which has been mishandled in any way will be removed from normal use and controlled via a hold tag attached to the device. The instrument must be recalibrated before this tag may be removed.

A method that represents "otherwise controlled" could be where, because of the nature of the instrument, calibration could occur just prior to use. In this case, the instrument would be evaluated, logged in the Use Record Log, and then used in the shop or field, returned to the controlled storage area, and logged in at time of use completion. This would be done for each use of the instrument.

17.1.12.3 Records

Records are to be established for each inspection device required in the conduct of acceptance and performance inspections. These records are to be available to provide confirmation of a current and valid calibration check, and the past history of any testing or measuring device when called for by a qualified worker, an inspector, or an auditor. These records are to contain the dates of each calibration check, a reference to the procedure used, and the signature of the responsible person performing the check.

CHAPTER 18

HUMAN FACTORS ENGINEERING/SAFETY PARAMETER DISPLAY SYSTEM

18.1 DETAILED CONTROL ROOM DESIGN REVIEW

Niagara Mohawk Power Corporation (NMPC) initiated a control room review program for the Nine Mile Point Nuclear Station - Unit 2 (Unit 2) in response to NUREG-0737, Supplement 1, and earlier guidance, which requires that all licensees and applicants for operating licenses (OL) conduct a detailed control room design review (DCRDR) to identify and correct design deficiencies. NUREG-0700, "Guidelines for Control Room Design Review," issued in September 1981, provides human engineering guidelines to assist each licensee and applicant in performing a detailed control room review. The NMPC program emphasizes determination of the adequacy of information available to the Operator to effectively mitigate emergency conditions. The review program is also designed to correct human factors problems and to improve controls and displays determined to be discrepant from good human factors practices. The DCRDR process, as suggested by NUREG-0700, is divided into four major activities: planning, review, assessment and implementation, and reporting. The human engineering processes developed to address the DCRDR requirements are described in Sections 18.1.1 through 18.1.3.

18.1.1 Reporting Requirements for the DCRDR

NUREG-0737, Supplement 1, requires the submittal of a program plan containing the following major elements: 1) a qualified multidisciplinary review team; 2) use of function and task analysis; 3) control room inventory comparison; 4) control room survey; 5) human engineering observation (HEO) assessment; and 6) verification of design improvements.

The program plan, which describes how each of the requirements listed above would be (or had been) accomplished, was submitted to the Nuclear Regulatory Commission (NRC) in June 1984.

18.1.2 Summary of Supplement 1 Human Factors Activities to be Performed

The adequacy of the control room was reviewed to determine whether it could provide the system status information, control capabilities, feedback and performance aids necessary for personnel to accomplish their functions and tasks effectively. In addition, characteristics outside the scope of the NRC's DCRDR requirements for the existing control room instrumentation, controls, other equipment and physical arrangements were identified that either add to or detract from Operator performance. The details of the review are included in the DCRDR Final Summary Program Implementation Report which was submitted to the NRC by letter NMP2L-0488 dated September 16, 1985. Six review processes were used to analyze the man/machine interface within the control room: 1) operating experience review (historical document review and Operator survey); 2) system review, function review and task analysis; 3) control room inventory; 4) control room checklist supplement; 5) verification of task performance capabilities; and 6) validation of control room functions.

The first three are foundation processes in which frames of reference and benchmarks for discrepancy identification were established. The last three are investigative processes in which the benchmarks were applied and HEOs identified. Activities performed during these two groups of processes are explained below.

18.1.2.1 Foundation Processes

Industry-wide reviews of Licensee Event Reports (LERs) for similarly designed General Electric-5 (GE-5) plants were analyzed. Since these reports have generic applicability, they were used to identify conditions which affect the probability for Operator error and the safe operation of the generating Station. In addition, operating personnel completed questionnaires and were interviewed to obtain feedback based on previous operating experience.

A control room inventory was conducted on a system-by-system basis to identify all instrumentation, controls, and equipment within the control room. This information was compared to the requirements identified through the analysis of Operator tasks.

A systems review and function allocation review was conducted. Operator task lists were prepared and used during the task analysis and validation of the control room capabilities. These analyses established the information flow and control requirements between the Operator and the control boards.

18.1.2.2 Investigative Processes

Using the foundation processes as a basis, the investigative processes provided the appropriate information necessary to determine the adequacy of the control room from a human engineering perspective. Deficiencies were identified and documented during this part of the review. This step was followed by a verification of task performance capabilities which included: 1) availability and adequacy of the instrumentation and controls, and 2) efficient interface between the Operator and the control board.

Subject to the verification process, a validation of the control room functions was conducted. This procedure determined whether the functions allocated to the operating crew could be accomplished within the structure of the defined emergency

TABLE 18.2-1

SPDS PARAMETER SET

KEY

SPDS Display SFS - Safety Function Status Display
SPDS Display PWR - Reactivity Control Display
SPDS Display CLG - Core Cooling Display
SPDS Display RCS - Coolant System Integrity Display
SPDS Display CNT - Containment Integrity Display
SPDS Display RRC - Radioactivity Control Display

X - SPDS Parameter on this display
+ - Supplemental Information on this display
* - Shown on Safety Function Status Display

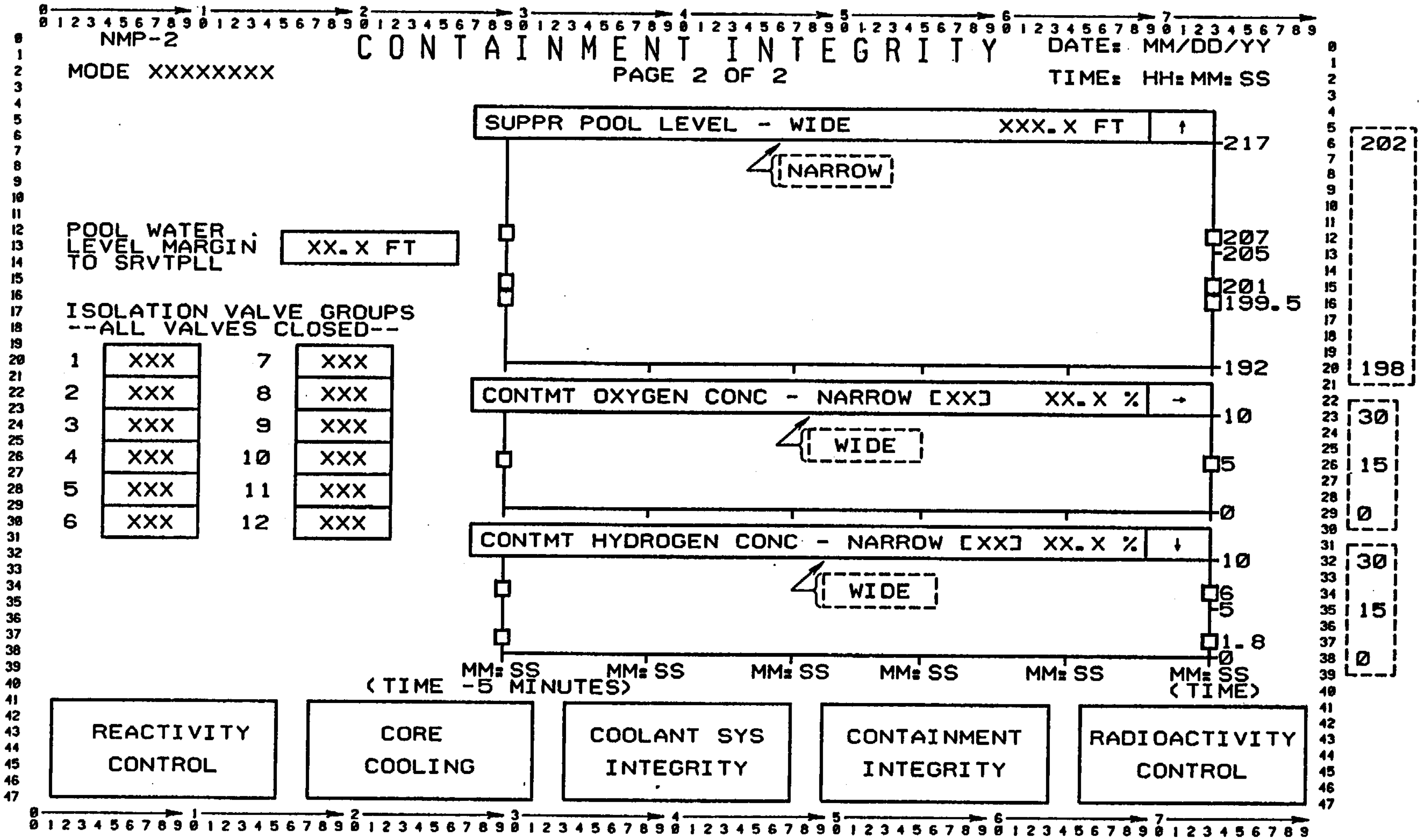
Parameter (Critical & Supplemental)	SFS	PWR	CLG	RCS	CNT	RRC
APRM REACTOR POWER	*	X				
BELOW DWSIPL CURVE					+	
CONDENSER VACUUM	*					
CONTAINMENT ISOLATION VALVE GP POS			X	X	X	X
CONTAINMENT HYDROGEN CONC	*				X	
CONTAINMENT OXYGEN CONC	*				X	
DRYWELL GASEOUS ACTIVITY						+
DRYWELL HIGH RADIATION	*					+
DRYWELL PARTICULATE ACTIVITY						+
DRYWELL PRESSURE	*	+		X	X	
DRYWELL TEMPERATURE	*	+	+	+	X	
DW TO SC DIFF PRESSURE					+	
ECCS INJECTION VALVE POSITION			+			
ECCS LINE FLOW RATE			+			
GENERATOR OUTPUT	*					
MAIN STACK ACTIVITY	*					X
MAIN STEAM LINE RADIATION	*					X
NUMBER OF SRV OPEN		X	X	X		
OFFGAS ACTIVITY	*					X
REACTOR BUILDING VENT ACTIVITY	*					X
REACTOR CORE FLOW	*					
REACTOR PRESSURE	*	X	X	X		
REACTOR WATER LEVEL	*	X	X	+		
SRM COUNT RATE		X				
SRM DETECTOR POSITION		+				
SUPPR CHAMBER AIR PRESSURE	*				X	
SUPPR CHAMBER AIR TEMPERATURE	*					
SUPPR CHAMBR PRESS MRGN TO PCPL					+	
SUPPR CHAMBR PRESS MRGN TO PSP					+	
SUPPR POOL LVL MARGIN TO HCLL-INACTIVE					+	
SUPPR POOL LVL MARGIN TO SRVTPLL					+	
SUPPR POOL TEMP MARGIN TO HCTL					+	
SUPPR POOL WATER LEVEL	*				X	
SUPPR POOL WATER TEMPERATURE	*	+			X	

TABLE 18.2-2 (Cont'd.)

Variable	Range(s)	SPDS Point	ERF PID / Process Input
Drywell Particulate Activity	$2.15E^{-9}$ - $1.0E^{-5}$ UCI/CC	SPDSA130 (+)	CMSRA102 - 2CMS*RUZ10A CMSRA103 - 2CMS*RUZ10B
Drywell Pressure	0 to 150 psig -5 to +5 psig	SPDSA111	CMSPA100 - 2CMS*PT2A (Wide) CMSPA101 - 2CMS*PT2B (Wide) CMSPA102 - 2CMS*PT1A (Nar) CMSPA103 - 2CMS*PT1B (Nar)
Drywell Spray Init. Pressure Limit (DWSIPL)	See Process Input Limits	SPDSA104	SPDSA111 - Drywell Pressure SPDSA103 - Drywell Temp
Drywell Temperature	50 - 350°F	SPDSA103	CMSTA108 - 2CMS*TE101 CMSTA109 - 2CMS*TE102 CMSTA110 - 2CMS*TE103 CMSTA111 - 2CMS*TE104 CMSTA112 - 2CMS*TE105 CMSTA113 - 2CMS*TE106 CMSTA117 - 2CMS*TE116 CMSTA118 - 2CMS*TE117 CMSTA119 - 2CMS*TE118 CMSTA120 - 2CMS*TE119 CMSTA121 - 2CMS*TE120 CMSTA122 - 2CMS*TE121
Drywell Temperature Margin to DWSIPL	See Process Input Limits	SPDSA106	SPDSA104 - DWSIPL SPDSA103 - Drywell Temperature
Drywell to Suppression Chamber Differential Pressure	+ or -	SPDSA132	SPDSA111 - Drywell Pressure SPDSA102 - Suppression Chamber Pressure
Generator Output	0 to +1800 MWt	SPDSA133 (+)	SPGQA100 - PMS: SPGQG01
Heat Capacity Level Limit (HCLL) - Inactive	See Process Input Limits	SPDSA120	SPDSA119 - Suppression Pool Temperature Margin to HCTL SPDSA117 - Suppression Pool Level
HPCS Flow	0 - 10,000 gpm	SPDSA140 (+)	CSHFA100 - 2CSH*FT104
HPCS Injection Valve	Yes, No, or Unk	SPDSC122 (+)	CSHZC101 - 2CSH*MOV107
LPCI - A Injection Valve	Yes, No, or Unk	SPDSC118 (+)	RHSZC112 - 2RHS*MOV24A
LPCI - B Injection Valve	Yes, No, or Unk	SPDSC119 (+)	RHSZC113 - 2RHS*MOV24B
LPCI - C Injection Valve	Yes, No, or Unk	SPDSC120 (+)	RHSZC114 - 2RHS*MOV24C
LPCS Injection Valve	Yes, No, or Unk	SPDSC121 (+)	CSLZC101 - 2CSL*MOV104

TABLE 18.2-2 (Cont'd.)

Variable	Range(s)	SPDS Point	ERF PID / Process Input
SRV Open (Number of)	1 to 18	SPDSA142	MSSZC111 - 2MSS*PSV131 MSSZC112 - 2MSS*PSV132 MSSZC113 - 2MSS*PSV133 MSSZC114 - 2MSS*PSV134 MSSZC115 - 2MSS*PSV135 MSSZC116 - 2MSS*PSV136 MSSZC117 - 2MSS*PSV137 MSSZC118 - 2MSS*PSV120 MSSZC119 - 2MSS*PSV121 MSSZC120 - 2MSS*PSV122 MSSZC121 - 2MSS*PSV123 MSSZC122 - 2MSS*PSV124 MSSZC123 - 2MSS*PSV125 MSSZC124 - 2MSS*PSV126 MSSZC125 - 2MSS*PSV127 MSSZC126 - 2MSS*PSV128 MSSZC127 - 2MSS*PSV129 MSSZC128 - 2MSS*PSV130
SRV Tail Pipe Level Limit (SRVTPLL)	See Process Input Limits	SPDSA122	SPDSA109 - Reactor Pressure SPDSA117 - Suppression Pool Level
Suppression Chamber Air Pressure	0 - 60 psig	SPDSA102	CMSPA104 - 2CMS*PT7A CMSPA105 - 2CMS*PT7B
Suppression Chamber Air Temperature	50 - 350°F	SPDSA129 (+)	CMSTA114 - 2CMS*TE107 CMSTA115 - 2CMS*TE108 CMSTA116 - 2CMS*TE109 CMSTA123 - 2CMS*TE122 CMSTA124 - 2CMS*TE123 CMSTA125 - 2CMS*TE124
Suppression Chamber Pressure Margin to PCPL	See Process Input Limits	SPDSA116	SPDSA102 - Suppression Chamber Pressure SPDSA112 - Primary Containment Pressure Limit (PCPL)
Suppression Chamber Pressure Margin to PSP	See Process Input Limits	SPDSA110	SPDSA102 - Suppression Chamber Pressure SPDSA108 - Pressure Suppression Pressure (PSP)
Suppression Pool Water Level	192 - 217 Ft (Wide) 198 - 202 Ft (Narrow)	SPDSA117	CMSLA100 - 2CMS*LT9A Wide CMSLA101 - 2CMS*LT9B Wide CMSLA102 - 2CMS*LT11A Narrow CMSLA103 - 2CMS*LT11B Narrow
Suppression Pool Water Level Margin to HCLL - Inactive	See Process Input Limits	SPDSA121	SPDSA117 - Suppression Pool Level SPDSA120 - Heat Capacity Level Limit (HCLL)



NOTE: PERIMETER GRID IS FOR INFORMATION ONLY.
ALARM MARKS ARE FOR INFORMATION/ILLUSTRATION ONLY AND DO NOT REPRESENT ACTUAL SETPOINT VALUES.

FIGURE 18.2-6 (SHEET 2 OF 2)

CONTAINMENT INTEGRITY DISPLAY
(PAGE 2 OF 2)

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

APPENDIX A

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RELOAD ANALYSIS

A.0 INTRODUCTION

Cycle 8/Reload 7

The Updated Safety Analysis Report (USAR) describes in detail the design and analysis that forms the licensing basis for Nine Mile Point Nuclear Station - Unit 2 (Unit 2). It is primarily based on information that bounded Cycle 1, the initial fuel load. Appendix A represents the cycle-specific information and analytical results for each reload, which includes the specific fuel loaded in the core and the respective safety analysis. Appropriate cross-references are provided within the USAR chapters and this appendix.

The reload safety analysis is based on the General Electric (GE) report, General Electric Standard Application for Reactor Fuel (GESTAR II), described in Reference 1. GESTAR II represents generic information relative to the GE fuel design and analysis and consists of a description of the fuel design and fuel thermal-mechanical, nuclear, and thermal-hydraulic analyses bases. It provides information and methods used to determine reactor limits that are independent of a plant-specific application. Plant-specific information and the transient and accident methods used are given in the United States (US) supplement. Proposed changes to GESTAR II are submitted to the appropriate regulatory body for review and approval. A listing of Nuclear Regulatory Commission (NRC)-approved amendments is provided in GESTAR II. All approved changes are incorporated as a revision into the text.

This appendix to the USAR reflects the Cycle 8, Reload 7 design and analysis. Since the reload reflects the fuel-related description and analytical results, the cycle-specific information affects Chapters 4, 5, 6, and 15. This Appendix reflects changes to only those chapters with an Appendix A designator.

Unit 2 was originally licensed to operate at reactor core power levels not in excess of 3,323 MWt. Beginning with Cycle 5, the licensed core thermal power limit was increased by 4.3 percent to 3,467 MWt. The cycle-specific transient analyses and core operating limits described in this appendix include the effects of power uprate.

The Unit 2 design is intended to be valid for the licensed life of the plant. The supplemental cycle-specific safety analysis assures that the plant can be operated safely and not pose any undue risk to the health and safety of the public. This is accomplished by demonstrating that radioactive releases from plants for normal operation, anticipated operational occurrences, and postulated accidents meet applicable regulations.

Unit 2 plant operation must meet various safety requirements defined in the Code of Federal Regulations (CFR). In order to evaluate the safety impact of the current cycle, fuel lattice physics calculations and 3-D simulation, transient, and accident evaluations were performed. The NRC-approved methodologies described in GESTAR II were used.

The transient analysis (Section A.15) is based on results which fully bound the licensed operating states. This analysis evaluates the extension of the operating domain to include the extended load line limit region (ELLLR) and increased core flow (ICF) to 105 percent of rated core flow.

The core-wide nuclear and thermal reactivity characteristics, when combined with the rest of the plant systems and equipment, determine the normal steady-state operation, transient and accident performance of the plant. The limiting transients performed are described in detail in Section A.15.

The evaluation utilizes the following methodologies and boundary conditions. The items that are different from the Cycle 1 analysis are marked "*". These items were initially evaluated for application in Cycle 2, Reload 1. Analyses for subsequent reload cycles are performed to confirm the applicability of these operational conditions and methodologies to Unit 2. The results of these analyses are summarized in this Appendix. In addition, the unit was evaluated for concurrent operational options as shown on Figure A.0-1.

1. GEMINI system of methods.*

2. GEXL-PLUS correlation.*

3. Extended load line limit (ELLL).*

4. Increased core flow (ICF).*

5. One main steam isolation valve (MSIV) out of service (OOS) (closed).* Detailed discussion is provided in Appendix 15D.

6. End of cycle-recirculation pump trip (EOC-RPT) OOS.

7. Turbine bypass OOS.

8. Up to two safety relief valves (SRVs) OOS (including automatic depressurization system [ADS]).

9. Operation with a single recirculation loop. Detailed discussion is provided in Appendix 15B.

A.4.3 Nuclear Design

A.4.3.1 Design Basis

No change has been made to this section as a result of the reload.

A.4.3.2 Description

No change has been made to this section as a result of the reload.

A.4.3.2.1 Nuclear Design Description

The nuclear and thermal hydraulic characteristics of the fuel bundles are simulated in a GE lattice computer model and 3-D simulator for the development of the reload core loading pattern. This loading pattern considered the integrated effect of mixing the new bundles with the irradiated bundles in the core. The objective of this loading pattern is to optimize the fuel burnup efficiency. The consideration includes meeting predetermined target radial and axial power distributions, thermal limits, and fuel cycle exposures. The reload core reference loading pattern and its target cycle exposure are provided in the SRLR (Reference 6, Section A.4.4.7).

The Cycle 8 core loading consists of 248 fresh GE11 bundles with an average enrichment of 4.07 weight percent mixed with 272 irradiated GE11 (100 bundles at 4.14 weight percent enrichment and 172 bundles at 4.13 weight percent enrichment) bundles remaining from Cycle 7, 236 irradiated GE11 (3.75 weight percent enrichment) bundles remaining from Cycle 6, and 8 irradiated GE11 (3.49 weight percent enrichment) bundles remaining from Cycle 5.

A.4.4 Thermal-Hydraulic Design

A.4.4.1 Design Bases

No change has been made to this section as a result of the reload.

A.4.4.2 Description of the Thermal-Hydraulic Design of the Reactor Core

No change has been made to this section as a result of the reload.

A.4.4.3 Description of the Thermal-Hydraulic Design of the Reactor Coolant System

No change has been made to this section as a result of the reload.

A.4.4.4 Evaluation

The thermal-hydraulic design of the reactor core and reactor coolant system (RCS) is based upon an objective of no fuel damage during normal operation or during anticipated operational occurrences.

The uncertainty for the inputs used in the bounding statistical analysis is discussed in Chapter 4, Section 4.4.2.9. The results of the analysis show that at least 99.9 percent of the fuel rods in the core are expected to avoid boiling transition if the MCPR is equal to or greater than the applicable value in the Technical Specifications. The safety limit MCPR value for the current fuel cycle is 1.09 for two-recirculation-loop operation and 1.10 for single-loop operation (SLO) (Reference 6).

The generation of the MCPR operating limit requires a statistical analysis of the core near the limiting MCPR condition. The statistical analysis is used to determine the MCPR corresponding to the transient design requirement given in GESTAR II. The GEMINI methods are used for current reloads versus the previous GENESIS methods used in Cycle 1.

The GEMINI methods replace the previous ODYN GENESIS methods in which a 1.044 factor was applied to the transient MCPR results. With the GEMINI methods, the MCPR response for each event is determined using statistically determined scram times. Event-unique adders are applied to adjust for Technical Specification scram times and other uncertainties and conservatism to develop the operating limit MCPR values from the analytically determined MCPR responses.

Unit 2 has implemented the Boiling Water Reactor Owners' Group (BWROG) Long-Term Stability Solution Option III (Oscillation Power Range Monitor - OPRM) as described in Reference 7.

Plant-specific analysis incorporating the Option III hardware is described in Reference 8.

Reload validation has been performed in accordance with Reference 9. The two conditions evaluated are for a postulated oscillation at 45 percent core flow steady state operation and following a two recirculation pump trip from the limiting full power operation state point.

Unit 2 will maintain the GE SIL-380 and NRC Bulletin No. 88-07 (Reference 10) recommendations as an alternate method for stability protection in the event that the OPRMs are inoperable. No stability analysis is required for this option, as documented in Reference 11.

A.4.4.4.1 Critical Power

The GEXL critical power correlation was utilized for Cycle 1 fuel (P8x8R) in thermal-hydraulic evaluations. For current fuel cycles, the GEXL-PLUS correlation is used. This correlation is discussed in Reference 1.

A.4.4.5 Testing and Verification

No change has been made to this subsection as a result of the reload.

A.4.4.6 Instrumentation Requirements

No change has been made to this subsection as a result of the reload.

A.4.4.7 References

1. General Electric Co., General Electric Standard Application for Reactor Fuel, including United States Supplement, NEDE-24011-P-A and NEDE-24011-P-A-US (latest approved revision.)

2. General Electric Co., General Electric Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application, NEDO-10958A, January 1977.

3. Deleted.

4. Letter, C. O. Thomas (NRC) to H. C. Pfefferlen (GE), Acceptance for Referencing of Licensing Topical Report NEDE-24011, Revision 6, Amendment 8, Thermal Hydraulic Stability Amendment to GESTAR II, April 24, 1985.

5. General Electric Co., Service Information Letter No. 380, Revision 1, BWR Core Thermal Hydraulic Stability, February 14, 1984.

6. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

7. General Electric Co., BWR Owners' Group Long-Term Stability Solutions Licensing Methodology, NEDO-31960-A, November 1995.

8. General Electric Co., Licensing Basis Hot Bundle Oscillation Magnitude for Nine Mile Point Unit 2, GENE-A13-00381-05, Revision 1, April 1998.

9. General Electric Co., Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, NEDO-32465-A, August 1996.

10. NRC Bulletin No. 88-07, Supplement 1, Power Oscillations in Boiling Water Reactors (BWRs).

11. Letter, C. O. Thomas (NRC) to H. C. Pfefferlen (GE), Acceptance for Referencing of Licensing Topical Report NEDE-24011, Revision 6, Amendment 8, Thermal Hydraulic Stability Amendment to GESTAR II, April 25, 1985.

A.5.2.2.2.3 Evaluation of Results

Safety/Relief Valve Capacity

The required SRV capacity is determined by analyzing the pressure rise from a MSIV closure with flux scram transient as documented in GESTAR II[1]. Adequacy of the SRV capacity has been reconfirmed for current fuel cycle operation (Reference 3). The Unit 2 Technical Specifications allow two SRVs to be OOS. This allowance was conservatively assumed to apply also to the spring action of the valves and no credit was taken for the two valves with the lowest setpoint. Results of this analysis demonstrate that the peak pressure obtained in the reactor vessel is below the ASME upset criteria of 1375 psig even with two SRVs OOS and assuming a 3-percent drift in the SRVs setpoints.

The adequacy of the SRVs has also been confirmed for operation with one MSIV OOS (closed) concurrent with two SRVs OOS (see Section A.15D).

Pressure Drop in Inlet and Discharge

Pressure drop on the piping from the reactor vessel to the valves is taken into account in calculating the maximum vessel pressures. Pressure drop in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent backpressure on each SRV from exceeding 40 percent of the valve inlet pressure, thus assuring choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping. Each SRV has its own separate discharge line.

A.5.2.3 Reactor Coolant Pressure Boundary Materials

No change has been made to this subsection as a result of the reload.

A.5.2.4 In-service Inspection and Testing of Reactor Coolant Pressure Boundary

No change has been made to this subsection as a result of the reload.

A.5.2.5 Reactor Coolant Pressure Boundary and ECCS Leakage Detection System

No change has been made to this subsection as a result of the reload.

A.5.2.6 References

1. General Electric Co., General Electric Standard Application for Reactor Fuel, including United States Supplement, NEDE-24011-P-A and NEDE-24011-P-A-US (latest approved revision).

2. General Electric Co. Design Report 22A7122, Overpressure Protection Report, Revision 2.

3. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

A.6 ENGINEERED SAFETY FEATURES

Chapter 6 provides information on the engineered safety feature (ESF) systems and components that are designed to ensure that the LOCAs are mitigated and the radioactivity releases from these accidents are limited. The ECCS performance analyses resulting from the LOCA have been reexamined for the current cycle to show conformance with 10CFR50.46 acceptance criteria. LOCA consideration is one of the requirements for fuel design. The following is the information resulting from the reload analysis on Chapter 6.

The safety and plant performance design bases for the nuclear design are described in GESTAR II(1). Specifically the new fuel design meets all the fuel thermal, mechanical and LOCA design and analysis criteria using GE design and analysis codes approved for these applications.

Starting with the Cycle 4 LOCA evaluation, the SAFER/GESTR-LOCA application methodology was used. The SAFER/GESTR-LOCA analytical models are documented in Section S.2 of GESTAR II(1). Significant fuel parameters utilized in the analysis are listed in Table A.6-2.

The results of this evaluation for the current fuel cycle show that the plant ECCS will perform its function meeting the 10CFR50.46 2200°F PCT and 17-percent maximum oxidation fraction acceptance criteria for all normal operating conditions and with allowable equipment OOS. The summary of Unit 2 LOCA evaluation results is given in Table 6-1 of NEDC-31830P(3) and in the SRLR(2).

A.6.1 References

1. General Electric Co., General Electric Standard Application for Reactor Fuel, including United States Supplement, NEDE-24011-P-A and NEDE-24011-P-A-US (latest approved revision).

2. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

3. Nine Mile Point Nuclear Power Station Unit 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, NEDC-31830P Revision 1, November 1990.

A.15.0 GENERAL

As in Chapter 15, Section A.15 examines the effects of the anticipated process disturbances and postulated component failures to determine their consequences, and to evaluate the capability built into the plant to control or accommodate such failures and events.

Events discussed in Chapter 15, Sections 15.3, 15.5, 15.6, 15.7 and 15.8, are not limiting events or are addressed generically in GESTAR II[1] and are not reanalyzed for each reload. GE evaluates the entire spectrum of events in order to establish the most limiting events in a meaningful manner. It is these events that are quantified in this section.

The scope of the events analyzed includes anticipated (unplanned, but expected) operational occurrences (e.g., loss of electrical load); off-design abnormal (unexpected or infrequent) transients that induce system disturbances, postulated accidents of low probability (e.g., the sudden loss of integrity of a major component); and, finally, hypothetical events of extremely low probability (e.g., an anticipated transient without the operation of the entire control rod drive [CRD] system).

A.15.0.1 Analytical Objective

The spectrum of postulated initiating events is divided into categories based upon 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. The plant safety analysis evaluates the ability of the plant to operate within regulatory guidelines without undue risk to public health and safety.

For reload cycles, only events which define the operating limits in the previous cycle or are close to the limiting cases are reanalyzed. The unanalyzed events still remain in the licensing basis of the plant.

A.15.0.2 Analytical Categories

Transient and accident events are discussed in individual categories in Chapter 15, Section 15.0.2. Each event evaluated is assigned to one of the analytical categories listed below:

1. Decrease in core coolant temperature
2. Increase in reactor pressure
3. Decrease in reactor core coolant flow rate
4. Reactivity and power distribution anomalies
5. Increase in reactor coolant inventory
6. Decrease in reactor coolant inventory
7. Radioactive release from a subsystem or component
8. Anticipated transients without scram

A.15.0.3 Event Evaluation

A.15.0.3.1 Identification of Causes and Frequency Classification

Situations and causes which lead to the initiating event analyzed are described within the categories designated above. The frequency of occurrence of each event is summarized on the bases of available operating plant history for the transient event. Events for which inconclusive data exist are discussed separately within each event section.

Each initiating event within the major groups is assigned to one of three frequency groups defined in Chapter 15, Section 15.0.3.1.

A.15.0.3.2 Sequence of Events and System Operations

Each transient or accident is discussed and evaluated in terms of:

1. Step-by-step sequence of events from initiation to final stabilized condition.

2. Extent to which normally operating plant instrumentation and controls are assumed to function.

3. Extent to which plant and reactor protection systems (RPS) are required to function.

4. Credit taken for the functioning of normally operating plant systems.

5. Operation of engineered safety systems that is required.

6. Effect of a single failure or an Operator error on the event.

A.15.0.3.3 Core and System Performance

The analyses documented in this Appendix are for the Cycle 8 core used for the nuclear evaluations given in Section A.4.4.

A.15.0.3.3.1 Introduction

The models used to analyze the core and system performance during abnormal operational transients are given in Reference 1. An acceptable criterion was determined to be that ≥99.9 percent of the fuel rods in the core would not be expected to experience boiling transition[2]. This criterion is met by demonstrating that incidents of moderate frequency do not result in a MCPR less than the safety limit MCPR specified in the Technical Specifications.

A.15.0.7 References

1. General Electric Co., General Electric Standard Application for Reactor Fuel, including United States Supplement, NEDE-24011-P-A and NEDE-24011-P-A-US (latest approved revision).

2. General Electric Co., General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application, NEDO-10959 and NEDE-10958, November 1973.

3. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

TABLE A.15.0-4

CYCLE 8 INPUT PARAMETERS AND INITIAL CONDITIONS FOR TRANSIENT ANALYSIS

1.	Thermal power level, MWt	
	Warranted value	3,467
	Analysis value	3,467(6)
2.	Steam flow, lb/hr	
	Warranted value	15.0×10^6
	Analysis value	15.0×10^6(6)
3.	Core Flow, lb/hr(1)	113.9×10^6
	% Rated	105
4.	Feedwater flow rate, lb/hr	
	Warranted value	15.0×10^6
	Analysis value	15.0×10^6
5.	Feedwater temperature, °F	425(2)
6.	Vessel dome pressure, psig	1020
7.	Vessel core pressure, psig	1036.3
8.	Turbine bypass capacity, % NBR	21.7
9.	Core coolant inlet enthalpy, Btu/lb	530.2
10.	Turbine inlet pressure, psig	988.5
11.	Fuel lattice	SRLR (Ref. 3)
12.	Core average gap conductance, Btu/sec-ft^2-°F	0.397
13.	Core bypass flow, %	14.7
14.	Required MCPR operating limit	SRLR (Ref. 3)
15.	MCPR safety limit	SRLR (Ref. 3)
16.	Doppler coefficient (-)¢/°F	
	Nominal EOC	(3)
	Analysis data	(3)

TABLE A.15.0-4 (Cont'd.)

17. Void coefficient (-)¢/% rated voids	
Nominal EOC	(3)
Analysis data for power increase events	(3)
Analysis data for power decrease events	(3)
18. Core average rated void fraction, %	(3)
19. Scram reactivity, $ K	
Analysis data	(3)
20. Control rod drive speed,	
Position versus time	Figure 15.0-3
21. Jet pump ratio, M	2.39
22. SRV capacity, % NBR	107 @ 1145 psig
Manufacturer	Dikkers
Quantity installed	18
23. Relief function delay, sec	0.4
24. Relief function response	
Time constant, sec	0.1
25. Safety function delay, sec	0.0
26. Safety function response stroke	
Time, sec	0.3
27. Setpoints for SRVs	
Safety function (lowest), psig	1200
Safety function (all others), psig	1210, 1221, 1231, 1241,
Relief function, psig	1121, 1131, 1141, 1151, 1161
28. Number of valve groupings simulated	
Safety function, No.	9(4)
Relief function, No.	9(4)
29. High flux trip, % NBR	
Analysis setpoint	123
30. High pressure scram, psig	
Analysis setpoint	1,086

It is bounded by other transients in this analytical category. No new analysis has been performed.

A.15.1.4 Inadvertent Safety/Relief Valve Opening

Detailed description of this transient is provided in Chapter 15, Section 15.1.4.

This event was not identified as one of the transients that is affected by reload in GESTAR II[2]. It has been shown in the Cycle 1 analysis that the response of this event is very mild from the viewpoint of fuel protection. Thermal margins are unchanged and MCPR response remains essentially unchanged. For the reload, this event will behave similarly to the Cycle 1 analysis. It is bounded by other transients under this analytical category. No new analysis has been performed.

A.15.1.5 Spectrum of Steam System Piping Failures Inside and Outside of Containment in a PWR

No change has been made to this section as a result of the reload.

A.15.1.6 Inadvertent RHR Shutdown Cooling Operation

Detailed description of this transient is provided in Chapter 15, Section 15.1.6.

This event was not identified as one of the transients that is affected by the reload in GESTAR II[2]. No Cycle 1 analysis was performed for this transient since it was shown that 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.

A.15.1.7 References

1. Qualification of the One-Dimensional Core Transient Model for BWR, October 1978 (NEDO-24154).

2. General Electric Co., General Electric Standard Application for Reactor Fuel, including United States Supplement, NEDE-24011-P-A and NEDE-24011-P-A-US (latest approved revision).

3. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

considerations. The ΔCPR for this event is reported in the SRLR[2] and may provide the basis for the OLMCPR values presented in the COLR.

Generator Load Rejection with Bypass Failure and Turbine Generator Trip RPT Out of Service

Analysis of the generator load rejection event with bypass failure was also performed for Unit 2 operation with the turbine generator trip RPT OOS. As in all the load rejection cases, the analysis also assumed that only 16 of the 18 installed SRVs are in service, so it demonstrates that operation with these features concurrently OOS (turbine generator RPT and 2 SRVs) is acceptable.

Nuclear characteristics and scram inputs assumed in the analysis conservatively bound EOC conditions. The recirculation pumps are eventually tripped (transferred to low speed) on high pressure but that occurs after the maximum change in CPR has already occurred. For the purpose of conservative analysis, no credit was taken for the automatic fast transfer of the pump power supply to the outside grid; the pumps are assumed to remain powered from the main generator and thus increase in speed with the turbine generator overspeed. Peak vessel pressure is essentially unchanged from the base event as it is limited by the SRVs (16 assumed to be in service). The resulting MCPR operating limits for Cycle 8 operation with the RPT OOS are less limiting than those calculated for the turbine trip without bypass event (see Section A.15.2.3).

A.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 0.20 sec; the less time it takes to close, the more severe the pressurization effect. In addition, plant operation is under partial arc turbine admission. This mode is slightly less severe for this event than the full arc configuration which was assumed.

The GEMINI methodology used in the analysis of the generator load rejection cases with bypass failure uses nominal initial power EOC reactivity characteristics and scram speed. However, the MCPR evaluation includes statistical allowances for uncertainties in simulation and plant parameters (including power and scram speed).

Other systems utilized for protection in this event were assumed to have the most conservative allowable response. Anticipated plant behavior is therefore expected to reduce the actual severity of the transient.

The analysis assumed SRV setpoints that are 3 percent above the actual nominal setpoints. In addition, the peak pressure will be bounded by limiting overpressure transient analyzed in Section A.5.

A.15.2.2.4 Barrier Performance

Generator Load Rejection - With Bypass

Peak pressure remains within normal operating range and no threat to the barrier exists.

Generator Load Rejection with Bypass Failure

The peak nuclear system pressure at the bottom of the reactor vessel is well below the ASME upset transient pressure limit of 1375 psig for both the base event and the case with the one MSIV also OOS, as documented in the SRLR(2). Fuel barrier performance is assured by the OLMCPRs that are established.

A.15.2.2.5 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 via SRV operation as described in Section 15.1.2.5.

A.15.2.3 Turbine Trip

The detailed description of this transient is provided in Chapter 15, Section 15.2.3.

These events (turbine trip with and without bypass) were not identified as transients that are affected by the fuel reload in GESTAR II(1) (for the standard analysis). It has been shown in the Cycle 1 analysis that transient responses of both these events are similar to but bounded by the generator load rejection event. For reload cores, an evaluation is performed to determine if this AOO could potentially alter the previous cycle MCPR operating limit. If it does, the results will be reported in the supplemental reload licensing report.

The turbine trip event could potentially be limiting for the equipment OOS options identified on Figure A.0-1. For Cycle 8, analysis of the turbine trip without bypass event was performed for Unit 2 operation with the EOC-RPT OOS because it establishes the more restrictive operating limits for MCPR. The resulting OLMCPR for Cycle 8 operation with the EOC-RPT OOS are given in the SRLR(2) and the COLR.

A.15.2.4 Main Steam Isolation Valve Closures

The detailed description of this transient is provided in Chapter 15, Section 15.2.4.

These events (closure of one or more MSIVs) were not identified as transients that are affected by the fuel reload in GESTAR II[1]. It has been shown in the Cycle 1 analysis that transient responses of both of these events are bounded by the generator load rejection event. For the reload, these events will behave similarly to the Cycle 1 analysis; therefore, no new analysis has been performed.

A.15.2.5 Loss of Condenser Vacuum

Detailed description of this transient is provided in Chapter 15, Section 15.2.5.

This event was not identified as one of the transients that is affected by the reload in GESTAR II[1]. It has been shown in the Cycle 1 analysis that the transient MCPR response of this event is bounded by the generator load rejection and turbine trip events. For the reload, this event will behave similarly to the Cycle 1 analysis; therefore, no new analysis has been performed.

A.15.2.6 Loss of Ac Power

Detailed description of the transient is provided in Chapter 15, Section 15.2.6.

Loss of ac power events were not identified as transients that are affected by the reload in GESTAR II[1]. It has been shown in the Cycle 1 analyses that the initial transient for the loss of normal and preferred Station service transformers is similar to the RPT transient. The transient response for the loss of all grid connections takes on the characteristic response of the standard full load rejection event. For the reload, these events will behave similarly to Cycle 1. They are bounded by other transients under this same analytical category. No new analysis has been performed.

A.15.2.7 Loss of Feedwater Flow

Detailed description of this transient is provided in Chapter 15, Section 15.2.7.

This event was not identified as one of the transients that is affected by the reload in GESTAR II[1]. It has been shown in the Cycle 1 analysis that there is no increase in heat flux; therefore, thermal margins are not threatened. Reactor inventory is maintained by RCIC and/or HPCS. For the reload, this event will behave similarly to Cycle 1 analysis. It is bounded by other transients under the same analytical category. No new analysis has been performed.

A.15.2.8 Feedwater Line Break

No change has been made to this subsection as a result of the reload.

A.15.2.9 Failure of RHR Shutdown Cooling

Detailed description of this transient is provided in Chapter 15, Section 15.2.9.

This event was not identified as one of the transients that is affected by the reload in GESTAR II[1]. The Cycle 1 analysis demonstrated the capability to safely transfer fission product decay heat and other residual heat from the reactor core at such a rate that specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded. For the reload, this event will behave similarly to the Cycle 1 analysis. It is bounded by other transients under the same analytical category. No new analysis has been performed.

A.15.2.10 References

1. General Electric Co., General Electric Standard Application for Reactor Fuel, including United States Supplement, NEDE-24011-P-A and NEDE-24011-P-A-US (latest approved revision).

2. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

core power is less than 5 percent and the changes in pressure are negligible.

A.15.4.2.5 Radiological Consequences

An evaluation of the radiological consequences was not made for this event since no radioactive material is released from the fuel.

A.15.4.3 Control Rod Maloperation (System Malfunction or Operator Error)

The control rod malfunction results in a positive reactivity insertion into the core. It is stated in Chapter 15, Section 15.4.3, that this event is included in the evaluation cited in the two control RWE transients (low power and at power condition). This conclusion remains valid for the reload.

A.15.4.4 Abnormal Startup of Idle Recirculation Pump

Detailed description of this transient is provided in Chapter 15, Section 15.4.4.

This event was not identified as one of the transients that is affected by the reload in GESTAR II[1]. It has been shown in the Cycle 1 analysis that the transient response of this event is not limiting and it is bounded by the RWE. For the reload, this event will behave similarly to the Cycle 1 analysis; therefore, no new analysis has been performed.

A.15.4.5 Recirculation Flow Control Failure With Increasing Flow

Detailed description of this transient is provided in Chapter 15, Section 15.4.5.

This event was not identified as one of the transients that is affected by the reload in GESTAR II[1]. It was shown in the Cycle 1 analysis that the transient response of this event is bounded by the RWE. MCPR remains above the safety limit. For the reload, this event will behave similarly to the Cycle 1 analysis; therefore, no new analysis has been performed.

A.15.4.6 Chemical and Volume Control System Malfunctions

Not applicable to BWRs.

A.15.4.7 Misplaced Bundle Accident

Detailed description of this transient is provided in Chapter 15, Section 15.4.7.

This event was not identified as one of the transients that is affected by the reload in GESTAR II[1]. As approved for GESTAR II, the analysis of the mislocated bundle accident is performed only for initial cores and not performed for reload cores. Analysis of the mislocated bundle accident is performed for reload cores where the resultant CPR response may establish the operating limit MCPR, and the misoriented bundle accident is evaluated on a cycle-specific basis.

A.15.4.8 Spectrum of Rod Ejection Accidents

Not applicable to BWRs.

A.15.4.9 Control Rod Drop Accident

Detailed description of this transient is provided in Chapter 15, Section 15.4.9.

This event was not identified as one of the events to be analyzed by the reload in GESTAR II[1]. It was shown in the Cycle 1 analysis that the peak fuel enthalpy is within the design criterion of 280 cal/gm and that the radiological consequences are acceptable. GESTAR II[1] documents the generic acceptability of the banked position withdrawal sequence (BPWS) cores without cycle-specific reanalysis.

BPWS plants normally operate with the rod worth minimizer (RWM) alone, and for the first 50 percent of the rods, the effective withdrawal is in the form of (stepped) defined bank patterns. Beyond 50 percent, it is also in the form of stepped bank withdrawal.

For the first 50 percent, the BPWS bank positions result in lower peak rod reactivity worths for the CRDA than the rod sequence control system (RSCS) (nonbanked) patterns.

Even though the BPWS is more restrictive than sequences allowed by the RSCS in Unit 2 for the first 50 percent control rod withdrawal, the Technical Specifications require administration of this withdrawal sequence through the RWM and plant operating procedures.

Consequently, adherence to BPWS reduces control rod worth such that the postulated CRDA is well under the design criterion of 280 cal/gm.

A.15.4.10 References

1. General Electric Co., General Electric Standard Application for Reactor Fuel, GESTAR II, NEDE-24011-P-A, and United States Supplement GESTAR II, NEDE-24011-P-A-US, (latest approved revision).

2. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

A.15B RECIRCULATION SYSTEM SINGLE-LOOP OPERATION

Recirculation system single-loop operation (SLO) is discussed in detail in Appendix 15B. A summary of the affected transient analyses results is provided in Tables 15B.3-4 and 15B.3-5. The results for Cycle 2 demonstrate large margins between the two-loop limits and SLO limits. Due to these large margins, it is concluded that SLO analyses will remain bounded by two-loop operation for future reload cycles. A reanalysis of equipment OOS for SLO in the current fuel cycle confirms that the conclusions presented in Appendix 15B for Cycle 2 remain applicable. The limiting MAPLHGR reduction factor and the cycle-specific safety limit MCPR for SLO is documented in the SRLR[1] and the COLR.

References

1. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

A.15D ONE MAIN STEAM LINE ISOLATION VALVE OUT OF SERVICE

Operation with one MSIV OOS is discussed in detail in Appendix 15D. The effects of operation with one MSIV OOS on cycle-specific transient analyses are included in the following sections:

A.5 Overpressure Protection. Analysis for the reload showed a slight peak pressure increase with one MSIV OOS (concurrent with two SRVs OOS). The peak pressure at the bottom of the vessel and the peak steam line pressure are documented in the SRLR[1] and continue to be less than the ASME Code upset limit of 1375 psig.

A.15.1.2 Feedwater Controller Failure, Maximum Demand. The analysis performed for Cycle 2 concluded that the results for this event are milder than the load rejection event (Section A.15.2.2). The equipment OOS analysis for the current fuel cycle demonstrates that this conclusion remains applicable.

A.15.2.2 Generator Load Rejection. The analysis performed for the reload showed that the MCPR operating limits for this event are bounded by those established for the standard normal operation configuration case (Reference 1). Therefore, specific MCPR operating limits for operation with one MSIV OOS need not be specified in the COLR.

References

1. Global Nuclear Fuel Report, Supplemental Reload Licensing Report for Nine Mile Point Unit 2, Reload 7, Cycle 8, J11-03614SRLR, Revision 0, January 2000.

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NINE MILE POINT NUCLEAR STATION UNITS 1 AND 2
OPERATIONS PHASE

Technical Specification Reference: Throughout the QATR are references to Technical Specification requirements. Where a specific Technical Specification is referenced, it is noted as either "CTS" or "ITS." CTS refers to the current Technical Specifications for both Nine Mile Point Nuclear Station - Units 1 and 2 (Unit 1 and Unit 2). ITS refers to the Unit 2 Technical Specifications in the "Improved Technical Specifications" (ITS) format. This reference is valid following Nuclear Regulatory Commission (NRC) approval of Niagara Mohawk Power Corporation's (NMPC) ITS submittal and implementation of the associated License Amendment. In summary, CTS always relates to a Unit 1 current Technical Specification reference while CTS relates to a Unit 2 Technical Specification reference only before NRC approval of the ITS submittal, after which ITS identifies the appropriate Unit 2 Technical Specification reference.

B.0 INTRODUCTION

This Quality Assurance Program Topical Report (QATR) fulfills the requirement for a description of the Quality Assurance (QA) Program for the operations phase of the Nine Mile Point Nuclear Station Units 1 and 2. This QATR supersedes the previous QA Program for Nine Mile Point Unit 1, and Chapter 17 of the Nine Mile Point Unit 2 FSAR relating to the operating phase.

The QATR applies to organizations performing work that affects the operation, maintenance or modification of safety-related structures, systems or components. Accountability for the quality of safety-related work rests with the performer, whereas accountability for verifying the quality of that work rests with the verifying organizations.

This QATR provides for performing operation, maintenance and modification of both Units 1 and 2 consistent with ANSI/ASME NQA-1, ANSI/ANS-3.2 and Branch Technical Position (BTP) APCSB 9.5-1, Appendix A. The Nuclear Division Policy and Directives Manual, approved by the Chief Nuclear Officer, sets forth the overall program for controlling these activities. The total program consists of the Policy, the Nuclear Division Directives, and lower tier documents developed to implement the requirements addressed in the Nuclear Division Policy and Directives Manual, and is consistent with the QATR.

In the event of a conflict between non-QA programmatic controls contained in this QATR and related commitments contained in the Unit 1 and Unit 2 FSARs, the latter shall take precedence.

Questions with respect to the content or applicability of the QATR should be referred to the Manager Quality Assurance.

B.1 ORGANIZATION

B.1.1 POLICY

NMPC is responsible for establishing and implementing the QA Program for the operations phase of the Nine Mile Point Nuclear Station. Although authority for development and execution of specified parts of the program may be delegated to others, e.g., suppliers, NMPC retains overall responsibility.

This section of the QATR identifies the NMPC organizations responsible for activities affecting the operation, maintenance or modification of safety-related and fire protection structures, systems, or components, and describes the assigned authorities and duties for quality-attaining functions and for quality verification functions. Each organizational department is responsible for the quality of its own work.

Quality-assuring functions include establishing the QA Program and verifying that activities affecting the quality of safety-related structures, systems, components, and services are performed in accordance with QA Program requirements. Quality-assuring functions are performed by personnel within various organizational units as well as Nuclear Quality Assurance (NQA). The NQA organization, independent from impacts of cost and schedule, has direct access to management levels to assure the ability to identify quality problems; initiate, recommend or provide solutions; and verify implementation of solutions. The size of the NQA organization is determined by the scope of operations activities and their importance to safety.

B.1.2 IMPLEMENTATION

B.1.2.1 Responsibility and Authority

The Chief Executive Officer (CEO), Niagara Mohawk Power Corporation (NMPC), has ultimate responsibility for safe operation of the Nine Mile Point Nuclear Station. Authority and responsibility for establishing and implementing the QA Program for Station operations, maintenance, and modifications is delegated by the CEO to the Chief Nuclear Officer and the Manager Quality Assurance, as described herein. The NMPC Upper Management Nuclear Organization is shown in Unit 1 UFSAR Figure XIII-1 and Unit 2 USAR Figure 13.1-1. Departmental responsibilities for QA Program elements are summarized in Table B-1.

B.1.2.1.1 Nuclear Division Responsibilities

The Chief Nuclear Officer reports to the NMPC CEO and has overall responsibility for the administration and operation of the Nuclear Division including the Plant Generation and Engineering functions, Nuclear Safety Assessment and Support (NSAS), Business Management, Human Resource Development, and Nuclear Communications and Public Affairs.

Responsibilities of the Director Nuclear Communications and Public Affairs, General Manager Business Management and Director Human Resource Development are described in Unit 1 UFSAR Section XIII.A and Unit 2 USAR Section 13.1.1. Organizational responsibilities for the Fire Protection Program are described in Unit 1 UFSAR Appendix 10A and Unit 2 USAR Appendix 9A. Nuclear Generation, Nuclear Engineering and Nuclear Safety Assessment and Support responsibilities are described below.

1. The Vice President Nuclear Generation reports to the Chief Nuclear Officer, and has overall divisional responsibility for plant operation to assure safe, orderly, and efficient plant operation is achieved. Additionally, the Vice President Nuclear Generation has oversight responsibility of the Assessment and Corrective Action Group. The Plant Managers and the Director - Assessment and Corrective Action report directly to this Vice President. See Table B-1 for QA Program element responsibilities. Activities performed under the responsibility of the Vice President Nuclear Generation include:

   a. Controlling the preparation, review, and approval of certain procedures and instructions;

   b. Ensuring that technical, operations and maintenance personnel are appropriately qualified for their duties;

   c. Providing the necessary corrective action, evaluation, processing and reporting of nonconforming conditions;

   d. Providing for timely identification and corrective action of conditions adverse to quality;

   e. Providing assessments of determined applicability for industry and in-plant operating experience;

f. Providing oversight of the Branch Self-Assessment program; and

g. DER trend analysis.

Responsibilities and duties of the Plant Managers, the Director - Assessment and Corrective Action, and the remainder of the Nuclear Generation organization are described in Unit 1 UFSAR Chapter XIII and Unit 2 USAR Chapter 13.

2. The Vice President Nuclear Engineering reports to the Chief Nuclear Officer. Responsibilities and duties of the Vice President Nuclear Engineering and the Nuclear Engineering organization are described in Unit 1 UFSAR Section XIII.A.1 and Unit 2 USAR Section 13.1.1. See Table B-1 for QA Program element responsibilities.

3. The Vice President Nuclear Safety Assessment and Support reports to the Chief Nuclear Officer and is responsible for Quality Assurance, Licensing, Training/Emergency Preparedness, Security, and the Unit 2 Independent Safety Engineering Group (ISEG).

See Table B-1 for QA Program element responsibilities. Nuclear Safety Assessment and Support responsibilities are described in Unit 1 UFSAR Section XIII and Unit 2 USAR Section 13.

a. Independent Safety Engineering Group (Unit 2 Only)

<u>Function</u>

The Independent Safety Engineering Group (ISEG) shall function to examine Unit 2 operating characteristics, NRC issuances, industry advisories, Licensee Event Reports, and other sources of Unit 2 design and operating experience information, including units of similar design, which may indicate areas for improving Unit 2 safety. The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities, or other means of improving Unit 2 safety to the Vice President Nuclear Safety Assessment and Support.

Composition

The ISEG shall be composed of at least five, dedicated, full-time engineers located on site. Each shall have a bachelor's degree in engineering or related science and at least 2 yr of professional level experience in his/her field, at least 1 yr of which experience shall be in the nuclear field.

Responsibilities

The principal function of the ISEG is to examine plant operating characteristics and the various NRC and industry licensing and service advisories, and to recommend areas for improving plant operations or safety. The ISEG will perform independent review of plant activities, including maintenance modifications, operational concerns, and analysis, and make recommendations to the Vice President Nuclear Safety Assessment and Support.

Records

Records of activities performed by the ISEG shall be prepared, maintained, and forwarded each calendar month to the Vice President Nuclear Safety Assessment and Support.

4. The Manager Quality Assurance has overall authority and responsibility for formulating and directing the QA Program. The Manager Quality Assurance reports to the Vice President Nuclear Safety Assessment and Support for administrative issues and QA activities outside the NSAS organization, and reports directly to the Chief Nuclear Officer for all QA activities relating to the NSAS organization.

   The Manager Quality Assurance's responsibilities include verifying that the policies and procedures associated with the overall quality of design, operation, maintenance, and modification of Unit 1 and Unit 2 are effectively implemented and result in safely-operated plants within design and licensing basis commitments. Tasks performed to fulfill these responsibilities are delineated in site procedures and include:

   - Audits
   - Surveillances
   - Inspections and NDE Examinations

- Procurement QA
- Exercising Stop Work Authority
- Records Management
- Document Control

a. The Supervisor Quality Inspection reports to the Manager Quality Assurance and is responsible for activities that include, but are not limited to, inspections and examinations for product acceptance of modification and maintenance activities (safety related and nonsafety related), performing in-service inspection (ISI) examinations (visual and NDE), and performing erosion/corrosion examinations.

b. The Supervisor Quality Assessment reports to the Manager Quality Assurance and is responsible for QA activities that include, but are not limited to, performing QA audits and conducting performance-based surveillances.

c. The Supervisor Procurement Quality Assurance reports to the Manager Quality Assurance and is responsible for QA activities that include, but are not limited to, performing supplier evaluations and source surveillances of selected procurements.

d. Supervisors of Quality Services report to the Manager Quality Assurance and are responsible for activities that include, but are not limited to, managing support services associated with quality and nonquality records management, document control, and administrative services (QA clerical support functions).

B.1.2.1.2 Corporate Support Responsibilities

Certain corporate departments provide support services in the areas of: (1) testing and maintenance of electrical power system protective devices and metering equipment; (2) calibration and maintenance of portable measuring and test equipment; and (3) fire protection and fire personnel training. These corporate support functions are described in Unit 1 UFSAR Section III.A.1 and Unit 2 USAR Section 13.1.1.

B.2.2.13 Development, control and use of computer programs affecting nuclear power plant safety-related design and operation are subject to appropriate controls.

B.2.2.14 Responsibility and authority for planning and implementing indoctrination and training programs are delegated to each department. The training and indoctrination program provides for the following as appropriate:

1. Personnel responsible for performing and verifying activities that affect quality are familiar with the activities and the requirements identified in applicable quality-related manuals, instructions, procedures, and drawings.

2. Proficiency tests are utilized where appropriate to determine that individuals can perform their assigned tasks.

3. Personnel who perform inspections, examination, tests, audit and special process activities are trained and qualified in accordance with applicable requirements. Certificates of qualification (where required) designate specific areas of qualification and the bases for the qualification.

4. Provisions are included for retraining, reexamination and recertification (where certification is required) to ensure that proficiency is maintained.

5. Training content and attendance records, and required qualification and certification records are maintained.

B.2.2.15 The management of NMPC at the CEO level assesses the scope, status, adequacy, and compliance of the QA Program for the Stations at a predetermined regularity. Management at this level employs the following means to assess the program.

1. The Chief Nuclear Officer is responsible for reporting on the status, adequacy and effectiveness of the NMPC QA Program.

2. The Chief Nuclear Officer regularly attends Niagara Mohawk Holdings, Inc., Nuclear Oversight Committee meetings, CEO meetings, and co-tenant meetings, and makes verbal presentations regarding quality-related matters. When necessary, the Manager Quality Assurance assists with these

presentations. Minutes of these meetings are generally documented.

Certain actions of the Safety Review and Audit Board (SRAB) and of the Station Operations Review Committee (SORC) result in audits and/or reports by which members of these offsite and onsite review committees are made aware, on a regular basis, of the effectiveness of the QA Program.

B.2.2.16 Safety Review and Audit Board

1. Function

The SRAB shall function to provide independent review and audit of designated activities in the areas of:

a. Nuclear power plant operations

b. Nuclear engineering

c. Chemistry and radiochemistry

d. Metallurgy

e. Instrumentation and control

f. Radiological safety

g. Mechanical and electrical engineering

h. Quality assurance practices

i. Other appropriate fields associated with the unique characteristics of the nuclear power plant

The SRAB shall report to and advise the Chief Nuclear Officer on those areas of responsibility specified under Items 7 and 8 of this section.

2. Composition

The SRAB shall be composed of the following:

Chairman:	Vice President, Manager or Staff Engineer
Member:	Plant Manager or Designee
Member:	Staff Engineer - Nuclear
Member:	Staff Engineer - Mechanical or Electrical
Member:	Consultant (Item 4 of this section)

3. Alternates

All alternate members shall be appointed in writing by the SRAB Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in SRAB activities at any one time.

4. Consultants

Consultants shall be utilized as determined by the SRAB Chairman to provide expert advice to the SRAB.

5. Meeting Frequency

The SRAB shall meet at least once per calendar quarter during the initial year of unit operation following fuel loading and at least once per 6 months thereafter.

6. Quorum

The quorum of the SRAB necessary for the performance of the SRAB review and audit functions of the Technical Specifications shall consist of not less than a majority of the members including alternates. The quorum requires the presence of the Chairman or the Chairman's designated alternate and no more than a minority of the quorum shall have line responsibility for operations of the facility.

7. Review

The SRAB shall be responsible for the review of:

a. The safety evaluations for: 1) changes to procedures, equipment, or systems, and 2) tests or experiments completed under the provision of 10CFR50.59 to verify that such actions did not constitute an unreviewed safety question;

b. Proposed changes to procedures, equipment, or systems which involve an unreviewed safety question as defined in 10CFR50.59;

c. Proposed tests or experiments which involve an unreviewed safety question as defined in 10CFR50.59;

d. Proposed changes to Technical Specifications or the Operating License;

e. Violations of codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance;

f. Significant operating abnormalities or deviations from normal and expected performance of unit equipment that affect nuclear safety;

g. All Reportable Events;

h. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety; and

i. Reports and meeting minutes of the SORC.

8. Audits

Audits of unit activities shall be performed under the cognizance of the SRAB. These audits shall encompass:

a. The conformance of unit operation to provisions contained within the Technical Specifications and applicable license conditions at least once every 12 months;

b. The performance, training, and qualifications of the entire unit staff at least once every 12 months;

c. The results of actions taken to correct deficiencies occurring in unit equipment, structures, systems, or method of operation that affect nuclear safety, at least once every 6 months;

d. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10CFR50, at least once every 24 months;

e. The facility Emergency Plan and implementing procedures at least once every 12 months;

f. The facility Security Plan and implementing procedures at least once every 12 months;

g. The Radiological Environmental Monitoring Program and the results thereof at least once every 12 months;

h. The Offsite Dose Calculation Manual (ODCM) and implementing procedures at least once every 24 months;

i. The Process Control Program and implementing procedures for processing and packaging of radioactive wastes at least once every 24 months;

j. Any other area of unit operation considered appropriate by the SRAB or the Vice President Nuclear Generation;

k. The Fire Protection Program and implementing procedures at least once per 24 months;

l. An independent fire protection and loss prevention program inspection and audit shall be performed at least once per 12 months utilizing either qualified offsite licensee personnel or an outside fire protection firm;

m. An inspection and audit of the fire protection and loss prevention program shall be performed by an outside qualified fire consultant at intervals no greater than 36 months.

9. Authority

The SRAB shall report to and advise the Chief Nuclear Officer on those areas of responsibility specified in Items 7 and 8 of this section.

10. Records

Records of SRAB activities shall be prepared, approved, and distributed as indicated below:

a. Minutes of each SRAB meeting shall be prepared, approved, and forwarded to the Chief Nuclear Officer within 14 days following each meeting.

b. Reports of reviews encompassed by Items 7.b, e, f, g and h of this section shall be prepared, approved, and forwarded to the Chief Nuclear Officer within 14 days following completion of the review.

c. Audit reports encompassed by Item 8 of this section shall be forwarded to the Chief Nuclear Officer and to the management positions responsible for the areas audited within 30 days after completion of the audit by the auditing organization.

B.2.2.17 Station Operations Review Committee

Details of SORC responsibilities are discussed in Section XIII-G.1 of the Unit 1 UFSAR and Section 13.4 of the Unit 2 USAR.

1. Function

The SORC shall function to advise the Plant Manager on all matters related to nuclear safety.

2. Composition

The SORC shall be composed of the following:

Chairman:	Plant Manager
Vice-Chairman/Member:	Manager Operations
Vice-Chairman/Member:	Manager Technical Support
Member:	Manager QA Operations
Member:	Manager Maintenance
Member:	Manager Chemistry
Member:	Manager Radiation Protection

3. Alternates

All alternate members shall be appointed in writing by the SORC Chairman or Vice-Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in SORC activities at any one time.

4. Meeting Frequency

The SORC shall meet at least once every calendar month and as convened by the SORC Chairman, Vice-Chairman, or a designated alternate.

5. Quorum

The quorum of the SORC necessary for the performance of the SORC responsibility and authority provisions of the Technical Specifications shall consist of the Chairman or a Vice-Chairman, and four members including alternates.

6. Responsibilities

The SORC shall be responsible for:

a. Investigation of all violations of the Technical Specifications, including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence, to the Vice President Nuclear Generation and to the SRAB.

b. Review of all Reportable Events, and submitting the results of this review to the SRAB and Vice President Nuclear Generation.

c. Review of unit operations to detect potential hazards to nuclear safety.

d. Performance of special reviews, investigations, or analyses and reports thereon as requested by the Plant Manager or the SRAB.

e. Safety evaluations and analyses resulting from technical review and control activities identified in Items 1, 2, 3 and 5 of Section B.5.2.9 (Unit 2).

f. Review of Licensee-initiated changes to the ODCM prior to implementation. Changes become effective upon acceptance by SORC.

7. Duties

The SORC shall:

a. Render determinations in writing with regard to whether or not each item considered under Items 6.a through 6.e, above, constitutes an unreviewed safety question.

b. Provide written notification within 24 hr to the Vice President Nuclear Generation and the SRAB of disagreement between the SORC and the Plant Manager; however, the Plant Manager shall have responsibility for resolution of such disagreements pursuant to Technical Specifications 6.1.1 (CTS)/5.1.1 (ITS).

c. Review Safety Limit Violation Reports, submit Safety Limit Violation Report to SRAB and Vice President Nuclear Generation within 14 days of the violation, and notify the

SRAB and Vice President Nuclear Generation within 24 hr in the event a Safety Limit is violated.

8. Records

The SORC shall maintain written minutes of each SORC meeting that, at a minimum, document the result of all SORC activities performed under the responsibilities and authority provisions of the Technical Specifications and this section. Copies shall be provided to the Vice President Nuclear Generation and the SRAB.

B.2.2.18 The Quality First Program (Q1P) provides NMPC and contractor employees an opportunity to communicate their quality concerns regarding operation, maintenance or modification while keeping their identity confidential, if they desire, and to receive feedback regarding the results of investigations with respect to their concerns. Quality concerns determined to be valid are acted upon by the responsible organization, and the actions are verified prior to closeout.

B.5 INSTRUCTIONS, PROCEDURES AND DRAWINGS

B.5.1 POLICY

Activities affecting the quality of safety-related structures, systems, components and services are accomplished using instructions, procedures and drawings (including vendor manuals) appropriate to the circumstances. These documents include appropriate acceptance criteria.

ANSI/ASME NQA-1 and ANSI/ANS-3.2 commitments contained in Table B-2 of this QATR have been translated into procedural matrices to assure that implementing procedures cover the QA commitments.

B.5.2 IMPLEMENTATION

B.5.2.1 General organizational responsibilities are described in Section B.1, ORGANIZATION.

B.5.2.2 Instructions, procedures, drawings, or vendor manuals incorporate (1) a description of the activity to be accomplished and (2) appropriate quantitative (e.g., tolerances and operating limits) and qualitative (e.g., workmanship standards) acceptance criteria.

B.5.2.3 Nuclear division and departmental procedures provide for implementation of the requirements contained in the committed standards. They describe responsibilities, controls and activities to be accomplished in carrying out commitments. When appropriate, they specify methods and techniques for performing required work.

B.5.2.4 Measures are provided to assure that correct procedures are available and that they are used in the performance of safety-related activities.

B.5.2.5 Inspections, tests, administrative controls, fire drills and training required by the Fire Protection Program are accomplished in accordance with approved instructions, procedures or drawings.

B.5.2.6 Technical Specification required plant procedures are reviewed by an individual knowledgeable in the area affected by the procedure as follows:

1. All applicable plant procedures are reviewed/revised as required by programmatic control stimuli such as: licensee commitments, industry events, vendor technical input, deviation/event reporting, user feedback, plant modifications, Station events or training

experiences, and QA input. The adequacy of the procedure review, approval and control process for procedures that are used within a 24-month interval* will be reviewed during QA audits at least every 2 yr as required by 10CFR50 Appendix B. Administrative procedures, and procedures used during every fuel cycle, are included in this population.

2. Infrequently used procedures (procedures of a routine nature that have not been used or reviewed in the previous 24-month interval*) are reviewed prior to use to determine their adequacy. A revision of a procedure constitutes a procedure review. Procedures used during every fuel cycle are not included in this population.

3. Nonroutine plant procedures, such as emergency operating procedures, alarm response procedures, special operating procedures, and other procedures whose usage may be dictated by an event, are reviewed at least every 2 yr and revised as appropriate. A full revision of a procedure, or detailed scrutiny of a procedure as part of a documented training program, drill, simulator exercise or other such activity, constitutes a procedure review.

4. Emergency plan implementing procedures are reviewed at least annually and revised as appropriate. A full revision of a procedure, or detailed scrutiny of a procedure as part of a documented training program, drill, simulator exercise or other such activity, constitutes a procedure review.

B.5.2.7 Review and Approval

Each procedure of Technical Specifications 6.8.1 (CTS)/5.4.1 (ITS), and changes thereto, shall be reviewed in accordance with Section B.5.2.9 and approved prior to implementation by the branch manager for the functional area of the procedure or higher levels of management as governed by administrative procedures. Each procedure of Technical Specifications 6.8.1 (CTS)/5.4.1 (ITS) shall be reviewed periodically as set forth in administrative procedures.

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* A 24-month interval is defined as 24 months with a maximum allowable extension of 25 percent consistent with the Technical Specification provision for extension of surveillance requirements.

B.5.2.8 Temporary Changes

Temporary changes to procedures of Technical Specifications 6.8.1 (CTS)/5.4.1 (ITS) may be made provided:

1. The intent of the original procedure is not altered;

2. The change is approved by two members of the unit management staff, at least one of whom holds a Senior Operator license on the unit affected; and

3. The change is documented, reviewed in accordance with Section B.5.2.9, and approved within 14 days of implementation by the branch manager for the functional area of the procedure or higher levels of management as governed by administrative procedures.

B.5.2.9 Technical Review and Control Activities

1. Each procedure and program required by Technical Specifications 6.8 (CTS)/5.4 (ITS) and other procedures that affect nuclear safety, and changes thereto, shall be prepared by a qualified individual/organization. Each such procedure, and changes thereto, shall be reviewed by an individual/group other than the individual/group that prepared the procedure, or changes thereto, but who may be from the same organization as the individual/group that prepared the procedure, or changes thereto. Approval of procedures and programs, and changes thereto, and their safety evaluations shall be controlled by administrative procedures.

2. Proposed changes to the Technical Specifications shall be prepared by a qualified individual/organization. The preparation of each proposed Technical Specifications change shall be reviewed by an individual/group other than the individual/group that prepared the proposed change, but who may be from the same organization as the individual/group that prepared the proposed change. Proposed changes to the Technical Specifications shall be approved by the Plant Manager.

3. Proposed modifications to unit structures, systems, and components that affect nuclear safety shall be designed by a qualified individual/organization. Each such modification shall be reviewed by an individual/group other

than the individual/group that designed the modification, but who may be from the same organization as the individual/group that designed the modification. Proposed modifications to structures, systems, and components and the safety evaluations shall be approved before implementation by the Plant Manager or the Manager Technical Support, as previously designated by the Plant Manager.

4. Individuals responsible for reviews performed in accordance with Items 1, 2, 3 and 5 of this section shall be members of the Station supervisory staff, previously designated by the Plant Manager to perform such reviews. Each such review shall include a determination of whether or not additional, cross-disciplinary review is necessary. If deemed necessary, such review shall be performed by the appropriate designated Station review personnel.

5. Proposed tests and experiments that affect Station nuclear safety and are not addressed in the UFSAR or Technical Specifications and their safety evaluations shall be reviewed by the Plant Manager or the Manager Technical Support, as previously designated by the Plant Manager.

6. The Plant Manager shall assure the performance of special reviews and investigations, and the preparation and submittal of reports thereon, as requested by the Vice President Nuclear Generation.

7. The facility security program and implementing procedures shall be reviewed at least every 12 months. Recommended changes shall be approved by the Plant Manager and transmitted to the Vice President Nuclear Generation and to the Chairman of the SRAB.

8. The facility emergency plan and implementing procedures shall be reviewed at least every 12 months. Recommended changes shall be approved by the Plant Manager and transmitted to the Vice President Nuclear Generation and to the Chairman of the SRAB.

9. The Plant Manager shall assure the performance of a review by a qualified individual/organization of changes to the radiological waste treatment systems.

10. Review of any accidental, unplanned, or uncontrolled radioactive release, including the preparation of reports covering evaluation, recommendations, and disposition of the corrective action to prevent recurrence and the forwarding of these reports to the Vice President Nuclear Generation and to the SRAB.

11. Review of changes to the Process Control Program and the ODCM. Approval of any changes shall be made by the Plant Manager or a designee before implementation of such changes.

12. Reports documenting each of the activities performed under Items 1 through 9 of this section shall be maintained. Copies shall be provided to the Vice President Nuclear Generation and the SRAB.

B.17 QUALITY ASSURANCE RECORDS

B.17.1 POLICY

QA records are records that furnish documentary evidence of the quality of items and services. Such documents are prepared by the originator and maintained by designated organizations. They are accurate, complete and legible and are protected against damage, deterioration or loss. They are identifiable and retrievable.

B.17.2 IMPLEMENTATION

B.17.2.1 General organizational responsibilities are described in Section B.1, ORGANIZATION.

B.17.2.2 Documents that furnish evidence of quality of items and services are generated and controlled in accordance with the procedures that govern those activities. Such documents are considered Quality Assurance records upon completion.

<u>Record Retention</u>

In addition to the applicable record retention requirements of Title 10 of the Code of Federal Regulations (10CFR), the following records shall be retained for at least the minimum period indicated.

1. The following records shall be retained for at least 5 yr:

    a. Records and logs of unit operation covering time interval at each power level.

    b. Records and logs of principal maintenance activities, inspections, repair, and replacement of principal items of equipment related to nuclear safety.

    c. All Reportable Events submitted to the Commission.

    d. Records of surveillance activities, inspections, and calibrations required by the Technical Specifications.

    e. Records of changes made to the procedures required by Technical Specifications 6.8.1 (CTS)/5.4.1 (ITS).

    f. Records of radioactive shipments.

g. Records of sealed source and fission detector leak tests and results.

h. Records of annual physical inventory of all sealed source material of record.

2. The following records shall be retained for the duration of the unit Operating License:

   a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the UFSAR.

   b. Records of new and irradiated fuel inventory, fuel transfers, and assembly burnup histories.

   c. Records of radiation exposure for all individuals entering radiation control areas.

   d. Records of gaseous and liquid radioactive material released to the environs.

   e. Records of transient or operational cycles for those unit components designed for a limited number of transients or cycles. For Unit 2, these components are specified in Technical Specification Table 5.7.1-1 (CTS)/USAR (ITS).

   f. Records of reactor tests and experiments.

   g. Records of training and qualification for current members of the unit staff.

   h. Records of in-service inspections performed pursuant to the Technical Specifications.

   i. Records of quality assurance activities required by the QATR and not listed under Item 1 of this section.

   j. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10CFR50.59.

   k. Records of meetings of the SORC and the SRAB.

   l. Records of the service lives of all snubbers, including the date at which the service life commences and associated installation and maintenance records (Unit 2).

m. Records of analyses required by the Radiological Environmental Monitoring Program that would permit evaluation of the accuracy of the analysis at a later date. This should include procedures effective at specified times and QA records showing that these procedures were followed.

n. Records of unit radiation and contamination surveys.

B.17.2.3 A document becomes a record when completed. At that time it is designated as a lifetime or nonpermanent record and is transmitted to file. Nonpermanent records have specified retention times. Lifetime records are maintained for the life of the item and/or plant as appropriate.

B.17.2.4 In-process documents are controlled by the originator until completed and transmitted to file.

B.17.2.5 Records may be original documents, legible copies, or in various microform formats.

B.17.2.6 Authorized personnel may issue corrections or supplements to records. Procedures address acceptable methods of making corrections to records.

B.17.2.7 Traceability between the record and the item or activity to which it applies is provided.

B.17.2.8 Records are stored in appropriate fire rated facilities, or in remote dual facilities to prevent damage, deterioration, or loss due to natural or unnatural causes.

B.18 AUDITS

B.18.1 POLICY

Audits are carried out to provide an independent evaluation of compliance and effectiveness of the QA Program, including those elements of the program implemented by suppliers. Audits are performed in accordance with written procedures or checklists by qualified personnel not having direct responsibility in the areas audited. Audit results are documented and are reviewed by management. Follow-up action is taken where indicated.

B.18.2 IMPLEMENTATION

B.18.2.1 General organizational responsibilities are described in Section B.1, ORGANIZATION.

B.18.2.2 NQA audits are performed:

1. To provide a comprehensive independent verification and evaluation of quality-related procedures and activities; and

2. To verify and evaluate the QA programs, procedures, and activities of suppliers.

B.18.2.3 Audits are performed in accordance with established schedules. Applicable QA Program elements are audited at least once every 2 years.

B.18.2.4 SRAB audits are performed as specified in the Unit Technical Specifications.

B.18.2.5 Regularly scheduled audits are supplemented by special audits when appropriate. Conditions which may warrant special audits include:

1. Significant changes are made in the QA Program.

2. When it is suspected that quality has been adversely affected.

3. When an independent assessment of program effectiveness is considered appropriate.

B.18.2.6 Audits include an objective evaluation of quality-related practices, procedures, instructions, activities, items, documents and records to confirm that the QA Program is effective and properly implemented. The following activities are included:

1. Indoctrination and training program.

2. Interface control between NMPC organizational units and between NMPC and its principal contractors.

3. Corrective action.

4. M&TE calibration.

5. Nonconformance control.

6. FSAR commitments.

7. Activities associated with computer codes.

8. Activities associated with design verification performed by designers' immediate supervisor.

B.18.2.7 Audit procedures and the scope, plans, checklists and results of individual audits are documented.

B.18.2.8 Personnel selected for auditing assignments have experience or are given training commensurate with the needs of the audit and have no direct responsibilities in the areas audited.

B.18.2.9 Lead auditors are qualified and certified in accordance with approved procedures.

B.18.2.10 Audit data are analyzed to identify any quality deficiencies and assess the effectiveness of the QA Program. Audit reports are distributed to the responsible management of both the audited and auditing organizations.

B.18.2.11 Management of the audited organization takes appropriate action to correct observed deficiencies and to identify the cause and prevent recurrence of any significant conditions adverse to quality. Follow-up is performed by NQA to ensure that the appropriate corrective action is taken and is effective. Such follow-up includes re-audits when necessary.

B.18.2.12 QA audits are conducted and documented to verify compliance with the Fire Protection Program.

Fire Protection Program audits are performed per the requirements of the applicable Technical Specifications.

Fire protection audits may be combined during a specific audit period provided the scope of the audit

TABLE B-1

QUALITY ASSURANCE PROGRAM
RESPONSIBILITY MATRIX

Regulatory Requirements			Industry Standards		NMPC Policy/Directives and Implementing Organization Procedures						
						Procedures					
						VP-NSAS					
10CFR50 Appendix B		BTP 9.5-1 Appendix A	NQA-1	ANS-3.2	NMPC Management Policy and Directives	QA	NL	NT	NE	NG	NTP[1]
I.	Organization	C	1,1s-1	1 3.1 3.3 3.4.2	X	X	[2]	[2]	X	X	
II.	QA Program	C	2,2s-1 2s-2 2s-3	3.1 3.3 5.1 5.3 3.4.2 3.5	X	X		X	X	X	X
III.	Design Control	C.1	3,3s-1	5.2.7.2	X				X	X	X
IV.	Procurement Document Control	C.1	4,4s-1	5.2.13.1	X				X		X
V.	Instructions, Procedures & Dwgs.	C.2	5	5.2.7 5.3	X		X	X	X		X
VI.	Document Control		6,6s-1	5.2.15	X	X	X				X
VII.	Control of Purch. Matl.	C.3	7,7s-1	5.2.13.2	X				X	X	X
VIII.	Ident./Control of Matl.		8,8s-1	5.2.13.3	X				X	X	X
IX.	Control of Special Processes		9,9s-1	5.2.18 5.2.12	X	X				X	
X.	Inspection	C.4, C.6	10,10s-1	5.2.17	X	X			X	X	X
XI.	Test Control	C.5	11,11s-1	5.2.19	X				X	X	
XII.	Control of M&TE		12,12s-1	5.2.16	X	X				X	
XIII.	Handling, Storage and Shipping		13,13s-1	5.2.13.4	X				X	X	X

TABLE B-1 (Cont'd.)

Regulatory Requirements			Industry Standards		NMPC Policy/Directives and Implementing Organization Procedures						
						Procedures					
						VP-NSAS					
10CFR50 Appendix B		BTP 9.5-1 Appendix A	NQA-1	ANS-3.2	NMPC Management Policy and Directives	QA	NL	NT	NE	NG	NIP[1]
XIV.	Inspection, Test, and Operating Status	C.6	14	5.2.6 5.2.14	X					X	
XV.	Nonconforming Materials, Parts, or Components	C.7	15,15s-1	5.2.14	X	X			X	X	X
XVI.	Corrective Actions	C.8	16	5.2.11	X	X			X	X	X
XVII.	Quality Assurance Records	C.9	17,17s-1	5.2.12	X	X	X	X	X	X	X
XVIII.	Audits	C.10	18,18s-1	4.5	X	X					

(1) Nuclear Interface Procedure (NIP) includes QA Organization as well as other nuclear organization responsibilities.
(2) Functional positions and responsibilities within the NSAS organization are established and controlled by NSAS Administrative Procedure.

NMPC Organizations

NSAS - Nuclear Safety Assessment and Support, which includes:
QA - Quality Assurance
NL - Nuclear Licensing
NT - Nuclear Training
NE - Nuclear Engineering and Procurement
NG - Nuclear Generation, which includes: Operations, Maintenance, Chemistry, Radiation Protection, Technical Support, and Work Control Outage

TABLE B-3 (Cont'd.)

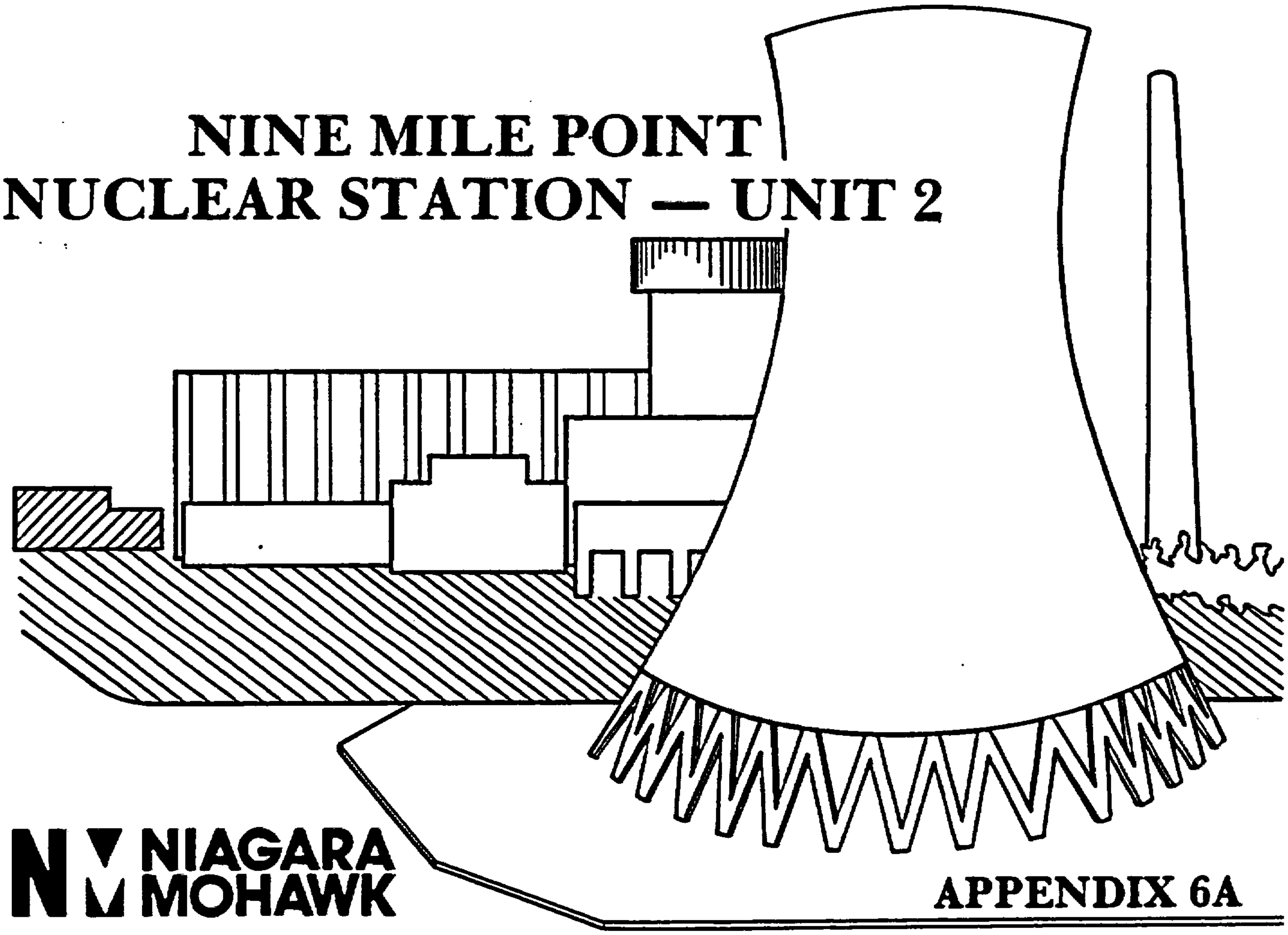
	DOCUMENT	INTERPRETATION/EXCEPTION
	b. Para. 1.1	Requirements - This paragraph refers to "...all activities affecting those functions important to safety..." Exception - NMPC is committed to a program based on controls applied to safety-related systems, components and services.
	c. Para. 3.4.2	Requirement - This paragraph establishes requirements for the qualifications of the onsite Operations organization. Implementation - In lieu of these controls, NMPC will comply with those controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs and the related Technical Specifications.
	d. Section 4	Requirements - These paragraphs establish requirements for reviews and audits. Implementation - In lieu of these controls, NMPC will comply with those controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs, the related Technical Specifications, and Section B.18 of this QATR.
	e. Section 5	Requirement - Reference is made within this section to the ANSI/ANS-3.2 General Appendix for typical activities which should be covered by written procedures. Implementation - In lieu of these controls, NMPC will comply with those controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs, the related Technical Specifications, and Section B.5 of the QATR.
	f. Para. 5.2.1.6	Requirement - This section provides rules for the maximum number of hours at a duty station. Implementation - In lieu of these controls, NMPC will comply with those controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs and the related Technical Specifications.
	g. Para. 5.2.2	Requirement - Portions of this paragraph specify approvals for temporary procedure changes. Implementation - In lieu of these controls, NMPC will comply with those controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs, the related Technical Specifications, and Section B.5 of the QATR.
	h. Para. 5.2.7	Requirement - This paragraph requires the use of ANSI/IEEE-336-1980. Implementation - In lieu of the referenced standard, Table B-2 of this QATR commits to IEEE-336-1971.

TABLE B-3 (Cont'd.)

	DOCUMENT	INTERPRETATION/EXCEPTION
	o. Para. 5.2.13.2	Requirement - Where required by law, regulation or contract requirements, documentary evidence that items conform to procurement requirements shall be available at the nuclear power plant site prior to installation or use of such items. Interpretation - NMPC requires that the required documentary evidence be available at the site prior to use, but not necessarily prior to installation. This allows installation to proceed under specified conditions while any missing documents are being obtained, but precludes dependence on the item for safety purposes.
	p. Para. 5.2.13.4	Requirement - This paragraph refers to ANSI/ASME N45.2.2-1978. Exception - In lieu of the referenced standard, NMPC is committed to ANSI/ASME NQA-2-1983, part 2.2, for nuclear safety-related permanent plant modifications and maintenance activities.
	q. Para. 5.2.15	Requirement - This paragraph established administrative controls for the review, approval and control of procedures. Implementation - In lieu of these controls, NMPC will comply with those controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs and the related Technical Specifications as follows: as an alternative to performing procedure reviews no less frequently than every 2 yr to determine if changes are necessary or desirable, NMPC has programmatic controls in place to continually identify procedure revisions which may be needed to ensure procedures are appropriate for the circumstances and are maintained current.
	r. Para. 5.2.16	Requirement - Records shall be made and equipment suitably marked to indicate calibration status. Exception - Installed plant instrumentation calibration status is tracked through the PMST database. Calibration status of portable measurement & test equipment (M&TE) may be labeled on the case or attached to the device. For instances where size or application precludes attaching the calibration labels on the device, the device shall be uniquely identified and traceable to its calibration record.
	s. Para. 5.2.16	Requirement - This paragraph references ANSI/IEEE-336-1980. Implementation - In lieu of the referenced standard, NMPC commits to IEEE-336-1971. (See Table B-2, Item 8.)
	t. Para. 5.3	Requirement - This paragraph establishes administrative controls for written procedures. Implementation - In lieu of these controls, NMPC will comply with those controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs, the related Technical Specifications, and Section B.5 of the QATR.

UPDATED SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2



NIAGARA MOHAWK

APPENDIX 6A

DESIGN ASSESSMENT REPORT FOR HYDRODYNAMIC LOADS

SECTION 6A.1

INTRODUCTION

6A.1.1 Purpose

The purpose of the Design Assessment Report for Hydrodynamic Loads (DAR) is to present the completed design assessment of the Nine Mile Point Nuclear Station - Unit 2 (Unit 2) for hydrodynamic loads associated with safety/relief valve (SRV) discharge and the postulated loss-of-coolant accident (LOCA) in a boiling water reactor (BWR) Mark II containment.

For the design basis assessment, the methods used to define, apply, and combine the loads are in compliance with the following Nuclear Regulatory Commission (NRC) documents as outlined in Table 6A.1-1:

1. NUREG-0487, Supplements 1 and 2
   Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria

2. NUREG-0808
   Mark II Containment Program Load Evaluation and Acceptance Criteria

3. NUREG-0802
   Safety/Relief Valve - Quencher Loads Evaluation Reports - BWR Mark II and III Containments

4. NUREG-0783 (Draft)
   Suppression Pool Temperature Limits for BWR Containments

5. NUREG-0763
   Guidelines for Confirmatory Inplant Tests of Safety-Relief Valve Discharges for BWR Plants

The basic supporting document for the Unit 2 design assessment is the Mark II Containment Dynamic Forcing Functions Information Report (DFFR), Revision 4[1]. Additional references will be cited where the methods are different from those described in DFFR Revision 4 or where a particular loading condition was not addressed in DFFR Revision 4.

NOTE: The DAR for Unit 2 that was submitted in July 1976 has been superseded in its entirety by this appendix. Appendix 6A is the DAR.

6A.1.2 Scope

NRC letters[2,3] to Niagara Mohawk Power Corporation (NMPC) discussed the SRV and LOCA hydrodynamic load phenomena associated with the BWR Mark II containment. Specific requests for additional information included with each letter formed the initial basis for the Unit 2 design assessment. In the course of investigating the Mark II hydrodynamic phenomena, the requirements for design assessment have been refined, and are now contained in the NUREGs referenced in Section 6A.1.1. In this appendix, the Mark II acceptance criteria are addressed item by item to document the compliance identified in Section 6A.1.1.

6A.1.3 Summary of Design Assessment

A design assessment has been performed on structures, equipment, and piping subjected to loads resulting directly or indirectly from suppression pool hydrodynamic phenomena. These are as follows:

1. Reactor building basemat and structures and primary containment structures.
2. Primary containment internal structures including the reactor pressure vessel (RPV) pedestal and drywell floor.
3. Primary containment basemat, wall, and pedestal liners.
4. Downcomers.
5. Auxiliary structures such as platforms, ladders, and support frames in the primary containment.
6. Safety-related piping and pipe supports located within the primary containment and reactor building.
7. Safety-related equipment located within primary containment and reactor building.
8. RPV, RPV internals, and associated equipment.
9. Recirculation piping and floor- and pipe-mounted equipment.
10. Control and instrumentation equipment.

Section 6A.2.1 provides a general description of the suppression pool hydrodynamic loading phenomena. Sections 6A.3 and 6A.4 provide more detail for the SRV and LOCA loads, respectively. Load combinations, acceptance criteria, and the methods of combining peak dynamic responses are given in Section 6A.2.2. Other dynamic loads with which hydrodynamic loads must be combined are identified in Section 6A.2.3.

Section 6A.2.4 describes the approach used in performing the Unit 2 design assessment for each of the three following classifications of loading functions:

1. Submerged Structure/Pool Swell Loads Loads directly applied by suppression pool hydrodynamic phenomena to wetwell internal structures and the drywell floor.

2. Building Response Loads Suppression pool hydrodynamic loads applied directly to the suppression pool boundaries (primary containment shell, basemat, and RPV pedestal) and then indirectly to structures, piping, and equipment in the drywell and reactor building due to building dynamic response.

3. Related Effects Other design assessment activities related to suppression pool hydrodynamic phenomena but not included in the above classifications, such as suppression pool temperature response and downcomer/SRV discharge line (SRVDL) fatigue evaluations.

Sections 6A.5 through 6A.9 provide the results of the Unit 2 design assessment. Detailed results of the nuclear steam supply system (NSSS) piping and major safety-related equipment evaluations are presented in Sections 3.9 and 3.10.

Section 6A.5 covers the dynamic responses of the primary structures and provides the amplified response spectra (ARS) used in the NSSS and balance-of-plant (BOP) piping and equipment evaluations, the results of which are presented in Section 6A.9.

Section 6A.6 presents the design assessment results for the primary structures; Section 6A.7, the results for the primary containment liner; and Section 6A.8, the results for the reactor building. Section 6A.10 describes the suppression pool temperature response to plant transients involving SRV discharge and describes the pool temperature monitoring system.

Table 6A.1-1 provides a summary of suppression pool hydrodynamic loads used in the Unit 2 design assessment for each affected structure. T-quenchers are used as the SRV discharge devices, and the design assessment is based upon vendor design information[4]. The design assessment has demonstrated that sufficient design margins exist in plant structures and components to withstand the effects of the hydrodynamic loads.

6A.1.4 General Arrangement of Suppression Pool Structures

Figures 6A.1-1 through 6A.1-3 show the general arrangement of the suppression chamber, internal structures, and drywell floor penetrations.

6A.1.5 References

1. Mark II Containment Dynamic Forcing Functions, GE Report NEDO-21061, Rev. 4, November 1981.

2. NRC letter to Niagara Mohawk Power Corporation dated April 18, 1975.

3. NRC letter to Niagara Mohawk Power Corporation dated April 21, 1975.

4. Nine Mile Point Unit 2, Thermo Hydraulic Quencher Design of the Safety Relief System, Kraftwerk Union Technical Report No. KWU/R/14/21/1979.

5. Pennsylvania Power & Light Company, Susquehanna Steam Electric Station Units 1 and 2, Docket Nos. 50-387 and 50-388, Design Assessment Report, April 1978.

SECTION 6A.2

LOADS AND LOAD COMBINATIONS

6A.2.1 Load Description - Suppression Pool Hydrodynamic Loads and Related Effects

The sequences of hydrodynamic events that occur during a SRV actuation and a postulated LOCA are described in this section. The objective is to describe potential load-producing conditions used in design evaluations.

6A.2.1.1 Safety/Relief Valve Actuation

SRVs are utilized to provide pressure relief during certain reactor transients. SRV actuation may occur:

1. In response to a reactor system transient pressure increase (pressure actuation).

2. As the result of planned Operator actuation (manual operation).

3. As the result of a failure or error affecting one SRV (inadvertent) opening.

4. As part of the automatic depressurization system (ADS).

Both inadvertent and manual operation involves a single SRV. Pressure actuation involves the sequential opening of from one to all SRVs during vessel pressure rise. The opening sequence depends on the SRV pressure setpoints. ADS valves are actuated simultaneously in response to intermediate break accident (IBA) conditions (Section 6A.2.1.2.2). Steam discharged through the valves is routed through discharge lines to be condensed into the suppression pool. The end of each discharge pipe is fitted with a quencher to promote heat transfer between the air-steam mixture and the water in the suppression pool.

Prior to a typical actuation, the SRV discharge piping contains ambient air and a column of water. The height of the column is determined by the submergence of the SRVDL in the suppression pool, and the difference in the drywell and suppression chamber overpressure. Upon SRV actuation, steam compresses the air in the discharge piping resulting in a pressure buildup which forces the water column through the quencher. Water and air from the SRV line is expelled followed by steady-state steam discharge. This is called the line-clearing phase of the SRV discharge. Loads associated with line clearing are transient SRV pipe pressure and thermal loads, pipe reaction forces from transient pressure wave, and fluid motion in the pipe. The line-clearing loads are discussed in Section 6A.3.4.

Following water clearing, the compressed air is formed into high-pressure air bubbles as it accelerates into the suppression pool. The bubbles undergo several oscillating expansions and contractions as they rise to the pool surface. The oscillating air bubbles interact with the suppression pool water producing an oscillating pressure field. The oscillating pressure field exerts a load on the primary containment submerged boundaries. This is referred to as SRV air-clearing load (Section 6A.3.4.7). The water jet and air bubbles also exert drag loads on submerged structures. The submerged structure loads during SRV actuations are discussed in Section 6A.3.4.8.

Following the air-clearing phase, steady steam discharge flow is established and continues until the SRV is closed or the reactor is depressurized. Test data indicate that stable steam condensation exists and the steam is condensed completely in the vicinity of the quencher(1). Analysis of the suppression pool temperature is presented in Section 6A.10. While there is no appreciable suppression pool boundary and submerged structure load during steam condensation, some pipe reaction and thrust forces do act on the quencher body and its support. These loads are discussed in Sections 6A.3.4.4 through 6A.3.4.6. The event-time relationship for a typical SRV discharge is shown on Figure 6A.2-1.

6A.2.1.2 Loss-of-Coolant Accidents

A spectrum of postulated LOCAs is considered to assess the design adequacy of the primary containment system. The hypothetical events and accident conditions are described in this section.

6A.2.1.2.1 Design Basis Accident

The design basis accident (DBA) utilized in the DAR is defined as the LOCA that results in the highest drywell pressure. Usually this is either a double-ended break of a recirculation pump suction line or a main steam line (MSL). The mass and energy release from the break causes rapid pressurization of the drywell and expulsion of the water initially in the downcomers. During the downcomer-clearing process, the water exiting the downcomers forms submerged jets in the suppression pool. The water jets cause impingement and drag loads on structures near the paths of the jets as well as pressure loads on the submerged boundaries. The water jet loads are presented in Sections 6A.4.2 and 6A.4.9.

Following downcomer clearing, air purged from the drywell forms bubbles at the downcomer exits. As the flow of air and steam from the drywell continues, the LOCA bubbles expand with the bubble pressure nearly equal to the drywell pressure. The expanding bubbles create a pressure field in the suppression pool that results in loads on submerged structures and on the pool boundaries. LOCA air bubble loads are discussed in Sections 6A.4.3 and 6A.4.9.

The continued injection of drywell air and the resultant expansion and coalescence of air bubbles produces a rapid rise in the suppression pool surface. This is called the suppression pool swell phase. Any structures close to the suppression pool surface experience impact loads as the rising suppression pool surface strikes the lower surface of the structures, followed by drag loads as the suppression pool surface continues past the structure. In addition, the rising water compresses the suppression chamber air and produces an upward force on the drywell floor. The rising water is eventually stopped by the compressed air in the suppression chamber. The air bubbles break through the surface and gravity-induced suppression pool fallback begins, settling the water back in the suppression pool. The impact and drag loads on any structures along the path of suppression pool swell and fallback, as well as the drywell floor uplift load, are presented in Sections 6A.4.4 and 6A.4.9.

After the suppression pool swell transient, a period of high steam flow rate through the downcomer occurs, followed by a decreasing flow rate as the blowdown continues. Test data show that the steam is entirely condensed in the downcomer exit region. The condensation process is influenced by the downcomer flow rate and the fraction of air flow. At high downcomer flow rates, the steam-water interface oscillates outside the downcomer exit. This phenomenon, referred to as condensation oscillation, produces oscillatory pressure loads on the suppression pool boundaries and submerged structures. Condensation oscillation is discussed in Section 6A.4.5 and the associated submerged structure load in Section 6A.4.9.

At lower steam flow rates, the steam bubbles at the downcomer exit alternately grow and collapse. This unsteady condensation process is referred to as chugging. Chugging also generates pressure oscillation loads on the suppression pool boundaries and submerged structure loads. In addition, the steam bubbles collapse may be asymmetric and produce lateral loads on the downcomer itself. Lateral loads are discussed in Section 6A.4.7. Chugging loads on suppression pool boundaries and submerged structures are presented in Sections 6A.4.6 and 6A.4.9, respectively.

The event-time relationship for a DBA is shown on Figure 6A.2-2. No SRV actuation is mechanistically possible during the DBA due to the associated rapid depressurization of the reactor vessel.

6A.2.1.2.2 Intermediate Break Accident

An IBA is defined as a liquid line break of approximately 0.1 sq ft. The break size is small enough that rapid depressurization of the RPV does not occur. However, the reactor inventory loss is sufficiently rapid to cause a reduction in reactor water level. Consequently, the ADS depressurizes the RPV and allows the low-pressure emergency core cooling system (ECCS) pump to reflood the vessel. The ADS actuates on a level 1 reactor water level signal coincident with the high drywell pressure signal. A timer in the ADS logic delays actuation until approximately 105 sec (assumed) after the time of coincident initiation signals. When activated, the ADS mechanically actuates the ADS valves, overriding any pressure-actuated valve discharges.

The drywell pressurization rate resulting from an IBA is significantly less than that from a DBA. The downcomer clearing load is less than that resulting from a DBA and there is no significant suppression pool swell. The resulting IBA loads on suppression pool boundaries, submerged structures and equipment are bounded by the corresponding load from a DBA.

For intermediate size breaks, the steam flow rate through the downcomers may be insufficient to cause condensation oscillations. However, chugging loads will occur until the reactor vessel blowdown is reduced to a flow rate where chugging becomes insignificant. To cover the whole spectrum of events, a low downcomer mass flux condensation oscillation load is still defined and used in combination with the ADS load. The event-time relationship for an IBA is shown on Figure 6A.2-3.

6A.2.1.2.3 Small Break Accident

A small break accident (SBA) is defined as an event in which the fluid loss rate from the reactor system is insufficient to depressurize the reactor or result in a decrease of reactor water level. A typical SBA is a 0.01-sq ft steam line break. Following the break, the drywell pressure slowly increases until the high drywell pressure scram setting is reached. The reactor scrams, but the main steam isolation valves (MSIVs) may not close immediately. By conservatively postulating that the MSIVs do close immediately, the reactor system experiences a pressure increase when an isolation transient occurs and SRVs actuate to control system pressure.

Drywell pressure continues to increase at a rate dependent on the size of the break. The pressure increase depresses the water level in the downcomer until the water is expelled and air and steam enter the suppression pool. The air flow rate is such that the air bubbles through the suppression pool without causing suppression pool swell. The steam condenses and drywell air passes to the suppression chamber air space. The suppression chamber gradually pressurizes at a rate dependent upon the air carryover rate. Eventually, all the drywell air is carried over to the suppression chamber and the suppression chamber pressurization rate is controlled by the suppression pool heatup rate.

Vacuum breakers are provided on the drywell floor to vent air back to the drywell when the blowdown is over.

The steam flow rate through the downcomers for a SBA is insufficient to cause condensation oscillations. There may be sufficient steam flow to cause chugging. As the reactor vessel depressurizes and cools down, the downcomer steam mass flux decreases so that the downcomers may not remain cleared. Steam condensation can occur at the water interface inside the downcomers and on the walls of the downcomer pipe.

As a result of a postulated MSIV closure, the SRVs initially discharge for reactor vessel pressure relief in response to the isolation transient. Following the initial discharge, SRV cycling may occur based upon RCBP and valve setpoint. When the suppression pool temperature reaches the Technical Specification limit of 120°F, the Operator (following procedures) begins a controlled shutdown depressurization at the rate of 100°F/hr using manual operation of the SRVs if MSIVs are closed, or using the main condenser if MSIVs are open. The event-time relationship for a typical SBA is shown on Figure 6A.2-4.

6A.2.2 Load Combinations and Acceptance Criteria

The suppression pool hydrodynamic loads, as well as the mechanistic relationships between SRV and LOCA loads, are described in Section 6A.2.1. These relationships form the basis for Mark II load combinations.

Design load combinations resulting from this basis are presented in Table 6A.2-1. Following are several important features of the design load combinations:

1. All combinations of SRV and LOCA loads could occur with or without an operating basis earthquake (OBE)/safe shutdown earthquake (SSE).

2. Without a LOCA event, SRV actuation could occur with or without a seismic event.

3. Without SRV actuation, a LOCA event could occur with or without a seismic event.

The appropriate designation of acceptance criteria for structures and components is to be evaluated as important as the identification of design load combinations. Once acceptance criteria are associated with design load combinations, it becomes evident that many simplifications to Table 6A.2-1 can be made, while still retaining all appropriate combinations. The resulting design basis load combinations and acceptance criteria will vary for different types of structures and components, since different design procedures and codes are applicable. These are discussed in detail in the following sections.

6A.2.2.1 Reinforced Concrete Structures

The load combinations and acceptance criteria for the Unit 2 reinforced concrete structures, including the basemat, pedestal, and primary containment, are presented in Table 6A.2-2. This is consistent with Table 5-1 of the DFFR, Rev. 4[2]. As discussed there, the factored load philosophy of the strength design method is employed for the assessment of Mark II hydrodynamic loads. This is consistent with the original factored load design in accordance with ACI-318-77, Building Code Requirements for Reinforced Concrete.

Load combinations 1 and 2 (Table 6A.2-2) for normal operation with and without thermal effects are based on ACI-318-77, Paragraphs 9.2.1 and 9.2.7. Load combinations 3 through 7a cover the same combinations of events as ASME Section III, Division 2, with SRV actuations also included. With the inclusion of SRV loads, load factors are adjusted to provide consistent safety margins.

It is noted that substantial simplification from Table 6A.2-1 has been achieved by two means. First, SBA and IBA effects are grouped together. This is reasonable since their effects are generally comparable and both can occur with the same possible SRV actuation cases. Second, the various SRV actuation cases are not called out separately. For design assessment purposes, the most severe SRV actuation case possible should be considered. For Unit 2, the maximum results from any SRV actuation case, including an all-valve discharge, are conservatively used in combinations with SBA and IBA events as well as in combinations without LOCA events.

6A.2.2.2 Steel Structures

Load combinations and acceptance criteria for steel structures in Unit 2 are presented in Table 6A.2-3 (steel structures are not addressed in the DFFR[2]). Table 6A.2-3 contains the same event combinations as Table 6A.2-2; however, unfactored loads are used with stress allowables that reflect the probability of occurrence of each load combination. The stress allowables are in accordance with the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings. This approach is identical to that used in the original design with the dynamic effects of SRV and LOCA loads now included.

6A.2.2.3 Piping and Equipment

Load combinations and acceptance criteria for BOP and NSSS piping and equipment are presented in Tables 6A.2-1a and 6A.2-1b, respectively. This is consistent with Table 5-2 of DFFR Rev. 4[2] and NUREG-0800[3].

The load combination methods are described in Section 6A.2.2.5 and are consistent with NUREG-0800[3]. The applicable load cases and the dynamic analysis procedures used for Unit 2 are consistent with NUREG-0800[3] as follows:

SEB-2 and MEB-4	Use ±15 percent peak broadening of ARS.

SEB-3 and MEB-5	Use Regulatory Guide (RG) 1.92 to combine modal responses.
MEB-2	Use OBE damping for normal/upset conditions; use design basis earthquake (DBE) damping for emergency/faulted conditions.
MEB-7(a)	Annulus pressurization effects are combined with SSE.
MEB-7(b)	OBE plus SRV is treated as an upset condition on an evaluation basis.
MEB-8	Criteria to assure functional capability for all essential components are in conformance with NUREG/CR-0261 and consistent with NUREG-0800[3].

6A.2.2.4 Reactor Pressure Vessel and Internals

Load combinations and acceptance criteria for the RPV and internals are presented in Table 6A.2-1b.

6A.2.2.5 Combination of Dynamic Responses

For all the mechanical systems, components, and supports in Tables 6A.2-1a and 6A.2-1b, the dynamic responses to the dynamic loads such as LOCA, SRV, and OBE/SSE are combined by the square root of the sum of squares (SRSS) method[4]. The NRC topical report evaluation[5] and Revision 1 of NUREG-0484[6] accept the SRSS method for the Mark II load combinations.

Various dynamic loads for applicable Category I structures such as LOCA, SRV, and OBE/SSE are combined by the absolute sum method for designing structural components.

6A.2.3 Other Dynamic Loads

The Unit 2 design basis loads are defined in or are derived from information presented in the appropriate sections of the Final Safety Analysis Report (FSAR). The major design loads, in addition to normal operating conditions, result from LOCA and seismic events.

The design basis LOCA loads include the quasi-static pressure and temperature transients in the primary containment, pipe rupture loads, annulus pressurization, and hydrodynamic loads in the suppression chamber and the drywell. The quasi-static pressure and temperature transients are defined in FSAR Section 6.2. Pipe rupture loads are described in FSAR Section 3.6A. Annulus pressurization is discussed in Section 6A.4.8. Hydrodynamic loads are specified in Section 6A.4.

The Unit 2 DBE ground response spectra are defined in FSAR Section 3.7A. One special subset of seismic loads not discussed in the FSAR is referred to as seismic sloshing and is described below.

Sloshing is a term used to describe the dynamic response of the suppression pool water due to the movement of its boundary walls, these boundaries being the primary containment, pedestal, and basemat. The sloshing response of water will generate hydrodynamic pressure loads on the boundary walls and drag loads on structures submerged in the suppression pool. These loads have been determined for both the OBE and the SSE and included in appropriate acceptance criteria for plant structures.

The formulation of the seismic sloshing problems in annular and circular tanks can be found in NUREG/CR-1083[7] and a technical paper[8]. The solution consists of solving the Laplace equation to derive a velocity potential. Ground motion is introduced into the solution through the boundary conditions which are time dependent. The associated eigen-value problem is solved to determine the natural frequencies and mode shapes of the sloshing movements. Water displacements, velocities, and dynamic pressures are derived from the potential function. Drag loads are calculated for velocity drag, acceleration drag, and lift with corrections for unsteady flow and interference from neighboring structures.

Free surface deflection time history due to SSE ground motion at r=14.167 ft (pedestal outer radius), θ=0 degrees for the suppression pool, is given on Figure 6A.2-5. The extreme values of the free surface deflection are -3.02 ft and 3.02 ft for the outer suppression pool and -2.05 ft and 2.05 ft for the inner suppression pool. In this analysis two horizontal components and one vertical component of the earthquake are acting simultaneously. Each horizontal component has maximum value of acceleration of 0.15 g (SSE). The vertical component of acceleration conservatively meets the requirements of RG 1.60 as discussed in Section 3.7A.

The maximum dynamic pressure caused by SSE ground motion on pedestal, primary containment wall, and basemat occurs at approximately 9.25 sec. The distribution in the x-z plane for θ=0 degrees and θ=180 degrees is given on Figures 6A.2-6 and 6A.2-7, respectively. The maximum dynamic pressure acting on the primary containment wall is +2.58 psi and -2.63 psi. The maximum dynamic pressure acting on the pedestal wall occurs on the inside diameter and is +1.88 psi and -2.09 psi. The maximum responses for OBE are one-half of SSE.

Submerged structure load time histories were calculated on structures listed in Table 6A.4-3. Sensitivity studies were made to locate the structures that had the maximum response to sloshing. A typical OBE load time history for a 1.25-ft section of quencher arm for SRV line SVV-012-67-3 is given on Figures 6A.2-8 through 6A.2-10.

Other design loads include wind, flood, and missiles as described in FSAR Sections 3.3, 3.4, and 3.5, respectively.

6A.2.4 Approach Used for Design Assessment

Section 6A.2.4 describes the manner in which the Unit 2 design assessment for suppression pool hydrodynamic loads has been accomplished. Section 6A.2.4.1 describes the direct loads considered in the Unit 2 design assessment. Indirect loading due to building response is discussed in Section 6A.2.4.2. Section 6A.2.4.3 covers hydrodynamic load considerations not appropriate for Sections 6A.2.4.1 or 6A.2.4.2.

6A.2.4.1 Submerged Structure/Suppression Pool Swell Loads

The hydrodynamic loads described in Section 6A.2.1 act on the submerged boundaries of the suppression pool and on structures within the suppression pool. During suppression pool swell, hydrodynamic loads also act on the suppression chamber airspace boundary and the drywell floor, as well as structures in the suppression pool swell zone above the suppression pool. Figures 6A.2-11 through 6A.2-26 describe the time relationships of hydrodynamic loads acting on the following structures:

1. Drywell floor (Figure 6A.2-11).
2. Downcomers (Figures 6A.2-12 through 6A.2-15).
3. Suppression chamber walls above water level (Figure 6A.2-16).
4. Submerged suppression chamber (Figures 6A.2-17 through 6A.2-20).
5. Submerged structures (Figures 6A.2-21 through 6A.2-24).
6. Structures above suppression pool, below breakthrough (Figure 6A.2-25).
7. Structures above breakthrough (Figure 6A.2-26).

Section 6A.3 discusses the suppression pool boundary loads due to SRV discharge.

Section 6A.4 discusses the LOCA-related suppression pool boundary loads due to downcomer clearing, condensation oscillations, and chugging as well as the vertical and lateral chugging loads on the downcomers. Section 6A.4 also describes the methods used to calculate the bulk suppression pool swell transient; loads on submerged structures within the suppression pool due to SRV discharge, downcomer clearing, condensation oscillations, and chugging; and loads on structures in and above the suppression pool due to pool swell. SRV discharge and LOCA-related suppression pool boundary loads affect structures and components outside the suppression pool by exciting the primary containment and the reactor building. The methods used to calculate these building response loads are described in Section 6A.2.4.2.

6A.2.4.2 Building Response Load

To determine the dynamic response of the containment structures when subjected to SRV discharge and LOCA loads, a finite element-based computer program, Dynamic Stress Analysis of Axisymmetric Structures under Arbitrary Loading, developed by S. Ghosh and E. Wilson and modified by Stone & Webster Engineering Corporation (SWEC) (Appendix 3A), was utilized.

Mathematical models are developed which model the mat, the primary containment, the shield wall, the reactor pedestal, and the reactor building. The stiffening effects of the RPV stabilizer and star truss are also included. The major dimensions of the structures and identification of their general arrangement are illustrated on Figures 1.2-12, 3.8-11, and 3.8-20.

Figure 6A.5-1 depicts the structural model used to represent the complete reactor building and supporting rock. Solid axisymmetric elements are used to represent the rock to a radius and depth of approximately 3 mat radii, with axisymmetric thin shell elements representing the structures. The external dimensions of the rock were selected to preserve free-field motions. The boundary conditions for the rock, at a radius of approximately three times the mat radius, are fixed at the base of the rock and simply supported along the height of the rock.

Figure 6A.5-1 shows a relatively uniform element spacing in the area of the primary containment with varying element size in the reactor building areas. This spacing has been used because the loads are applied to the pool boundaries within this area and a precise definition of internal loads is required.

The equations of motion are solved numerically by direct integration. The effects of structural damping have been included in the dynamic analysis, unless otherwise noted. The Rayleigh damping technique is utilized in which the damping matrix is assumed to be linearly proportional to the mass and stiffness matrix of the structure. The constants of proportionality are chosen to obtain maximums of 4- and 7-percent damping values for reinforced concrete structures under normal operating conditions for SRV loads and LOCA-related loads, respectively, for frequencies between 10 and 60 Hz. These limits were selected in order to conservatively encompass the range of frequencies in which significant dynamic response occurs.

The SRV and LOCA load definitions are defined in Sections 6A.3 and 6A.4. In general, the pressure loads on the suppression pool boundaries due to a SRV discharge or LOCA event vary both circumferentially and meridionally with time. At any point in time, this pressure field can be represented meridionally by a discretization into zones and circumferentially by a Fourier series at each of the meridional zones. Therefore, the spatial and time-wise variation of pressure can be represented by pressure time histories at each zone for each Fourier series term.

The equations of motion are solved numerically by direct integration and the acceleration time histories at selected locations are computed. ARS are developed from the resultant structural acceleration time histories. These ARS are used as input to evaluate the adequacy of the piping systems and other equipment.

6A.2.4.3 Related Effects

The Unit 2 design assessment for hydrodynamic loads is not limited to suppression pool load definition and plant response. In the case of SRV steam discharge, the conditions of concern are simultaneous high mass flux and high suppression pool temperature in the vicinity of the SRV discharge device. The local temperature/mass flux limit for the KWU T-quencher device is discussed in Sections 6A.3.2 and 6A.10.2. The maximum temperature difference between the mass average (bulk) suppression pool temperature and that in the vicinity of the quencher is discussed in Section 6A.10.2. Section 6A.10.2 provides a description of the suppression pool bulk temperature transients for various events involving SRV discharge. The bulk suppression pool temperature transients are compared against the local temperature limit for the device. Section 6A.10.1 describes the Unit 2 suppression pool temperature monitoring system which alerts the Operator to take certain actions to mitigate suppression pool temperature transients. These actions are consistent with the Technical Specifications.

6A.2.5 References

1. Tests of T-Quencher Jets Discharging into a Pool at Uniform Temperatures Up to Saturation, SAI Technical Report, July 1979.

2. General Electric Company, Mark-II Containment Dynamic Forcing Functions, NEDO-21061, Rev. 4, November 1981.

3. Nuclear Regulatory Commission, Standard Review Plan, NUREG-0800, Rev. 2, July 1981.

4. General Electric Company, Technical Basis for the Use of the Square Root of the Sum of Squares (SRSS) Method for Combining Dynamic Loads for Mark II Plants, NEDO-24010-P, July 1977; NEDO-24010-1, Supplement 1, October 1978; NEDO-24010-2, Supplement 2, December 1978; NEDO-24010-3, Supplement 3, August 1979.

5. USNRC Staff Evaluation of GE Technical Report NEDE-24010-P and Supplements 1 through 3, Letter from R. J. Mattson (NRC) to H. Chou (Mark-II Owners Group), June 25, 1980.

6. Methodology for Combining Dynamic Responses, USNRC Report, NUREG-0484, Rev. 1, May 1980.

7. Sloshing of Water in Annular Pressure-Suppression Pool of Boiling Water Reactor Under Earthquake Ground Motions, NUREG/CR-1083 LBL6754, October 1979.

8. Three-Directional Fluid Pool Seismic Sloshing Analysis, ASME Journal of Pressure Vessel Technology, Vol. 103, February 1981.

9. Functional Capability Criteria for Essential Mark II Piping, NEDO-21985, September 1978.

10. USNRC Memo from J. P. Knight, Division of Engineering, to R. L. Tedesco, Division of Licensing, dated July 17, 1980.

SECTION 6A.3

SAFETY RELIEF VALVE LOADS

6A.3.1 Introduction

This section discusses the methodology used for the design evaluation of the MSL SRV discharge system of Unit 2.

The discharge system is designed to minimize the loading on components inside the containment during SRV operations. Of particular concern is the avoidance of steam condensation instability associated with SRV discharge of high mass steam flux into a hot suppression pool. This phenomenon can induce high containment excitations that result in severe loading on components[1,2].

Unit 2 utilizes a Kraftwerk Union (KWU) designed T-quencher device connected to the end of the SRVDL in the suppression pool. Through a series of model and in-plant tests[3-8], KWU has shown that quenchers maintain their stable quenching performance even when local pool temperatures approach boiling.

Section 6A.3.2 discusses important plant and operating parameters that influence the thermal hydraulic performance of the quenchers and the associated loads on walls and submerged structures in the suppression pool. Justifications are provided to show that the results of KWU quencher tests, used as a basis for the KWU load specification for T-quenchers, are applicable to Unit 2 and can be used for design. The discussion includes methods for calculating boundary pressure loads, submerged structure loads, and quencher arm, body, and support loads (Section 6A.3.4).

In Section 6A.3.5, key results of the Karlstein quencher tests (KTG)[9,10] are compared with those of the Unit 2 load specification. This comparison shows that the Unit 2 load specification is bounding and hence conservative.

The effects of power uprate (to a rated core thermal power of 3,467 MWt) on SRV loads have been evaluated, as documented in Reference 18. This evaluation concluded that Unit 2 SRV load definitions are not impacted by power uprate for either first or subsequent SRV actuations.

6A.3.2 Thermal Hydraulic Design Consideration of the Quencher

A short description of the major physical phenomena and a summary of important parameters that influence the pressure oscillation is presented prior to discussing the thermal hydraulic quencher design.

6A.3.2.1 Description of the Physical Phenomena

The Unit 2 SRV discharge system for the MSLs consists of 18 SRVs, whose discharges are individually piped into the suppression pool through the SRVDLs. Inside the suppression pool, each SRVDL is connected to a quencher device that directs the discharge through more than 1,000 small holes.

There are several plant operational transients that can result in a pressure rise in the reactor vessel. During these transients, the SRVs will open as necessary to prevent the pressure from exceeding allowable limits. Following this SRV actuation, steam flows into the discharge line of the relief system. The discharge line is normally filled with air and a column of water at the submerged end. The inertia effect of the water column slows the outflow of the enclosed air volume and causes the discharge line to be pressurized. The increased pressure affects acceleration of the water column that is eventually expelled from the discharge system through the quencher outlet. This phenomenon is known as vent clearing. The vent clearing process induces loads on the discharge line and quencher arms, body, and support. These loads are discussed in Appendix 6D, Sections 6D.3.4.4 through 6D.3.4.6.

The vent clearing of water is followed by the expulsion of the initially enclosed steam-air mixture through the quencher holes. This exhausted pressurized gas (steam-air mixture) forms an oscillating system with the surrounding pool water in which the gas acts as the spring and the water as the mass.

This steam-air bubble coalition continues to oscillate while rising due to buoyancy. KWU tests[3-8] have shown that the oscillating pressure usually becomes negligible before the bubble rises to the water surface.

The bubble pressure oscillation induces flow fields in the suppression pool. As a result, the wetted suppression pool boundary experiences a pressure loading, and the components submerged in the pool experience submerged structure loadings. These are discussed in Appendix 6D, Sections 6D.3.4.7 and 6D.3.4.8.

6A.3.2.2 Vent Clearing Pressure

(Proprietary - See Appendix 6D, Section 6D.3.2.2.)

6A.3.2.3 Major Parameters Influencing Pool Pressure Oscillation

(Proprietary - See Appendix 6D, Section 6D.3.2.3.)

6A.3.2.3.1 Suppression Pool Temperature Limits

With regard to the influence of suppression pool temperature on pool pressure amplitude described in Appendix 6D, Section

6D.3.2.3, Item 2, emergency operating procedures (EOPs) have applied the conclusions of NEDO-30832, "Elimination of Limit on BWR Suppression Pool Temperature for SRV Discharge with Quenchers." The conclusions are that the need for temperature limits on BWRs which use T-quenchers is no longer necessary. It further concludes that the SRV condensation loads are low compared to loads due to other events which are already considered in the containment structural evaluations. However, Technical Specifications establish an operating envelope for suppression pool temperature (110°F reactor scram requirement) and reactor pressure (1052 psig automatic reactor scram) which is more restrictive than the operating envelope defined in Figure 6D.3-1 of Appendix 6D.

6A.3.2.4 Thermal Performance of the Quencher

(Proprietary - See Appendix 6D, Section 6D.3.2.4.)

6A.3.3 Unit 2 SRV Discharge System Description

The Unit 2 SRV discharge system consists of 18 SRVs that are set to open at one of five pressure levels (Table 6A.3-1). Two valves are set at the lowest level and four valves each are set at one of the other four levels. Each of the SRVs discharges into a pipe that directs the steam flow into the suppression pool. The discharge line ends in a vertical run of pipe and is connected through a sliding joint to a KWU-designed T-quencher device (Figure 6A.3-1 and Figure 6D.3-2 of Appendix 6D).

6A.3.3.1 SRV Specification

Unit 2 uses 18 Dikker's direct-acting SRVs for the four MSLs. Each valve has a separate spring-actuated safety setpoint and a pneumatic-actuated relief setpoint (Table 6A.3-1).

6A.3.3.1.1 SRV Flow Rates

The valve steam discharge rate depends on the upstream (MSL) pressure (assuming choked flow through the valve throat). The maximum and minimum mass flux through the valves as a function of upstream pressure are given on Figure 6A.3-2.

6A.3.3.1.2 Valve Opening Time

The valve opening times for typical main steam SRVs are estimated to range from 20 to 150 msec. A recent test[11] has shown that for the Dikker's valve used in Unit 2, the typical valve opening time for steam flow is approximately 50 to 60 msec. Hence, the use of the 20-msec valve opening time yields conservative results for vent clearing analysis.

6A.3.3.1.3 Automatic Depressurization System

The ADS employs 7 of the 18 SRVs to rapidly depressurize the MSL under certain emergency conditions such as IBA. The ADS valves are actuated automatically and simultaneously. The quencher locations associated with these ADS valves are shown on Figure 6A.3-3.

6A.3.3.1.4 SRV Opening Events

There are a number of operational transients that can result in a pressure rise in the reactor vessel. SRVs are actuated as necessary to prevent the pressure from exceeding allowable limits. For most of these events, the SRV will open only once. However, some events can result in a closure of the MSIVs and subsequent cycling of the SRVs. Although a scram occurs simultaneously with the isolation, the reactor continues to generate steam due to core decay heat. Until the residual heat removal (RHR) system becomes available to extract the decay heat, the SRVs are the primary means of controlling pressure in the vessel.

For Unit 2, which is a 251 BWR/5 with motor-driven feedwater pumps, General Electric Company (GE) has estimated that a total of 5,200 valve actuations can occur over the 40-yr plant life (Table 6A.3-2)[12]. The cumulative effect of these valve actuations needs to be evaluated on equipment and piping components (Section 6A.3.4.9).

6A.3.3.2 Discharge Line Geometry

The steam discharge from each SRV is piped into the suppression pool through discharge lines of various lengths. The drywell portion of the discharge lines consists of 10-in NPS Schedule 40 pipes while the suppression chamber portion consists of 12-in NPS Schedule 120 pipes. The discharge line geometries for the shortest (152 ft) and longest (224 ft) lines and the anchor points between the in-plant T-quencher and the SRVs are shown on Figures 6A.3-4 and 6A.3-5. The line length, submergence length and length of the first pipe segment between the SRV and the first elbow are provided in Table 6A.3-3. The numerical results of the maximum backpressure and flow rate are based on steady-state steam blowdown results which are calculated from SWEC computer program STEHAM (Appendix 3A). The corresponding line air volumes at high water level for these lines are 74 and 113.6 cu ft, respectively.

Two vacuum breakers in parallel are provided for each line above the drywell floor. The vacuum breakers are used to limit the reflood height of suppression pool water into the SRVDL and the resulting higher loading on subsequent valve actuations. Section 6A.3.4.1 provides a more detailed description of the vacuum breakers' performance.

The discharge line in the suppression pool is connected to the quencher through a sliding joint (Figure 6D.3-3 of Appendix 6D). The sliding joint design allows for an axial thermal expansion of the discharge line.

Tests of the KWU T-quencher design were performed at the Karlstein test facility with discharge line geometries very similar to those of Unit 2[9,10]. The results verified the adequacy and performance of the quencher design in meeting design criteria (Section 6A.3.5).

6A.3.3.3 T-Quencher Geometry

(Proprietary - See Appendix 6D, Section 6D.3.3.3.)

6A.3.3.4 Quencher Arrangement in the Suppression Pool

The 18 quenchers associated with the 18 SRVs are arranged in the form of a ring in the suppression pool (Figure 6A.3-3). The quenchers are supported from the basemat of the pool with the center line of the quenchers 3.5 ft above the basemat. The azimuthal locations of the quenchers have been arranged in such a way that quenchers associated with SRVs of the same pressure setpoints are spaced out around the pool to distribute the loads as uniformly as possible.

6A.3.4 SRV-Related Loads

The quencher design has a significant effect on the vent-clearing transient and its associated loads. The loading conditions on the discharge system are described in the following sections. These loading conditions apply to the SRV piping and quencher body, arms, and support.

6A.3.4.1 SRV Backpressure

The maximum SRV backpressure during steady-state blowdown was investigated analytically[13] and by GE computer code RVFOR04[14] for the Unit 2 discharge system. As expected, the longest line yields the highest SRV backpressure. In all cases, the maximum steady-state SRV line pressures are less than the GE-specified design value of 575 psig.

The transient SRV backpressure was also investigated for both the first actuation case and the subsequent actuation case. In the subsequent actuation case, the SRV was assumed to open at peak reflood (as predicted by GE computer code RVR1Z02[15] and assuming only one of the two vacuum breakers was operating). In all cases, the maximum transient SRV line pressures are found to be less than the GE-specified design value of 625 psig.

6A.3.4.2 SRV System Water Clearing Pressure Load

(Proprietary - See Appendix 6D, Section 6D.3.4.2.)

6A.3.4.3 SRV Discharge Line Loads

During water clearing, different portions of the discharge line are subjected to various dynamic loads due to flow changes within the line (pressure and momentum changes). These loads are generated using the SWEC computer code STEHAM (Appendix 3A), which models the discharge line, sliding joint, and quencher.

The impacts of these dynamic loads are analyzed using one of the piping analysis computer programs (Appendix 3A). The resulting stresses are then combined with other loads to evaluate the design adequacy in meeting applicable piping code requirements.

The KWU-specified load on the discharge system due to the sliding joint at the quencher is shown on Figure 6D.3-5 of Appendix 6D.

6A.3.4.4 Quencher Body Loads

(Proprietary - See Appendix 6D, Section 6D.3.4.4.)

6A.3.4.5 Quencher Arm Loads

(Proprietary - See Appendix 6D, Section 6D.3.4.5.)

6A.3.4.6 Quencher Support Loads

(Proprietary - See Appendix 6D, Section 6D.3.4.6.)

6A.3.4.7 Loads on Suppression Pool Wetted Boundaries

(Proprietary - See Appendix 6D, Section 6D.3.4.7.)

6A.3.4.8 Loads on Submerged Structures

(Proprietary - See Appendix 6D, Section 6D.3.4.8.)

6A.3.4.9 Fatigue Load Analysis

GE has estimated that over the 40-yr operating life of a BWR plant, a total of 253 events can occur that would result in the actuation of one or more SRVs[11]. Of these events, 169 are isolation-type events that cause a cycling of the SRV and constitute a majority of the estimated total of 5,200 SRV actuations for the low set valves in Unit 2.

The actuation of these SRVs and the associated steam condensation in the suppression pool generate hydrodynamic loads that act on plant components either directly, in the form of hydrodynamic forces on submerged structures, or indirectly in the form of support excitations resulting from the building acceleration response to the suppression pool wetted boundary pressure loading. The cumulative effect of these loads over the 40-yr plant operating life can lead to fatigue on the affected components and must be considered in the design evaluation.

A complete fatigue assessment in accordance with applicable ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, is performed on downcomers, SRVDLs in the wetwell, and Safety Class 1 piping components affected by the SRV-related loads. This evaluation is supplemental to the design loads specified elsewhere in this section. A brief summary of the methods used to perform the fatigue evaluation is presented in the following sections.

6A.3.4.9.1 Event Occurrence Analysis

(Proprietary - See Appendix 6D, Section 6D.3.4.9.1.)

6A.3.4.9.2 Equivalent Number of Load Occurrences

(Proprietary - See Appendix 6D, Section 6D.3.4.9.2.)

6A.3.4.9.3 Equivalent Stress Cycles

(Proprietary - See Appendix 6D, Section 6D.3.4.9.3.)

6A.3.4.9.4 Load Combinations and Fatigue Usage Factors

Piping and equipment in the primary containment are subject to numerous dynamic and hydrodynamic loads from normal, upset, and LOCA-related plant operating conditions. For purposes of fatigue evaluation, all of the following loads are included: 1) cyclic effects due to direct or indirect hydrodynamic loads including SRV actuation, CO, and chugging, 2) significant thermal and pressure transients, and 3) seismic events. The determination of load combinations is explained in Section 6A.2.2.

The affected components are analyzed for the appropriate load combinations. The combined stresses and corresponding equivalent stress cycles are computed to obtain the fatigue usage factors in accordance with applicable ASME III Codes. The cumulative usage factors (CUFs) of these components are then shown to be less than unity.

6A.3.5 Verification of SRV Load Specification

The quencher design for Unit 2 and the load specification on the wetted boundaries of the suppression pool, on the submerged structures, and on the pressure relief system, are based on parametric model test studies and full-scale in-plant test results from a similar quencher design used in KWU BWR plants. In order to verify these load specifications and further verify the quencher's steam-condensing characteristics, full-scale, single-cell tests were conducted at the KWU test facility at Karlstein, West Germany. Appendix 6D, Section 6D.3.5.1, contains a brief description of the test objective, test setup, and test results.

6A.3.5.1 Karlstein Quencher Tests

(Proprietary - See Appendix 6D, Section 6D.3.5.1.)

6A.3.5.2 Applicability of Test Results to Unit 2

(Proprietary - See Appendix 6D, Section 6D.3.5.2.)

6A.3.5.3 Comparison of SRV Load Specification to Test Data

(Proprietary - See Appendix 6D, Section 6D.3.5.3.)

6A.3.5.4 Compliance with NUREG-0763 - Guidelines for Confirmatory In-plant Tests of Safety/Relief Valve Discharges for BWR Plants

Unit 2 uses the same T-quencher designed by KWU as that used in Susquehanna Steam Electric Station (SSES) and tested at Karlstein. The quencher arm, body, and hole pattern are all the same; therefore, the quencher performances are anticipated to be similar. Appendix 6D, Table 6D.3-14, provides a comparison of the discharge line parameters for Karlstein, SSES, and Unit 2. The discharge line parameters, geometry, and vacuum breaker size are very similar to each other. Furthermore, the quencher location and orientation in Unit 2 are similar to the Karlstein test configuration, and the concrete containment which Unit 2 used in its design would preclude any significant fluid structure interaction. Therefore, it is concluded that the Karlstein tests have provided sufficient confirmation of the Unit 2 SRV load specification and that no plant-specific SRV testing is necessary.

Further discussion of the similarity of Unit 2 SRV discharge conditions to those of other plants is provided in the following sections.

6A.3.5.4.1 Introduction

This section presents justification that there is no need to perform plant-specific SRV testing to confirm the adequacy of quencher loads used in the Unit 2 design. NUREG-0763[16] states that in-plant testing is required to substantiate SRV load specifications unless the applicant can demonstrate that discharge conditions in its plant are sufficiently similar to those in previously tested plants. This action precludes the need for additional testing. To date, one U.S. BWR Mark II plant, LaSalle County Station (LSCS), has performed in-plant SRV testing, and SSES has performed full-scale prototypical SRV testing.

The discussion herein compares the critical parameters of Unit 2 with those of the Limerick Generating Station (LGS), LSCS, and SSES projects as outlined in NUREG-0763. NUREG-0763 provides five criteria which must be satisfied to show that existing test data are applicable to a particular plant. These criteria were established to examine the key parameters that affect hydrodynamic loads and pool temperature gradients (and are not concerned with plant parameters that do not affect these loads). Specifically, the criteria address plant similarities for the quenchers, SRVDLs and their configuration, mass flow rates, suppression pool geometries, and structural parameters in the pool region which might influence the loading definition. The criteria do not consider differences in plant parameters which do not affect the loading definition.

The comparison of key parameters demonstrates that the comparison of these plants provides sufficient confirmation of the Unit 2 SRV load specifications. All important quencher, SRVDL, suppression pool geometry, and structural properties at Unit 2 are similar to SSES, LSCS, and LGS; therefore, SSES and LSCS SRV discharge test data provide adequate confirmation for the Unit 2 design loads, and an in-plant SRV discharge test is not required for Unit 2.

6A.3.5.4.2 Evaluation of Criteria

Each of the five criteria in NUREG-0763 is examined to demonstrate that the key conditions affecting SRV loading are similar to previously tested plants. The key parameters affecting the suppression pool hydrodynamic loads have been identified by extensive generic test programs. With this information, the intent is to examine each of the five criteria and demonstrate that similarities exist among LSCS, LMG, SSES, and Unit 2, and that a sound basis exists for the definition of the SRV discharge hydrodynamic loads. The criteria are stated, a comparison is made with the plants, and any differences are discussed.

Criterion 1

This criterion requires that the discharge device be similar to those previously tested.

The T-quencher for LSCS, SSES, LGS, and Unit 2 was designed by KWU. The essential parameters of the quenchers (quencher configuration, arm dimension and spacing, hole pattern and sizes) are the same for each plant.

Criterion 2

This criterion states that discharge line parameters, line length, area and volume, quencher submergence, vacuum breaker size, and available pool area per quencher must be similar to previously tested plants.

A comparison of the SRV line parameters for LSCS, SSES, LGS, and Unit 2 is made in Table 6A.3-4. The SRVDL air volume, submergence, and vacuum breaker size do not differ significantly.

Table 6A.3-4 indicates that the Unit 2 SRVDL air volume is within 5 percent of the SSES air volume and bounded by LSCS.

The influence of the vacuum breakers is primarily on consecutive valve actuation (CVA). Because Unit 2 and SSES have the same vacuum breaker size, the SSES test results will be applicable to Unit 2.

The effect of SRVDL lengths is primarily on SRV backpressure. The longest line length for Unit 2 is 14 percent longer than LSCS's longest SRVDL. The longer SRVDL will increase the line pressure drop due to higher (fl/D) friction losses. This increases the backpressure on the SRV exit and, if permitted to become large enough, will allow the SRV flow to become unchoked, reducing its effectiveness for reactor pressure relief. To address this concern, the SSES DAR reported SRV test backpressures at 319 psi at 1,080 psi reactor pressure of the 625 psi allowable. The Unit 2 frictional losses are greater than those of SSES. The maximum expected backpressure for Unit 2 at the same test conditions would be slightly greater. For Unit 2, the backpressure is 527 psi at 1,535 psi reactor pressure of the 625 psi allowable. Since the longest line length at Unit 2 produces backpressures less than the allowable, line length is not a problem.

In conclusion, the longest Unit 2 SRVDL will produce the predicted pool pressures while ensuring that SRV flow remains choked with line pressures well below the allowable.

The available pool surface area has not been found to affect bubble frequency, but the pressure amplitude tends to decrease with the increase of available pool surface area. It has been found that SSES has approximately the same pool surface area per quencher as Unit 2.

Criterion 3

Criterion 3 states that the flow rate of the steam per unit area of discharge line and the net flow rate of steam through the line may determine the air column dynamics and pool temperature gradients during an extended actuation. These parameters must be similar to those of previously tested plants.

The steam flow rate per unit area of discharge line and the net flow rates for Unit 2, SSES, and LGS are shown in Table 6A.3-4.

During an extended valve actuation test, it is expected that these plants should have similar performances.

Criterion 4

This criterion states that the quencher location and orientation in the pool and pool geometry must show that all features of the pool configuration are similar to previously tested plants.

Table 6A.3-5 compares quencher data among Unit 2, SSES, LSCS, and LGS. Based on the data given, there are no significant differences. The pool depth at Unit 2 is between LSCS and SSES. In order to compare Unit 2 submergence depths, pool widths vary among plants. For Unit 2, the pool width is approximately 10-percent wider than the SSES pool width; however, the pool area per quencher is similar (see Table 6A.3-4). It is further noted that all Unit 2 geometry is very similar to the full-scale prototypical test stand geometry at Karlstein performed by SSES.

Criterion 5

The characteristics of the containment structure may affect peak boundary pressure and frequencies of air bubble oscillation. For example, in-plant tests conducted in a concrete containment will not be considered to have direct application for a freestanding steel containment unless adequate justification for fluid/structure interaction has been demonstrated.

Since SSES, LGS, LSCS, and Unit 2 have similar plant construction, this is adequate justification that similar fluid/structure interaction is prevalent for these three plants. The Unit 2 containment is a concrete structure effectively 5.25-ft thick, with a steel liner 3/8-in thick in the suppression pool area (see Table 6A.3-6); this is slightly thinner than SSES and LGS, but thicker than LSCS.

6A.3.5.4.3 Conclusion

The comparison of key parameters for each of the five criteria presented and addressed in the previous sections demonstrates that discharge conditions are sufficiently similar among Unit 2, LSCS, SSES, and LGS. LSCS has performed an in-plant SRV test. The SSES quencher was verified under full-scale single cell tests conducted at the KWU laboratories in Karlstein, West Germany. The SRVDL characteristics, suppression pool geometry, and structural properties are similar for all three plants. From this comparison, the need is eliminated for in-plant testing to substantiate the SRV load specification at Unit 2. Those items that do differ slightly, such as soil shear wave velocity, do not have a significant effect on SRV loadings. Therefore, Unit 2 meets the criteria established in NUREG-0763 for exemption from in-plant testing.

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TABLE 6A.9-4

LOAD ASSESSMENT

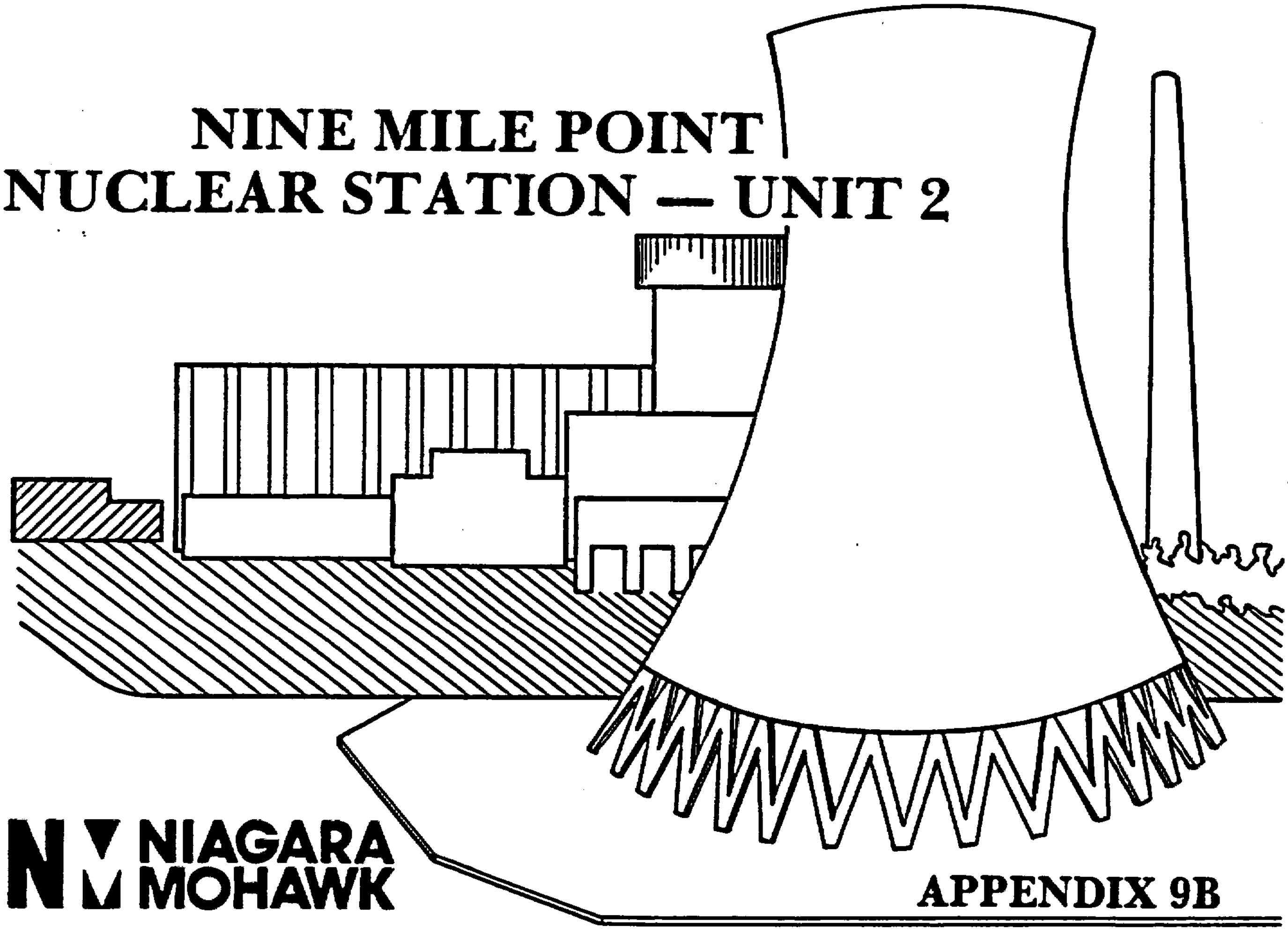
Component: Reactor Core Isolation Cooling Piping (Figure 6A.9-2)

Service Level	Acceptance Criteria	Actual Stress (psi)/CUF	Allowable Stress (psi)/CUF	Actual/ Allowable	Location Component (Node)
Normal and Upset	EQ 9<1.5 S_m	22,132	26,790	0.826	Elbow (35)
	EQ 12<3.0 S_m	15,291	53,580	0.285	Branch (31)
	EQ 13<3.0 S_m	51,946	53,580	0.970	Branch (31)
	CUF<1.0	0.975	1.000	0.975	Branch (31)
Emergency	EQ 9<2.25 S_m	39,344	40,185	0.979	Elbow (35)
Faulted	EQ 9<3.0 S_m	40,623	53,580	0.758	Elbow (35)

NOTES: EQ = Equation
CUF = Cumulative Usage Factor

UPDATED SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2



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APPENDIX 9B

APPENDIX R REVIEW SAFE SHUTDOWN ANALYSIS

APPENDIX 9B

APPENDIX R REVIEW
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SECTION 9B.4

SAFE SHUTDOWN SYSTEM CAPABILITY

9B.4.1 Introduction

When considering the effects of fire, those systems associated with achieving and maintaining safe shutdown conditions assume major importance to plant and public safety. The methodology for this analysis consisted of establishing performance criteria for achieving safe shutdown, identifying those systems which would be utilized in attaining the required performance criteria, then evaluating those systems as to their safe shutdown capability. The system requirements for the safe shutdown analysis were established from Standard Review Plan (SRP) 9.5.1, Revision 3, which states that "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..." and that "both trains or equipment necessary to achieve cold shutdown may be damaged by a single fire, including an exposure fire, but damage must be limited so that at least one train can be repaired or made operable within 72 hr using onsite capability."

9B.4.2 Safe Shutdown Model

The limiting safety consequences that have been established and are used in evaluating a fire event at Unit 2 are:

1. No calculated fuel failures.

2. Reactor coolant boundary integrity.

3. Primary containment integrity.

These limiting safety consequences have been translated into a set of functional performance criteria to establish system requirements for safe shutdown with or without offsite power available. These performance criteria are (Figure 9B.4-1):

1. Reactivity control - achieve and maintain reactor subcritical.

2. Decay Heat Removal to Hot Shutdown - provide a heat sink for decay heat removal to hot shutdown.

3. Maintain Coolant Inventory - ensure that the water level is maintained at acceptable levels above the fuel.

4. Depressurize - safely reduce reactor vessel pressure.

5. Decay Heat Removal to Cold Shutdown - provide a heat sink for decay heat removal to cold shutdown.

9B.4.3 Safe Shutdown Capability

In the event of a fire, safe shutdown of Unit 2 can be achieved in several diverse means depending upon the location of the fire, the availability of electrical power, and the components rendered inoperable. A fire event coincident with a loss of offsite power (LOOP) is the limiting scenario and represents a "worst case" approach. For this reason the safe shutdown capability of fire areas, with the exception of fire area 60 (service water pump area), has been analyzed for a fire that occurs in any one subarea simultaneously with a LOOP. For fire area 60, an analysis was performed and concluded that this area does not contain any alternative shutdown equipment which requires the assumption of a LOOP to the equipment, and a fire in this area will not induce a LOOP. Therefore, for fire area 60, a LOOP assumption was not applied. However, assumption of a LOOP concurrent with a fire in a fire area is more limiting than any other scenarios wherein offsite power is available. In the fire scenario where offsite power remains available, a maximum of flexibility is afforded in the selection of systems unaffected by the fire which could be used to reach safe shutdown conditions.

The options available to achieve a safe shutdown in the event of a LOOP are:

1. If the HPCS system is available, reactor water level can be maintained, as required, using HPCS. Reactor overpressurization can be relieved by the main steam safety relief valves (SRVs). Suppression pool cooling can be accomplished by the residual heat removal (RHR) system. To achieve cold shutdown from this point, it may be necessary to manually depressurize the reactor vessel using the SRVs automatic depressurization system (ADS) so that the shutdown cooling mode of RHR can be initiated.

2. If reactor core isolation cooling (RCIC) is available, it can be used, as required, to maintain vessel inventory.

3. If HPCS and RCIC are not available, the "pseudo" LPCI mode of RHR can be used to maintain vessel inventory. Controls for HPCS are not available from the RSP and RCIC is postulated to be unavailable.

   <u>"Pseudo" LPCI Mode</u>

   An alternate method of maintaining level in the reactor vessel is provided. This alternate method is described as the "pseudo" LPCI mode of RHR and is used for maintaining reactor level above the top of active fuel

(TAF) subsequent to an Appendix R fire in the control room.

The "pseudo" LPCI mode will take suction from the suppression pool and deliver water to the reactor vessel through remote manual shutdown cooling valve 2RHS*MOV40A/B via the discharge piping of 2RCS*P1A or 2RCS*P1B. This valve can be operated from the remote shutdown room. This mode differs from the normal shutdown cooling mode of RHR in that relatively cold water from the suppression pool is delivered to the RCS, which is at near rated temperature. Due to the significant differential water temperature between the RPV and the suppression pool, this mode can be used one time only for the postulated Appendix R fire.

For this "pseudo" LPCI mode of RHR, it is postulated that the high-pressure injection systems of HPCS and RCIC are not available. Controls for HPCS are not available from the remote shutdown panel (RSP), and RCIC is postulated to be inoperable due to hot shorts resulting from a fire in the main control room. Thus, to depressurize the RPV to allow the RHR pumps to operate, four of the SRVs will be used since the controls for only four SRVs are available from the RSPs.

The "pseudo" LPCI mode will satisfy the safe shutdown criteria and allow the reactor water level to be maintained above the top of the core while plant operation is from the RSP during and after a postulated fire in the main control room.

Suppression pool cooling can be accomplished by RHR. To achieve cold shutdown from this point, it may be necessary to manually depressurize the reactor vessel using the SRVs (ADS) so that the shutdown cooling mode of RHR can be initiated.

Two redundant trains of systems are available to achieve a safe shutdown under each of these options. Each train is powered from a separate emergency diesel generator (2EGS*EG1-Division I and 2EGS*EG3-Division II). Either train, in conjunction with RCIC, HPCS, or ADS "pseudo" LPCI can be relied upon to shut down the plant.

Likewise, should a fire affect a portion of one train, the corresponding portion in the other train can remain available. The HPCS system is powered from a separate diesel generator (2EGS*EG2-Division III). If both HPCS and RCIC equipment and cables required for safe shutdown are located in the same fire area, an analysis was performed and corrective actions taken to ensure that at least one train is always available to safely shut down the plant.

For a detailed description of those systems required to achieve a shutdown, the following cross-reference is provided:

System	FSAR Section
ADS	6.3
HPCS	6.3
LPCS	6.3
RCIC	5.4.6
RHR	5.4.7
Service Water	9.2.1
Diesel Generator Support Systems	9.5.4 to 9.5.8
HVAC Systems	9.4
Onsite Power Systems	8.3
Control Systems for ESF Systems	7.3
Control Systems Required for Safe Shutdown	7.4
Other Control Systems Required for Safety	7.6
Safety-Related Display Instrumentation (other than those provided at remote shutdown panels)	7.5

9B.4.4 Safe Shutdown Analysis

The SSDSs have been divided into a total of four trains consistent with the options discussed in Section 9B.4.3 (Figure 9B.4-2).

9B.4.4.1 Event Description

The evaluation fire event is selected to cover the range of postulated conditions required by SRP 9.5.1 Revision 3. The reactor is operating at rated power when a fire event occurs in and is confined to a single fire area. The safe shutdown train is evaluated for all fire areas except fire area 60 (service water pump area) assuming that offsite power is not available for 72 hr. For fire area 60, an analysis performed concluded that this area does not contain any alternative shutdown equipment which requires the assumption of a LOOP for 72 hr and a fire in this area will not induce a LOOP condition. However, the LOOP assumption results in a loss of feedwater and main condenser as a heat sink.

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9B.4.4.2 Assumptions

This analysis of the SSDSs is based on the following assumptions:

1. No credit is assumed for offsite power except in fire area 60.

2. Reactor scrams automatically or Operator scrams reactor. All control rods are fully inserted.

3. All of the SSDSs not affected by the fire event are considered to be available and to function normally.

4. For all fire areas except fire area 60 (service water pump area), the fire event does not occur simultaneously or coincident with any other abnormal conditions except a LOOP. For fire area 60, an analysis was performed and concluded that this area does not contain any alternative shutdown equipment requiring a LOOP assumption and, in addition, will not cause a fire-induced LOOP condition. Therefore, a LOOP assumption was not applied to fire area 60. No other challenges to the SSDSs are considered as part of this analysis.

5. Plant operating and system actuation parameters are consistent with the plant safety analysis and Technical Specifications for the initiating event.

6. Components inside the primary containment are not affected by the fire since it is inerted.

9B.4.4.3 Results

An analysis was performed to evaluate the capability of the four principal trains of systems to achieve the objectives specified in SRP 9.5.1. The minimum required components within each train were analyzed to demonstrate the ability of the subsystems within each train to meet the performance goals. In addition, environmental control systems were identified and evaluated to ensure the operability of the required safe shutdown equipment.

9B.4.4.3.1 Shutdown with HPCS Available

There are at least two distinct trains of systems available to reach a safe shutdown under this option. Safe shutdown can be accomplished with either Division I or Division II components available. These two cases represent the most limiting cases, since a maximum of flexibility is afforded when both divisions are available.

In this scenario, it is assumed that the reactor is isolated (i.e., main steam isolation valves (MSIVs) closed) due to the scram and LOOP. The pressure buildup within the vessel resulting from the scram can be limited by the actuation of the main steam SRVs. HPCS can be initiated upon low water level to make up for the steam that is being blown down to the suppression pool through the SRVs. The SRVs can cycle opened and closed periodically as reactor vessel temperature and pressure rise and fall. HPCS can also operate periodically to maintain reactor water inventory, as necessary. In addition, low-pressure core spray (LPCS) and low-pressure coolant injection (LPCI) can be used to maintain water level once the vessel pressure has been sufficiently reduced.

The suppression pool cooling mode of RHR (either Division I-loop A or Division II-loop B or both if available) can be initiated to limit the peak suppression pool temperature and to provide a path for the removal of core decay heat to the UHS through the RHR heat exchanger(s) and the service water (SWP) system.

Once hot shutdown has been achieved and it is decided to proceed to a cold shutdown, it may be necessary to manually actuate the SRVs (ADS) (either Division I or Division II or both if available) to further depressurize the vessel to 335°F and 95 psig. At this point, the shutdown cooling mode of RHR can be initiated to reach cold shutdown.

9B.4.4.3.2 Shutdown with RCIC Available

There are at least two distinct trains of systems available to reach a safe shutdown under this option, too. Safe shutdown can again be accomplished with RCIC and either Division I or Division II components available.

It is again assumed that the reactor is isolated due to the scram and LOOP. RCIC can be initiated upon low water level to make up for the steam that is being blown down to the pool through the SRVs. In addition, LPCS and LPCI can be used to maintain water level once the vessel pressure has been sufficiently reduced.

The pool cooling mode of RHR can be initiated to limit the peak suppression pool temperature and to provide a path for the removal of core decay heat to the UHS through the RHR heat exchanger(s) and the SWP system.

Once hot shutdown has been achieved and it is decided to proceed to a cold shutdown, it may be necessary to manually actuate the SRVs (ADS) (either Division I or Division II or both, if available) to further depressurize the vessel to 335°F and 95 psig. At this point, the shutdown cooling mode of RHR can be initiated to reach cold shutdown.

9B.4.4.3.3 Shutdown With ADS "Pseudo" LPCI

In the event of control room/relay room fire and loss of the RCIC system, ADS with pseudo injection of the LPCI system (through the recirculation lines) can be used to accomplish safe shutdown.

Once hot shutdown has been established and it is decided to proceed to a cold shutdown, it may be necessary to manually actuate the SRVs (either Division I or II or both, if available) to further depressurize the vessel to 95 psig and 335°F. At this point, the shutdown cooling mode of RHR can be initiated to achieve cold shutdown.

9B.4.4.3.4 Auxiliary and Support Systems

All of the auxiliary and support systems that are required to operate to ensure a safe shutdown of the plant have two distinct trains. The analysis assumed that either the Division I or

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Division II portions of these systems were always available. In case both Divisions were to be available, maximum flexibility would be provided since either or both trains could be operated as needed to support safe shutdown.

The auxiliary and support systems reviewed include:

1. SWP System - Required to provide cooling water for:

    a. RHR heat exchangers

    b. RHR pump seal coolers

    c. Spent fuel heat exchangers

    d. Diesel generators

    e. Safety-related heating, ventilating and air conditioning (HVAC) systems

2. Spent Fuel Pool Cooling (SFC) System - Required to remove decay heat generated within the spent fuel pool.

3. HVAC Systems - Required to maintain environmental control. These systems include:

    a. Reactor Building Ventilation (HVR) - Provides space cooling within the reactor building and auxiliary bays for safety-related components.

    b. Control Building Ventilation (HVC) and Chilled Water (HVK) - Provide cooling for control room, relay rooms, standby switchgear area, battery areas, and the remote shutdown area.

    c. Yard Structures Ventilation (HVY) - Provides space cooling for the SWP pumps.

    d. Diesel Generator Building Ventilation (HVP) - Provides space cooling for the diesel generator building.

4. Diesel Generator Support Systems - Required to support the startup and operation of the diesel generators. These systems include:

    a. Diesel Generator Air Startup (EGA)

    b. Diesel Generator Fuel Oil (EGF)

5. Reactor Building Closed Loop Cooling Water (CCP) System - The only portions of CCP required to operate are the

block valves that must close to allow for cooling water flow to the residual heat system (RHS) pump seal coolers, and the SFC heat exchangers from the SWP system instead of the CCP system.

9B.4.4.3.5 Safe Shutdown Control Monitoring Systems

There are certain parameters which must be controlled to ensure that safe shutdown is achieved and the fission product release barriers are retained.

Fuel integrity is ensured if reactivity is controlled and heat transfer from the reactor core to the primary coolant is maintained within limits.

Heat rejection from the reactor coolant system (RCS) at an acceptable rate ensures that the reactor vessel pressure limits are not exceeded.

Containment integrity is ensured if there are no failures in the isolation features and pressure limits are not exceeded.

For a discussion of the control systems provided to control and monitor a safe shutdown, see Final Safety Analysis Report (FSAR) Sections 7.3, 7.4, and 7.6. These instrumentation systems are redundant so that at least one division can be available.

9B.4.4.4 Conclusions

The above analysis demonstrates that at least four distinct trains are available to achieve a safe shutdown. When HPCS is available, the two trains discussed achieve a shutdown in a similar manner, the only difference being electrical power supply, Division I or Division II. Likewise, the two trains discussed for the case in which RCIC is available achieve a shutdown in a similar manner, the only difference again being electrical supply power, Division I or Division II. This analysis demonstrates that each of the four principal trains satisfies the five functional performance criteria given in Section 9B.4.2 and, therefore, does not exceed any of the limiting safety consequences.

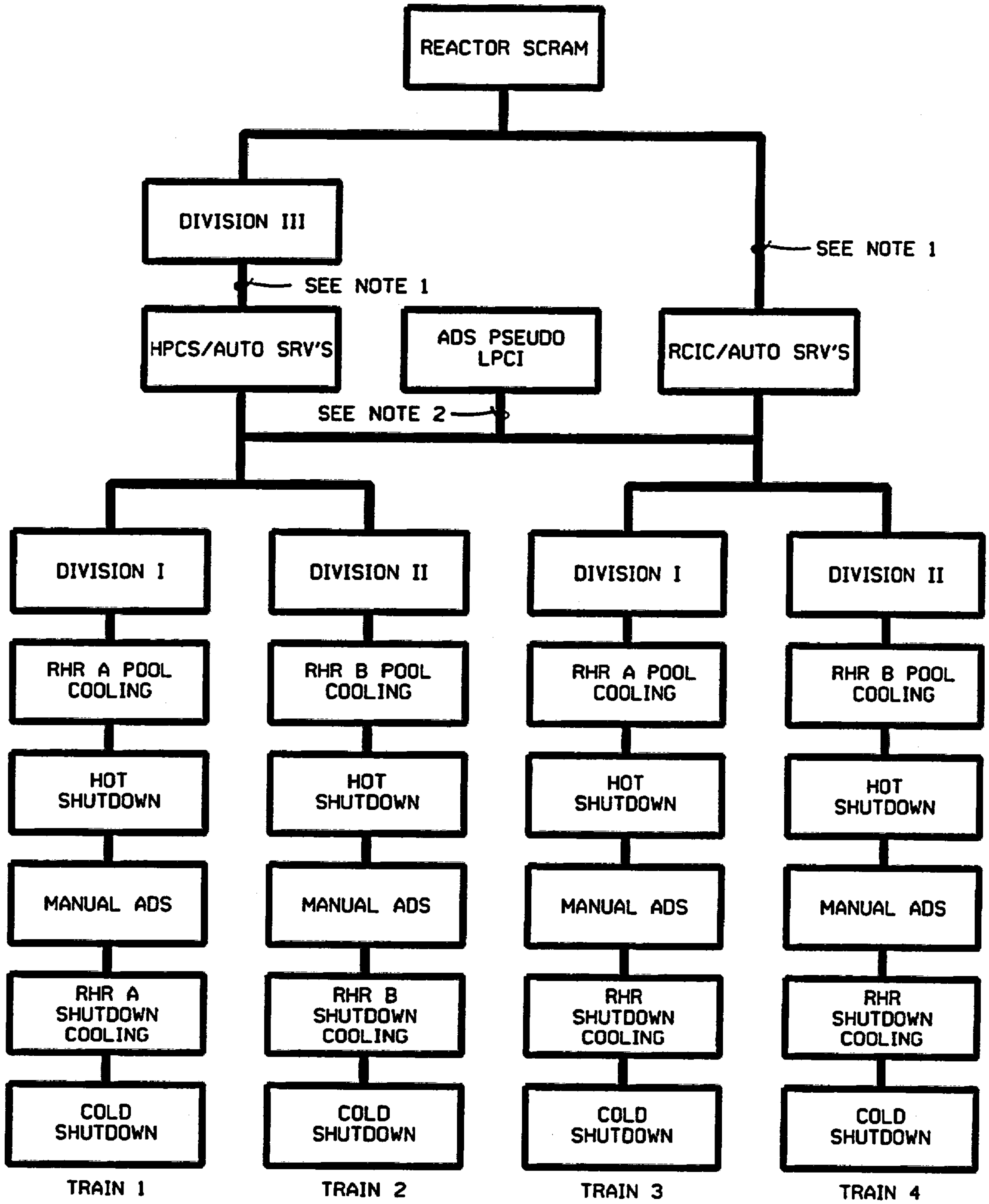
9B.4.5 Safe Shutdown Electrical Power Supply

The emergency electrical power sources and distribution systems required to maintain operability of safe shutdown equipment are discussed in detail in Chapter 8 of the FSAR.

9B.4.6 Safe Shutdown Monitoring Instrumentation

There are certain parameters that must be controlled to ensure that safe shutdown is achieved and the fission product release barriers are retained.

Detailed descriptions of systems to monitor these parameters are given in FSAR Chapter 7.



NOTES:

1. IF BOTH HPCS/RCIC EQUIPMENT & CABLES ARE LOCATED IN FIRE AREAS, AN ANALYSIS WAS PERFORMED TO ENSURE THAT AT LEAST ONE TRAIN IS ALWAYS AVAILABLE TO SAFELY SHUTDOWN THE PLANT.
2. ADS PSEUDO LPCI METHOD CAN BE UTILIZED FROM RSS ROOM AS AN ALTERNATE TO RCIC, AND FROM CONTROL ROOM AS REDUNDANT TO RCIC OR HPCS.

FIGURE 9B.4-2

SAFE SHUTDOWN TRAINS

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
UPDATED SAFETY ANALYSIS REPORT

SECTION 9B.5

ASSOCIATED CIRCUITS

9B.5.1 Introduction

Associated circuits are circuits which are not completely independent of the SSDSs and components. Failure of these circuits can potentially affect the SSDSs. A fire in a given fire area can potentially affect systems and components which were thought to be independent of that area. The three categories of the associated circuits are:

1. Circuits that are not needed for safe shutdown but share a common power supply with safe shutdown circuits and are susceptible to fire.

2. Circuits which can affect components whose spurious operation would adversely affect safe shutdown capability and are susceptible to fire.

3. Circuits which share an enclosure (raceway, panel, junction box, etc.) with safe shutdown circuits but are themselves not needed for safe shutdown and are susceptible to fire.

9B.5.2 Analysis

Each of the three safety divisions (I, II, and III) supplies its own safety loads on Unit 2. The design of the electrical distribution system does not permit connection of an out-of-division or nonsafety load to a safety bus (without interposing a qualified and coordinated isolation device). In addition, redundant divisions are physically separated in accordance with Section III.G-2 of Appendix R. These design features negate the possibility of Type 1 and 3 associated circuits as defined above. However, an analysis performed identified a small number of Type 1 associated circuits. These circuits are administratively controlled in the event of a fire to achieve and maintain safe shutdown. In addition, the results of the multiple high-impedance faults (MHIF) analysis conclude that all Appendix R associated circuits by common power source are appropriately protected so that any fire-induced MHIF in any fire area will not adversely affect the safe shutdown capability of the plant.

Associated circuits of Type 2 that result as a consequence of spurious operation of certain devices are described in Section 9B.5.3.

9B.5.3 Spurious Operation

Spurious operation of powered components can potentially have a serious effect on the safety of the plant. Spurious operation is the result of a hot short for components which are energized to actuate. Open circuits and short-to-ground will not affect energized-to-actuate components (motor-operated valves [MOVs], pumps, fans, etc.). De-energized to actuate components (fail-safe air-operated valve [AOV], solenoid-operated valve [SOV], or a relay) can change position on loss of power.

The approach that will be used in the evaluation of spurious operation will be to:

1. Identify remotely-controlled components or groups of components that would have an adverse effect on safe shutdown as a result of spurious operation.

2. Determine the electrical circuits that are electrically associated with the devices identified in Item 1.

3. Determine routing of cables by fire area.

4. Determine if spurious operation is both possible as a result of routing and unacceptable for safe shutdown.

Spurious operation will be evaluated on a function-by-function basis. Those functions are:

1. Reactivity control.

2. Decay heat removal control.

3. Reactor coolant inventory control.

4. Containment isolation control.

Important components will be identified for each function and mode of operation. Once it is determined that cables for important components are susceptible to fire, a further evaluation of the specific cable will be performed.

The following guidelines will be used in evaluating the potential for spurious operation.

1. Phase-to-phase hot shorts in a 3-phase cable will not cause operation.

2. Open circuits are of no consequence in energize-to-operate circuits.

3. Hot shorts in control cables can cause spurious operation.

4. There has to be a mechanistic short in a cable that is in the fire area for spurious operation to take place (i.e., a motor starter can be spuriously actuated if its contactor is energized). This can only happen in certain wires, not all wires. Therefore, the appropriate wire(s) must be in the fire zone for spurious operation to occur.

Valves can be mispositioned, thus causing a variety of effects on plant systems. Closure can block required flow paths. Opening can divert fluid from the process via the primary system connection or can bypass a heat exchanger or create a flow path that bypasses the core.

9B.5.3.1 Reactivity Control

Reactivity control is attained by insertion of the control rods into the reactor. The control rod drive (CRD) system provides the means to insert and retract the control rods within the reactor core.

Once the reactor has been shut down by the insertion of the control rods, there is no available mechanism for a return to criticality other than rod withdrawal. The design layout of the reactor protection system (RPS) and the CRD system does not provide any mechanism for return to criticality other than manual control rod withdrawal by the Operators.

9B.5.3.2 Decay Heat Removal

Identification of Systems and Components

Those systems needed for decay heat removal were determined by first identifying heat transfer paths between the reactor core and the UHSs. Those systems which are necessary for the maintenance of these heat transfer paths were then identified.

Decay heat removal systems can fail from spurious operation which:

1. Blocks flow.

2. Diverts flow such as bypass of a heat exchanger.

3. Diverts fluid inventory from the cooling path.

4. Fails an auxiliary system that can cause failure of a component in the heat removal path.

Those components that can cause system failure due to spurious operations will be identified as part of the analysis.

There are two redundant loops for each of the decay heat removal systems (ADS, suppression pool cooling mode of RHR, and shutdown cooling mode of RHR), the SWP system, and other support systems. Flow blockage or bypassing of flow around a RHR heat exchanger in one loop is not a concern, provided that the remaining loop is available to remove decay heat.

9B.5.3.3 Reactor Coolant Inventory Control

The reactor vessel water level must be maintained above the top of the core. This objective is achieved by ensuring that inventory loss does not exceed inventory makeup. The potential for loss of inventory was investigated by review of the plant fluid systems interfacing with the reactor vessel. It is determined that, considering plant design bases and Appendix R assumption for spurious operations of devices, loss of inventory is not a concern.

The review also included high-pressure to low-pressure interfaces that exist in the systems that interface with the reactor vessel. These interfaces were examined to determine whether spurious actuation of a sufficient number of devices could result in the overpressurization and subsequent failure of low pressure systems leading to a loss of inventory. Changes necessary for those valves identified as the boundary between the high pressure to low pressure systems were identified and implemented. Table 9B.5-1 lists the system boundaries reviewed, and identified resolution.

The reactor vessel level can also decrease if there is ADS blowdown or a decrease in makeup from the core spray or injection systems (HPCS, RCIC, LPCS, and LPCI). Review of the present design layout and system operations indicated that, based on Appendix R design base requirements and assumptions, for a single fire in any fire area of the plant, at minimum one train of core spray and/or injection system would be available which can maintain vessel water level.

9B.5.3.4 Containment Isolation

Containment integrity is ensured if the containment is not overpressurized and containment leakage paths are isolated. Pathways with an excess flow check valve or a reverse flow check valve are not included in the Appendix R analysis since they will prevent containment leakage. Pathways that form a closed loop with the containment are not considered since they do not provide a leakage path. Instrument and other small lines (1 in and less) also are excluded since any inventory loss would be insignificant. Only those systems which penetrate the containment and have the potential for releasing coolant inventory to the environment are included in the Appendix R program.

TABLE 9B.5-1

HIGH-/LOW-PRESSURE INTERFACES

System Boundaries	Description	Resolution
DER-Reactor Building Equipment Drain 2DER*MOV128	WCS drain valve	Note 1
MSS-Main Steam 2MSS*MOV112 2MSS*AOV6A, B, C, D 2MSS*AOV7A, B, C, D	 Main steam drain Main steam isolation Main steam isolation	 Note 1 Note 3 Note 3
RHS-Residual Heat Removal 2RHS*MOV22A, B 2RHS*MOV80A, B 2RHS*MOV113 2RHS*MOV67A, B 2RHS*MOV32A, B	 Steam supply to RHS*E1 Steam supply to RHS*E1 Shutdown cooling suction Shutdown cooling return RHS*E1 return to ICS	 Note 1 Note 1 Note 1 Note 1 Note 1
WCS-Reactor Water Cleanup 2WCS-MOV106 2WCS-MOV107 2WCS-AOV26A, B, C, D 2WCS-AOV28A, B, C, D 2WCS-AOV29A, B, C, D 2WCS-AOV30A, B, C, D 2WCS-AOV44A, B, C, D 2WCS-AOV51A, B, C, D 2WCS-AOV52A, B, C, D 2WCS-AOV53A, B, C, D 2WCS-AOV54A, B, C, D 2WCS-AOV61A, B, C, D	 Drain to liquid waste Drain to main condenser Demineralizer vent/drain Demineralizer vent/drain Demineralizer vent/drain Demineralizer vent/drain Demineralizer vent/drain Demineralizer vent/drain Demineralizer vent/drain Demineralizer vent/drain Demineralizer vent/drain Demineralizer vent/drain	 Note 1 Note 1 Note 2a Note 2b Note 2b Note 2b Note 2b Note 2b Note 2a Note 2c Note 2c Note 2b

NOTES:

1. Valve is de-energized and disconnected from power source (breaker open, fuse pulled) during normal plant operation. This is not meant to preclude use of these valves during normal operation but to ensure that valves remain de-energized when not in use.

2a. Outboard AOVs 2WCS-AOV26A, B, C and D are in series with inboard AOVs 2WCS-AOV52A, B, C and D. The mechanical air supply valve to these outboard and inboard AOVs is normally closed during plant normal operation. This is not meant to preclude use of these valves during normal operation but to ensure that valves remain closed when not in use. Changes to inboard AOVs 2WCS-AOV52A, B, C and D are not required but the inboard and outboard valves are supplied by the same mechanical air supply.

2b. Control circuits of these AOVs are wired in series with redundant isolation switch contacts located in different fire areas separated by 3-hr fire barriers. No single fire could cause sufficient spurious operations to violate the high-/low-pressure interface paths. Isolation switches will be normally in open position during plant normal operation. This is not meant to preclude use of these valves during normal operation but to ensure that valves remain closed when not in use.

2c. Outboard AOVs 2WCS-AOV53A, B, C and D are in series with inboard AOVs 2WCS-AOV54A, B, C and D. The mechanical air supply valve to these outboard AOVs is normally closed during normal plant operation. This is not meant to preclude use of these valves during normal operation but to ensure that valves remain closed when not in use. Changes to inboard AOVs 2WCS-AOV54A, B, C and D are not required because mechanical air supply to outboard AOVs is administratively controlled and spurious actuation of inboard AOVs would not cause high-/low-pressure interface failure.

3. These valves are normally open in the event of a control room fire. They are closed by the Operator and subsequently disconnected from their power source to ensure no spurious operation.

TABLE 9B.6-1

FIRE AREA/FIRE SUBAREA/FIRE ZONE IDENTIFICATION

Fire Area/Fire Subarea	Fire Zone	Description
North Aux Bldg/FA1	201SW 202SW 203SW 211SW 231SW 221SW	LPCS Room, North Auxiliary Bay, El 175 ft RHS Pump Room A, North Auxiliary Bay, El 175 ft RHS Heat Exchanger Room A, North Auxiliary Bay, El 175 ft North Auxiliary Bay, El 198 ft North Auxiliary Bay, Electrical Room, El 240 ft Auxiliary Bay, North Access Area B, El 215 ft
Reactor Bldg/FA2	204SW	Reactor Building, RCIC Pump Room, El 175 ft
South Aux Bldg/FA3	207SW 208SW 206SW 214SW 239SW 224SW	RHS Pump Room B, South Auxiliary Bay, El 175 ft RHS Pump Room C, South Auxiliary Bay, El 175 ft RHS Heat Exchanger Room B, South Auxiliary Bay, El 175 ft South Auxiliary Bay, El 198 ft South Auxiliary Bay, Electrical Room, El 240 ft Auxiliary Bay, South Access Area B, El 215 ft
Reactor Bldg/ FA4	205NZ	Reactor Building, HPCS Room, El 175 ft
FA8	301NW 302NW	Electrical Tunnel, 140° Electrical Tunnel, 35°
Control Bldg/FA21	327NW 342XL	Control Building, HPCS Cable Routing Area, El 244 ft Control Building, HPCS Switchgear Room, El 261 ft
Diesel Gen Bldg/ FA28	402SW	Division I, Diesel Generator Room Division I, Diesel Generator Control Room
FA29	403SW	Division II, Diesel Generator Room Division II, Diesel Generator Control Room
FA30	404SW	Division III, HPCS Diesel Generator Room Division III, HPCS Diesel Generator Control Room
Control Bldg/FA75	339NZ	Control Building, Division III, Battery Room, El 261 ft
Control Building/ FA16	306NZ 312NZ 321NW 332NW 352NW 371NW	Control Building General Area, El 214 ft Control Building General Area, East, El 214 ft Control Building Cable Chase, West, El 237 ft Control Building Cable Chase, West, El 261 ft Control Building Cable Chase, West, El 288 ft Control Building Cable Chase, West, El 306 ft
FA17	305NW 322NW	Control Building Cable Chase, West, El 214 ft Control Building, Division I Cable Routing Area, El 237 ft

TABLE 9B.6-1 (Cont'd.)

Fire Area/Fire Subarea	Fire Zone	Description
	325NW	Control Building, Division I, Cable Routing Area, El 244 ft
	333XL	Control Building, Division I Standby Switchgear Room, El 261 ft
	334NZ	Control Building, Division I Battery Room, El 261 ft
	343NZ	Control Building Remote Shutdown Room, West
FA18	304NW	Electrical Tunnel, 230°
	309NW	Control Building Cable Chase, East, El 214 ft
	324NW	Control Building Cable Chase, East, El 237 ft
	337NW	Control Building Cable Chase, East, El 261 ft
	359NW	Control Building Cable Chase, East, El 288 ft
	377NW	Control Building Cable Chase, East, El 306 ft
FA19	323NW	Control Building, Division II, Cable Routing Area, El 237 ft
	326NW	Control Building, Division II, Cable Routing Area, El 244 ft
	336XL	Control Building, Division II, Standby Switchgear Room, El 261 ft
	335NZ	Control Building, Division II Battery Room, El 261 ft
	338NZ	Control Building Remote Shutdown Room, East
FA22	340NZ	Control Building, Division I, HVAC Room, El 261 ft
FA23	341NZ	Control Building, Division II, HVAC Room, El 261 ft
FA24	356NZ	Control Building, PGCC Relay Room, El 288 ft
FA25	360NZ	Control Building, Division I, HVAC Room, El 288 ft
FA26	373NZ	Control Building, Main Plant Control Room, El 306 ft
FA27	378NZ	Control Building, Division II, HVAC Room, El 306 ft
FA72	351NZ	Control Building Corridor/Instrument Shop, El 288 ft
FA76	380NZ	Control Building Corridor, Lunch Room, Work Release Room, and Ladies' & Men's Toilet Rooms, El 306 ft
FA88	331NW	Control Building Corridor, El 261 ft
Tunnels/FA50	256NZ	Main Steam Tunnel
FA48	236NZ	Electrical Tunnel Vent Room, El 237 ft, Div. I
FA55	361NZ	Pipe Tunnel
	363NZ	Pipe Tunnel, El 244 ft
	237NZ	Electrical Tunnel Vent Room, El 237 ft, Div. II
	362NZ	Radwaste Tunnel

TABLE 9B.6-1 (Cont'd.)

Fire Area/Fire Subarea	Fire Zone	Description
Service Water Pump Area/FA60	807NZ	Service Water Pump Room B
FA61	806NZ	Service Water Pump Room A
Intake Area/FA71	802NZ 803NZ	Intake Area Screenwell Building
Reactor Building/FSA34	212SW 222SW 232SW 243SW 252SW 261SW 271SW 273SW 281NZ	Reactor Building General Area, North, El 175 ft Reactor Building General Area, North, El 215 ft Reactor Building General Area, North, El 240 ft Reactor Building General Area, North, El 261 ft Reactor Building General Area, North, El 289 ft Reactor Building General Area, North, El 306 ft Reactor Building General Area, Northwest, El 328 ft Reactor Building General Area, Northeast, El 328 ft Reactor Building General Area
FSA35	213SW 223SW 238SW 245SW 255SW 262SW 274SW	Reactor Building General Area, South, El 175 ft Reactor Building General Area, South, El 215 ft Reactor Building General Area, South, El 240 ft Reactor Building General Area, South, El 261 ft Reactor Building General Area, South, El 289 ft Reactor Building General Area, South, El 306 ft Reactor Building General Area, Southeast, El 328 ft
FA87	087SW	Reactor Building Division I, SFC Pump Room, El 289 ft

TABLE 9B.6-3

LIST OF FIRE ZONES/AREAS BY DRAWING NUMBERS

Drawing No.	Building/Elevation	Fire Zone I.D. Numbers
Figure 9A.3-2	Reactor Bldg LPCS Room North Aux Bay El 175'-0"	201SW
	Reactor Bldg RHS Pump Rm A North Aux Bay El 175'-0"	202SW
	Reactor Bldg RHS Heat Exchanger Rm A North Aux Bay El 175'-0"	203SW
	Reactor Bldg RCIC Pump Rm El 175'-0"	204SW
	Reactor Bldg HPCS Room El 175'-0"	205NZ
	Reactor Bldg RHS Heat Exchanger Rm B South Aux Bay El 175'-0"	206SW
	Reactor Bldg RHS Pump Rm B South Aux Bay El 175'-0"	207SW
	Reactor Bldg RHS Pump Rm C South Aux Bay El 175'-0"	208SW
	North Aux Bay El 198'-0"	211SW
	Reactor Bldg General Area North El 175'-0"	212SW
	Reactor Bldg General Area South El 175'-0"	213SW
	South Aux Bay El 198'-0"	214SW
Figure 9A.3-3	Access Area B North Aux Bay El 215'-0"	221SW
	Reactor Bldg General Area North El 215'-0"	222SW
	Reactor Bldg General Area South El 215'-0"	223SW
	South Aux Bay El 215'-0"	224SW
	Electrical Tunnel 140°	301NW
	Electrical Tunnel 35°	302NW
	Electrical Tunnel 315°	303NW
	Electrical Tunnel 230°	304NW
	Control Bldg Cable Chase West El 214'-0"	305NW
	Control Bldg General Area El 214'-0"	306NZ
	Control Bldg Cable Chase East El 214'-0"	309NW
	Control Bldg General Area El 214'-0"	312NZ
	Pipe Tunnel El 244'-0"	363NZ

TABLE 9B.6-3 (Cont'd.)

Drawing No.	Building/Elevation	Fire Zone I.D. Numbers
Figure 9A.3-4	North Aux Bay Motor Control Centers El 240'-0" Reactor Bldg General Area North El 240'-0" HVAC Rm Div 1 El 237'-0" HVAC Rm Div 2 El 237'-0" Reactor Bldg General Area South El 240'-0" South Aux Bay Motor Control Centers El 240'-0" Control Bldg Cable Chase West El 237'-0" Control Bldg Div 1 Cable Routing Area El 237'-0" Control Bldg Div 2 Cable Routing Area El 237'-0" Control Bldg Cable Chase East El 237'-0" Control Bldg Div 1 Cable Routing Area El 244'-0" Control Bldg Div 2 Cable Routing Area El 244'-0" Control Bldg HPCS Cable Routing Area El 244'-0" Pipe Tunnel El 244'-0" Pipe Tunnel El 244'-0" Pipe Tunnel El 244'-0" Service Water Pump Room A and Stairwell Enclosures El 224'-0" Service Water	231SW 232SW 236NZ 237NZ 238SW 239SW 321NW 322NW 323NW 324NW 325NW 326NW 327NW 361NZ 362NZ 363NZ 806NZ 807NZ
Figure 9A.3-5	Reactor Bldg General Area North El 261'-0" Reactor Bldg General Area South El 261'-0" Standby Gas Treatment Rm B El 261'-0" Standby Gas Treatment Rm A El 261'-0" Main Steam Tunnel El 240'-0" Control Bldg Corridor El 261'-0" Control Bldg Div 1 Cable Chase West El 261'-0" Control Bldg Div 1 Standby Switchgear Room El 261'-0" Control Bldg Div 1 Battery Room El 261'-0" Control Bldg Div 2 Battery Room El 261'-0" Control Bldg Div 2 Standby Switchgear Rm El 261'-0" Control Bldg Div 2 & 3 Cable Chase West El 261'-0" Control Bldg Remote Shutdown Room B El 261'-0" & HVAC Rm El 274'-0" Control Bldg HPCS Battery Room El 261'-0" Control Bldg Div 1 Chiller Room B El 261'-0" Control Bldg Div 2 Chiller Room El 261'-0" Control Bldg High Pressure Core Spray Switchgear Room Control Bldg Remote Shutdown Rm A El 261'-0" & HVAC Rm El 274'-0" Div 1 Diesel Generator Rm El 261'-0" & Day Tank Rm El 272'-0"	243SW 245SW 247NZ 248NZ 256NZ 331NW 332NW 333XL 334NZ 335NZ 336XL 337NW 338NZ 339NZ 340NZ 341NZ 342XL 343NZ 402SW

TABLE 9B.6-3 (Cont'd.)

Drawing No.	Building/Elevation	Fire Zone I.D. Numbers
Figure 9A.3-5 (cont'd.)	Div 2 Diesel Generator Rm El 261'-0" & Day Tank Room El 272'-0"	403SW
	HPCS Diesel Generator Rm El 261'-0" & Day Tank Room El 272'-0"	404SW
	Service Water Intake and Discharge Shafts	802NZ
	Screenwell Bldg El 261'-0"	803NZ
	Diesel Fire Pump Room	804NW
	Service Water Pump Room A	806NZ
	Service Water Pump Room B	807NZ
Figure 9A.3-6	Standby Gas Treatment Bldg HVAC Room El 286'-0"	251NW
	Reactor Bldg General Area North El 289'-0"	252SW
	Reactor Bldg General Area South El 289'-0"	255SW
	Control Bldg Instrument Shop and Corridor El 288'-6"	351NZ
	Control Bldg Cable Chase West El 288'-6"	352NW
	Control Bldg PGCC Relay Rm El 288'-6"	356NZ
	Reactor Bldg Div 1 SFC Pump Room El 289'-0"	087SW
	Control Bldg Div 2 & 3 Cable Chase East El 288'-6"	359NW
	Control Bldg Div 1 HVAC Rm El 288'-6"	360NZ
	Turbine Bldg Cols 8-12 El 277'-6"	731SW
	Screenwell Bldg El 261'-0"	803NZ
Figure 9A.3-7	Reactor Bldg Pipe Chase El 306'-6"	261SW
	Reactor Bldg General Area South El 306'-6"	262SW
	Control Bldg Div 1 Cable Chase West El 306'-0"	371NW
	Control Bldg Main Plant Control Room El 306'-0"	373NZ
	Control Bldg Div 2 & 3 Cable Chase East El 306'-0"	377NW
	Control Bldg Div 2 HVAC Rm El 306'-0"	378NZ
	Control Bldg Corridor El 306'-0"	380NZ
	Screenwell Bldg El 261'-0"	803NZ

TABLE 9B.6-3 (Cont'd.)

Drawing No.	Building/Elevation	Fire Zone I.D. Numbers
Figure 9A.3-8	Reactor Bldg General Area NW El 328'-10" Reactor Bldg General Area NE El 328'-10" Reactor Bldg General Area SE El 328'-10" Reactor Bldg General Area El 353'-10" & 409'-3 1/4"	271SW 273SW 274SW 281NZ

SECTION 9B.8

RESULTS OF FIRE PROTECTION ANALYSIS FOR SAFE SHUTDOWN CAPABILITY IN ACCORDANCE WITH 10CFR50 APPENDIX R

9B.8.1 Balance of Plant Areas

The results of the fire protection analysis for the SSDSs by fire areas/subareas where safe shutdown equipment is located are provided in Tables 9B.8-1 and 9B.8-2. Table 9B.8-1 lists by fire area/fire subarea all equipment required for safe shutdown in case of a fire. This list also indicates the safe shutdown train associated with each item of equipment. Table 9B.8-2 gives the conclusion of the analysis.

The assumptions used in this analysis are as follows:

1. Fire occurs in any one fire area at a time.

2. All safe shutdown cables and equipment located in the fire area where the fire occurs are lost.

3. All safe shutdown equipment located outside of the fire area, but fed by the cables passing through the fire area, is disabled.

4. Spurious maloperation of the equipment fed by cables passing through the fire area may occur under the condition stated in Section 9B.5.3.

5. Safe shutdown cables not passing through the fire area where the fire occurs remain unaffected.

The evaluation considered cable routing as of April 30, 1988. Controls have been established to ensure that future cable routing will not affect the safe shutdown analysis (SSA).

The primary containment was not included in the evaluation since it is inerted.

9B.8.2 Control Room and Relay Room

The main control and relay rooms fire protection analysis postulates a fire in the main control or relay rooms that necessitates evacuation of the main control room and verifies that capability for safe shutdown of the plant exists from the remote shutdown room and other local control stations outside the main control or relay rooms. An exposure fire in the main control or relay rooms involving in situ combustibles which may disable all safe shutdown trains is not considered a credible event. A fire involving transient combustibles in the main control or relay rooms which disables all safe shutdown trains is also considered unlikely since the main control room is continuously manned; both the main control and relay rooms are provided with ionization-type smoke detection and Halon suppression systems (for floor sections or modules); and, administrative procedures would generally limit transient combustibles from being brought into the main control or relay rooms. However, since the NRC requires that a major fire be postulated in the control or relay rooms, the following information addresses this contingency.

The fire areas and fire zones involved are as follows:

Fire Area FA26, Main Control Room, El 306 ft

Fire Zones

373 NZ	Control room panels
374 SG	PGCC underfloor, west
375 SG	PGCC underfloor, east
376 XG	PGCC underfloor, south
381 SG	PGCC underfloor bench

Fire Area FA24, Relay Room, El 288 ft

Fire Zones

353 SG
354 SG
356 NZ
357 XG
358 XG
362 NZ

The assumptions used in this analysis are as follows:

1. A fire occurs and requires evacuation of the main control room. Operators scram the reactor and initiate MSIV closure before evacuating the area.

2. The entire main control or relay room is considered lost; no automatic initiation signals for mitigating systems are available after evacuation.

3. LOOP occurs coincidental with the fire in the main control or relay rooms (this provides the limiting safe shutdown scenario).

4. A single, spurious maloperation in addition to the loss of all automatic signals is considered for evaluation purposes for components controlled from the main control room. The worst-case spurious maloperation is one SRV remaining open until corrected by Operator action. However, for RHR shutdown cooling mode of operation, the worst-case maloperation is loss of any

one of the shutdown cooling supply line isolation valves.

5. In cases of high-/low-pressure interface, multiple devices located in series and controlled from the main control room may spuriously maloperate, resulting in any one high-/low-pressure interface failure at a time.

6. For a control room fire with no LOOP, the Operators have to place the SWP system in a one-pump-per-division configuration prior to exiting the control room.

9B.8.2.1 Safe Shutdown Systems

Selected equipment in safe shutdown trains 1, 2, 3, and 4 are used to mitigate the effect of fires in the main control or relay rooms. Most of this equipment is located in the remote shutdown room and includes manual control of four ADS SRVs, the RCIC system, the "pseudo" LPCI, and the shutdown cooling and suppression pool cooling modes of the RHR system. In the case of shutdown from the remote shutdown panel (RSP), and availability of the RCIC system, RCIC operation followed by RHR shutdown cooling is the preferred safe shutdown method. The ADS "pseudo" LPCI operation would be utilized if the RCIC system is not available.

Due to the control room fire, alternate shutdown cooling may be required to achieve and maintain cold shutdown. Manual manipulation of the RHR minimum flow valves and the RHR LPCI injection valves for alternate shutdown cooling would be required.

A more complete description follows:

Various systems that may be used for safe shutdown of the plant in case of a fire in the main control or relay rooms are as follows:

1. RCIC/ "Pseudo" LPCI - To maintain reactor water level.

2. ADS - To depressurize the reactor pressure vessel (RPV), if required.

3. RHR - To maintain suppression pool temperature within design limits and for shutdown cooling.

4. CMS/ RSS - Instrumentation systems to indicate plant parameters necessary to perform the shutdown function, such as reactor water level and pressure, suppression pool level and temperature, etc.

5. Other support systems

   a. EGA, EGS, EGF - Emergency diesel generators (Divisions I and II) and their auxiliary systems (such as fuel oil and starting air).

   b. ENS/EJS/EHS/BYS/LAC - Onsite emergency power distribution systems.

   c. SWP - Cooling water for the emergency diesel generator jacket coolers, SFC and RHR heat exchangers, and various area unit coolers as required.

   d. Ventilation and air conditioning for cooling remote shutdown room, emergency switchgear rooms, diesel generator rooms, electrical tunnels, and others.

   e. SFC - To cool the spent fuel pool.

All of the above systems, except EJS and EHS, have monitoring/control automatic actuation circuits in the main control room. The necessary instrumentation and controls for monitoring and operating RCIC, SRV, RHR, CMS, RSS, and SWP are provided at the RSP.

The necessary controls/monitoring for diesel generator support systems are available on local control panels outside the main control or relay rooms.

The equipment associated with the above systems that may be used for safe shutdown from the RSP are listed in Table 9B.8-3.

9B.8.2.2 Safe Shutdown Scenario

The sequence of plant response and Operator actions assumed in this analysis after a major fire in the control/relay room, including the spurious maloperation, is as follows (note that times shown are estimated; actual times will be established by analysis):

Time	Event
0	Control Room Operator initiates reactor scram by placing the reactor mode switch in shutdown position, closes MSIVs and trips the feedwater pumps from the main control room. LOOP occurs.

Time	Event
	Note:
	In the event of a control room fire with no LOOP, Operators have to place the SWP system in a one-pump-per-division configuration prior to exiting the control room.
	Operators leave main control room (control building el 306'-0").
3-5 sec	MSIVs close.
<10 sec	Main steam SRVs lift discharging to suppression pool; one SRV fails to reclose due to fire-initiated spurious maloperation.
<90 sec	Operator operates the disconnect switch (control building el 306'-0") to ensure that the feedwater pumps are tripped.
5 min	Operator action is taken (such as de-energizing MSIV solenoid breakers) which provides confirmation that the MSIV closure has occurred (control building el 261'-0").
	Operators operate disconnect switches (control building el 306'-0") to isolate the control room.
≤10 min	Operators operate transfer switches in RSP to transfer control to RSP (control building el 261'-0").
	Complete start of RCIC from the RSP (if not already running).
	De-energize (close) the open SRV from the RSP.
	At this point, hot shutdown is achieved.
≤15 min	Operators locally control cooling fans 2HVP*FN1A-D and reposition the recirculation dampers 2HVP*MOD6A-D and/or discharge dampers 2HVP*MOD1A-D as appropriate to maintain acceptable temperature conditions in the diesel generator rooms.
25 min	As required, other support systems are started locally.
>30 min	If required to maintain suppression pool temperature within limits, the Operator initiates suppression pool cooling with Division I RHR system.

Time	Event
>60 min	As required, other support systems are started locally.
>120 min	After reactor pressure decreases to <105 psig, Operators initiate Division II RHR shutdown cooling to place the reactor in cold shutdown condition from the RSP.
≤72 hr	The reactor reaches cold shutdown (≤200°F) condition.

The reactor vessel/core containment parameters and spent fuel pool will remain within acceptable limits during this scenario.

9B.8.2.3 Solutions to Control/Relay Room Fire

1. Administrative controls
2. Justification by analysis
3. Modifications

In case of a fire in the main control or relay rooms, design modifications were implemented to maintain availability and controllability of systems required for safe shutdown and to prevent spurious maloperations of the control circuits. This included the following:

1. Added manual control switches on the RSP.

   See Table 9B.8-3 for circuits that are added to the RSP.

2. Provided disconnect switches outside the main control or relay rooms to prevent spurious maloperations.

   See Table 9B.8-3 for circuits provided with disconnect switches.

3. Removed permissives/interlocks from the main control/relay rooms under RSP operating mode.

   Specific procedures have been developed to address administrative control of this equipment to ensure safe operation from the RSP.

4. Provided additional protection for control power supplies to circuits on the RSP.

Additional protection for control power supplies to the circuits on the RSP has been provided by adding an additional fuse in parallel with each existing fuse, connected through the transfer switches. When the transfer switches are operated to isolate the control and relay rooms and establish control of the RSP, the new sets of fuses are put into service. This eliminates the possibility of loss of control power supply at the RSP due to a fire in the control or relay rooms.

Table 9B.8-3 lists the circuits provided with the additional fuse.

9B.8.2.4 Conclusions

With the above design modifications, capability exists for safe shutdown of the plant from the RSP and other local control stations outside the main control and relay rooms in the unlikely event of a fire in the main control or relay rooms, requiring evacuation of these areas. After scram, tripping of the feedwater system (FWS) pumps, and MSIV closure, all manual operations, including the initiation of core cooling, can be completed within 10 min of evacuation of the main control room. After this initial period, additional actions can be initiated from the RSP or locally, as required, to bring the reactor to cold shutdown. The reactor vessel/core containment fuel pool parameters remain within acceptable limits during the postulated scenario. Necessary administrative procedures, operating instructions, and Operator training are provided for the main control and relay rooms fire event.

TABLE 9B.8-1

LIST OF AFFECTED SAFE SHUTDOWN EQUIPMENT
BY FIRE AREA/FIRE ZONE

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
FA1 Aux. Bay North El 175, 198 215 & 240	201SW	2CSL*FE107	3	
		2CSL*P1	3	
		2CSL*P2	3	
		2HVR*TIS22A	1,3	
		2HVR*TIS22B	1,3	
		2HVR*UC402A-M1/M2	1,3	
		2HVR*UC402B-M1/M2	1,3	
		2HVR*MST402A	1,3	
		2HVR*MST402B	1,3	
		CABLES	1,3	
	202SW	2CCP*AOV37A	1,3	
		2CCP*AOV38A	1,3	
		2CCP*SOV37A	1,3	
		2CCP*SOV38A	1,3	
		2HVR*TIS23A	1,3	
		2HVR*TIS23D	1,3	
		2HVR*UC401A	1,3	
		2HVR*UC401D	1,3	
		2HVR*MST401A	1,3	
		2HVR*MST401D	1,3	
		2RHS*FE14A	1,3	
		2RHS*MOV2A	1,3	
		2RHS*P1A	1,3	
		2RHS*V1	1,3	
		2RHS*V39	1,3	
		2SWP*AOV20A	1,3	
		2SWP*AOV22A	1,3	
		2SWP*SOV20A	1,3	
		2SWP*SOV22A	1,3	
		CABLES	1,3	
	203SW	2*JB0207	1,3	
		2*JB0208	1,3	
		2HVR*TIS116	1,3	
		2RHS*CE11A	1,3	
		2RHS*LT28A	1,3	
		2RHS*MOV12A	1,3	
		2RHS*MOV32A	1,3	
		2RHS*MOV37A	1,3	
		2RHS*MOV8A	1,3	
		2RHS*SOV17A	1,3	
		2RHS*TE13A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2RHS*V13	1,3	
		2RHS*V23	1,3	
		2RHS*V24	1,3	
		2RHS*V27	1,3	
		2RHS*V270	1,3	
		2RHS*V271	1,3	
		2RHS*V28	1,3	
		2RHS*V29	1,3	
		2RHS*V30	1,3	
		2SWP*MOV33A	1,3	
		2SWP*MOV90A	1,3	
		2SWP*TE12A	1,3	
		CABLES	1,3	
FA1 Aux. Bay North El 198'	211SW	2HVR*UC405	1,3	
		2HVR*MST405	1,3	
		2RHS*MOV26A	1,3	
		2RHS*MOV27A	1,3	
		2RHS*MOV9A	1,3	
		2RHS*SV34A	1,3	
		2RHS*SV62A	1,3	
		2RHS*TE10A	1,3	
		2RHS*V183	1,3	
		2RHS*V196	1,3	
		2SWP*PT140A	1,3	
		CABLES	1,3	
FA1 Aux. Bay North El 215'	221SW	2*JB0020	1,3	
		2*JB0022	1,3	
		2*JB0024	1,3	
		2*JB0060	1,3	
		2*JB0085	1,3	
		2*JB0355	1,3	
		2SWP*MOV19A	1,3	
		CABLES	1,3,4	
FA1 Aux. Bay North El 240'	231SW	2CMS*AE6A	1,3	
		2CMS*AE71A	1,3	
		2CMS*AIZ6A	1,3	
		2CMS*AIZ71A	1,3	
		2CMS*E/I6A	1,3	
		2CMS*E/I71A	1,3	
		2CMS*PNL66A	1,3	
		2CMS*AIT6A	1,3	
		2CMS*AIT71A	1,3	
		2CMS*AIY6A	1,3	
		2CMS*AIY71A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2CMS*AT6A	1,3	
		2CMS*AT71A	1,3	
		2CMS*PNL73A	1,3	
		2CMS*SOV64A	1,3	
		2CMS*SOV65A	1,3	
		2DMS*MCCA1	1,3	
		2EHS*MCC102	1,3	
		2EJA*PNL100A	1,3	
		2EJA*XD100A	1,3	
		2EJS*PNL101A	1,3	
		2EJS*PNL103A	1,3	
		2EJS*PNL104A	1,3	
		2HVR*TIS19A	1,3	
		2HVR*TIS19B	1,3	
		2HVR*UC408A	1,3	
		2HVR*UC408B	1,3	
		2HVR*MST408A	1,3	
		2HVR*MST408B	1,3	
		2ICS*MOV129	1,3,4	
		2SCV*PNL101A	1,3	
		2SCV*XD101A	1,3	
		CABLES	1,3,4	
FA2 Reactor Bldg. RCIC Pump Room El 175'	204SW	2*JB0743	1,3,4	
		2*JB0815	1,3,4	
		2*TB7060	1,3,4	
		2HVR*TIS30A	1,3,4	
		2HVR*UC412A	1,3,4	
		2HVR*MST412A	1,3,4	
		2ICS*ED1	1,3,4	
		2ICS*ED2	1,3,4	
		2ICS*E1	1,3,4	
		2ICS*FE101	1,3,4	
		2ICS*HYV151	1,3,4	
		2ICS*LS132	1,3,4	
		2ICS*MOV116	1,3,4	
		2ICS*MOV120	1,3,4	
		2ICS*MOV124	1,3,4	
		2ICS*MOV150	1,3,4	
		2ICS*PCV115	1,3,4	
		2ICS*P1	1,3,4	
		2ICS*P2	1,3,4	
		2ICS*T1	1,3,4	
		CABLES	1,3,4	
		2ICS*I/P115	1,3,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
FA3 Aux. Bay South El 175, 198 215, & 240	206SW	2*JB0356	2,4	
		2HVR*TIS115	2,4	
		2RHS*CE11B	2,4	
		2RHS*LT28B	2,4	
		2RHS*MOV12B	2,4	
		2RHS*MOV32B	2,4	
		2RHS*MOV37B	2,4	
		2RHS*SOV17B	2,4	
		2RHS*V14	2,4	
		2RHS*V25	2,4	
		2RHS*V26	2,4	
		2RHS*V272	2,4	
		2RHS*V273	2,4	
		2RHS*V31	2,4	
		2RHS*V32	2,4	
		2RHS*V33	2,4	
		2RHS*V34	2,4	
		2SWP*MOV33B	2,4	
		2SWP*MOV90B	2,4	
		2SWP*TE12B	2,4	
		CABLES	2,4	
	207SW	2*JB0184	2,4	
		2*JB0209	2,4	
		2*JB0210	2,4	
		2CCP*AOV37B	2,4	
		2CCP*AOV38B	2,4	
		2CCP*SOV37B	2,4	
		2CCP*SOV38B	2,4	
		2HVR*TIS23C	2,4	
		2HVR*TIS23F	2,4	
		2HVR*UC401C	2,4	
		2HVR*UC401F	2,4	
		2HVR*MST401C	2,4	
		2HVR*MST401F	2,4	
		2RHS*MOV149	2,4	
		2RHS*MOV4B	2,4	
		2RHS*MOV8B	2,4	
		2RHS*P1B	2,4	
		2RHS*PT3B	2,4	
		2RHS*TE13B	2,4	
		2RHS*V11	2,4	
		2RHS*V2	2,4	
		2RHS*V42	2,4	
		2RHS*V5	2,4	
		2RHS*V89	2,4	
		2RHS-V91	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2SWP*AOV20B	2,4	
		2SWP*AOV22B	2,4	
		2SWP*SOV20B	2,4	
		2SWP*SOV22B	2,4	
		CABLES	2,4	
	208SW	2HVR*TIS23B	2,4	
		2HVR*TIS23E	2,4	
		2HVR*UC401B	2,4	
		2HVR*UC401E	2,4	
		2HVR*MST401B	2,4	
		2HVR*MST401E	2,4	
		2RHS*MOV4C	2,4	
		2RHS*P1C	4	
		2RHS*PT3C	2,4	
		2RHS*V3	2,4	
		2RHS*V6	2,4	
		CABLES	2,4	
		2RHS*FE14B	2,4	
		2RHS*FE14C	2,4	
FA3 Aux. Bay South El 198'	214SW	2*JB0021	2,4	
		2*JB0023	2,4	
		2HVR*UC406	2,4	
		2HVR*MST406	2,4	
		2RHS*MOV26B	2,4	
		2RHS*MOV27B	2,4	
		2RHS*MOV9B	2,4	
		2RHS*SV34B	2,4	
		2RHS*SV62B	2,4	
		2RHS*TE10B	2,4	
		2RHS*V189	2,4	
		CABLES	2,4	
FA3 Aux. Bay South El 215'	224SW	2*JB0013	2,4	
		CABLES	2,4,3	NOTE 20
FA3 Aux. Bay South El 240'	239SW	2CMS*AE6B	2,4	
		2CMS*AE71B	2,4	
		2CMS*AIZ6B	2,4	
		2CMS*AIZ71B	2,4	
		2CMS*E/I6B	2,4	
		2CMS*E/I71B	2,4	
		2CMS*PNL66B	2,4	
		2CMS*AIT6B	2,4	
		2CMS*AIT71B	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2CMS*AIY6B	2,4	
		2CMS*AIY71B	2,4	
		2CMS*AT6B	2,4	
		2CMS*AT71B	2,4	
		2CMS*PNL73B	2,4	
		2CMS*SOV64B	2,4	
		2CMS*SOV65B	2,4	
		2DMS*MCCB1	2,4	
		2EHS*MCC302	2,4	
		2EJA*PNL300B	2,4	
		2EJA*XD300B	2,4	
		2EJS*PNL302B	2,4	
		2EJS*PNL303B	2,4	
		2EJS*PNL304B	2,4	
		2HVR*TIS16A	2,4	
		2HVR*TIS16B	2,4	
		2HVR*UC409A	2,4	
		2HVR*UC409B	2,4	
		2HVR*MST409A	2,4	
		2HVR*MST409B	2,4	
		2SCV*PNL301B	2,4	
		2SCV*XD301B	2,4	
		CABLES	2,4,3	NOTE 20
FA4 Reactor Bldg. HPCS Room El 175'	205NZ	2CSH*FE105	1,2	
		2CSH*P1	1,2	
		2CSH*P2	1,2	
		2CSH*RV113	1,2	
		2CSH*RV114	1,2	
		2CSH*TW126	1,2	
		2CSH*V17	1,2	
		2CSH*V55	1,2	
		2CSH*V59	1,2	
		2CSH*V9	1,2	
		2HVR*TIS24A	1,2	
		2HVR*TIS24B	1,2	
		2HVR*UC403A	1,2	
		2HVR*MST403A	1,2	
		CABLES	1,2	
FA8 Elec. Tunnel 140° and 35°	301NW	2SWP*RE23A	1,3	
		2SWP*FS23A	1,3	
		2SWP*CAB23A	1,3	
		CABLES	1,3,4	
	302NW	CABLES	1,3,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
FA21	327NW	2*JB5053	1,2	
Control		2*JB5054	1,2	
Bldg.		2*JB5055	1,2	
HPCS		2*JB5056	1,2	
Cable Area		2*JB5058	1,2	
El 244'		2*JB5339	1,2	
		2*JB8018	1,2	
		2*JB8019	1,2	
		2*JB8030	1,2	
		2*JB8089	1,2	
		2*JB8090	1,2	
		CABLES	1,2	
	342XL	2BYS*CHGR2C1	1,2	
		2BYS*CHGR2C2	1,2	
		2EHS*MCC201	1,2	
		2EJS*X2	1,2	
		2ENS*SWG102	1,2	
		2HVC*TE111	1,2	
		2HVC*UC102	1,2	
		2LAC*PNLE03	1,2	
		2SCV*XD200P	1,2	
		2SCV*PNL200P	1,2	
		2SWP*AOV581	1,2	
		2SWP*SOV581	1,2	
		2LAC*XLE03	1,2	
		2HVC*MST102	1,2	
		CABLES	1,2	
FA28	402SW	2*JB8000	1,3	
Div. I		2*JB8057	1,3	
Diesel Gen.		2*JB8058	1,3	
Room		2*JB8059	1,3	
		2*JB8060	1,3	
		2*JB8061	1,3	
		2*JB8062	1,3	
		2*JB8063	1,3	
		2*JB8064	1,3	
		2*JB8065	1,3	
		2*JB8155	1,3	
		2*JB8156	1,3	
		2*JB8397	1,3	
		2*JB8476	1,3	
		2*TB5000	1,3	
		2BYS*PNL204A	1,3	
		2CES*IPNL406	1,3	
		2CES*IPNL407	1,3	
		2EGA-C1A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2EGA-C2A	1,3	
		2EGA*FLT1A	1,3	
		2EGA*PSV25A	1,3	
		2EGA*PSV26A	1,3	
		2EGA*PS10A	1,3	
		2EGA*PS19A	1,3	
		2EGA*PS20A	1,3	
		2EGA*PS21A	1,3	
		2EGA*PS6A	1,3	
		2EGA*PS7A	1,3	
		2EGA*PS9A	1,3	
		2EGA-SV1A	1,3	
		2EGA-SV2A	1,3	
		2EGA*SV3A	1,3	
		2EGA*SV4A	1,3	
		2EGA*TK1A	1,3	
		2EGA*TK2A	1,3	
		2EGA*TRP1A	1,3	
		2EGA-TRP2A	1,3	
		2EGA-LI17A	1,3	
		2EGA-LI18A	1,3	
		2EGA-PI11A	1,3	
		2EGA-PI12A	1,3	
		2EGA-PI13A	1,3	
		2EGA-PI14A	1,3	
		2EGA-PI15A	1,3	
		2EGF*FE13A	1,3	
		2EGF*LS12A	1,3	
		2EGF*LS5A	1,3	
		2EGF*LS7A	1,3	
		2EGF*LS8A	1,3	
		2EGF*P1A	1,3	
		2EGF*P1C	1,3	
		2EGF*STR1A	1,3	
		2EGF*STR1C	1,3	
		2EGF*TK1A	1,3	
		2EGF*TK3A	1,3	
		2EGF*V20	1,3	
		2EGF-FIS13A	1,3	
		2EGF-LT10A	1,3	
		2EGF-LIT11A	1,3	
		2EGF-LT15A	1,3	
		2EGF-PDIS20A	1,3	
		2EGF-PDIS20C	1,3	
		2EGF-PI14A	1,3	
		2EGF-PI14C	1,3	
		2EGO*P1A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2EGS*EG1	1,3	
		2EGS*PNL11	1,3	
		2EGS*P1A	1,3	
		2EGT*CH2	1,3	
		2EGT*CH4	1,3	
		2HVP*AOD4A	1,3	
		2HVP*AOD4C	1,3	
		2HVP*DMP15A	1,3	
		2HVP*DMP15B	1,3	
		2HVP*DMP17A	1,3	
		2HVP*DMP19A	1,3	
		2HVP*DMP19C	1,3	
		2HVP*FN1A	1,3	
		2HVP*FN1C	1,3	
		2HVP*FS8A	1,3	
		2HVP*FS8C	1,3	
		2HVP*MOD1A	1,3	
		2HVP*MOD1C	1,3	
		2HVP*MOD6A	1,3	
		2HVP*MOD6C	1,3	
		2HVP*SOV4A	1,3	
		2HVP*SOV4C	1,3	
		2HVP*TE10A	1,3	
		2HVP*TE11A	1,3	
		2HVP*TIS13A	1,3	
		2HVP*UC1A	1,3	
		2HVP*MST1A	1,3	
		2SWP*FT76A	1,3	
		2SWP*MOV66A	1,3	
		2SWP*MOV95A	1,3	
		2SWP*PT66A	1,3	
		2SWP*PT95A	1,3	
		CABLES	1,3,4	
FA29 Div. II Diesel Gen. Room	403SW	2*JB8001	2,4	
		2*JB8008	2,4	
		2*JB8044	2,4	
		2*JB8073	2,4	
		2*JB8098	2,4	
		2*JB8157	2,4	
		2*JB8158	2,4	
		2*JB8194	2,4	
		2*JB8195	2,4	
		2*JB8477	2,4	
		2*TB5001	2,4	
		2BYS*PNL204B	2,4	
		2CES*IPNL408	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2CES*IPNL412	2,4	
		2EGA-C1B	2,4	
		2EGA-C2B	2,4	
		2EGA*FLT1B	2,4	
		2EGA-LI17B	2,4	
		2EGA-LI18B	2,4	
		2EGA*PS10B	2,4	
		2EGA*PS19B	2,4	
		2EGA*PS20B	2,4	
		2EGA*PS21B	2,4	
		2EGA*PS6B	2,4	
		2EGA*PS7B	2,4	
		2EGA*PS9B	2,4	
		2EGA-SV1B	2,4	
		2EGA-SV2B	2,4	
		2EGA*SV3B	2,4	
		2EGA*SV4B	2,4	
		2EGA*TK1B	2,4	
		2EGA*TK2B	2,4	
		2EGA*TRP1B	2,4	
		2EGA-TRP2B	2,4	
		2EGA-PI11B	2,4	
		2EGA-PI12B	2,4	
		2EGA-PI13B	2,4	
		2EGA-PI14B	2,4	
		2EGA-PI15B	2,4	
		2EGF*FE13B	2,4	
		2EGF*LS12B	2,4	
		2EGF*LS5B	2,4	
		2EGF*LS7B	2,4	
		2EGF*LS8B	2,4	
		2EGF*P1B	2,4	
		2EGF*P1D	2,4	
		2EGF*STR1B	2,4	
		2EGF*STR1D	2,4	
		2EGF*TK1B	2,4	
		2EGF*TK3B	2,4	
		2EGF*V40	2,4	
		2EGF-FIS13B	2,4	
		2EGF-LT10B	2,4	
		2EGF-LT15B	2,4	
		2EGF-LI11B	2,4	
		2EGF-PDIS20B	2,4	
		2EGF-PDIS20D	2,4	
		2EGF-PI14B	2,4	
		2EGF-PI14D	2,4	
		2EGO*P1B	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2EGS*EG3	2,4	
		2EGS*PNL31	2,4	
		2EGS*P1B	2,4	
		2EGT*CH3	2,4	
		2EGT*CH5	2,4	
		2HVP*AOD4B	2,4	
		2HVP*AOD4D	2,4	
		2HVP*DMP15C	2,4	
		2HVP*DMP15D	2,4	
		2HVP*DMP17B	2,4	
		2HVP*DMP19B	2,4	
		2HVP*DMP19D	2,4	
		2HVP*FN1B	2,4	
		2HVP*FN1D	2,4	
		2HVP*FS8B	2,4	
		2HVP*FS8D	2,4	
		2HVP*MOD1B	2,4	
		2HVP*MOD1D	2,4	
		2HVP*MOD6B	2,4	
		2HVP*MOD6D	2,4	
		2HVP*SOV4B	2,4	
		2HVP*SOV4D	2,4	
		2HVP*TE10B	2,4	
		2HVP*TE11B	2,4	
		2HVP*TIS13B	2,4	
		2HVP*UC1B	2,4	
		2HVP*MST1B	2,4	
		2SWP*FT76B	2,4	
		2SWP*MOV66B	2,4	
		2SWP*MOV95B	2,4	
		2SWP*PT66B	2,4	
		2SWP*PT95B	2,4	
		CABLES	2,4,3	NOTE 20
		2*JB8398	2,4	
FA30 Div. III HPCS Diesel Gen. Room	404SW	2*JB5332	1,2	
		2*JB5333	1,2	
		2*JB5334	1,2	
		2*JB8002	1,2	
		2*JB8003	1,2	
		2*JB8159	1,2	
		2*JB8160	1,2	
		2CES*IPNL413	1,2	
		2CES*IPNL414	1,2	
		2EGA-C3	1,2	
		2EGA-C4	1,2	
		2EGA*FLT2	1,2	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2EGA*PCV115	1,2	
		2EGA*PCV116	1,2	
		2EGA*PS106	1,2	
		2EGA*PS109	1,2	
		2EGA*PS110	1,2	
		2EGA*PS117	1,2	
		2EGA*PS119	1,2	
		2EGA*PS120	1,2	
		2EGA*PS121	1,2	
		2EGA*PS122	1,2	
		2EGA*SV111	1,2	
		2EGA*SV112	1,2	
		2EGA*TK3	1,2	
		2EGA*TK4	1,2	
		2EGA-TRP4	1,2	
		2EGA-PI113	1,2	
		2EGA-PI114	1,2	
		2EGA-SV101	1,2	
		2EGA-SV102	1,2	
		2EGF*FE104	1,2	
		2EGF*IPNL112	1,2	
		2EGF*LS103	1,2	
		2EGF*LS106	1,2	
		2EGF*LS108	1,2	
		2EGF*LS109	1,2	
		2EGF*P2A	1,2	
		2EGF*P2B	1,2	
		2EGF*STR2A	1,2	
		2EGF*STR2B	1,2	
		2EGF*TK2	1,2	
		2EGF*TK4	1,2	
		2EGF*V60	1,2	
		2EGF-FIS104	1,2	
		2EGF-LT101	1,2	
		2EGF-LT105	1,2	
		2EGF-LI102	1,2	
		2EGF-PDIS24A	1,2	
		2EGF-PDIS24B	1,2	
		2EGF-PI16A	1,2	
		2EGF-PI16B	1,2	
		2EGS*EG2	1,2	
		2HVP*AOD5A	1,2	
		2HVP*AOD5B	1,2	
		2HVP*DMP16A	1,2	
		2HVP*DMP16B	1,2	
		2HVP*DMP18	1,2	
		2HVP*DMP20A	1,2	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2HVP*DMP20B	1,2	
		2HVP*FN2A	1,2	
		2HVP*FN2B	1,2	
		2HVP*FS9A	1,2	
		2HVP*FS9B	1,2	
		2HVP*MOD2A	1,2	
		2HVP*MOD2B	1,2	
		2HVP*MOD7A	1,2	
		2HVP*MOD7B	1,2	
		2HVP*SOV5A	1,2	
		2HVP*SOV5B	1,2	
		2HVP*TE103	1,2	
		2HVP*TE107	1,2	
		2HVP*TIS120	1,2	
		2HVP*UC2	1,2	
		2HVP*MST2	1,2	
		2SWP*FT535	1,2	
		2SWP*MOV94A	1,2	
		2SWP*MOV94B	1,2	
		CABLES	1,2	
FA75 Control Bldg. Div. III Batt. Room El 261'	339NZ	2BYS*BAT2C	1,2	
		CABLES	1,2	
FA16 Control Bldg. Cable Chase West	306NZ	CABLES	1,2,3	NOTE 19
	312NZ	CABLES	1,3,4	
	321NW	2*JB5016	1,3	
		2*JB5081	1,3	
		2*JB5147	1,3	
		2*JB8014	1,3	
		2*JB8015	1,3	
		CABLES	1,3,4	NOTE 25
	332NW	2*JB5118	1,3	
		2HVC*AOD169	1,3	
		2HVC*SOV169	1,3	
		CABLES	1,3,4	NOTE 25
	352NW	2*JB5047	1,3	
		2BYS*PNL201A	1,3	
		2BYS*PNL202A	1,3	
		2SCM*PNL101A	1,3	
		2SCM*PNL102A	1,3	
		2SCM*PNL103A	1,3	
		2SCM*PNL104A	1,3	
		2SCM*PNL105A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2SCM*XD101A	1,3	
		2SCM*XD102A	1,3	
		2SCM*XD103A	1,3	
		2SCM*XD104A	1,3	
		2SCM*XD105A	1,3	
		2VBS*PNL101A	1,3	
		CABLES	1,3,4	NOTE 25
	371NW	2VBS*PNLA103	1,3	
		2CES*PNL415	1,3	
		CABLES	1,3,4	
FA17 Control Bldg.	305NW	CABLES	1,3,4	NOTE 25
	322NW	2*JB5004	1,3	
		2*JB5014	1,3	
		2*JB5018	1,3	
		2*JB5039	1,3	
		2*JB5043	1,3	
		2*JB5092	1,3	
		2*JB5093	1,3	
		2*JB5119	1,3	
		2*JB5128	1,3	
		2*JB5150	1,3	
		2*JB5160	1,3	
		2*JB8028	1,3	
		2*JB8080	1,3	
		2*JB8082	1,3	
		2*JB8084	1,3	
		2*JB8091	1,3	
		2HVC*AOD170	1,3	
		2HVC*AOD213	1,3	
		2HVC*FS172	1,3	
		2HVC*SOV170	1,3	
		2HVC*SOV213	1,3	
		2HVC*TE174	1,3	
		2HVC*UC106	1,3	
		2HVC*MST106	1,3	
		2SWP*AOV573	1,3	
		2SWP*SOV573	1,3	
		CABLES	1,3,4	
	325NW	2*JB5049	1,3	
		CABLES	1,3,4	
	333XL	2BYS*CHGR2A1	1,3	
		2BYS*CHGR2A2	1,3	
		2BYS*SWG002A	1,3	
		2EHS*MCC103	1,3	NOTE 25
		2EJA*PNL101A	1,3	
		2EJA*XD101A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2EJS*PNL100A	1,3	
		2EJS*US1	1,3	
		2EJS*X1A	1,3	
		2EJS*X1B	1,3	
		2ENS*SWG101	1,3	
		2HVC*TE38A	1,3	
		2LAC*PNL100A	1,3	
		2LAC*XLE01	1,3	
		2LAC*PNLE01	1,3	
		2LAC*XLE04	1,3	
		2LAC*XLE06	1,3	
		2VBA*UPS2A	1,3	
		CABLES	1,3,4	
	334NZ	2*JB5153	1,3	
		2BYS*BAT2A	1,3	
		2HVC*UC101A	1,3	
		2HVC*UC108A	1,3	
		2HVC*MST101A	1,3	
		2HVC*MST108A	1,3	
		2SWP*AOV154A	1,3	
		2SWP*AOV78A	1,3	
		2SWP*SOV154A	1,3	
		2SWP*SOV78A	1,3	
		CABLES	1,3,4	
	343NZ	2CES*PNL405	1,3	NOTE 17
		2HVC*ACU3A	1,3	
		2HVC*TIS22A	1,3	
		2HVK*FE28A	1,3	
		2HVK*RV37A	1,3	
		2HVK*TW26A	1,3	
		2HVK*TW27A	1,3	
		2SWP*FI200A	1,3	
		2SWP*FI200C	1,3	
		2SWP*FI200E	1,3	
		2SWP*FI201A	1,3	
		2SWP*FY200A	1,3	
		2SWP*FY200C	1,3	
		2SWP*FY200E	1,3	
		2SWP*FY201A	1,3	
		2SWP*PWRS200A	1,3	
		2SWP*PWRS200C	1,3	
		2SWP*PWRS200E	1,3	
		2SWP*PWRS201A	1,3	
		CABLES	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
FA18	304NW	2SWP*CAB23B	2,4	
Control		2SWP*RE23B	2,4	
Bldg.,		2SWP*FS23B	2,4	
Elec		CABLES	2,4,1,3	NOTES 20, 26
Tunnel	309NW	NONE	-	
230°	324NW	2*JB5148	2,4	
		2*JB5149	2,4	
		CABLES	1,2,4,3	NOTES 20, 26
	337NW	2*JB5123	2,4	
		2HVC*AOD177	2,4	
		2HVC*SOV177	2,4	
		CABLES	1,2,4,3	NOTES 20, 26
	359NW	2BYS*PNL201B	2,4	
		2BYS*PNL202B	2,4	
		2SCM*PNL301B	2,4	
		2SCM*PNL302B	2,4	
		2SCM*PNL303B	2,4	
		2SCM*PNL304B	2,4	
		2SCM*PNL305B	2,4	
		2SCM*XD301B	2,4	
		2SCM*XD302B	2,4	
		2SCM*XD303B	2,4	
		2SCM*XD304B	2,4	
		2SCM*XD305B	2,4	
		2VBS*PNL301B	2,4	
		CABLES	1,2,4,3	NOTES 20, 26
	377NW	2VBS*PNLB103	2,4	
		2CES*PNL416	2,4	
		CABLES	1,2,4,3	NOTES 20, 26
FA19	323NW	2*JB5015	2,4	
Control		2*JB5019	2,4	
Bldg.		2*JB5026	2,4	
		2*JB5040	2,4	
		2*JB5044	2,4	
		2*JB5050	2,4	
		2*JB5082	2,4	
		2*JB5094	2,4	
		2*JB5105	2,4	
		2*JB5124	2,4	
		2*JB5138	2,4	
		2*JB5163	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2*JB8075	2,4	
		2*JB8077	2,4	
		2*JB8079	2,4	
		2*JB8081	2,4	
		2*JB8083	2,4	
		2*JB8085	2,4	
		2*JB8092	2,4	
		2HVC*AOD178	2,4	
		2HVC*AOD179	2,4	
		2HVC*AOD214	2,4	
		2HVC*AOD215	2,4	
		2HVC*FS196	2,4	
		2HVC*SOV178	2,4	
		2HVC*SOV179	2,4	
		2HVC*SOV214	2,4	
		2HVC*SOV215	2,4	
		2HVC*TE198	2,4	
		2HVC*UC107	2,4	
		2HVC*MST107	2,4	
		2SWP*AOV574	2,4	
		2SWP*SOV574	2,4	
		CABLES	1,2,4,3	NOTE 20
	326NW	2*JB5017	2,4	
		2*JB8016	2,4	
		2*JB8017	2,4	
		2*JB8029	2,4	
		CABLES	1,2,4	
	335NZ	2*JB5155	2,4	
		2BYS*BAT2B	2,4	
		2HVS*UC101B	2,4	
		2HVC*UC108B	2,4	
		2HVC*MST101B	2,4	
		2HVC*MST108B	2,4	
		2SWP*AOV154B	2,4	
		2SWP*AOV78B	2,4	
		2SWP*SOV154B	2,4	
		2SWP*SOV78B	2,4	
		CABLES	2,4,3	NOTE 20
	336XL	2BYS*CHGR2B1	2,4	
		2BYS*CHGR2B2	2,4	
		2BYS*SWG002B	2,4	
		2EHS*MCC303	2,4	NOTE 26
		2EJA*PNL301B	2,4	
		2EJA*XD301B	2,4	
		2EJS*PNL300B	2,4	
		2EJS*US3	2,4	
		2EJS*X3A	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2EJS*X3B	2,4	
		2ENS*SWG103	2,4	
		2HVC*TE38B	2,4	
		2LAC*PNL300B	2,4	
		2LAC*XLE02	2,4	
		2LAC*PNLE02	2,4	
		2LAC*XLE05	2,4	
		2LAC*XLE07	2,4	
		2VBA*UPS2B	2,4	
		CABLES	1,2,4,3	NOTE 20
	338NZ	2CES*PNL405	2,4	NOTE 17
		2HVC*ACU3B	2,4	
		2HVC*TIS22B	2,4	
		2HVK*FE28B	2,4	
		2HVK*RV37B	2,4	
		2HVK*TW26B	2,4	
		2HVK*TW27B	2,4	
		2SWP*FI200B	2,4	
		2SWP*FI200D	2,4	
		2SWP*FI200F	2,4	
		2SWP*FI201B	2,4	
		2SWP*FY200B	2,4	
		2SWP*FY200D	2,4	
		2SWP*FY200F	2,4	
		2SWP*FY201B	2,4	
		2SWP*PWRS200B	2,4	
		2SWP*PWRS200D	2,4	
		2SWP*PWRS200F	2,4	
		2SWP*PWRS201B	2,4	
		CABLES	2,4	
FA22 Control Bldg.	340NZ	2*JB5069	1,3	
		2*JB5116	1,3	
		2*JB5117	2,4	NOTE 3
		2EJS*PNL102A	1,3	
		2HVC*AOD54A	1,3	
		2HVC*AOD54B	2,4	NOTE 3
		2HVC*FS56A	1,3	
		2HVC*FS56B	2,4	NOTE 3
		2HVC*FS56C	2,4	NOTE 3
		2HVC*FS56D	1,3	
		2HVC*SOV54A	1,3	
		2HVC*SOV54B	2,4	NOTE 3
		2HVC*TIS29A	1,3	
		2HVC*UC103A	1,3	
		2HVC*MST103A	1,3	
		2HVK*CHL1A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2HVK*FE15A	1,3	
		2HVK*FT15A	1,3	
		2HVK*LS16A	1,3	
		2HVK*LS41A	1,3	
		2HVK*P1A	1,3	
		2HVK*RV14A	1,3	
		2SWP*FT29A	1,3	
		2SWP*MOV67A	1,3	
		2SWP*PT79A	1,3	
		2SWP*P2A	1,3	
		2SWP*TE35A	1,3	
		2SWP*TE91A	1,3	
		2SWP*TV35A	1,3	
		CABLES	1,3	
		CABLES	2,4	NOTE 3
FA23 Control Bldg.	341NZ	2*JB5070	2,4	
		2EJS*PNL301B	2,4	
		2HVC*TIS29B	2,4	
		2HVC*UC103B	2,4	
		2HVC*MST103B	2,4	
		2HVK*CHL1B	2,4	
		2HVK*FE15B	2,4	
		2HVK*FT15B	2,4	
		2HVK*LS16B	2,4	
		2HVK*P1B	2,4	
		2SWP*FT29B	2,4	
		2SWP*MOV67B	2,4	
		2SWP*PT79B	2,4	
		2SWP*P2B	2,4	
		2SWP*TE35B	2,4	
		2SWP*TE91B	2,4	
		2SWP*TV35B	2,4	
		CABLES	2,4	
FA24 Control Bldg. Relay Room	See Section 9B.8.2			
FA25 Control Bldg. HVAC Room El 288'	360NZ	2*JB5006	1,3	
		2*JB5008	1,3	
		2*JB5009	2,4	NOTE 2
		2*JB5032	1,3	
		2*JB5045	1,3	
		2*JB5079	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2*JB5113	1,3	
		2*JB5114	1,3	
		2HVC*ACU1A	1,3	
		2HVC*ACU2A	1,3	
		2HVC*AOD12A	1,3	
		2HVC*AOD148	1,3	
		2HVC*AOD6A	1,3	
		2HVC*CH12A	1,3	
		2HVC*FLT1A	1,3	
		2HVC*FN4A	1,3	
		2HVC*FS13A	1,3	
		2HVC*FS16A	2,4	NOTE 2
		2HVC*FS23A	2,4	NOTE 2
		2HVC*FS24A	1,3	
		2HVC*FS26A	2,4	NOTE 2
		2HVC*FS36A	1,3	
		2HVC*FS9A	1,3	
		2HVC*PNLCH12A	1,3	
		2HVC*SOV12A	1,3	
		2HVC*SOV148	1,3	
		2HVC*SOV6A	1,3	
		2HVC*TE37A	1,3	
		2HVC*TE37B	2,4	NOTE 2
		2HVK*SOV36A	1,3	
		2HVK*TV21A	1,3	
		2HVK*TV22A	1,3	
		2HVK*TW10A	1,3	
		2HVK*TW11A	1,3	
		2HVK*TW12A	1,3	
		2HVK*TW13A	1,3	
		2HVK*FE20A	1,3	
		CABLES	1,3	
		CABLES	2,4	NOTES 2,5
FA26 Control Bldg. PGCC El 306'	See Section 9B.8.2			
FA27 Control Bldg. Div. II HVAC	378NZ	2*JB5007	2,4	
		2*JB5046	2,4	
		2*JB5080	2,4	
		2*JB5109	2,4	
		2*JB5110	2,4	
		2HVC*ACU1B	2,4	
		2HVC*ACU2B	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2HVC*AOD12B	2,4	
		2HVC*AOD6B	2,4	
		2HVC*CH11B	2,4	
		2HVC*FLT1B	2,4	
		2HVC*FN4B	2,4	
		2HVC*FS13B	2,4	
		2HVC*FS16B	1,3	NOTE 2
		2HVC*FS23B	1,3	NOTE 2
		2HVC*FS24B	2,4	
		2HVC*FS26B	1,3	NOTE 2
		2HVC*FS35A	1,3	NOTE 2
		2HVC*FS35B	2,4	
		2HVC*FS9B	2,4	
		2HVC*SOV12B	2,4	
		2HVC*SOV6B	2,4	
		2HVC*TE34A	1,3	NOTE 2
		2HVC*TE34B	2,4	
		2HVK*TV21B	2,4	
		2HVK*TV22B	2,4	
		2HVK*TW10B	2,4	
		2HVK*TW11B	2,4	
		2HVK*TW12B	2,4	
		2HVK*TW13B	2,4	
		2HVK*FE20B	2,4	
		CABLES	2,4	
		CABLES	1,3	NOTE 2
FA76 Control Bldg. Corridor, Lunch Room, Work Release Room, and Ladies and Mens Toilet Rooms El 306'	380NZ	2*JB5115	1,3	
		2HVC*AOD61A	1,3	
		2HVC*SOV61A	1,3	
		CABLE	1,3,2,4	NOTE 7
FA50 Main Steam Tunnel	256NZ	2MSS*AOV7A	1,2,3,4	NOTE 14
		2MSS*AOV7B	1,2,3,4	NOTE 14
		2MSS*AOV7C	1,2,3,4	NOTE 14
		2MSS*AOV7D	1,2,3,4	NOTE 14
		CABLES	1,3	
	731SW	NONE		

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
FA48 Elec. Tunnel Vent Room, Div. I El 237'	236NZ	2HVC*TE155	1,3	
		2HVC*UC104	1,3	
		2HVC*MST104	1,3	
		CABLES	1,3	
FA55	237NZ	2*JB0359	2,4	
		2*JB0578	2,4	
		2*JB5125	2,4	
		2HVC*AOD192	2,4	
		2HVC*AOD193	2,4	
		2HVC*FS161	2,4	
		2HVC*SOV192	2,4	
		2HVC*SOV193	2,4	
		2HVC*TE165	2,4	
		2HVC*UC105	2,4	
		2HVC*MST105	2,4	
		2SWP*AOV571	2,4	
		2SWP*SOV571	2,4	
		CABLES	2,4	
		CABLES	1,3	NOTES 9, 23,22
	361NZ	2*JB8148	1,3	NOTE 10
		2*JB8149	2,4	
		2SWP*FT523	2,4	
		2SWP*FT533	2,4	
		2SWP*FV47A	1,3	NOTE 9
		2SWP*FV47B	2,4	
		2SWP*MOV93B	2,4	
		2SWP*PT142B	2,4	
		2SWP*PT54B	2,4	
		2SWP*FV54B	2,4	
		2SWP*FV54A	1,3	NOTE 9
		2SWP*CAB146B	2,4	
		2SWP*RUW146B	2,4	
		CABLES	1,3	NOTE 9
		CABLES	2,4	
	362NZ	2CSH*LT3A	1,2	
		2CSH*LT3B	1,2	
		2ICS*LT3A	1,3	NOTE 22
		2ICS*LT3C	1,3	NOTE 22
		CABLES	2,4	
		CABLES	1,3	NOTES 9, 22,23
	363NZ	CABLES	1,3	NOTE 12

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
FA60 Service Water Pump Area	807NZ	2*JB2001	2,4	
		2*JB2003	2,4	
		2*JB2044	2,4	
		2*JB2046	2,4	
		2*JB2048	2,4	
		2*JB2051	2,4	
		2*JB2053	2,4	
		2*JB2055	2,4	
		2*JB2057	2,4	
		2*JB2059	2,4	
		2*JB2300	2,4	
		2EHS*MCC301	2,4	
		2HVY*TIS33B	2,4	
		2HVY*TIS33D	2,4	
		2HVY*UC2B	2,4	
		2HVY*UC2D	2,4	
		2HVY*MST2B	2,4	
		2HVY*MST2D	2,4	
		2SWP*FT200B	2,4	
		2SWP*FT200D	2,4	
		2SWP*FT200F	2,4	
		2SWP*FT96B	2,4	
		2SWP*FT96D	2,4	
		2SWP*FT96F	2,4	
		2SWP*MOV1B	2,4	
		2SWP*MOV1D	2,4	
		2SWP*MOV1F	2,4	
		2SWP*MOV3B	2,4	
		2SWP*MOV50B	2,4	
		2SWP*MOV74B	2,4	
		2SWP*MOV74D	2,4	
		2SWP*MOV74F	2,4	
		2SWP*PDT1B	2,4	
		2SWP*PDT1D	2,4	
		2SWP*PDT1F	2,4	
		2SWP*PT2B	2,4	
		2SWP*PT4B	2,4	
		2SWP*PT4D	2,4	
		2SWP*PT4F	2,4	
		2SWP*PT6B	2,4	
		2SWP*PT6D	2,4	
		2SWP*PT6F	2,4	
		2SWP*PT139B	2,4	
		2SWP*P1B	2,4	
		2SWP*P1D	2,4	
		2SWP*P1F	2,4	
		2SWP*STR4B	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2SWP*STR4D	2,4	
		2SWP*STR4F	2,4	
		2SWP*TE31B	2,4	
		2SWP*MOV50A	1,3	NOTE 1
		CABLES	2,4	
		CABLES	1,3	NOTES 1, 12
FA61 Service Water Pump Area	806NZ	2*JB2000	1,3	
		2*JB2002	1,3	
		2*JB2045	1,3	
		2*JB2047	1,3	
		2*JB2049	1,3	
		2*JB2050	1,3	
		2*JB2052	1,3	
		2*JB2054	1,3	
		2*JB2056	1,3	
		2*JB2058	1,3	
		2*JB2303	1,3	
		2EHS*MCC101	1,3	
		2HVY*TIS33A	1,3	
		2HVY*TIS33C	1,3	
		2HVY*UC2A	1,3	
		2HVY*UC2C	1,3	
		2HVY*MST2A	1,3	
		2HVY*MST2C	1,3	
		2SWP*FT200A	1,3	
		2SWP*FT200C	1,3	
		2SWP*FT200E	1,3	
		2SWP*FT96A	1,3	
		2SWP*FT96C	1,3	
		2SWP*FT96E	1,3	
		2SWP*MOV1A	1,3	
		2SWP*MOV1C	1,3	
		2SWP*MOV1E	1,3	
		2SWP*MOV3A	1,3	
		2SWP*MOV74A	1,3	
		2SWP*MOV74C	1,3	
		2SWP*MOV74E	1,3	
		2SWP*PDT1A	1,3	
		2SWP*PDT1C	1,3	
		2SWP*PDT1E	1,3	
		2SWP*PT139A	1,3	
		2SWP*PT2A	1,3	
		2SWP*PT4A	1,3	
		2SWP*PT4C	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2SWP*PT4E	1,3	
		2SWP*PT6A	1,3	
		2SWP*PT6C	1,3	
		2SWP*PT6E	1,3	
		2SWP*P1A	1,3	
		2SWP*P1C	1,3	
		2SWP*P1E	1,3	
		2SWP*STR4A	1,3	
		2SWP*STR4C	1,3	
		2SWP*STR4E	1,3	
		2SWP*TE31A	1,3	
		CABLES	1,3	
FA71 Intake Area	802NZ	2SWP*MOV77A	1,3	NOTE 12
		2SWP*MOV77B	2,4	
		2SWP*LS30A	1,3	NOTE 12
		2SWP*MOV30A	1,3	NOTE 12
		2SWP*TE64A	1,3	NOTE 12
		2SWP*TE65A	1,3	NOTE 12
		2SWP*LS30B	2,4	
		2SWP*MOV30B	2,4	
		2SWP*TE64B	2,4	
		2SWP*TE65B	2,4	
		CABLES	2,4	
		CABLES	1,3	NOTE 12
	803NZ	2SWP*LS73A	1,3	NOTE 12
		2SWP*LS73B	2,4	
		CABLES	2,4	
		CABLES	1,3	NOTE 12
FA72 Control Bldg. Corridor/ Inst. Shop El 288'	351NZ	CABLES	2,4	NOTE 7
		CABLES	1,3	
FSA34 Reactor Bldg. North Half	212SW	2*JB0016	1,3	
		2*JB0094	1,3	
		2*JB0295	1,3	
		2*JB0297	1,3	
		2*JB0299	1,3	
		2*JB0301	1,3	
		2*JB0303	1,3	
		2*JB0305	1,3	
		2*JB0693	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2*JB0744	2,3,4	NOTE 20
		2*JB0813	1,3,4	
		2*JB0915	1,3	
		2*JB1216	1,3,4	
		2CES*RAK001	1,3	
		2CES*RAK017	1,3	
		2CES*RAK018	1,3	
		2CMS*EFV9A	1,3	
		2CMS*LT11A	1,3	
		2CMS*LT9A	1,3	
		2CMS*TE50A	1,3	
		2CMS*TE50B	2,4	NOTE 13
		2CMS*TE50C	1,3	
		2CMS*TE50D	2,4	NOTE 13
		2CMS*TE51A	1,3	
		2CMS*TE51B	2,4	NOTE 13
		2CMS*TE51C	1,3	
		2CMS*TE51D	2,4	NOTE 13
		2CMS*TE52A	1,3	
		2CMS*TE52B	2,4	NOTE 13
		2CMS*TE52C	1,3	
		2CMS*TE52D	2,4	NOTE 13
		2CMS*TE53A	1,3	
		2CMS*TE53B	2,4	NOTE 13
		2CMS*TE53C	1,3	
		2CMS*TE53D	2,4	NOTE 13
		2CMS*TE54A	1,3	
		2CMS*TE54B	2,4	NOTE 13
		2CMS*TE54C	1,3	
		2CMS*TE54D	2,4	NOTE 13
		2CMS*V80A	1,3	
		2CMS*V81A	1,3	
		CABLES	1,3	
		CABLES	2,4	NOTES 13, 20,21
FSA34 Reactor Bldg. North Half	212SW	2HVR*TIS25A	1,3	
		2HVR*TIS25B	1,3	
		2HVR*UC404A	1,3	
		2HVR*UC404B	1,3	
		2HVR*MST404A	1,3	
		2HVR*MST404B	1,3	
		2ICS*FT101	1,3,4	
		2ICS*FT102	1,3,4	
		2ICS*MOV122	1,3,4	
		2ICS*MOV136	1,3,4	
		2ICS*MOV143	1,3,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2ICS*MOV148	2,3,4	NOTE 20
		2ICS*MOV164	1,3,4	
		2ICS*PDT167	1,3,4	
		2ICS*PT1A	1,3,4	
		2ICS*PT1B	1,3,4	
		2ICS*PT103	1,3,4	
		2ICS*PT105	1,3,4	
		2ICS*PT106	1,3,4	
		2ICS*PT167X	1,3,4	
		2ICS*PT167Y	1,3,4	
		2RHS*FT14A	1,3	
		2RHS*FT60A	1,3	
		2RHS*FT86A	1,3	
		2RHS*FV38A	1,3	
		2RHS*MOV1A	1,3	
		2RHS*MOV23A	1,3	
		2RHS*MOV4A	1,3	
		2RHS*PDT18A	1,3	
		2RHS*PI87A	1,3	
		2RHS*PT111	1,3	
		2RHS*PT21A	1,3	
		2RHS*PT3A	1,3	
		2RHS*PT5A	1,3	
		2RHS*PT6A	1,3	
		2RHS*PT7A	1,3	
		2RHS*PT75A	1,3	
		2RHS*PT76A	1,3	
		2RHS*PV21A	1,3	
		2RHS*SOV21A	1,3	
		2RHS*SOV70A	1,3	
		2RHS*V10	1,3	
		2RHS-V178	1,3	
		2RHS*V195	1,3	
		2RHS-CE101	1,3	
		2RHS-TE140	1,3	
		2SWP*FT13A	1,3	
		2SWP*FT201A	1,3	
		2SWP*MOV17A	1,3	
		2SWP*MOV18A	1,3	
	222SW	2*JB0005	1,3	
		2*JB0014	1,3	
		2*JB0433	1,3	
		2*JB0695	1,3	
		2*JB0702	1,3	
		2*JB0919	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2*JB1650	1,3	
		2CCP*MOV14A	1,3	
		2CCP*MOV18A	1,3	
		2CES*RAK010	1,3	
		2CES*Z57E	1,3	
		2CMS*EFV8A	1,3	
		2CMS*SOV26C	1,3	
		2CMS*SOV35A	1,3	
		2CMS*V78A	1,3	
		2CMS*V79A	1,3	
		2CSH*MOV105	1,2	NOTE 24
		2CSH*V7	1,2	NOTE 6
		2HVR*TIS26A	1,3	
		2HVR*TIS26B	1,3	
		2HVR*TIS26C	1,3	
		2HVR*UC407A	1,3	
		2HVR*UC407B	1,3	
		2HVR*UC407C	1,3	
		2HVR*MST407A	1,3	
		2HVR*MST407B	1,3	
		2HVR*MST407C	1,3	
		2ISC*LT13A	1,3	
		2RHS*MOV22A	1,3	
		2RHS*MOV80A	1,3	
		2RHS*PNL100	1,3,2,4	NOTE 21
		2SFC*E1A	1,3	
		2SFC*FE36A	1,3	
		2SFC*FT36A	1,3	
		2SFC*HV37A	1,3	
		2SFC*TE8A	1,3	
		2SFC*TW7A	1,3	
		2SFC*TW9A	1,3	
		2SFC*V225	1,3	
		2SFC*V37A	1,3	
		2SFC*V39A	1,3	
		2SFC*V70A	1,3	
		2SFC-PI14A	1,3	
		2SFC-PI15A	1,3	
		2SFC-TI7A	1,3	
		2SFC-TI9A	1,3	
		2WCS*FT67X	1,3	
		CABLES	1,3,4	
	232SW	2CES*Z07E	1,3	
		2CES*Z08E	1,3	
		2CES*Z09E	1,3	
		2CES*Z10E	1,3	
		2HVR*TIS27A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2HVR*UC410A	1,3	
		2HVR*MST410A	1,3	
		2RHS*MOV40A	1,3	
		2RHS*V71	1,3	
		CABLES	1,3,4	
	243SW	2*JB0152	1,3	
		2*JB0629	1,3	
		2*JB0631	1,3	
		2CES*RAK004	1,3	
		2CES*RAK005	1,2	NOTE 19
		2CMS*SOV32A	1,3	
		2DER-PT134	1,3	
		2HVR*TIS28A	1,3	
		2HVR*TIS35A	1,3	
		2HVR*UC411A	1,3	
		2HVR*UC414A	1,3	
		2HVR*MST411A	1,3	
		2HVR*MST414A	1,3	
		2ISC*LT10B	1,2	NOTE 19
		2ISC*LT10D	1,2	NOTE 19
		2ISC*LT11A	1,3	
		2ISC*LT7C	1,3	
		2ISC*PT15C	1,3	
		2ISC*PT16B	1,2	NOTE 19
		2ISC*PT16D	1,2	NOTE 19
		2ISC*LT11D	1,3	
		2ISC*LT12A	1,3	
		2ISC*LT7D	1,3	
		2ISC*LT8A	1,3	
		2ISC*LT8B	1,3	
		2ISC*LT9A	1,3	
		2ISC*LT9C	1,3	
		2ISC*PT15D	1,3	
		2ISC*PT17A	1,3	
		2ISC*PT17C	1,3	
		2ISC*PT2A	1,3	
		2ISC*PT2B	1,3	
		2ISC*PT4C	1,3	
		2ISC*PT4D	1,3	
		2ISC*PT5A	1,3	
		2ISC*PT5D	1,3	
		2ISC*PT6A	1,3	
		2RHS*PDT24A	1,3	
		2RSS*LT114	1,3	
		2RSS*PT102	1,3	
		CABLES	1,3,4	
		CABLES	1,2	NOTE 19

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
	252SW	2*JB0064	1,3	
		2*JB0067	1,3	
		2*JB0121	1,3	
		2*JB0122	1,3	
		2*JB0123	1,3	
		2*JB0340	1,3	
		2*JB0346	1,3	
		2*JB0814	1,3,4	
		2*JB1671	1,3	
		2*JB1672	2,4	NOTE 15
		2HVR*AOD1A	1,3	
		2HVR*AOD204	1,3	
		2HVR*AOD34A	1,3	
		2HVR*AOD6A	1,3	
		2HVR*AOD9A	1,3	
		2HVR*SOVX1A	1,3	
		2HVR*SOVX1B	1,3	
		2HVR*SOVX6A	1,3	
		2HVR*SOVX6B	1,3	
		2HVR*SOVX9A	1,3	
		2HVR*SOVX9B	1,3	
		2HVR*SOV204	1,3	
		2HVR*SOV34A	1,3	
		2HVR*TIS31A	1,3	
		2HVR*UC413A	1,3	
		2ICS*AOV156	1,3,4	
		2ICS-LS221	1,3,4	
		2ICS*MOV126	1,3,4	
		2RHS*MOV24A	1,3	
		2RHS*V143	2,4	NOTE 6
		2RHS*V70	1,3	
		2SWP*AOV97A	1,3	
		2SWP*SOV97A	1,3	
		2HVR*UC413B	2,4	NOTE 15
		CABLES	1,3,4	
		CABLES	2,4	NOTE 15
	261SW	2*JB0600	1,3	
		2SFC*V227A	1,3	
		2SFC*V227B	2,4	NOTE 6
		CABLES	1,3	
	271SW	2*JB0019	1,3	
		2*JB0027	1,3	
		2*JB0448	1,3	
		2*JB0450	1,3	
		2SFC*AOV19A	1,3	
		2SFC*AOV33A	1,3	
		2SFC*HV35A	1,3	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2SFC*HV54A	1,3	
		2SFC*LS33A	1,3	
		2SFC*LS33C	1,3	
		2SFC*LS34A	1,3	
		2SFC*SOV19A	1,3	
		2SFC*SOV33A	1,3	
		2SFC*SOV35A	1,3	
		2SFC*SOV54A	1,3	
		2SFC*TE31A	1,3	
		2SFC*V100B	1,3	
		2SFC*V101B	1,3	
		2SFC*V102B	1,3	
		2SFO-V260A	1,3	
		2SFC-LT2A	1,3	
		CABLES	1,3	
	273SW	2SFC*V100A	1,3	
		2SFC*V101A	1,3	
		2SFC*V102A	2,4	NOTE 6
		2SFC*V104B	1,3	
		2SFC*V105B	1,3	
		2SFC*V107	2,4	NOTE 6
		2SFC-V260B	2,4	NOTE 6
		2SFC*V9	1,3	
		CABLES	1,3	
		CABLES	2,4	NOTE 15
	281NZ	2HVR*AOD10A	1,3	
		2HVR*SOVX10A	1,3	
		2HVR*SOVY10A	1,3	
		CABLES	1,3	
FA87 SFC Pump Room A Div. I	FA087* -SW	2SFC*P1A	1,3	
		2SFC*FE58A	1,3	
		2SFC*FT58A	1,3	
		2SFC-PI60A	1,3	
		CABLES	1,3	
		2SFC*V13A	1,3	
		2SFC*V20A	1,3	
		2SFC*V21A	1,3	
		2SFC*V256A	1,3	
FSA35 Reactor Bldg. South Half	213SW	2*JB0017	2,4	
		2*JB0084	2,4	
		2*JB0170	2,4	
		2*JB0296	2,4	

* This zone number is used for editorial purposes only.

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2*JB0298	2,4	
		2*JB0300	2,4	
		2*JB0302	2,4	
		2*JB0304	2,4	
		2*JB0306	2,4	
		2*JB0694	2,4	
		2CES*RAK021	2,4	
		2CES*RAK024	1,2	
		2CES*RAK029	2,4	
		2CMS*EFV9B	2,4	
		2CMS*LT11B	2,4	
		2CMS*LT9B	2,4	
		2CMS*TE55A	1,3	NOTE 13
		2CMS*TE55B	2,4	
		2CMS*TE55C	1,3	NOTE 13
		2CMS*TE55D	2,4	
		2CMS*TE56A	1,3	NOTE 13
		2CMS*TE56B	2,4	
		2CMS*TE56C	1,3	NOTE 13
		2CMS*TE56D	2,4	
		2CMS*TE57A	1,3	NOTE 13
		2CMS*TE57B	2,4	
		2CMS*TE57C	1,3	NOTE 13
		2CMS*TE57D	2,4	
		2CMS*TE58A	1,3	NOTE 13
		2CMS*TE58B	2,4	
		2CMS*TE58C	1,3	NOTE 13
		2CMS*TE58D	2,4	
		2CMS*TE59B	2,4	
		2CMS*TE59C	1,3	NOTE 13
		2CMS*TE59D	2,4	
		2CMS*V80B	2,4	
		2CMS*V81B	2,4	
		2CSH*EFV2	1,2	
		2CSH*FT104	1,2	
		2CSH*FT105	1,2	
		2CSH*LT123	1,2	
		2CSH*LT124	1,2	
		2CSH*MOV101	1,2	
		2CSH*MOV118	1,2	
		2CSH*PDT109	1,2	
		2CSH*PI103	1,2	
		2CSH*PT102	1,2	
		2CSH*PT105	1,2	
		2CSH*PT117	1,2	
		2CSH-PI128	1,2	
		2HVR*TIS25C	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2HVR*TIS25D	2,4	
		2HVR*UC403B	1,2	
		2HVR*UC404C	2,4	
		2HVR*UC404D	2,4	
		2HVR*MST403B	1,2	
		2HVR*MST404C	2,4	
		2HVR*MST404D	2,4	
		2ICS*PDT168	2,3,4	NOTE 20
		2ICS*PT168X	2,3,4	NOTE 20
		2ICS*PT168Y	2,3,4	NOTE 20
		2RHS*FT14B	2,4	
		2RHS*FT14C	2,4	
		2RHS*FT60B	2,4	
		2RHS*FT86B	2,4	
		2RHS*FT86C	2,4	
		2RHS-LS78B	2,4	
		2RHS*MOV1B	2,4	
		2RHS*MOV1C	2,4	
		2RHS*MOV2B	2,4	
		2RHS*MOV23B	2,4	
		2RHS*PI50C	2,4	
		2RHS*PI87B	2,4	
		2RHS*PI87C	2,4	
		2RHS*PT114	2,4	
		2RHS*PT21B	2,4	
		2RHS*PT3B	2,4	
		2RHS*PT3C	2,4	
		2RHS*PT5B	2,4	
		2RHS*PT5C	2,4	
		2RHS*PT6B	2,4	
		2RHS*PT6C	2,4	
		2RHS*PT7B	2,4	
		2RHS*PT7C	2,4	
		2RHS*PT75B	2,4	
		2RHS*PT76B	2,4	
		2RHS*PV21B	2,4	
		2RHS*SOV21B	2,4	
		2RHS-STR2B	2,4	
		2RHS-TIS79B	2,4	
		2RHS-TRP1B	2,4	
		2RHS-V108	2,4	
		2RHS-V151	2,4	
		2RSS*LT105	2,4	
		2SWP*FT13B	2,4	
		2SWP*FT201B	2,4	
		2SWP*MOV15A	1,2	
		2SWP*MOV15B	1,2	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2SWP*MOV17B	2,4	
		2SWP*MOV18B	2,4	
		CABLES	2,4	
		CABLES	1,3	NOTES 13, 20
	223SW	2*JB0015	2,4	
		2*JB0061	2,4	
		2*JB0160	2,4	
		2*JB0434	2,4	
		2*JB0632	2,4	
		2*JB0696	2,4	
		2*JB0703	2,4	
		2*JB0920	2,4	
		2*JB1651	2,4	
		2CCP*MOV14B	2,4	
		2CCP*MOV18B	2,4	
		2CES*Z58E	2,4	
		2CMS*EFV8B	2,4	
		2CMS*SOV26D	2,4	
		2CMS*V78B	2,4	
		2CMS*V79B	2,4	
		2HVR*TIS26D	2,4	
		2HVR*TIS26E	2,4	
		2HVR*UC407D	2,4	
		2HVR*UC407E	2,4	
		2HVR*MST407D	2,4	
		2HVR*MST407E	2,4	
		2RHS*FV38B	2,4	
		2RHS*MOV22B	2,4	
		2RHS*MOV80B	2,4	
		2SFC*E1B	2,4	
		2SFC*FE36B	2,4	
		2SFC*FT36B	2,4	
		2SFC-PI14B	2,4	
		2SFC-PI15B	2,4	
		2SFC*TE8B	2,4	
		2SFC*TW7B	2,4	
		2SFC*TW9B	2,4	
		2SFC*V37B	2,4	
		2SFC*V39B	2,4	
		2SFC*V70B	2,4	
		2SFC-TI7B	2,4	
		2SFC-TI9B	2,4	
		CABLES	2,4	
		CABLES	1,2,3	NOTE 20
	238SW	2*JB0012	2,4	
		2CES*Z19E	2,4,3	NOTE 20

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2CES*Z20E	2,4,3	NOTE 20
		2CES*Z21E	2,4	
		2CES*Z25E	2,4	
		2HVR*TIS27B	2,4	
		2HVR*TIS27C	2,4	
		2HVR*UC410B	2,4	
		2HVR*UC410C	2,4	
		2HVR*MST410B	2,4	
		2HVR*MST410C	2,4	
		2RHS*MOV113	1,2,3,4	NOTE 4
		2RHS*MOV40B	2,4	
		2RHS*V22	2,4	
		2RHS*V38	1,3	NOTE 6
		CABLES	2,4	
		CABLES	1,2,3,4	NOTES 20, 4
	245SW	2*JB0630	2,4	
		2CES*RAK009	2,4	
		2CES*RAK026	1,2	
		2CES*RAK027	2,4	
		2CMS*SOV32B	2,4	
		2HVR*TIS28B	2,4	
		2HVR*TIS28C	2,4	
		2HVR*TIS35B	2,4	
		2HVR*UC411B	2,4	
		2HVR*UC411C	2,4	
		2HVR*UC414B	2,4	
		2HVR*MST411B	2,4	
		2HVR*MST411C	2,4	
		2HVR*MST414B	2,4	
		2ICS*MOV121	1,3,4	NOTE 20
		2ISC*LT13B	2,4	
		2ISC*LT10A	1,2	
		2ISC*LT10C	1,2	
		2ISC*LT11B	2,4	
		2ISC*LT11C	1,2	
		2ISC*LT12B	2,4	
		2ISC*LT7A	1,2	
		2ISC*LT7B	2,4	
		2ISC*LT8C	2,4	
		2ISC*LT8D	2,4	
		2ISC*LT9B	2,4	
		2ISC*LT9D	2,4	
		2ISC*PT15A	1,2	
		2ISC*PT15B	2,4	
		2ISC*PT16A	1,2	
		2ISC*PT16C	1,2	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
		2ISC*PT2C	2,4	
		2ISC*PT2D	2,4	
		2ISC*PT4A	1,2	
		2ISC*PT4B	2,4	
		2ISC*PT6B	2,4	
		2RHS*PDT24B	2,4	
		2RHS*PDT24C	2,4	
		2SFC*PT3B	2,4	
		2SFC*PT30B	2,4	
		CABLES	2,4	
		CABLES	1,3	NOTES 20, 7
	255SW	2*JB0039	2,4	
		2*JB0065	2,4	
		2*JB0066	2,4	
		2*JB0452	2,4	
		2*JB0646	1,2	
		2CSH*MOV107	1,2	
		2RHS*FT105	2,4	
		2RHS*MOV104	1,3	NOTE 4
		2RHS*MOV24B	2,4	
		2RHS*MOV24C	2,4	
		2RHS*V159	2,4	
		2RHS*V79	2,4	
		2SFC*FE58A	1,3	NOTE 6
		2SFC*FE58B	2,4	
		2SFC*FT58A	1,3	NOTE 7
		2SFC*FT58B	2,4	
		2SFC*HV17B	2,4	
		2SFC*HV6B	2,4	
		2SFC-PI60A	1,3	NOTE 6
		2SFC*P1B	2,4	
		2SFC*SOV17B	2,4	
		2SFC*SOV6B	2,4	
		2SFC*V13A	1,3	NOTE 6
		2SFC*V13B	2,4	
		2SFC*V20A	1,3	NOTE 6
		2SFC*V20B	2,4	
		2SFC*V21A	1,3	NOTE 6
		2SFC*V21B	2,4	
		2SFC*V256A	1,3	NOTE 6
		2SFC*V256B	2,4	
		2SFC-PI60B	2,4	
		CABLES	2,4	
		CABLES	1,3	NOTES 7,4
	262SW	2SFC*V7	2,4	
		CABLES	2,4	

TABLE 9B.8-1 (Cont'd.)

Fire Area	Fire Zone	Affected Equipment	Affected Train	Remarks
	274SW	CABLES	2,4	
	272SW	NONE		
FA88 Control Bldg. Corridor El 261'	331NW	CABLES	1,2,3	

TABLE 9B.8-1 (Cont'd.)

LEGEND OF NOTES

NOTE 1 -	This fire area does not contain any alternative shutdown equipment requiring the LOOP assumption. In addition, a fire in this area will not cause and induce offsite power condition. Therefore, LOOP assumption is not applied for this fire area. Motor-operated valves 2SWP*MOV50A and 50B are normally open and, even if it remains open during a fire condition, safe shutdown can be achieved.
NOTE 2 -	In case of loss of this device, the associated air conditioning unit can be manually energized from the control room; therefore, safe shutdown capability exists.
NOTE 3 -	In case of loss of this device, enough infiltration will be available to maintain design temperature; therefore, safe shutdown capability exists.
NOTE 4 -	In case of loss of this equipment, an alternate shutdown cooling path will be used; therefore, safe shutdown capability exists.
NOTE 5 -	The damper operates in safe mode in case of loss of power supply; therefore, safe shutdown capability exists.
NOTE 6 -	Mechanical devices are not affected by failure of electrical systems.
NOTE 7 -	Alternate equipment is available in another fire subarea.
NOTE 8 -	Deleted.
NOTE 9 -	This equipment is fail-safe design; therefore, safe shutdown capability exists.
NOTE 10 -	The junction box feeds fail-safe design equipment; therefore, safe shutdown capability exists.
NOTE 11 -	Deleted.
NOTE 12 -	In case of a fire in this subarea, this equipment will be operated manually through proper administrative procedure.
NOTE 13 -	In case of a fire in this area, pool cooling will be initiated through proper administrative procedure.

TABLE 9B.8-2

RESULTS OF FIRE PROTECTION ANALYSIS FOR
SAFE SHUTDOWN CAPABILITY
IN ACCORDANCE WITH 10CFR50 APPENDIX R

BALANCE OF PLANT AREAS

Fire Area — FA1, Auxiliary Bay North, El 175, 198, 215, & 240 ft

Fire Zones in This Fire Area

201SW	LPCS Room
202SW	RHS Room A
203SW	RHS Heat Exchanger Room A
211SW	North Auxiliary Bay, El 198 ft
221SW	Auxiliary Bay, North Access Area B, El 215 ft
231SW	North Auxiliary Bay, Electrical Room, El 240 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 2.

Fire Area — FA2, Reactor Building, El 175 ft

Fire Zones in This Fire Area

204SW	RCIC Pump Room

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 2.

TABLE 9B.8-2 (Cont'd.)

Fire Area FA3, Auxiliary Bay South, El 175, 198, 215, 240 ft

Fire Zones in This Fire Area

206SW	RHS Heat Exchanger Room B
207SW	RHS Pump Room B
208SW	RHS Pump Room C
214SW	South Auxiliary Bay, El 198 ft
224SW	Auxiliary Bay, South Access Area B, El 215 ft
239SW	South Auxiliary Bay, Electrical Room, El 240 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 1 and 3.

Fire Area FA4, Reactor Building, El 175 ft

Fire Zones in This Fire Area

205NZ	HPCS Room

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 3 and 4.

TABLE 9B.8-2 (Cont'd.)

Fire Area FA8, Electrical Tunnel

Fire Zones in This Fire Area

301NW	Electrical Tunnel, 140°
302NW	Electrical Tunnel, 35°

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 2.

Fire Area FA21, Control Building

Fire Zones in This Fire Area

327NW	HPCS Cable Routing Area, El 244 ft
342XL	HPCS Switchgear Room, El 261 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 3 and 4.

TABLE 9B.8-2 (Cont'd.)

Fire Area FA28, Diesel Generator Building

Fire Zones in This Fire Area

402SW Division I Diesel Generator Room

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 2.

Fire Area FA29, Diesel Generator Building

Fire Zones in This Fire Area

403SW Division II Diesel Generator Room

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 1 and 3.

Fire Area FA30, Diesel Generator Building

Fire Zones in This Fire Area

404SW Division III Diesel Generator Room

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 3 and 4.

Fire Area FA75, Control Building, El 261 ft

Fire Zones in This Fire Area

339NZ	Division III Battery Room

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 3 and 4.

Fire Area FA16, Control Building

Fire Zones in This Fire Area

306NZ	Cable Chase West, El 214 ft
312NZ	Control Building Vault, El 214 ft
321NW	Cable Chase West, El 237 ft
332NW	Cable Chase West, El 261 ft
352NW	Cable Chase West, El 288 ft
371NW	Cable Chase West, El 306 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 2.

Fire Area FA17, Control Building

Fire Zones in This Fire Area

305NW	General Area, El 214 ft
322NW	Division I Cable Routing Area, El 237 ft
325NW	Division I Cable Routing Area, El 244 ft
333XL	Division I Switchgear Room, El 261 ft
334NZ	Division I Battery Room, El 261 ft
343NZ	Remote Shutdown Room A

Proposed Modifications

The following cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 2.

Fire Area FA18, Control Building

Fire Zones in This Fire Area

304NW	Electrical Tunnel 230°
309NW	Cable Chase East, El 214 ft
324NW	Cable Chase East, El 237 ft
337NW	Cable Chase East, El 261 ft
359NW	Cable Chase East, El 288 ft
377NW	Cable Chase East, El 306 ft

TABLE 9B.8-2 (Cont'd.)

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 3.

Fire Area FA19, Control Building

Fire Zones in This Fire Area

323NW	Division II Cable Routing Area, El 237 ft
326NW	Division II Cable Routing Area, El 244 ft
335NZ	Division II Battery Room, El 261 ft
336XL	Division II Switchgear Room, El 261 ft
338NZ	Remote Shutdown Room B

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 3.

Fire Area FA22, Control Building

Fire Zones in This Fire Area

340NZ	Division I HVAC Room, El 261 ft

TABLE 9B.8-2 (Cont'd.)

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 2 and 4.

Fire Area FA23, Control Building

Fire Zones in This Fire Area

341NZ Division II HVAC Room, El 261 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 1 and 3.

Fire Area FA24, Control Building PGCC Relay Room, El 288 ft

See Section 9B.8.2.

Fire Area FA25, Control Building

Fire Zones in This Fire Area

360NZ Division I HVAC Room, El 288 ft

TABLE 9B.8-2 (Cont'd.)

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 2 and 4.

Fire Area FA48, Electrical Tunnel, Ventilation Room, Div. 1, El 237 ft

Fire Zones in This Fire Area

236NZ Division I Electrical Tunnel Ventilation Room, El 237 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area in compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of fire in this fire area, safe shutdown capability exists through safe shutdown trains 2 and 4.

Fire Area FA27, Control Building

Fire Zones in This Fire Area

378NZ Division II HVAC Room, El 306 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 1 and 3.

Fire Area FA76, Control Building

Fire Zones in This Fire Area

380NZ Corridor, Lunch Room, Work Release Room, and Ladies' and Mens' Toilet Rooms, El 306 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 4.

Fire Area FA50, Main Steam Tunnel

Fire Zones in This Fire Area

256NZ Main Steam Tunnel

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 2 and 4.

TABLE 9B.8-2 (Cont'd.)

Fire Area   FA55, Pipe Tunnel

Fire Zones in This Fire Area

237NZ	Division II Electrical Tunnel Ventilation Room, El 237 ft
361NZ	Pipe Tunnel, El 245 ft
362NZ	Radwaste Tunnel, El 237 ft
363NZ	Pipe Tunnel, El 244 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 3.

TABLE 9B.8-2 (Cont'd.)

Fire Area FA60, Service Water Pump Pit

Fire Zones in This Fire Area

807NZ Service Water Pump Room B

Proposed Modifications

The following equipment/cables have been modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 1 and 3.

Fire Area FA72, Control Building, El 288 ft, Corridor and Instrument Shop

Fire Zones in this Fire Area

351NZ Control Building, Corridor and Instrument Shop, El 288 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 4.

TABLE 9B.8-2 (Cont'd.)

Fire Area FA61, Service Water Pump Pit

Fire Zones in This Fire Area

806NZ Service Water Pump Room A

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 2 and 4.

Fire Area FA71, Intake Area

Fire Zones in This Fire Area

802NZ Intake and Discharge Shaft Building
803NZ Screenwell Building

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown trains 1 and 3.

TABLE 9B.8-2 (Cont'd.)

Fire Subarea FSA34, Reactor Building, North Half

Fire Zones in This Fire Subarea

212SW	General Area, El 175 ft
222SW	General Area, El 215 ft
232SW	General Area, El 240 ft
243SW	General Area, El 261 ft
252SW	General Area, El 289 ft
261SW	General Area, El 306 ft
271SW	General Area, El 328 ft
273SW	General Area, El 328 ft
281NZ	General Area, El 328 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire subarea into compliance with Section III.G.2 of Appendix R:

NONE

Conclusion

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 2.

Fire Subarea FSA35, Reactor Building, South Half

Fire Zones in This Fire Subarea

213SW	General Area, El 175 ft
223SW	General Area, El 215 ft
238SW	General Area, El 240 ft
245SW	General Area, El 261 ft
255SW	General Area, El 288 ft
262SW	General Area, El 306 ft
274SW	General Area, El 328 ft

Proposed Modifications

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire subarea into compliance with Section III.G.2 of Appendix R:

NONE

TABLE 9B.8-2 (Cont'd.)

<u>Conclusion</u>

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 3.

<u>Fire Area</u> FA87

<u>Fire Zones in This Fire Area</u>

087SW Reactor Building Division I SFC Pump Room

<u>Proposed Modifications</u>

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R.

NONE

<u>Conclusion</u>

In case of fire in this fire area, safe shutdown capability exists through safe shutdown trains 2 and 4.

<u>Fire Area</u> FA88, Control Building, Corridor, El 288 ft

<u>Fire Zones in This Fire Area</u>

331NW Control Building, Corridor, El 288 ft

<u>Proposed Modifications</u>

The following equipment/cables are being modified in accordance with methods outlined in Section 9B.6 to bring this fire area into compliance with Section III.G.2 of Appendix R:

NONE

<u>Conclusion</u>

In case of a fire in this fire area, safe shutdown capability exists through safe shutdown train 4.

TABLE 9B.8-3

APPENDIX R CONTROL ROOM/RELAY ROOM FIRE CIRCUIT ANALYSIS

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
ABS	2ABS-XI	Auxiliary Boiler Service Transformer	Black	No	Disconnected at ENS Switchgear
BYS	2BYS*CHGR2A2	125-V Battery Charger Division I	Green	No	N/R, Not Controlled in PGCC
BYS	2BYS*CHGR2A1	125-V Battery Charger Standby Division I	Green	No	N/R, Not Controlled in PGCC
BYS	2BYS*CHGR2B2	125-V Battery Charger Division II	Yellow	No	N/R, Not Controlled in PGCC
BYS	2BYS*CHGR2B1	125-V Battery Charger Standby Division II	Yellow	No	N/R, Not Controlled in PGCC
BYS	2BYS*SWG002A	125-V dc Switchgear Division I	Green	No	N/R, Fused Both Inside and Outside PGCC
BYS	2BYS*SWG002B	125-V dc Switchgear Division II	Yellow	No	N/R, Fused Both Inside and Outside PGCC
BYS	2BYS*PNL201A	125-V dc Distribution Panel Division I	Green	No	N/R, Not Controlled in PGCC
BYS	2BYS*PNL204A	125-V dc Distribution Panel Division II	Green	No	N/R, Not Controlled in PGCC
BYS	2BYS*PNL201B	125-V dc Distribution Panel Division I	Yellow	No	N/R, Not Controlled in PGCC
BYS	2BYS*PNL204B	125-V dc Distribution Panel Division II	Yellow	No	N/R, Not Controlled in PGCC
BYS	2BYS*BAT2A	125-V Standby Battery Division I	Green	No	N/R, Not Controlled in PGCC
BYS	2BYS*BAT2B	125-V Standby Battery Division II	Yellow	No	N/R, Not Controlled in PGCC
CCP(2)	2CCP*MOV18A	RBCLCW Spent Fuel HX 2SFC*E1A	Green	No	N/R
CCP(2)	2CCP*MOV18B	RBCLCW Spent Fuel HX 2SFC*E1B	Yellow	No	N/R
CCP(2)	2CCP*AOV37A	RBCLCW 2RHS*P1A S1 Coolers	Green	No	N/R
CCP(2)	2CCP*AOV37B	RBCLCW 2RHS*P1B S1 Coolers	Yellow	No	N/R
CMS	2CMS*TE50A	Suppression Pool Temperature Elements	Green	Yes	TE Wired to 2RSS*TI103
CMS	2CMS*TE51B	Suppression Pool Temperature Elements	Yellow	Yes	TE Wired to 2RSS*TI104
CMS	2CMS*TE52A	Suppression Pool Temperature Elements	Green	Yes	TE Wired to 2RSS*TI103
CMS	2CMS*TE53B	Suppression Pool Temperature Elements	Yellow	Yes	TE Wired to 2RSS*TI104
CMS	2CMS*TE54A	Suppression Pool Temperature Elements	Green	Yes	TE Wired to 2RSS*TI103
CMS	2CMS*TE55B	Suppression Pool Temperature Elements	Yellow	Yes	TE Wired to 2RSS*TI104
CMS	2CMS*TE56A	Suppression Pool Temperature Elements	Green	Yes	TE Wired to 2RSS*TI103
CMS	2CMS*TE57B	Suppression Pool Temperature Elements	Yellow	Yes	TE Wired to 2RSS*TI104
CMS	2CMS*TE58A	Suppression Pool Temperature Elements	Green	Yes	TE Wired to 2RSS*TI103
CMS	2CMS*TE59B	Suppression Pool Temperature Elements	Yellow	Yes	TE Wired to 2RSS*TI104
CSH(2)	2CSH*MOV110	HPCS Test Bypass to CND Tank	Purple	No	Note 6
CSL(2)	Various	Various	Green	No	N/R
DER(2)	2DER*MOV128	Reactor Water Drain Isolation Valve	Black	No	Note 6
DER(2)	2DER*MOV129	Reactor Water Drain Isolation Valve	Black	No	N/R, In Series with 2DER*MOV128
DMS	2DMS*MCCA1	125-V dc MCC Reactor Building El 240	Green	No	N/R, Not Controlled in PGCC
DMS	2DMS*MCCB1	125-V dc MCC Reactor Building El 240	Yellow	No	N/R, Not Controlled in PGCC
EGA(3)	Various	Emergency Diesel Generator Starting Air System	Green/Yellow	No	N/R
EGF(3)	Various	Emergency Diesel Generator Fuel Oil System	Green/Yellow	No	N/R (LCL Controls with no PGCC Interlock)

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
EGP	2EGS*EG1	4160-V ACB-101-1 Division I EDG Output	Green	No	Dedicated Disconnect Switch to Isolate PGCC Controls and Engage Local Test Switch
EGP	2EGS*EG3	4160-V ACB-103-14 Division II EDG Output	Yellow	No	Dedicated Disconnect Switch to Isolate PGCC Controls and Engage Local Test Switch
EGP	2EGS*EG1	4160-V ACB-101-N1 Division I EDG Neutral	Green	No	N/R for Diesel Generator Operation
EGP	2EGS*EG3	4160-V ACB-103-N1 Division II EDG Neutral	Yellow	No	N/R for Diesel Generator Operation
EGS(3)	2EGS*EG1	2EGS*EG1 Control	Green	No	Dedicated Disconnect Switch to Isolate PGCC Dedicated Disconnect Switch to Bypass PGCC to Permit Auto Start/Control
EGS(3)	2EGS*EG3	2EGS*EG3 Control	Yellow	No	Dedicated Disconnect Switch to Isolate PGCC Dedicated Disconnect Switch to Bypass PGCC to Permit Auto Start/Control
EHS	2EHS*MCC101	600-V MCC Screenwell El 261	Green	No	Individually Listed in Respective Systems
EHS	2EHS*MCC102	600-V MCC Reactor Building El 240	Green	No	Individually Listed in Respective Systems
EHS	2EHS*MCC103	600-V MCC Control Building Room A 240	Green	No	Individually Listed in Respective Systems
EHS	2EHS*MCC301	600-V MCC Screenwell El 261	Yellow	No	Individually Listed in Respective Systems
EHS	2EHS*MCC302	600-V MCC Reactor Building El 240	Yellow	No	Individually Listed in Respective Systems
EHS	2EHS*MCC303	600-V MCC Control Building Room B El 240	Yellow	No	Individually Listed in Respective Systems
EJA	2EJA*PNL100A	Reactor Building 120-V Heater Panel	Green	No	N/R, Not Controlled in PGCC
EJA	2EJA*PNL101A	Control Building 120/240 Heater Panel	Green	No	N/R, Not Controlled in PGCC
EJA	2EJA*PNL300B	Reactor Building 120-V Heater Panel	Yellow	No	N/R, Not Controlled in PGCC
EJA	2EJA*PNL301B	Control Building 120/240 Heater Panel	Yellow	No	N/R, Not Controlled in PGCC
EJS	2EJS*US1	4.16-kV FDR to Transformer 2EJS*X1A/1B	Green	No	Disconnect Switch to Isolate PGCC
EJS	2EJS*US3	4.16-kV FDR to Transformer 2EJS*X3A/3B	Yellow	No	Control and Engage Local Test Switch
EJS	2EJS*US1	600-V U.S. Emergency Switchgear Normal Supply Breaker	Green	No	Disconnect Switch to Isolate PGCC
EJS	2EJS*US3	600-V U.S. Emergency Switchgear Normal Supply Breaker	Yellow	No	Control and Engage Local Test Switch
EJS	2EJS*PNL100A	Switchgear Room A Emergency 600-V Panel	Green	No	N/R, Not Controlled in PGCC
EJS	2EJS*PNL300B	Switchgear Room B Emergency 600-V Panel	Yellow	No	N/R, Not Controlled in PGCC
EJS	2EJS*PNL101A	Switchgear Room A Emergency 600-V Panel	Green	No	N/R, Not Controlled in PGCC
EJS	2EJS*PNL103A	AB-N Emergency 600-V Panel	Green	No	N/R, Not Controlled in PGCC
EJS	2EJS*PNL104A	AB-N Emergency 600-V Panel	Green	No	N/R, Not Controlled in PGCC
EJS	2EJS*PNL302B	AB-S Emergency 600-V Panel	Yellow	No	N/R, Not Controlled in PGCC
EJS	2EJS*PNL303B	AB-S Emergency 600-V Panel	Yellow	No	N/R, Not Controlled in PGCC
EJS	2EJS*PNL304B	AB-S Emergency 600-V Panel	Yellow	No	N/R, Not Controlled in PGCC
EJS	2EJS*PNL301B	Switchgear Room B Emergency 600-V Panel	Yellow	No	N/R, Not Controlled in PGCC
EJS	2EJS*US1	600-V U.S. Emergency Switchgear Altn Supply Breaker	Green	No	N/R, Not Used for Appendix R Control Room Fire Scenario
EJS	2EJS*US3	600-V U.S. Emergency Switchgear Altn Supply Breaker	Yellow	No	N/R, Not Used for Appendix R Control Room Fire Scenario
EJS	2EJS*PNL102A	AB-N Emergency 600-V Panel	Green	No	N/R, Not Controlled in PGCC

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
ENS	2ENS*SWG101	4160-V ACB-101-11 Feed to Normal Bus 2NNS-SWG014	Green	No	Disconnect Switch to Isolate PGCC Control and Engage Local Test Switch
ENS	2ENS*SWG101	4160-V ACB-101-10, 101-13 Feed From RSST	Green	No	Disconnect Switch to Isolate PGCC Control and Engage Local Test Switch
ENS	2ENS*SWG103	4160-V ACB-103-8 Feed to Normal Bus 2NNS-SWG015	Yellow	No	Disconnect Switch to Isolate PGCC Control and Engage Local Test Switch
ENS	2ENS*SWG103	4160-V ACB-103-2, 103-4 Feed From RSST	Yellow	No	Disconnect Switch to Isolate PGCC Control and Engage Local Test Switch
ENS	2ENS*SWG101	LOCA Activated Relays 71X1, 71X3 for Diesel Generator Auto Start	Green	No	Disconnect Switch to Isolate Local Relays from PGCC
ENS	2ENS*SWG103	LOCA Activated Relays 71X1, 71X3 for Diesel Generator Auto Start	Yellow	No	Disconnect Switch to Isolate Local Relays from PGCC
EPS	2EPS*SWG001	13.8-kV Emergency SWG001	Green	No	N/R, Not on Diesel Generator Buses. Controls are Fail-Safe Design
EPS	2EPS*SWG003	13.8-kV Emergency SWG003	Green	No	N/R, Not on Diesel Generator Buses. Controls are Fail-Safe Design
EPS	2EPS*SWG002	13.8-kV Emergency SWG002	Yellow	No	N/R, Not on Diesel Generator Buses. Controls are Fail-Safe Design
EPS	2EPS*SWG004	13.8-kV Emergency SWG004	Yellow	No	N/R, Not on Diesel Generator Buses. Controls are Fail-Safe Design
FWS	2FWS-P1A	Reactor Feed Pump P1A Breaker 1-8	Black	No	Dedicated Disconnect Switch to Preclude Vessel Overfill
FWS	2FWS-P1B	Reactor Feed Pump P1B Breaker 3-7	Black	No	Dedicated Disconnect Switch to Preclude Vessel Overfill
FWS	2FWS-P1C	Reactor Feed Pump P1C ACB 1-13	Black	No	Dedicated Disconnect Switch to Preclude Vessel Overfill
FWS	2FWS-P1C	Reactor Feed Pump P1C ACB 3-12	Black	No	Dedicated Disconnect Switch to Preclude Vessel Overfill
GTS	2GTS*MOV1A	Standby Gas Treatment Filter Train A Inlet	Green	No	Not Required for Safe Shutdown
GTS	2GTS*MOV2A	Standby Gas Treatment Filter Train A Inlet	Green	No	Not Required for Safe Shutdown
GTS	2GTS*FN1A	*Flt 1A Discharge Fan	Green	No	Not Required for Safe Shutdown
GTS	2GTS*MOV1B	Standby Gas Treatment Filter Train B Inlet	Yellow	No	Not Required for Safe Shutdown
GTS	2GTS*AOV2B	Standby Gas Treatment Filter Train B Inlet	Yellow	No	Not Required for Safe Shutdown
GTS	2GTS*FN1B	*Flt 1B Discharge Fan	Yellow	No	Not Required for Safe Shutdown
HVC[3]	2HVC*FN4B	Battery Room Exhaust Fan Division II	Yellow	No	Disconnect Switch and Second Fuse at MCC to Start and Run Equipment
HVC[3]	2HVC*FN4A	Battery Room Exhaust Fan Division I	Green	No	Disconnect Switch and Second Fuse at MCC to Start and Run Equipment
HVC[3]	2HVC*UC101A	Standby Switchgear Room A Unit Cooler	Green	No	Disconnect Switch and Second Fuse at MCC to Start and Run Equipment
HVC[3]	2HVC*UC101B	Standby Switchgear Room B Unit Cooler	Yellow	No	Disconnect Switch and Second Fuse at MCC to Start and Run Equipment
HVC[3]	2HVC*UC104	Control Building Cable Tunnel Unit Cooler	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVC	2SWP*AOV572	Electrical Tunnel N*UC104 Service Water Vlv	Green	No	Disconnect Switch to Open Service Water Valve

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
HVC(3)	2HVC*UC105	Control Building Cable Tunnel Unit Cooler	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVC	2SWP*AOV571	Electrical Tunnel S*UC105 Service Water Valve	Yellow	No	Disconnect Switch to Open Service Water Valve
HVC(3)	2HVC*UC106	Cable Area Base Unit Cooler	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVC	2SWP*AOV573	Cable Area Division I *UC106 Service Water Valve	Green	No	Disconnect Switch to Open Service Water Valve
HVC(3)	2HVC*UC107	Cable Area Base Unit Cooler	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVC	2SWP*AOV574	Cable Area Division II *UC107 Service Water Valve	Yellow	No	Disconnect Switch to Open Service Water Valve
HVC(3)	2HVC*UC108A	Control Building Standby Switchgear Room A	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVC	2SWP*AOV154A	Standby Switchgear Room *UC101A Service Water Valve	Green	No	Disconnect Switch to Open Service Water Valve
HVC(3)	2HVC*AOD170	HVC Unit Cooler Discharge Dampers	Green	No	Disconnect to Open Discharge Dampers
HVC(3)	2HVC*AOD178	HVC Unit Cooler Discharge Dampers	Yellow	No	Disconnect to Open Discharge Dampers
HVC(3)	2HVC*AOD183	HVC Unit Cooler Discharge Dampers	Green	No	Disconnect to Open Discharge Dampers
HVC(3)	2HVC*AOD193	HVC Unit Cooler Discharge Dampers	Yellow	No	Disconnect to Open Discharge Dampers
HVC(3)	2HVC*UC108B	Control Building Standby Switchgear Room B	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVC	2SWP*AOV154B	Standby Switchgear Room *UC101B Service Water Valve	Yellow	No	Disconnect Switch to Open Service Water Valve
HVC	2SWP*AOV78A	Control Building Standby Switchgear Room A Unit Cooler *UC108A Service Water Valve	Green	No	Disconnect Switch to Open Service Water Valve
HVC	2SWP*AOV78B	Control Building Standby Switchgear Room A Unit Cooler *UC108B Service Water Valve	Yellow	No	Disconnect Switch to Open Service Water Valve
HVK(3)	Various	Various	Green/Yellow	No	Manual Alignment of SWP for Long-Term Cooling
HVP(3)	2HVP*AOD4A	2EGS*G1 Room Inlet Damper	Green	No	Disconnect Switch to Open Dampers
HVP(3)	2HVP*FN1A	Safety-Related Axial Fans - DG	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVP(3)	2HVP*MOD1A	Standby Diesel Generator Room Exhaust	Green	No	Disconnect Switch to Open Dampers
HVP(3)	2HVP*AOD4C	2EGS*G1 Room Inlet Damper	Green	No	Disconnect Switch to Open Dampers
HVP(3)	2HVP*FN1C	Safety-Related Axial Fans - DG	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVP(3)	2HVP*MOD1C	Standby Diesel Generator Room Exhaust	Green	No	Disconnect Switch to Open Dampers
HVP(3)	2HVP*AOD4B	2EGS*G3 Room Inlet Damper	Yellow	No	Disconnect Switch to Open Dampers
HVP(3)	2HVP*FN1B	Safety-Related Axial Fans - DG	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVP(3)	2HVP*MOD1B	Standby Diesel Generator Room Exhaust	Yellow	No	Disconnect Switch to Open Dampers
HVP(3)	2HVP*AOD4D	2EGS*G3 Room Inlet Damper	Yellow	No	Disconnect Switch to Open Dampers
HVP(3)	2HVP*FN1D	Safety-Related Axial Fans - DG	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVP(3)	2HVP*MOD1D	Standby Diesel Generator Room Exhaust	Yellow	No	Disconnect Switch to Open Dampers
HVP(3)	2HVP*UC1A	DG 1 Unit Cooler Standby Diesel Generator Room	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
HVP[3]	2HVP*UC1B	DG 3 Unit Cooler Standby Diesel Generator Room	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVP[3,2]	2HVP*MOD6A	Standby Diesel Generator Room Recirc Dmpr	Green	No	Manual Repositioning of Dampers to Maintain Acceptable Temperature Conditions
	2HVP*MOD6C	Standby Diesel Generator Room Recirc Dmpr	Green	No	Manual Repositioning of Dampers to Maintain Acceptable Temperature Conditions
	2HVP*MOD6B	Standby Diesel Generator Room Recirc Dmpr	Yellow	No	Manual Repositioning of Dampers to Maintain Acceptable Temperature Conditions
	2HVP*MOD6D	Standby Diesel Generator Room Recirc Dmpr	Yellow	No	Manual Repositioning of Dampers to Maintain Acceptable Temperature Conditions
HVR	2HVR*TIS23A	RHR Pump Room A	Green	No	N/R
HVR[3]	2HVR*UC401A	RHR Pump Room A - Unit Cooler	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVR	2HVR*TIS23C	RHR Pump Room B	Yellow	No	N/R
HVR[3]	2HVR*UC401C	RHR Pump Room B - Unit Cooler	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVR	2HVR*TIS116	RHR Heat Exchanger Room A	Green	No	N/R
HVR[3]	2HVR*UC405	RHR Heat Exchanger Room - Unit Cooler	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVR	2HVR*TIS115	RHR Heat Exchanger Room B	Yellow	No	N/R
HVR[3]	2HVR*UC406	RHR Heat Exchanger Room - Unit Cooler	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVR	2HVR*TIS30A	General Area El 261	Green	No	N/R
HVR[3]	2HVR*UC412A	RCIC Pump Room - Unit Cooler	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVR	2HVR*TIS31A	*UC413A Inlet Temperature	Green	No	N/R
HVR[3]	2HVR*UC413A	Emergency Recirc Unit Cooler	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVR[3]	2HVR*AOD6A	*UC413A Inlet Damper	Green	No	Disconnect Switch to Open Damper
HVR[2]	2HVR*FS18A	Reactor Building Emergency Recirc *UC413A	Green	No	N/R
HVR[2]	2HVR*FS18C	Reactor Building Emergency Recirc *UC413A	Green	No	N/R
HVY[3]	2HVY*UC2A	SWP Pump Bay A Unit Cooler	Green	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVY	2HVY*TIS33A	SWP Pump Bay A Area Temperature	Green	No	N/R
HVY[3]	2HVY*UC2B	SWP Pump Bay B Unit Cooler	Yellow	No	Disconnect Switch/Second Fuse to Start and Run Equipment
HVY	2HVY*TIS33B	SWP Pump Bay B Area Temperature	Yellow	No	N/R
IAS[3]	2IAS*SOVX181	ADS Header "A" Flow	Green	Yes	Disconnect Switch/Second Fuse at RSS Panel
IAS[3]	2IAS*SOVY181	ADS Header "A" Flow	Green	No	Disconnect Switch to Prevent Valve Opening
IAS[3]	2IAS*SOVX186	ADS Header "B" Flow	Yellow	Yes	Disconnect Switch/Second Fuse at RSS Panel
IAS[3]	2IAS*SOVY186	ADS Header "B" Flow	Yellow	No	Disconnect Switch to Prevent Valve Opening
IAS[3]	2IAS*SOV164	Instrument Air Containment Isolation Valve	Green	Yes	Disconnect Switch/Second Fuse at RSS Panel
IAS[3]	2IAS*SOV165	Instrument Air Containment Isolation Valve	Yellow	Yes	Disconnect Switch/Second Fuse at RSS Panel

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
ICS(3)	2ICS*MOV129	Pump Suction from Condensate Storage Tank	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS-C1	Gland Seal Compressor	Green	No	N/R
ICS(3)	2ICS*MOV124	RCIC Test FCV to Condensate Storage Tank	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*FV108	Test Bypass to Condensate Storage Tank	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV116	RCIC Lube Oil Water Supply	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV122	RCIC Turbine Exhaust to Suppression Pool	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV136	RCIC Pump Suction from Suppression Pool	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV143	RCIC Minimum Flow to Suppression Pool	Green	No	N/R
ICS(3)	2ICS*MOV148	RCIC Vacuum Breaker Isolation Valve (Inboard)	Yellow	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV164	RCIC Vacuum Breaker Isolation Valve (Outboard)	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV150	2ICS-T1 Turbine Throttle Valve	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*HYV151	2ICS-T1 Turbine Governing Valve	Green	No	N/R (local control)
ICS(3)	2ICS*MOV120	RCIC Steam Supply Valve to Turbine	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV126	RCIC Injection Shutoff Valve	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV121	Steam Supply Line Isolation Valve (Outboard)	Green	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV128	RCIC Steam Supply Line Isolation Valve (Inboard)	Yellow	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*MOV170	RCIC Steam Line Warmup	Yellow	Yes	RSS Transfer Switch Disconnects PGCC and Enables Emergency Fuse at MCC
ICS(3)	2ICS*P2	RCIC System Pressure Pump	Green	No	N/R
ISC(2)	Various	Various	Yellow	No	See Individual System
LAC	2LAC*PNL100A	Control Room A Emergency Lighting Panel	Green	No	N/R, Not Controlled in PGCC
LAC	2LAC*PNL300B	Control Room B Emergency Lighting Panel	Yellow	No	N/R, Not Controlled in PGCC
LAC	2LAC*PNLE01	Lighting Panel	Green	No	N/R, Not Controlled in PGCC
LAC	2LAC*PNLE04	Lighting Panel	Green	No	N/R, Fusing Outside PGCC is Sufficient
LAC	2LAC*PNLE06	Lighting Panel	Green	No	N/R, Fusing Outside PGCC is Sufficient
LAC	2LAC*PNLE02	Lighting Panel	Yellow	No	N/R, Not Controlled in PGCC
LAC	2LAC*PNLE05	Lighting Panel	Yellow	No	N/R, Fusing Outside PGCC is Sufficient
LAC	2LAC*PNLE07	Lighting Panel	Yellow	No	N/R, Fusing Outside PGCC is Sufficient

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
MSS(3)	2MSS*AOV6A	Main Steam Isolation Valve (Inboard)	Green/Yellow	No	Manually pull inboard/outboard isolation breakers
MSS(3)	2MSS*AOV6B	Main Steam Isolation Valve (Inboard)	Green/Yellow	No	Manually pull inboard/outboard isolation breakers
MSS(3)	2MSS*AOV6C	Main Steam Isolation Valve (Inboard)	Green/Yellow	No	Manually pull inboard/outboard isolation breakers
MSS(3)	2MSS*AOV6D	Main Steam Isolation Valve (Inboard)	Green/Yellow	No	Manually pull inboard/outboard isolation breakers
MSS(3)	2MSS*AOV7A	Main Steam Isolation Valve (Outboard)	Green/Yellow	No	Manually pull inboard/outboard isolation breakers
MSS(3)	2MSS*AOV7B	Main Steam Isolation Valve (Outboard)	Green/Yellow	No	Manually pull inboard/outboard isolation breakers
MSS(3)	2MSS*AOV7C	Main Steam Isolation Valve (Outboard)	Green/Yellow	No	Manually pull inboard/outboard isolation breakers
MSS(3)	2MSS*AOV7D	Main Steam Isolation Valve (Outboard)	Green/Yellow	No	Manually pull inboard/outboard isolation breakers
MSS(2)	2MSS*MOV111	Main Steam Drain Isolation Valve (Inboard)	Yellow	No	N/R
MSS(2)	2MSS*MOV112	Main Steam Drain Isolation Valve (Outboard)	Green	No	Note 6
MSS(2)	2MSS*MOV208	Inboard MSIV Drain	Green	No	N/R
MSS(3)	2MSS*PSV121	Main Steam Line A Safety/Relief Valve	Green/Yellow	Yes	Disconnect Switch to Disconnect PGCC Interlocks
MSS(3)	2MSS*PSV127	Main Steam Line B Safety/Relief Valve	Green/Yellow	Yes	Disconnect Switch to Disconnect PGCC Interlocks
MSS(3)	2MSS*PSV129	Main Steam Line C Safety/Relief Valve	Green/Yellow	Yes	Disconnect Switch to Disconnect PGCC Interlocks
MSS(3)	2MSS*PSV137	Main Steam Line D Safety/Relief Valve	Green/Yellow	Yes	Disconnect Switch to Disconnect PGCC Interlocks
MSS(2)	2MSS*PSV126	Main Steam Line B Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV130	Main Steam Line C Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV134	Main Steam Line D Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV120	Main Steam Line A Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV122	Main Steam Line A Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV123	Main Steam Line A Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV124	Main Steam Line B Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV125	Main Steam Line B Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV128	Main Steam Line B Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV131	Main Steam Line C Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV132	Main Steam Line C Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV133	Main Steam Line C Safety/Relief Valve	Green/Yellow	NO	Disconnect Switch to Disconnect Relief Valve Function

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
MSS(2)	2MSS*PSV135	Main Steam Line D Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
MSS(2)	2MSS*PSV136	Main Steam Line D Safety/Relief Valve	Green/Yellow	No	Disconnect Switch to Disconnect Relief Valve Function
SVV(8)	2SVV-TE129	Main Steam Line C Relief Temp	Black	No	N/R
SVV(8)	2SVV-TE137	Main Steam Line D Relief Temp	Black	No	N/R
NNS	2NNS-SWG016	4160-V Switchgear 16	Black	No	N/R, Not Required for Safe Shutdown
NNS	2NNS-SWG017	4160-V Switchgear 17	Black	No	N/R, Not Required for Safe Shutdown
NNS	2NNS-SWG018	4160-V Switchgear 18	Black	No	N/R, Not Required for Safe Shutdown
RCS(2)	2RCS*SOV104	2RCS-P1A Discharge Sample Isolation Valve (Inboard)	Yellow	No	N/R
RCS(2)	2RCS*SOV105	2RCS-P1A Discharge Sample Isolation Valve (Outboard)	Green	No	N/R
RHS(2)	2RHS*MOV15A	RHR A Reactor Containment Spray	Green	No	N/R, Normally Closed, No Hi/Low Interface
RHS(2)	2RHS*MOV25A	RHR A Reactor Containment Spray	Green	No	N/R, Normally Closed, No Hi/Low Interface
RHS(2)	2RHS*MOV15B	RHR B Reactor Containment Spray	Yellow	No	N/R, Normally Closed, No Hi/Low Interface
RHS(2)	2RHS*MOV25B	RHR B Reactor Containment Spray	Yellow	No	N/R, Normally Closed, No Hi/Low Interface
RHS(2)	2RHS*MOV33A	RHR A Suppression Pool Spray	Green	No	Disconnect Switch/Second Fuse to MCC
RHS(2)	2RHS*MOV33B	RHR B Suppression Pool Spray	Yellow	No	To Drive Valve Closed
RHS(2)	2RHS*SOV120	Sampling System Test Return	Green	No	N/R
RHS(2)	2RHS*SOV121	Sampling System Test Return	Yellow	No	N/R
RHS(2)	2RHS*LV17A	2RHS*E1A Level Control	Green	No	N/R, Refer to *MOV32A, *MOV32B, *MOV37A, and *MOV37B
RHS(2)	2RHS*LV17B	2RHS*E1B Level Control	Yellow	No	N/R, Refer to *MOV32A, *MOV32B, *MOV37A, and *MOV37B
RHS(2)	2RHS*MOV26A	RHR H. E. A Vent to Suppression Pool	Green	No	N/R
RHS(2)	2RHS*MOV27A	RHR H. E. A Vent to Suppression Pool	Green	No	N/R
RHS(2)	2RHS*MOV26B	RHR H. E. B Vent to Suppression Pool	Yellow	No	N/R
RHS(2)	2RHS*MOV27B	RHR H. E. B Vent to Suppression Pool	Yellow	No	N/R
RHS(2)	2RHS*SOV35A	RHR A Reactor Sampling System Isolation Valve	Yellow	No	N/R
RHS(2)	2RHS*SOV36A	RHR A Reactor Sampling System Isolation Valve	Green	No	N/R
RHS(2)	2RHS*SOV35B	RHR B Reactor Sampling System Isolation Valve	Green	No	N/R
RHS(2)	2RHS*SOV36B	RHR B Reactor Sampling System Isolation Valve	Yellow	No	N/R
RHS(2)	2RHS*MOV115	RHR Service Water Crosstie	Yellow	No	N/R
RHS(2)	2RHS*MOV116	RHR Service Water Crosstie	Yellow	No	N/R
RHS(2)	2RHS*MOV22A	RHR A Steam Line Isolation	Green	No	Note 6 - Hi/Low Interface
RHS(2)	2RHS*MOV22B	RHR B Steam Line Isolation	Yellow	No	Note 6 - Hi/Low Interface
RHS(2)	2RHS*MOV80A	Steam Line A Isolation Valve Bypass	Green	No	Note 6 - Hi/Low Interface
RHS(2)	2RHS*MOV80B	Steam Line B Isolation Valve Bypass	Yellow	No	Note 6 - Hi/Low Interface
RHS(3)	2RHS*MOV9A	RHR Heat Exchanger A Shell Side Inlet	Green	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV9B	RHR Heat Exchanger B Shell Side Inlet	Yellow	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV12A	RHR Heat Exchanger A Shell Side Outlet	Green	Yes	Second Fuse at MCC

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
RHS(3)	2RHS*MOV12B	RHR Heat Exchanger B Shell Side Outlet	Yellow	Yes	Second Fuse at MCC
RHS(3)	2RHS*P1A	Residual Heat Removal Pump A	Green	Yes	Second Fuse at Switchgear
RHS(3)	2RHS*P1B	Residual Heat Removal Pump B	Yellow	Yes	Second Fuse at Switchgear
RHS(3)	2RHS*MOV40A	RHR A Shutdown Cooling Return	Green	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV40B	RHR B Shutdown Cooling Return	Yellow	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV67A	RHR A Shutdown Cooling CV Bypass	Green	Yes	Note 6
RHS(3)	2RHS*MOV67B	RHR B Shutdown Cooling CV Bypass	Yellow	Yes	Note 6
RHS(3)	2RHS*MOV112	RHR Shutdown Cooling Suction Isolation	Yellow	Yes	Second Fuse at MCC, Note 6
RHS(3)	2RHS*MOV113	RHR Shutdown Cooling Suction Isolation	Green	Yes	Note 6
RHS(3)	2RHS*FV38A	RHR Loop A Test Return	Green	Yes	Disconnect Switch/Second Fuse at MCC
RHS(3)	2RHS*FV38B	RHR Loop B Test Return	Yellow	Yes	Disconnect Switch/Second Fuse at MCC
RHS(3)	2RHS*MOV104	RHR Head Spray Isolation	Green	Yes	Second Fuse to MCC
RHS(2)	2RHS*MOV32A	RHR H. E. A Flow to RCIC	Green	No	Note 6
RHS(2)	2RHS*MOV32B	RHR H. E. B Flow to RCIC	Yellow	No	Note 6
RHS(2)	2RHS*MOV37A	RHR H. E. A Flow to Suppression Pool	Green	No	Note 6
RHS(2)	2RHS*MOV37B	RHR H. E. B Flow to Suppression Pool	Yellow	No	Note 6
RHS(3)	2RHS*MOV142	RHR Discharge to Radwaste	Green	Yes	Second Fuse at MCC, Note 6
RHS(3)	2RHS*MOV1A	RHR Pump P1A Suction	Green	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV1B	RHR Pump P1B Suction	Yellow	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV2A	RHR A Shutdown Cooling Suction	Green	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV2B	RHR B Shutdown Cooling Suction	Yellow	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV8A	RHR H. E. E1A Bypass	Green	Yes	Disconnect Switch/Second Fuse at MCC
RHS(3)	2RHS*MOV8B	RHR H. E. E1B Bypass	Yellow	Yes	Disconnect Switch/Second Fuse at MCC
RHS(3)	2RHS*MOV149	RHR Discharge to Radwaste	Yellow	Yes	Second Fuse at MCC, Note 6
RHS(3)	2RHS*MOV30A	RHR A Return to Suppression Pool Isolation	Green	Yes	Second Fuse at MCC
RHS(3)	2RHS*MOV30B	RHR B Return to Suppression Pool Isolation	Yellow	Yes	Second Fuse at MCC
RHS(7)	2RHS*MOV24A	RHR LPCI Injection	Green	No	Not Required
RHS(7)	2RHS*MOV24B	RHR LPCI Injection	Yellow	No	Not Required
RHS(7)	2RHS*MOV4A	RHR Min. Flow	Green	No	Not Required
RHS(7)	2RHS*MOV4B	RHR Min. Flow	Yellow	No	Not Required
RTX	2RTX-XSR1A	115/13.8-kV Reserve Transformer A	Black	No	No Fix Required; In Case of Loss of This, Emergency Diesel Will Start
RTX	2RTX-XSR1B	115/13.8-kV Reserve Transformer B	Black	No	No Fix Required; In Case of Loss of This, Emergency Diesel Will Start
SCM	2SCM*XD102A	Dist Transformer 600-V - 120/240	Green	No	Not Required for Safe Shutdown
SCM	2SCM*XD104A	Dist Transformer 600-V - 120/240	Green	No	Not Required for Safe Shutdown
SCM	2SCM*XD302B	Dist Transformer 600-V - 120/240	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*XD304B	Dist Transformer 600-V - 120/240	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*XD103A	Dist Transformer 600-V - 120/240	Green	No	Not Required for Safe Shutdown
SCM	2SCM*XD101A	Dist Transformer 600-V - 120/240	Green	No	Not Required for Safe Shutdown
SCM	2SCM*XD105A	Dist Transformer 600-V - 120/240	Green	No	Not Required for Safe Shutdown
SCM	2SCM*XD303B	Dist Transformer 600-V - 120/240	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*XD301B	Dist Transformer 600-V - 120/240	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*XD305B	Dist Transformer 600-V - 120/240	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*PNL102A	120-V Dist Panel	Green	No	Not Required for Safe Shutdown
SCM	2SCM*PNL104A	120-V Dist Panel	Green	No	Not Required for Safe Shutdown
SCM	2SCM*PNL103A	120-V Dist Panel	Green	No	Not Required for Safe Shutdown

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
SCM	2SCM*PNL101A	120-V Dist Panel	Green	No	Not Required for Safe Shutdown
SCM	2SCM*PNL105A	120-V Dist Panel	Green	No	Not Required for Safe Shutdown
SCM	2SCM*PNL302B	120-V Dist Panel	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*PNL304B	120-V Dist Panel	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*PNL301B	120-V Dist Panel	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*PNL303B	120-V Dist Panel	Yellow	No	Not Required for Safe Shutdown
SCM	2SCM*PNL305B	120-V Dist Panel	Yellow	No	Not Required for Safe Shutdown
SCV	2SCV*PNL101A	GTS Miscellaneous 120/240-V Panel	Green	No	Not Required for Safe Shutdown
SCV	2SCV*PNL301B	GTS Miscellaneous 120/240-V Panel	Yellow	No	Not Required for Safe Shutdown
SFC[1,2]	2SFC*HV35A	2SFC*TK1A Inlet Valve	Green	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*HV35B	2SFC*TK1B Inlet Valve	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*HV54A	Skimmer Surge Tank Outlet	Green	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*HV54B	Skimmer Surge Tank Outlet	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*HV6A	Spent Fuel Pool Cooling Water Cross Connect	Green	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*HV6B	Spent Fuel Pool Cooling Water Cross Connect	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*LS33A	Skimmer Surge Tank Level	Green	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*LS33C	Skimmer Surge Tank Level	Green	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*AOV33A	Skimmer Surge Tank Level Control	Green	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*LS33B	Skimmer Surge Tank Level	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*LS33D	Skimmer Surge Tank Level	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*AOV33B	Skimmer Surge Tank Level	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*LT32A	Spent Fuel Pool Surge Tank Water Level	Green	No	N/R, PGCC Indication Only
SFC[2]	2SFC*LT32B	Spent Fuel Pool Surge Tank Water Level	Yellow	No	N/R, PGCC Indication Only
SFC[2]	2SFC*LS34A	SFC Skimmer Surge Tank High Level	Green	No	N/R
SFC[2]	2SFC*LS34B	SFC Skimmer Surge Tank High Level	Yellow	No	N/R
SFC[2]	2SFC*TE31A	Spent Fuel Pool Surge Tank Outlet Temperature	Green	No	N/R
SFC[2]	2SFC*TE31B	Spent Fuel Pool Surge Tank Outlet Temperature	Yellow	No	N/R
SFC[2]	2SFC*PT3A	Spent Fuel Pool Circulating Pump A Suction Pressure	Green	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*PT3B	Spent Fuel Pool Circulating Pump B Suction Pressure	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*PT30A	Spent Fuel Pool Circulating Pump A Discharge Pressure	Green	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*PT30B	Spent Fuel Pool Circulating Pump B Discharge Pressure	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*FT36A	Spent Fuel Pool Cooling System Flow	Green	No	N/R
SFC[2]	2SFC*FT36B	Spent Fuel Pool Cooling System Flow	Yellow	No	N/R
SFC[2]	2SFC*FT58A	SFC Pump Discharge Flow	Green	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*FT58B	SFC Pump Discharge Flow	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[2]	2SFC*P1A	SFC Water Circulating Pump A	Green	No	Disconnect Switch to Disconnect PGCC Control
SFC[2]	2SFC*P1B	SFC Water Circulating Pump B	Yellow	No	Disconnect Switch to Disconnect PGCC Control
SFC[1,2]	2SFC*AOV154	SFC Filter Header Inlet Isolation Valve	Yellow	No	N/R, Manual Closer of Valve Long Term
SFC[1,2]	2SFC*AOV153	SFC Filter Header Inlet Isolation Valve	Green	No	N/R, Manual Closer of Valve Long Term
SFC[1,2]	2SFC*HV18A	2SFC-FLT1A Inlet	Green	No	N/R, Manual Closer of Valve Long Term
SFC[1,2]	2SFC*HV18B	2SFC-FLT1B Inlet	Yellow	No	N/R, Manual Closer of Valve Long Term

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
SFC[1,2]	2SFC*HV17A	2SFC-FLT1A Bypass	Green	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*HV17B	2SFC-FLT1B Bypass	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*HV37A	2SFC*E1A Heat Exchanger	Green	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*HV37B	2SFC*E1B Heat Exchanger	Yellow	No	N/R, Manual Alignment of System Long Term
SFC[1,2]	2SFC*AOV19A	2SFC-FLT1A Outlet	Green	No	N/R
SFC[1,2]	2SFC*AOV19B	2SFC-FLT1B Outlet	Yellow	No	N/R
SFC[2]	2SFC*TE8A	Spent Fuel Pool Heat Exchanger Outlet Temperature	Green	No	N/R
SFC[2]	2SFC*TE8B	Spent Fuel Pool Heat Exchanger Outlet Temperature	Yellow	No	N/R
SWP[3]	2SWP*P1A	SWP Pumps *P1A	Green	Yes	Dedicated SWP Disconnect Switch/Second Fuse
SWP[3]	2SWP*P1C	SWP Pumps *P1C	Green	Yes	Dedicated SWP Disconnect Switch/Second Fuse
SWP[3]	2SWP*P1E	SWP Pumps *P1E[9]	Green	Yes	Dedicated SWP Disconnect Switch
SWP[3]	2SWP*P1B	SWP Pumps *P1B	Yellow	Yes	Dedicated SWP Disconnect Switch/Second Fuse
SWP[3]	2SWP*P1D	SWP Pumps *P1D	Yellow	Yes	Dedicated SWP Disconnect Switch/Second Fuse
SWP[3]	2SWP*P1F	SWP Pumps *P1F[9]	Yellow	Yes	Dedicated SWP Disconnect Switch
SWP[3]	2SWP*MOV74A	SWP Pump 2SWP*P1A Discharge Valve	Green	Yes	RMS/Transfer to RSS Panel/Second Fuse to MCC
SWP[3]	2SWP*MOV74C	SWP Pump 2SWP*P1C Discharge Valve	Green	Yes	RMS/Transfer to RSS Panel/Second Fuse to MCC
SWP[3]	2SWP*MOV74E	SWP Pump 2SWP*P1E Discharge Valve	Green	Yes	RMS/Transfer to RSS Panel/Second Fuse to MCC
SWP[3]	2SWP*MOV74B	SWP Pump 2SWP*P1B Discharge Valve	Yellow	Yes	RMS/Transfer to RSS Panel/Second Fuse to MCC
SWP[3]	2SWP*MOV74D	SWP Pump 2SWP*P1D Discharge Valve	Yellow	Yes	RMS/Transfer to RSS Panel/Second Fuse to MCC
SWP[3]	2SWP*MOV74F	SWP Pump 2SWP*P1F Discharge Valve	Yellow	Yes	RMS/Transfer to RSS Panel/Second Fuse to MCC
SWP[3]	2SWP*STR4A and MOV1A	SWP Str (Motor-Operated) and Backwash Valve (Motor-Operated)	Green	No	Dedicated SWP Disconnect Switch to Start and Run Equipment/Open Valve
SWP[3]	2SWP*STR4C and MOV1C	SWP Str (Motor-Operated) and Backwash Valve (Motor-Operated)	Green	No	Dedicated SWP Disconnect Switch to Start and Run Equipment/Open Valve
SWP[3]	2SWP*STR4E and MOV1E	SWP Str (Motor-Operated) and Backwash Valve (Motor-Operated)	Green	No	Dedicated SWP Disconnect Switch to Start and Run Equipment/Open Valve
SWP[3]	2SWP*STR4B and MOV1B	SWP Str (Motor-Operated) and Backwash Valve (Motor-Operated)	Yellow	No	Dedicated SWP Disconnect Switch to Start and Run Equipment/Open Valve
SWP[3]	2SWP*STR4D and MOV1D	SWP Str (Motor-Operated) and Backwash Valve (Motor-Operated)	Yellow	No	Dedicated SWP Disconnect Switch to Start and Run Equipment/Open Valve
SWP[3]	2SWP*STR4F and MOV1F	SWP Str (Motor-Operated) and Backwash Valve (Motor-Operated)	Yellow	No	Dedicated SWP Disconnect Switch to Start and Run Equipment/Open Valve
SWP[3]	2SWP*MOV3A	SWP to TBCLCW Isolation Valve	Green	No	Dedicated SWP Disconnect Switch to Close Valve/Second Fuse at MCC
SWP[3]	2SWP*MOV3B	SWP to TBCLCW Isolation Valve	Yellow	No	N/R
SWP[2]	2SWP*MOV19A	SWP to CCP Heat Exchanger Isolation Valve	Green	No	Dedicated SWP Disconnect Switch to Close Valve/Second Fuse at MCC
SWP[2]	2SWP*MOV19B	SWP to CCP Heat Exchanger Isolation Valve	Yellow	No	N/R
SWP[2]	2SWP*FV47A	SWP to Circulating Water Isolation Valve	Green	No	Dedicated SWP Disconnect Switch
SWP[2]	2SWP*FV54A	SWP to Circulating Water Isolation Valve	Green	No	N/R
SWP[2]	2SWP*FV47B	SWP to Circulating Water Isolation Valve	Yellow	No	Dedicated SWP Disconnect Switch
SWP[2]	2SWP*FV54B	SWP to Circulating Water Isolation Valve	Yellow	No	N/R
SWP[2]	2SWP*MOV599	Turbine Building Discharge Isolation Valve	Green	No	N/R
SWP[2]	2SWP*MOV93A	Reactor Building Discharge Isolation Valve	Green	No	Dedicated SWP Disconnect Switch to Close Valve/Second Fuse at MCC
SWP[2]	2SWP*MOV93B	Reactor Building Discharge Isolation Valve	Yellow	No	N/R

TABLE 9B.8-3 (Cont'd.)

System	Equipment	Description	Electrical Division	Controlled From RSS Panel	Control Circuit Arrangement
SWP[2]	2SWP*MOV50A	Service Water Cross Header Isolation Valve	Green	No	N/R
SWP[2]	2SWP*MOV50B	Service Water Cross Header Isolation Valve	Yellow	No	N/R
SWP[2]	2SWP*MOV21A	SWP to SFC Isolation Valve	Green	No	N/R
SWP[2]	2SWP*MOV21B	SWP to SFC Isolation Valve	Yellow	No	N/R
SWP[3]	2SWP*MOV66A	SWP to 2EGS*EG1 Cooler	Green	Yes	RMS/Transfer to RSS Panel/Second Fuse at MCC
SWP[3]	2SWP*MOV66B	SWP to 2EGS*EG3 Cooler	Yellow	Yes	RMS/Transfer to RSS Panel/Second Fuse to MCC
SWP[3]	2SWP*MOV33A	Service Water FR 2RHS*E1A	Green	Yes	Fuse at MCC
SWP[3]	2SWP*MOV33B	Service Water FR 2RHS*E1B	Yellow	Yes	Fuse at MCC
SWP[3]	2SWP*MOV90A	Service Water to Heat Exchanger 2RHS*E1A	Green	Yes	Second Fuse at MCC
SWP[3]	2SWP*MOV90B	Service Water to Heat Exchanger 2RHS*E1B	Yellow	Yes	Second Fuse at MCC
SWP[3]	2SWP*SSR1A, 2A, 3A	SWP Bar Rack Heater Intake Structure #1	Green	No	Add Dedicated SWP Disconnect Switch to Activate Heaters - Second Fuse to MCC
SWP[3]	2SWP*SSR4A, 5A, 6A	SWP Bar Rack Heater Intake Structure #2	Green	No	
SWP[3]	2SWP*SSR1B, 2B, 3B	SWP Bar Rack Heater Intake Structure #1	Yellow	No	
SWP[3]	2SWP*SSR4B, 5B, 6B	SWP Bar Rack Heater Intake Structure #2	Yellow	No	
VBA	2VBA*UPS2A	Division I Control UPS	Green	No	Disconnect Switch to Disconnect PGCC Metering
VBA	2VBA*UPS2B	Division II Control UPS	Yellow	No	Disconnect Switch to Disconnect PGCC Metering
VBS	2VBS*PNL101A	120-V UPS Distribution Panel	Green	No	N/R
VBS	2VBS*PNL301B	120-V UPS Distribution Panel	Yellow	No	N/R
VBS	2VBS*PNL102A	120-V UPS Distribution Panel	Green	No	N/R, Not Used for REM Shutdown
VBS	2VBS*PNL302B	120-V UPS Distribution Panel	Yellow	No	N/R, Not Used for REM Shutdown
WCS[2]	2WCS-MOV106	RWCU Drain to Waste Collector Tank	Black	No	Note 6
WCS[2]	2WCS-MOV107	RWCU Drain to Main Condenser	Black	No	Note 6

(1) Time to reach 150°F is 4.8 hr following the loss of cooling during normal operation.
(2) Denotes evaluated for spurious action.
(3) Denotes required for safe shutdown.
(4) Deleted.
(5) Deleted.
(6) Operating procedures to require valve to be maintained in the closed/de-energized state, de-energized from the power sources.
(7) Valves need to be manually manipulated to initiate alternate shutdown cooling.
(8) Capability to monitor SRV tail piece thermocouple for temperature is provided at junction box 2-JB5511. This can be used for verification of cold shutdown.
(9) Operation from remote shutdown requires control fuse replacement.

SECTION 9B.9

ALTERNATE SHUTDOWN ANALYSIS

9B.9.1 Introduction

The results of the Appendix R SSA (Section 9B.8) show that, at minimum, one of the four trains of SSDSs will remain free of damage due to a fire in any fire area except for the power generation control complex (PGCC), which includes the main control room and relay room. A remote shutdown system (RSS) is provided to achieve and maintain hot and cold shutdown in case of a fire in the PGCC. The design of the RSS meets the requirements of Section III.L of Appendix R.

9B.9.2 Description

The RSPs are located in separate fire areas in the control building, el 261 ft, in an area enclosed by 3-hr fire-rated barriers (Fire Areas [FA]19 and FA17, Figure 9A.3-5).

The RSS design is described in detail in Section 7.4.1.4. Manual keylock transfer switches are provided in the RSPs. These transfer switches isolate controls from the main control room and transfer controls to the remote shutdown room. Control power supplies and control logics are also transferred.

Control switches are provided on the RSP for manual control of the systems required for hot and cold shutdown.

Instrumentation is provided in the RSP to indicate necessary plant parameters.

The remote shutdown room is divided into two separate rooms, each enclosed by 3-hr rated barriers. FA19 (zone 338NZ) contains Division II components which constitute safe shutdown trains 2 and 4, while FA17 (zone 343NZ) contains Division I components which constitute safe shutdown trains 1 and 3.

Access to the remote shutdown room is administratively controlled.