Duke Energy Company
Oconee Nuclear Station
UPDATED FINAL SAFETY ANALYSIS REPORT

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Revision	Effective Date	Issue Date	Revision	Effective Date	Issue Date
1	12/31/91	06/30/92	26	12/31/16	6/30/17
2	12/31/92	06/30/93	27	12/31/17	6/30/18
3	12/31/93	06/30/94	28	12/31/19	6/30/20
4	12/31/94	06/30/95	29	12/31/21	6/30/22
5	12/31/95	06/30/96			
6	12/31/96	06/30/97			
7	12/31/97	06/30/98			
8	12/31/98	06/30/99			
9	12/31/99	06/30/00			
10	12/31/00	06/30/01			
11	12/31/01	06/30/02			
12	12/31/02	06/30/03			
13	12/31/03	06/30/04			
14	12/31/04	06/30/05			
15	12/31/05	06/30/06			
16	12/31/06	06/30/07			
17	12/31/07	06/30/08			
18	12/31/08	06/30/09			
19	12/31/09	06/30/10			
20	12/31/10	06/30/11			
21	12/31/11	06/30/12			
22	12/31/12	06/30/13			
23	12/31/13	06/30/14			
24	12/31/14	06/30/15			
25	12/31/15	6/30/16			

Table of Contents

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List of Tables

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List of Figures

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1.0 Introduction and General Description of Plant

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1.1 Introduction

This updated Final Safety Analysis Report is submitted in support of Duke Power Company's licenses to operate the three-unit Oconee Nuclear Station located on the shore of Lake Keowee in Oconee County, South Carolina. The station location is shown on Duke's Service Area Map, Figure 1-1.

The organization of this report is in accordance with Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants - LWR Edition". Every attempt has been made to be responsive to the format and intent of that guide and to be consistent with the content of the original Final Safety Analysis Report (FSAR).

Construction of Oconee 1, 2, and 3 was authorized by the United States Atomic Energy Commission by issuance of construction permits CPPR-33, 34, and 35, on November 6, 1967, in Dockets 50-269, 270 and 287. Operation of Oconee 1, 2, and 3 was authorized by the United States Atomic Energy Commission by issuance of operating licenses DPR-38, 47, and 55 on February 6, 1973, October 6, 1973, and July 19, 1974 respectively.

The three units are substantially identical except for certain auxiliary systems which are shared. Sharing of these systems and components is not detrimental to the safe operation of any unit. General arrangements of major equipment and structures, including the Reactor Building, Auxiliary Building, and Turbine Building, are shown in Figure 1-2 through Figure 1-9.

The Oconee units are generally similar to those of other current pressurized water reactors. Differences include the generation of superheated steam in once-through steam generators, the use of Keowee Hydro Station as an emergency power source and the use of gravity flow for emergency condenser cooling.

The Nuclear Steam Supply System is a pressurized water type using chemical shim and control rods for reactivity control. The Babcock & Wilcox Company (B&W) is the supplier for the Nuclear Steam Supply System and the initial fuel cores and reloads for each of the three units. Replacement steam generators and reactor vessel heads were supplied by Babcock & Wilcox Canada (BWC).

All physics and core thermal hydraulics information in this report is based upon a reference core design of 2568 MWt. Site parameters, principal structures, engineered safeguards, and accidents are evaluated for a core output of 2568 MWt.

Duke is fully responsible for the complete safety and adequacy of the station. Company personnel perform most safety-related activities including design engineering, construction, maintenance, testing, and operating the station. Technical qualifications of key personnel are given in Chapter 13.

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1.2 General Plant Description

1.2.1 Site Characteristics

The site is characterized by a one-mile exclusion radius; remoteness from population centers; sound, hard rock foundation for structures; freedom from flooding; an abundant supply of cooling water; an on-site hydroelectric station capable of supplying ample emergency power; and favorable conditions of hydrology, geology, seismology, and meteorology.

1.2.2 Station Description

1.2.2.1 General Arrangement

The general arrangement of the major equipment and structures is shown in Figure 1-2 through Figure 1-9.

1.2.2.2 Nuclear Steam Supply System

Each Nuclear Steam Supply System consists of a pressurized water reactor and a two-loop Reactor Coolant System. The mechanical, thermal-hydraulic, and nuclear design of the reactor core is similar to other systems operating or under construction.

The fuel assembly design information is given in Section 4.2.2.

The control rod assembly design information is given in Section 4.5.2.2.

The two steam generators are vertical, straight tube units producing super-heated steam at constant pressure. With the once-through design, natural circulation flow is adequate to remove full decay heat without the use of reactor coolant pumps. Thus, with total loss of pumps, departure from nucleate boiling will not occur in the core.

An electrically heated pressurizer establishes and maintains the reactor coolant pressure and provides a surge chamber and a water reserve to accommodate reactor coolant volume changes during operation.

The reactor coolant pumps (two in each loop) are vertical, single speed, centrifugal units equipped with controlled leakage shaft seals.

1.2.2.3 Containment System

The prestressed, post-tensioned, steel lined, concrete Reactor Building is designed to withstand the maximum internal pressure resulting from an analysis of a spectrum of Reactor Coolant System and Main Steam line leaks.

Isolation valves are provided on fluid piping penetrating the Reactor Building to provide containment integrity when required. Isolation valves which are required to be closed for containment isolation function are either check valves, normally closed valves, or automatic remotely operated valves actuated by signals received from the Engineered Safeguards Protective System.

All electrical and fluid penetrations with the exception of those penetrations listed in Section 6.5.1.2 are grouped in a penetration room. Any leakage that might occur from any of these penetrations (except the noted lines) will be exhausted through a unit vent. Access hatches are provided with double seals, and the volume between the seals is piped to the penetration room. Provision is made to leak test all the access hatch closures.

1.2.2.4 Engineered Safeguards Systems

Engineered Safeguards Systems reduce the potential radiation dose to the general public from the Maximum Hypothetical Accident to less than the guideline values of 10CFR100. Automatic isolation of Reactor Building fluid penetrations that are not required for limiting the consequences of the accident reduces potential leakage paths. Long term potential releases following the accident are reduced by rapidly decreasing the Reactor Building pressure to near atmospheric, thereby reducing the driving potential for fission product escape.

In addition, the Engineered Safeguards System provides ample core cooling following the worst postulated loss-of-coolant accident. This is accomplished by the High Pressure Injection, Low Pressure Injection, and Core Flood Systems. These systems, coupled with the thermal, hydraulic, and blowdown characteristics of the reactors, reliably minimize metal-water reactions to acceptable values per 10CFR 50.46.

Each reactor unit has the following engineered safeguards equipment, with the normal operating mode of each as indicated:

1. High Pressure Injection System - a portion is used in normal reactor operation.
2. Low Pressure Injection System - operates for shutdown cooling.
3. Core flooding tanks - normally ready for operation.
4. Reactor Building Spray System - normally shutdown.
5. Reactor Building emergency coolers - operate for Reactor Building cooling during normal operation.
6. Penetration Room Ventilation System - test operation during normal operation. (not required for event mitigation due to adoption of alternate source term)
7. Reactor Building Isolation System - normally ready for operation and testable.
8. Low Pressure Service Water System - normally in service.

Except for the shared Unit 1&2 Low Pressure Service Water System, the Engineered Safeguards Systems are independent for each unit. Table 1-2 lists the major equipment in each system.

1.2.2.5 Unit Control

The reactor is controlled by control rod movement and regulation of the boric acid concentration in the reactor coolant. Between 15 percent and 100 percent full power the Integrated Control System maintains constant average reactor coolant temperature. Constant steam pressure is maintained over the full power range.

The Reactor Protective System and the Engineered Safeguards System automatically initiate appropriate action whenever the parameters monitored by these systems reach pre-established set-points. These systems act to trip the reactor, provide core cooling, close isolation valves, and initiate the operation of standby systems as required.

1.2.2.6 Electrical System and Emergency Power

Each of the three nuclear units at Oconee have up to eight available sources of electrical power:

1. Eight 230 kV transmission lines from three directions and three 525 kV transmission lines from three directions serve Oconee. (counts as one source).
2. The other two nuclear units. (counts as two sources).
3. The Central Switchyard or the Lee Steam Station Combustion Turbines via the 100 kV transmission line (capable of being separated from other system loads).
4. One of the quick-starting on-site Keowee Hydroelectric 87,500 KVA Generating Units connected to Oconee by an underground 13.8 kV cable.
5. The other Keowee Hydroelectric Generating Unit connected to Oconee by an overhead 230 kV transmission line.
6. One of the Keowee Hydroelectric Generator Units connected to the Protected Service Water building electrical equipment through an underground 13.8kV cable.
7. The other Keowee Hydroelectric Generator Unit connected to the Protected Service Water building electrical equipment through an underground 13.8kV cable.

Oconee has multiple redundant buses and tie buses supplying power to loads, instruments, and controls. The engineered safeguards for each unit are generally arranged on a three-component basis and supplied from three separate auxiliary power buses, each of which can be supplied from any of the six principal sources of power.

The sources of power and associated electrical equipment will insure safe functioning of the station and its engineered safeguards.

1.2.2.7 Steam and Power Conversion System

The Steam and Power Conversion System for each unit is designed to remove heat energy from the reactor coolant in the two steam generators and convert it to electrical energy. The closed feedwater cycle will condense the steam and heat feedwater for return to the steam generators.

1.2.2.8 Fuel Handling and Storage

Both new and spent fuel are stored in the spent fuel pool and transferred to and from the Reactor Building via the fuel transfer tubes. One spent fuel pool is shared between Oconee 1 and 2, and a separate spent fuel pool is provided for Oconee 3. The system is designed to minimize the possibility of mishandling or maloperations that could cause fuel assembly damage or potential fission product release, or both. In addition to the spent fuel pools, the Independent Spent Fuel Storage Installation (ISFSI) is available, at Oconee, to provide long-term storage of irradiated fuel assemblies. Refer to the Oconee Site Specific and General License System ISFSI UFSARs for further details.

1.2.2.9 Radioactive Waste Control

Gaseous Waste Disposal Systems collect, holdup as necessary, filter, monitor, release, and record the gaseous effluent from the station. Liquid Waste Disposal Systems provide for collection, holdup, treatment, monitoring, disposal, and recording of liquid wastes. Solid radioactive wastes are stored, packaged, and shipped off-site. Greater than originally anticipated gas and liquid waste volumes led Duke Power to build an Interim Radwaste Facility. This facility included liquid processing equipment, volume reduction equipment and associated auxiliary systems. Other than four holdup tanks used for decay of gaseous waste, there is no longer any waste processing done at the Interim Radwaste Facility. A separate Radwaste

Facility has been added to handle increased liquid waste volumes. The systems which comprise the facility are Resin Recovery, Liquid Processing and Recycle, and Waste Solidification. The facility is capable of processing and packaging for burial these types of waste in optimal fashion.

1.2.2.10 Standby Shutdown Facility (SSF)

The Standby Shutdown Facility provides capability to shutdown the nuclear reactors from outside the control room in the event of a fire, flood, or sabotage-related emergency. The SSF is also credited as the alternate AC (AAC) power source and the source of decay heat removal required to demonstrate safe shutdown during the required station blackout coping duration. It provides additional "defense-in-depth" by serving as a backup to safety-related systems. The SSF has the capability of maintaining Mode 3 (with Tave $\geq$ 525°F) in all three units for approximately three days following a loss of normal AC power. It is designed to maintain reactor coolant system (RCS) inventory, maintain RCS pressure, remove decay heat, and maintain shutdown margin.

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1.4 Identification of Agents and Contractors

Duke Power Company, through its corporate organization, is responsible for the design, purchasing, construction, and operation of Oconee, a practice successfully followed for all of the Company's major generating facilities now in service or planned.

Duke contracted with B&W to design, manufacture, and deliver to the site three complete Nuclear Steam Supply Systems and fuel. In addition, B&W supplied technical direction of erection; and consultation for initial fuel loading, testing, and initial startup of the complete Nuclear Steam Supply System with coordination, scheduling, and administrative direction by Duke.

The Bechtel Corporation was retained by Duke as a general consultant to provide such engineering assistance as needed during the design and construction of the station. Layout, engineering, and design of the Reactor Buildings were assigned to Bechtel.

Duke retained Pittsburgh Testing Laboratory for shop inspection of valves and piping as required. As consultants on seismology and meteorology, the firm of Dames & Moore was retained. Duke also retained Mr. William V. Conn from Atlanta, Georgia, for geology studies and the Law Engineering Testing Company for subsurface investigations under the direction of Dr. George F. Sowers.

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Appendix 1A. Tables

Table 1-1. Key Dates in Oconee History

Oconee Unit 1			
1. Construction Permit (CPPR-33)			
	Application	Approved by NRC	Expiration Date
Original	November 28, 1966	November 6, 1967	February 28, 1971
Extensions	1. Feb. 19, 1971 & Feb. 23, 1971	February 27, 1971	September 30, 1971
	2. Aug. 6, 1971	August 30, 1971	January 31, 1972
	3. Dec. 20, 1971	January 28, 1972	June 30, 1972
	4. June 2, 1972	June 27, 1972	February 28, 1973
2. Operating License (DPR-38)		February 6, 1973	February 6, 2013
3. Renewed Operating License (DPR-38)		May 23, 2000	February 6, 2033
Oconee Unit 2			
1. Construction Permit (CPPR-34)			
	Application	Approved by NRC	Expiration Date
Original	November 28, 1966	November 6, 1967	February 28, 1971
Extensions	1. Jan. 25, 1972	March 1, 1972	February 28, 1973
	2. Jan. 25, 1973	February 28, 1973	September 1, 1973
	3. July 3, 1973	July 30, 1973	October l, 1973
	4. Aug. 29, 1973	September 24, 1973	November 4, 1973
2. Operating License (DPR-47)		October 6, 1973	October 6, 2013
3. Renewed Operating License (DPR-47)		May 23, 2000	October 6, 2033
Oconee Unit 3			
1. Construction Permit (CPPR-35)			
	Application	Approved by NRC	Expiration Date
Original	May 25, 1967	November 6, 1967	August 1, 1973
Extensions	1. July 3, 1973	July 30, 1973	June 30, 1974
	2. May 14, 1974	July 5, 1974	September 30, 1974
2. Operating License (DPR-55)		July 19, 1974	July 19, 2014
3. Renewed Operating License (DPR-55)		May 23, 2000	July 19, 2034
Commercial Operation Dates:	Unit I July 15, 1973		

Unit 2 September 9, 1974
Unit 3 December 16, 1974

Table 1-2. Engineered Safeguards Equipment

System	Total Equipment Installed/Unit
High Pressure Injection System	3 pumps 1 storage tank
Low Pressure Injection System	2 pumps[1] 2 heat exchangers
Core Flooding Tanks	2 tanks
Reactor Building Spray System	2 pumps 2 spray headers
Reactor Building Coolers	3 coolers 3 fans
Penetration RoomVentilation System	2 fans 2 filter assemblies
Low Pressure Service Water System	3 pumps (Units 1&2) 2 pumps (Unit 3)

Note:

1. Plus one installed spare pump

Table 1-3. Deleted Per 1997 Update

Appendix 1B. Figures

Figure 1-1. Duke Power Service Area

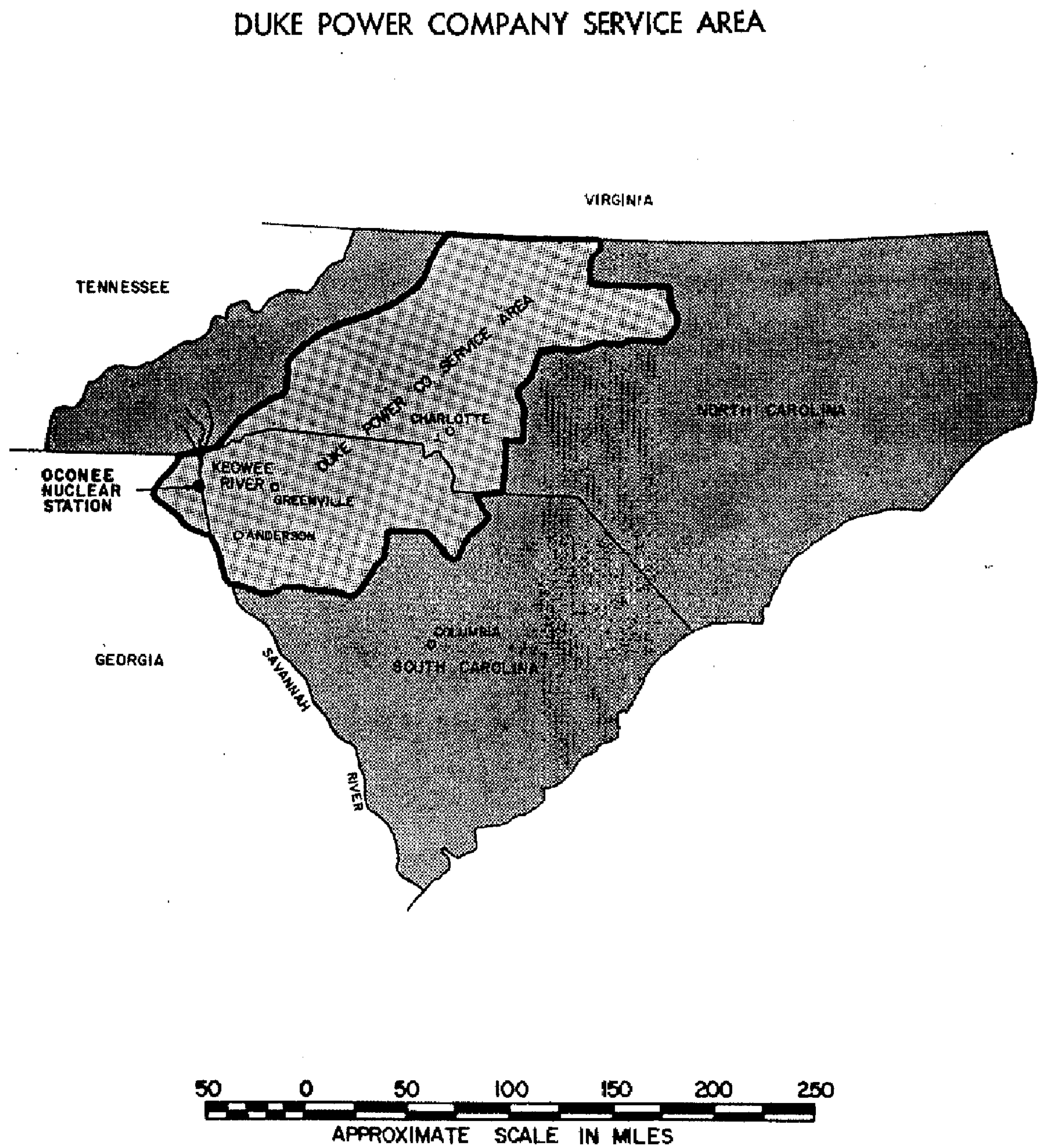

Figure 1-2. General Arrangement, Floor Plan Elevation 758+0

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 1-3. General Arrangement, Floor Plan Elevation 771+0 and Elevation 775+0

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 1-4. General Arrangement, Floor Plan Elevation 783+9

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 1-5. General Arrangement, Floor Plan Elevation 796+6

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 1-6. General Arrangement, Floor Plan Elevation 809+3

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 1-7. General Arrangement, Floor Plan Elevation 822+0

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 1-8. General Arrangement, Floor Plan Elevation 838+0 and Elevation 844+0

Security-Related Withheld Under 10 CFR 2.390

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Figure 1-9. General Arrangement, Sections

Security-Related Withheld Under 10 CFR 2.390

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Table of Contents

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List of Tables

List of Figures

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2.0 Site Characteristics

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2.1 Geography and Demography

2.1.1 Site Location and Description

2.1.1.1 Specification Of Location

Oconee Nuclear Station is located in eastern Oconee County, South Carolina, approximately 8 miles northeast of Seneca, South Carolina at latitude 34°-47'-38.2"N and longitude 82°-53'-55.4"W. Duke Power Company's Lake Keowee occupies the area immediately north and west of the site. The Corps of Engineer's Hartwell Reservoir is south of the site. Duke's Lake Jocassee lies approximately 11 miles to the north. Figure 2-1 shows the site location with respect to neighboring states and counties within 50 miles. Figure 2-2 shows the relationship of the site with Lakes Keowee and Hartwell and the topography within 5 miles. Figure 2-3 shows the general geographical and topographical features within 50 miles of the site.

2.1.1.2 Site Area Map

Figure 2-4 shows the site layout, property lines, and other structures within the site area. There are no industrial, commercial, institutional, recreational or residential structures within the site boundary.

Located within 1 mile of the station center are the World of Energy (Visitor Center) and boat docks, the Keowee Hydroelectric Station, the 183 Annex, the South-Lake Services office complex and appurtenances, the Mosquito Control Facility and boat dock, and the Employee Recreational Facilities (including Employee Softball Field Restroom Building, Employee Recreational Site Restroom Building, Picnic Shelter, and boat dock). All of these facilities are Duke properties. Old Pickens Church and Cemetery, an historic property which is not used for regular services, occupies a small property to the east of the station.

The exclusion area is defined as a 1 mile radius from the station center.

2.1.1.3 Boundaries for Establishing Effluent Release Limits

The boundary for establishing gaseous effluent release limit is the exclusion area. The exclusion area is defined as a 1 mile radius from the station center. For the purposes of satisfying 10 CFR Part 20, the "Restricted Area," for gaseous release purposes only, is the same as the exclusion area as defined above. The boundary for liquid effluent is a 154 ft. wide by 216 ft. long area at the Keowee Dam extending from the face of the powerhouse to the crest of the tailrace. This area lies within the I mile radius for establishing gaseous effluent limits. The exclusion area boundary and the site boundary fences for the liquid effluents are shown in Figure 2-5.

Access to the owner-controlled area is normally controlled by automatic gates equipped with magnetic card readers. The OCA is periodically patrolled by security personnel.

2.1.2 Exclusion Area Authority and Control

2.1.2.1 Authority

All the property within the I mile radius exclusion area is owned in fee, including mineral rights, by Duke except for the small rural church plot belonging to Old Pickens Church, rights-of-way for existing highways and approximately 9.8 acres of U. S. Government property involved with Hartwell Reservoir.

The Hartwell property is either a portion of the Hartwell Reservoir or subject to flooding and not suitable for other uses. Duke has obtained from the owners of the church plot and from the United States the right to restrict activities on these properties and to evacuate them of all persons at any time without prior notice if, in its opinion, such evacuation is necessary or desirable in the interest of public health and safety.

The property which is within the exclusion area and which is not owned by Duke is shown on Figure 2-4.

2.1.2.2 Control of Activities Unrelated to Plant Operation

Unrelated activities are limited to the highways through the Exclusion Area, Duke's Visitor Center, Cresent Resources, the Mosquito Control Facility and boat dock, recreation on the lakes, and the Old Pickens Church and Cemetery which are historical landmarks and will not be used for regular services. The only commercial enterprises within the Exclusion Area will be Duke's Keowee Hydroelectric Station, Crescent Resources and the Oconee Nuclear Station.

2.1.2.3 Arrangements for Traffic Control

Arrangements have been made with the South Carolina State Highway Department to control and limit traffic on public highways in the Exclusion Area should it become necessary in the interest of public health and safety.

2.1.3 Population Distribution

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

The 1970 population distribution is based on the 1970 census. The 2010 population projection is a linear extrapolation of the 1910-1960 long term trend adjusted upward to anticipate lake proximity developments extending out as much as 20 miles from the site, particularly in the NW and NNW sectors.

Figure 2-6 shows the location and population of population centers within 100 miles of Oconee. The largest city, Knoxville, Tennessee, located 97 miles northwest of the site, had a 1970 population of 174,587. The nearest population center is Anderson, South Carolina, located approximately 21 miles to the south southeast of the plant, with a 1970 population of 27,556.

2.1.3.1 Population Within 10 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

Table 2-1 gives the 1970 population distribution within 10 miles of Oconee. The projected population for 2010 are shown on Table 2-2. The current population distribution is shown in Section J of the Oconee Nuclear Site Emergency Plan.

2.1.3.2 Population Between 10 and 50 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

Table 2-3 and Table 2-4 show the 1970 and projected 2010 population distribution. Figure 2-6 shows population centers within 100 miles of the site.

2.1.3.3 Transient Population

When the Lake Keowee's 300 mile shoreline is fully developed the estimated transient population will be 36,000. This estimate is based on development of lakeside lots, public access areas, and expanded commercial activities to take advantage of expanded recreational opportunities. There will not be any cottages within the Exclusion Area.

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

The estimated transient population within the low population boundary is 2000 for 1970 and 19000 for 2010.

The visitors center, located on Duke Property just north of the plant and within the Exclusion Area, was host to 510,000 people during its first 25 months of operation.

There are no industries within 5 miles of the site therefore no industrial transients.

2.1.3.4 Low Population Zone

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

The actual permanent population within the low population boundary (6 miles from site) is 3620 for 1970 and estimated to be 8900 for 2010.

2.1.3.5 Population Center

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

The nearest population center is Anderson, South Carolina, located approximately 21 miles to the south southeast of the plant (Figure 2-6).

2.1.3.6 Population Density

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

Table 2-5 and Table 2-6 tabulate the population density to 50 miles for 1970 and projected density for 2010.

2.1.3.7 Updated Population Information

The above sections contain population data for 1970 and population data projections for 2010. Actual population data is subject to constant change. The Oconee Nuclear Station Site Emergency Plan is the licensing document which contains the most recent population statistics based on 10 year census information.

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2.2 Nearby Industrial, Transportation, and Military Facilities

2.2.1 Location and Routes

Figure 2-3 shows the transportation routes within 5 miles of Oconee. There are no oil or gas pipelines within 5 miles of the site, except that natural gas distribution pipelines are located approximately 3.5 miles from the site in the direction of Six Mile, 2.5 miles from the site in the direction of Seneca, and 2.6 miles from the site in the direction of Walhalla.

2.2.2 Descriptions

2.2.2.1 Description of Facilities

There are no industrial or military facilities or activities within 5 miles of Oconee.

2.2.2.2 Description of Products and Materials

The highways passing through the 1 mile radius exclusion area are State and local roads with infrequent trucking of hazardous chemicals and explosives since the general area is nonindustrial.

Hydrazine is stored and used on site as described in Section 2.2.3.1.3.

2.2.2.3 Pipelines

There are no pipelines within 5 miles of Oconee, except for natural gas distribution pipelines located approximately 3.5 miles from the site in the direction of Six Mile, 2.5 miles from the site in the direction of Seneca, and 2.6 miles from the site in the direction of Walhalla. The lines, which run parallel to highways 183 and 130, are considered high pressure with an operating pressure of approximately 400 psi.

2.2.3 Evaluation of Potential Accidents

2.2.3.1 Determination of Design Basis Events

2.2.3.1.1 Explosions

An incident involving fire, chemicals or explosives at the closest point along the highway would be more than 1000 feet from the Reactor and Auxiliary Buildings. We believe that fire or chemical reactions at this distance would not affect plant operation. The blast pressure (Reference 1) from a truck loaded with 40,000 pounds (Reference 2) of TNT at this distance would be less than the design tornado loading on the structures.

2.2.3.1.2 Deleted per 1990 Update

2.2.3.1.3 Toxic Chemicals

If a highway incident should result in the release of toxic gases, the gases under most circumstances would either move in a direction away from the plant or be sufficiently dispersed by the time they reach the plant that they would not interfere with the safe operation of the plant. But if adverse environmental conditions should make it necessary, the plant could safely be operated or shut down from the control room. The control room is an enclosed area which can be isolated from the outside environment. Portable breathing equipment is also provided to allow access to areas outside the control room.

Paragraph Deleted Per Rev. 29 Update

Hydrazine in concentrations up to 54.4% can be stored on-site in various size containers. The amount of hydrazine on-site at any time should be ≤10 (340 gallon containers) of 54.4% hydrazine which equals 15,885 lbs. of hydrazine. If a concentration <54.4% is stored on-site, then the total amount of hydrazine allowed on-site should be based on lbs. of hydrazine and not the number of containers. The total amount of hydrazine for any percent concentration should be ≤15,885 lbs. of hydrazine. Hydrazine is used to maintain feedwater chemistry during power operation and Steam Generator wet layup chemistry during outages. Hydrazine is also used as needed to reduce reactor coolant dissolved oxygen concentrations during unit startups. It is unlikely that leaks from hydrazine containers stored on-site could result in dangerous concentrations in the control room. In addition, the control room can be isolated from the outside environment and portable breathing equipment is also available.

2.2.3.1.4 Fires

Liquid material spills would follow the pattern of roadside drainage toward Lake Keowee and Keowee River. On the event flammable material should reach the cooling water intake structure and burn, the cooling water pumps and related equipment would likely not be affected, but the operation of these pumps is not required for plant safety, and the most serious consequence would be a plant shutdown due to lack of condenser cooling water.

2.2.3.2 Effects of Design Basis Events

No design basis events have been identified in Section 2.2.3.1.

2.2.4 References

1. Effects of Impact and Explosion, AD 221 586, National Defense Research Committee, Vol. 1, 1946.
2. Interstate Commerce Commission and Department of Transportation Regulations of Maximum Truck Limit.

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2.3 Meteorology

Meteorology is evaluated for use in structural design and in consideration of environmental safeguards for gaseous releases. The following paragraphs summarize the atmospheric characteristics pertinent to these design bases.

"HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED"

2.3.1 Regional Climatology

2.3.1.1 General Climate

In addition to synoptic features that are modified in the crossing and descent of the Appalachian Mountains, the mountains cause channeling of surface winds. As a result, the prevailing wind direction is bimodal, with maximum frequencies in the sectors north-northeast to east-northeast and southwest to west.

2.3.1.2 Regional Meteorological Conditions for Design and Operating Bases

In general, the threat of tropical storms in the fall months of the year (and sometimes in other months) is present almost every year. Table 2-7 indicates the frequency of occurrences of conditions which produce some effect on the weather at the nuclear plant site. In the 95 years of record shown, 164 storms of tropical origin affected the area in some manner. There were only 11 years in the 95 in which no storms affecting the area occurred. There were six years where more than twice the average number of storms occurred.

Despite the fact that so many storms have influenced the area, no hurricane conditions which would include damaging winds of major proportions have ever been reported, so far as is known. Normally, by the time a tropical cyclone has passed onto the continent to the nuclear site area, winds have always been reduced below hurricane strength. However, major problems have been encountered with rainfall amounts generally four to five inches within a 24-hour period and occasionally up to nine to ten inches. Stations within a 50-mile radius of the nuclear site have reported up to double the latter amount but normally over more than a single 24-hour period (References 1, 2 3, and 4).

Tornado events are rather rare and cover extremely small areas. In order to provide for more than a superficial estimate, it was decided to ascertain the frequency of tornadoes for Oconee County in South Carolina as well as those which occurred in the peripheral counties in Georgia, South Carolina, and North Carolina. Accordingly, records were examined for the following counties:

In Georgia: Rabun, Habersham, Stephens, Franklin, and Hart

In South Carolina: Oconee, Pickens, and Anderson

In North Carolina: Macon, Jackson, Transylvania, and Henderson

(References 5, 6, 7, 8, 9, and 10 were consulted.)

The records revealed that five tornadoes have occurred in Oconee County and 17 the peripheral counties in the 50-year period from 1916 through 1965. These storms, however, were only those which had tracks long enough to plot. In order to gain a more realistic figure, the overall statistics showed that each of these figures should be multiplied by 2.5 yielding 55 tornadoes in the 12-county area in the 50-year period. This is considered a reasonable estimate of those tornadoes which reached the ground. Funnel clouds not reaching the ground *have also been observed but are not included in the above statistics. Tornadoes reach their maximum frequency during the spring months of the year and normally are more likely in April and May at the site.*

The values above indicate only 13 tornadoes in Oconee County in the 50-year period and the relative incidence of tornadoes proximal to the site area is small.

Table 2-8 indicates the mean number of thunderstorm days which are encountered in the plant site vicinity. A thunderstorm day is defined as a day in which thunder is heard at any time in the 24-hour period. Past experience indicates that increasing the thunderstorm day statistic by 10 to 15 percent will provide a reasonable estimate of the frequency of actual thunderstorms in the area.

The site is located in a region characterized by a generally high frequency of low wind speeds and calm conditions. These characteristics lead to a relatively high forecast of high-pollution-potential days as shown in Figure 2-7. The duration and frequency of calm and near-calm conditions for three nearly locations are tabulated by season in Table 2-9.

2.3.2 Local Meteorology

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2.3.2.1 Normal and Extreme Values Of Meteorological Parameters

Table 2-10 illustrates the overall wind direction and speed statistics for a five-year period (1959-1963) at Greenville, South Carolina. In general, the NE sector and the WSW sector (22.5 degree sectors) dominate the flow over the site area. The NNE, NE, and ENE sectors account for 30.7 percent of all winds while the SW, WSW, and W sectors account for 25.2 percent. These sectors combined then account for 55.9 percent of all winds at the Greenville, South Carolina airport station. This dominance is important as it continues to appear in all wind statistics in varying degrees as the study progresses. Apparently, the main reason for this dominance is the nearby Appalachian Mountain range which causes surface winds to channel toward these directions whenever the opportunity affords itself. The wind rose is schematically shown in Figure 2-8.

Winds of three knots or less occurred 17.4 percent of the time at Greenville. Winds greater than ten knots appear to favor the prevailing directions. (One knot = 0.515 meters per second.)

Table 2-11 illustrates the diurnal variation of wind speeds at various hours of the day. Lighter winds dominate the nighttime hours while the strongest winds tended to occur in the afternoon. The statistics illustrate the typical diurnal pattern of wind speeds.

Table 2-12 shows the frequency of calms and near-calm (winds equal to or less than one knot) conditions at three locations. Calm conditions occur on the average some 332 hours per year or about 4.0 percent of the time. Of these calms, 93.4 percent last less than six hours. Wind speeds equal to or less than one knot occur 4.21 percent of the time and of these conditions 93.5 percent last less than six hours. (The prolonged calm condition shown on Table 2-12 in the 36 - 41 hour winter block was investigated. The observation was made at Charlotte, North Carolina immediately after the anemometer had been moved from a building top level to the ground. Thus one can ignore this as a statistic applicable to the discussion.)

Reference 14 indicates that winds can be expected to reach a highest speed in excess of 50 miles per hour in any month of the year as an estimate of maximum winds to be encountered. Fourteen years of record for Greenville, South Carolina Municipal Airport indicate that 50 miles *per hour has been exceeded at least once for every month of the year except September where it was 47. Two months of the year showed values of 70 and 79 miles per hour, the former in January 1948, and the latter in October 1946. Clemson, South Carolina records (Reference 15B) indicate that the highest one-minute wind speed was 73 miles per hour in June of 1948.*

Table 2-13 and Table 2-14 illustrate the percentage distribution of annual winds at Athens, Georgia as observed at 0630 Eastern Standard Time. These statistics are derived from an analysis of the Adiabatic Chart records of the Athens, Georgia Rawinsonde data. The period of record is December 1, 1959 through November 30, 1961. The data have been analyzed and documented in Reference 16. The wind roses are schematically shown in Figure 2-9 and Figure 2-10.

The winds observed over Athens, Georgia are probably more representative than those from any other Rawinsonde station near the site. Note that the height above ground in each table is variable. This is because the winds are normally transmitted at standard pressure levels in the atmosphere rather than at fixed heights.

Table 2-13 indicates that the wind sectors which dominate the flow at around 1000 feet above terrain are the NE, ENE, and E sectors (24.54 percent) and the W, WNW, and NW sectors (33.43 percent). These sectors combined account for about 58 percent of all winds. Compared to the surface winds, there has been a shift of dominance from the northeast sector to the northwest - more westerly flow. Calms occurred only 12 times.

Table 2-14 portrays wind conditions 2300-2800 feet above the ground. At this level, wind sector dominance has shifted to westerly flow. In fact, the WSW, W, and WNW sectors account for 33.6 percent of all winds, whereas the SW, WSW, W, WNW, and NW sectors account for 49.8 percent of all winds. Calms occurred less than eight times in the total period of record.

The combination of the surface and upper winds indicates that in the layer between the ground and about 3000 feet, there is likely to be considerable wind shear. As a matter of interest, the change in wind direction with height was examined in a previous study (Reference 16) as a function of the lapse rate in the lower 50 meters of the atmosphere. The results for the two-year period of record are shown in Table 2-15. Note that the directional shear for stable conditions is from 50 to 100 percent greater than for unstable conditions. This favors slightly greater diffusive properties at the site than is calculated with a single wind direction prevailing throughout the diffusion period during a stable condition, particularly if any significant depth of atmosphere is taken into account.

Figure 2-11 represents cumulative probability of wind directional persistence at Greenville, South Carolina, for winds observed annually. Curve A represents the duration of persistence for a single sector wind direction, i.e., from the northeast, or from the southwest. Note that about 70 percent of all wind directions persist for only one hour. About 94 percent persist for three hours or less, etc.

Curve B indicates the persistence of a single wind direction plus or minus one additional direction on either side of the prime direction, i.e., northeast plus north-northeast and east-northeast (67.5 degrees). Curve B shows that 93 percent of all winds persist five hours or less under these conditions. Curve C indicates the persistence of a single wind direction plus and minus two additional directions on either side of the prime direction (112.5 degrees). About 90 percent of all wind directions persist for ten hours or less.

The above wind persistence statistics are derived for all wind directions, including calms. Directional persistence statistics are also calculated. However, the statistics for a single wind sector essentially show similar results to Curve A. Table 2-16 reveals persistence values by direction. Two values are shown for each of the two seasons, the average value P, and the root-

mean-square value RMSP. The merit of the RMSP values is that these are reasonable approximations of the 65 to 70 percent frequency of occurrence level. In other words, 65 to 70 percent of all persistence values were less than the RMSP figures.

The remaining two columns in each case are those specific events when the wind condition persisted 24 hours or more. (1-41 means one case of 41 hours duration.)

Table 2-16 deals with wind directions for a single 67.5 degree sector (or single sector plus and minus one sector). Table 2-17 deals with single wind directions for a single 112.5 degree sector (or single sector plus and minus two sectors).

Table 2-16 reveals that the most persistent winds come from the prevailing directions as might be expected. Table 2-17 shows a more confused pattern in general, but again shows prevailing wind dominance.

The nearest station of long-term surface temperature is that of Clemson, South Carolina where some 68 years of record are available. The means and extremes shown in Table 2-18 for minimum temperatures are all on the cooler side than records available from the Greenville WBAS, South Carolina weather station and are regarded as more representative of the nuclear site area. The References for these records are listed as 15A through 15F.

Clemson, South Carolina records are also used to gain estimates of rainfall statistics. Some 71 years of record are available as shown in Table 2-19. Again References 15A through 15F are used as source material. Considerable fluctuation in precipitation from month to month and from year to year is experienced from the normals shown in Table 2-19. From a brief examination of Reference 14, it can be postulated that the normal annual precipitation for the site area is actually about ten percent higher than at Clemson. It is interesting to note that the maximum rainfall occurrences in short periods of time have all been associated with proximal tropical storms or their aftermath. However, severe thunderstorms can produce similar amounts of rainfall in the same periods of time.

By dividing the wind directional frequency for heavy precipitation intensity by the total precipitation wind directional frequency for each direction, directions which are more likely to produce heavy precipitation can be determined. Those directions which produce frequencies greater than the average are north through west and southeast plus south-southeast. These are directions which dominate the showery weather regimes at the site, particularly the thundershowers.

Precipitation occurs only 9.8 percent of all hours of the year.

Statistics related to wind directions and speeds while precipitation is falling are shown in Table 2-20 (Reference 17). The most frequent wind sectors are NNE, NE, and ENE which account for 52 percent of all precipitation winds. The table is set up in terms of precipitation intensities. Precipitation rates determine these intensities and are normally classed as light, moderate and heavy. Approximately 90 percent of all precipitation at Greenville, South Carolina during this five-year (1959-1963) period was light, seven percent was moderate, and about three percent was heavy. The precipitation wind rose is schematically shown in Figure 2-12.

Comparison with all of the surface wind data in Table 2-10 shows that with winds from the southwest through west to north (the mountain exposure side), precipitation occurs about five percent of the time, while all other directions experience twice this percentage.

In 1961, Pasquill (Reference 18) suggested that a relationship might be established which would be useful for estimating the frequency of various wind-temperature lapse rate conditions for a given area. The inputs were:

Time of Day

Cloud Cover

Surface Wind Speed

The wind speed that was used was that observed at ten meters above the ground. Essentially his classification system identified six categories of stability regimes. These have come to be known as Pasquill categories. These are:

Pasquill Categories	*Stability Class*
A	*Extremely Unstable*
B	*Unstable*
C	*Slightly Unstable*
D	*Neutral*
E	*Stable*
F	*Extremely Stable*

Although Pasquill suggested the initial classification scheme, it remained merely a scheme until Turner (Reference 19) quantified it into a reasonably rigorous method. The technique is amenable for use with standard United States Weather Bureau hourly weather observations which are readily available at the National Climatic Center at Asheville, North Carolina, for certain specific United States Weather Bureau weather stations - namely those which observe the weather 24 hours per day throughout the year.

The closest station to the site which maintains such records is Greenville, South Carolina. Data was procured for the Greenville WBAS, South Carolina location (References 20 and 21) and the classification of the hourly weather records into Pasquill categories was accomplished for the two-year period of records selected for analysis.

The Pasquill categories selected follow:

Pasquill Category	*Stability*
A-B	*Unstable*
C	*Slightly Unstable*
D	*Neutral*
E	*Stable*
F	*Extremely Stable*

The period of record was December I, 1959 through November 30, 1961. The results of these classifications are shown in Table 2-21 and Table 2-22. A wind direction rose for Pasquill E and F conditions is shown on Figure 2-13.

Table 2-21 shows the percentage frequency of occurrence of the Pasquill categories and their associated mean wind speeds by direction. All values in the percentage columns are in terms of percent of total observations. Column 1 deals with the Pasquill C category, Column 2 with the Pasquill D category, Column 3 with the Pasquill E and F categories, while Column 4 deals with the Pasquill F category alone. All winds are in knots. Total percentages by categories are also shown.

Table 2-22 completes the Pasquill classification effort. Column 5 deals with Pasquill A-B, unstable categories or "Lapse" conditions. Column 6 deals with a category which normally falls under Pasquill A-B but does not if a stack is used to vent at the site. Column 6 indicates the percentage frequency of fumigation from a stack release. Fumigation is typical of the early portion of the day between sunrise and roughly ten AM.

Column 7 of Table 2-22 shows the results of combining all wind data. Note particularly the dominance of northeasterly and west-southwesterly flow in the sample data. Column 8 shows the results of a much larger sample of data taken for the entire five-year period, 1959-1963, (Reference 12).

The frequency of wind directions for the limited sample shown in Column 7 is correlated with the much larger sample shown in Column 8. The correlation coefficient is +0.987, showing that the limited sample indeed possesses a very high agreement with the much larger sample.

Work completed over a period of years has produced a useful relationship which was applied to the nuclear site area in mountain-plain relationships. It is found (Reference 22) that with terrain differences of greater than about 200 feet, the minimum or early morning temperature observed on hilltops is fairly representative of the free air temperature at the same altitude above proximal valley locations. Thus, it is possible to obtain estimates of the frequency of temperature inversions by comparing hilltop minimum temperatures with valley floor minimum temperatures. Subsequent tower measurements in the same valley location indicate that this postulation, indeed, possesses considerable merit in assessing the strength and frequency of the low-level temperature inversions. Examination of climatic records (Reference 23) for South Carolina indicates that some estimate of temperature inversion frequency might be possible through a comparison of daily minimum temperatures from Paris Mountain Fire Tower, located seven miles north of Greenville, South Carolina, at an altitude of 2047 feet and Clemson, South Carolina, at an altitude of 850 feet.

Limited data permitted the analysis of some 602 days representing the four seasons of the year for the two-year period of December 1, 1959 through November 30, 1961. It is possible to examine the daily minimum temperature difference (Paris Mountain Fire Tower minus Clemson) for these days and compare these differences with Pasquill Stability classes as observed from hourly weather observations at Greenville, South Carolina, on the same days at hours near dawn. Table 2-23 shows the results. The table essentially shows that, in general, the Pasquill classes do match the proper average temperature differences.

Combined Pasquill E and F conditions logged for the entire two-year period from Greenville, South Carolina, for the dawn hour revealed the following frequency of inversions by season:

Frequency of Pasquill E and F Conditions (Inversions)

	Winter	***Spring***	***Summer***	***Fall***
Two years of Dawn-Hour Records at Greenville, South Carolina	*43.96%*	*56.52%*	*65.58%*	*60.56%*
602 Days of Paris Mountain-Clemson Records	*49.14%*	*54.30%*	*67.41%*	*53.10%*

As a result of the above, it appears that the estimates shown by the Pasquill Stability classes are reasonable estimates for inversion data at and near the proposed nuclear site.

STAR Processing of Greenville-Spartanburg Airport is shown for the period January, 1975 - December, 1975 in Table 2-24. The five-year period of January, 1968 - December, 1972 is shown in Table 2-25. The STAR program gives annual joint frequency distributions of wind *speed and wind direction by atmospheric stability. These tables will be used to judge the representativeness of a year of onsite data with regard to long-term conditions (e.g., five-year period) as described in Section 2.3.3.*

2.3.2.2 Potential Influence Of the Plant and its Facilities on Local Meteorology

Several modifications to the local climatology occur as site development progresses. The initial clearing and leveling of land at the specific site location produces an increase in drainage potential of light winds within the site boundary.

The addition of the large bodies of water has three effects on meteorology. First, it lessens ground frictional effects and tends to increase the wind speeds, most noticeably under light wind conditions. Second, the large bodies of water increase the humidity by about ten percent in the area and tend to decrease the frequency of Pasquill F and to increase the frequency of Pasquill E conditions. Third, the creation of a major lake area in the vicinity of the nuclear plant serves to increase the precipitation approximately an additional five to ten percent.

The heat load on the lake, due to the operation of the nuclear plant, results in additional local fogging during some days of the year, although the area beyond the lake that is affected is not expected to be large. The increase of temperature of the lake results in the evaporation of about 32 million gallons of additional water per day from the reservoir into the atmosphere.

The incremental offset in the diffusion climatology due to heated water discharge should be in the direction of improvement, but is not of a magnitude to warrant special emphasis. The effect of warmer surface waters in the vicinity of the discharge increases the speed change of air flow from land to water and decreases the change of wind range for such trajectories (Reference 24). In regard to further modification of low-level stability, additional enhancement is tempered, to some extent, from effects of the relatively large deep reservoir. A conservative assessment would assume some improvement, but minimal impact on the total climate.

Figure 2-2 shows a detailed topography, as modified by the plant, to 5 mi. Figure 2-3 shows the general topography within a 50 mi. radius of the plant.

Figure 2-14 through Figure 2-23 show plots of the maximum elevation versus distance from the center of the plant in each of the sixteen 22.5 degree compass point sectors radiating from the plant to a distance of ten miles.

2.3.3 Onsite Meteorological Measurements Programs

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2.3.3.1 Early Meteorological Studies (1966-1975)

Onsite meteorological measurements used in diffusion analyses were conducted for various time periods and measurement locations. These time periods include October 19, 1966 through January 23, 1967, June 19, 1967 through May 31, 1968, March 15, 1970 through March 14, 1972, and January, 1975 through December, 1975. Data for the period June 19, 1968 through June 19, 1969 is discussed in relation to the valley drainage model in Section 2.3.4.2.

The evaluations of two comprehensive meteorological surveys conducted on-site confirm that the meteorological characteristics of the site are favorable for the Oconee Nuclear Station.

The first survey, started in mid-October 1966 and extended until late October 1967, was a study of near-ground diffusion climatology. Wind data were continuously recorded, on a 14 meter pole located near mid-site (see Figure 2-24). Temperature gradients were determined by *thermographs located in standard United States Weather Bureau Cotton Region Instrument Shelters stationed on the site at varying terrain elevations. A standard recording precipitation gage with wind shield was installed near the base of the 14 meter pole. The results of this study established the frequency of wind conditions with varying lapse rates near ground. The results are shown below:*

1. *Frequency of temperature inversions of total hourly observations was 24 percent.*
2. *Direction of predominating inversion wind was north (Figure 2-25).*
3. *Inversion wind speed average was 1.40 meters per second.*
4. *The minimum average standard deviation of inversion winds in any sector for the one year averages 6.6 degrees.*

Wind roses presenting near-ground data, Figure 2-25, Figure 2-26, and Figure 2-27 compared to Greenville-Spartanburg, South Carolina Airport data (Figure 2-8 and Figure 2-13), reflect wind reorientation by nearby mountain ranges and some channeling by the river valley.

The second survey was started in June of 1967, using the permanent station equipment at the time, to establish meteorological parameters related to elevated (vent) releases. Reference to Figure 2-24 illustrates the arrangement of meteorological instrumentation required to initiate this study. Investigations of winds and atmospheric stability were made at vent effluent levels by wind and temperature gradient measuring systems mounted on the 46 meter tower. In addition to tower meteorological instrumentation, a standard weather instrument shelter containing a thermograph and a mercury-in-glass dry bulb thermometer, for comparison was set up near the tower base. A standard recording precipitation gage with wind shield was also installed nearby.

A brief summary of data through the first year (June 19, 1967 through May 31, 1968) shows the following:

1. *The average wind speed recorded by the anemometer at elevation 1028 ft (232 ft above plant yard level) was 6.5 miles per hour or about 3 meters per second for all conditions, and about 2 meters per second during inversions.*
2. *The dominant all-wind direction was northerly which accounts for 10.98 percent of all observations (Figure 2-28 and Figure 2-29).*
3. *The average standard deviation associated with winds less than 1 meter per second was about 22 degrees. As expected, the standard deviations decreased generally as wind speeds increased.*
4. *A frequency of inversions of approximately 40 percent was found for the one year of tower data compared to 24 percent for near-ground observations. Although the two periods of observations are not chronologically identical, one would expect the inversion duration time to be less near-ground due to more rapid inversion "burn-off"; however, it is also noteworthy that the frequency of inversions for the Greenville-Spartanburg Airport for Pasquill-Turner computations also increased for the year during tower observations compared to near-ground observation period.*
5. *The maximum amount of rain was from the northeast where during the year 7.09 inches of rain fell in an aggregate of 71 hours (Figure 2-30).*

2.3.3.2 Continuous Meteorological Data Collection

Meteorological data has been taken continuously onsite since June 23, 1967. Meteorological measurements include wind direction and speed, horizontal wind direction fluctuation, temperature, and vertical temperature gradient. The current relative position of instruments with respect to station yard is noted in Figure 2-5. Relative elevations of both surface levels and instrument levels are depicted in Figure 2-24.

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The location of the 46m wind measuring sensors on the microwave tower (Figure 2-5), was appropriate for estimating wind direction and speed for vent releases. Inasmuch as low level flow direction could not be adequately represented by a 10m sensor due to 20m trees near the tower base, all low level input was derived from sensors atop the tower. Wind speed was adjusted by a power law relationship in accordance with the evaluation in Reference 25. The location of the 46m meteorological system was taken as reasonably representative of topography in the vicinity of the plant with respect to wind direction and vertical temperature gradient. The surface immediately below the tower was characterized as a grassy area.

The effect on vertical temperature gradient from the positioning at 1.5m (June 23, 1967 to February 24, 1977) was to introduce some uncertainty where partially elevated releases were concerned. Consequently, the lower level was moved to 10m on February 24, 1977. The following is offered as the limits in uncertainty in delta temperature measured at 1.5m. A bias toward very unstable lapse rates during the day is seen by the occurrence of intense lapse conditions in the existing data. It was suspect, however, after observing daytime stability Class A rates at other Duke Power lake sites, in that the total number of Class A conditions would not change appreciably with the lower sensor at 10 meters. The effect of the 20 meter trees on unstable lapse rates should not have been significant. These trees were not sufficiently dense to constitute a canopy, and the effect could be disregarded during well mixed conditions. The bias towards more stable profiles at night did not readily appear in the strength of inversions typical at the site. This condition was not unexpected since the 20m trees would provide radiative exchange, to some extent, tending to sustain relatively warmer temperatures near the ground. Assuming the effect of the trees was to shift the temperature profile below 20 meters toward a less stable rate, the measured gradient with the 1.5m sensor could be slightly less stable or slightly more stable than a gradient measured with a 10m sensor. No pronounced bias toward anomalously stable conditions is expected in the pre-February 24, 1977 data.

Table 2-26 depicts joint frequencies of wind direction and speed by stability class for the period March 15, 1970 through March 14, 1972. Stability is defined in terms of vertical temperature gradient and indexed as follows, for the period:

Stability Class	***Vertical Temperature Gradient Range (°c) between 46m and 1.5m***
ONS	*46m - 1.5m dT* ***(°c)***
A	*dT ≤ -0.85*
B *C*	*-0.85< dT ≤ -0.67*
D	*-0.67 < dT ≤ -0.22*
E	*-0.22 < dT ≤ +0.67*
F	*+0.67 < dT ≤ +1.78*
G	*dT > +1.78*

Table 2-27 is a display of the joint frequency of wind direction and speed by atmospheric stability type for both low-level and high-level wind summaries for the period, January, 1975 through December, 1975. Comparison of Table 2-27 with Greenville-Spartanburg Airport data (Table 2-24 and Table 2-25) forms the basis for judging the representativeness of data for this time period with regard to long-term conditions (e.g., five year period). Consideration of wind speed by stability type for the two periods shows a lower wind speed in general for the period January, 1975 through December, 1975; the occurrence of calms and winds less than 4 knots are up about four percentage points from 23 percent for the period January, 1968 through December, 1972. A slight shift in stability is noted for the period January, 1975 through December, 1975; intermediately stable and unstable Classes E, F, and C, respectively, decreased while strongly stable and unstable Classes G, A, and B increased. Minor changes in wind direction frequencies are also noted for the period January, 1975 through December, 1975; prevailing wind sectors north, northeast, south, southwest, and south-southwest increased their frequency, at the expense of the other sectors. On balance, the period is taken as reasonably representative of long-term conditions in the vicinity of the site.

When the lower temperature sensor was moved from the 1.5 m level to the 10m level on the microwave tower the ranges in vertical temperature gradient, used to determine stability class changed to the following(22 Feb 1977 -22 April 1988):

Stability Class	***Vertical Temperature Gradient Range (°c) between 46m -10m***
ONS	*46m - 1.5m dT* ***(°c)***
A	*dT ≤ -0.68*
B *C*	*-0.68< dT ≤ -0.54*
D	*-0.54 < dT ≤ -0.18*
E	*-018 < dT ≤ +0.54*
F	*+0.54 < dT ≤ +1.44*
G	*dT > +1.44*

Since April 17, 1984, operational measurements have consisted of near real-time digital outputs in addition to the previous analog system. An entirely new set of instrumentation was installed at this time, including the measurement of dew point at the 10 m level. A supplemental low-level wind system at 10 m level was installed January 30, 1981, (see Figure 2-5 and Figure 2-24). The type of rain gauge was changed to a tipping bucket rain gauge, and was relocated near the supplemental wind system, as well.

1988-Present

The primary meteorological tower was relocated to approximately 1750 ft. northwest of its original location at the microwave tower on April 23, 1988. Relocating the meterological tower became necessary due to the erection of the new Administration Building near the microwave tower. The building's close proximity to the tower would have significantly influenced air flow near the tower. The relative position of the new tower is shown in Figure 2-4 and Figure 2-5 and the instrumentation elevations relative to the plant are given in Figure 2-24.

The new 60 meter high meteorological tower began operation on April 23, 1988, with wind speed and direction measured at the 10m and 60m levels and delta temperature measured between these intervals. The dew point temperature system was not reinstalled, since no regulatory requirements for this parameter at Oconee Nuclear Station. Instrument specifications are the same as those given in the 1984-1988 listing, with the exception of discontinued dewpoint measurements. Both upper and lower wind direction sensors for the northwest tower were upgraded from potentiometric sensors to resolver sensors. This improved performance and reliability. The wind direction sensor for the supplemental tower at Keowee River was upgraded June 22, 1990. The wind speed range was set at 0-60 mph until September 11, 1996, when it was increased to a range of 0-90 mph.

Because of the change in distance between temperature sensors (50m) for measuring ΔT, the stability classifications are defined by new delta temperature ranges as given below:

Stability Class	***Delta Temperature Range (°C) Between 60m - 10m***
A	*dT ≤ - 0.95*
B	*-0.95 < dT ≤ -0.85*
C	*-0.85 < dT ≤ -0.75*
D	*-0.75 < dT ≤ -0.25*
E	*-0.25 < dT ≤ +0.75*
F	*+0.75 < dT ≤ +0.2.00*
G	*dT> +2.0*

Instrumentation signals are processed digitally, transmitted via buried cable to the plant, and then processed back to analog for use by the chart recorders and the plant OAC at the time 1-minute average data collection began which is available on the OAC's in the Control Room.

Near real-time digital outputs of meteorological measurements are summarized for end-to-end 15 minute periods for use in a near real-time puff-advection model to calculate offsite dose during potential radiological emergencies. The Operator Aid Computer (OAC) system computes the 15 minute quantities from a sampling interval of 60 seconds. It calculates 15 minute average values for high and low level wind direction and speed; 15 minute averages are also calculated for delta temperature and ambient temperature. Total water equivalence is computed for precipitation. All 15 minute values are stored with a 24 hour recall. Permanent archiving of data from the digital system is made by combining the 15 minute quantities into one hour values.

Periodic equipment calibration and maintenance checks are performed in the field for all parameters, as specified by station procedure. Semiannual calibration checks are performed as per associated station procedures, listed below.

Instrument specifications for operational measurements are:

1. *Wind Direction*
    a. *Manufacturer MetOne*
    b. *Time-averaged digital accuracy ± 3 degrees of azimuth*
    c. *Time-averaged analog accuracy ± 6 degrees of azimuth*
    d. *Starting threshold 0.3m/sec at 10 degrees initial deflection*

e. Damping ratio 0.4 at 10 degrees initial deflection

f. Distance constant 1.1m

2. <u>Wind Speed</u>

a. Manufacturer MetOne

b. Time-averaged digital accuracy ± 0.27 m/sec for speeds < 27 m/sec

c. Time-averaged analog accuracy ± 0.40 m/sec for speeds < 27 m/sec

d. Starting threshold 0.45 m/sec

e. Distance constant 1.5m

3. <u>Temperature</u>

a. Manufacturer MetOne

b. Time-averaged digital accuracy ± 0.3 degrees C

c. Time-averaged analog accuracy ± 0.5 degrees C

4. <u>Delta Temperature</u>

a. Manufacturer MetOne

b. Time-averaged digital accuracy ± 0.10 degrees C

c. Time-averaged analog accuracy ± 0.15 degrees C

5. <u>Precipitation</u>

a. Manufacturer MetOne

b. Digital accuracy ± 6% of total accumulation at 15 cm/hr

c. Analog accuracy ± 9% of total accumulation at 15 cm/hr

d. Resolution 0.25mm

2.3.4 Short-Term Diffusion Estimates

2.3.4.1 Objectives

Conservative and realistic estimates of atmospheric dilution factors at the site boundary or exclusion area boundary and at the outer boundary of the low population zone are provided in this subsection for various time periods to 30 days. Various periods of onsite and offsite data are used in the different studies conducted and are noted in the text where appropriate.

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2.3.4.2 Calculations

Reference 26 indicates that the equation used for calculating the two-hour site boundary relative concentration is:

$$\frac{X}{Q} = \frac{1}{\bar{u}(\pi\sigma_y\sigma_z + cA)}$$

In this equation σ_y and σ_z are the standard deviations of the cloud concentration in the horizontal and vertical directions, respectively. These values are normally determined from on-site observations. In lieu thereof, it is permissible to use graphical values as shown in Reference 27. The σ_y σ_z values are those which are appropriate for the one mile (1610 meters) exclusion radius of the site.

Normal assumptions to be used with this equation are:

1. *Moderate temperature inversion - Pasquill F Conditions prevail.*
2. *Unidirectional wind for two consecutive hours.*
3. *Average wind speed ($\bar{u}$) is one meter per second.*
4. *Building shape factor (c) is between 0.5 and 2.0.*
5. *Building cross-section (A) is in square meters.*

Each of the entry values to the equation is discussed below.

Pasquill F conditions occur frequently at the site. Their overall frequency has been documented at 24 percent in an earlier section of this report. It is estimated that this frequency will diminish to about 12 percent when all lakes in the vicinity of the nuclear plant are full. The frequency of Pasquill F conditions is expected to diminish, while Pasquill E conditions will increase from a current eight percent to about 14 percent of all observations. Thus, there is about a 50-50 chance, once the site is completed, that an inversion condition will be either Pasquill F or E.

The assumption of the unidirectional wind for two hours was examined. Neglecting calms, in a sample of 547 hours of Pasquill F conditions, only 68 cases were found where winds persisted from the same direction for two hours. Thus, it appears that this assumption is conservative.

The average wind speed ($\bar{u}$) observed under Pasquill F conditions (neglecting calms) was found to be 1.9 meters per second for the Greenville area. It is recommended that this wind speed be used for on-site wind speed estimates.

The building shape factor (c) was assumed to be equal to 1.0.

The cross-sectional areas of the buildings are shown in Figure 2-31. The minimum total building cross-section is 5180 square meters, while the front view area is 6792 square meters. The minimum building complex cross-section will be oriented in such a manner as to take advantage of increased flow due to site air drainage patterns, although no credit is taken for this in the analysis.

The values for entry into the equation are:

$\bar{u}$	=	1.9 mps
σ_y	=	60 m
σ_z	=	20 m
$\frac{X}{Q}$	=	5.9×10^{-5}
c	=	1.0
A	=	5180 m^2

An investigation was conducted to determine the most pessimistic theoretical 24-hour period at the site.

Thirty months of data from Greenville, South Carolina were scanned and those days where the average wind speeds for the entire day were approximately two meters per second or less were studied in detail. Thirty-seven cases were documented. Each hour of each day was classified according to the Pasquill method and a composite was derived which shows the poorest diffusion condition observed for each hour of the day during the 37 cases examined. The composite conditions are shown in Table 2-28.

Examination of Table 2-28 indicates that the poorest composite diffusion day would be to start at 1700 hours and maintain a Pasquill F condition for 16 consecutive hours, then one hour of Pasquill E, and finally seven hours of Pasquill D. This could be referred to as the most pessimistic theoretical 24-hour day for diffusion. (Meteorologically, this type of day would be difficult to achieve since cloud cover would be required to arrive immediately after dawn. Normally, if low cloud cover forms, it indicates that moisture sufficient to raise the probability of fog to very high values must have existed. In which case, fog would have been expected earlier, and some relaxation of the F and E criteria for the early morning hours would be realized).

This condition (as shown in Table 2-28) was not observed. It merely serves to document what might be termed a poorest possible diffusion day. This day is recommended for use in diffusion calculations.

Dispersion factors (X/Q, seconds m^{-3}) as shown in Table 2-29 are to be used for accident (10CFR100) and routine operational (10CFR20) analyses. The 1973 SER (Reference 30) for addition of Units 2 and 3 superceded the values originally agreed to for Unit 1 in 1970. Dispersion factors for elevated releases were based on analysis of on-site meteorological data. The factors given for ground releases were negotiated through discussions with the AEC/DRL staff during the early summer of 1970. These discussions were related to the additional meteorological studies in support of the 0 to 2 hour Valley Drainage Model presented later in this subsection. During the negotiations, Duke has agreed to reduce the Reactor building design leakage rate from 0.5 percent by volume in 24 hours to 0.25 percent by volume and increase the atmospheric dispersion factors for ground releases. It was agreed to depart from the dispersion factors for ground releases as submitted previously and supported by the Near Ground Study and the Valley Drainage Model. The accepted ground release dispersion factor at the exclusion area boundary (one mile) for Oconee Units 1, 2, and 3 was originally 1.16×10^{-4} for the 0-2 hour analysis. This value was then increased to 2.20 E-4 by the 1973 SER..

Table 2-30 indicates appropriate dispersion factors to be used during various release conditions. (e.g. averaging times and releases modes.)

Estimates of atmospheric dispersion of radioactive effluents employed a Gaussian straight-line trajectory model for evaluation at routine releases. The data of 1975 used in Section 2.3.3 was applied as a data base for these estimates. Joint recovery of wind speed, direction, and stability data was 86 percent for the period.

The calculational grid contains 504 receptors. Seventy-two receptors are located at five degree intervals on each of seven radii from the Exclusion Area Boundary to a distance of five miles from the nearest reactor vent.

The model calculated hourly relative concentration (X/Q) values at each receptor for each hour of the period. These values were accumulated, then averaged to obtain the field of annual average X/Q values.

Releases from the 60 meter vent stacks were considered partially elevated and partially ground level releases. The fraction of the plume material which remains elevated depends on the ratio of exit velocity to wind speed at release height. This fraction was calculated from equations 7 and 8 of Regulatory Guide 1.111.

Plume height for elevated releases was calculated from equation 4 of Regulatory Guide 1.111. Stack downwash is determined from equation 5 of the same reference. Plume rise is computed from the exit velocity (20 m sec^{-1}), stack diameter (1.8 m) and annual mean wind speed at vent height (3 m sec^{-1}) according to Reference 28. The effect of terrain on effective plume height is included according to Reference 29. If all heights are referenced to plant grade, h_e is the effective plume height without terrain correction, and h_t is the height of the terrain feature: then the corrected plume height is h_e - $h_t/2$. An exception noted is that plume height is constrained to remain between h_e and $h_e/2$. The h_t values represent the highest terrain in the vicinity of the receptor within the 22.5° sector.

The equation employed for each hourly X/Q calculation for the ground release portion is

$$(X/Q)_g = \frac{F_g}{u_1(\pi\sigma_y\sigma_z + cA)} \exp\left[\frac{-y_1^2}{2(\sigma_y^2 + cA/\pi)}\right]$$

The equation employed for the elevated portion is

$$(X/Q)_e = \frac{F_e}{u_2\pi\sigma_y\sigma_z}\left[\exp\left(\frac{-y_2^2}{2\sigma_y^2}\right) + \exp\left(\frac{-H^2}{2\sigma_z^2}\right)\right]$$

F_g and F_e are the fractions of the plume which are ground level and elevated respectively.

$u_1$and u_2 are the low level and high level average wind speeds respectively (m/sec.). A minimum value of .447 m/sec is assumed.

cA is the mixing zone for the aerodynamically entrained effluent. It is one half the cross-sectional area of the adjacent containment structure normal to the wind, that is 1150 m^2.

Y_1 and Y_2 are the lateral distances of the receptor from the wind direction vectors u_1 and u_2 respectively.

H is the plume height considering all corrections as discussed above (m).

σ_y and &sigma$_z$ are the crosswind and vertical plume standard deviations (m) which are functions of atmospheric stability and distance downwind. Stability categories were determined by vertical temperature gradient according to Regulatory Guide 1.23. Standard deviation values were consistent with Reference 19.

The factor ($\pi\sigma_y\sigma_z + cA$) is a measure of plume spread. This factor was restricted to be no greater than ($3\pi\sigma_y\sigma_z$) as recommended in Regulatory Guide 1.111.

The $(X/Q)_g$ values were modified to account for plume depletion by dry deposition. The method employed was as recommended in Regulatory Guide 1.111.

The X/Q value at each receptor for each hour is the sum of the elevated contribution and the ground level contribution. Successive hourly values were calculated to crosswind distances of ± 20 degrees from observed wind directions. Points in the computational grid beyond ± 20 degrees for any one hour were assumed at zero relative concentration for that hour.

Regulatory Guide 1.111 suggests the use of a correction factor to adjust the computed X/Q values. The Oconee station is located in a river valley which does induce some channelling and valley drainage wind; therefore, the river valley correction factors of the above reference are applicable. Although the derivation of these factors is not presented in the Guide, they are a result of a limited comparison of a Gaussian straight-line X/Q projection and variable trajectory model X/Q projecton for a hypothetical valley site where all winds are parallel to the valley axis. Also, recirculation of effluent with a time scale of about 24 hours is the most probable cause of the different X/Q values. A significant percentage of winds not along the valley axis at Oconee and the relatively short duration of higher activity effluent releases would result in lower correction factors or no correction at the Oconee station. Since there was no evidence to confirm or quantify the above hypotheses, the indicated correction factors for river valley sites were applied. The resulting X/Q values are conservative estimates.

The diffusion model used for this study differed from the recommendations of Regulatory Guide 1.111. The principal differences from the Guide were as follows:

1. *X/Q values are calculated at 5° intervals instead of averaged over 22.5° sectors;*
2. *X/Q values are accumulated from a chronological record of meteorological data instead of employing the joint frequency distribution developed from the meteorological data; and*
3. *For the purpose of achieving realistic X/Q estimates, a less conservative terrain correction is employed.*

Because the onsite winds were recorded to the nearest 5° direction, the model effectively assumes that the plume centerline impacts some radial line of receptors at each hour. This assumption is slightly more conservative than the sector average approach. The use of a time series of meteorological data would be no different from the use of a well formulated frequency distribution of the same data. Finally, the terrain correction prohibits impaction of the plume centerline onto terrain features, but does simulate the approach of the plume toward hills as they are forced over or around the obstruction.

Values for dry deposition (m^{-2}) were calculated according to Regulatory Guide 1.111. These D/Q values account for the terrain correction factors considered above. Also they consider the fractional breakdown of elevated and ground level plume contributions to D/Q in the same manner as the X/Q values above. Wind direction, speed, and stability frequencies for these calculations were obtained from a joint frequency distribution of hourly onsite meteorology for the period of record (1975).

All X/Q and D/Q values at specific receptors were interpolated from isopleth fields generated using the above mentioned receptor grid.

Values of X/Q, adjusted for dry deposition, are shown for selected receptors in Table 2-31. Relative deposition values, depicted in Table 2-32, are computed for the same set of receptors. X/Q values, which do not allow for removal processes, are presented in Table 2-33.

For the 0 to 2 hour accident relative concentration, X/Q, a value of 7.41×10^{-5} was submitted based on the valley drainage concept. Additional meteorological studies were performed subsequent to this submittal which gave evidence that the valley drainage model is conservative. These studies show a X/Q value of 6.12×10^{-5} as being descriptive of the 0 to 2 hour accident relative concentration; therefore, the relative concentration value of 7.41×10^{-5} will not be changed. The following is a description of additional meteorological studies supporting this conclusion.

The site dispersion characteristics were investigated with five instruments (Figure 2-32) indicating and recording wind direction and speed, two of which were elevated. During these studies, vertical temperature gradients were measured at two locations. Fifteen SF_6 (Sulfur Hexafluoride) gas-tracer experiments were conducted under poor diffusion conditions, during periods with a temperature inversion, without fog or precipitation. Sampling points are shown in (Figure 2-33) with the SF_6 test release point shown in (Figure 2-34).

The 0 to 2 hour accident relative concentration was recalculated using the equation $X/Q = (\bar{u}\pi\sigma_y\sigma_z)^{-1}$. Wind speed was obtained from the microwave tower instrument. Standard deviations of the lateral concentration distribution (Sigma Y) were computed from Pasquill assignments for standard deviations of the horizontal wind azimuth (Sigma Theta). Standard deviation of the horizontal wind was derived from wind range on the microwave tower instrument. Standard deviations of the vertical concentration distribution (Sigma Z) were determined by vertical temperature gradients for the following class intervals.

Pasquill Categories	**Vertical Temp. Gradient Class Intervals**	
F	>	2.0F in 150 feet
E		2.0 to 0.1F in 150 ft.
D		0.0 to - 1.4F in 150 ft.
C	-	1.5 to - 2.9F in 150 ft.
B	-	3.0 to - 4.5F in 150 ft.
A	<	-4.5F in 150 ft.

Pasquill assignments for Sigma Z were again made for categories A, B, and C; however, for D, E, and F gas-tracer test values, were substituted. Test Sigma Y values, although larger than Pasquill values, were not used because analysis for given stabilities and wind speeds showed horizontal dispersion too directionally dependent. It is noteworthy that Sigma Y was computed and used without a building effect term. Gas-tracer test results implied that Pasquill Sigma Z values for D, E, and F were too low. A reasonable representation for standard deviation of the vertical concentration distribution was sought for these class intervals, and based on test results, redefined as follows:

Pasquill Stability	Sigma Z
D	50m
E	50m
F	40m

A relative concentration calculation was made for each pair of valid consecutive observations from the microwave tower wind and temperature data. Relative concentration was computed as the average of the two one hour concentrations, if in successive hours, there was an overlap in plume widths defined as 4.30 Sigma Y. Relative concentration was computed from the highest one hour concentration averaged with ten percent of the lowest one hour concentration, if successive hours showed no overlap as above, but did give an overlap of wind range sectors. Finally, relative concentration was computed from the highest one hour concentration averaged with 0, if successive hours showed no overlap of wind range sectors. A relative concentration *frequency distribution was determined for the period June 1, 1968 to May 31, 1969 (Table 2-34). A hand calculation check on the relative concentration program ascertained its validity.*

Wind speed for each hour was read as the average speed in the preceding 30 minute period. Wind speeds less than or equal to 0.9 miles per hour were read as 1.0 miles per hour. Wind range read for each hour also covered the preceding 30 minute period. Vertical temperature differentials read for each hour covered a period of 30 minutes before and after the hour. Further, vertical temperature differentials for each hour were read: (a) as highest value if all readings positive, (b) as highest value if both positive and negative readings occurred the same hour, (c) as 0 if both 0 and negative readings occurred the same hour, and (d) as the lowest value if all readings were negative during the same hour.

Data from the five wind instruments were evaluated simultaneously and classified into five flow patterns. Comparisons were made of flow patterns during gas-tracer test (January 15, 1970 to March 11, 1970) with those during temperature inversions from available data of an earlier period (October 13, 1969 to November 23, 1969). The most frequent test flow pattern was also the most frequent configuration during the earlier period. All five patterns occurred in both periods.

Sample calculation at 1 mile (1609 meters):

$$X/Q = (\bar{u}\pi\sigma_y\sigma_z)^{-1}$$

Input Parameters:

$\bar{u}$ = 2.5 meters per second

wind range = 15°

vertical temperature differential = 3°F in 150 feet

σ_θ = 15/6 = 2.5°

σ_y = 57 meters

σ_z = 40 meters

X/Q = 1/(3.1416)(2.5)(57)(40)

X/Q = 5.58 x 10^{-5} seconds per meter^3

The procedures for the study analysis are summarized below:

1. *Note each pass through a detection area and approximate time of the pass. Place data points marking positions where SF_6 is detected in a sequential space order (not time).*
2. *From map of area, determine the average distance from the source to the detection stations.*
3. *Convert the source strength, Q, to micrograms per second from the release rate data.*
4. *Convert the detector scale readings to micrograms per cubic meter.*
5. *Estimate the average wind speed from surface instrumentation, and when applicable, microwave tower winds.*
6. *Utilize computer program to fit a Gaussian curve to the spatially ordered data points.*

7. *Find the first and second moment arms of the distribution of concentration. From the first moment arm, note the center line position; from the second moment arm, note the variance of the horizontal dispersion of the concentration.*
8. *Take positive square root of the variance to get a standard deviation in the horizontal, Sigma Y.*
9. *Obtain center line concentration by X =* $A\sigma_y - 1\ (2\pi)^{-1/2}$ *where A is the area under the distribution curve.*
10. *Calculate the standard deviation in the vertical, Sigma Z, by* $\sigma_z = Q(\pi\bar{u}\sigma_y X)^{-1}$ *which is applicable for a ground release.*
11. *Determine the stability category by the temperature differential on the microwave tower.*
12. *Using graphs of Sigma Y and Sigma Z as functions of stability and distance from a source, locate test values.*
13. *Following the curvature of the Pasquill curves for the stability found in Number 11 above, read Sigma Y and Sigma Z values for one (1) mile from the graph.*
14. *Compute the center line values X/Q at one (1) mile by X/Q =* $[\pi\bar{u}\sigma_y(1\ \text{mi.})\sigma_z(1\ \text{mi.})]^{-1}$ *.*

Results of the gas-tracer experiment are shown in Table 2-35.

A 1.4 wind speed correction factor for the period June 1968 to September 1969 may be warranted, based on a calibration check made October 1, 1969, and comparative wind speed data at Greenville-Spartanburg and Oconee. A relative concentration frequency distribution was determined with a 1.4 wind speed correction factor for the period June 1, 1968 to May 31, 1969, (Table 2-36). No wind speed correction was factored into the 0 to 2 hour accident relative concentration value of 6.12×10^{-5}*.*

Table 2-37 displays comparative wind speed data for Greenville-Spartanburg and Oconee from June, 1968 to January, 1970. Comparisons were made at 13:00 EST for wind speeds equal to or greater than 9.2 mph (i.e. eight knots) at Greenville-Spartanburg.

Supplemental data is presented and includes an all occurrence annual joint frequency distribution, a Pasquill F annual joint frequency distribution, a Pasquill E annual joint frequency distribution, a Pasquill A, B, C, and D annual joint frequency distribution, a relative concentration frequency distribution based on single hour calculations, and SF_6 *sample locations. This material is presented in Table 2-38, Table 2-39 and Figure 2-37.*

To assess the effects of topography on short-term diffusion estimates, terrain profiles were plotted for the 16 principal points of the compass within the 0.5 mile radius. Maximum and minimum elevations were recorded for each of the eight principal lines drawn to gain an estimate of potential drainage wind flow. The results are shown below:

Orientation	*Maximum Height Upstream*	*Minimum Height Downstream*	*Difference*
From N to S	*870 feet*	*740 feet*	*130 feet*
From NNW to SSE	*880*	*710*	*170*
From NW to SE	*827*	*690*	*137*

Orientation	*Maximum Height Upstream*	*Minimum Height Downstream*	*Difference*
From WNW to ESE	*872*	*680*	*192*
From W to E	*910*	*670*	*240*
From WSW to ENE	*817*	*700*	*117*
From SW to NE	*917*	*750*	*167*
From SSW to NNE	*862*	*760*	*102*

All of the eight lines pass through the central site area, i.e., from one-half mile north through the site center to one-half mile south. In general, the results show that the drainage of wind would be toward the east within the site exclusion radius.

Within the 3.0 mile radius - USGS topographic maps permit estimates of the overall drainage possibilities out to a three-mile radius. Figure 2-38 shows the results of a gross assessment of the terrain. The terrain at elevations equal to or less than 800 feet is shaded to more readily portray the potential drainage wind area. It is important to note that this approximate plot assumes that all proposed lakes are full in the final configuration as proposed for this area. Note that, although drainage to the east and east-south-east is shown for the central site area, the terrain modifies the drainage flow direction to that following the Keowee River.

2.3.5 Long-Term Diffusion Estimates

2.3.5.1 Objectives

The adequacy of onsite meteorological data in terms of long-term diffusion estimates is presented in this subsection. The discussion of long-term diffusion factors is presented in Section 2.3.4 for continuity purposes.

“HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED”

2.3.5.2 Calculations

Examination of the joint frequency of wind direction and speed by atmospheric stability class reveals a preponderance of air flow movement down the Keowee River valley axis at Oconee. This is taken as symptomatic of the occurrence of gravity induced flows during stable atmospheric conditions when winds are observed in this direction. In the absence of a straight walled river valley in the vicinity of Oconee, interactions of gravity flows on a smaller scale with the more general gravity flow down the Keowee River valley are postulated for flows near the surface. An indication of near surface flow during these conditions cannot be ascertained by a simple measurement of wind direction at the surface.

Considering the above, tower data at Oconee has been analyzed and can be shown representative of long-term diffusion conditions at the site. For the X/Q and D/Q models employed, meteorological and effluent exit conditions as given above result in only about 2 percent of total radioactivity released at ground level. Some portion of this 2 percent would occur during synoptic flows, and thus would be adequately represented by tower data. Consequently, annual doses can be represented by X/Q and D/Q estimates with wind direction inputs from tower data.

For other than gravity flow conditions, air flow trajectories can be assumed to be adequately represented by straight line flow on all time and distance scales to a distance of five miles. For the relatively undulating terrain surrounding Oconee, the measurement of wind speed and delta temperature from the meteorological tower is viewed as characteristic of prevailing conditions at the site.

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2.4 Hydrologic Engineering

2.4.1 Hydrologic Description

2.4.1.1 Site and Facilities

The location and description of Oconee presented in Chapter 1 and Chapter 2 include reference to figures showing the general arrangement, layout and relevant elevations of the station. Yard grade is 796 ft. mean sea level (msl). The mezzanine floor elevation in the Turbine, Auxiliary, and Service Buildings is 796.5 it. (msl). Exterior accesses to these buildings are at elevation 796.5 ft. (msl).

All of the man-made dikes and dams forming the Keowee Reservoir rise to an elevation of 815 ft. msl including the intake channel dike. The crest of the submerged weir in the intake canal is at elevation 770 ft. msl.

Changes to the natural drainage of the original site are shown on Figure 2-4.

2.4.1.2 Hydrosphere

The main hydrologic features influencing the plant are the Jocassee and Keowee Reservoirs. Lake Jocassee was created in 1973 with the construction of the Jocassee Dam on the Keowee River. The lake provides pump storage capacity to the reversible turbine-generators of the Jocassee Hydroelectric Station, located approximately 11 miles north of the plant. At full pond, elevation 1110 ft. msl, Lake Jocassee has a surface area of 7565 Ac, a shoreline of approximately 75 mi, a volume of 1,160,298 Ac-ft., and a total drainage area of about 148 sq mi.

Lake Keowee was created in 1971 with the construction of the Keowee Dam on the Keowee River and the Little River Dam on the Little River. Its primary purpose is to provide cooling water for the plant and water to turn the turbines of the Keowee Hydroelectric Station. At full pond, elevation 800 ft. msl, Lake Keowee has a surface area of 18,372 Ac, a shoreline of approximately 300 mi, a volume of 955,586 Ac-ft., and a total drainage area of about 439 sq mi. The Jocassee and Keowee Reservoirs and the hydroelectric stations located at these reservoirs are owned and operated by Duke.

The area presently provides for a few raw water users. The City of Greenville and the Town of Seneca take their raw water supplies from Lake Keowee. The Town of Anderson, the Town of Clemson, the Town of Pendleton, Clemson University, and several industrial plants take their raw water supplies from Hartwell Reservoir.

Greenville's raw water intake is located approximately 2 miles north of the plant on Lake Keowee. Seneca's raw water intake is located approximately 7 miles south of the plant on the Little River Arm of Lake Keowee. Anderson raw water intake is located approximately 40 river miles downstream of the Keowee tailrace and also supplies Pendleton, Clemson and Clemson University.

The existing raw water intakes for Greenville, Seneca, and Anderson are shown and located relative to the site on Figure 2-39.

2.4.2 Floods

2.4.2.1 Flood History

Since Oconee is located near the ridgeline between the Keowee and Little River valleys, or more than 100 ft. above the maximum known flood in either valley, the records of past floods are not directly applicable to siting considerations.

2.4.2.2 Flood Design Consideration

In accordance with sound engineering practice, records of past floods as well as meteorological records and statistical procedures have been applied in studies of floods through the Keowee and Jocassee Reservoirs as a basis for spillway and freeboard design.

At the time of initial design, the spillway capacities for Lake Keowee and Jocassee were selected in accordance with the empirical expression for design discharge:

$$Q = C\sqrt{DA}$$

Where Q	=	peak discharge in cfs
D A	=	drainage area in square miles
C	=	5000, a runoff constant judged to be characteristic of the drainage area

The following tabulation gives pertinent data on this design flood flow:

Lake Keowee[1]	Lake Jocassee	
439	148	Drainage area at damsite, sq mi
25,200 (Newry Gage D A 455 sq mi)	21,000 (Jocassee Gage D A 148 sq mi)	Maximum recorded flow at nearby USGS gages, cfs
8-13-40	10-4-64	Data of maximum flow
1939-1961	1950-1965	Period of record
105,000	61,000	Spillway design discharge, cfs
800	1,110	Full pond elevation
815	1,125	Crest of dam elevation
0	0	Surcharge on full pond for design discharge
4	2	Number of spillway gates
38 ft. x 35 ft.	40 ft. x 32 ft.	Size of spillway gates
		Discharge capacity, cfs
107,200	45,700	Spillway

Lake Keowee[1]	Lake Jocassee	
–	16,500 (2 units of 4)	Dependable flood flow through units
107,200	62,200	Total discharge capacity, cfs

Note:

1. Little River and Keowee River Arms

The above discharge capacities assume no surcharge above normal full pond level. Statistical analyses have shown design reservoir inflows for both Lake Keowee and Lake Jocassee equal to respective design discharge capacities outlined above to have recurrence intervals less frequent than once in 10,000 years. The above discharge capacities were used for initial design purposes only. The actual as-built data is described below. The size of the spillway gates that were constructed at Jocassee are 38ft x 33ft.

The spillway gates for Keowee are as listed above. The actual discharge capacities during a Probable Maximum Flood (PMF) event are greater than shown above. The surcharge on full pond during the PMF is 8.9ft and 12ft for Keowee and Jocassee respectively. The spillway discharge capacity is 140,000cfs and 74,000cfs for Keowee and Jocassee respectively. The dependable flood flow through units is 0cfs for Keowee and 26,600cfs for Jocassee. The total discharge capacity is 140,000cfs for Keowee. The total combined discharge capacity is 100,600cfs for Jocassee although only 85,405cfs is assumed in the PMF analysis of record.

The maximum wave height and wave run-up have been calculated for Lake Keowee and Lake Jocassee by the Sverdrup-Munk formulae. The results of these calculations are as follows:

Wave Height	Wave Run-Up	Maximum Fetch	Lake
3.70 ft.	7.85 ft.	8 miles	Keowee (Keowee River Arm)
3.02 ft.	6.42 ft.	4 miles	Jocassee
3.02 ft.	6.42 ft.	4 miles	Keowee (Little River Arm)

The wave height and wave run-up figures are vertical measurements above full pond elevations as tabulated above.

Studies were also made to evaluate effects on reservoirs and spillways of maximum hypothetical precipitation occurring over the entire respective drainage areas. This rainfall was estimated to be 26.6 inches within a 48 hour period. Unit hydrographs were prepared based on a distribution in time of the storms of October 4-6, 1964, for Jocassee and August 13-15, 1940, for Keowee. Results are summarized as follows:

Keowee	Jocassee	
147,800	70,500	Maximum spillway discharge, cfs
808.0	1114.6	Maximum reservoir elevation
7.0 ft.	10.4 ft.	Freeboard below top of dam

While spillway capacities at Keowee and Jocassee have been designed to pass the design flood with no surcharge on full pond, the dams and other hydraulic structures have been designed with adequate freeboard and structural safety factors to safely accommodate the effects of maximum hypothetical precipitation. Because of the time-lag characteristics of the runoff hydrograph after a storm, it is not considered credible that the maximum reservoir elevation due to maximum hypothetical precipitation would occur simultaneously with winds causing maximum wave heights and run-ups.

Two Reinforced Concrete Trenches extend through the Intake Dike with a minimum elevation of 810+0 with all removable covers removed. These Trenches are protected from wave action by the CCW Intake Structure and the Causeway at the west end of the Intake Structure. Therefore, only the maximum reservoir elevation of 808+0 is applicable with regard to flooding through the reinforced concrete trenches.

The maximum Keowee tailwater level during hydro operation has been calculated to be elevation 672.0 ft. (msl), which is 124 ft. below the nuclear station yard elevation 796.0 ft. (msl).

The maximum discharge calculated, due to hydro operating, is expected to be 19,800 cfs. The minimum discharge calculated with no units operating, is expected to be 30 cfs.

In summary, the above results of flood studies show that Lakes Keowee and Jocassee are designed with adequate margins to contain and control floods which pose no risk to the nuclear site.

2.4.3 Probable Maximum Flood on Streams and Rivers

2.4.3.1 Probable Maximum Precipitation

See Section 2.4.2.2.

2.4.3.2 Deleted per 1990 Update

2.4.3.3 Runoff and Stream Course Models

See Section 2.4.2.2.

2.4.3.4 Probable Maximum Flood Flow

See Section 2.4.2.2.

2.4.3.5 Deleted per 1990 Update

2.4.3.6 Coincident Wind Wave Activity

See Section 2.4.2.2.

2.4.4 Potential Dam Failures, Seismically Induced

Duke has designed the Keowee Dam, Little River Dam, Jocassee Dam, Intake Canal Dike, and the Intake Canal Submerged Weir based on sound Civil Engineering methods and criteria. These designs have been reviewed by a board of consultants and reviewed and approved by the Federal Power Commission in accordance with the license issued by that agency. The Keowee Dam, Little River Dam, Jocassee Dam, Intake Canal Dike, and the Intake Canal Submerged Weir have also been designed to have an adequate factor of safety under the same conditions of seismic loading as used for design of Oconee.

The construction, maintenance, and inspection of the dams are consistent with their functions as major hydro projects. The safety of such structures is the major objective of Duke's designers and builders, with or without the presence of the nuclear station.

2.4.5 Deleted per 1990 Update

2.4.6 Deleted per 1990 Update

2.4.7 Deleted per 1990 Update

2.4.8 Deleted per 1990 Update

2.4.9 Deleted per 1990 Update

2.4.10 Flooding Protection Requirements

See Section 3.4.

2.4.11 Low Water Considerations

2.4.11.1 Deleted per 1990 Update

2.4.11.2 Deleted per 1990 Update

2.4.11.3 Deleted per 1990 Update

2.4.11.4 Deleted per 1990 Update

2.4.11.5 Deleted per 1990 Update

2.4.11.6 Heat Sink Dependability Requirements

Oconee has four sources of water for shutdown and cooldown. These sources are: (1) water from Lake Keowee via the intake canal using the circulating water pumps; (2) gravity flow through the circulating water system; (3) water trapped between the submerged weir in the intake canal and the intake structure in the event of a loss of Lake Keowee and; (4) 8,776,948 gallons of water trapped in the plants Circulating Water System (below elevation 791 ft.) with appropriate valving, pumping and recirculation as a backup in the event of the loss of all external water supplies.

2.4.12 Deleted per 1990 Update

2.4.13 Groundwater

2.4.13.1 Description and Onsite Use

2.4.13.1.1 Regional Groundwater Conditions

The Oconee site lies within the drainage area of the Little and Keowee Rivers which flow southerly into the Seneca River and subsequently discharge into the main drainage course of the Savannah River. The average annual rainfall at the site area is approximately 53 inches.

The deposits of the Little and Keowee drainage basin are generally of low permeability which result in nearly total runoff to the two rivers and their numerous tributary creeks. Runoff occurs soon after precipitation, particularly during the spring and summer months when the soil percolation rates are exceeded by the short term but higher yielding rainfall periods. The area is characterized by youthful narrow streams and creeks which discharge into the mature Little and Keowee Rivers.

Throughout the area, groundwater occurs at shallow depths within the saprolite (residual soil which is a weathering product of the underlying parent rock) soil mantle overlying the metamorphic and igneous rock complex (Reference 1). Refer to Section 2.5. This saprolite soil, which ranges in thickness from a few feet to over 100 feet, is the aquifer for most of the groundwater supply. Wells are shallow and few exceed a total depth of 100 feet. Depths to water commonly range from 5 to 40 feet below the land surface. Seasonal fluctuation is wholly dependent of the rainfall and the magnitude of change may vary considerably from well to well due to the limited areas of available recharge. Average fluctuation is about 3 to 5 feet. Both surface water and groundwater in this area are of low mineral content and generally of good quality for all uses.

To determine the general groundwater environment surrounding the proposed site, groundwater levels were established in numerous domestic wells and exploratory drill holes within a four-mile radius. Additional data was obtained from interviews with local residents regarding specific wells and discussions with State and Federal personnel. The results of the groundwater level survey are shown on Figure 2-40. The results demonstrate that local subsurface drainage generally travels down the topographic slopes within the more permeable saprolite soil zones toward the nearby surface creek or stream. Gross drainage is southward to the Little and Keowee Rivers which act as a base for the gradient.

Because the topography and thickness of the residual soil, overlying bedrock control the hydraulic gradient throughout the area, and further, the relief is highly variable within short distances, it is not possible to assign a meaningful average gradient for the 15 square mile area surveyed. In all small areas studied within the four-mile radius, the groundwater hydraulic gradient is steep and conforms to the topographic slope. Water released on the surface will percolate downward and move toward the main drainage channels at an estimated rate of 150 to 250 feet per year.

The gradient throughout the area represents the upper surface of unconfined groundwater and therefore is subject to atmospheric conditions. Confined groundwater occurs only locally as evidenced by the existence of isolated springs and a few exploratory drill holes which encountered artesian conditions. These examples do not reflect general conditions covering large areas but merely represent isolated local strata within the saprolite soil which contain water under a semi-perched condition and/or permeable strata overlain by impermeable clay lenses which have been breached by erosion at its exit and recharged short distances upslope by vertical percolation.

The site area is on a moderately sloping, northwest trending topographic ridge which forms a drainage divide between the Little and Keowee Rivers located approximately 0.5 mile to the west and east, respectively. Groundwater levels at the site, measured during the 1966 drilling program and subsequently in four piezometer holes drilled for pre-construction monitoring purposes, ranged from elevation 792 ft. (msl) to 696 ft. (msl). The slope of this apparently free water surface is predominantly southeasterly toward the Keowee River and its tributary drainage channels. An average hydraulic gradient to the southeast of approximately 8.0 percent was plotted along a line of measured wells. This closely conforms to the existing topography as expected. Refer to Figure 2-41 for measured water levels and typical water table profile.

Field permeability tests conducted during the 1966 exploratory program within the saprolite soil yielded values ranging from 100 to 250 feet per year. Refer to Section 2.4.13.2.2. The permeability tests were performed in holes of varying depths to determine if the zoned typed weathering of the saprolite soil affects vertical permeability. Based on the test results, inspection of nearby road cuts, and a study of the exploratory drill logs, it is tentatively concluded that the surficial saprolite possesses lower permeability values than that found in the deeper strata. This correlates with the general profile of the saprolite in that the later stages of weathering produce a soil having a higher clay content than the more coarse-grained silty sand sediments below. This natural process of weathering results in the formation of a partial barrier to downward movement of surface water.

2.4.13.1.2 Groundwater Quality

The surface water and groundwater of the area is generally of good quality (Reference 2). Of the wells surveyed, none were noted where water treatment is being conducted. Temperature of well water measured ranged from a low of 46 to a high of 59 degrees. The majority of readings were from 50 to 53 degrees Fahrenheit.

Water contains different kinds and amounts of mineral constituents. Temperature, pressure and length of time water is in contact with various rock types and soils determine the type and amount of mineral constituents present. Because ground waters are in intimate contact with the host rocks for longer periods of time, they have a more uniform and concentrated mineral content than surface waters. The mineral content of natural surface waters in the Piedmont Province is low due to the relative insolubility of the granitic, gneissic, and schistose host rocks and the reduced contact time caused by rapid runoff in the mountainous areas.

Tabulated below are the surface water constituents reported in parts per million from the Keowee River near Jocassee, South Carolina. The water sample was taken and analyzed by the U.S. Geological Survey, Water Resources Division in June 1965.

Silica (SiO_2)	7.8	Carbonate (CO_3)	0.0
Iron (Fe)	0.01	Bicarbonate (HCO_3)	7.0
Calcium (Ca)	1.0	Sulfate (SO_4)	1.0
Magnesium (Mg)	0.1	Chloride (Cl)	0.6
Sodium (Na)	1.2	Fluoride (F)	0.1
Potassium (K)	0.4	Nitrate (NO_3)	0.1
Dissolved Solids	15.0	Phosphate (PO_4)	0.0

	Hardness as $CaCO_3$	3.0
	pH	6.6
	Specific Conductance	13.0

Present and future environmental monitoring will be completed per Selected Licensee Commitments, the Oconee NPDES Permit Groundwater Monitoring Plan, and the Oconee Landfill Permit requirements. Based on industry experience, a radiological ground water monitoring program was established for Oconee. Refer to Section 11.8

Soil surveys conducted by the U.S. Department of Agriculture in cooperation with the South Carolina Agricultural Experiment Station assign pH values of between 5.0 and 6.0 for the Hayesville and Cecil soil series which are present at the site area (Reference 3). Surface water samples taken from the Keowee River within one mile of the site have a pH of 6.5 to 7.0. Groundwater at the site has a pH ranging between 5.5 and 6.0.

The cation exchange potential can be evaluated by knowing the SAR (Sodium Absorption Ratio), saturation extract values, and the pH of the soil. Two samples of saprolite soil were obtained from drill holes used in determining field permeability values and tested for Sodium Absorption Ratio (SAR). The results are tabulated as follows:

Sample No.	**pH**	**Saturation Extract Values Milligram-equivalent per 100 grains of soil**				**SAR**
		Cond. (mhos)	Calcium	Magnesium	Sodium	
1	5.8	5	0.015	0.000	0.0108	0.122
2	5.7	7	0.010	0.000	0.0166	0.235

Considering the amount of soil that is available is so great, it is evident that many times the amount of strontium and/or cesium contained in the waste could be absorbed. Further, the distribution coefficient for ion exchange of radionuclides with the sediments is dependent on the pH of the water in the formation (Reference 4). The distribution coefficient is a ratio of the reaction of these radionuclides that are absorbed on the soil and the fraction remaining in solution. It is expected that the soils surrounding Oconee have a ratio in the range of 80 to 150, and consequently a substantially lower average velocity for any radionuclide to that of natural water will result.

The estimated maximum rate of movement of water through the soils is about 0.75 feet per day. Using this rate in relation with the above distribution coefficient, bulk density and porosity of the soil, and ratio of the weight of soil to volume of groundwater it indicates the radionuclide velocity will be about .0015 that of groundwater. Using a safety factor of five for variance in flow and competition for exchangeable sodium ions, it would require more than 1000 years for strontium or cesium ions to migrate a distance of one-half mile. In summary, the movement would be so extremely slow that the saprolite soil is an effective natural barrier to the migration of radionuclides.

2.4.13.2 Sources

2.4.13.2.1 Groundwater Users

The completed field survey of approximately 30 wells determined that groundwater usage is almost entirely from the permeable zones within the saprolite with only minor amounts obtained from the underlying fractured bedrock. Yields from these shallow wells are low, generally less than 5 gpm, and are used to supply domestic water for homes and irrigation of lawns, gardens, and limited amounts for livestock. With only a few exceptions, the wells are hand dug, equipped with bucket lift and/or jet pump, and 40 to 60 feet deep. At present, there is no industrial demand for groundwater within the area.

2.4.13.2.2 Program of Investigation

Permeability tests were performed in borings to determine permeabilities of the soil underlying the site. The tests were run according to the Bureau of Reclamations Field Permeability Tests, Designation E-19. Figure 2-42 shows the arrangement of the field test equipment along with a brief description of the procedure used in determining the soil permeability test results. Test results are from 5 borings as presented in Table 2-93. The formulae used in the calculations of the k values are shown in Figure 2-43.

2.4.13.2.3 Groundwater Conditions Due to Keowee Reservoir

As previously discussed, the groundwater levels at the site range from elevation 792 ft. (msl) to below elevation 696 ft. (msl). The Keowee Reservoir will operate with a maximum pool elevation of 800 ft. (msl). This will result in raising the surface water elevation to that datum on the northern and western portions of land adjoining Oconee. It will also raise the existing groundwater table for those local areas bordering the reservoir where presently the ground water surface is below elevation 800.0 ft (msl). The reservoir will materially contribute in establishing a potentially larger recharge area and where it affects the groundwater will result in a more stable hydraulic gradient with less seasonal fluctuation than presently exists.

Preliminary studies indicate that Keowee Reservoir will create the following groundwater conditions at Oconee.

1. Groundwater should continue to migrate downslope through the saprolite soil on a slightly steeper gradient in a southeasterly direction toward the Keowee River base datum.
2. There are two topographic divides which will separate the nuclear station from the nearby reservoir: (1) a one-half mile wide north-south stretch of terrain west of the site, and (2) a narrow 500 foot wide ridge north of the site. Recent groundwater measurements in drill hole K-12, located atop the northern ridge, show water table conditions exist at about elevation 810 ft. (msl).
3. It is unknown if the saprolite soil existing beneath those topographic ridges provide a hydraulic connection between the nuclear plant and the reservoir. However, it is probable that there will be avenues of slow seepage whereby percolating water may locally raise the groundwater surface at the plant to an elevation approaching elevation 800 ft. (msl). A drainage system will be provided to control all seepage encountered.
4. There should be no reversal of groundwater movement at the site, and all water will percolate downward and away from the plant area.
5. The construction of Keowee Dam and Reservoir will not create adverse groundwater conditions at the plant site.

6. Infiltration of domestic wells, located beyond the proposed one-mile exclusion radius, by surface water from the site should not be possible under the existing or future groundwater conditions imposed by Keowee Reservoir.

2.4.13.3 Deleted per 1990 Update

2.4.13.4 Deleted per 1990 Update

2.4.13.5 Design Bases for Subsurface Hydrostatic Loading

See Section 2.4.13.2.3.

2.4.14 References

1. *Geologic Notes*, Division of Geology, State Devel opment Board, Vol. 7, No. 5, September-October 1963.
2. *Chemical Character of Surface Waters of South Carolina* , South Carolina State Development Board, (Bulletin No. 16C) 1962.
3. *Soil Survey - Oconee County, South Carolina*, United States Department of Agriculture, Series 1958, No. 25, February 1963.
4. *Storage of Radioactive Wastes in Basement Rock Beneath the Savannah River Plant*, DP-844 Waste Disposal and Processing (TID-4500, 28th Ed.), March 1964.

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2.5 Geology, Seismology, and Geotechnical Engineering

2.5.1 Basic Geologic and Seismic Information

Geologic and seismic investigative studies for Oconee Nuclear Station include the following:

1. a review of the available geological and seismological literature pertaining to the region;
2. a geological reconnaissance of the site, performed primarily for the purpose of evaluating the possibility of active faulting in the area;
3. geophysical explorations and laboratory tests to provide parameters for evaluating the response of foundation materials to earthquake ground motion;
4. an evaluation of the seismic history to aid in the selection of the design earthquake that the station might experience; and
5. The development and recommendation of aseismic design parameters for the proposed structures.

The geologic field work at the site started concurrently with the drilling. The site reconnaissance is a continuation of the geologic field work done for the Keowee Dam. Local outcrops, though scarce, are examined and the rock types, joint and foliation orientation noted.

The 21 borings completed at the Oconee Nuclear Site, supplemented by information from the nearby Keowee Hydro Site borings, have been sufficient for a determination of the geologic structure and petrography.

The structures are founded on normal Piedmont granite gneisses. The construction characteristics of the residual soils overlying the rock are known and present no problems in design or construction. The rock underlying the site, below surface weathering, is hard and structurally sound and contains no defects which would influence the design of heavy structures.

The southeastern Piedmont rocks are highly stable seismologically, and the Oconee Nuclear Site should be one of the nation's most inactive areas with respect to earthquake activity.

2.5.1.1 Regional Geology

The regional structure is typical of the southern Piedmont and Blue Ridge. The region was subjected to compression in the northwest-southeast direction which produced a complex assortment of more or less parallel folds whose axes lie in a northeast-southwest direction. The Blue Ridge uplift was the climax of the folding, and it was accompanied by major faulting, along a line stretching northeast through Atlanta and Gainesville, Georgia and across South Carolina, 11 miles northwest of the site. This has been termed the Brevard Fault.

The age of these uplifts has not been agreed on by geologists. The consensus of geologic opinion seems to require a period of severe deformation followed by at least one additional period of less severity. Probably all occurred during the Paleozoic Era, but it has been suggested that the last major uplift was as late as the Triassic (180 million years ago) when the Coastal Plain to the east was downwarped. A number of investigators have maintained that the major deformative movements occurred at least 225 million years ago. However, all the resulting stresses have not yet been fully dissipated.

There is no evidence of any displacement along these faults during either historic times or during the Geologic Recent Era as indicated in displacements in the residual soils that blanket the region. While the well known Brevard Fault passes 11 miles northwest of the site, there is no indication of a major fault in the immediate vicinity of the site. Furthermore, the major faults of the region are ancient and dormant, except for minor adjustments at considerable depth. Therefore, there is no indication of any structural hazard to foundations.

The site is underlain by crystalline rocks which are a part of the southeastern Piedmont physiographic province. This northeastward - trending belt of ancient metamorphic rocks extends northward from Alabama east of the Appalachians, and in South Carolina crosses the State from the Fall Line on the east to the Blue Ridge and Appalachian Mountains on the west. These rocks are generally recognized as being divided into four northeast-southwest trending belts in the Carolinas. From southeast to northwest they are the Carolina slate belt, Charlotte belt, Kings Mountain belt, and Inner Piedmont belt. The Oconee Nuclear Site is in the western, or Inner Piedmont Belt.

The Piedmont metamorphic rocks of the site were formed under many different combinations of pressure and temperature, and represent a complex succession of geologic events. The formerly accepted concept that the Piedmont consists only of the deep, worn-down roots of ancient mountains now seems untenable. The older theory that the rocks were exclusively of igneous origin is being replaced by the proposition that they represent highly metamorphosed sediments which have been folded, faulted, and injected to result in one of the most complex geologic environments in the world. It can be said with certainty, however, that these rocks represent some of the oldest on the continent. The new techniques of dating by radioactive decay have placed the age of the metamorphic episodes that produced these rocks as occurring from 1,100 my (million years) to 260 my ago. The successive northeastward trending bands of rocks vary greatly in lithology from granitic types to highly basic classifications, with gneisses and schists being the predominant classifications petrographically. In summary, the regional geology of the Oconee Nuclear Site can be accepted as typical of the southeastern Piedmont - narrow belts of metamorphic rocks trending northeast, with the foliation dipping generally to the southeast. The regional geologic map is shown in Figure 2-44.

2.5.1.2 Site Geology

2.5.1.2.1 Geologic History, Physiography, and Lithography

The rock present at this site is metamorphic. It is believed to be Precambrian in age; thus, it was formed over 600 million years ago. The complete history of this region is quite complex and has not been fully unravelled. However, it is the consensus of the geologic opinion that the formation consisted of thick strata of sedimentary rocks which were later downwarped and altered by heat and pressure. This first rock formed is termed the country rock.

More than one episode of regional metamorphism transformed the rock into metasediments with accompanying injection and mobilization by plastic flow.

Since the formation of the country rock, most of the mass has been altered or replaced by injection of granite gneiss, biotite hornblende gneiss, and one or possibly more pegmatite dikes.

It is not definite which is the younger: the granite gneiss injection or the biotite hornblende gneiss injection. The limited evidence points to the granite gneiss as the younger of the two.

The pegmatite dikes are the youngest rock known at this site. One such dike is exposed in the road cut on the east side of the state highway passing through the site. It clearly shows the pegmatite cutting through the older rocks, and thus, demonstrates that it is the youngest.

Regional metamorphism, folding, and some minor faulting occurred concurrently much of this early time.

This site is located within the Inner Piedmont Belt, at this locality the westernmost component of the Piedmont Physiographic Province. The topography of the area is undulating to rolling; the surface elevations ranging from about 700 feet to 900 feet. The region is moderately well dissected with rounded hilltops, representing a mature regional development. The area is well drained by several intermittent streams flowing away from the center of the site in a radial pattern. The general station area is shown on the maps in Figure 2-45, Figure 2-46, Figure 2-2, and Figure 2-4.

The local geology of the Oconee Nuclear Site is typical of the southeastern Inner Piedmont Belt. The foundation rock is biotite and hornblende gneiss, striking generally northeast, with the foliation dipping southeast. The rock is overlain by residual soils, which vary from silty clays at the surface, where the rock decomposition has completed its cycle, to partially weathered rock, and finally to sound rock.

The strike of the foliation planes or bands of mineral segregation is north 6 degrees to 15 degrees east with an average dip of 22 degrees to 28 degrees to the southeast. However, due to the local folding or warping at this site, minor variations in the strike and dip of the foliation will occur within the site.

It is almost inevitable that when minor compression folding of this nature occurs, some minor shear displacements will result. We noted only one such displacement. In boring NA-20, at depth of about 79.6 feet below the ground surface, a shear displacement of about one-half inch was recorded. This should not be considered uncommon where hard rock or possibly slightly plastic rock has been folded. While the rock is being folded, minute cracks in the rock develop. The acting compressive forces then cause slight shifts or displacements in the rock resulting in a more relaxed state. The shear displacement noted in boring NA-20, was completely healed or recemented. There is no evidence noted of any recent displacements.

There have been periods of erosion and perhaps even continuous erosion since the close of the Paleozoic Era. The rock now encountered at this site represents the deeper portions of the original metamorphic complex.

The rock encountered at this site is of three main types; light to medium gray granite gneiss, light gray to black biotite hornblende gneiss and white quartz pegmatite with local concentrations of mica, both muscovite and biotite varieties.

The dominate rock type at this site is the light to medium gray granite gneiss. This rock type is generally moderately hard and hard below the initial soft layers encountered in the rock surface. Joints in this rock are brown iron stained in the upper softer layers, but in the deeper harder rock, the joints are not stained. This helps illustrate that the jointing at this site does not control the weathering or decomposition of the rock.

The second most abundant rock type is the biotite hornblende gneiss. The rock is generally weathered or softer to a greater depth than the granite gneiss. This is probably due to the higher percentage of biotite mica. Biotite mica is a potassium magnesium-iron aluminum silicate. The iron content of the biotite mica causes the rate of decomposition to accelerate. However, generally at the deeper portions of the borings, the biotite hornblende gneiss hardness increases to moderately hard or harder. Only a few thin soft layers were noted in this rock in the deeper portion of the borings.

A few layers of hard quartz pegmatite with local concentrations of mica were recorded. The thickness of the pegmatite layers are generally less than three feet. These pegmatite layers are dikes. A dike is a sheetlike body of igneous rock that fills a fissure in the older rock which it encountered while in a molten condition. There is an exposure of mica-quartz pegmatite dike on the east side of the state road cut passing through this project. This dike exposure is about

3.5 feet wide, but due to the lack of knowledge of orientation of the dike, the exact width cannot be computed. The quartz pegmatite encountered in the borings probably represent other smaller dikes of the same material. These dikes are of hard, sound and durable material and should cause no concern to construction or foundation requirements.

2.5.1.2.2 Rock Weathering

Where heavily banded with dark biotite and hornblende the rock is weaker than in its lighter colored portions, since the highly foliated biotite will split along the foliations, and is also more subject to weathering and consequent rock decay. The borings indicate that even after apparently sound rock has been reached local bands or zones of biotite - usually less than a foot thick - may be soft and weathered to considerable depths.

Rock weathering at the Oconee Nuclear Site is about normal for Piedmont biotite gneisses. While highly variable, the normal range of depth before sound rock is reached is 30 to 50 feet. Although the weathering is deep, the resulting residual materials - clays, silts, and weathered rock - are structurally strong, and are used for the foundations of moderately loaded structures.

2.5.1.2.3 Jointing

The rock at this site is moderately jointed. All of the visible rock outcrops were studied in attempting to determine the correct orientation of the joint patterns. Some moderately good rock outcrops were found and several joint pattern orientations measured. While studying and logging the rock cores, all of the joint dips were recorded. The dips of the joint patterns recorded in the rock cores were associated with the dips measured in the rock outcrops.

The rock has apparently not been subjected to stresses causing high concentrations of joints. The core borings indicate that jointing is widely spaced, and has not influenced the weathering pattern. Joints are about equally divided between strike and dip joints, with occasional oblique joints.

Four joint patterns were found, two of which appear to be most significant. The two most significant joint patterns are: strike north 55 degrees east with a dip of 61 degrees northwest, and strike north 28 degrees west with a dip of 85 degrees southwest. The other two joint patterns are: strike north 9 degrees west with a dip of 67 degrees southwest and strike northsouth with a dip of 74 degrees west. The strike and dip of the joints are shown on Figure 2-47.

2.5.1.2.4 Ground Water

Subsurface water is typical of Piedmont area. The top of the zone of saturation, or water table, follows the topography, but is deeper in the uplands and more shallow in valley bottoms. It migrates through the pores of the weathered rock, where the feldspars have disintegrated and left intersticial spaces between the quartz grains. Additional water is contained in the deeper fractures and joints below the sound rock line. The water table is not stationary, but fluctuates continually as a reflection seasonal precipitation. Additional information on ground water is included in Section 2.4.13.

2.5.2 Vibratory Ground Motion

2.5.2.1 Seismicity

Two different methods of evaluating earthquakes are in general used. These are the Modified Mercalli (MM) Intensity (damage) Scale and the Richter Magnitude Scale. The magnitude of, and the intensities resulting from, an earthquake are only indirectly related. The Richter Magnitude is an approximate measure of the total amount of energy released by an earthquake. The Modified Mercalli Intensity, however, is an estimate of the amount of damage caused at a particular site by an earthquake. The intensity of an earthquake at a particular site is only a general indicator of the amount of ground motion since it is a damage criteria and, therefore, dependent on structural considerations as well as ground motion amplitude. The actual amplitude of ground motion at a particular site is dependent upon the following factors:

1. the total amount of energy released by earthquake;
2. the distance of the site from the focus of the earthquake; and
3. the thickness and dynamic properties of the materials above the basement rock complex.

A considerable number of earthquakes have been felt in the region. However, most of these shocks resulted in a little or no damage. A plot of the more significant shocks, occurring prior to 1961 and those having a recorded intensity of Modified Mercalli V or larger, is shown on Figure 2-48, Earthquake Epicenters.

Accurate locations for earthquake epicenters have only been available since the installation of modern seismographs in the region. Previous to these installations, epicentral locations, based upon known damage and reports of people who felt the earthquake, could be in considerable error. Even with instrumental locations, epicenters could be in error by 20 miles or so. It is estimated that major shocks in the region would probably have been recorded for at least 200 years. However, smaller earthquakes before about 1850 were probably either unrecorded or were unreliably located.

Several large earthquakes outside the area shown on Figure 2-48 have been felt in the region. North of the region, the closest major shocks had epicenters in the St. Lawrence Rift valley or on the folded and faulted coast of Massachusetts. The catastrophic earthquakes of 1811 and 1812 near New Madrid, Missouri, approximately 480 miles from the site, are the closest known large earthquakes to the west. These shocks were probably related to the Ozark Dome. With the exception of the earthquakes at Charleston, South Carolina, no major shocks have occurred south or east of the site within the continental United States. These distant large earthquakes are unrelated to any of the known faulting within the crystalline-metamorphic or overthrust zones in which the site is located.

The largest earthquakes close to the site occurred near Charleston in August, 1886, some 200 miles from the site. Two shocks occurring closely in time, had an intensity estimated to be about Modified Mercalli IX at the epicenter and were perceptible over an area of greater than two million square miles. However, damage was confined to a relatively small area. Aftershocks of the main earthquake had intensities ranging up to Modified Mercalli VII. These shocks may be associated with a downfaulted Triassic basin under the coastal plain.

There have been two moderate earthquakes in the immediate vicinity of the plant since construction began.

In 1971, an earthquake occurred near Seneca, South Carolina. The descriptions of this event which occurred at 07:42 (EST) on July 13, 1971 have been examined from various sources. A MM intensity VI was assigned to the event by USGS based primarily on the report of a cracked chimney near Newry, about 10 km south of the present epicentral area. A detailed examination of the buildings and chimneys by Sowers and Fogle (1978) convinced them that the chimney in question had been broken and in a state of disrepair before the shock. They assigned an intensity IV (MM) to the shaking at Newry.

The July 13, 1971 event at 07:42 AM EDT was preceded by a felt shock at about 4:15 AM EDT and followed by at least one felt aftershock at 7:45 AM (Sowers and Fogle, 1978).

On August 25, 1979 (9:31 PM EDST, Aug. 26) a magnitude 3.7 earthquake occurred in the vicinity of Lake Jocassee, South Carolina. This MM intensity VI event was felt in an area of about 15,000 sq. km and was recorded locally on the three station Lake Jocassee seismographic network, and regionally on seismic stations in South Carolina, North Carolina, Georgia, Tennessee, and Virginia. During the period (August 26, 1979 - September 15, 1979) 26 aftershocks were recorded and they ranged in magnitude from -.60 to 2.0.

A list of earthquakes in the region, based on data available at the time of this update, is provided in Table 2-94.

2.5.2.2 Geologic Structures and Tectonic Activity

The region (defined as North Carolina and South Carolina, and parts of Georgia, Alabama, Tennessee, and Virginia) is comprised of three large northeast-southwest trending tectonic zones: The coastal plain, the crystalline-metamorphic zone and the overthrust zone. These zones are shown on Figure 2-49 Regional Tectonics.

The site is located nearly in the center of the crystalline-metamorphic zone, which consists of six generally recognized metamorphic belts. From southeast to northwest these are: The Carolina slate belt, Charlotte belt, Kings Mountain belt, Inner Piedmont belt, Brevard belt, and Blue Ridge belt. The site location is within the Inner Piedmont belt. The rocks in the belts consist of metamorphosed sediments and volcanics that have been folded, faulted, and intruded with igneous rocks. These belts are delineated by differing degrees of metamorphism. Generally, the degree of metamorphism becomes progressively less from the northwest to the southeast.

The oldest metamorphic rocks are located in the Blue Ridge belt. The more easterly belts of younger rocks have undergone progressively less metamorphism.

To the north and west are found a series of fault systems. Since these faults are both numerous and extensive, they can be grouped together and referred to as the overthrust zone, as shown on Figure 2-49. These faults no doubt resulted from the formation of the Appalachians.

The great system of thrust faults in the overthrust zone and most of the known faulting within the crystalline-metamorphic zone apparently occurred during the last period of metamorphism (260 million years ago).

During the Triassic Period (180 to 225 million years ago), sediments were deposited over parts of the exposed metamorphic belts. These deposits and the older metamorphics were intruded by a system of northwest-trending diabase dikes and were faulted by northeast-trending normal faults in the late Triassic Time (200 million years ago). Some of the older faults within the crystalline-metamorphic zone may have been active at this time.

From the late Triassic time until the present, the coastal plain has accumulated a sedimentary cover over its crystalline-metamorphic bedrock. These sediments overlap the bedrock and thicken toward the southeast, effectively masking any ancient faulting in the basement.

It is considered possible that igneous activity has occurred in the region after the Triassic because volcanic bentonitic clays of Eocene (approximately 50 million years ago) and possible Miocene age (12 million years ago) have been mapped in the sediments of the coastal plain in South Carolina. The source of this volcanic activity is presently unknown.

Faulting: The names, distances and directions from the proposed site, and the probable age of the known faulting in the region are as follows:

Name	Distance-Direction From Site	Probable Age Millions of Years
Brevard Fault	11 Miles NW	260
Dahlonega Fault	40 Miles W	260
Whitestone Fault	47 Miles NW	260
Towaliga Fault	90 Miles S	260
Cartersville Fault	104 Miles W	260
Gold Hill Fault	115 Miles E	260
Goat Rock Fault	140 Miles SW	260
Triassic, Deep River Basin, N.C. and S.C.	140 Miles E	200
Triassic, Danville Basin, N.C.	145 Miles NE	200
Crisp and Dooly Counties, Ga.	190 Miles SW	12 to 70
Probable Triassic Basin Charleston, S.C.	200 Miles SE	200

The locations of these faults with respect to the site are shown on Figure 2-49.

The first seven faults are all associated with the last metamorphic period. The Brevard, Whitestone, Dahlonega, and Cartersville faults apparently form an interrelated system. This system separates the eastern metamorphic belts from the Blue Ridge metamorphic belt and the overthrust zone on the west.

The Towaliga, Goat Rock, and Gold Hill Faults, and the Kings Mountain belt apparently form another interrelated alignment within the eastern metamorphic belts. The Kings Mountain belt is not considered a fault. Its association and alignment in relation to the three known faults mentioned and the location of earthquake epicenters within the area bounded by these features, lead to the conclusion that these features form an interrelated alignment.

There is no surface indication that any of these three faults have been active since the Triassic Period (200 million years).

Two fault locations in the region have been thoroughly investigated by borings. These are the Cartersville fault near the Allatoona Dam, and the Oconee-Conasauga fault in Georgia. These faults were found to be completely healed and not to have moved in many millions of years.

The Triassic basins of the Carolinas and further north may be due to the release of the compressional forces which formed the Appalachians. These basins are down-faulted grabens which are filled with Triassic sediments. Two earthquakes in the vicinity of McBee, South Carolina, may be related to an extension of a Triassic basin which has been inferred in the Chesterfield-Durham area.

Some faulting within the tertiary sediments in Dooly, Crisp, and Clay Counties, Georgia, has been mapped. The true areal extent of this faulting is unknown. This faulting apparently ranges from Cretaceous to possibly Miocene in age (70 to 12 million years).

The earthquake activity near Charleston, South Carolina, may indicate an active fault in that region. However, no evidence of surface faulting has been found.

2.5.2.3 Correlation of Earthquake Activity with Geologic Structures or Tectonic Provinces

The region surrounding the site can be divided into three major areas on the basis of the regional tectonics and the seismic history. These major seismic areas are:

1. the overthrust zone and Blue Ridge metamorphic belt;
2. the crystalline-metamorphic zone, exclusive of the Blue Ridge belt; and
3. the coastal plain.

The greatest number of recorded shocks have occurred within the overthrust zone and the Blue Ridge metamorphic belt northwest of the Brevard, Whitestone, Dahlonega, and Cartersville fault system. The epicenters in this area are generally widely scattered.

There have been a small number of earthquakes within the crystalline-metamorphic zone, exclusive of the Blue Ridge metamorphic belt. These earthquakes, extending from central Georgia to North Carolina, may be associated with the Towaliga, Goat Rock, Gold Hill, Kings Mountain alignment.

The coastal plain has experienced few earthquakes outside of the Charleston area. Four shocks, at Wilmington, North Carolina and Savannah, Georgia, have occurred but are unrelated to any known faulting, although the Wilmington shocks were adjacent to the Cape Fear Arch.

The only earthquake which does not closely fit this system of seismic areas is the 1924 shock in Pickens County, South Carolina (MM V Intensity). However, it is likely that this earthquake is associated with the overthrust-Blue Ridge seismic area.

2.5.2.4 Maximum Earthquake Potential

The assignment of probable future earthquake activity can only be based upon the previous record and the known geology of the area. Although the seismic history of the region is fairly short, a reasonable picture of the seismicity of the area becomes apparent from a study of the epicenter locations and the regional tectonics.

There are three significant zones of seismic activity in the general vicinity of the site; the Brevard and related faults zone, the overthrust zone, and the Towaliga, Goat Rock, Gold Hill, Kings Mountain alignment.

An evaluation of the earthquake activity and the regional geology can result in the selection of a series of maximum-sized shocks which are likely to occur in these various areas. Conservatively, we can assume that the previous maximum-sized shock on a particular fault zone can occur during the economic life of the proposed power station at perhaps the nearest approach of the particular fault system to the proposed site.

Zone	Location	(MM) Intensity at Epicenter	Estimated Magnitude (Richter)

Zone	Location	(MM) Intensity at Epicenter	Estimated Magnitude (Richter)
Brevard Fault Zone	11 Miles NW	VI	Less than 4½ to 5
Overthrust	75 Miles NW	VIII	Less than 5½ to 6
Towaliga, Goat Rock Gold Hill, Kings Mountain Alignment	30 Miles SE	VII-VIII	Less than 5½ to 6

2.5.2.5 Seismic Wave Transmission Characteristics of the Site

Static and dynamic engineering properties of the soil and rock materials that underlie the site are discussed in Section 2.5.4. Design response spectra that include considerations of the thickness and distribution of these materials are discussed in Section 2.5.2.8.

2.5.2.6 Maximum Hypothetical Earthquake (MHE)

The MHE acceleration value is 0.10 g for Class 1 structures founded on bedrock and 0.15 g for structures founded on overburden. The design response spectra are covered in Section 2.5.2.8.

2.5.2.7 Design Base Earthquake

It is considered likely that the shocks listed in Section 2.5.2.4 could occur no closer than the indicated distances from the site during the life of the planned facilities. Since the magnitudes of these shocks are fairly small, the distance from the epicenter becomes extremely important. Ground accelerations would diminish rapidly with the distance from the epicenter. Although larger earthquakes occur within other fault zones, the highest ground accelerations at the site would be experienced from an earthquake along the Brevard fault zone. The assumption of a shock of less than Richter Magnitude five occurring along the Brevard fault zone at its closest location to the site (11 miles), would give ground motions on the order of five percent of gravity at the site. Vertical ground accelerations, as contrasted to the horizontal accelerations, would be only slightly less than five percent of the gravity in the competent rock at the site.

The DBE acceleration value is 0.05 g for both vertical and horizontal ground acceleration. The design response spectra are covered in Section 2.5.2.8.

2.5.2.8 Design Response Spectra

The Recommended Ground Motion for the 0.05 g, 0.10 g, and 0.15 g earthquakes are presented on Figure 2-50, Figure 2-52, and Figure 2-54.

The Recommended Ground Motion shows the expected maximum ground acceleration, velocity and displacement versus frequency at the site for the DBE and MHE. These plots are the expected ground motions of a particle within the rock at foundation level, and does not indicate the motions to be expected within a structure.

The Recommended Response Spectra curves for the 0.05 g, 0.10 g, and 0.15 g earthquakes are presented on Figure 2-51, Figure 2-53, and Figure 2-55. The upper curve on the

Recommended Response Spectra shows the expected maximum acceleration, velocity and displacement versus frequency that would be experienced by a simple inverted pendulum which has no damping if the pendulum was excited by the ground motions specified in the Recommended Ground Motion Spectrum. The other curves on the graph are plotted to show the effects of damping.

2.5.3 Surface Faulting

This information is discussed in Section 2.5.1 and Section 2.5.2.

2.5.4 Stability of Subsurface Materials and Foundations

2.5.4.1 Geologic Features

This information is discussed in Section 2.5.1.

2.5.4.2 Properties of Subsurface Materials

The materials underlying the site can be characterized by four zones. These four zones are shown on the subsurface profiles in Figure 2-56 through Figure 2-64 and are described in the following sections.

Zone 1 (Red Sandy Silty Clay or Clayey Silty Sand)

This residual soil derived from the in-place weathering of the parent rock, is the zone at the surface. This soil has been severely desiccated and partially cemented by oxidation of the iron it contains. This soil is strong, incompressible, and should not swell appreciably when saturated.

Zone 2 (Micaceous Silty Sand)

The second zone, like the first is derived from the in-place weathering of the parent rock. This zone consists of micaceous silty sand; decomposed rock that retains the relic structure of the original rock, often termed "saprolite". As is indicated by the standard penetration resistance, it is firm near the ground surface in the switchyard area (where it is thickest) but becomes denser with increasing depth. At this plant site, much of this zone has penetration resistances of 30 blows per foot or more and could be described either as a dense soil or a very soft rock. In general, this stratum is elastic and somewhat compressible because it has lost most of the intercrystalline bonds of the rock due to weathering, while much of the mica has not weathered sufficiently to lose its resiliency. The compressibility decreases and the rigidity increases with increasing density as reflected in the penetration resistances. In spite of this elastic nature, it is strong when confined and exhibits limited cohesion (both inter-particle bonding and capillary tension) as well as internal friction.

Zone 3 (Alternate Seams of the Soft Decomposed Rock and Hard Partially Decomposed Rock)

The third zone is the transition between soil and rock. This zone of alternate hard and soft weathered rock is exceedingly variable in its properties depending on the relative thicknesses of the contrasting seams. It is stronger than the saprolite zone above in shear across the seams but no stronger than the weakest seam parallel to them. The elasticity and compressibility are in proportion to the thickness of the soft seams because by comparison, the harder seams do not appreciably deflect under stress.

Zone 4 (Relatively Sound Rock)

The relatively sound rock below is both strong and rigid. The strength and elastic properties of small intact portions of the rock range from those of good concrete to several times those of concrete. The properties of the mass, however, are partially controlled by the joints and fissures. Therefore, the modulus of elasticity, the strength and the deflection of the mass are all somewhat lower than might be deduced from small scale laboratory tests of individual samples.

2.5.4.3 Exploration

A grid pattern of borings was established to provide the maximum amount of information for determining the foundation and soil conditions and permit flexibility in final plant layout, alignment, and elevation.

The general station area is shown on the included Location and Topographic Map, Figure 2-46 and the site and boring layout is shown on the Boring Plan, Figure 2-65.

The drilling, sampling, and rock coring were performed in accordance with methods specified by the American Society for Testing and Materials:

“Penetration Testing and Split Barrel Sampling of Soils” - D-1586-64T

“Diamond Core Drilling for Site Investigation” - D-2311-62T

“Thin Walled Tube Sampling of Soils” - D-1587-63T

NX and BX size rock cores were drilled at this site. The respective diameters of the rock cores are 2-1/8 and 1-5/8 inches. Boring logs are given in Figure 2-66 through Figure 2-115.

A limited amount of auger drilling, not required by the plant foundation exploration outline, was done in the vicinity of boring NA-9 in conjunction with seismic field testing. Also, auger boring was done for a piezometer installation to be used during percolation inflow tests made for groundwater analysis and evaluation.

Various laboratory tests were run on cores from Borings NA-4 and NA-9.

Compressional wave velocity and specific gravity measurements were performed on four cores. The results of these measurements are shown in Table 2-95.

Measurements were run on eight cores from the two borings to determine Young's modulus, Poisson's ratio, and ultimate crushing strength. The results of these measurements are shown in Table 2-96.

2.5.4.4 Geophysical Surveys

An uphole velocity survey was Performed on Boring NA-9. A Dynametric Interval Timer, Model 117-A, capable of measuring times of 0.0001 seconds, was used. Explosives in the boring of up to one-half pound of dynamite were used to create the shock wave.

The calculated velocities from this survey are somewhat anomalous because of the weathered and fractured character of the rock.

Two seismic refraction lines were shot across the site. A Mandrel Industries Interval Timer, ER-75, 12-trace refraction seismograph was used to record the lines. Explosives were used to provide the shock waves.

The location of the uphole boring and the seismic lines are shown on Figure 2-117.

Two cross sections through the site along the seismic refraction lines is shown on Figure 2-118. The interpretations on these cross sections are based upon the uphole velocity survey, the seismic refraction lines and velocity measurements on core samples. This interpretation of the velocities is considered generally reliable. These velocities are general averages and small areas within the site may not fit the cross section because the character and the depth and degree of weathering of the rock at the site varies greatly in short distances. The water table elevation may also vary somewhat from that shown on the cross sections.

The pattern of microtremor motion was recorded at the site. The instrument used is capable of a maximum gain of 150,000. However, this site is extremely quiet and no appreciable amplitudes were recorded. (For example, a truck passing along the road less than 75 feet from the geophone produced double amplitudes of only 2.5 x 10^{-6} inches of ground motion.)

Because of the extremely low amplitudes of both the microtremor and the refraction energies, it was decided to perform an attenuation curve of the ground motion produced by explosives. Both the microtremor equipment and a Sprengnether Blast Recorder were used to measure the ground motion at 50, 100, 200, and 400 feet from 40-pound charges. This attenuation curve was compared with attenuation curves from sites with known characteristics to gain a better idea of the probable ground motion characteristics of the site. The results of this data indicated a marked attenuation of ground motion with distance.

2.5.4.5 Deleted per 1990 Update

2.5.4.6 Groundwater Conditions

This information is discussed in Section 2.4.13.

2.5.4.7 Response of Soil and Rock to Dynamic Loading

Under dynamic load the elastic materials may deform significantly. Experience with vibratory loading at a number of high-pressure pumping stations has demonstrated sufficient elastic response which can develop to be troublesome. The site is in a region of definite but infrequent seismic activity of moderate intensity. Under such dynamic loadings, foundations supported upon any appreciable thickness of the resilient micaceous materials could respond unfavorably, developing some magnification of the amplitude compared to the more rigid rock below.

Detailed studies of the elastic qualities of the soil-rock mass supporting the critical structures could probably develop a configuration for the structure-foundation system that would not provide amplification for the seismic frequencies anticipated. Such an analysis, however, is dependent on (1) an accurate evaluation of the rock-soil-structure elastic response and (2) an accurate knowledge of seismic frequency spectra. Available theories on soil-structure response are approximate at best and must be corrected from empirical observations made during earthquakes. Realistic frequency spectra must properly be determined from observations of ground motion during seismic activity of the same intensity as anticipated. Unfortunately, there was no instrumental observation of any of the earthquakes of the region sufficiently close to the site that either reliable frequency spectra or structural response of the soil can be evaluated. Microtremors, while of academic interest, are not of sufficient magnitude to make a reliable evaluation of earthquake response of the magnitude of those observed. In fact, there is some evidence that microseisms may arise from different mechanisms, particularly superficial, near surface strains and adjustments.

2.5.4.8 Deleted per 1990 Update

2.5.4.9 Earthquake Design Basis

The earthquake design basis is discussed in Section 2.5.2.

2.5.4.10 Static Stability

Although the individual critical station units may not tolerate substantial settlement, they are functionally inter-connected only by piping. This can absorb some differential movements if it is anticipated in the design.

Because of the relatively small thickness of the surface clayey soils and the irregular topography, the upper zone does not have an appreciable influence on the design of foundations for the major structures. This stratum does furnish excellent support for the smaller structures where there is no cut or only shallow fill.

Under static load alone, a major design consideration for heavy structures is the elastic deflection and consolidation of the micaceous soils of the saprolite zone and the micaceous, more weathered layers of the zone of alternate hard and soft seams. Experience, confirmed by laboratory tests, has shown that these materials can support power station loadings without appreciable settlement when the densities are sufficient, that is the penetration resistances consistently exceed 30 blows per foot.

2.5.5 Deleted per 1990 Update

2.5.6 Embankments and Dams

2.5.6.1 Deleted per 1990 Update

2.5.6.2 Exploration

A thorough investigation has been made of the Keowee-Little River dam foundations (including the dam at the east end of the Oconee intake canal) by the Law Engineering Testing Company under the direction of Professor George F. Sowers.

A total of 74 soil and rock borings have been made to investigate the foundations of the Keowee and Little River dams and that of the dike at the east end of the Oconee intake canal. One hundred forty-six additional borings have been made to investigate foundations of nearby Keowee and Oconee structures and waterways.

At Keowee, 23 undisturbed samples were taken for laboratory testing to determine shear strength of the foundations.

At Little River, 19 undisturbed samples were taken for laboratory testing to determine shear strengths of the foundation.

2.5.6.3 Foundation and Abutment Treatment

At Keowee dam, based on test results, the extent of removal of material is specified such that shear strength of remaining material would equal or exceed shear strength of dam embankment. All alluvial material is removed. Since monitoring of any seepage in vicinity of the river itself would be extremely difficult due to backwater of Hartwell reservoir, a shallow grout curtain (10 ft-15 ft) is installed between and below the elevation 685 contours. The foundation report specifically notes that grouting is not required “to improve stability, reduce consolidation, or increase impermeability.” The permeability of the intact reservoir soils varied between 1×10^{-3} and 1×10^{-4} feet per second as determined by laboratory tests.

Due to proximity of Keowee powerhouse (and its excavation) to left embankment, a core trench to rock is installed to provide a positive cutoff. A shallow grout curtain is placed below the bottom of core trench.

At Little River dam, as at Keowee, all material weaker in shear than the embankment materials and alluvium is excavated. A shallow (10 ft-15 ft) grout curtain is placed between and below elevation 675 contours. The permeability of the intact reservoir soils varied between 1 x 10^{-4} and 1 x 10^{-6} feet per second as determined by laboratory tests.

At Keowee and Little River dams and at Oconee intake canal dike, a three layer graded filter is placed under the downstream third of the dams and dike to intercept safely any seepage through the embankment and foundation. The dam abutments and upstream reservoir areas have natural blankets of residual, impervious material, and it is expected that these will prevent excessive seepage through the foundation.

2.5.6.4 Deleted per 1990 Update

2.5.6.5 Slope Stability

2.5.6.5.1 Static Analyses

Static analyses are performed for both Keowee and Little River dams, and these studies are checked by re-analyzing the most critical circles of failure independently. The conditions studied, both upstream and downstream, included “steady state seepage”, “sudden drawdown”, and “construction” before the reservoir was filled, utilizing the appropriate shear strength data for each condition.

2.5.6.5.2 Seismic Analyses

The static analyses extend to include the effect of acceleration and the resulting “inertia forces” on stability. The method utilized is that proposed by N. Newmark (1965) in the Rankine Lecture at the Institution of Civil Engineers (London).

In this analysis a steady acceleration is assumed to be applied to the centroid of the potentially sliding segment of soil in the direction which produces the greatest increase in overturning moment.

The results show that the embankments will have safety factors of 1.0 or more when the steady state acceleration is introduced. Of course, as Dr. Newmark points out, this dynamic approach is not rigorous because earthquakes loadings are transient, not steady, but the results should be on the safe side.

For earthquake loadings, the minimum permissible safety factor considered prudent by such organizations as the Corps of Engineers is 1.0 when combined with steady state seepage.

2.5.6.5.3 Shear Parameters

The shear parameters utilized in Section 2.5.6.5.1 and Section 2.5.6.5.2 are the consolidated-undrained or R values which impose a rapid change in stress upon a soil that has consolidated under sustained load. The load change is applied so rapidly that no change in water content could occur even though the soils are saturated. The rate of loading, however, could not be termed “dynamic”. In dynamic loading of such clayey soils, viscous forces would be mobilized, and therefore, the strength would be somewhat greater.

Only one loading cycle is employed. In loose cohesionless soils or sensitive clays repeated loading can cause a change in structure and progressive loss in strength. Previous experience with the undisturbed soils of the region, as well as the compacted soils, shows that the soils do not suffer progressive breakdown with repeated load. Therefore, the static shear parameters should be safe and the steady state acceleration, N, for seismic loading will be substantially the same as for static.

2.5.6.6 Seepage Control

Investigation and corrective action are discussed in Section 2.5.6.2 and Section 2.5.6.3 respectively. Permeability is discussed in Section 2.4.

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Appendix 2A. Tables

Table 2-1. 1970 Population Distribution 0-10 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

SECTOR	***0-1 MILE***	***1-2 MILES***	***2-3 MILES***	***3-4 MILES***	***4-5 MILES***	***5-10 MILES***	***TOTAL***
N	*0*	*0*	*0*	*0*	*0*	*40*	*40*
NNE	*0*	*0*	*0*	*38*	*22*	*60*	*120*
NE	*0*	*0*	*0*	*115*	*235*	*2,000*	*2,350*
ENE	*0*	*22*	*38*	*108*	*112*	*681*	*961*
E	*0*	*0*	*0*	*140*	*417*	*670*	*1,227*
ESE	*0*	*0*	*51*	*70*	*131*	*1,326*	*1,578*
SE	*0*	*0*	*80*	*6*	*70*	*8,472*	*8,628*
SSE	*0*	*0*	*0*	*0*	*45*	*7,792*	*7,837*
S	*0*	*19*	*29*	*6*	*140*	*2,027*	*2,221*
SSW	*0*	*6*	*0*	*0*	*112*	*7,000*	*7,118*
SW	*0*	*19*	*0*	*128*	*166*	*538*	*851*
WSW	*0*	*13*	*80*	*181*	*35*	*1,102*	*1,411*
W	*0*	*0*	*150*	*38*	*102*	*1,419*	*1,709*
WNW	*0*	*3*	*22*	*51*	*26*	*1,456*	*1,558*
NW	*0*	*0*	*0*	*13*	*32*	*920*	*965*
NNW	*0*	*3*	*3*	*13*	*16*	*881*	*916*
TOTAL	*0*	*85*	*453*	*907*	*1,661*	*36,384*	*39,490*

Table 2-2. 2010 Projected Population Distribution 0-10 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

SECTOR	***0-1 MILE***	***1-2 MILES***	***2-3 MILES***	***3-4 MILES***	***4-5 MILES***	***5-10 MILES***	***TOTAL***
N	*0*	*0*	*35*	*123*	*27*	*615*	*800*
NNE	*0*	*35*	*215*	*46*	*8*	*446*	*750*
NE	*0*	*15*	*33*	*76*	*89*	*1,125*	*1,338*
ENE	*0*	*18*	*38*	*81*	*142*	*1,666*	*1,945*
E	*0*	*22*	*44*	*68*	*308*	*1,645*	*2,087*
ESE	*0*	*18*	*34*	*14*	*97*	*3,280*	*3,443*
SE	*0*	*10*	*27*	*22*	*66*	*3,865*	*3,990*
SSE	*0*	*12*	*18*	*26*	*133*	*7,722*	*7,911*
S	*0*	*10*	*12*	*36*	*203*	*2,885*	*3,146*
SSW	*0*	*48*	*137*	*12*	*6*	*11,285*	*11,488*
SW	*0*	*31*	*99*	*37*	*28*	*2,207*	*2,402*
WSW	*0*	*12*	*79*	*30*	*79*	*4,593*	*4,793*
W	*0*	*21*	*90*	*84*	*81*	*1,867*	*2,143*
WNW	*0*	*26*	*53*	*65*	*58*	*1,513*	*1,715*
NW	*0*	*311*	*515*	*465*	*78*	*1,303*	*2,672*
NNW	*0*	*297*	*374*	*884*	*44*	*751*	*2,350*
TOTAL	*0*	*886*	*1,803*	*2,069*	*1,447*	*46,768*	*52,973*

SOURCE: *U.S. Census 1910-1960, Extrapolation (for 2010) by Dr. C. Horace Hamilton, Department of Rural Sociology, North Carolina State University, Raleigh, N.C.*

Table 2-3. 1970 Population Distribution 0-50 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

SECTOR	*0-10 MILES*	*10-20 MILES*	*20-30 MILES*	*30-40 MILES*	*40-50 MILES*	*TOTAL*
N	*40*	*52*	*2,479*	*1,087*	*20,659*	*24,317*
NNE	*120*	*1,095*	*3,514*	*13,879*	*21,431*	*40,039*
NE	*2,350*	*5,007*	*4,608*	*2,702*	*24,312*	*38,979*
ENE	*961*	*9,323*	*61,552*	*43,989*	*25,285*	*141,110*
E	*1,227*	*18,322*	*78,884*	*47,398*	*17,518*	*163,349*
ESE	*1,578*	*1,425*	*17,561*	*5,519*	*5,704*	*31,787*
SE	*8,628*	*3,390*	*44,033*	*12,708*	*9,835*	*78,594*
SSE	*7,837*	*4,957*	*16,200*	*6,836*	*2,700*	*38,530*
S	*2,221*	*4,500*	*3,040*	*10,990*	*12,033*	*32,784*
SSW	*7,118*	*3,681*	*4,265*	*8,811*	*6,384*	*30,259*
SW	*851*	*3,748*	*12,904*	*4,317*	*5,352*	*27,172*
WSW	*1,411*	*5,606*	*7,506*	*8,772*	*14,639*	*37,934*
W	*1,709*	*1,969*	*2,884*	*2,760*	*2,716*	*12,038*
WNW	*1,558*	*835*	*1,977*	*2,563*	*1,740*	*8,673*
NW	*965*	*588*	*1,772*	*9,804*	*2,771*	*15,900*
NNW	*916*	*340*	*1,448*	*6,700*	*11,833*	*21,237*
TOTAL	*39,490*	*64,838*	*264,627*	*188,835*	*184,912*	*742,702*

Table 2-4. 2010 Projected Population Distribution 0-50 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

SECTOR	*0-10 MILE*	*10-20 MILES*	*20-30 MILES*	*30-40 MILES*	*40-50 MILES*	*TOTAL*
N	*800*	*570*	*3,213*	*1,400*	*30,600*	*36,583*
NNE	*750*	*1,141*	*3,970*	*19,100*	*29,500*	*54,461*
NE	*1,338*	*3,355*	*6,018*	*4,700*	*26,100*	*41,511*
ENE	*1,945*	*12,325*	*60,430*	*53,000*	*41,400*	*169,100*
E	*2,087*	*19,600*	*127,913*	*75,300*	*23,800*	*248,700*
ESE	*3,443*	*4,285*	*15,572*	*9,000*	*7,400*	*39,700*
SE	*3,990*	*5,700*	*54,210*	*13,200*	*6,900*	*84,000*
SSE	*7,911*	*4,015*	*19,574*	*7,600*	*2,300*	*41,400*
S	*3,146*	*3,140*	*4,932*	*6,000*	*8,400*	*25,618*
SSW	*11,488*	*3,190*	*4,336*	*6,100*	*3,100*	*28,214*
SW	*2,402*	*7,400*	*9,129*	*4,500*	*900*	*24,331*
WSW	*4,793*	*4,105*	*15,176*	*10,700*	*16,900*	*51,674*
W	*2,143*	*1,535*	*4,264*	*4,100*	*3,600*	*15,642*
WNW	*1,715*	*1,085*	*3,152*	*2,200*	*2,300*	*10,452*
NW	*2,672*	*525*	*2,204*	*9,400*	*4,800*	*19,601*
NNW	*2,350*	*695*	*1,693*	*4,800*	*13,700*	*23,238*
TOTAL	*52,973*	*72,666*	*335,786*	*231,100*	*221,700*	*914,225*

SOURCE: *U.S. Census 1910-1960, Extrapolation (for 2010) by Dr. C. Horace Hamilton, Department of Rural Sociology, North Carolina State University, Raleigh N.C*

Table 2-5. 1970 Cumulative Population Density 0-50 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

SECTOR	0-1 MILE	0-2 MILES	0-3 MILES	0-4 MILES	0-5 MILES	0-10 MILES	0-20 MILES	0-30 MILES	0-40 MILES	0-50 MILES
N	0	0	0	0	0	2	1	15	12	49
NNE	0	0	0	12	12	6	15	27	59	81
NE	0	0	0	38	71	120	93	68	47	79
ENE	0	28	34	55	57	47	131	406	368	285
E	0	0	0	46	114	62	248	557	464	330
ESE	0	0	29	40	51	80	38	116	83	64
SE	0	0	45	28	32	439	153	317	219	159
SSE	0	0	0	0	9	399	162	164	114	78
S	0	25	27	18	19	113	85	55	66	66
SSW	0	8	3	2	24	362	137	85	76	61
SW	0	25	5	48	64	43	58	99	69	55
WSW	0	17	53	90	63	72	89	82	74	77
W	0	0	85	62	59	87	47	37	30	24
WNW	0	4	14	25	21	79	30	25	22	18
NW	0	0	0	4	9	49	20	19	42	32
NNW	0	4	3	6	7	47	16	15	30	43
TOTAL	0	7	19	29	40	126	83	130	111	95

Table 2-6. 2010 Projected Cumulative Population Density 0-50 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

SECTOR	*0-1 MILE*	*0-2 MILES*	*0-3 MILES*	*0-4 MILES*	*0-5 MILES*	*0-10 MILES*	*0-20 MILES*	*0-30 MILES*	*0-40 MILES*	*0-50 MILES*
N	0	0	20	52	38	41	17	26	19	74
NNE	0	44	141	97	62	38	24	33	79	110
NE	0	19	27	41	43	68	60	61	49	84
ENE	0	23	32	45	57	99	181	423	406	342
E	0	28	37	44	90	101	275	847	715	502
ESE	0	23	29	22	33	175	98	132	103	80
SE	0	13	21	19	26	203	123	362	245	170
SSE	0	15	17	18	39	403	151	178	124	84
S	0	13	12	19	53	160	80	63	55	52
SSW	0	61	105	65	41	585	186	108	80	57
SW	0	39	73	55	40	122	124	107	75	49
WSW	0	15	51	40	41	244	113	136	111	104
W	0	27	63	64	56	109	47	45	38	32
WNW	0	33	45	47	41	87	36	34	26	21
NW	0	395	467	423	279	136	41	31	47	40
NNW	0	377	379	510	326	120	39	27	30	47
TOTAL	0	70	95	95	79	169	100	163	138	116

Table 2-7. Frequency of Tropical Cyclones in Georgia, South Carolina and North Carolina Plus Coastal Waters

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Period (Years)	***Total***	***Average per Year***	***No. Years with no Tropical Storms***	***No. Years with Double the Average No.***
1871-1875	*8*	*1.6*	*0*	*0*
1876-1885	*18*	*1.8*	*1*	*1*
1886-1895	*19*	*1.9*	*2*	*1*
1896-1905	*21*	*2.1*	*1*	*0*
1906-1915	*16*	*1.6*	*0*	*0*
1916-1925	*12*	*1.2*	*3*	*2*
1926-1935	*16*	*1.6*	*1*	*0*
1936-1945	*12*	*1.2*	*1*	*1*
1946-1955	*25*	*2.5*	*2*	*0*
1956-1965	*17*	*1.7*	*0*	*1*
Total (95 Years)	*164*		*11*	*6*

Note: *(References 1, 2 and 3)*

Table 2-8. Mean Monthly Thunderstorm Days and Thunderstorms for Nuclear Plant Site

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Month	***Thunderstorm Days***	***Thunderstorms***
Jan	*1*	*1.1*
Feb	*1.5*	*1.6*
Mar	*3.5*	*3.8*
Apr	*4*	*4.6*
May	*7*	*8.0*
Jun	*11*	*12.6*
Jul	*13*	*15.0*
Aug	*10*	*11.5*
Sept	*5*	*5.8*
Oct	*1.5*	*1.6*
Nov	*1.5*	*1.6*
Dec	*1*	*1.1*
Annual	*60*	*68.3*

Note:

1. *Reference 11*

Table 2-9. Duration and Frequency (in Hours) of Calm and Near-Calm Winds Average of Three Locations(1) (1/59 - 12/63)

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Duration (Hours)	*Winter*	*Spring*	*Summer*	*Fall*	*Annual*
A. Calm Conditions: Calm at all locations					
01-05	*74.2(2)*	*70.4*	*94.7*	*92.5*	*331.8*
06-11	*3.9*	*3.4*	*5.9*	*6.9*	*20.1*
12-17	*0.3*	*0.3*	*0.8*	*1.3*	*2.7*
18-23	*0.0*	*0.0*	*0.1*	*0.3*	*0.4*
24-29	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
30-35	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
36-41	*0.1*	*0.0*	*0.0*	*0.0*	*0.1*
Total					*355.1*
B. Average Wind Speed: 1 Knot or Less					
01-05	*76.2*	*74.5*	*98.9*	*95.6*	*345.2*
06-11	*4.0*	*3.5*	*6.1*	*7.1*	*20.7*
12-17	*0.3*	*0.3*	*0.8*	*1.3*	*2.7*
18-23	*0.0*	*0.0*	*0.1*	*0.3*	*0.4*
24-29	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
30-35	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
36-41	*0.1*	*0.0*	*0.0*	*0.0*	*0.1*
Total					*369.1*

Note:

1. *The three locations were Charlotte WBAS, Winston-Salem WBAS, North Carolina; and Greenville WBAS and Greenville-Spartanburg WBAS, South Carolina.*
2. *Hours per season or hours per year as appropriate.*
3. *Reference 13.*

Table 2-10. Annual Surface Wind Rose For Greenville, South Carolina (1/59 - 12/63)[1]

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

	Wind Speeds in Knots							
Wind Direction	***1.3***	***4-6***	***7-10***	***11-16***	***17-21***	***22-27***	***Total Freq.***	***Mean Speed***
N	*1.2[2]*	*2.4*	*2.2*	*1.1*	*0.1*	*.0*	*7.0*	*7.1*
NNE	*0.8*	*2.7*	*2.7*	*1.0*	*0.1*	*.0*	*7.3*	*7.2*
NE	*1.2*	*5.2*	*6.0*	*2.1*	*0.2*	*.0*	*14.7*	*7.5*
ENE	*0.8*	*3.6*	*3.2*	*1.0*	*0.1*	*.0*	*8.7*	*7.0*
E	*1.3*	*2.5*	*1.5*	*0.2*	*.0*	*.0*	*5.5*	*5.5*
ESE	*0.8*	*1.3*	*0.5*	*.0*	*.0*	*.0*	*2.6*	*4.8*
SE	*0.9*	*1.4*	*0.4*	*.0*	*.0*	*.0*	*2.7*	*4.6*
SSE	*0.5*	*1.0*	*0.4*	*.0*	*.0*	*.0*	*1.9*	*5.1*
S	*1.0*	*2.0*	*1.0*	*0.1*	*.0*	*.0*	*4.1*	*5.4*
SSW	*0.5*	*1.9*	*1.5*	*0.4*	*.0*	*.0*	*4.3*	*6.6*
SW	*1.0*	*3.6*	*3.5*	*1.3*	*0.1*	*.0*	*9.5*	*7.2*
WSW	*0.7*	*2.9*	*3.7*	*1.8*	*0.3*	*0.1*	*9.5*	*8.2*
W	*0.8*	*2.4*	*2.0*	*0.8*	*0.2*	*.0*	*6.2*	*7.2*
WNW	*0.6*	*2.2*	*1.2*	*0.4*	*0.1*	*.0*	*4.5*	*6.6*
NW	*1.1*	*2.4*	*0.7*	*0.2*	*.0*	*.0*	*4.4*	*5.3*
NNW	*0.6*	*1.5*	*0.9*	*0.4*	*0.1*	*.0*	*3.5*	*6.7*
Calm							*3.6*	
	13.8	*39.0*	*31.4*	*10.8*	*1.3*	*0.1*	*100.0*	*6.6*

Note:

1. *Reference 12*
2. *Percent Frequency*

Table 2-11. Percent Frequency of Wind Speeds at Various Hours Through the Day - Greenville, S. C. (1/59 - 12/63)[1]

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

	Wind Speed in Knots							
Hour	***0***	***1-3***	***4-6***	***7-10***	***11-16***	***17-21***	***22-23***	***34+***
01	*4.3*	*20.1*	*42.8(2)*	*25.2*	*7.0*	*.6*	*0*	*0*
04	*4.7*	*21.0*	*42.9(2)*	*23.8*	*7.3*	*.4*	*0*	*0*
07	*4.1*	*19.0*	*39.6(2)*	*29.4*	*6.9*	*.9*	*.2*	*0*
10	*1.5*	*8.2*	*34.6*	*39.0(2)*	*15.7*	*1.4*	*.1*	*0*
13	*0.7*	*4.9*	*32.0*	*41.1(2)*	*18.4*	*2.6*	*.4*	*0*
16	*0.6*	*6.1*	*31.6*	*41.2(2)*	*16.8*	*3.2*	*.6*	*0*
19	*2.9*	*14.0*	*46.5(2)*	*26.1*	*9.0*	*1.3*	*.1*	*.1*
22	*7.5*	*16.2*	*43.1(2)*	*25.3*	*6.6*	*1.1*	*.1*	*.0*
Average	*3.3*	*13.7*	*39.1(2)*	*31.4*	*11.0*	*1.4*	*.1*	*.1*

Note:

1. *Reference 12*
2. *Indicates the Speed Class of the 50 Percent Level*

Table 2-12. Duration and Frequency of Calm and Near-Calm Winds Average of Three Locations[2] (1/59 - 12/63)

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Duration (Hours)	***Winter***	***Spring***	***Summer***	***Fall***	***Annual***
A. Calm Conditions: Calm at all Locations					
		Incidents/Season/Stations			
01-05	*74.2*	*70.4*	*94.7*	*92.5*	*331.8*
06-11	*3.9*	*3.4*	*5.9*	*6.9*	*20.1*
12-17	*0.3*	*0.3*	*0.8*	*1.3*	*2.7*
18-23	*0.0*	*0.0*	*0.1*	*0.3*	*0.4*
24-29	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
30-35	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
36-41	*0.1*	*0.0*	*0.0*	*0.0*	*0.1*
Total					*355.1*
B. Average Wind Speed: 1 Knot or Less					
01-05	*76.2*	*74.5*	*98.9*	*95.6*	*345.2*
06-11	*4.0*	*3.5*	*6.1*	*7.1*	*20.7*
12-17	*0.3*	*0.3*	*0.8*	*1.3*	*2.7*
18-23	*0.0*	*0.0*	*0.1*	*0.3*	*0.4*
24-35	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
36-41	*0.1*	*0.0*	*0.0*	*0.0*	*0.1*
Total					*369.1*

Note:

1. *Frequency of incidents/season/station were determined by dividing 15 into total number of occurrences for each season-duration group (5 years of record times 3 stations = 15).*
2. *Reference 13 - The three locations were Charlotte WBAS, Winston-Salem WBAS, North Carolina; and Greenville WBAS and Greenville-Spartanburg WBAS, South Carolina.*

Table 2-13. Percentage Distribution of Athens, Georgia Annual Winds at 0630 Eastern Standard Time (800-1300 Feet Above Ground)

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Wind Direction	*1-5 (1)*	*6-10*	*11-14*	*>15*	*Totals*
N	*1.84*	*1.55*	*0.14*	*0*	*3.53*
NNE	*0.99*	*0.14*	*0.28*	*0*	*1.41*
NE	*2.11*	*1.55*	*0.42*	*0*	*4.09*
ENE	*2.82*	*5.08*	*3.24*	*1.97*	*13.12*
E	*2.26*	*3.95*	*1.13*	*0*	*7.33*
ESE	*2.12*	*2.12*	*0.71*	*0.14*	*5.08*
SE	*1.41*	*0.99*	*0.85*	*0.14*	*3.39*
SSE	*1.27*	*1.27*	*0.28*	*0.14*	*2.96*
S	*1.83*	*0.42*	*0.28*	*0.14*	*2.68*
SSW	*2.12*	*2.12*	*0.71*	*0.28*	*5.22*
SW	*1.41*	*3.95*	*1.13*	*0.42*	*6.91*
WSW	*1.55*	*2.96*	*1.13*	*0.28*	*5.92*
W	*2.96*	*4.09*	*2.54*	*0.71*	*10.30*
WNW	*2.40*	*4.94*	*4.37*	*1.13*	*12.83*
NW	*1.83*	*5.22*	*3.10*	*0.14*	*10.30*
NNW	*2.12*	*1.83*	*0.28*	*0*	*4.23*
Calm					*0.71*
	31.03	*42.17*	*20.6*	*5.50*	*100.01*

Note:

1. *Wind Speeds in Meters/Sec*
2. *Reference 16*
3. *December 1, 1954 through November 30, 1961*

Table 2-14. Percentage Distribution of Athens, Georgia Annual Winds at 0630 Eastern Standard Time (2300-2800 Feet Above Ground)

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Wind Direction	*1-5* [(1)]	*6-10*	*11-14*	*>15*	*Totals*
N	*1.46*	*1.32*	*0.44*	*0.44*	*3.66*
NNE	*1.61*	*0.88*	*0.15*	*0*	*2.64*
NE	*1.75*	*0.88*	*0.29*	*0.15*	*3.07*
ENE	*2.19*	*2.78*	*1.02*	*0.88*	*6.87*
E	*1.90*	*4.24*	*0.44*	*0.29*	*6.87*
ESE	*2.34*	*2.78*	*0.29*	*0.44*	*5.85*
SE	*1.32*	*1.02*	*0.29*	*0.29*	*2.92*
SSE	*1.61*	*1.61*	*0.29*	*0.88*	*4.39*
S	*1.32*	*1.90*	*0.44*	*0.88*	*4.54*
SSW	*1.61*	*1.32*	*0.88*	*0.88*	*4.69*
SW	*2.92*	*3.22*	*1.02*	*1.61*	*8.77*
WSW	*1.70*	*4.09*	*1.02*	*1.02*	*7.83*
W	*2.78*	*4.53*	*2.34*	*2.49*	*12.14*
WNW	*3.95*	*4.53*	*2.92*	*2.19*	*13.59*
NW	*1.46*	*2.34*	*1.75*	*1.90*	*7.45*
NNW	*1.32*	*2.49*	*0.73*	*0.29*	*4.83*
Calm					*0.44*
	31.24	*39.93*	*14.31*	*14.63*	*100.+*

Note:

1. *Wind Speeds in Meters/Sec*
2. *Reference 16*
3. *December 1, 1954 through November 30, 1961*

Table 2-15. Average Wind Direction Change with Height, Athens, Georgia, by Lapse Rates in the Lowest 50 Meters-Two Years of Record [1]

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Height Above Ground (meters)	***Stable***	***Unstable***
50	*4.6°*	*3°*
100	*9.6°*	*6°*
150	*14.2°*	*8.4°*
200	*18.6°*	*11°*
250	*25°*	*13.6°*
300	*28°*	*17.5°*
350	*33°*	*19.2°*
400	*37°*	*21.1°*

Note:

1. *Reference 16*
2. *Years of Record are DEC 1959 - NOV 1961*

Table 2-16. 67.5° Sector Wind Direction Persistence Duration (in Hours) Greenville, S. C. WBAS
["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Direction	***Summer*** $\overline{P}$	***Summer RMSP***	***Winter*** $\overline{P}$	***Winter RMSP***	***Summer*** $\overline{P}$ **> 24Hrs.**	***Winter*** $\overline{P}$ **> 24Hrs.**
N	*1.49*	*1.82*	*3.23*	*4.67*	*0*	*0*
NNE	*2.75*	*3.51*	*3.47*	*4.65*	*0*	*0*
NE	*4.02*	*6.70*	*5.65*	*11.13*	*1-29*	*1-48*
ENE	*2.96*	*3.80*	*7.73*	*15.0*	*0*	*1-52,1-71*
E	*2.75*	*3.75*	*2.74*	*3.45*	*0*	*0*
ESE	*2.53*	*3.55*	*1.43*	*1.66*	*0*	*0*
SE	*1.35*	*1.57*	*1.38*	*1.84*	*0*	*0*
SSE	*2.04*	*2.59*	*3.00*	*3.64*	*0*	*0*
S	*1.86*	*2.79*	*1.72*	*2.13*	*0*	*0*
SSW	*2.02*	*2.70*	*2.41*	*3.01*	*0*	*0*
SW	*3.32*	*4.84*	*3.27*	*4.67*	*0*	*0*
WSW	*4.34*	*9.87*	*5.29*	*7.95*	*0*	*0*
W	*2.70*	*3.45*	*2.29*	*3.04*	*0*	*0*
WNW	*2.90*	*4.18*	*2.63*	*3.13*	*0*	*0*
NW	*2.26*	*3.01*	*1.60*	*1.86*	*0*	*0*
NNW	*1.67*	*2.10*	*2.33*	*2.99*	*0*	*0*
Calm	*1.58*	*1.77*	*1.87*	*2.28*	*0*	*0*

Table 2-17. 112.5° Sector Wind Direction Persistence Duration (in Hours) (Greenville, S. C. WBAS)
["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Wind Direction	*Summer* $\overline{P}$	*Summer RMSP*	*Winter* $\overline{P}$	*Winter RMSP*	*Summer* $\overline{P}$ > 24Hrs.	*Winter* $\overline{P}$ > 24Hrs.
N	*2.51*	*3.09*	*6.24*	*10.28*	*0*	*1-28, 1-31*
NNE	*4.49*	*6.88*	*4.67*	*6.57*	*0*	*0*
NE	*11.89*	*20.46*	*15.56*	*28.05*	*1-41, 1-57, 1-64, 1-44, 1-45*	*1-26, 1-51, 1-66, 1-101*
ENE	*5.03*	*7.53*	*10.00*	*15.70*	*0*	*1-26, 1-32, 1-36, 1-41*
E	*5.36*	*5.79*	*5.40*	*7.92*	*1-56*	*1-24*
ESE	*4.15*	*5.73*	*4.10*	*6.42*	*0*	*1-24*
SE	*2.19*	*3.86*	*4.00*	*6.50*	*0*	*0*
SSE	*2.24*	*2.79*	*3.42*	*3.84*	*0*	*0*
S	*2.76*	*3.26*	*3.92*	*6.28*	*0*	*1-29*
SSW	*3.83*	*5.32*	*2.58*	*3.17*	*0*	*0*
SW	*6.71*	*11.70*	*5.62*	*7.79*	*1-29, 1-40, 1-25, 1-37, 1-24*	*1-26*
WSW	*9.74*	*16.40*	*6.68*	*10.00*	*1-58, 1-24 1-60, 1-25*	*1-31*
W	*5.68*	*8.70*	*4.30*	*5.48*	*1-25*	*0*
WNW	*3.78*	*5.13*	*5.28*	*7.94*	*0*	*1-35*
NW	*3.71*	*4.74*	*2.83*	*3.66*	*0*	*0*
NNW	*2.47*	*3.13*	*5.20*	*8.10*	*0*	*0*

Table 2-18. Surface Temperature (°F) Clemson, S. C. (68 Years of Record) [(1)]

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Month	***Absolute Min.***	***Mean Min.***	***Mean***	***Mean Max.***	***Absolute Max.***
Jan	*-5*	*+33*	*43.6*	*54*	*80*
Feb	*-7*	*34*	*45.5*	*57*	*82*
Mar	*+10*	*40*	*52.2*	*64*	*89*
Apr	*24*	*48*	*60.5*	*73*	*93*
May	*33*	*57*	*68.9*	*81*	*100*
Jun	*42*	*65*	*76.2*	*88*	*105*
Jul	*49*	*68*	*78.6*	*89*	*104*
Aug	*52*	*67*	*77.8*	*88*	*104*
Sep	*38*	*62*	*73.1*	*84*	*104*
Oct	*23*	*50*	*62.2*	*75*	*98*
Nov	*10*	*39*	*51.4*	*64*	*86*
Dec	*+2*	*33*	*44.0*	*55*	*81*
Annual	*22.6*	*49.7*	*61.2*	*72.7*	*93.8*

Note:

1. *References 15a-f*

Table 2-19. Surface Precipitation (Inches) Clemson, S. C. (71 Years of Record) (2)

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Normals		***Month***	***Amount***
Jan	*4.88*	*Highest Annual*	*73.70 (1936)*
Feb	*5.28*	*Lowest Annual*	*37.07 (1941)*
Mar	*5.23*	*Heaviest Snowfall*	*14.1 inches (Dec 1930)*
Apr	*4.16*		
May	*3.83*	*Heaviest Rainfall - Short Periods of Time(1)*	
Jun	*4.32*	*in 1 hour*	*3.18 inches 7/17/40*
Jul	*5.09*	*in 2 hours*	*4.38 inches 7/17/40*
Aug	*4.91*	*in 3 hours*	*4.48 inches 7/17/40*
Sep	*3.64*	*in 6 hours*	*4.48 inches 7/17/40*
Oct	*3.25*	*in 12 hours*	*5.42 inches 8/12-13/40*
Nov	*3.04*	*in 24 hours*	*9.92 inches 9/29/36*
Dec	*5.27*		
Annual	*52.90*		

Note:

1. *All records were associated with tropical storms*
2. *References 15a-f.*

Table 2-20. Precipitation - Wind Statistics - Greenville, S. C. 1959-1963 (By Precipitation Intensities) [1]

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Wind Direction	***Light***		***Moderate***		***Heavy***		***Total***	
	%	***Speed***	***%***	***Speed***	***%***	***Speed***	***%***	***Speed***
N	*0.351*	*6.58*	*0.030*	*6.69*	*0.023*	*12.10*	*0.404*	*6.90*
NNE	*0.659*	*7.62*	*0.052*	*9.26*	*0.018*	*8.50*	*0.729*	*7.76*
NE	*2.526*	*9.19*	*0.219*	*10.97*	*0.082*	*10.00*	*2.827*	*9.35*
ENE	*1.381*	*8.24*	*0.128*	*9.52*	*0.034*	*7.53*	*1.543*	*8.33*
E	*0.486*	*6.16*	*0.057*	*6.28*	*0.018*	*10.25*	*0.561*	*6.30*
ESE	*0.221*	*5.45*	*0.014*	*5.83*	*0.009*	*7.25*	*0.244*	*5.54*
SE	*0.203*	*4.98*	*0.023*	*5.70*	*0.018*	*7.25*	*0.244*	*5.22*
SSE	*0.171*	*5.95*	*0.016*	*7.29*	*0.014*	*6.83*	*0.201*	*6.12*
S	*0.399*	*6.93*	*0.023*	*8.00*	*0.009*	*8.75*	*0.431*	*7.03*
SSW	*0.395*	*8.05*	*0.034*	*10.20*	*0.014*	*9.33*	*0.443*	*8.26*
SW	*0.591*	*7.39*	*0.046*	*8.40*	*0.009*	*6.50*	*0.646*	*7.45*
SWS	*0.507*	*7.36*	*0.016*	*7.43*	*0.005*	*17.50*	*0.528*	*7.46*
W	*0.278*	*7.29*	*0.014*	*7.83*	*0.014*	*13.00*	*0.306*	*7.58*
WNW	*0.157*	*6.35*	*0.001*	*8.40*	*0.016*	*9.71*	*0.184*	*6.76*
NW	*0.171*	*5.97*	*0.007*	*7.33*	*0.009*	*13.50*	*0.187*	*6.38*
NNW	*0.153*	*7.08*	*0.014*	*8.83*	*0.018*	*14.75*	*0.185*	*7.96*
Calm	*0.132*	*-*	*0.005*	*-*	*0*	*-*	*0.137*	*-*
Totals	*8.781*		*0.709*		*0.310*		*9.800*	

Note:

1. *Reference 17.*
2. *Percentages are expressed in terms of the percentage of total hours in the five-year period. Wind speeds are in knots.*

Table 2-21. Pasquill Stability Categories for Greenville, South Carolina

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

	Column 1		*Column 2*		*Column 3*		*Column 4*	
Wind Direction	P_C	$\bar{u}_C$	P_D	$\bar{u}_D$	P_{E+F}	$\bar{u}_{E+F}$	P_F	$\bar{u}_F$
N	*1.66*	*10.326*	*2.42*	*10.189*	*2.10*	*4.371*	*1.52*	*3.567*
NNE	*1.42*	*9.083*	*2.25*	*8.662*	*1.80*	*4.821*	*1.13*	*3.851*
NE	*4.01*	*9.308*	*4.13*	*8.570*	*4.07*	*4.971*	*2.34*	*3.870*
ENE	*2.90*	*8.251*	*1.91*	*7.487*	*2.34*	*4.522*	*1.73*	*3.843*
E	*1.19*	*6.800*	*0.47*	*4.714*	*1.46*	*3.674*	*1.34*	*3.468*
ESE	*0.42*	*6.680*	*0.34*	*4.450*	*0.74*	*3.045*	*0.74*	*3.045*
SE	*0.34*	*5.850*	*0.25*	*4.200*	*1.30*	*3.494*	*1.25*	*3.392*
SSE	*0.49*	*6.621*	*0.20*	*5.500*	*0.61*	*3.361*	*0.58*	*3.206*
S	*1.19*	*7.486*	*0.59*	*5.257*	*1.47*	*3.966*	*1.32*	*3.705*
SSW	*1.37*	*9.247*	*0.51*	*7.733*	*1.10*	*4.538*	*0.75*	*3.614*
SW	*3.18*	*9.883*	*1.15*	*7.824*	*2.37*	*4.614*	*1.73*	*3.941*
WSW	*4.25*	*11.570*	*2.17*	*10.164*	*1.93*	*5.491*	*0.85*	*4.180*
W	*2.12*	*10.720*	*1.34*	*9.089*	*1.85*	*4.486*	*1.39*	*3.829*
WNW	*0.90*	*11.566*	*0.81*	*8.562*	*2.27*	*4.455*	*1.76*	*3.913*
NW	*0.68*	*9.425*	*0.47*	*6.214*	*2.74*	*4.130*	*2.18*	*3.574*
NNW	*0.51*	*9.700*	*0.36*	*8.810*	*1.10*	*4.277*	*0.85*	*3.640*
Calm	*0.20*	*0*	*0.37*	*0*	*2.76*	*0*	*2.76*	*0*
Total Percent	*26.83*	*9.47*	*19.74*	*8.26*	*32.01*	*4.06*	*24.22*	*3.72*

Note:

1. *$\bar{u}$ in knots above*
2. *P in % of total observations*
3. *5904 observations equally distributed throughout the year for a two-year period from December 1, 1959 through November 30, 1961*
4. *References 20 and 21*

Table 2-22. Pasquill Stability Category and Supplemental Data for Greenville, S. C.

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Wind Direction	*Column 5*		*Column 6*		*Column 7*		*Column 8*[(4)]	
	P_L	$\bar{u}_L$	P_{fum}	$\bar{u}_{fum}$	P_{all}	$\bar{u}_{all}$	P_{5yrs}	$\bar{u}_{5yrs}$
N	*0.36*	*5.286*	*0.35*	*5.000*	*6.90*	*7.93*	*7.00*	*7.1*
NNE	*0.81*	*4.375*	*0.19*	*4.353*	*6.41*	*7.09*	*7.30*	*7.2*
NE	*1.34*	*4.861*	*0.68*	*5.417*	*14.23*	*7.25*	*14.70*	*7.5*
ENE	*1.80*	*3.849*	*0.38*	*4.912*	*9.30*	*6.19*	*8.70*	*7.0*
E	*1.32*	*4.449*	*0.23*	*4.550*	*4.67*	*4.84*	*5.50*	*5.5*
ESE	*0.86*	*4.098*	*0.07*	*4.000*	*2.40*	*4.32*	*2.60*	*4.8*
SE	*0.93*	*4.473*	*0.05*	*2.500*	*2.82*	*4.40*	*2.70*	*4.6*
SSE	*0.76*	*4.178*	*0.05*	*3.500*	*2.08*	*4.69*	*2.00*	*5.1*
S	*1.20*	*4.535*	*0.10*	*3.444*	*4.49*	*5.26*	*4.10*	*5.4*
SSW	*1.25*	*4.486*	*0.17*	*4.533*	*4.37*	*6.53*	*4.30*	*6.6*
SW	*2.27*	*4.619*	*0.32*	*4.670*	*9.24*	*6.86*	*9.50*	*7.2*
WSW	*1.10*	*4.585*	*0.39*	*5.400*	*9.80*	*9.10*	*9.50*	*8.2*
W	*0.83*	*5.020*	*0.54*	*4.896*	*6.79*	*7.37*	*6.20*	*7.2*
WNW	*0.73*	*5.302*	*0.38*	*5.176*	*5.17*	*6.44*	*4.50*	*6.6*
NW	*0.56*	*4.394*	*0.46*	*4.122*	*5.02*	*4.98*	*4.40*	*5.3*
NNW	*0.44*	*4.385*	*0.13*	*4.417*	*2.55*	*6.01*	*3.50*	*6.7*
Calm	*0.10*	*0*	*0.27*	*0*	*3.75*	*0*	*3.50*	*-*
Total Percent	*16.66*	*4.479*	*4.76*	*4.527*	*100.00*	*6.44*	*100.00*	*6.57*

Note:

1. *$\bar{u}$ in knots above.*
2. *P in % of total observations.*
3. *Based on 5904 observations equally distributed throughout the two-year period from December 1, 1959 through November 30, 1961.*
4. *Entire 5 year period 1959 - 1963.*
5. *References 20, 21, and 12.*

Table 2-23. Average Temperature Difference (°F) at Minimum Temperature Time[1]. (Paris Mountain Fire Tower - Clemson) Versus Pasquill Stability Class (From Greenville, South Carolina Hourly Observations)

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED"]

Pasquill Stability Class	***Season***				
	Winter	***Spring***	***Summer***	***Fall***	***Annual***
C	*-5.43*	*-5.75*	*-6.60*	*-4.63*	*-4.93*
D	*-1.28*	*-2.05*	*-2.28*	*0.00*	*-1.37*
E	*+3.96*	*+2.25*	*-1.59*	*+2.31*	*+1.75*
F	*+5.18*	*+4.87*	*+1.11*	*+4.18*	*+3.72*

Note:

1. *602 Days of Record from December 1, 1959 through November 30, 1961.*
2. *Reference 23.*

Table 2-24. Joint Frequency Distribution of Wind Speed and Wind Direction for each Stability Class, for Greenville-Spartanburg, South Carolina for 1975

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED."]

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.000405	0.001370	0.000000	0.000000	0.000000	0.000000	0.001775
NNE	0.000747	0.001027	0.000000	0.000000	0.000000	0.000000	0.001775
NE	0.000747	0.001027	0.000000	0.000000	0.000000	0.000000	0.001775
ENE	0.000444	0.000000	0.000000	0.000000	0.000000	0.000000	0.000444
E	0.001051	0.002055	0.000000	0.000000	0.000000	0.000000	0.003106
ESE	0.000444	0.000000	0.000000	0.000000	0.000000	0.000000	0.000444
SE	0.000444	0.000000	0.000000	0.000000	0.000000	0.000000	0.000444
SSE	0.000101	0.000342	0.000000	0.000000	0.000000	0.000000	0.000444
S	0.002281	0.001712	0.000000	0.000000	0.000000	0.000000	0.003993
SSW	0.000101	0.000342	0.000000	0.000000	0.000000	0.000000	0.000444
SW	0.000304	0.001027	0.000000	0.000000	0.000000	0.000000	0.001331
WSW	0.000444	0.000000	0.000000	0.000000	0.000000	0.000000	0.000444
W	0.000607	0.002055	0.000000	0.000000	0.000000	0.000000	0.002662
WNW	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
NW	0.000101	0.000342	0.000000	0.000000	0.000000	0.000000	0.000444
NNW	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
TOTAL	0.008219	0.011301	0.000000	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF A STABILITY = 0.019521

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH A STABILITY = 0.004452

DIRECTION	SPEED(KTS) 0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.006538	0.004795	0.000685	0.000000	0.000000	0.000000	0.012017
NNE	0.000681	0.002055	0.001370	0.000000	0.000000	0.000000	0.004105
NE	0.002972	0.004452	0.000685	0.000000	0.000000	0.000000	0.008109
ENE	0.001462	0.002055	0.000000	0.000000	0.000000	0.000000	0.003517
E	0.003359	0.007192	0.000342	0.000000	0.000000	0.000000	0.010893
ESE	0.002586	0.001712	0.000342	0.000000	0.000000	0.000000	0.004641
SE	0.001559	0.002740	0.000342	0.000000	0.000000	0.000000	0.004641
SSE	0.002731	0.002740	0.001712	0.000000	0.000000	0.000000	0.007183
S	0.002481	0.006507	0.002397	0.000000	0.000000	0.000000	0.011385
SSW	0.003025	0.002055	0.000685	0.000000	0.000000	0.000000	0.005765
SW	0.002191	0.004452	0.003767	0.000000	0.000000	0.000000	0.010410
WSW	0.000729	0.002397	0.002740	0.000000	0.000000	0.000000	0.005866
W	0.003069	0.005137	0.001712	0.000000	0.000000	0.000000	0.009918
WNW	0.001414	0.001712	0.000000	0.000000	0.000000	0.000000	0.003126
NW	0.001365	0.001370	0.000342	0.000000	0.000000	0.000000	0.003078
NNW	0.001510	0.002397	0.000685	0.000000	0.000000	0.000000	0.004593
TOTAL	0.037671	0.053767	0.017808	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF B STABILITY = 0.109247

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH B STABILITY = 0.011301

SPEED(KTS)

DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.003056	0.004452	0.004795	0.001027	0.000000	0.000000	0.013330
NNE	0.001528	0.004795	0.004110	0.000000	0.000000	0.000000	0.010432
NE	0.000685	0.004452	0.003425	0.000000	0.000000	0.000000	0.008562
ENE	0.000053	0.000342	0.004795	0.000000	0.000000	0.000000	0.005190
E	0.000474	0.003082	0.003767	0.000000	0.000000	0.000000	0.007323
ESE	0.000263	0.001712	0.000685	0.000000	0.000000	0.000000	0.002661
SE	0.000764	0.002397	0.000685	0.000000	0.000000	0.000000	0.003846
SSE	0.000764	0.002397	0.000342	0.000000	0.000000	0.000000	0.003504
S	0.001027	0.004110	0.003767	0.000000	0.000000	0.000000	0.008904
SSW	0.001264	0.003082	0.005822	0.000000	0.000000	0.000000	0.010169
SW	0.000316	0.002055	0.011986	0.001027	0.000000	0.000000	0.015385
WSW	0.000369	0.002397	0.003425	0.000685	0.000000	0.000000	0.006876
W	0.000369	0.002397	0.003767	0.000342	0.000000	0.000000	0.006876
WNW	0.000158	0.001027	0.001027	0.000000	0.000000	0.000000	0.002213
NW	0.000053	0.000342	0.000685	0.000000	0.000000	0.000000	0.001080
NNW	0.000501	0.000685	0.002055	0.000000	0.000342	0.000000	0.003583
TOTAL	0.011644	0.039726	0.055137	0.003082	0.000342	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF C STABILITY = 0.109932

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH C STABILITY = 0.006849

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.006592	0.020890	0.006849	0.006507	0.001370	0.000000	0.042208
NNE	0.004712	0.016096	0.026027	0.004452	0.000000	0.000000	0.051287
NE	0.004019	0.014041	0.020548	0.005479	0.000000	0.000000	0.044087
ENE	0.002473	0.006164	0.007534	0.000685	0.000000	0.000000	0.016856
E	0.003659	0.008904	0.003767	0.001027	0.000000	0.000000	0.017358
ESE	0.001337	0.003767	0.001370	0.000342	0.000000	0.000000	0.006816
SE	0.002364	0.002740	0.002055	0.000000	0.000000	0.000000	0.007159
SSE	0.001337	0.003767	0.001027	0.000685	0.000000	0.000000	0.006816
S	0.003709	0.009247	0.008219	0.003767	0.000000	0.000000	0.024942
SSW	0.002431	0.008562	0.010959	0.004795	0.000342	0.000342	0.027431
SW	0.002841	0.014041	0.019863	0.016781	0.002397	0.000000	0.055923
WSW	0.001487	0.004795	0.009589	0.008904	0.001712	0.000000	0.026487
W	0.002966	0.006849	0.006164	0.003082	0.002055	0.000685	0.021801
WNW	0.002314	0.002397	0.000000	0.000342	0.000000	0.000000	0.005054
NW	0.001086	0.002055	0.000342	0.001712	0.000000	0.000000	0.005196
NNW	0.002565	0.004110	0.003082	0.005822	0.000000	0.000000	0.015578
TOTAL	0.045890	0.128424	0.127397	0.064384	0.007877	0.001027	

RELATIVE FREQUENCY OF OCCURRENCE OF D STABILITY = 0.375000

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH D STABILITY = 0.022260

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.000000	0.011301	0.010616	0.000000	0.000000	0.000000	0.021918
NNE	0.000000	0.013356	0.003425	0.000000	0.000000	0.000000	0.016781
NE	0.000000	0.004795	0.002397	0.000000	0.000000	0.000000	0.007192
ENE	0.000000	0.002397	0.000342	0.000000	0.000000	0.000000	0.002740
E	0.000000	0.003082	0.000000	0.000000	0.000000	0.000000	0.003082
ESE	0.000000	0.001027	0.000000	0.000000	0.000000	0.000000	0.001027
SE	0.000000	0.001712	0.000000	0.000000	0.000000	0.000000	0.001712
SSE	0.000000	0.002740	0.000000	0.000000	0.000000	0.000000	0.002740
S	0.000000	0.008219	0.000000	0.000000	0.000000	0.000000	0.008219
SSW	0.000000	0.002740	0.001712	0.000000	0.000000	0.000000	0.004452
SW	0.000000	0.007192	0.005822	0.000000	0.000000	0.000000	0.013014
WSW	0.000000	0.003082	0.002055	0.000000	0.000000	0.000000	0.005137
W	0.000000	0.003767	0.002055	0.000000	0.000000	0.000000	0.005822
WNW	0.000000	0.000685	0.000342	0.000000	0.000000	0.000000	0.001027
NW	0.000000	0.000685	0.001712	0.000000	0.000000	0.000000	0.002397
NNW	0.000000	0.003082	0.005137	0.000000	0.000000	0.000000	0.008219
TOTAL	0.000000	0.069863	0.035616	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF E STABILITY = 0.105479

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH E STABILITY = 0.000000

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.013303	0.027740	0.000000	0.000000	0.000000	0.000000	0.041043
NNE	0.005385	0.012329	0.000000	0.000000	0.000000	0.000000	0.017713
NE	0.002281	0.003767	0.000000	0.000000	0.000000	0.000000	0.006048
ENE	0.000954	0.000342	0.000000	0.000000	0.000000	0.000000	0.001296
E	0.005021	0.001027	0.000000	0.000000	0.000000	0.000000	0.006048
ESE	0.002176	0.001712	0.000000	0.000000	0.000000	0.000000	0.003888
SE	0.002429	0.001027	0.000000	0.000000	0.000000	0.000000	0.003456
SSE	0.001222	0.001370	0.000000	0.000000	0.000000	0.000000	0.002592
S	0.005769	0.007192	0.000000	0.000000	0.000000	0.000000	0.012961
SSW	0.004204	0.006164	0.000000	0.000000	0.000000	0.000000	0.010369
SW	0.006770	0.012671	0.000000	0.000000	0.000000	0.000000	0.019442
WSW	0.003430	0.006507	0.000000	0.000000	0.000000	0.000000	0.009937
W	0.004847	0.010274	0.000000	0.000000	0.000000	0.000000	0.015121
WNW	0.001149	0.002740	0.000000	0.000000	0.000000	0.000000	0.003888
NW	0.001776	0.005137	0.000000	0.000000	0.000000	0.000000	0.006913
NNW	0.002640	0.005137	0.000000	0.000000	0.000000	0.000000	0.007777
TOTAL	0.063356	0.105137	0.000000	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF F STABILITY = 0.168493

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH F STABILITY = 0.034932

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.018437	0.000000	0.000000	0.000000	0.000000	0.000000	0.018437
NNE	0.007658	0.000000	0.000000	0.000000	0.000000	0.000000	0.007658
NE	0.005389	0.000000	0.000000	0.000000	0.000000	0.000000	0.005389
ENE	0.002836	0.000000	0.000000	0.000000	0.000000	0.000000	0.002836
E	0.001844	0.000000	0.000000	0.000000	0.000000	0.000000	0.001844
ESE	0.002269	0.000000	0.000000	0.000000	0.000000	0.000000	0.002269
SE	0.003404	0.000000	0.000000	0.000000	0.000000	0.000000	0.003404
SSE	0.002978	0.000000	0.000000	0.000000	0.000000	0.000000	0.002978
S	0.005531	0.000000	0.000000	0.000000	0.000000	0.000000	0.005531
SSW	0.005673	0.000000	0.000000	0.000000	0.000000	0.000000	0.005673
SW	0.009360	0.000000	0.000000	0.000000	0.000000	0.000000	0.009360
WSW	0.004964	0.000000	0.000000	0.000000	0.000000	0.000000	0.004964
W	0.006524	0.000000	0.000000	0.000000	0.000000	0.000000	0.006524
WNW	0.006524	0.000000	0.000000	0.000000	0.000000	0.000000	0.006524
NW	0.006666	0.000000	0.000000	0.000000	0.000000	0.000000	0.006666
NNW	0.006382	0.000000	0.000000	0.000000	0.000000	0.000000	0.006382
TOTAL	0.096438	0.000000	0.000000	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF G STABILITY = 0.096438

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH G STABILITY = 0.049863

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.049998	0.070548	0.022945	0.007534	0.001370	0.000000	0.152395
NNE	0.025738	0.049658	0.034932	0.004452	0.000000	0.000000	0.114779
NE	0.016122	0.032534	0.027055	0.005479	0.000000	0.000000	0.081191
ENE	0.008863	0.011301	0.012671	0.000685	0.000000	0.000000	0.033520
E	0.018931	0.025342	0.007877	0.001027	0.000000	0.000000	0.053177
ESE	0.008917	0.009932	0.002397	0.000342	0.000000	0.000000	0.021589
SE	0.011301	0.010616	0.003082	0.000000	0.000000	0.000000	0.025000
SSE	0.010315	0.013356	0.003082	0.000685	0.000000	0.000000	0.027438
S	.026574	0.036986	0.014384	0.003767	0.000000	0.000000	0.081711
SSW	0.019134	0.022945	0.019178	0.004795	0.000342	0.000342	0.066739
SW	0.022122	0.041438	0.041438	0.017808	0.002397	0.000000	0.125204
WSW	0.012383	0.019178	0.017808	0.009589	0.001712	0.000000	0.060671
W	0.019931	0.030479	0.013699	0.003425	0.002055	0.000685	0.070273
WNW	0.007657	0.008562	0.001370	0.000342	0.000000	0.000000	0.017931
NW	0.008917	0.009932	0.003082	0.001712	0.000000	0.000000	0.023643
NNW	0.012205	0.015411	0.010959	0.003822	0.000342	0.000000	0.044739
TOTAL	0.279109	0.408219	0.235959	0.067466	0.008219	0.001027	

TOTAL RELATIVE FREQUENCY OF OBSERVATIONS = 1.000001

TOTAL RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE = 0.150343

Table 2-25. Joint Frequency Distribution of Wind Speed and Wind Direction for each Stability Class, for Greenville-Spartanburg, South Carolina for 1968-1972

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED."]

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.000286	0.000890	0.000000	0.000000	0.000000	0.000000	0.001177
NNE	0.000566	0.000274	0.000000	0.000000	0.000000	0.000000	0.000840
NE	0.000461	0.000548	0.000000	0.000000	0.000000	0.000000	0.001008
ENE	0.000230	0.000274	0.000000	0.000000	0.000000	0.000000	0.000504
E	0.000202	0.000890	0.000000	0.000000	0.000000	0.000000	0.001092
ESE	0.000314	0.000274	0.000000	0.000000	0.000000	0.000000	0.000588
SE	0.000131	0.000205	0.000000	0.000000	0.000000	0.000000	0.000336
SSE	0.000062	0.000274	0.000000	0.000000	0.000000	0.000000	0.000336
S	0.000476	0.000616	0.000000	0.000000	0.000000	0.000000	0.001092
SSW	0.000177	0.000411	0.000000	0.000000	0.000000	0.000000	0.000588
SW	0.000345	0.000411	0.000000	0.000000	0.000000	0.000000	0.000756
WSW	0.000292	0.000548	0.000000	0.000000	0.000000	0.000000	0.000840
W	0.000355	0.000822	0.000000	0.000000	0.000000	0.000000	0.001177
WNW	0.000461	0.000548	0.000000	0.000000	0.000000	0.000000	0.001008
NW	0.000115	0.000137	0.000000	0.000000	0.000000	0.000000	0.000252
NNW	0.000047	0.000205	0.000000	0.000000	0.000000	0.000000	0.000252
TOTAL	0.004521	0.007329	0.000000	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF A STABILITY = 0.011849

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH A STABILITY = 0.002192

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.002982	0.003767	0.001096	0.000000	0.000000	0.000000	0.007845
NNE	0.001779	0.002945	0.001233	0.000000	0.000000	0.000000	0.005957
NE	0.001577	0.003973	0.002055	0.000000	0.000000	0.000000	0.007604
ENE	0.001538	0.001986	0.001781	0.000000	0.000000	0.000000	0.005305
E	0.002376	0.003699	0.001027	0.000000	0.000000	0.000000	0.007102
ESE	0.002578	0.002671	0.001096	0.000000	0.000000	0.000000	0.006345
SE	0.001551	0.002123	0.000822	0.000000	0.000000	0.000000	0.004497
SSE	0.001242	0.001233	0.000479	0.000000	0.000000	0.000000	0.002954
S	0.002510	0.002740	0.001438	0.000000	0.000000	0.000000	0.006688
SSW	0.001343	0.001507	0.001027	0.000000	0.000000	0.000000	0.003877
SW	0.001456	0.003493	0.003356	0.000000	0.000000	0.000000	0.008306
WSW	0.001570	0.003904	0.002877	0.000000	0.000000	0.000000	0.008351
W	0.001652	0.002397	0.001781	0.000000	0.000000	0.000000	0.005830
WNW	0.001284	0.002466	0.000548	0.000000	0.000000	0.000000	0.004298
NW	0.001131	0.001644	0.000822	0.000000	0.000000	0.000000	0.003597
NNW	0.001649	0.001575	0.000753	0.000000	0.000000	0.000000	0.003978
TOTAL	0.028219	0.042123	0.022192	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF B STABILITY = 0.092534

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH B STABILITY = 0.006096

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.001663	0.004384	0.004452	0.000342	0.000000	0.000000	0.010841
NNE	0.001017	0.003014	0.004041	0.000479	0.000000	0.000000	0.008552
NE	0.000606	0.003425	0.006096	0.000890	0.000000	0.000000	0.011017
ENE	0.000508	0.002329	0.004178	0.000753	0.000000	0.000000	0.007768
E	0.001017	0.003014	0.002534	0.000274	0.000000	0.000000	0.006839
ESE	0.000813	0.001575	0.001370	0.000000	0.000000	0.000000	0.003759
SE	0.000428	0.001438	0.000411	0.000068	0.000000	0.000000	0.002346
SSE	0.000347	0.001370	0.000822	0.000000	0.000000	0.000000	0.002539
S	0.001122	0.004178	0.003219	0.000342	0.000000	0.000000	0.008862
SSW	0.000633	0.002055	0.004178	0.000890	0.000000	0.000000	0.007756
SW	0.000712	0.003767	0.009658	0.001849	0.000068	0.000000	0.016054
WSW	0.000663	0.003219	0.009247	0.002055	0.000205	0.000000	0.015389
W	0.000625	0.003630	0.004041	0.000411	0.000000	0.000000	0.008707
WNW	0.000727	0.001438	0.001164	0.000342	0.000000	0.000000	0.003672
NW	0.000459	0.001781	0.002329	0.000411	0.000000	0.000000	0.004979
NNW	0.000303	0.001712	0.002534	0.000205	0.000000	0.000000	0.004755
TOTAL	0.011644	0.042329	0.060274	0.009315	0.000274	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF C STABILITY = 0.123836

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH C STABILITY = 0.004452

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.004835	0.011849	0.011644	0.009658	0.000890	0.000000	0.038876
NNE	0.004716	0.015274	0.022534	0.007055	0.000068	0.000000	0.049648
NE	0.004775	0.015753	0.028904	0.014110	0.000822	0.000000	0.064364
ENE	0.001457	0.005616	0.010411	0.003425	0.000137	0.000000	0.021046
E	0.002181	0.006507	0.004726	0.001027	0.000000	0.000000	0.014441
ESE	0.002033	0.004041	0.001507	0.000205	0.000000	0.000000	0.007786
SE	0.001949	0.003356	0.001575	0.000068	0.000000	0.000000	0.006949
SSE	0.001713	0.002055	0.001164	0.000342	0.000000	0.000000	0.005274
S	0.002665	0.007945	0.005685	0.002397	0.000000	0.000000	0.018692
SSW	0.001391	0.004452	0.007123	0.003356	0.000137	0.000068	0.016528
SW	0.003091	0.008288	0.019384	0.016507	0.002329	0.000068	0.049667
WSW	0.001843	0.008767	0.014726	0.014726	0.001301	0.000068	0.041432
W	0.001423	0.005342	0.004110	0.005137	0.000342	0.000068	0.016423
WNW	0.000926	0.002534	0.001849	0.001712	0.000137	0.000000	0.007158
NW	0.000919	0.001849	0.002055	0.003836	0.000068	0.000000	0.008727
NNW	0.001550	0.001986	0.002329	0.004932	0.000411	0.000000	0.011208
TOTAL	0.037466	0.109616	0.139726	0.088493	0.006644	0.000274	

RELATIVE FREQUENCY OF OCCURRENCE OF D STABILITY = 0.378219

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH D STABILITY = 0.013616

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.000000	0.012192	0.008356	0.000000	0.000000	0.000000	0.020548
NNE	0.000000	0.012397	0.005342	0.000000	0.000000	0.000000	0.017740
NE	0.000000	0.005959	0.002945	0.000000	0.000000	0.000000	0.008904
ENE	0.000000	0.002123	0.001027	0.000000	0.000000	0.000000	0.003151
E	0.000000	0.002055	0.000068	0.000000	0.000000	0.000000	0.002123
ESE	0.000000	0.001438	0.000205	0.000000	0.000000	0.000000	0.001644
SE	0.000000	0.001781	0.000137	0.000000	0.000000	0.000000	0.001918
SSE	0.000000	0.002260	0.000068	0.000000	0.000000	0.000000	0.002329
S	0.000000	0.006575	0.000822	0.000000	0.000000	0.000000	0.007397
SSW	0.000000	0.003425	0.001575	0.000000	0.000000	0.000000	0.005000
SW	0.000000	0.007740	0.006986	0.000000	0.000000	0.000000	0.014726
WSW	0.000000	0.007260	0.005479	0.000000	0.000000	0.000000	0.012740
W	0.000000	0.005411	0.002945	0.000000	0.000000	0.000000	0.008356
WNW	0.000000	0.002877	0.001370	0.000000	0.000000	0.000000	0.004247
NW	0.000000	0.002534	0.002466	0.000000	0.000000	0.000000	0.005000
NNW	0.000000	0.002740	0.003836	0.000000	0.000000	0.000000	0.006575
TOTAL	0.000000	0.078767	0.043630	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF E STABILITY = 0.122397

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH E STABILITY = 0.000000

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.006878	0.021096	0.000000	0.000000	0.000000	0.000000	0.029974
NNE	0.005508	0.017671	0.000000	0.000000	0.000000	0.000000	0.023180
NE	0.004399	0.009589	0.000000	0.000000	0.000000	0.000000	0.013988
ENE	0.001679	0.003356	0.000000	0.000000	0.000000	0.000000	0.005036
E	0.002296	0.001781	0.000000	0.000000	0.000000	0.000000	0.004076
ESE	0.001702	0.002055	0.000000	0.000000	0.000000	0.000000	0.003757
SE	0.002661	0.001575	0.000000	0.000000	0.000000	0.000000	0.004236
SSE	0.002181	0.002055	0.000000	0.000000	0.000000	0.000000	0.004236
S	0.005220	0.006849	0.000000	0.000000	0.000000	0.000000	0.012069
SSW	0.002616	0.005137	0.000000	0.000000	0.000000	0.000000	0.007753
SW	0.004524	0.009384	0.000000	0.000000	0.000000	0.000000	0.013908
WSW	0.004799	0.010548	0.000000	0.000000	0.000000	0.000000	0.015346
W	0.003656	0.008493	0.000000	0.000000	0.000000	0.000000	0.012149
WNW	0.002845	0.006507	0.000000	0.000000	0.000000	0.000000	0.009352
NW	0.002936	0.005616	0.000000	0.000000	0.000000	0.000000	0.008552
NNW	0.001977	0.005137	0.000000	0.000000	0.000000	0.000000	0.007114
TOTAL	0.057877	0.116849	0.000000	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF F STABILITY = 0.174726

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH F STABILITY = 0.025000

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.018437	0.000000	0.000000	0.000000	0.000000	0.000000	0.018437
NNE	0.007658	0.000000	0.000000	0.000000	0.000000	0.000000	0.007658
NE	0.005389	0.000000	0.000000	0.000000	0.000000	0.000000	0.005389
ENE	0.002836	0.000000	0.000000	0.000000	0.000000	0.000000	0.002836
E	0.001844	0.000000	0.000000	0.000000	0.000000	0.000000	0.001844
ESE	0.002269	0.000000	0.000000	0.000000	0.000000	0.000000	0.002269
SE	0.003404	0.000000	0.000000	0.000000	0.000000	0.000000	0.003404
SSE	0.002978	0.000000	0.000000	0.000000	0.000000	0.000000	0.002978
S	0.005531	0.000000	0.000000	0.000000	0.000000	0.000000	0.005531
SSW	0.005673	0.000000	0.000000	0.000000	0.000000	0.000000	0.005673
SW	0.009360	0.000000	0.000000	0.000000	0.000000	0.000000	0.009360
WSW	0.004964	0.000000	0.000000	0.000000	0.000000	0.000000	0.004964
W	0.006524	0.000000	0.000000	0.000000	0.000000	0.000000	0.006524
WNW	0.006524	0.000000	0.000000	0.000000	0.000000	0.000000	0.006524
NW	0.004666	0.000000	0.000000	0.000000	0.000000	0.000000	0.004666
NNW	0.006382	0.000000	0.000000	0.000000	0.000000	0.000000	0.006382
TOTAL	0.096438	0.000000	0.000000	0.000000	0.000000	0.000000	

RELATIVE FREQUENCY OF OCCURRENCE OF G STABILITY = 0.096438

RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE WITH G STABILITY = 0.049863

	SPEED(KTS)						
DIRECTION	0 - 3	4 - 6	7 - 10	11 - 16	17 - 21	GREATER THAN 21	TOTAL
N	0.034721	0.054178	0.025548	0.010000	0.000890	0.000000	0.125338
NNE	0.023149	0.051575	0.033151	0.007534	0.000068	0.000000	0.115478
NE	0.018681	0.039247	0.040000	0.015000	0.000822	0.000000	0.113750
ENE	0.008650	0.015685	0.017397	0.004178	0.000137	0.000000	0.046047
E	0.011142	0.017945	0.008356	0.001301	0.000000	0.000000	0.038744
ESE	0.010231	0.012055	0.004178	0.000205	0.000000	0.000000	0.026670
SE	0.010004	0.010479	0.002945	0.000137	0.000000	0.000000	0.023566
SSE	0.008451	0.009247	0.002534	0.000342	0.000000	0.000000	0.020575
S	0.018454	0.028904	0.011164	0.002740	0.000000	0.000000	0.061262
SSW	0.011199	0.016986	0.013904	0.004247	0.000137	0.000068	0.046542
SW	0.019028	0.033082	0.039384	0.018356	0.002397	0.000068	0.112316
WSW	0.015406	0.034247	0.032329	0.016781	0.001507	0.000048	0.100337
W	0.014052	0.026096	0.012877	0.005548	0.000342	0.000068	0.058984
WNW	0.011570	0.016370	0.004932	0.002055	0.000137	0.000000	0.035063
NW	0.010773	0.013562	0.007671	0.004247	0.000068	0.000000	0.036321
NNW	0.010651	0.013356	0.009452	0.005137	0.000411	0.000000	0.039007
TOTAL	0.236164	0.393013	0.265822	0.097808	0.006918	0.000274	

TOTAL RELATIVE FREQUENCY OF OBSERVATIONS = 1.000000

TOTAL RELATIVE FREQUENCY OF CALMS DISTRIBUTED ABOVE = 0.103219

Table 2-26. Joint Frequencies of Wind Direction and Speed by Stability Class (March 1970 - March 1972)

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED."]

OCONEE METEOROLOGICAL SURVEY TOWER DATA — FOR PERIOD OF MAR. 15,1970 THRU MAR. 14,1972

SUMMARY OF PASQUILL A — WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 5-16-72

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >=9.5 M/S
360.0 -N-	NO	132	15	68	35	8	4	0	2	0	0	0
	PCT	0.92	0.10	0.47	0.24	0.05	0.03	0.00	0.01	0.00	0.00	0.00
22.5 -NNE-	NO	99	5	48	26	10	5	3	2	0	0	0
	PCT	0.69	0.03	0.33	0.18	0.07	0.03	0.02	0.01	0.00	0.00	0.00
45.0 -NE-	NO	172	10	56	30	16	23	18	10	9	0	0
	PCT	1.20	0.07	0.39	0.21	0.11	0.16	0.13	0.07	0.06	0.00	0.00
67.5 -ENE-	NO	161	8	29	31	20	32	25	13	2	1	0
	PCT	1.12	0.05	0.20	0.22	0.14	0.22	0.17	0.09	0.01	0.01	0.00
90.0 -E-	NO	165	8	47	52	32	18	6	2	0	0	0
	PCT	1.15	0.05	0.33	0.36	0.22	0.13	0.04	0.01	0.00	0.00	0.00
112.5 -ESE-	NO	137	18	59	35	12	11	2	0	0	0	0
	PCT	0.96	0.13	0.41	0.24	0.08	0.08	0.01	0.00	0.00	0.00	0.00
135.0 -SE-	NO	255	15	76	81	50	22	8	2	1	0	0
	PCT	1.78	0.10	0.53	0.56	0.35	0.15	0.05	0.01	0.01	0.00	0.00
157.5 -SSE-	NO	200	5	31	63	52	31	12	4	2	0	0
	PCT	1.39	0.03	0.22	0.44	0.36	0.22	0.08	0.03	0.01	0.00	0.00
180.0 -S-	NO	270	11	49	64	56	45	27	14	2	2	0
	PCT	1.88	0.08	0.34	0.45	0.39	0.31	0.19	0.10	0.01	0.01	0.00
202.5 -SSW-	NO	374	4	53	105	86	67	32	18	8	0	1
	PCT	2.61	0.03	0.37	0.7[illegible]	0.60	0.47	0.22	0.13	0.05	0.00	0.01
225.0 -SW-	NO	388	5	81	113	60	44	27	33	17	5	3
	PCT	2.71	0.03	0.56	0.79	0.42	0.31	0.19	0.23	0.12	0.03	0.02
247.5 -WSW-	NO	204	4	50	47	17	19	16	17	14	5	15
	PCT	1.42	0.03	0.35	0.33	0.12	0.13	0.11	0.12	0.10	0.03	0.10
270.0 -W-	NO	164	8	53	35	8	22	19	16	9	9	5
	PCT	1.28	0.05	0.37	0.24	0.05	0.15	0.13	0.11	0.06	0.06	0.03
292.5 -WNW-	NO	113	7	31	15	10	6	8	8	8	6	14
	PCT	0.79	0.05	0.22	0.10	0.07	0.04	0.05	0.05	0.05	0.04	0.10
315.0 -NW-	NO	123	14	41	15	12	3	6	9	4	5	14
	PCT	0.86	0.10	0.29	0.10	0.08	0.02	0.04	0.06	0.03	0.03	0.10
337.5 -NNW-	NO	84	12	38	21	4	4	2	2	0	1	0
	PCT	0.59	0.08	0.26	0.15	0.03	0.03	0.01	0.01	0.00	0.01	0.00
CALM	NO	0										
	PCT	0.00										
TOTAL	NO	3061	149	810	758	453	356	211	152	76	34	52
	PCT	21.36	1.04	5.65	5.36	3.16	2.48	1.47	1.06	0.53	0.24	0.36

TOTAL VALID OBSERVATIONS 14333

TOTAL OBSERVATIONS 17545

OCONEE METEOROLOGICAL SURVEY TOWER DATA FOR PERIOD OF MAR. 15,1970 THRU MAR. 14,1972

SUMMARY OF PASQUILL B+C WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 5-16-72

WIND SECTOR	ITEM	SECTOR TOTAL	WIND SPEED CLASS 1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >=9.5 M/S
360.0	NO	20	3	8	3	4	0	0	2	0	0	0
-N-	PCT	0.14	0.02	0.05	0.02	0.03	0.00	0.00	0.01	0.00	0.00	0.00
22.5	NO	34	6	8	8	2	2	5	2	1	0	0
-NNE-	PCT	0.24	0.04	0.05	0.05	0.01	0.01	0.03	0.01	0.01	0.00	0.00
45.0	NO	57	3	8	9	11	7	9	6	3	1	0
-NE-	PCT	0.40	0.02	0.05	0.06	0.08	0.05	0.06	0.04	0.02	0.01	0.00
67.5	NO	52	0	10	2	12	9	7	7	3	1	1
-ENE-	PCT	0.36	0.00	0.07	0.01	0.08	0.06	0.05	0.05	0.02	0.01	0.01
90.0	NO	37	4	11	10	5	7	0	0	0	0	0
-E-	PCT	0.26	0.03	0.08	0.07	0.03	0.05	0.00	0.00	0.00	0.00	0.00
112.5	NO	32	5	9	12	4	2	0	0	0	0	0
-ESE-	PCT	0.22	0.03	0.06	0.08	0.03	0.01	0.00	0.00	0.00	0.00	0.00
135.0	NO	51	11	16	11	9	4	0	0	0	0	0
-SE-	PCT	0.36	0.08	0.11	0.08	0.06	0.03	0.00	0.00	0.00	0.00	0.00
157.5	NO	40	1	11	12	7	6	2	1	0	0	0
-SSE-	PCT	0.28	0.01	0.08	0.08	0.05	0.04	0.01	0.01	0.00	0.00	0.00
180.0	NO	48	5	9	6	8	10	4	3	2	0	1
-S-	PCT	0.33	0.03	0.06	0.04	0.05	0.07	0.03	0.02	0.01	0.00	0.01
202.5	NO	74	2	13	12	14	11	5	10	5	2	0
-SSW-	PCT	0.52	0.01	0.09	0.08	0.10	0.08	0.03	0.07	0.03	0.01	0.00
225.0	NO	75	7	9	8	18	7	11	10	2	3	0
-SW-	PCT	0.52	0.05	0.06	0.05	0.13	0.05	0.08	0.07	0.01	0.02	0.00
247.5	NO	37	3	6	4	3	2	7	2	4	0	6
-WSW-	PCT	0.26	0.02	0.04	0.03	0.02	0.01	0.05	0.01	0.03	0.00	0.04
270.0	NO	24	3	4	3	0	4	2	2	1	0	5
-W-	PCT	0.17	0.02	0.03	0.02	0.00	0.03	0.01	0.01	0.01	0.00	0.03
292.5	NO	21	2	9	0	0	0	0	3	3	1	3
-WNW-	PCT	0.15	0.01	0.06	0.00	0.00	0.00	0.00	0.02	0.02	0.01	0.02
315.0	NO	28	4	8	2	1	3	2	0	2	1	5
-NW-	PCT	0.20	0.03	0.05	0.01	0.01	0.02	0.01	0.00	0.01	0.01	0.03
337.5	NO	26	4	8	8	3	1	0	0	0	0	2
-NNW-	PCT	0.18	0.03	0.05	0.05	0.02	0.01	0.00	0.00	0.00	0.00	0.01
CALM	NO	0										
	PCT	0.00										
TOTAL	NO	656	63	147	110	101	75	54	48	26	9	23
	PCT	4.58	0.44	1.03	0.77	0.70	0.52	0.38	0.33	0.18	0.06	0.16

TOTAL VALID OBSERVATIONS 14333

TOTAL OBSERVATIONS 17545

OCONEE METEOROLOGICAL SURVEY TOWER DATA

SUMMARY OF PASQUILL D

FOR PERIOD OF MAR. 15,1970 THRU MAR. 14,1972

WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 5-16-72

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 MPH / .45-1.49 M/S	3.3-5.5 / 1.5-2.49	5.6-7.8 / 2.5-3.49	7.9-13.0 / 3.5-4.49	10.1-12.3 / 4.5-5.49	12.4-14.5 / 5.5-6.49	14.6-16.7 / 6.5-7.49	16.8-19.0 / 7.5-8.49	19.1-21.2 / 8.5-9.49	>21.2 MPH / >=9.5 M/S
360.0 -N-	NO	30	10	10	3	4	1	1	0	1	0	0
	PCT	0.21	0.07	0.07	0.02	0.03	0.01	0.01	0.00	0.01	0.00	0.00
22.5 -NNE-	NO	43	2	8	12	11	4	6	0	0	0	0
	PCT	0.30	0.01	0.05	0.08	0.08	0.03	0.04	0.00	0.00	0.00	0.00
45.0 -NE-	NO	95	7	10	18	9	18	19	11	2	1	0
	PCT	0.66	0.05	0.07	0.13	0.06	0.13	0.13	0.08	0.01	0.01	0.00
67.5 -ENE-	NO	55	4	7	10	12	13	6	0	3	0	0
	PCT	0.38	0.03	0.05	0.07	0.08	0.09	0.04	0.00	0.02	0.00	0.00
90.0 -E-	NO	63	6	20	14	8	9	4	1	1	0	0
	PCT	0.44	0.04	0.14	0.10	0.05	0.06	0.03	0.01	0.01	0.00	0.00
112.5 -ESE-	NO	26	4	12	7	3	0	0	0	0	0	0
	PCT	0.18	0.03	0.08	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00
135.0 -SE-	NO	35	7	12	7	7	2	0	0	0	0	0
	PCT	0.24	0.05	0.08	0.05	0.05	0.01	0.00	0.00	0.00	0.00	0.00
157.5 -SSE-	NO	43	6	14	10	8	3	1	1	0	0	0
	PCT	0.30	0.04	0.10	0.07	0.05	0.02	0.01	0.01	0.00	0.00	0.00
180.0 -S-	NO	44	4	7	7	4	7	9	3	3	0	0
	PCT	0.31	0.03	0.05	0.05	0.03	0.05	0.06	0.02	0.02	0.00	0.00
202.5 -SSW-	NO	65	3	9	16	8	14	9	4	1	1	0
	PCT	0.45	0.02	0.06	0111	0.05	0.10	0.06	0.03	0.01	0.01	0.00
225.0 -SW-	NO	98	2	23	25	13	9	14	11	1	0	0
	PCT	0.68	0.01	0.16	0.17	0.09	0.06	0.10	0.08	0.01	0.00	0.00
247.5 -WSW-	NO	38	5	10	2	2	5	8	2	1	0	3
	PCT	0.26	0.03	0.07	0.01	0.01	0.03	0.05	0.01	0.01	0.00	0.02
270.0 -W-	NO	51	8	10	3	5	4	6	5	3	0	7
	PCT	0.36	0.05	0.07	0.02	0.03	0.03	0.04	0.03	0.02	0.00	0.05
292.5 -WNW-	NO	24	2	6	2	1	1	2	0	3	1	6
	PCT	0.17	0.01	0.04	0.01	0.01	0.01	0.01	0.00	0.02	0.01	0.04
315.0 -NW-	NO	36	14	9	1	1	1	1	1	3	1	4
	PCT	0.25	0.10	0.06	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.03
337.5 -NNW-	NO	26	6	9	6	3	0	0	0	1	0	1
	PCT	0.18	0.04	0.06	0.04	0.02	0.00	0.00	0.00	0.01	0.00	0.01
CALM	NO	0										
	PCT	0.00										
TOTAL	NO	772	90	176	143	99	91	86	39	23	4	21
	PCT	5.38	0.63	1.23	1.00	0.69	0.63	0.60	0.27	0.16	0.03	0.15

TOTAL VALID OBSERVATIONS 14333

TOTAL OBSERVATIONS 17545

OCONEE METEOROLOGICAL SURVEY TOWER DATA FOR PERIOD OF MAR. 15,1970 THRU MAR. 14,1972

SUMMARY OF PASQUILL E WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 5-16-72

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >=9.5 M/S
360.0	NO	391	50	135	129	49	19	4	3	0	0	2
-N-	PCT	2.73	0.35	0.94	0.90	0.34	0.13	0.03	0.02	0.00	0.00	0.01
22.5	NO	392	35	92	126	64	44	21	4	6	0	0
-NNE-	PCT	2.73	0.24	0.64	0.88	0.45	0.31	0.15	0.03	0.04	0.00	0.00
45.0	NO	611	42	87	120	129	108	90	25	8	2	0
-NE-	PCT	4.26	0.29	0.61	0.84	0.90	0.75	0.63	0.17	0.05	0.01	0.00
67.5	NO	390	30	84	93	92	39	27	15	9	1	0
-ENE-	PCT	2.72	0.21	0.59	0.65	0.64	0.27	0.19	0.10	0.06	0.01	0.00
90.0	NO	313	33	92	106	46	24	8	2	0	2	0
-E-	PCT	2.18	0.23	0.64	0.74	0.32	0.17	0.05	0.01	0.00	0.01	0.00
112.5	NO	165	34	56	47	11	13	2	2	0	0	0
-ESE-	PCT	1.15	0.24	0.39	0.33	0.08	0.09	0.01	0.01	0.00	0.00	0.00
135.0	NO	182	39	57	42	21	17	3	2	0	1	0
-SE-	PCT	1.27	0.27	0.40	0.29	0.15	0.12	0.02	0.01	0.00	0.01	0.00
157.5	NO	166	21	43	44	35	20	2	1	0	0	0
-SSE-	PCT	1.16	0.15	0.30	0.31	0.24	0.14	0.01	0.01	0.00	0.00	0.00
180.0	NO	217	31	36	58	38	25	19	7	2	1	0
-S-	PCT	1.51	0.22	0.25	0.40	0.26	0.17	0.13	0.05	0.01	0.01	0.00
202.5	NO	401	18	64	75	82	73	49	28	12	0	0
-SSW-	PCT	2.80	0.13	0.45	0.52	0.57	0.51	0.34	0.20	0.08	0.00	0.00
225.0	NO	570	35	94	100	84	87	93	60	15	2	0
-SW-	PCT	3.98	0.24	0.65	0.70	0.59	0.61	0.65	0.42	0.10	0.01	0.00
247.5	NO	363	20	54	62	51	69	57	24	11	3	12
-WSW-	PCT	2.53	0.14	0.38	0.43	0.36	0.48	0.40	0.17	0.08	0.02	0.08
270.0	NO	364	39	79	37	26	33	52	32	28	16	22
-W-	PCT	2.54	0.27	0.55	0.26	0.18	0.23	0.36	0.22	0.20	0.11	0.15
292.5	NO	206	22	36	18	16	15	15	25	15	16	28
-WNW-	PCT	1.44	0.15	0.25	0.13	0.11	0.10	0.10	0.17	0.10	0.11	0.20
315.0	NO	275	36	82	50	24	15	15	8	21	5	19
-NW-	PCT	1.92	0.25	0.57	0.35	0.17	0.10	0.10	0.05	0.15	0.03	0.13
337.5	NO	233	38	89	55	19	14	8	4	0	0	6
-NNW-	PCT	1.63	0.26	0.62	0.38	0.13	0.10	0.05	0.03	0.00	0.00	0.04
CALM	NO	17										
	PCT	0.12										
TOTAL	NO	5239	523	1180	1162	787	615	465	242	127	49	89
	PCT	36.55	3.65	8.23	8.11	5.49	4.29	3.24	1.69	0.89	0.34	0.62

TOTAL VALID OBSERVATIONS 14333

TOTAL OBSERVATIONS 17545

OCONEE METEOROLOGICAL SURVEY TOWER DATA

SUMMARY OF PASQUILL F

FOR PERIOD OF MAR. 15,1970 THRU MAR. 14,1972

WIND OCCURRENCES BY SECTOR + SPEED CLASS IND. OCCURR,PERCENT)

DATE OF REPORT 5-16-72

WIND SECTOR	ITEM	SECTOR TOTAL	WIND SPEED CLASS 1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >=9.5 M/S
360.0 -N-	NO	384	38	160	150	30	6	0	0	0	0	0
	PCT	2.68	0.26	1.12	1.05	0.21	0.04	0.00	0.00	0.00	0.00	0.00
22.5 -NNE-	NO	213	24	93	76	16	1	2	1	0	0	0
	PCT	1.48	0.17	0.65	0.53	0.11	0.01	0.01	0.01	0.00	0.00	0.00
45.0 -NE-	NO	170	23	83	45	12	4	2	1	0	0	0
	PCT	1.19	0.16	0.58	0.31	0.08	0.03	0.01	0.01	0.00	0.00	0.00
67.5 -ENE-	NO	106	12	50	31	5	5	0	1	0	1	1
	PCT	0.74	0.08	0.35	0.22	0.03	0.03	0.00	0.01	0.00	0.01	0.01
90.0 -E-	NO	88	19	30	31	5	3	0	0	0	0	0
	PCT	0.61	0.13	0.21	0.22	0.03	0.02	0.00	0.00	0.00	0.00	0.00
112.5 -ESE-	NO	53	11	25	12	4	1	0	0	0	0	0
	PCT	0.37	0.08	0.17	0.08	0.03	0.01	0.00	0.00	0.00	0.00	0.00
135.0 -SE-	NO	84	9	33	26	13	3	0	0	0	0	0
	PCT	0.59	0.06	0.23	0.18	0.09	0.02	0.00	0.00	0.00	0.00	0.00
157.5 -SSE-	NO	84	10	26	26	17	5	0	0	0	0	0
	PCT	0.59	0.07	0.18	0.18	0.12	0.03	0.00	0.00	0.00	0.00	0.00
180.0 -S-	NO	108	14	27	26	14	21	6	0	0	0	0
	PCT	0.75	0.10	0.19	0.18	0.10	0.15	0.04	0.00	0.00	0.00	0.00
202.5 -SSW-	NO	124	8	31	35	24	12	9	3	1	1	0
	PCT	0.86	0.05	0.22	0.24	0.17	0.08	0.06	0.02	0.01	0.01	0.00
225.0 -SW-	NO	173	16	49	32	35	24	15	1	0	0	1
	PCT	1.21	0.11	0.34	0.22	0.24	0.17	0.10	0.01	0.00	0.00	0.01
247.5 -WSW-	NO	142	13	40	29	30	14	6	8	2	0	0
	PCT	0.99	0.09	0.28	0.20	0.21	0.10	0.04	0.05	0.01	0.00	0.00
270.0 -W-	NO	185	34	58	29	20	15	10	11	6	2	0
	PCT	1.29	0.24	0.40	0.20	0.14	0.10	0.07	0.08	0.04	0.01	0.00
292.5 -WNW-	NO	159	23	67	29	16	10	6	5	1	2	0
	PCT	1.11	0.16	0.47	0.20	0.11	0.07	0.04	0.03	0.01	0.01	0.00
315.0 -NW-	NO	246	39	123	50	19	6	4	1	2	1	1
	PCT	1.72	0.27	0.86	0.35	0.13	0.04	0.03	0.01	0.01	0.01	0.01
337.5 -NNW-	NO	337	38	155	104	30	5	4	1	0	0	0
	PCT	2.35	0.26	1.08	0.72	0.21	0.03	0.03	0.01	0.00	0.00	0.00
CALM	NO	3										
	PCT	0.02										
TOTAL	NO	2656	331	1050	731	290	135	64	33	12	7	3
	PCT	18.53	2.31	7.33	5.10	2.02	0.94	0.45	0.23	0.08	0.05	0.02

TOTAL VALID OBSERVATIONS 14333

TOTAL OBSERVATIONS 17545

OCONEE METEOROLOGICAL SURVEY TOWER DATA — FOR PERIOD OF MAR. 15,1970 THRU MAR. 14,1972

SUMMARY OF PASQUILL G — WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 5-16-72

WIND SECTOR	ITEM	SECTOR TOTAL	WIND SPEED CLASS 1.0-3.2 MPH / .45-1.49 M/S	3.3-5.5 / 1.5-2.49	5.6-7.8 / 2.5-3.49	7.9-10.0 / 3.5-4.49	10.1-12.3 / 4.5-5.49	12.4-14.5 / 5.5-6.49	14.6-16.7 / 6.5-7.49	16.8-19.0 / 7.5-8.49	19.1-21.2 / 8.5-9.49	>21.2 MPH / >=9.5 M/S
360.0	NO	370	35	144	139	46	6	0	0	0	0	0
-N-	PCT	2.58	0.24	1.00	0.97	0.32	0.04	0.00	0.00	0.00	0.00	0.00
22.5	NO	143	28	69	38	8	0	0	0	0	0	0
-NNE-	PCT	1.00	0.20	0.48	0.26	0.05	0.00	0.00	0.00	0.00	0.00	0.00
45.0	NO	97	18	41	27	8	2	1	0	0	0	0
-NE-	PCT	0.68	0.13	0.29	0.19	0.05	0.01	0.01	0.00	0.00	0.00	0.00
67.5	NO	72	10	31	18	11	2	0	0	0	0	0
-ENE-	PCT	0.50	0.07	0.22	0.13	0.08	0.01	0.00	0.00	0.00	0.00	0.00
90.0	NO	55	7	27	13	5	1	2	0	0	0	0
-E-	PCT	0.38	0.05	0.19	0.09	0.03	0.01	0.01	0.00	0.00	0.00	0.00
112.5	NO	31	6	14	7	1	2	1	0	0	0	0
-ESE-	PCT	0.22	0.04	0.10	0.05	0.01	0.01	0.01	0.00	0.00	0.00	0.00
135.0	NO	102	11	36	39	14	2	0	0	0	0	0
-SE-	PCT	0.71	0.08	0.25	0.27	0.10	0.01	0.00	0.00	0.00	0.00	0.00
157.5	NO	65	11	22	23	8	1	0	0	0	0	0
-SSE-	PCT	0.45	0.08	0.15	0.16	0.05	0.01	0.00	0.00	0.00	0.00	0.00
180.0	NO	55	8	18	17	10	1	1	0	0	0	0
-S-	PCT	0.38	0.05	0.13	0.12	0.07	0.01	0.01	0.00	0.00	0.00	0.00
202.5	NO	64	11	23	18	10	2	0	0	0	0	0
-SSW-	PCT	0.45	0.08	0.16	0.13	0.07	0.01	0.00	0.00	0.00	0.00	0.00
225.0	NO	142	19	42	46	25	8	1	0	1	0	0
-SW-	PCT	0.99	0.13	0.29	0.32	0.17	0.05	0.01	0.00	0.01	0.00	0.00
247.5	NO	111	23	40	29	10	5	3	0	0	0	1
-WSW-	PCT	0.77	0.16	0.28	0.20	0.07	0.03	0.02	0.00	0.00	0.00	0.01
270.0	NO	99	18	37	24	10	5	2	2	1	0	0
-W-	PCT	0.69	0.13	0.26	0.17	0.07	0.03	0.01	0.01	0.01	0.00	0.00
292.5	NO	110	26	52	19	4	4	3	2	0	0	0
-WNW-	PCT	0.77	0.18	0.36	0.13	0.03	0.03	0.02	0.01	0.00	0.00	0.00
315.0	NO	168	35	80	37	8	4	3	0	1	0	0
-NW-	PCT	1.17	0.24	0.56	0.26	0.05	0.03	0.02	0.00	0.01	0.00	0.00
337.5	NO	242	33	100	77	26	4	1	0	0	0	1
-NNW-	PCT	1.69	0.23	0.70	0.54	0.18	0.03	0.01	0.00	0.00	0.00	0.01
CALM	NO	3										
	PCT	0.02										
TOTAL	NO	1926	299	776	571	204	69	18	4	3	0	2
	PCT	13.44	2.09	5.41	3.98	1.42	0.34	0.13	0.03	0.02	0.00	0.01

TOTAL VALID OBSERVATIONS 14333 — TOTAL OBSERVATIONS 17545

Table 2-27. Joint Frequency Tables of Wind Direction and Speed by Atmospheric Stability - Low and High Level (January 1975 - December 1975)

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED."]

OCONEE LOW LEVEL
SUMMARY OF PASQUILL A

WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO, OCCUMH,PERCENT)
DATE OF REPORT 4-14-76

WIND SPEED CLASS

WIND SECTOR		TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0	NO	44	23	18	3	0	0	0	0	0	0	0
-N-	PCT	0.59	0.31	0.24	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22.5	NO	63	39	14	7	2	1	0	0	0	0	0
-NNE-	PCT	0.84	0.52	0.19	0.09	0.03	0.01	0.00	0.00	0.00	0.00	0.00
45.0	NO	87	24	29	22	11	1	0	0	0	0	0
-NE-	PCT	[illegible]	0.32	0.39	0.29	0.14	0.01	0.00	0.00	0.00	0.00	0.00
67.5	NO	102	16	28	22	19	11	4	1	1	0	0
-ENE-	PCT	1.36	0.21	0.37	0.29	0.25	0.14	0.05	0.01	0.01	0.00	0.00
90.0	NO	104	14	41	29	15	4	1	0	0	0	0
-E-	PCT	[illegible]	0.19	0.54	0.39	0.20	0.05	0.01	0.00	0.00	0.00	0.00
112.5	NO	66	16	29	12	7	1	1	0	0	0	0
-ESE-	PCT	0.88	0.21	0.39	0.16	0.09	0.01	0.01	0.00	0.00	0.00	0.00
135.0	NO	77	25	35	13	2	1	0	1	0	0	0
-SE-	PCT	1.03	0.33	0.47	0.17	0.03	0.01	0.00	0.01	0.00	0.00	0.00
157.5	NO	97	21	54	17	5	0	0	0	0	0	0
-SSE-	PCT	1.29	0.28	0.72	0.23	0.07	0.00	0.00	0.00	0.00	0.00	0.00
180.0	NO	132	36	47	40	4	4	1	0	0	0	0
-S-	PCT	1.76	0.48	0.63	0.53	0.05	0.05	0.01	0.00	0.00	0.00	0.00
202.5	NO	228	23	74	80	33	13	3	1	1	0	0
-SSW-	PCT	3.04	0.31	0.98	1.07	0.44	0.17	0.04	0.01	0.01	0.00	0.00
225.0	NO	208	26	86	50	14	12	12	6	2	0	0
-SW-	PCT	2.77	[illegible]	[illegible]	0.67	0.19	0.16	0.16	0.08	0.03	0.00	0.00
247.5	NO	112	22	42	22	8	5	8	3	1	1	0
-WSW-	PCT	1.49	0.29	0.56	0.29	0.11	0.07	0.11	0.04	0.01	0.01	0.00
270.0	NO	119	33	39	21	8	7	4	1	4	1	1
-W-	PCT	1.58	0.44	0.52	0.28	0.11	0.09	0.05	0.01	0.05	0.01	0.01
292.5	NO	94	23	19	10	3	10	11	8	6	3	1
-WNW-	PCT	1.25	0.31	0.25	0.13	0.04	0.13	0.14	0.11	0.08	0.04	0.01
315.0	NO	53	22	13	5	2	2	5	0	2	2	0
-NW-	PCT	0.71	0.29	0.17	0.07	0.03	0.03	0.07	0.00	0.03	0.03	0.00
337.5	NO	40	24	14	0	0	2	0	0	0	0	0
-NNW-	PCT	0.53	0.32	0.19	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
CALM	NO	4										
	PCT	0.05										
TOTAL	NO	1626	387	562	353	133	74	50	21	17	7	2
	PCT	21.65	5.15	7.75	4.70	1.77	0.98	0.67	0.28	0.23	0.09	0.03

AVERAGE WIND SPEED 5.73 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE LOW LEVEL
SUMMARY OF PASQUILL C

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR.PERCENT)
DATE OF REPORT 4-14-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0 -N-	NO	28	12	13	2	0	0	1	0	0	0	0
	PCT	0.37	0.16	0.17	0.03	0.00	0.00	0.01	0.00	0.00	0.00	0.00
22.5 -NNE-	NO	18	8	4	3	2	0	0	0	0	0	1
	PCT	0.24	0.11	0.05	0.04	0.03	0.00	0.00	0.00	0.00	0.00	0.01
45.0 -NE-	NO	27	8	5	6	2	5	1	0	0	0	0
	PCT	0.36	0.11	0.07	0.08	0.03	0.07	0.01	0.00	0.00	0.00	0.00
67.5 -ENE-	NO	34	4	7	7	7	9	0	0	0	0	0
	PCT	0.45	0.05	0.09	0.09	0.09	0.12	0.00	0.00	0.00	0.00	0.00
90.0 -E-	NO	29	3	13	10	1	1	1	0	0	0	0
	PCT	0.39	0.04	0.17	0.13	0.01	0.01	0.01	0.00	0.00	0.00	0.00
112.5 -ESE-	NO	10	2	4	1	2	1	0	0	0	0	0
	PCT	0.13	0.03	0.05	0.01	0.03	0.01	0.00	0.00	0.00	0.00	0.00
135.0 -SE-	NO	26	8	16	2	0	0	0	0	0	0	0
	PCT	0.35	0.11	0.21	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157.5 -SSE-	NO	29	10	8	7	3	1	0	0	0	0	0
	PCT	0.39	0.13	0.11	0.09	0.04	0.01	0.00	0.00	0.00	0.00	0.00
180.0 -S-	NO	27	5	11	4	3	4	0	0	0	0	0
	PCT	0.36	0.07	0.14	0.05	0.04	0.05	0.00	0.00	0.00	0.00	0.00
202.5 -SSW-	NO	55	8	14	19	7	7	0	0	0	0	0
	PCT	0.73	0.11	0.19	0.25	0.09	0.09	0.00	0.00	0.00	0.00	0.00
225.0 -SW-	NO	43	9	11	8	4	5	4	0	1	1	0
	PCT	0.57	0.12	0.14	0.11	0.05	0.07	0.05	0.00	0.01	0.01	0.00
247.5 -WSW-	NO	29	12	7	4	2	2	2	0	0	0	0
	PCT	0.39	0.16	0.09	0.05	0.03	0.03	0.03	0.00	0.00	0.00	0.00
270.0 -W-	NO	20	5	5	1	2	1	2	1	1	1	1
	PCT	0.27	0.07	0.07	0.01	0.03	0.01	0.03	0.01	0.01	0.01	0.01
292.5 -WNW-	NO	17	4	2	1	1	0	3	3	1	1	1
	PCT	0.23	0.05	0.03	0.01	0.01	0.00	0.04	0.04	0.01	0.01	0.01
315.0 -NW-	NO	17	4	4	1	2	2	2	2	0	0	0
	PCT	0.23	0.05	0.05	0.01	0.03	0.03	0.03	0.03	0.00	0.00	0.00
337.5 -NNW-	NO	3	2	1	0	0	0	0	0	0	0	0
	PCT	0.04	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CALM	NO	1										
	PCT	0.01										
TOTAL	NO	412	104	125	76	38	38	16	6	3	3	3
	PCT	5.49	1.38	1.66	1.01	0.51	0.51	0.21	0.08	0.04	0.04	0.04

AVERAGE WIND SPEED 6.14 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE LOW LEVEL
SUMMARY OF PASQUILL D

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR.PERCENT)
DATE OF REPORT 4-14-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0 -N-	NO	61	18	31	9	1	0	1	1	0	0	0
	PCT	0.81	0.24	0.41	0.12	0.01	0.00	0.01	0.01	0.00	0.00	0.00
22.5 -NNE-	NO	53	12	22	17	2	0	0	0	0	0	0
	PCT	0.71	0.16	0.29	0.23	0.03	0.00	0.00	0.00	0.00	0.00	0.00
45.0 -NE-	NO	116	20	31	32	21	6	6	0	0	0	0
	PCT	1.54	0.27	0.41	0.43	0.28	0.08	0.08	0.00	0.00	0.00	0.00
67.5 -ENE-	NO	109	6	29	38	23	9	2	2	0	0	0
	PCT	1.45	0.08	0.39	0.51	0.31	0.12	0.03	0.03	0.00	0.00	0.00
90.0 -E-	NO	81	11	38	24	5	2	1	0	0	0	0
	PCT	1.08	0.14	0.51	0.32	0.07	0.03	0.01	0.00	0.00	0.00	0.00
112.5 -ESE-	NO	43	7	23	11	1	0	1	0	0	0	0
	PCT	0.57	0.09	0.31	0.14	0.01	0.00	0.01	0.00	0.00	0.00	0.00
135.0 -SE-	NO	57	16	28	11	2	0	0	0	0	0	0
	PCT	0.76	0.21	0.37	0.14	0.03	0.00	0.00	0.00	0.00	0.00	0.00
157.5 -SSE-	NO	52	15	23	10	4	0	0	0	0	0	0
	PCT	0.69	0.20	0.31	0.13	0.05	0.00	0.00	0.00	0.00	0.00	0.00
180.0 -S-	NO	80	13	32	26	6	1	1	0	1	0	0
	PCT	1.07	0.17	0.43	0.34	0.08	0.01	0.01	0.00	0.01	0.00	0.00
202.5 -SSW-	NO	96	17	26	24	14	10	3	0	1	0	1
	PCT	1.28	0.23	0.34	0.32	0.19	0.13	0.04	0.00	0.01	0.00	0.01
225.0 -SW-	NO	139	18	38	37	25	12	5	4	0	0	0
	PCT	1.85	0.24	0.51	0.49	0.33	0.16	0.07	0.05	0.00	0.00	0.00
247.5 -WSW-	NO	72	14	18	20	6	4	5	4	0	0	1
	PCT	0.96	0.19	0.24	0.27	0.08	0.05	0.07	0.05	0.00	0.00	0.01
270.0 -W-	NO	86	28	15	7	6	13	8	3	3	1	2
	PCT	1.15	0.37	0.20	0.09	0.08	0.17	0.11	0.04	0.04	0.01	0.03
292.5 -WNW-	NO	55	15	9	1	3	8	8	4	3	3	1
	PCT	0.73	0.20	0.12	0.01	0.04	0.11	0.11	0.05	0.04	0.04	0.01
315.0 -NW-	NO	43	14	12	3	2	2	5	4	1	0	0
	PCT	0.57	0.19	0.16	0.04	0.03	0.03	0.07	0.05	0.01	0.00	0.00
337.5 -NNW-	NO	49	26	18	2	1	1	1	0	0	0	0
	PCT	0.65	0.34	0.24	0.03	0.01	0.01	0.01	0.00	0.00	0.00	0.00
CALM	NO	4										
	PCT	0.05										
TOTAL	NO	1192	250	393	272	122	68	47	22	9	4	5
	PCT	15.87	3.33	5.23	3.62	1.62	0.90	0.63	0.29	0.12	0.05	0.07

AVERAGE WIND SPEED 6.07 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE LOW LEVEL
SUMMARY OF PASQUILL E

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 4-14-76

WIND SECTOR	ITEM	SECTOR TOTAL	WIND SPEED CLASS 1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0 -N-	NO	194	60	95	30	7	2	0	0	0	0	0
	PCT	2.58	0.80	1.26	0.40	0.09	0.03	0.00	0.00	0.00	0.00	0.00
22.5 -NNE-	NO	117	38	47	24	5	3	0	0	0	0	0
	PCT	1.56	0.51	0.63	0.32	0.07	0.04	0.00	0.00	0.00	0.00	0.00
45.0 -NE-	NO	179	28	57	56	30	6	0	0	0	0	0
	PCT	2.38	0.37	0.76	0.77	0.40	0.08	0.00	0.00	0.00	0.00	0.00
67.5 -ENE-	NO	124	22	42	31	21	5	1	2	0	0	0
	PCT	1.65	0.29	0.56	0.41	0.28	0.07	0.01	0.03	0.00	0.00	0.00
90.0 -E-	NO	84	18	40	20	3	1	1	0	0	0	1
	PCT	1.12	0.24	0.53	0.27	0.04	0.01	0.01	0.00	0.00	0.00	0.01
112.5 -ESE-	NO	44	14	21	7	2	0	0	0	0	0	0
	PCT	0.59	0.19	0.28	0.09	0.03	0.00	0.00	0.00	0.00	0.00	0.00
135.0 -SE-	NO	54	16	26	11	0	0	0	0	0	1	0
	PCT	0.72	0.21	0.34	0.14	0.00	0.00	0.00	0.00	0.00	0.01	0.00
157.5 -SSE-	NO	97	24	34	31	7	0	0	0	1	0	0
	PCT	1.29	0.32	0.45	0.41	0.09	0.00	0.00	0.00	0.01	0.00	0.00
180.0 -S-	NO	111	24	37	34	10	4	1	1	0	0	0
	PCT	1.48	0.32	0.49	0.45	0.13	0.05	0.01	0.01	0.00	0.00	0.00
202.5 -SSW-	NO	113	23	29	27	17	13	4	0	0	0	0
	PCT	1.50	0.31	0.39	0.36	0.23	0.17	0.05	0.00	0.00	0.00	0.00
225.0 -SW-	NO	162	18	39	41	36	17	8	2	0	0	1
	PCT	2.16	0.24	0.52	0.54	0.48	0.23	0.11	0.03	0.00	0.00	0.01
247.5 -WSW-	NO	127	25	37	27	15	11	10	1	0	1	0
	PCT	1.69	0.33	0.49	0.36	0.20	0.14	0.13	0.01	0.00	0.01	0.00
270.0 -W-	NO	133	23	43	21	11	16	12	4	0	2	1
	PCT	1.77	0.31	0.57	0.28	0.14	0.21	0.16	0.05	0.00	0.03	0.01
292.5 -WNW-	NO	115	26	20	13	27	7	8	9	3	1	1
	PCT	1.53	0.34	0.27	0.17	0.36	0.09	0.11	0.12	0.04	0.01	0.01
315.0 -NW-	NO	100	38	29	5	9	12	6	1	0	0	0
	PCT	1.33	0.51	0.39	0.07	0.12	0.16	0.08	0.01	0.00	0.00	0.00
337.5 -NNW-	NO	106	37	45	15	6	3	0	0	0	0	0
	PCT	1.41	0.49	0.60	0.20	0.08	0.04	0.00	0.00	0.00	0.00	0.00
CALM	NO	6										
	PCT	0.08										
TOTAL	NO	1860	434	641	395	206	100	51	20	4	5	4
	PCT	24.77	5.78	8.53	5.26	2.74	1.33	0.68	0.27	0.05	0.07	0.05

AVERAGE WIND SPEED 5.72 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE LOW LEVEL
SUMMARY OF PASQUILL F

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 4-14-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0 -N-	NO	314	127	145	36	5	1	0	0	0	0	0
	PCT	4.18	1.69	1.93	0.48	0.07	0.01	0.00	0.00	0.00	0.00	0.00
22.5 -NNE-	NO	116	42	43	27	4	0	0	0	0	0	0
	PCT	1.54	0.56	0.57	0.36	0.05	0.00	0.00	0.00	0.00	0.00	0.00
45.0 -NE-	NO	191	37	56	52	30	13	3	0	0	0	0
	PCT	2.54	0.49	0.74	0.69	0.40	0.17	0.04	0.00	0.00	0.00	0.00
67.5 -ENE-	NO	105	18	32	23	26	4	2	0	0	0	0
	PCT	1.40	0.24	0.43	0.31	0.34	0.05	0.03	0.00	0.00	0.00	0.00
90.0 -E-	NO	75	18	32	13	6	4	1	0	0	1	0
	PCT	1.00	0.24	0.43	0.17	0.08	0.05	0.01	0.00	0.00	0.01	0.00
112.5 -ESE-	NO	55	22	18	9	4	0	1	1	0	0	0
	PCT	0.73	0.29	0.24	0.12	0.05	0.00	0.01	0.01	0.00	0.00	0.00
135.0 -SE-	NO	54	17	19	10	2	0	3	1	1	0	1
	PCT	0.72	0.23	0.25	0.13	0.03	0.00	0.04	0.01	0.01	0.00	0.01
157.5 -SSE-	NO	82	20	22	27	8	1	3	0	1	0	0
	PCT	1.09	0.27	0.29	0.36	0.11	0.01	0.04	0.00	0.01	0.00	0.00
180.0 -S-	NO	85	16	27	29	10	2	0	1	0	0	0
	PCT	1.13	0.21	0.36	0.39	0.13	0.03	0.00	0.01	0.00	0.00	0.00
202.5 -SSW-	NO	58	18	16	12	3	7	1	1	0	0	0
	PCT	0.77	0.24	0.21	0.16	0.04	0.09	0.01	0.01	0.00	0.00	0.00
225.0 -SW-	NO	72	24	21	14	5	4	2	1	1	0	0
	PCT	0.96	0.32	0.28	0.19	0.07	0.05	0.03	0.01	0.01	0.00	0.00
247.5 -WSW-	NO	59	17	17	14	6	4	1	0	0	0	0
	PCT	0.79	0.23	0.23	0.19	0.08	0.05	0.01	0.00	0.00	0.00	0.00
270.0 -W-	NO	67	33	15	8	5	4	2	0	0	0	0
	PCT	0.89	0.44	0.20	0.11	0.07	0.05	0.03	0.00	0.00	0.00	0.00
292.5 -WNW-	NO	102	45	24	8	11	7	6	1	0	0	0
	PCT	1.36	0.60	0.32	0.11	0.14	0.09	0.08	0.01	0.00	0.00	0.00
315.0 -NW-	NO	111	51	46	5	4	5	0	0	0	0	0
	PCT	1.48	0.68	0.61	0.07	0.05	0.07	0.00	0.00	0.00	0.00	0.00
337.5 -NNW-	NO	174	84	76	10	3	1	0	0	0	0	0
	PCT	2.32	1.12	1.01	0.13	0.04	0.01	0.00	0.00	0.00	0.00	0.00
CALM	NO	6										
	PCT	0.08										
TOTAL	NO	1720	589	609	297	132	57	25	6	3	1	1
	PCT	22.90	7.84	8.11	3.95	1.76	0.76	0.33	0.08	0.04	0.01	0.01

AVERAGE WIND SPEED 4.81 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE LOW LEVEL
SUMMARY OF PASQUILL G

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR.PERCENT)

DATE OF REPORT 4-14-76

WIND SECTOR	ITEM	SECTOR TOTAL	WIND SPEED CLASS 1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0 -N-	NO	170	53	102	13	1	0	0	0	0	0	1
	PCT	2.26	0.70	1.36	0.17	0.01	0.00	0.00	0.00	0.00	0.00	0.01
22.5 -NNE-	NO	83	37	38	8	0	0	0	0	0	0	0
	PCT	1.11	0.49	0.51	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45.0 -NE-	NO	45	20	18	6	1	0	0	0	0	0	0
	PCT	0.60	0.27	0.24	0.08	0.01	0.00	0.00	0.00	0.00	0.00	0.00
67.5 -ENE-	NO	17	7	6	1	2	0	1	0	0	0	0
	PCT	0.23	0.09	0.08	0.01	0.03	0.00	0.01	0.00	0.00	0.00	0.00
90.0 -E-	NO	12	8	3	0	1	0	0	0	0	0	0
	PCT	0.16	0.11	0.04	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
112.5 -ESE-	NO	13	5	5	3	0	0	0	0	0	0	0
	PCT	0.17	0.07	0.07	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
135.0 -SE-	NO	18	7	8	3	0	0	0	0	0	0	0
	PCT	0.24	0.09	0.11	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157.5 -SSE-	NO	21	9	6	4	1	1	0	0	0	0	0
	PCT	0.28	0.12	0.08	0.05	0.01	0.01	0.00	0.00	0.00	0.00	0.00
180.0 -S-	NO	33	13	10	6	3	1	0	0	0	0	0
	PCT	0.44	0.17	0.13	0.08	0.04	0.01	0.00	0.00	0.00	0.00	0.00
202.5 -SSW-	NO	21	7	9	5	0	0	0	0	0	0	0
	PCT	0.28	0.09	0.12	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
225.0 -SW-	NO	24	8	9	6	1	0	0	0	0	0	0
	PCT	0.32	0.11	0.12	0.08	0.01	0.00	0.00	0.00	0.00	0.00	0.00
247.5 -WSW-	NO	27	15	7	4	1	0	0	0	0	0	0
	PCT	0.36	0.20	0.09	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00
270.0 -W-	NO	29	16	11	1	1	0	0	0	0	0	0
	PCT	0.39	0.21	0.14	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
292.5 -WNW-	NO	33	21	7	1	2	1	1	0	0	0	0
	PCT	0.44	0.28	0.09	0.01	0.03	0.01	0.01	0.00	0.00	0.00	0.00
315.0 -NW-	NO	48	25	21	0	1	1	0	0	0	0	0
	PCT	0.64	0.33	0.28	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
337.5 -NNW-	NO	80	32	43	5	0	0	0	0	0	0	0
	PCT	1.07	0.43	0.57	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CALM	NO	5										
	PCT	0.07										
TOTAL	NO	674	283	303	66	15	4	2	0	0	0	1
	PCT	8.97	3.77	4.03	0.88	0.20	0.05	0.03	0.00	0.00	0.00	0.01

AVERAGE WIND SPEED 3.84 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE LOW LEVEL
SUMMARY OF PASQUILL A+C+D+E+F+G

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 4-14-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 MPH / .45-1.49 M/S	3.3-5.5 MPH / 1.5-2.49 M/S	5.6-7.8 MPH / 2.5-3.44 M/S	7.9-10.0 MPH / 3.5-4.49 M/S	10.1-12.3 MPH / 4.5-5.49 M/S	12.4-14.5 MPH / 5.5-6.49 M/S	14.6-16.7 MPH / 6.5-7.49 M/S	16.8-19.0 MPH / 7.5-8.49 M/S	19.1-21.2 MPH / 8.5-9.49 M/S	>21.2 MPH / >9.5 M/S
360.0 -N-	NO	811	293	404	93	14	3	2	1	0	0	1
	PCT	10.80	3.90	5.38	1.24	0.19	0.04	0.03	0.01	0.00	0.00	0.01
22.5 -NNE-	NO	450	176	168	86	15	4	0	0	0	0	1
	PCT	5.99	2.34	2.24	1.14	0.20	0.05	0.00	0.00	0.00	0.00	0.01
45.0 -NE-	NO	645	137	196	176	95	31	10	0	0	0	0
	PCT	8.59	1.82	2.61	2.34	1.26	0.41	0.13	0.00	0.00	0.00	0.00
67.5 -ENE-	NO	491	73	144	122	98	38	10	5	1	0	0
	PCT	6.54	0.97	1.92	1.62	1.30	0.51	0.13	0.07	0.01	0.00	0.00
90.0 -E-	NO	385	72	167	96	31	12	5	0	0	1	1
	PCT	5.13	0.96	2.22	1.28	0.41	0.16	0.07	0.00	0.00	0.01	0.01
112.5 -ESE-	NO	231	66	100	43	16	2	3	1	0	0	0
	PCT	3.08	0.88	1.33	0.57	0.21	0.03	0.04	0.01	0.00	0.00	0.00
135.0 -SE-	NO	286	89	132	50	6	1	3	2	1	1	1
	PCT	3.81	1.18	1.76	0.67	0.08	0.01	0.04	0.03	0.01	0.01	0.01
157.5 -SSE-	NO	378	99	147	96	28	3	3	0	2	0	0
	PCT	5.03	1.32	1.96	1.28	0.37	0.04	0.04	0.00	0.03	0.00	0.00
180.0 -S-	NO	468	107	164	139	36	16	3	2	1	0	0
	PCT	6.23	1.42	2.18	1.85	0.48	0.21	0.04	0.03	0.01	0.00	0.00
202.5 -SSW-	NO	571	96	168	167	74	50	11	2	2	0	1
	PCT	7.60	1.28	2.24	2.22	0.98	0.67	0.14	0.03	0.03	0.00	0.01
225.0 -SW-	NO	648	103	204	156	85	50	31	13	4	1	1
	PCT	8.63	1.37	2.72	2.08	1.13	0.67	0.41	0.17	0.05	0.01	0.01
247.5 -WSW-	NO	426	105	128	91	38	26	26	8	1	2	1
	PCT	5.67	1.40	1.70	1.21	0.51	0.34	0.34	0.11	0.01	0.03	0.01
270.0 -W-	NO	454	138	124	59	33	41	28	9	8	5	5
	PCT	6.05	1.84	1.70	0.78	0.44	0.54	0.37	0.12	0.11	0.07	0.07
292.5 -WNW-	NO	416	134	81	34	47	33	37	25	13	8	4
	PCT	5.54	1.78	1.05	0.45	0.63	0.44	0.49	0.33	0.17	0.11	0.05
315.0 -NW-	NO	372	154	125	19	20	24	18	7	3	2	0
	PCT	4.95	2.05	1.66	0.25	0.27	0.32	0.24	0.09	0.04	0.03	0.00
337.5 -NNW-	NO	452	205	197	32	10	7	1	0	0	0	0
	PCT	6.02	2.73	2.62	0.43	0.13	0.09	0.01	0.00	0.00	0.00	0.00
CALM	NO	26										
	PCT	0.34										
TOTAL	NO	7484	2047	2653	1459	646	341	191	75	36	20	16
	PCT	99.65	27.26	35.33	19.43	8.60	4.54	2.54	1.00	0.48	0.27	0.21

AVERAGE WIND SPEED 5.42 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE HIGH LEVEL
SUMMARY OF PASQUILL A

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 5-18-76

WIND SECTOR	ITEM	SECTOR TOTAL	WIND SPEED CLASS 1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0 -N-	NO PCT	44 0.59	13 0.17	22 0.29	6 0.08	3 0.04	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00
22.5 -NNE-	NO PCT	63 0.84	20 0.27	30 0.40	7 0.09	3 0.04	2 0.03	0 0.00	1 0.01	0 0.00	0 0.00	0 0.00
45.0 -NE-	NO PCT	87 1.16	11 0.14	29 0.39	20 0.27	15 0.20	10 0.13	1 0.01	1 0.01	0 0.00	0 0.00	0 0.00
67.5 -ENE-	NO PCT	102 1.36	8 0.11	22 0.29	18 0.24	19 0.25	17 0.23	12 0.16	2 0.03	2 0.03	1 0.01	1 0.01
90.0 -E-	NO PCT	104 1.38	7 0.09	26 0.34	30 0.40	22 0.29	14 0.19	4 0.05	1 0.01	0 0.00	0 0.00	0 0.00
112.5 -ESE-	NO PCT	66 0.88	7 0.09	26 0.34	18 0.24	6 0.08	6 0.08	2 0.03	1 0.01	0 0.00	0 0.00	0 0.00
135.0 -SE-	NO PCT	77 1.03	8 0.11	37 0.49	21 0.28	7 0.09	2 0.03	1 0.01	0 0.00	1 0.01	0 0.00	0 0.00
157.5 -SSE-	NO PCT	97 1.29	11 0.14	37 0.49	37 0.49	7 0.09	5 0.07	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00
180.0 -S-	NO PCT	132 1.76	15 0.20	47 0.63	39 0.52	22 0.29	4 0.05	4 0.05	1 0.01	0 0.00	0 0.00	0 0.00
202.5 -SSW-	NO PCT	228 3.04	13 0.17	44 0.58	74 0.98	49 0.65	27 0.36	11 0.14	7 0.09	2 0.03	0 0.00	1 0.01
225.0 -SW-	NO PCT	208 2.77	8 0.11	63 0.84	61 0.81	31 0.41	12 0.16	8 0.11	12 0.16	7 0.09	4 0.05	2 0.03
247.5 -WSW-	NO PCT	112 1.49	14 0.19	25 0.33	32 0.43	15 0.20	8 0.11	2 0.03	4 0.05	8 0.11	2 0.03	2 0.03
270.0 -W-	NO PCT	119 1.58	20 0.27	36 0.48	23 0.31	15 0.20	7 0.09	6 0.08	1 0.01	5 0.07	0 0.00	6 0.08
292.5 -WNW-	NO PCT	94 1.25	14 0.19	23 0.31	10 0.13	6 0.08	2 0.03	2 0.03	13 0.17	8 0.11	6 0.08	10 0.13
315.0 -NW-	NO PCT	53 0.71	14 0.19	15 0.20	9 0.12	2 0.03	2 0.03	2 0.03	1 0.01	4 0.05	0 0.00	4 0.05
337.5 -NNW-	NO PCT	40 0.53	11 0.14	24 0.32	3 0.04	0 0.00	0 0.00	0 0.00	2 0.03	0 0.00	0 0.00	0 0.00
CALM	NO PCT	4 0.05										
TOTAL	NO PCT	1626 21.65	194 2.58	506 6.74	408 5.43	222 2.96	118 1.57	55 0.73	47 0.63	37 0.49	13 0.17	26 0.34

AVERAGE WIND SPEED 7.17 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE HIGH LEVEL
SUMMARY OF PASQUILL C

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR, PERCENT)

DATE OF REPORT 5-18-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
			WIND SPEED CLASS									
360.0 -N-	NO	28	9	9	9	0	0	0	1	0	0	0
	PCT	0.37	0.12	0.12	0.12	0.00	0.00	0.00	0.01	0.00	0.00	0.00
22.5 -NNE-	NO	18	6	6	4	1	1	0	0	0	0	0
	PCT	0.24	0.08	0.08	0.05	0.01	0.01	0.00	0.00	0.00	0.00	0.00
45.0 -NE-	NO	27	6	4	5	4	1	4	2	1	0	0
	PCT	0.36	0.08	0.05	0.07	0.05	0.01	0.05	0.03	0.01	0.00	0.00
67.5 -ENE-	NO	34	3	3	6	6	7	7	2	0	0	0
	PCT	0.45	0.04	0.04	0.08	0.08	0.09	0.09	0.03	0.00	0.00	0.00
90.0 -E-	NO	29	2	8	7	9	1	1	1	0	0	0
	PCT	0.3[illegible]	0.03	0.11	0.09	0.12	0.01	0.01	0.01	0.00	0.00	0.00
112.5 -ESE-	NO	10	1	1	4	1	2	1	0	0	0	0
	PCT	0.13	0.01	0.01	0.05	0.01	0.03	0.01	0.00	0.00	0.00	0.00
135.0 -SE-	NO	26	6	8	11	1	0	0	0	0	0	0
	PCT	0.35	0.08	0.11	0.14	0.01	0.00	0.00	0.00	0.00	0.00	0.00
157.5 -SSE-	NO	29	3	12	5	5	3	1	0	0	0	0
	PCT	0.39	0.04	0.16	0.07	0.07	0.04	0.01	0.00	0.00	0.00	0.00
180.0 -S-	NO	27	3	3	11	3	3	4	0	0	0	0
	PCT	0.36	0.04	0.04	0.14	0.04	0.04	0.05	0.00	0.00	0.00	0.00
202.5 -SSW-	NO	55	5	11	11	14	7	7	0	0	0	0
	PCT	0.73	0.07	0.14	0.14	0.19	0.09	0.09	0.00	0.00	0.00	0.00
225.0 -SW-	NO	43	7	10	7	4	4	4	3	2	0	2
	PCT	0.57	0.09	0.13	0.09	0.05	0.05	0.05	0.04	0.03	0.00	0.03
247.5 -WSW-	NO	29	6	9	5	3	2	2	1	1	0	0
	PCT	0.39	0.08	0.12	0.07	0.04	0.03	0.03	0.01	0.01	0.00	0.00
270.0 -W-	NO	20	5	4	1	1	2	1	1	2	0	3
	PCT	0.27	0.07	0.05	0.01	0.01	0.03	0.01	0.01	0.03	0.00	0.04
292.5 -WNW-	NO	17	2	3	2	0	1	0	1	2	3	3
	PCT	0.23	0.03	0.04	0.03	0.00	0.01	0.00	0.01	0.03	0.04	0.04
315.0 -NW-	NO	17	3	2	3	1	2	2	1	2	1	0
	PCT	0.23	0.04	0.03	0.04	0.01	0.03	0.03	0.01	0.03	0.01	0.00
337.5 -NNW-	NO	3	2	1	0	0	0	0	0	0	0	0
	PCT	0.04	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CALM	NO	1										
	PCT	0.01										
TOTAL	NO	412	69	94	91	53	36	34	13	10	4	8
	PCT	5.49	0.92	1.25	1.21	0.70	0.48	0.45	0.17	0.13	0.05	0.11

AVERAGE WIND SPEED 7.68 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

SUMMARY OF OCONEE HIGH LEVEL PASQUILL D

WIND OCCURRENCES BY SECTOR • SPEED CLASS (NO. OCCURR.PERCENT) FOR 1975

DATE OF REPORT 5-18-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0 -N-	NO	61	10	25	18	5	1	0	0	2	0	0
	PCT	0.81	0.13	0.33	0.24	0.07	0.01	0.00	0.00	0.03	0.00	0.00
22.5 -NNE-	NO	53	3	23	14	11	2	0	0	0	0	0
	PCT	0.71	0.04	0.31	0.19	0.14	0.03	0.00	0.00	0.00	0.00	0.00
45.0 -NE-	NO	116	14	18	31	23	15	8	6	1	0	0
	PCT	1.54	0.19	0.24	0.41	0.31	0.20	0.11	0.08	0.01	0.00	0.00
67.5 -ENE-	NO	109	4	20	24	25	21	7	5	2	1	0
	PCT	1.45	0.05	0.27	0.32	0.33	0.28	0.09	0.07	0.03	0.01	0.00
90.0 -E-	NO	81	3	27	24	19	5	2	0	1	0	0
	PCT	1.08	0.04	0.36	0.32	0.25	0.07	0.03	0.00	0.01	0.00	0.00
112.5 -ESE-	NO	44	4	15	17	7	0	0	1	0	0	0
	PCT	0.59	0.05	0.20	0.23	0.09	0.00	0.00	0.01	0.00	0.00	0.00
135.0 -SE-	NO	57	12	18	22	3	2	0	0	0	0	0
	PCT	0.76	0.16	0.24	0.29	0.04	0.03	0.00	0.00	0.00	0.00	0.00
157.5 -SSE-	NO	52	9	15	21	3	4	0	0	0	0	0
	PCT	0.69	0.12	0.20	0.28	0.04	0.05	0.00	0.00	0.00	0.00	0.00
180.0 -S-	NO	80	8	22	26	16	5	1	1	0	0	1
	PCT	1.07	0.11	0.29	0.34	0.21	0.07	0.01	0.01	0.00	0.00	0.01
202.5 -SSW-	NO	96	9	23	19	18	13	3	8	2	1	0
	PCT	1.28	0.12	0.31	0.25	0.24	0.17	0.04	0.11	0.03	0.01	0.00
225.0 -SW-	NO	139	11	26	32	27	20	11	5	5	2	0
	PCT	1.85	0.14	0.34	0.43	0.36	0.27	0.14	0.07	0.07	0.03	0.00
247.5 -WSW-	NO	72	8	18	13	14	6	4	2	4	3	0
	PCT	0.96	0.11	0.24	0.17	0.19	0.08	0.05	0.03	0.05	0.04	0.00
270.0 -W-	NO	86	16	19	13	2	5	11	5	9	1	5
	PCT	1.15	0.21	0.25	0.17	0.03	0.07	0.14	0.07	0.12	0.01	0.07
292.5 -WNW-	NO	55	9	12	4	0	3	3	8	6	3	7
	PCT	0.73	0.12	0.16	0.05	0.00	0.04	0.04	0.11	0.08	0.04	0.09
315.0 -NW-	NO	43	7	15	5	2	0	3	2	4	4	1
	PCT	0.57	0.09	0.20	0.07	0.03	0.00	0.04	0.03	0.05	0.05	0.01
337.5 -NNW-	NO	50	14	24	9	0	1	0	2	0	0	0
	PCT	0.67	0.19	0.32	0.12	0.00	0.01	0.00	0.03	0.00	0.00	0.00
CALM	NO	2										
	PCT	0.03										
TOTAL	NO	1194	141	320	292	175	103	53	45	36	15	14
	PCT	15.90	1.88	4.26	3.89	2.33	1.37	0.70	0.60	0.48	0.20	0.19

AVERAGE WIND SPEED 7.59 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE HIGH LEVEL
SUMMARY OF PASQUILL E

FOR 1975
WIND OCCURRENCES BY SECTOR • SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 5-18-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0	NO	194	33	86	47	19	7	2	0	0	0	0
-N-	PCT	2.58	0.44	1.14	0.63	0.25	0.09	0.03	0.00	0.00	0.00	0.00
22.5	NO	117	15	51	31	12	5	2	1	0	0	0
-NNE-	PCT	1.56	0.20	0.68	0.41	0.16	0.07	0.03	0.01	0.00	0.00	0.00
45.0	NO	179	8	46	49	41	29	6	0	0	0	0
-NE-	PCT	2.38	0.11	0.61	0.65	0.54	0.39	0.08	0.00	0.00	0.00	0.00
67.5	NO	124	15	23	33	25	19	5	1	1	2	0
-ENE-	PCT	1.65	0.20	0.31	0.44	0.33	0.25	0.07	0.01	0.01	0.03	0.00
90.0	NO	84	12	27	25	15	2	2	0	1	0	0
-E-	PCT	1.12	0.16	0.36	0.33	0.20	0.03	0.03	0.00	0.01	0.00	0.00
112.5	NO	44	7	19	12	4	2	0	0	0	0	0
-ESE-	PCT	0.59	0.09	0.25	0.16	0.05	0.03	0.00	0.00	0.00	0.00	0.00
135.0	NO	54	7	20	19	7	0	0	0	0	0	1
-SE-	PCT	0.72	0.09	0.27	0.25	0.09	0.00	0.00	0.00	0.00	0.00	0.01
157.5	NO	97	12	26	27	27	3	1	0	0	0	1
-SSE-	PCT	1.29	0.16	0.34	0.36	0.36	0.04	0.01	0.00	0.00	0.00	0.01
180.0	NO	111	10	32	35	21	6	5	0	2	0	0
-S-	PCT	1.48	0.13	0.43	0.47	0.28	0.08	0.07	0.00	0.03	0.00	0.00
202.5	NO	113	11	25	28	16	15	9	7	2	0	0
-SSW-	PCT	1.50	0.14	0.33	0.37	0.21	0.20	0.12	0.09	0.03	0.00	0.00
225.0	NO	162	11	25	33	34	31	11	11	5	1	0
-SW-	PCT	2.16	0.14	0.33	0.44	0.45	0.41	0.14	0.14	0.07	0.01	0.00
247.5	NO	127	15	29	29	17	12	8	11	4	1	1
-WSW-	PCT	1.69	0.20	0.39	0.39	0.23	0.16	0.11	0.14	0.05	0.01	0.01
270.0	NO	133	13	35	30	10	8	14	9	9	2	3
-W-	PCT	1.77	0.17	0.47	0.40	0.13	0.11	0.19	0.12	0.12	0.03	0.04
292.5	NO	117	16	26	8	13	20	10	8	4	7	5
-WNW-	PCT	1.56	0.21	0.34	0.11	0.17	0.27	0.13	0.11	0.05	0.09	0.07
315.0	NO	100	23	36	9	4	8	10	5	4	1	0
-NW-	PCT	1.33	0.31	0.48	0.12	0.05	0.11	0.13	0.07	0.05	0.01	0.00
337.5	NO	106	20	46	24	9	4	3	0	0	0	0
-NNW-	PCT	1.41	0.27	0.61	0.32	0.12	0.05	0.04	0.00	0.00	0.00	0.00
CALM	NO	4										
	PCT	0.05										
TOTAL	NO	1862	228	552	439	274	171	88	53	32	14	11
	PCT	24.79	3.03	7.35	5.84	3.65	2.28	1.17	0.70	0.43	0.19	0.14

AVERAGE WIND SPEED 7.14 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE HIGH LEVEL
SUMMARY OF PASQUILL F

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR, PERCENT)
DATE OF REPORT 5-18-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
			WIND SPEED CLASS									
360.0 -N-	NO	314	70	132	83	24	4	0	1	0	0	0
	PCT	4.18	0.93	1.76	1.10	0.32	0.05	0.00	0.01	0.00	0.00	0.00
22.5 -NNE-	NO	116	25	39	30	18	4	0	0	0	0	0
	PCT	1.54	0.33	0.52	0.40	0.24	0.05	0.00	0.00	0.00	0.00	0.00
45.0 -NE-	NO	191	19	55	42	32	26	11	5	1	0	0
	PCT	2.54	0.25	0.73	0.56	0.43	0.34	0.14	0.07	0.01	0.00	0.00
67.5 -ENE-	NO	106	12	21	22	19	23	7	2	0	0	0
	PCT	1.41	0.16	0.28	0.29	0.25	0.31	0.09	0.03	0.00	0.00	0.00
90.0 -E-	NO	75	10	26	22	6	5	3	1	1	0	1
	PCT	1.00	0.13	0.34	0.29	0.08	0.07	0.04	0.01	0.01	0.00	0.01
112.5 -ESE-	NO	55	11	21	8	10	3	0	1	0	1	0
	PCT	0.73	0.14	0.28	0.11	0.13	0.04	0.00	0.01	0.00	0.01	0.00
135.0 -SE-	NO	54	11	15	16	5	2	0	1	2	1	1
	PCT	0.72	0.14	0.20	0.21	0.07	0.03	0.00	0.01	0.03	0.01	0.01
157.5 -SSE-	NO	83	10	20	28	13	7	1	1	2	0	1
	PCT	1.11	0.13	0.27	0.37	0.17	0.09	0.01	0.01	0.03	0.00	0.01
180.0 -S-	NO	85	13	12	31	17	9	2	0	1	0	0
	PCT	1.13	0.17	0.16	0.41	0.23	0.12	0.03	0.00	0.01	0.00	0.00
202.5 -SSW-	NO	58	11	13	15	7	3	6	2	1	0	0
	PCT	0.77	0.14	0.17	0.20	0.09	0.04	0.08	0.03	0.01	0.00	0.00
225.0 -SW-	NO	72	12	21	18	9	4	4	1	2	0	1
	PCT	0.96	0.16	0.28	0.24	0.12	0.05	0.05	0.01	0.03	0.00	0.01
247.5 -WSW-	NO	59	10	17	11	11	5	4	0	1	0	0
	PCT	0.79	0.13	0.23	0.14	0.14	0.07	0.05	0.00	0.01	0.00	0.00
270.0 -W-	NO	68	22	23	6	6	4	4	1	2	0	0
	PCT	0.91	0.29	0.31	0.08	0.08	0.05	0.05	0.01	0.03	0.00	0.00
292.5 -WNW-	NO	102	20	44	7	7	9	7	5	2	1	0
	PCT	1.36	0.27	0.58	0.09	0.09	0.12	0.09	0.07	0.03	0.01	0.00
315.0 -NW-	NO	111	28	59	12	3	3	4	2	0	0	0
	PCT	1.48	0.37	0.78	0.16	0.04	0.04	0.05	0.03	0.00	0.00	0.00
337.5 -NNW-	NO	174	42	99	23	6	3	1	0	0	0	0
	PCT	2.32	0.56	1.32	0.31	0.08	0.04	0.01	0.00	0.00	0.00	0.00
CALM	NO	3										
	PCT	0.04										
TOTAL	NO	1723	326	617	374	193	114	54	23	15	3	4
	PCT	22.94	4.34	8.22	4.98	2.57	1.52	0.72	0.31	0.20	0.04	0.05

AVERAGE WIND SPEED 6.01 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE HIGH LEVEL
SUMMARY OF PASQUILL G

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR, PERCENT)

DATE OF REPORT 5-18-76

WIND SECTOR	ITEM	SECTOR TOTAL	WIND SPEED CLASS 1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
360.0	NO	170	29	78	55	7	1	0	0	0	0	0
-N-	PCT	2.26	0.39	1.04	0.73	0.09	0.01	0.00	0.00	0.00	0.00	0.00
22.5	NO	83	27	34	20	2	0	0	0	0	0	0
-NNE-	PCT	1.11	0.36	0.45	0.27	0.03	0.00	0.00	0.00	0.00	0.00	0.00
45.0	NO	45	15	19	7	3	1	0	0	0	0	0
-NE-	PCT	0.60	0.20	0.25	0.09	0.04	0.01	0.00	0.00	0.00	0.00	0.00
67.5	NO	17	7	4	2	2	1	0	0	1	0	0
-ENE-	PCT	0.23	0.09	0.05	0.03	0.03	0.01	0.00	0.00	0.01	0.00	0.00
90.0	NO	12	6	4	1	0	1	0	0	0	0	0
-E-	PCT	0.16	0.08	0.05	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.00
112.5	NO	13	4	3	5	1	0	0	0	0	0	0
-ESE-	PCT	0.17	0.05	0.04	0.07	0.01	0.00	0.00	0.00	0.00	0.00	0.00
135.0	NO	18	3	7	6	2	0	0	0	0	0	0
-SE-	PCT	0.24	0.04	0.09	0.08	0.03	0.00	0.00	0.00	0.00	0.00	0.00
157.5	NO	21	6	5	7	1	1	1	0	0	0	0
-SSE-	PCT	0.28	0.08	0.07	0.09	0.01	0.01	0.01	0.00	0.00	0.00	0.00
180.0	NO	33	11	8	7	3	3	0	1	0	0	0
-S-	PCT	0.44	0.14	0.11	0.09	0.04	0.04	0.00	0.01	0.00	0.00	0.00
202.5	NO	21	3	10	4	4	0	0	0	0	0	0
-SSW-	PCT	0.28	0.04	0.13	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00
225.0	NO	25	4	10	7	3	1	0	0	0	0	0
-SW-	PCT	0.33	0.05	0.13	0.09	0.04	0.01	0.00	0.00	0.00	0.00	0.00
247.5	NO	27	8	10	8	0	1	0	0	0	0	0
-WSW-	PCT	0.36	0.11	0.13	0.11	0.00	0.01	0.00	0.00	0.00	0.00	0.00
270.0	NO	29	10	11	6	1	1	0	0	0	0	0
-W-	PCT	0.39	0.13	0.14	0.08	0.01	0.01	0.00	0.00	0.00	0.00	0.00
292.5	NO	33	12	15	1	1	2	1	1	0	0	0
-WNW-	PCT	0.44	0.16	0.20	0.01	0.01	0.03	0.01	0.01	0.00	0.00	0.00
315.0	NO	48	19	20	7	0	1	1	0	0	0	0
-NW-	PCT	0.64	0.25	0.27	0.09	0.00	0.01	0.01	0.00	0.00	0.00	0.00
337.5	NO	80	19	44	14	3	0	0	0	0	0	0
-NNW-	PCT	1.07	0.25	0.58	0.19	0.04	0.00	0.00	0.00	0.00	0.00	0.00
CALM	NO	4										
	PCT	0.05										
TOTAL	NO	675	183	282	157	33	14	3	2	1	0	0
	PCT	8.99	2.44	3.75	2.09	0.44	0.19	0.04	0.03	0.01	0.00	0.00

AVERAGE WIND SPEED 4.80 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

OCONEE HIGH LEVEL
SUMMARY OF PASQUILL A+C+D+E+F+G

FOR 1975
WIND OCCURRENCES BY SECTOR + SPEED CLASS (NO. OCCURR,PERCENT)

DATE OF REPORT 5-18-76

WIND SECTOR	ITEM	SECTOR TOTAL	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >9.5 M/S
						WIND SPEED CLASS						
360.0 -N-	NO	811	164	352	218	58	13	2	2	2	0	0
	PCT	10.80	2.18	4.69	2.90	0.77	0.17	0.03	0.03	0.03	0.00	0.00
22.5 -NNE-	NO	450	96	183	106	47	14	2	2	0	0	0
	PCT	5.99	1.28	2.44	1.41	0.63	0.19	0.03	0.03	0.00	0.00	0.00
45.0 -NE-	NO	645	73	171	154	118	82	30	14	3	0	0
	PCT	8.59	0.97	2.28	2.05	1.57	1.09	0.40	0.19	0.04	0.00	0.00
67.5 -ENE-	NO	492	49	93	105	96	88	38	12	6	4	1
	PCT	6.55	0.65	1.24	1.40	1.28	1.17	0.51	0.16	0.08	0.05	0.01
90.0 -E-	NO	385	40	118	109	71	28	12	3	3	0	1
	PCT	5.13	0.53	1.57	1.45	0.94	0.37	0.16	0.04	0.04	0.00	0.01
112.5 -ESE-	NO	232	34	85	64	29	13	3	3	0	1	0
	PCT	3.09	0.45	1.13	0.85	0.39	0.17	0.04	0.04	0.00	0.01	0.00
135.0 -SE-	NO	286	47	105	95	25	6	1	1	3	1	2
	PCT	3.81	0.63	1.40	1.26	0.33	0.08	0.01	0.01	0.04	0.01	0.03
157.5 -SSE-	NO	379	51	115	125	56	23	4	1	2	0	2
	PCT	5.05	0.68	1.53	1.66	0.74	0.31	0.05	0.01	0.03	0.00	0.03
180.0 -S-	NO	468	60	124	149	82	30	16	3	3	0	1
	PCT	6.23	0.80	1.65	1.98	1.09	0.40	0.21	0.04	0.04	0.00	0.01
202.5 -SSW-	NO	571	52	126	151	108	65	36	24	7	1	1
	PCT	7.60	0.69	1.68	2.01	1.44	0.87	0.48	0.32	0.09	0.01	0.01
225.0 -SW-	NO	649	53	155	158	108	72	38	32	21	7	5
	PCT	8.64	0.70	2.06	2.10	1.44	0.96	0.51	0.43	0.28	0.09	0.07
247.5 -WSW-	NO	426	61	108	98	60	34	20	18	18	6	3
	PCT	5.67	0.81	1.44	1.30	0.80	0.45	0.27	0.24	0.24	0.08	0.04
270.0 -W-	NO	455	86	128	79	35	27	36	17	27	3	17
	PCT	6.06	1.14	1.70	1.05	0.47	0.36	0.48	0.23	0.36	0.04	0.23
292.5 -WNW-	NO	418	73	123	32	27	37	23	36	22	20	25
	PCT	5.57	0.97	1.64	0.43	0.36	0.49	0.31	0.48	0.29	0.27	0.33
315.0 -NW-	NO	372	94	147	45	12	16	22	11	14	6	5
	PCT	4.95	1.25	1.96	0.60	0.16	0.21	0.29	0.14	0.19	0.08	0.07
337.5 -NNW-	NO	453	108	238	73	18	8	4	4	0	0	0
	PCT	6.03	1.44	3.17	0.97	0.24	0.11	0.05	0.05	0.00	0.00	0.00
CALM	NO	18										
	PCT	0.24										
TOTAL	NO	7492	1141	2371	1761	950	556	287	183	131	49	63
	PCT	99.76	15.19	31.57	23.45	12.65	7.40	3.82	2.44	1.74	0.65	0.84

AVERAGE WIND SPEED 6.78 TOTAL VALID OBSERVATIONS 7510 TOTAL OBSERVATIONS 8760

Table 2-28. Composite Poorest Diffusion Conditions Observed for Each Hour of Day (Based on 30 Months of Data)

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

Hour of Day	*Pasquill Class*
00	*F*
01	*F*
02	*F*
03	*F*
04	*F*
05	*F*
06	*F*
07	*F*
08	*F*
09	*E*
10	*D*
11	*D*
12	*D*
13	*D*
14	*D*
15	*D*
16	*D*
17	*F*
18	*F*
19	*F*
20	*F*
21	*F*
22	*F*
23	*F*

Table 2-29. Dispersion Factors Used for Accident and Routine Operational Analyses X/Q
["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

July 1973 Safety Evaluation Report for Unit 2 and Unit 3 - Superseded 1970 SER Values for Facility				
Exclusion Area Boundary (1609 m)[3]				
	0-2 hrs			
Ground Releases	*2.20E-4*			
Deleted row per 2008 Update				
At Boundary of Low Population Zone (9650 m)[3]				
	0-8 h	*8-24 h*	*1 d - 4 d*	*4 d - 30 d*
Ground Releases	*2.35E-5*	*4.70E-6*	*1.50E-6*	*3.30E-7*
Deleted row per 2008 Update				

December 1970 Safety Evaluation Report for Unit 1 At Exclusion Area Boundary (1609 m)			
	0-2 hrs	*0-24 hrs*	*0-7 days*
Ground Releases	*1.16E-4*		
Elevated Releases	*3.35E-5*	*9.73E-6*	*2.98E-6*
At Boundary of Low Population Zone (9650 m)			
	0-24 hrs.	*0-30 days*	
Ground Releases[1]	*1.32E-5*	*7.2E-7*	
Elevated Releases[2]	*3.90E-6*	*3.42E-7*	
Long-Term (One Year) Exclusion Area Boundary			
Ground Releases	*4.61E-6*		
Elevated Releases	*8.74E-7*		

Note:

1. *At valley construction 10,464 m from site near Boundary of LPZ*
2. *9,658 m from site at Boundary of LPZ*
3. *Reference 30*

Table 2-30. Determining Appropriate Dispersion Factors. Table 2-29 to be Used During Various Release Conditions

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

	Release Condition	***Appropriate Dispersion Factor***
1.	*Fuel Handling Accident*	*0-2 hour ground release at exclusion area boundary*
2.	*Steam Line Failure*	*0-2 hour ground release at exclusion area boundary for steam line releases* *0-2 hour elevated release at exclusion area boundary for unit vent releases* *0-8 hours, 8-24 hours, 1-4 days, and 4-30 days at boundary of low population zone*
3.	*Rod Ejection Accident*	*0-2 hour ground release at exclusion area boundary for steam line releases* *0-2 hour elevated release at exclusion area boundary for unit vent releases* *0-8 hours, 8-24 hours, 1-4 days, and 4-30 days at boundary of low population zone*
4.	*Loss-of-Coolant Accident (assume 50 percent ground release and 50 percent elevated release after 90 percent iodine removal by filtration)*	*0-2 hour ground release at exclusion area boundary for steam line releases* *0-2 hour elevated release at exclusion area boundary for unit vent releases* *0-8 hours, 8-24 hours, 1-4 days, and 4-30 days at boundary of low population zone*
5.	*Maximum Hypothetical Accident (MHA)*	*0-2 hour ground release at exclusion area boundary for steam line releases* *0-2 hour elevated release at exclusion area boundary for unit vent releases* *0-8 hours, 8-24 hours, 1-4 days, and 4-30 days at boundary of low population zone*
6.	*Engineered Safeguards Leakage*	*0-2 hour elevated release at exclusion area boundary*
7.	*Lifetime Shim Bleed (continuous release)*	*Long-term elevated releases at exclusion area boundary*
8.	*Start-up expansion (7-day release)*	*0-7 day elevated releases at exclusion area boundary*
9.	*Reactor Building Purge*	*0-24 hour elevated release at exclusion area boundary*

	Release Condition	***Appropriate Dispersion Factor***
10.	*Steam Generator Tube Failure*	*0-2 hour ground release at exclusion area boundary for steam line releases* *0-2 hour elevated release at exclusion area boundary for unit vent releases* *0-8 hours, 8-24 hours, 1-4 days, and 4-30 days at boundary of low population zone*
11.	*Steam Generator Tube Leakage*	*Long-term elevated releases at exclusion area boundary*
12.	*Pressurizer and Letdown Storage Tank Venting*	*0-7 day elevated release at exclusion area boundary.*
13.	*Waste Gas Tank Rupture*	*0-2 hour elevated release at exclusion area boundary.*

Table 2-31. Oconee Nuclear Station X/Q at Critical Receptors to 5 Miles[(1)] (Depleted by Dry Deposition). Radial Distance (mi.) to Receptor with Highest X/Q in Sector and X/Q (sec. m-3) based on 1975 meteorology.

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

Compass Direction	*Milk Cow*		*Milk Goat*		*Meat Animal*		*Residence*		*Veg. Garden*		*EAB[(2)]*	
	mi.	*sec. m^{-3}*	*mi.*	*sec. m^{-3}*	*mi.*	*sec. m^{-3}*	*mi.*	*sec. m^{-3}*	*mi.*	*sec. m^{-3}*	*mi.*	*sec. m^{-3}*
N		-		-		-		-		-	*1*	*7.8E-8*
NNE		-		-		-	*4*	*7.8E-8*	*4*	*7.8E-8*	*1*	*1.1E-7*
NE	*3.5*	*6.3E-8*	*3*	*6.2E-8*	*3*	*6.2E-8*	*2*	*6.7E-8*	*2*	*6.7E-8*	*1*	*7.0E-8*
ENE	*4*	*5.7E-8*			*1.25*	*6.5E-8*	*1.25*	*6.5E-8*	*1.25*	*6.5E-8*	*1*	*6.9E-8*
E	*3*	*5.3E-8*	*4.5*	*4.5E-8*	*2*	*6.1E-8*	*2*	*6.1E-8*	*2*	*6.1E-8*	*1*	*4.4E-8*
ESE	*4.5*	*4.5E-8*			*2.5*	*5.6E-8*	*2*	*6.1E-8*	*2*	*6.1E-8*	*1*	*2.9E-8*
SE	*3*	*5.5E-8*	*2.5*	*5.5E-8*	*2.5*	*5.5E-8*	*2.5*	*5.5E-8*	*2.5*	*5.5E-8*	*1*	*3.3E-8*
SSE					*2*	*3.1E-7*	*2*	*3.1E-7*	*2*	*3.1E-7*	*1*	*2.6E-7*
S					*2*	*2.5E-7*	*2*	*2.5E-7*	*2*	*2.5E-7*	*1*	*2.6E-7*
SSW	*1.5*	*3.3E-7*			*1.5*	*3.3E-7*	*1.5*	*3.3E-7*	*1.5*	*3.3E-7*	*1*	*3.1E-7*
SW					*1.75*	*7.5E-8*	*1.75*	*7.5E-8*	*1.75*	*7.5E-8*	*1*	*7.5E-8*
WSW					*2.5*	*5.0E-8*	*2.5*	*5.0E-8*	*2.5*	*5.0E-8*	*1*	*5.9E-8*
W	*4.5*	*3.3E-8*			*2.5*	*4.3E-8*	*2.5*	*4.3E-8*	*2.5*	*4.3E-8*	*1*	*3.1E-8*
WNW					*2.75*	*3.5E-8*	*2.75*	*3.5E-8*	*2.75*	*3.5E-8*	*1*	*2.4E-8*
NW					*4*	*2.8E-8*	*4*	*2.8E-8*	*4*	*2.8E-8*	*1*	*3.9E-8*
NNW	*2.5*	*7.7E-8*					*2.5*	*8.3E-8*	*2.5*	*8.3E-8*	*1*	*6.6E-8*

Compass Direction	*Milk Cow*		*Milk Goat*		*Meat Animal*		*Residence*		*Veg. Garden*		*EAB*[2]	
	mi.	*sec.* m^{-3}	*mi.*	*sec.* m^{-3}	*mi.*	*sec.* m^{-3}	*mi.*	*sec.* m^{-3}	*mi.*	*sec.* m^{-3}	*mi.*	*sec.* m^{-3}

Note:

1. *The notation 2.1E-6 means 2.1 x* 10^{-6}
2. *Exclusion Area Boundary*

Table 2-32. Oconee Nuclear Station D/Q at Critical Receptors to 5 Miles[1]. Radial Distance (mi.) to Receptor with Highest D/Q in Sector and D/Q (m-2) based on 1975 meteorology

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

Compass Direction	*Milk Cow*		*Milk Goat*		*Meat Animal*		*Residence*		*Veg. Garden*		*EAB[2]*	
	mi.	*sec. m $^{-2}$*	*mi.*	*sec. m $^{-2}$*	*mi.*	*sec. m $^{-2}$*	*mi.*	*sec. m $^{-2}$*	*mi.*	*sec. m $^{-2}$*	*mi.*	*sec. m $^{-2}$*
N	-		-		-		-		-		1	2.3E-9
NNE	-		-		-		4	4.2E-10	4	4.2E-10	1	3.7E-9
NE	3.5	4.0E-10	3	5.0E-10	3	5.0E-10	2	8.0E-10	2	8.0E-10	1	2.5E-9
ENE	4	1.8E-10			1.25	1.0E-9	1.25	1.0E-9	1.25	1.0E-9	1	1.8E-9
E	3	2.7E-10	4.5	1.5E-10	1.25	8.0E-10	1.25	8.0E-10	1.25	8.0E-10	1	1.3E-9
ESE	4.5	1.1E-10			1.5	5.0E-10	1.5	5.0E-10	1.5	5.0E-10	1	1.0E-9
SE	3	1.4E-10	2.5	1.8E-10	2.5	1.8E-10	2.5	1.8E-10	2.5	1.8E-10	1	6.0E-10
SSE					2	1.2E-9	2	1.2E-9	2	1.2E-9	1	2.5E-9
S					2	1.3E-9	2	1.3E-9	2	1.3E-9	1	3.0E-9
SSW	1.5	2.4E-9			1.5	2.4E-9	1.5	2.4E-9	1.5	2.4E-9	1	3.5E-9
SW					1.75	6.0E-10	1.75	6.0E-10	1.75	6.0E-10	1	1.1E-9
WSW					2.5	4.4E-10	2.5	4.4E-10	2.5	4.4E-10	1	1.4E-9
W	4.5	1.5E-10			2.5	3.8E-10	2.5	3.8E-10	2.5	3.8E-10	1	1.0E-9
WNW					2.75	2.0E-10	2.75	2.0E-10	2.75	2.0E-10	1	7.0E-10
NW					4	9.9E-11	4	9.9E-11	4	9.9E-11	1	7.0E-10
NNW	2.5	3.7E-10					2.5	3.7E-10	2.5	1.3E-9	1	1.6E-9

Note:

1. *The notation 2.1E-6 means 2.1 x 10^{-6}*
2. *Exclusion Area Boundary*

Table 2-33. Oconee Nuclear Station X/Q at Critical Receptors to 5 Miles[1] (Non-Depleted). Radial Distance (mi.) to Receptor with Highest X/Q in Sector and X/Q (sec. m-3) based on 1975 meteorology.

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

	Milk Cow		***Milk Goat***		***Meat Animal***		***Residence***		***Veg. Garden***		***EAB[2]***	
Compass Direction	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***
N		*-*		*-*		*-*		*-*		*-*	*1*	*9.0E-8*
NNE		*-*		*-*		*-*	*4*	*8.3E-8*	*4*	*8.3E-8*	*1*	*1.1E-7*
NE	*3.5*	*6.4E-8*	*3*	*6.3E-8*	*3*	*6.3E-8*	*2*	*6.7E-8*	*2*	*6.7E-8*	*1*	*7.0E-8*
ENE	*4*	*5.7E-8*			*1.25*	*6.6E-8*	*1.25*	*6.6E-8*	*1.25*	*6.6E-8*	*1*	*6.9E-8*
E	*3*	*5.3E-8*	*4.5*	*4.5E-8*	*2*	*6.1E-8*	*2*	*6.1E-8*	*2*	*6.1E-8*	*1*	*4.4E-8*
ESE	*4.5*	*4.7-8*			*2.5*	*5.6E-8*	*2*	*6.2E-8*	*2*	*6.2E-8*	*1*	*3.5E-8*
SE	*3*	*5.5E-8*	*2.5*	*5.5E-8*	*2.5*	*5.5E-8*	*2.5*	*5.5E-8*	*2.5*	*5.5E-8*	*1*	*3.3E-8*
SSE					*2*	*3.2E-7*	*2*	*3.2E-7*	*2*	*3.2E-7*	*1*	*2.6E-7*
S					*2*	*2.5E-7*	*2*	*2.5E-7*	*2*	*2.5E-7*	*1*	*2.7E-7*
SSW	*1.5*	*3.4E-7*			*1.5*	*3.4E-7*	*1.5*	*3.4E-7*	*1.5*	*3.4E-7*	*1*	*3.4E-7*
SW					*1.75*	*7.5E-8*	*1.75*	*7.5E-8*	*1.75*	*7.5E-8*	*1*	*7.5E-8*
WSW					*2.5*	*5.0E-8*	*2.5*	*5.0E-8*	*2.5*	*5.0E-8*	*1*	*6.3E-8*
W	*4.5*	*3.6E-8*			*2.5*	*4.3E-8*	*2.5*	*4.3E-8*	*2.5*	*4.3E-8*	*1*	*3.8E-8*
WNW							*2.75*	*3.5E-8*	*2.75*	*3.5E-8*	*1*	*2.4E-8*
NW							*4*	*3.7E-8*	*4*	*3.7E-8*	*1*	*3.9E-8*
NNW	*2.5*	*8.3E-8*					*2.5*	*8.3E-8*	*2.5*	*8.3E-8*	*1*	*6.9E-8*

	Milk Cow		***Milk Goat***		***Meat Animal***		***Residence***		***Veg. Garden***		***EAB***[2]	
Compass Direction	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***	***mi.***	***sec. m^{-3}***

Note:

1. *The notation 2.1E-6 means 2.1 x 10^{-6}*
2. *Exclusion Area Boundary*

Table 2-34. Relative Concentration, X/Q, Frequency Distribution Without Wind Speed Correction(3)

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

Relative Concentration	*Frequency (No. of Obs.)*	*Percentage*	*Cumulative Per Cent*
$\geq$4.0 x10^{-4}	*0*	*0.00*	*0.00*
3.0-3.99 x10^{-4}	*0*	*0.00*	*0.00*
2.0-2.99 x10^{-4}	*8*	*0.09*	*0.09*
1.0-1.99 x10^{-4}	*35*	*0.41*	*0.51*
9.0-9.99 x10^{-5}	*20*	*0.24*	*0.74*
8 0-8.99 x10^{-5}	*53*	*0.62*	*1.37*
7.0-7.9 x10^{-5}	*106*	*1.25*	*2.62*
6.0-6.99 x10^{-5}	*229*	*2.70*	*5.32*
5.0-5.99 x10^{-5}	*506*	*5.97*	*11.28*
4.0-4.99 x10^{-5}	*838*	*9.88*	*21.16*
3.0-3.99 x10^{-5}	*1484*	*17.50*	*38.66*
2.0-2.99 x10^{-5}	*2313*	*27.27*	*65.93*
1.0-1.99 x10^{-5}	*2307*	*27.20*	*93.13*
9.0-9.99 x10^{-6}	*167*	*1.97*	*95.10*
8.0-8.99 x10^{-6}	*134*	*1.58*	*96.68*
7.0-7.99 x10^{-6}	*87*	*1.03*	*97.70*
6.0-6.99 x10^{-6}	*88*	*1.04*	*98.74*
5.0-5.99 x10^{-6}	*53*	*0.62*	*99.36*
4.0-4.99 x10^{-6}	*27*	*0.32*	*99.68*
$\leq$3.99 x10^{-6}	*27*	*0.32*	*100.00*
Totals	*8482*	*100.00*	*--- ---*

Note:

1. *Percentage of Valid Observations: 96.82*
2. *Average Relative Concentration = 2.92960 x 10^{-5}*
3. *Meteorological Period: June 1, 1968 - May 31, 1969*

Table 2-35. Gas-Tracer Experimental Results From January 15 - March 11, 1970

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED."]

Gas-Tracer Experimental Results

Test Date	Test Number	Time (hours)	Release Rate (micrograms per second)	$\bar{u}$ (meters per second)	Stability Category	Source to Receptor Distance (meters)	At Receptor: Center Line Concentration (micrograms per meter³)	At Receptor: Sigma Y (meters)	At Receptor: Sigma Z (meters)	At One Mile: Sigma Y (meters)	At One Mile: Sigma Z (meters)	At One Mile: Pi, Sigma Y, Sigma Z, $\bar{u}$ (meters³ per second)	At One Mile: Relative Concentration (seconds per meter³)
Jan. 15, 1970	1a	2100	90×10^3	5.36	F	176	9.40	38.6	14.70	270	74	3.36×10^5	3.97×10^{-6}
	1b	2200	90×10^3	5.36	F	680	3.59	145	10.74	225	19	7.19×10^4	1.38×10^{-5}
Jan. 28, 1970	Plume Measurements Indeterminable												
Jan. 31, 1970	Plume Measurements Indeterminable												
Feb. 5, 1970	2	2100	91×10^3	0.89	F	630	1.58	104	197	280	380	2.97×10^5	3.36×10^{-6}
Feb. 6, 1970	3	2040	85.8×10^3	0.89	F	835	3.49	90	313	57	490	7.17×10^4	1.40×10^{-5}
Feb. 10, 1970	4a	2156	83.3×10^3	1.34	E	190	9.02	38	57	260	280	3.06×10^5	3.76×10^{-6}
	4b	2210	91.6×10^3	1.79	E	357	9.30	26	67	108	186	1.12×10^5	8.85×10^{-6}
	4c	2250	86.7×10^3	1.79	E	411	3.68	62	67	210	172	2.03×10^5	4.92×10^{-6}
Feb. 11, 1970	Plume Measurements Indeterminable												
Feb. 12, 1970	5a	2055	85.5×10^3	1.56	E	530	2.54	55	44	152	180	7.44×10^4	1.34×10^{-5}
	5b	2115	88.5×10^3	1.34	E	530	3.79	22	72	205	168	1.44×10^5	6.09×10^{-6}
Feb. 17, 1970	6a	2210	89.7×10^3	3.13	E	399	8.29	74	14.9	260	38	9.71×10^4	1.02×10^{-5}
	6b	2250	88.0×10^3	1.79	E	426	16.6	34	27.5	115	82	5.30×10^4	1.88×10^{-5} *
Feb. 19, 1970	Plume Measurements Indeterminable												
Mar. 2, 1970	7	2240	89.2×10^3	0.89	F	451	1.54	45	461	138	920	3.55×10^5	2.81×10^{-6}
Mar. 3, 1970	8a	2018	85.0×10^3	0.89	E-F	450	3.63	43	193	138	500	1.97×10^5	5.08×10^{-6}
	8b	2110	83.3×10^3	0.89	E-F	450	6.21	38	126	125	300	1.04×10^5	9.53×10^{-6}
	8c	2200	86.6×10^3	0.89	E-F	450	2.10	73	195	220	500	1.07×10^5	1.25×10^{-6}
Mar. 5, 1970	Plume Measurements Indeterminable												
Mar. 10, 1970	9a	2045	91.4×10^3	0.67	E-F	120	9.38	32	145	300	1050	6.63×10^5	1.50×10^{-6}
	9b	2205	91.4×10^3	0.67	E-F	120	6.44	52	179	500	910	9.57×10^5	1.04×10^{-6}
	9c	2315	91.4×10^3	0.67	E-F	120	2.78	43	467	450	3500	3.31×10^6	5.01×10^{-7}
Mar. 11, 1970	Plume Measurements Indeterminable												

*Highest test relative concentration at one mile = 1.88×10^{-5} seconds per meter³

Table 2-36. Relative Concentration, X/Q, Frequency Distribution With Wind Speed Correction[3, 4]

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

Relative Concentration	***Frequency (No. of Obs.)***	***Percentage***	***Cumulative Per Cent***
$\geq 4.0 \times 10^{-4}$	*0*	*0.00*	*0.00*
$3.0\text{-}3.99 \times 10^{-4}$	*0*	*0.00*	*0.00*
$2.0\text{-}2.99 \times 10^{-4}$	*0*	*0.00*	*0.00*
$1.0\text{-}1.99 \times 10^{-4}$	*18*	*0.21*	*0.21*
$9.0\text{-}9.99 \times 10^{-5}$	*6*	*0.07*	*0.28*
$8.0\text{-}8.99 \times 10^{-5}$	*6*	*0.07*	*0.35*
$7.0\text{-}7.99 \times 10^{-5}$	*15*	*0.18*	*0.53*
$6.0\text{-}6.99 \times 10^{-5}$	*40*	*0.47*	*1.00*
$5.0\text{-}5.99 \times 10^{-5}$	*137*	*1.62*	*2.62*
$4.0\text{-}4.99 \times 10^{-5}$	*391*	*4.61*	*7.23*
$3.0\text{-}3.99 \times 10^{-5}$	*957*	*11.28*	*18.51*
$2.0\text{-}2.99 \times 10^{-5}$	*2087*	*24.58*	*43.09*
$1.0\text{-}1.99 \times 10^{-5}$	*3407*	*40.17*	*83.26*
$9.0\text{-}9.99 \times 10^{-6}$	*313*	*3.69*	*86.95*
$8.0\text{-}8.99 \times 10^{-6}$	*298*	*3.51*	*90.46*
$7.0\text{-}7.99 \times 10^{-6}$	*260*	*3.07*	*93.53*
$6.0\text{-}6.99 \times 10^{-6}$	*218*	*2.57*	*96.10*
$5.0\text{-}5.99 \times 10^{-6}$	*136*	*1.60*	*97.70*
$4.0\text{-}4.99 \times 10^{-6}$	*113*	*1.33*	*99.03*
$\leq 3.99 \times 10^{-6}$	*82*	*0.97*	*100.00*
Totals	*8482*	*100.00*	*--- ---*

Note:

1. *Percentage of Valid Observations: 96.82*
2. *Average Relative Concentration = 2.09257×10^{-5}*
3. *Period of Record: June 1, 1968 - May 31, 1969*
4. *Wind Speed Correction factor of 1.4 applied, based on calibration check on October 1, 1969*

Table 2-37. Comparative Wind Speed Data

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

Date	*Greenville-Spartanburg[(1)] (Average)*	*Oconee (Average)*	*Oconee to Greenville-Spartanburg (Ratio)*	*Oconee to Greenville-Spartanburg (Ratio x 1.4)*
June, 1968	*13.9 mph*	*7.6 mph*	*0.54*	*0.76*
July, 1968	*11.2 mph*	*6.3 mph*	*0.56*	*0.79*
August, 1968	*11.3 mph*	*6.8 mph*	*0.60*	*0.84*
September, 1968	*10.9 mph*	*5.6 mph*	*0.52*	*0.72*
October, 1968	*12.3 mph*	*8.1 mph*	*0.65*	*0.92*
November, 1968	*13.1 mph*	*7.4 mph*	*0.56*	*0.78*
December, 1968	*15.6 mph*	*9.3 mph*	*0.59*	*0.83*
January, 1969	*14.6 mph*	*8.1 mph*	*0.55*	*0.77*
February, 1969	*15.4 mph*	*11.0 mph*	*0.72*	*1.02*
March, 1969	*11.8 mph*	*7.7 mph*	*0.66*	*0.94*
April, 1969	*11.6 mph*	*7.8 mph*	*0.68*	*0.96*
May, 1969	*11.9 mph*	*6.8 mph*	*0.57*	*0.81*
June, 1969	*11.6 mph*	*6.5 mph*	*0.56*	*0.80*
July, 1969	*11.1 mph*	*5.5 mph*	*0.50*	*0.70*
August, 1969	*11.0 mph*	*8.2 mph*	*0.74*	*1.06*
September, 1969	*11.3 mph*	*7.3 mph*	*0.65*	*0.91*
[(2)]October, 1969	*12.1 mph*	*11.2 mph*	*0.92*	*- ---*
November, 1969	*12.5 mph*	*12.3 mph*	*0.97*	*- ---*

Date	***Greenville-Spartanburg[1] (Average)***	***Oconee (Average)***	***Oconee to Greenville-Spartanburg (Ratio)***	***Oconee to Greenville-Spartanburg (Ratio x 1.4)***
December, 1969	*12.6 mph*	*10.5 mph*	*0.83*	- ---
January, 1970	*13.0 mph*	*14.1 mph*	*1.08*	- ---

Note:

1. *Greenville-Spartanburg, S.C. Airport ESSA Station*
2. *Calibration Check - October 1, 1969*

Table 2-38. Supplemental Data Oconee Meteorological Survey (Tower Data) For Period of June 1, 1968 Thru May 31, 1969. Frequency of Total Relative Concentration for All Observations

["HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED."]

Relative Concentration	***Frequency No. of Obs.***	***Percentage***	***Cumulative Per Cent***
$\geq 4.0 \times 10^{-4}$	*20*	*0.24*	*0.24*
$3.0 - 3.99 \times 10^{-4}$	*4*	*0.05*	*0.28*
$2.0 - 2.99 \times 10^{-4}$	*1*	*0.01*	*0.29*
$1.0 - 1.99 \times 10^{-4}$	*52*	*0.61*	*0.91*
$9.0 - 9.99 \times 10^{-5}$	*20*	*0.24*	*1.14*
$8.0 - 8.99 \times 10^{-5}$	*71*	*0.84*	*1.98*
$7.0 - 7.99 \times 10^{-5}$	*86*	*1.01*	*2.99*
$6.0 - 6.99 \times 10^{-5}$	*194*	*2.28*	*5.27*
$5.0 - 5.99 \times 10^{-5}$	*407*	*4.79*	*10.06*
$4.0 - 4.99 \times 10^{-5}$	*783*	*9.22*	*19.28*
$3.0 - 3.99 \times 10^{-5}$	*1288*	*15.16*	*34.44*
$2.0 - 2.99 \times 10^{-5}$	*1961*	*23.08*	*57.52*
$1.0 - 1.99 \times 10^{-5}$	*2604*	*30.65*	*88.17*
$9.0 - 9.99 \times 10^{-6}$	*256*	*3.01*	*91.18*
$8.0 - 8.99 \times 10^{-6}$	*205*	*2.41*	*93.60*
$7.0 - 7.99 \times 10^{-6}$	*214*	*2.52*	*96.12*
$6.0 - 6.99 \times 10^{-6}$	*129*	*1.52*	*97.63*
$5.0 - 5.99 \times 10^{-6}$	*78*	*0.92*	*98.55*
$4.0 - 4.99 \times 10^{-6}$	*78*	*0.92*	*99.47*
$\leq 3.99 \times 10^{-6}$	*45*	*0.53*	*100.00*
TOTALS	*8496*	*100.00*	*--- ---*

Note:

1. *Percentage of Valid Observations - 96.98*
2. *Average Relative Concentration 3.11000×10^{-5}*

Table 2-39. Supplemental Data - Joint Frequency Distribution

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED."]

OCONEE METEOROLOGICAL SURVEY (TOWER DATA)

FOR PERIOD OF JUNE 19, 1968 THRU JUNE 19, 1969.

SUMMARY OF WIND OCCURRENCES BY SECTOR & SPEED CLASS (NO. OCCUR, PERCENT, STANDARD DEVIATION)

Wind Sector	Item	Sector Total	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >=9.5 M/S
360.0	No	1472	465	698	247	40	16	3	3	0	0	0
-N-	Pct	17.24	5.45	8.18	2.89	0.47	0.19	0.04	0.04	0.00	0.00	0.00
	Sd		16.0	7.5	6.1	9.1	11.8	12.5	6.4	0.0	0.0	0.0
22.5	No.	708	261	312	94	20	9	4	4	3	1	0
-NNE-	Pct	8.29	3.06	3.65	1.10	0.23	0.11	0.05	0.05	0.04	0.01	0.00
	Sd		16.5	9.5	7.0	11.5	5.0	5.6	5.4	11.7	5.0	0.0
45.0	No	842	224	281	185	85	35	15	14	3	0	0
-NE-	Pct	9.86	2.62	3.29	2.17	1.00	0.41	0.18	0.16	0.04	0.00	0.00
	Sd		17.9	10.1	6.8	6.1	6.4	5.6	6.2	6.4	0.0	0.0
67.5	No.	493	134	143	96	83	24	10	3	0	0	0
-ENE-	Pct	5.77	1.57	1.68	1.12	0.97	0.28	0.12	0.04	0.00	0.00	0.00
	Sd		18.7	10.7	8.0	7.8	6.6	6.3	4.7	0.0	0.0	0.0
90.0	No	508	177	195	74	47	8	6	1	0	0	0
-E-	Pct	5.95	2.07	2.28	0.87	0.55	0.09	0.07	0.01	0.00	0.00	0.00
	Sd		17.3	11.6	9.0	8.0	6.0	7.5	9.2	0.0	0.0	0.0
112.5	No	318	131	141	33	8	4	1	0	0	0	0
-ESE-	Pct	3.72	1.53	1.65	0.39	0.09	0.05	0.01	0.00	0.00	0.00	0.00
	Sd		16.6	11.0	11.7	9.7	11.0	10.8	0.0	0.0	0.0	0.0
135.0	No	307	87	154	47	18	1	0	0	0	0	0
-SE-	Pct	3.60	1.02	1.80	0.55	0.21	0.01	0.00	0.00	0.00	0.00	0.00
	Sd		14.5	11.6	11.4	8.1	25.0	0.0	0.0	0.0	0.0	0.0
157.5	No	161	52	74	27	6	2	0	0	0	0	0
-SSE-	Pct	1.89	0.61	0.87	0.32	0.07	0.02	0.00	0.00	0.00	0.00	0.00
	Sd		13.9	9.1	7.7	8.9	15.4	0.0	0.0	0.0	0.0	0.0
180.0	No	173	46	100	15	7	5	0	0	0	0	0
-S-	Pct	2.03	0.54	1.17	0.18	0.08	0.06	0.00	0.00	0.00	0.00	0.00
	Sd		11.7	6.7	4.4	2.6	2.5	0.0	0.0	0.0	0.0	0.0
202.5	No	304	49	110	59	55	20	10	1	0	0	0
-SSW-	Pct	3.56	0.57	1.29	0.69	0.64	0.23	0.12	0.01	0.00	0.00	0.00
	Sd		14.3	8.4	8.5	5.9	4.9	6.4	4.2	0.0	0.0	0.0
225.0	No	631	129	218	126	89	41	27	1	0	0	0
-SW-	Pct	7.39	1.51	2.55	1.48	1.04	0.48	0.32	0.01	0.00	0.00	0.00
	Sd		15.5	10.6	7.2	6.5	5.9	5.8	7.5	0.0	0.0	0.0
247.5	No	434	106	112	98	36	34	27	13	3	2	3
-WSW	Pct	5.08	1.24	1.31	1.15	0.42	0.40	0.32	0.15	0.04	0.02	0.04
	Sd		17.1	11.2	9.0	5.5	5.0	4.9	4.4	4.4	4.6	3.9
270.0	No	524	131	125	91	52	50	39	21	12	0	3
-W-	Pct	6.14	1.53	1.46	1.07	0.61	0.59	0.46	0.25	0.14	0.00	0.04
	Sd		18.5	12.4	9.0	6.5	5.4	4.0	4.6	4.6	0.0	4.2
292.5	No	364	117	114	46	39	25	9	7	5	1	1
-WNW-	Pct	4.26	1.37	1.34	0.54	0.46	0.29	0.11	0.08	0.06	0.01	0.01
	Sd		17.5	11.2	9.2	7.2	7.7	8.6	7.4	5.8	4.2	6.7
315.0	No	515	204	199	55	33	17	3	3	0	1	0
-NW-	Pct	6.03	2.39	2.33	0.64	0.39	0.20	0.04	0.04	0.00	0.01	0.00
	Sd		15.5	9.5	7.6	9.3	5.2	6.9	6.4	0.0	7.5	0.0
337.5	No	684	268	303	92	14	4	3	0	0	0	0
-NNW-	Pct	8.01	3.14	3.55	1.08	0.16	0.05	0.04	0.00	0.00	0.00	0.00
	Sd		15.4	7.0	6.2	8.7	11.3	13.3	0.0	0.0	0.0	0.0
Calm	No	99										
	Pct	1.16	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total	No	8537	2581	3279	1385	632	295	157	71	26	5	7
	Pct	100.0	30.23	38.41	16.22	7.40	3.46	1.84	0.83	0.30	0.06	0.08

OCONEE METEOROLOGICAL SURVEY (TOWER DATA)

FOR PERIOD JUNE 19, 1968 THRU JUNE 19, 1969

SUMMARY OF PASQUILL F WIND OCCURRENCES BY SECTOR & SPEED CLASS (NO. OCCUR, PERCENT, STANDARD DEVIATION)

Wind Sector	Item	Sector Total	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >=9.5 M/S
-N-	No.	499	131	260	95	12	1	0	0	0	0	0
	Pct	5.76%	1.51%	3.00%	1.10%	0.14%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-NNE-	No.	166	68	66	29	3	0	0	0	0	0	0
	Pct	1.92%	0.79%	0.76%	0.33%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-NE-	No.	135	61	57	13	3	0	0	1	0	0	0
	Pct	1.56%	0.70%	0.66%	0.15%	0.03%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%
-ENE-	No.	57	36	20	0	1	0	0	0	0	0	0
	Pct	0.66%	0.42%	0.23%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-E-	No.	116	55	55	4	1	1	0	0	0	0	0
	Pct	1.34%	0.63%	0.64%	0.05%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-ESE-	No.	65	30	32	3	0	0	0	0	0	0	0
	Pct	0.75%	0.35%	0.37%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-SE-	No.	41	18	19	2	2	0	0	0	0	0	0
	Pct	0.47%	0.21%	0.22%	0.02%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-SSE-	No.	23	10	11	2	0	0	0	0	0	0	0
	Pct	0.27%	0.12%	0.13%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-S-	No.	19	6	10	2	1	0	0	0	0	0	0
	Pct	0.18%	0.07%	0.12%	0.02%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-SSW-	No.	39	16	18	4	0	0	1	0	0	0	0
	Pct	0.45%	0.18%	0.21%	0.05%	0.00%	0.00%	0.01	0.00	0.00%	0.00%	0.00%
-SW-	No.	95	29	40	15	10	1	0	0	0	0	0
	Pct	1.10%	0.33%	0.46%	0.17%	0.12%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-WSW-	No.	75	31	23	17	3	0	1	0	0	0	0
	Pct	0.87%	0.36%	0.27%	0.20%	0.03%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
-W-	No.	102	43	28	23	5	2	0	0	1	0	0
	Pct	1.18%	0.50%	0.32%	0.27%	0.06%	0.02%	0.00%	0.00%	0.01%	0.00%	0.00%
-WNW-	No.	101	40	42	10	8	1	0	0	0	0	0
	Pct	1.17%	0.46%	0.48%	0.12%	0.09%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-NW-	No.	222	87	105	21	9	0	0	0	0	0	0
	Pct	2.56%	1.00%	1.21%	0.24%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-NNW-	No.	352	110	188	52	2	0	0	0	0	0	0
	Pct	4.06%	1.27%	2.17%	0.60%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Calm	No.	27	---	---	---	---	---	---	---	---	---	---
	Pct	0.31%	---	---	---	---	---	---	---	---	---	---
Total	No.	2134	771	974	292	60	6	2	1	1	0	0
	Pct.	24.64%	8.90%	11.25%	3.37%	0.69%	0.07%	0.02%	0.01%	0.01%	0.00%	0.00%

Total Valid Observations: 8661

OCONEE METEOROLOGICAL SURVEY (TOWER DATA)

FOR PERIOD JUNE 19, 1968 THRU JUNE 19, 1969

SUMMARY OF PASQUILL E WIND OCCURRENCES BY SECTOR & SPEED CLASS (NO. OCCUR, PERCENT, STANDARD DEVIATION)

Wind Sector	Item	Sector Total	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.1-21.2 8.5-9.49	>21.2 MPH >=9.5 M/S
-N-	No.	458	118	247	77	12	4	0	0	0	0	0
	Pct	5.29%	1.36%	2.85%	0.89%	0.14%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%
-NNE-	No.	166	52	85	23	3	2	1	0	0	0	0
	Pct	1.92%	0.68%	0.98%	0.27%	0.03%	0.02%	0.01%	0.00%	0.00%	0.00%	0.00%
-NE-	No.	138	40	61	26	10	1	0	0	0	0	0
	Pct	1.59%	0.46%	0.70%	0.30%	0.12%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-ENE-	No.	55	18	23	9	4	1	0	0	0	0	0
	Pct	0.64%	0.21%	0.27%	0.10%	0.05%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-E-	No.	56	25	23	4	4	0	0	0	0	0	0
	Pct	0.65%	0.29%	0.27%	0.05%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-ESE-	No.	42	18	20	1	2	0	1	0	0	0	0
	Pct	0.49%	0.21%	0.23%	0.01%	0.02%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
-SE-	No.	41	4	29	5	3	0	0	0	0	0	0
	Pct	0.47%	0.05%	0.34%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
-SSE-	No.	33	10	13	9	0	1	0	0	0	0	0
	Pct	0.38%	0.12%	0.15%	0.10%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-S-	No.	32	9	14	3	2	4	0	0	0	0	0
	Pct	0.37%	0.10%	0.16%	0.03%	0.02%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%
-SSW-	No.	51	6	20	7	13	4	1	0	0	0	0
	Pct	0.59%	0.07%	0.23%	0.08%	0.15%	0.05%	0.01%	0.00%	0.00%	0.00%	0.00%
-SW-	No.	130	22	46	34	22	6	0	0	0	[illegible]	0
	Pct	1.50%	0.25%	0.53%	0.39%	0.25%	0.07%	0.00%	0.00%	0.00%	0.00%	0.00%
-WSW-	No.	103	18	27	28	16	11	3	0	0	0	0
	Pct	1.19%	0.21%	0.31%	0.32%	0.18%	0.13%	0.03%	0.00%	0.00%	0.00%	0.00%
-W-	No.	136	25	27	30	22	17	10	4	1	0	0
	Pct	1.57%	0.29%	0.31%	0.35%	0.25%	0.20%	0.12%	0.05%	0.01%	0.00%	0.00%
-WNW-	No.	82	24	28	10	14	4	1	1	0	0	0
	Pct	0.95%	0.28%	0.32%	0.12%	0.16%	0.05%	0.01%	0.01%	0.00%	0.00%	0.00%
-NW-	No.	89	36	31	8	6	8	0	0	0	0	0
	Pct	1.03%	0.42%	0.36%	0.09%	0.07%	0.09%	0.00%	0.00%	0.00%	0.00%	0.00%
-NNW-	No.	127	54	54	15	3	1	0	0	0	0	0
	Pct	1.47%	0.62%	0.62%	0.17%	0.03%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
Calm	No.	14	---	---	---	---	---	---	---	---	---	---
	Pct	0.16%	---	---	---	---	---	---	---	---	---	---
Total	No.	1753	479	748	289	136	64	17	5	1	0	0
	Pct	20.25%	5.53%	8.64%	3.34%	1.57%	0.74%	0.20%	0.06%	0.01%	0.00%	0.00%

Total Valid Observations: 8656

OCONEE METEOROLOGICAL SURVEY (TOWER DATA)

FOR PERIOD JUNE 19, 1968 THRU JUNE 19, 1969

SUMMARY OF PASQUILL D WIND OCCURRENCES BY SECTOR & SPEED CLASS (NO. OCCUR, PERCENT, STANDARD DEVIATION)

Wind Sector	Item	Sector Total	1.0-3.2 .45-1.49	3.3-5.5 1.5-2.49	5.6-7.8 2.5-3.49	7.9-10.0 3.5-4.49	10.1-12.3 4.5-5.49	12.4-14.5 5.5-6.49	14.6-16.7 6.5-7.49	16.8-19.0 7.5-8.49	19.2-21.2 8.5-9.49	>21.2 MPH >=9.5 M/S
-N-	No.	505	211	188	73	18	10	3	2	0	0	0
	Pct	5.86%	2.49%	2.18%	0.85%	0.21%	0.12%	0.03%	0.02%	0.00%	0.00%	0.00%
-NNE-	No.	371	138	161	40	14	7	3	4	3	1	0
	Pct	4.30%	1.60%	1.87%	0.46%	0.16%	0.08%	0.03%	0.05%	0.03%	0.01%	0.00%
-NE-	No.	566	121	163	145	72	34	15	13	3	0	0
	Pct	6.57%	1.40%	1.89%	1.68%	0.84%	0.39%	0.17%	0.15%	0.03%	0.00%	0.00%
-ENE-	No.	374	76	100	85	77	23	10	3	0	0	0
	Pct	4.34%	0.88%	1.16%	0.99%	0.89%	0.27%	0.12%	0.03%	0.00%	0.00%	0.00%
-E-	No.	336	97	117	66	41	8	6	1	0	0	0
	Pct	3.90%	1.13%	1.36%	0.77%	0.48%	0.09%	0.07%	0.01%	0.00%	0.00%	0.00%
-ESE-	No.	213	84	90	29	6	4	0	0	0	0	0
	Pct	2.45%	0.97%	1.04%	0.34%	0.07%	0.05%	0.00%	0.00%	0.00%	0.00%	0.00%
-SE-	No.	224	65	105	40	13	1	0	0	0	0	0
	Pct	2.60%	0.75%	1.22%	0.46%	0.15%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-SSE-	No.	104	32	50	15	6	1	0	0	0	0	0
	Pct	1.21%	0.37%	0.58%	0.17%	0.07	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-S-	No.	122	28	79	10	4	1	0	0	0	0	0
	Pct	1.42%	0.32%	0.92%	0.12%	0.05%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
-SSW-	No.	214	27	72	48	42	16	8	1	0	0	0
	Pct	2.48%	0.31%	0.84%	0.56%	0.49%	0.19%	0.09%	0.01%	0.00%	0.00%	0.00%
-SW-	No.	406	79	131	77	57	34	27	1	0	0	0
	Pct	4.71%	0.92%	1.52%	0.89%	0.66%	0.39%	0.31%	0.01%	0.00%	0.00%	0.00%
-WSW-	No.	254	71	54	50	17	27	20	7	3	2	3
	Pct	2.95%	0.82%	0.63%	0.58%	0.20%	0.31%	0.23%	0.08%	0.03%	0.02%	0.03%
-W-	No.	287	63	70	38	25	31	24	17	11	0	3
	Pct	3.33%	0.73%	0.81%	0.44%	0.29%	0.36%	0.34%	0.20%	0.13%	0.00%	0.03%
-WNW-	No.	180	52	44	26	17	20	8	6	5	1	1
	Pct	2.09%	0.60%	0.51%	0.30%	0.20%	0.23%	0.09%	0.07%	0.06%	0.01%	0.01%
-NW-	No.	203	81	62	26	18	9	3	3	0	1	0
	Pct	2.36%	0.94%	0.72%	0.30%	0.21%	0.10%	0.03%	0.03%	0.00%	0.01%	0.00%
-NNW-	No.	200	102	58	25	9	3	3	0	0	0	0
	Pct	2.31%	1.18%	0.67%	0.29%	0.10%	0.03%	0.03%	0.00%	0.00%	0.00%	0.00%
Calm	No.	52	---	---	---	---	---	---	---	---	---	---
	Pct	0.60%	---	---	---	---	---	---	---	---	---	---
Total	No.	4611	1327	1544	793	436	229	135	58	25	5	7
	Pct	53.50%	15.40%	17.91%	9.20%	5.06%	2.66%	1.57%	0.67%	0.29%	0.06%	0.08%

Total Valid Observations: 8619

Note: Class D includes stability categories (A+B+C+D)

Table 2-40. Deleted per 2008 Update

Table 2-41. Deleted per 2008 Update

Table 2-42. Deleted per 2008 Update

Table 2-43. Deleted per 2008 Update

Table 2-44. Supplemental Data - SF_6 Detector Readings - Test Date: January 28, 1970

Point Number	Time (24 hr. clock)	Recorder Reading (%)
1	2111	56
2	2117	0
9A	2121	0
9B	2124	0
9C	2126	0
8	2131	0
1A	2134	0
1B	2136	0
1C	2138	0
1	2141	0
10A	2145	67
10B	2148	100
10C	2150	0
2A	2153	0
2B	2155	0
2C	2157	0
3	2159	2
3B	2202	0
3C	2205	0
3D	2207	0
3E	2210	0
3F	2213	0
4	2215	0
3	2221	0
2B	2223	0
2	2227	100
10A	2227	100
10C	2230	100
10D	2233	100
10E	2235	100
1D	2238	100

Table 2-45. Deleted per 2008 Update

Table 2-46. Deleted per 2008 Update

Table 2-47. Deleted per 2008 Update

Table 2-48. Deleted per 2008 Update

Table 2-49. Deleted per 2008 Update

Table 2-50. Deleted per 2008 Update

Table 2-51. Deleted per 2008 Update

Table 2-52. Deleted per 2008 Update

Table 2-53. Deleted per 2008 Update

Table 2-54. Deleted per 2008 Update

Table 2-55. Deleted per 2008 Update

Table 2-56. Deleted per 2008 Update

Table 2-57. Deleted per 2008 Update

Table 2-58. Deleted per 2008 Update

Table 2-59. Deleted per 2008 Update

Table 2-60. Deleted per 2008 Update

Table 2-61. Deleted per 2008 Update

Table 2-62. Deleted per 2008 Update

Table 2-63. Deleted per 2008 Update

Table 2-64. Deleted per 2008 Update

Table 2-65. Deleted per 2008 Update

Table 2-66. Deleted per 2008 Update

Table 2-67. Deleted per 2008 Update

Table 2-68. Deleted per 2008 Update

Table 2-69. Deleted per 2008 Update

Table 2-70. Deleted per 2008 Update

Table 2-71. Deleted per 2008 Update

Table 2-72. Deleted per 2008 Update

Table 2-73. Deleted per 2008 Update

Table 2-74. Deleted per 2008 Update

Table 2-75. Deleted per 2008 Update

Table 2-76. Deleted per 2008 Update

Table 2-77. Deleted per 2008 Update

Table 2-78. Deleted per 2008 Update

Table 2-79. Deleted per 2008 Update

Table 2-80. Deleted per 2008 Update

Table 2-81. Deleted per 2008 Update

Table 2-82. Deleted per 2008 Update

Table 2-83. Deleted per 2008 Update

Table 2-84 Deleted per 2008 Update

Table 2-85. Deleted per 2008 Update

Table 2-86. Deleted per 2008 Update

Table 2-87. Deleted per 2008 Update

Table 2-88. Deleted per 2008 Update

Table 2-89. Deleted per 2008 Update

Table 2-90. Deleted per 2008 Update

Table 2-91. Deleted per 2008 Update

Table 2-92. Deleted per 2008 Update

Table 2-93. Soil Permeability Test Results

WELL NO.	h (ft)	r (ft)	$\frac{h}{r}$	T_u (ft)	Q (ft^3/min)	T (°C)	WT Condition	k (ft./min)
NA-4W2	3.83	2.50	1.53 (1)	27.0	0.0175	23.5	Low	3.9×10^{-5}
NA-11AW2	14.0	0.833	16.8	31.0	0.133	20.5	High	3.3×10^{-4}
NA-13W1	6.17	0.833	7.42 (2)	27.0	0.0275	20.0	Low	2.0×10^{-4}
NA-15W1	14.0	0.833	16.8	30.3	0.240	20.5	High	6.1×10^{-4} (3)
NA-15W2	12.25	0.833	14.7	30.5	0.190	21.0	High	5.1×10^{-4}

Note:

1. $\frac{h}{r} << 10$, not acceptable
2. $\frac{h}{r} < 10$, possibly acceptable
3. For manual incremental test, $k = 7.4x10^{-4}\ ft/min$

Table 2-94. Significant Earthquakes in the Southeast United States (Intensity V or Greater)

Year	Date	Intensity (Modified Mercalli)	Epicentral Location: Locality	Epicentral Location: N.Lat.	Epicentral Location: W.Long.	Perceptible Area (Square Miles)
1843	January 4	VIII	Western Tennessee	35.2	90.0	400,000
1857	December 19	Not Listed	Charleston, S.C.	32.8	79.8	Not Listed
1872	June 17	V	Milledgeville, Ga.	33.1	83.3	Not Listed
1874	February 10 April 17	V	McDowell County, N.C.	35.7	82.1	Local
1875	November 1	VI	Northern Georgia	33.8	82.5	25,000
1875	December 22	VII	Arvonia, Virginia	37.6	78.5	50,000
1877	November 16	V	Western N.C. and Eastern Tennessee	35.5	84.0	5,000
1879	December 12	V	Charlotte, N.C.	35.2	80.8	Not Listed
1884	January 18	V	Wilmington, N.C.	34.3	78.0	Local
1885	August 6	IV-V	North Carolina	36.2	81.6	Local
1886	February 4	V	Alabama	32.8	88.0	1,600
1886	August 31	IX-X	Charleston, S.C	32.9	80.0	2,000,000
1886	October 22	VI	Charleston, S.C.	32.9	80.0	30,000
	October 22	VII	Charleston, S.C.	32.9	80.0	30,000
1886	November 5	VI	Charleston, S.C.	32.9	80.0	30,000
1889	July 19	VI	Memphis, Tenn.	35.2	90.0	Local
1897	April 30	IV-V	Tennessee and Ill.	Not Listed	Not Listed	Not Listed
1897	December 18	V	Ashland, Virginia	37.7	77.5	7,500

Year	Date	Intensity (Modified Mercalli)	Epicentral Location			Perceptible Area (Square Miles)
			Locality	N.Lat.	W.Long.	
1900	October 31	V	Jacksonville Fla.	30.4	81.7	Local
1902	October 18	V	Southeastern Tenn. and Northwestern Ga.	35.0	85.3	1,500
1903	January 23	VI	Georgia and S.C.	32.1	81.1	10,000
1904	March 4	V	Eastern Tenn.	35.7	83.5	5,000
1905	January 27-8	VII	Alabama	34	86	250,000
1907	April 19	V	South Carolina	32.9	80.0	10,000
1911	April 20	V	North Carolina- South Carolina Border	35.2	82.7	600
1912	June 12	VII	Summerville, S.C.	32.9	80.0	35,000
1912	June 20	V	Savannah, Georgia	32	81	Not Listed
1913	January 1	VII-VIII	Union County, S.C.	34.7	81.7	43,000
1913	March 28	VII	Eastern Tennessee	36.2	83.7	2,700
1913	April 17	V	Eastern Tennessee	35.3	84.2	3,500
1914	January 23	V	Eastern Tennessee	35.6	84.5	Local
1914	March 5	VI	Georgia	33.5	83.5	50,000
1914	September 22	V	South Carolina	33.0	80.3	30,000
1915	October 29	V	North Carolina	35.8	82.7	1,200
1916	February 21	VI	Western N.C.	35.5	82.5	200,000
1916	August 26	V	Western N.C.	36	81	3,800

Year	Date	Intensity (Modified Mercalli)	Epicentral Location: Locality	N.Lat.	W.Long.	Perceptible Area (Square Miles)
1916	October 18	VII	Alabama	33.5	86.2	100,000
1917	June 29	V	Alabama	32.7	87.5	Local
1918	June 21	V	Tennessee	36.1	84.1	3,000
1918	October 15	V	Western Tennessee	35.2	89.2	20,000
1920	December 24	V	Eastern Tennessee	36	85	Local
1924	October 20	V	Pickens County, S.C.	35.0	82.6	56,000
1926	July 8	VI	Southern Mitchell County, N.C.	35.9	82.1	Local
1927	June 16	V	Alabama	34.7	86.0	2,500
1928	November 2	VI	Western N.C.	36.0	82.6	40,000
1931	May 5	V-VI	Northern Alabama	33.7	86.6	6,500
1933	December 19	IV-V	Summerville, S.C.	33.0	80.2	Local
1935	January 1	V	North Carolina- Georgia Border	35.1	83.6	7,000
1939	May 4	V	Anniston, Ala.	33.7	85.8	Not Listed
1941	November 16	V-VI	Covington, Tenn.	35.5	89.7	Local
1945	June 13	V	Cleveland, Tenn.	35	84.5	Not Listed
1945	July 26	VI	Murray Lake, S.C.	34.3	81.4	25,000
1952	November 19	V	Charleston, S.C.	32.8	80.0	Not Listed
1952	July 16	VI	Dyersburg, Tenn.	36.2	89.6	Not Listed
1954	January 22	V	Athens and Etowah, Tennessee	35.3	84.4	Not Listed
1954	April 26	V	Memphis, Tenn.	35.2	90.1	Not Listed
1955	January 25	VI	Tenn-Arkansas- Missouri Border	35.6	90.3	30,000

Year	Date	Intensity (Modified Mercalli)	Epicentral Location: Locality	N.Lat.	W.Long.	Perceptible Area (Square Miles)
1955	March 29	VI	Finley, Tenn.	36.0	89.5	Not Listed
1955	September 5	V	Finley, Tenn.	36.0	89.5	Not Listed
1955	September 28	V	Virginia-N.C. Border	Not Listed	Not Listed	1,700
1955	December 13	V	Dyer County, Tenn.	36	89.5	Not Listed
1956	September 7	VI	Eastern Tennessee	35.5	84.0	8,300
1956	January 28	VI	Tennessee-Arkansas Border	35.6	89.6	Not Listed
1957	April 23	VI	Northern Alabama	34.5	86.7	11,500
1957	May 13	VI	Western N.C.	35.7	82	8,100
1957	June 23	V	Eastern Central Tennessee	36.5	84.5	Not Listed
1957	July 2	VI	Western N.C.	35.5	83.5	Not Listed
1957	November 24	VI	North Carolina- Tennessee Border	35	83.5	4,100
1958	March 5	V	Wilmington, N.C.	34.2	77.7	Not Listed
1958	April 8	V	Obion County, Tenn.	36.2	89.1	400
1958	October 20	V	Anderson, S.C.	34.5	82.7	Local
1959	August 3	VI	South Carolina	33	79.5	25,000
1959	August 12	VI	Alabama-Tennessee Border	35	87	2,800
1959	October 26	VI	Northeastern S.C.	34.5	80.2	4,800
1959	December 21	V	Finley, Tenn.	36	89.5	400
1960	January 28	V	Dyer County, Tenn.	36	89.5	Local
1960	March 12	V	Near Coast, S.C.	33	79	3,500

Year	Date	Intensity (Modified Mercalli)	Epicentral Location			Perceptible Area (Square Miles)
			Locality	N.Lat.	W.Long.	
1960	April 15	V	Eastern Tenn.	35.7	84	1,300
1960	April 21	V	Lake County, Tenn.	36.3	89.5	Local
1960	July 23	V	Charleston, S.C.	33	80	Local
1971	July 13	IV-VI	Seneca, S.C.	34 -35	82 -83	Local
1979	August 25	VI	Lake Jocassee, S.C.	35	83	5,800
1979	September 12	V	southwestern North Carolina	35.6	83.9	Not Listed
1980	July 27	VII	NE Kentucky, near Sharpsburg, KY	38.2	83.9	258,000
1980	December 2	VI	northwest Tennessee	36.2	89.4	800
1981	April 9	V	western North Carolina	35.5	82.1	Not Listed
1981	May 5	VI	near Hendersonville, NC	35.3	82.4	4,000
1981	August 7	VI	western Tennessee	36.0	89.1	4,000
1982	September 24	V	eastern Tennessee	35.7	84.3	Not Listed
1982	October 31	V	western Georgia	32.7	84.9	Not Listed
1983	March 25	V	western North Carolina	35.3	82.5	Not Listed
1983	November 6	V	near Charleston, SC	32.9	80.2	Not Listed
1984	February 14	VI	eastern Tennessee	36.1	83.7	Local
1984	August 17	V	central Virginia	37.9	78.3	Not Listed
1984	October 9	VI	near Ringgold, GA	34.8	85.2	3,100
1986	July 11	VI	northwest GA, near Chattanooga, TN	34.9	85.0	5,000
1986	December 10	V	central Virginia	37.6	77.5	25

Year	Date	Intensity (Modified Mercalli)	Epicentral Location			Perceptible Area (Square Miles)
			Locality	N.Lat.	W.Long.	
1987	March 27	VI	near Greenback, TN	35.6	84.2	9,000
1987	July 11	V	eastern Tennessee	36.1	83.8	Not Listed
1988	January 23	V	near Charleston, SC	32.9	80.2	Not Listed
1988	September 7	VI	NE Kentucky, near Sharpsburg, KY	38.1	83.9	40,000
1989	August 20	VI	near Littleville, AL	34.7	87.7	2,300
1990	November 13	V	near Charleston, SC	32.9	80.0	Not Listed

Table 2-95. Velocity Measurements

Boring	Depth of Core	Rock Description	Velocity (ft/sec)	Specific Gravity
NA-9	8.5'	Weathered Granite Gneiss	5,270	2.44
NA-4	31.0'	Granite Gneiss	11,900	2.85
NA-4	66.0'	Biotite Hornblende Gneiss	10,000	2.65
NA-9	90.0'	Granite Gneiss	10,100	2.68

Table 2-96. Core Measurements

Boring	Depth of Core	Description of Rock	Average Young's Modulus (E) (psi)	Average Poisson's Ration (σ)	Ultimate Crushing Strength (psi)
NA-4	14.0'	Weathered Granite Gneiss	$1.5x10^6$	(0.50) (1) (0.28)	5,000
NA-9	26.5'	Weathered Granite Gneiss	$1.8x10^6$	0.15	6,610
NA-9	41.0'	Slightly Weathered Granite Gneiss	$2.4x10^6$	0.20	7,540
NA-4	47.5'	Granite Gneiss	$4.8x10^6$	0.18	15,520
NA-9	55.0'	Biotite Hornblende Gneiss	$4.1x10^6$	0.11	(3)
NA-9	59.5'	Granite Gneiss	$5.1x10^6$	0.20(2)	16,480
NA-9	71.5'	Biotite Hornblende Gneiss	$(3.2x10^6)$(1) $(11.4x10^6)$	0.21	8,270
NA-9	98.0'	Granite Gneiss	$5.9x10^6$	0.20	12,320

Note:

1. Values are too far apart to average.
2. Single value, other strain gauge set did not work.
3. End failure on weak area of core, value approximately 11,000.

Appendix 2B. Figures

Figure 2-1. General Location

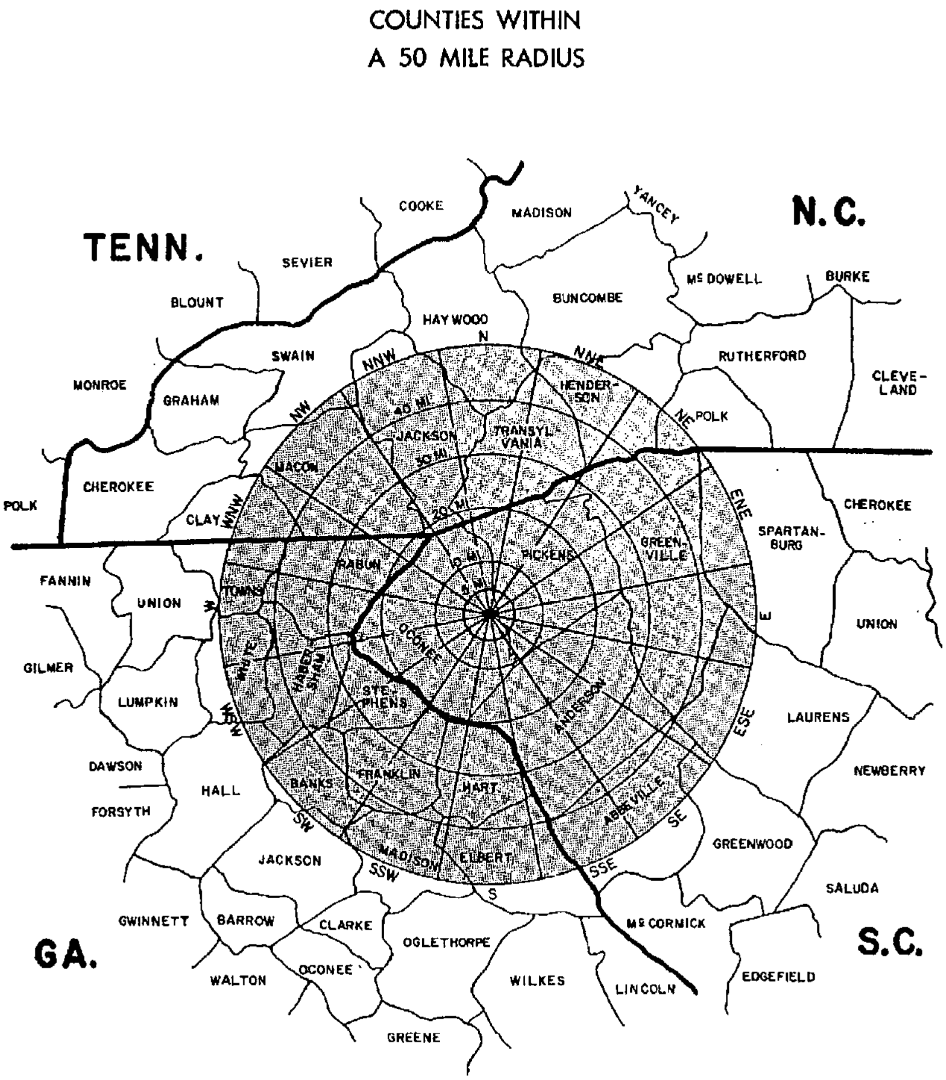


Figure 2-2. Topography within 5 Miles

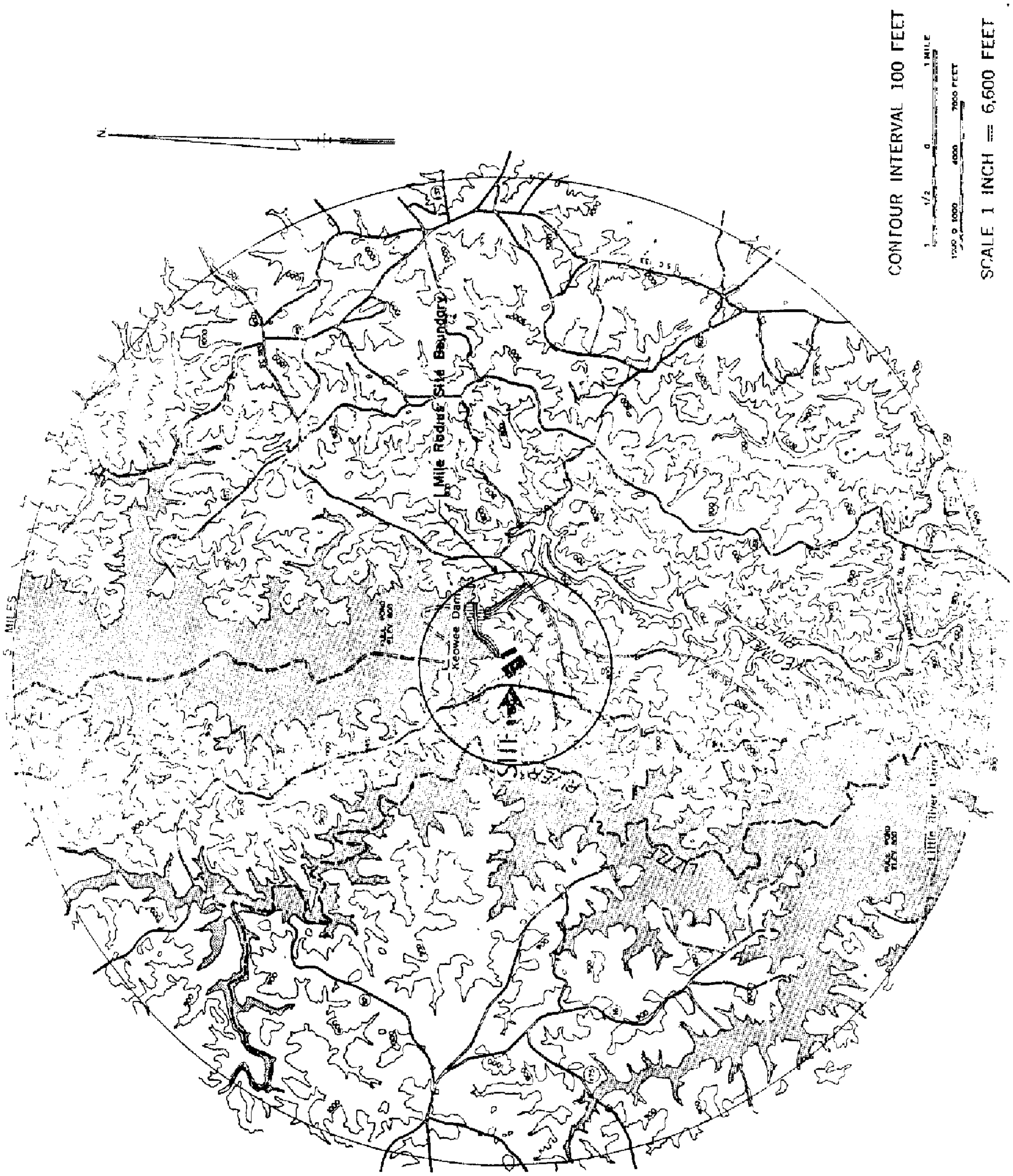


Figure 2-3. General Area Map

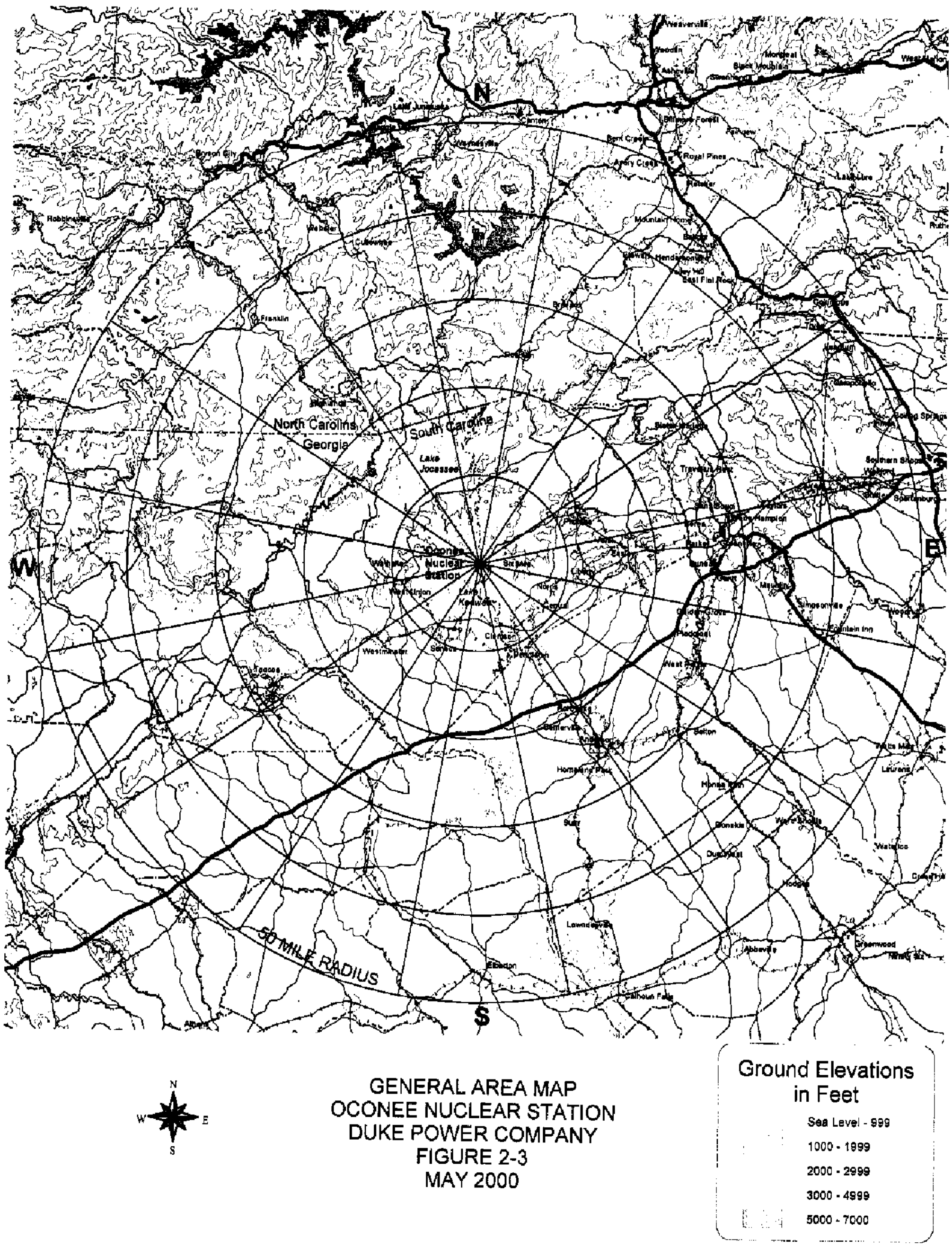


Figure 2-4. Site Plan

Figure 2-5. Radioactive Effluent Site Boundaries

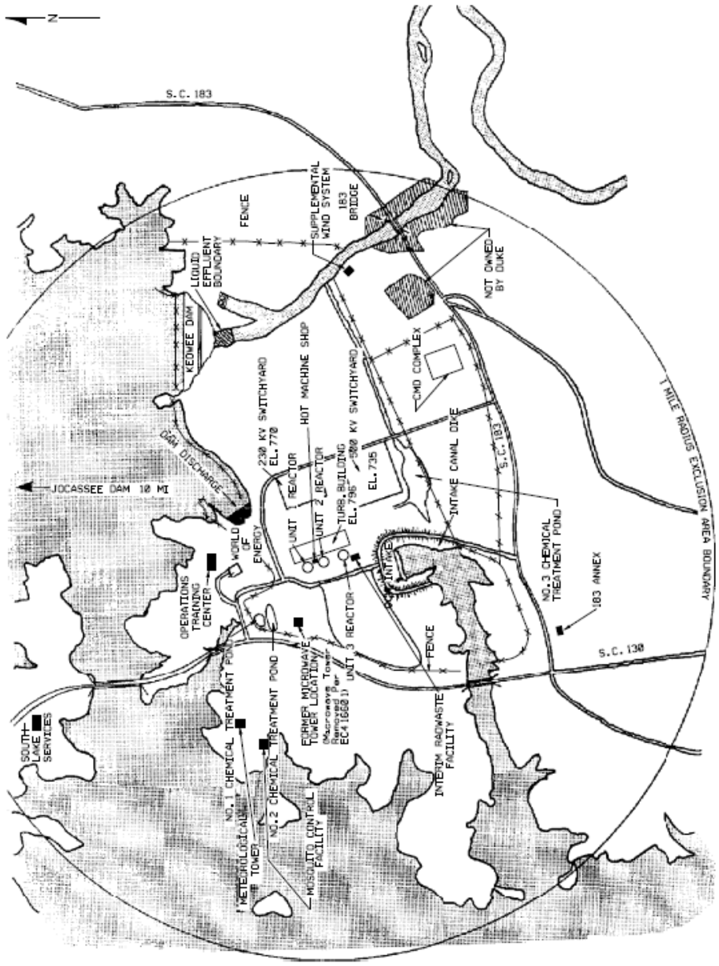
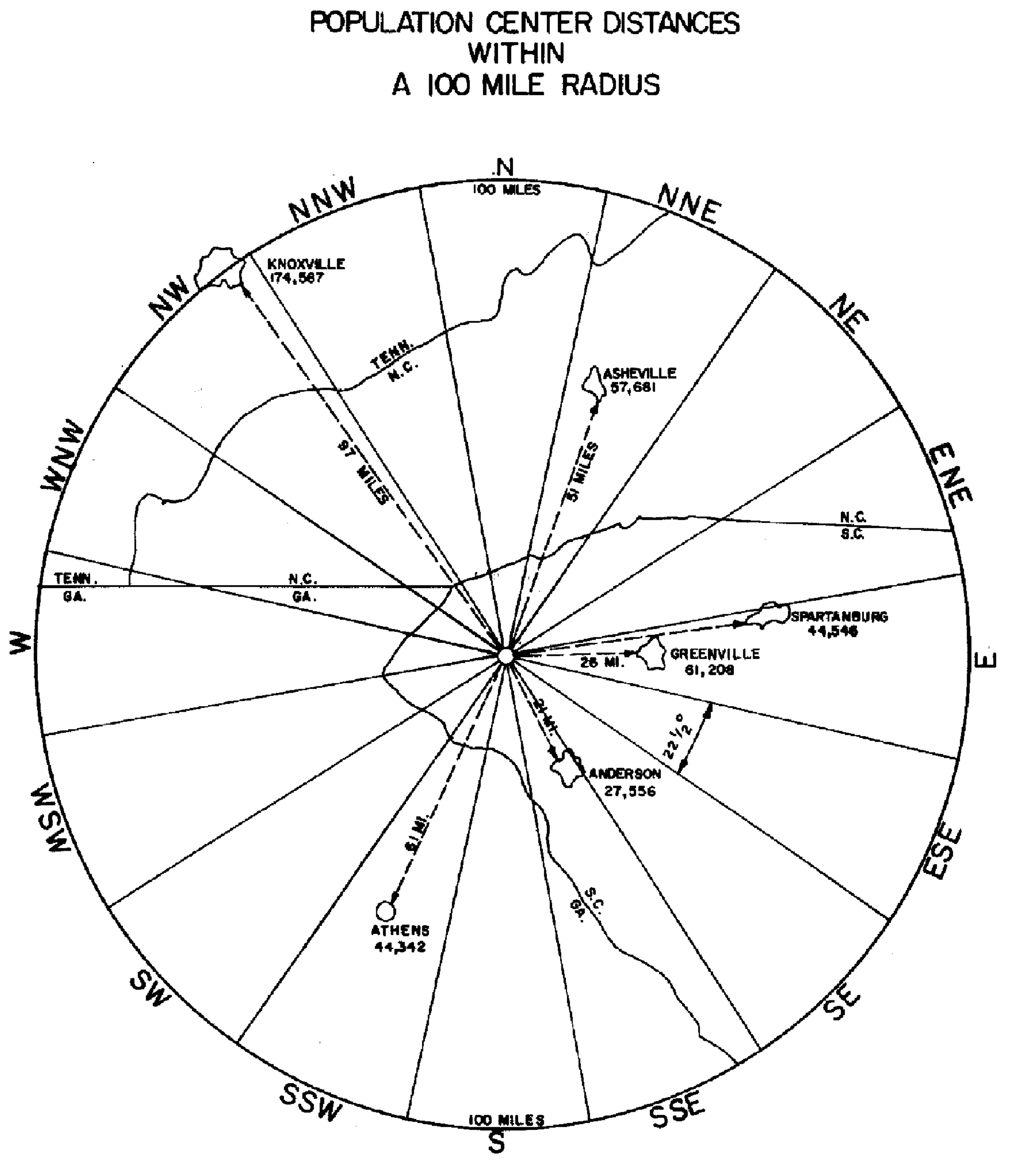


Figure 2-6. Population Centers within 100 Miles

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"



SOURCE: U.S. CENSUS 1970

Figure 2-7. Forecast of High-Pollution-Potential Days in the U.S.
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

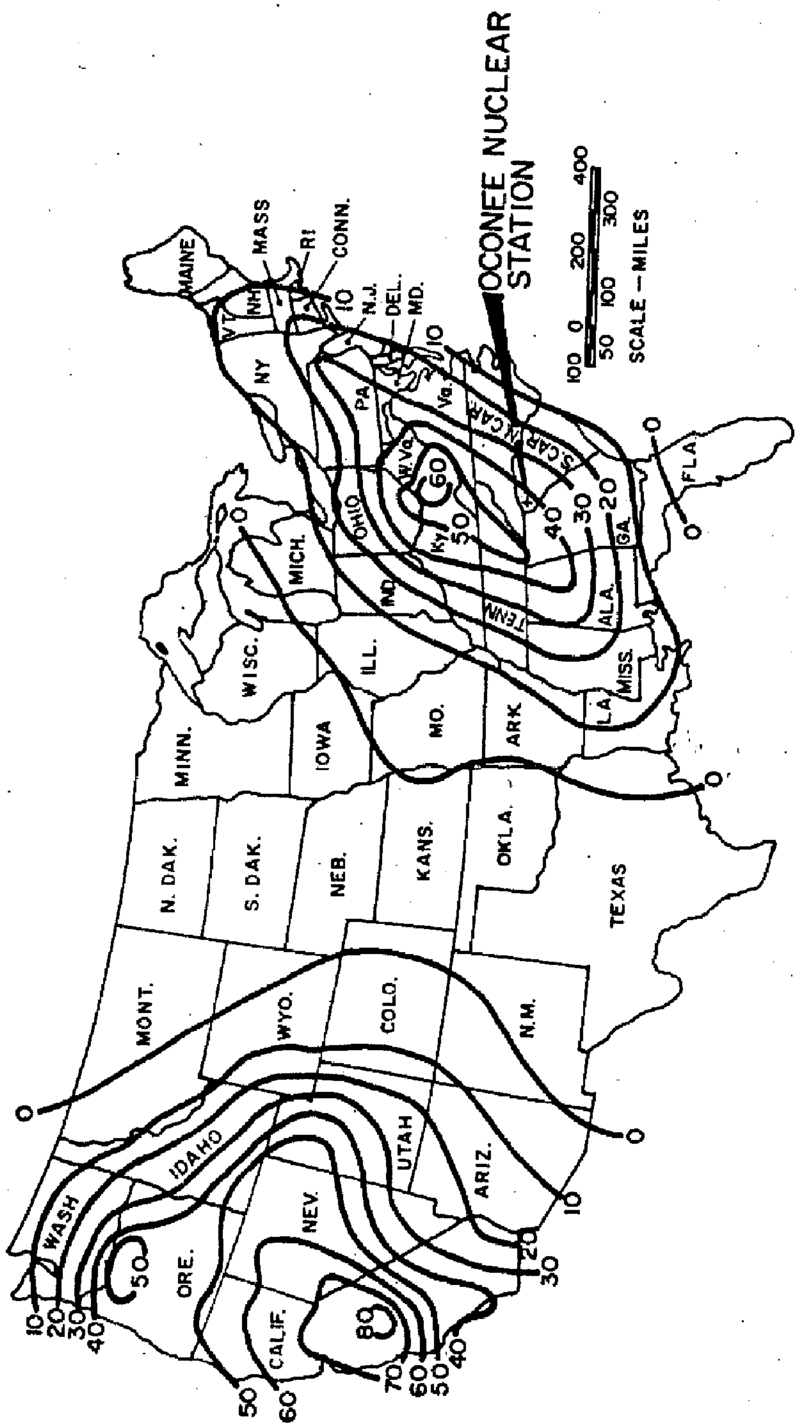


Figure 2-8. Annual Surface Wind Rose for Greenville, South Carolina, WBAS (1959-1963)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

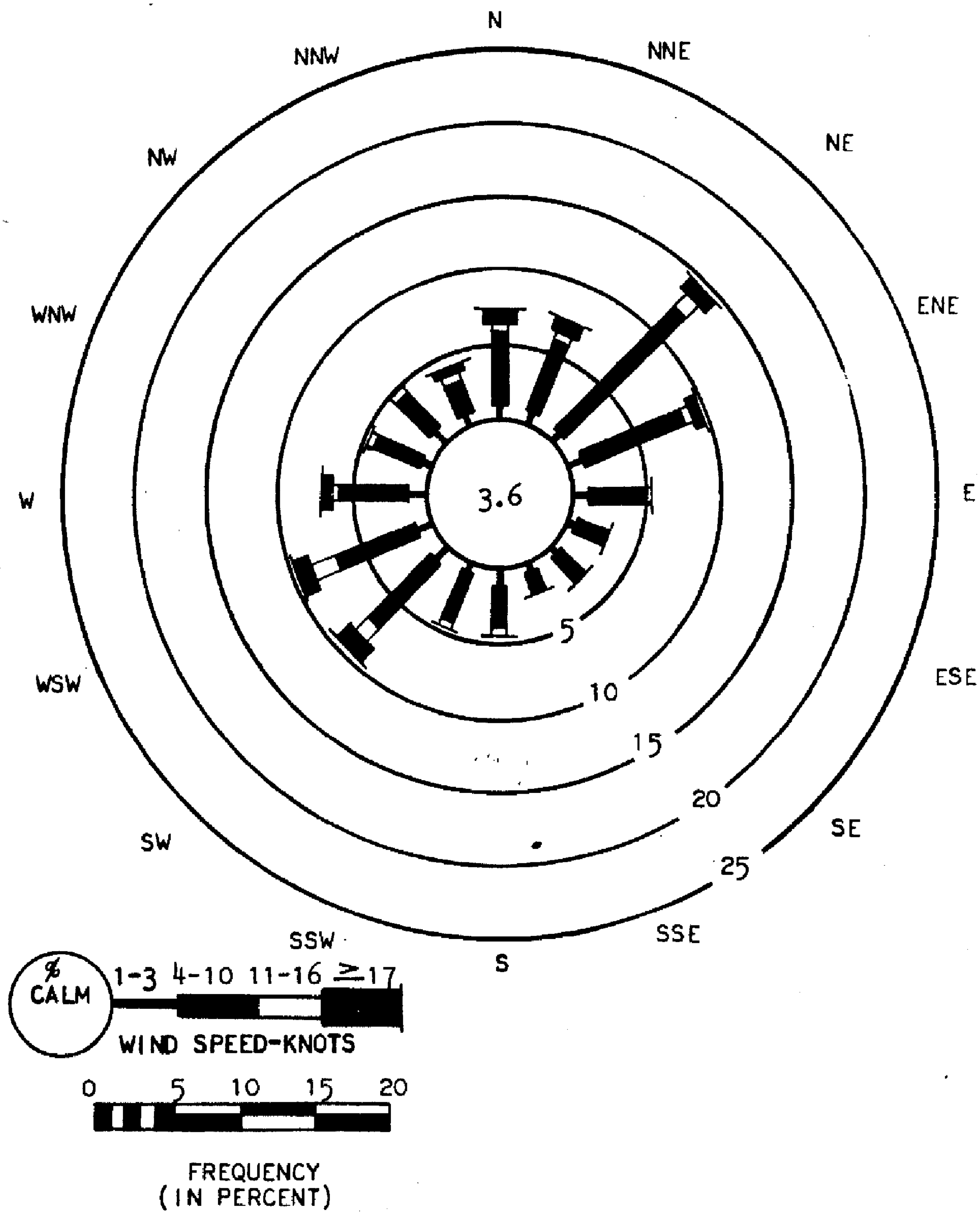
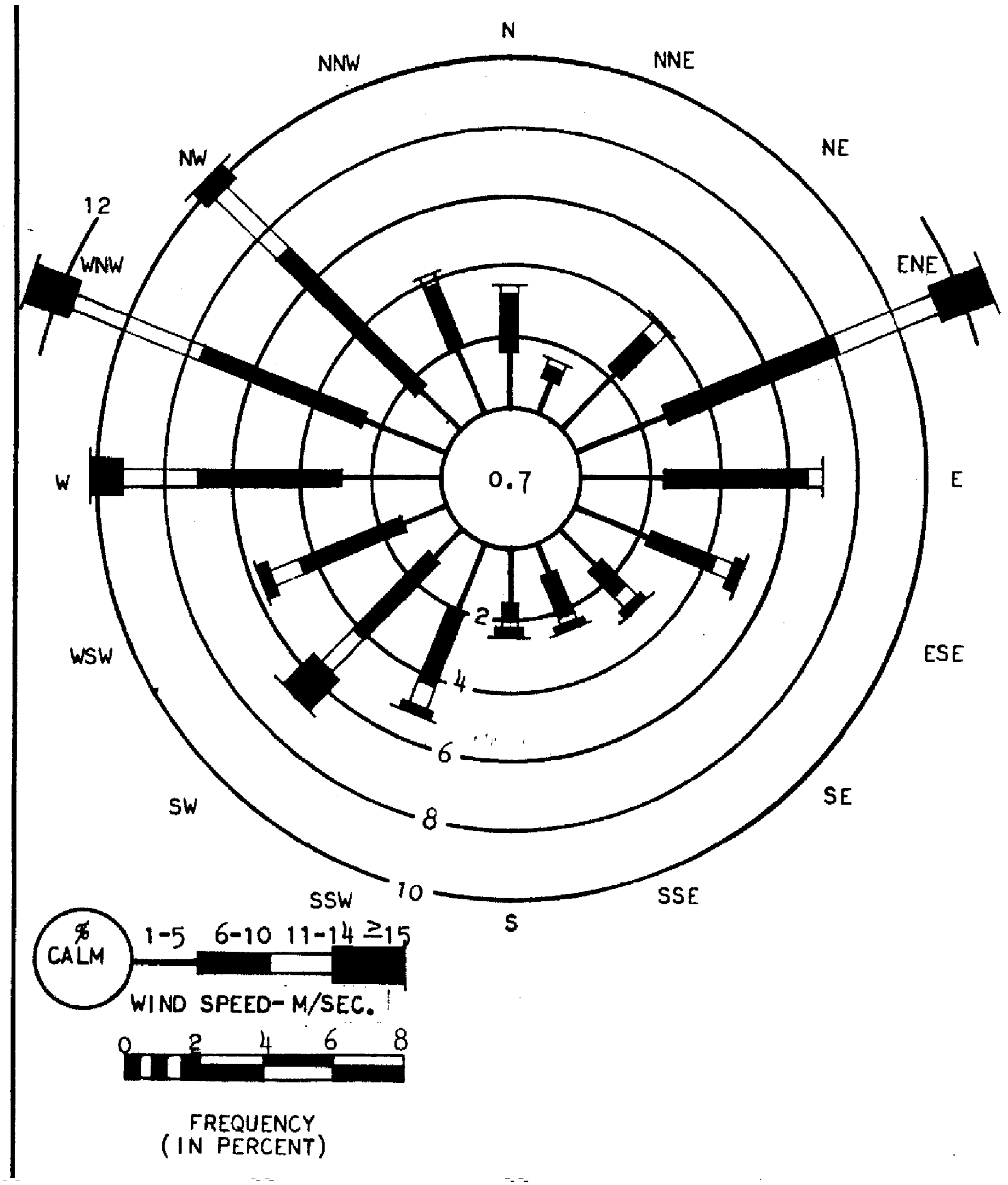


Figure 2-9. Upper Air Wind Rose-Athens, Georgia. 800-1300 ft above ground. (Dec 1954 - Nov 1961)

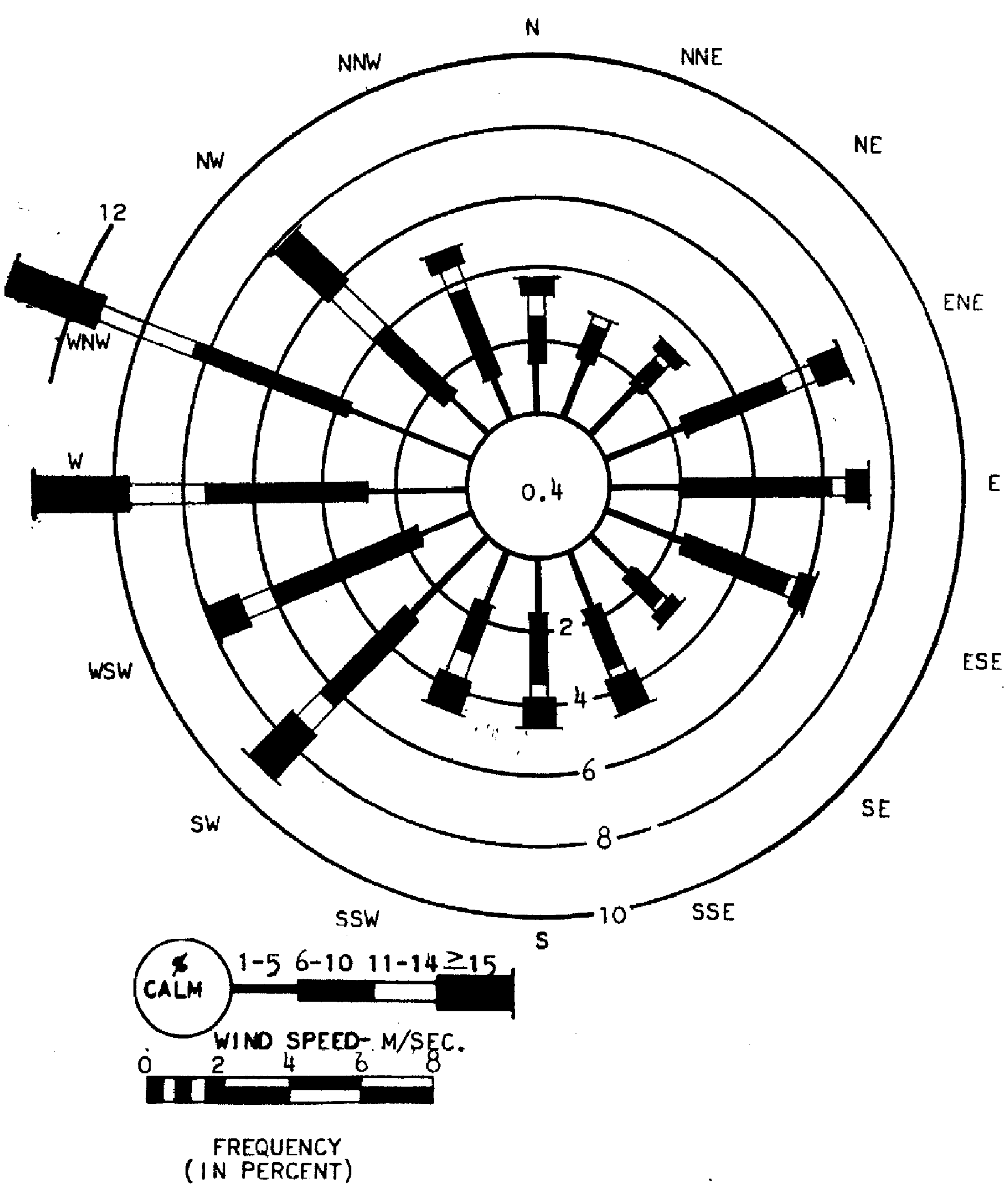
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]



Reference 16

Figure 2-10. Upper Air Wind Rose-Athens, Georgia. 2300-2800 ft above ground. (Dec 1959 - Nov 1961))

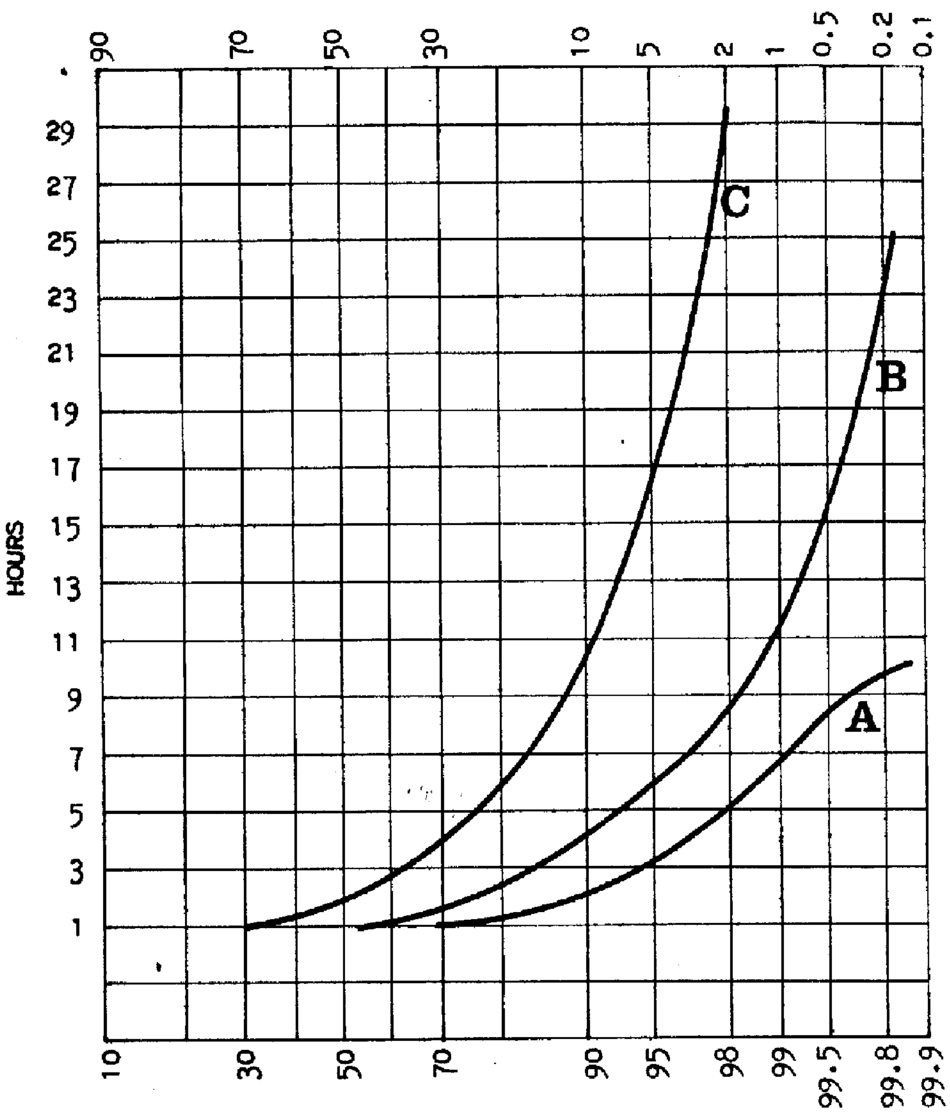
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]



Reference 16

Figure 2-11. Cumulative Probability of Wind Direction Persistence Duration at Greenville, SC

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]



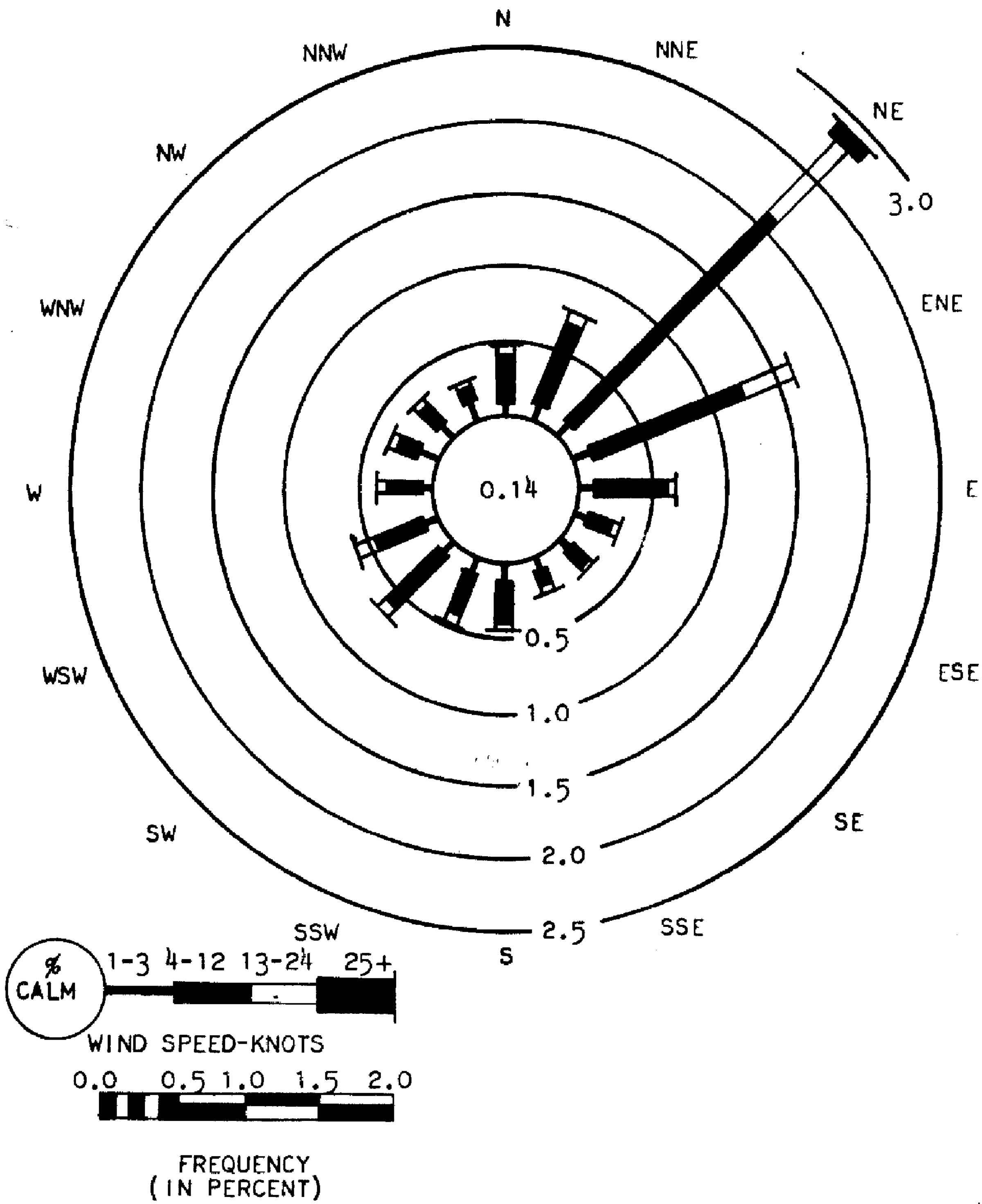
CURVE A-SINGLE SECTOR WINDS

CURVE B-SINGLE SECTOR WINDS PLUS AND MINUS
ONE ADDITIONAL SECTOR

CURVE C-SINGLE SECTOR WINDS PLUS AND MINUS
TWO ADDITIONAL SECTORS

Figure 2-12. Precipitation Surface Wind Rose for Greenville, South Carolina, WBAS (1959 - 1963)

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]



(Reference 17)

Figure 2-13. Surface Wind Direction Frequency Distribution During Low-Level Temperature Inversion Conditions

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

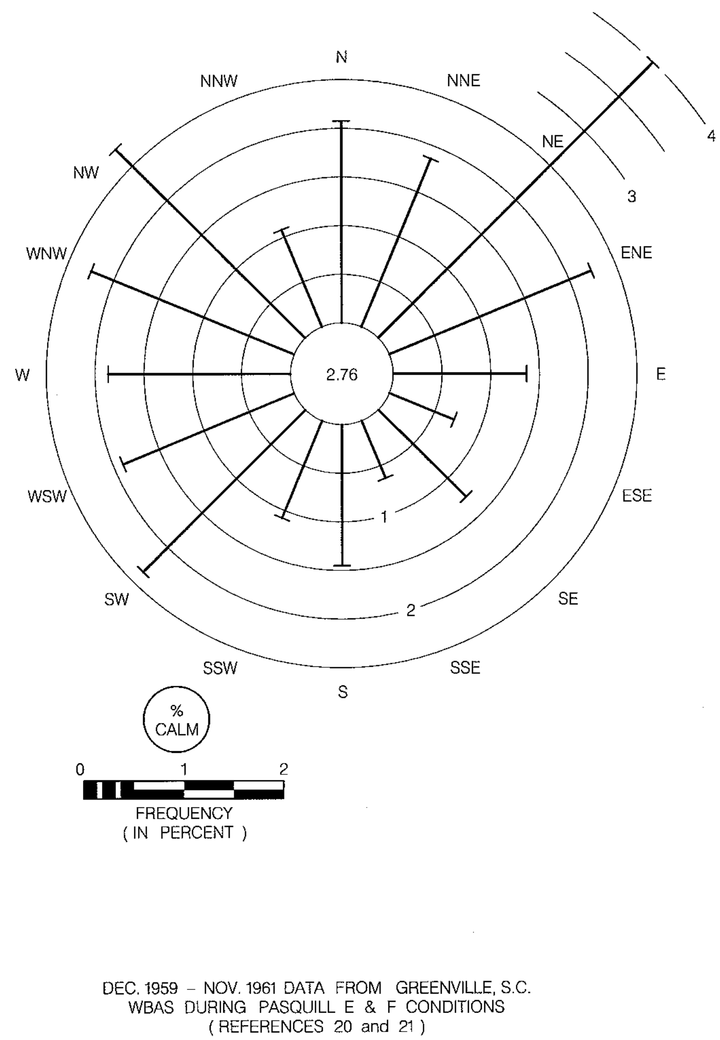


Figure 2-14. Maximum Topographic Elevation versus Distance (NNE and N sectors)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

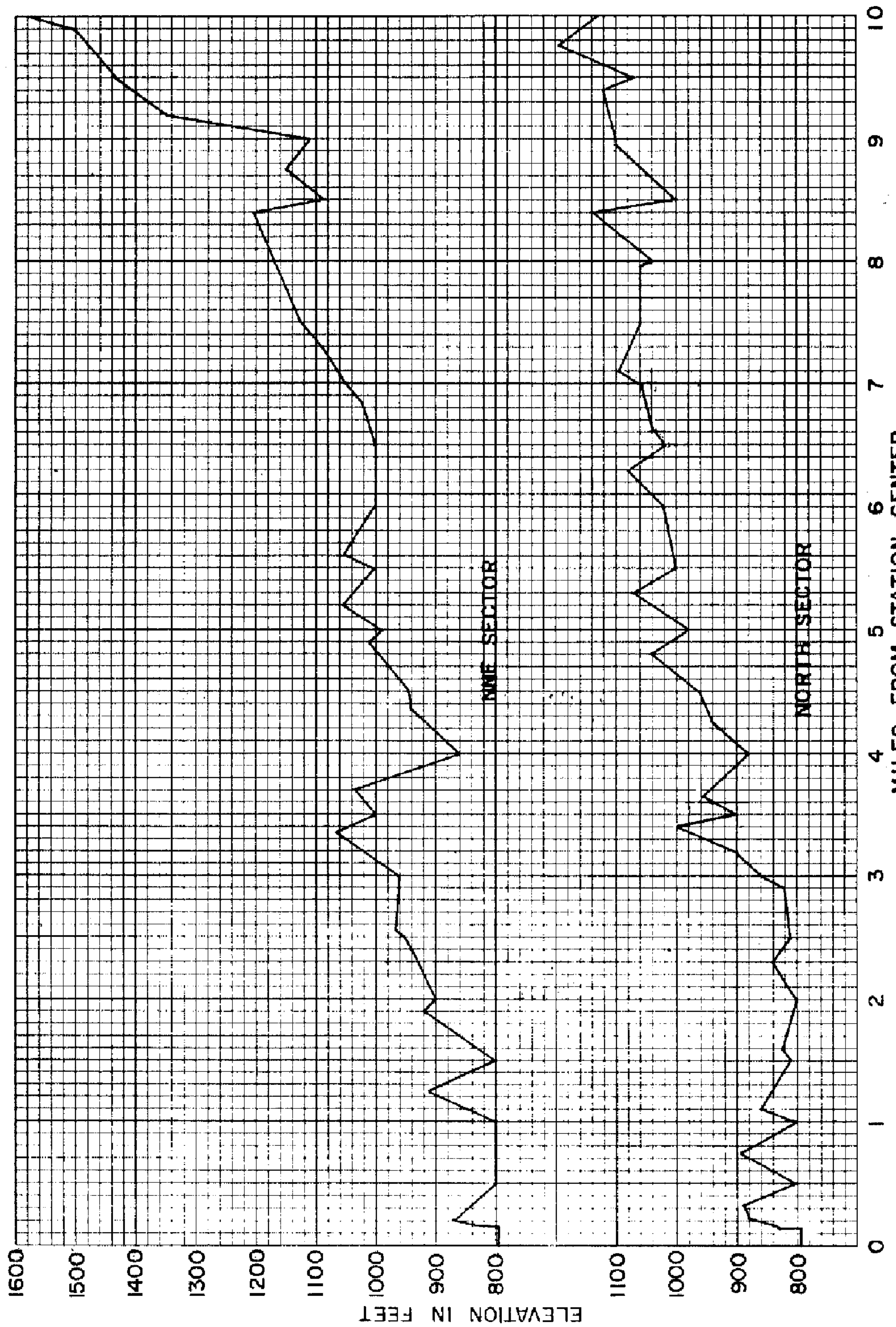


Figure 2-15. Maximum Topographic Elevation versus Distance (NE sector)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

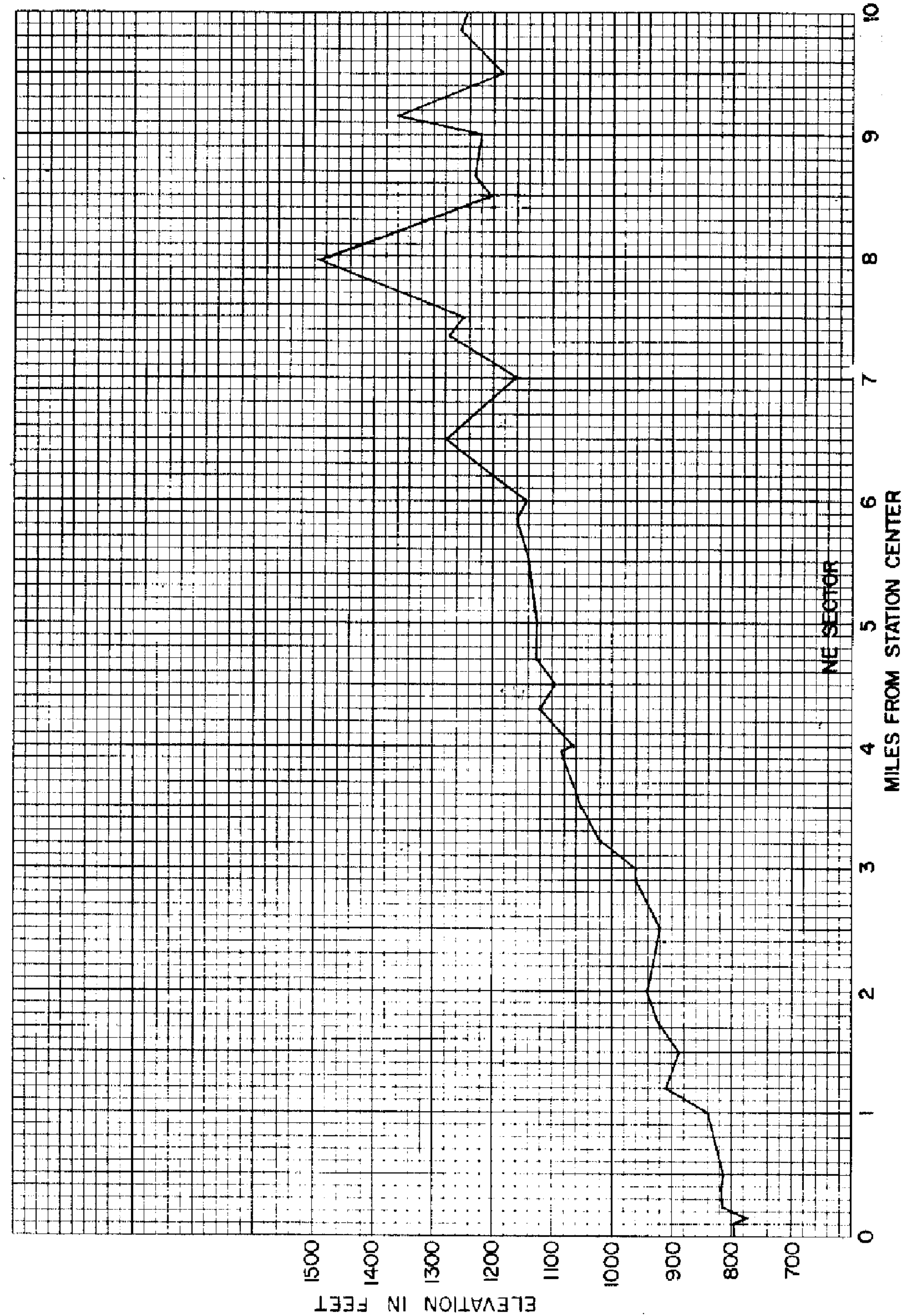


Figure 2-16. Maximum Topographic Elevation versus Distance (ENE sector)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

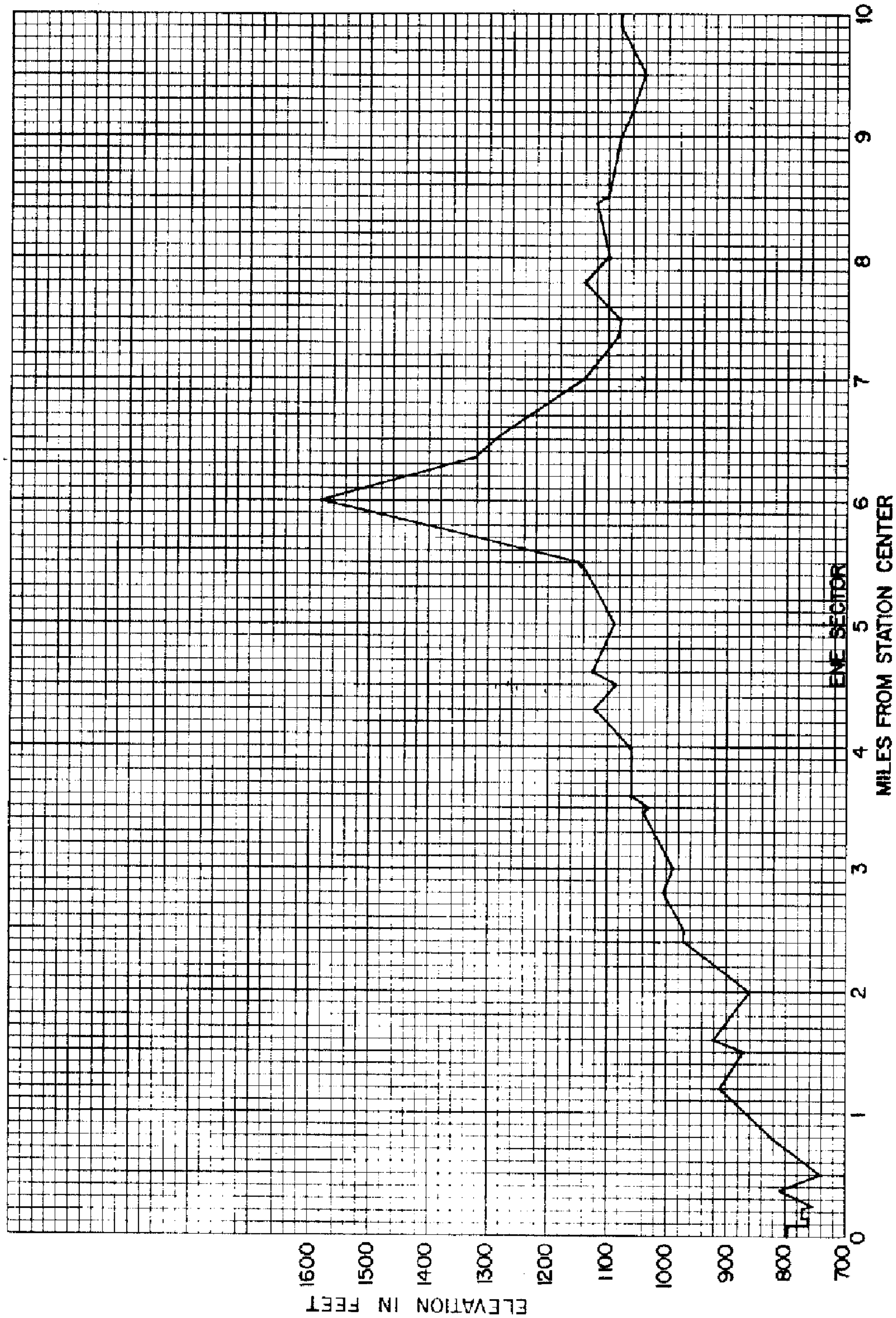


Figure 2-17. Maximum Topographic Elevation versus Distance (ESE and E sectors)

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

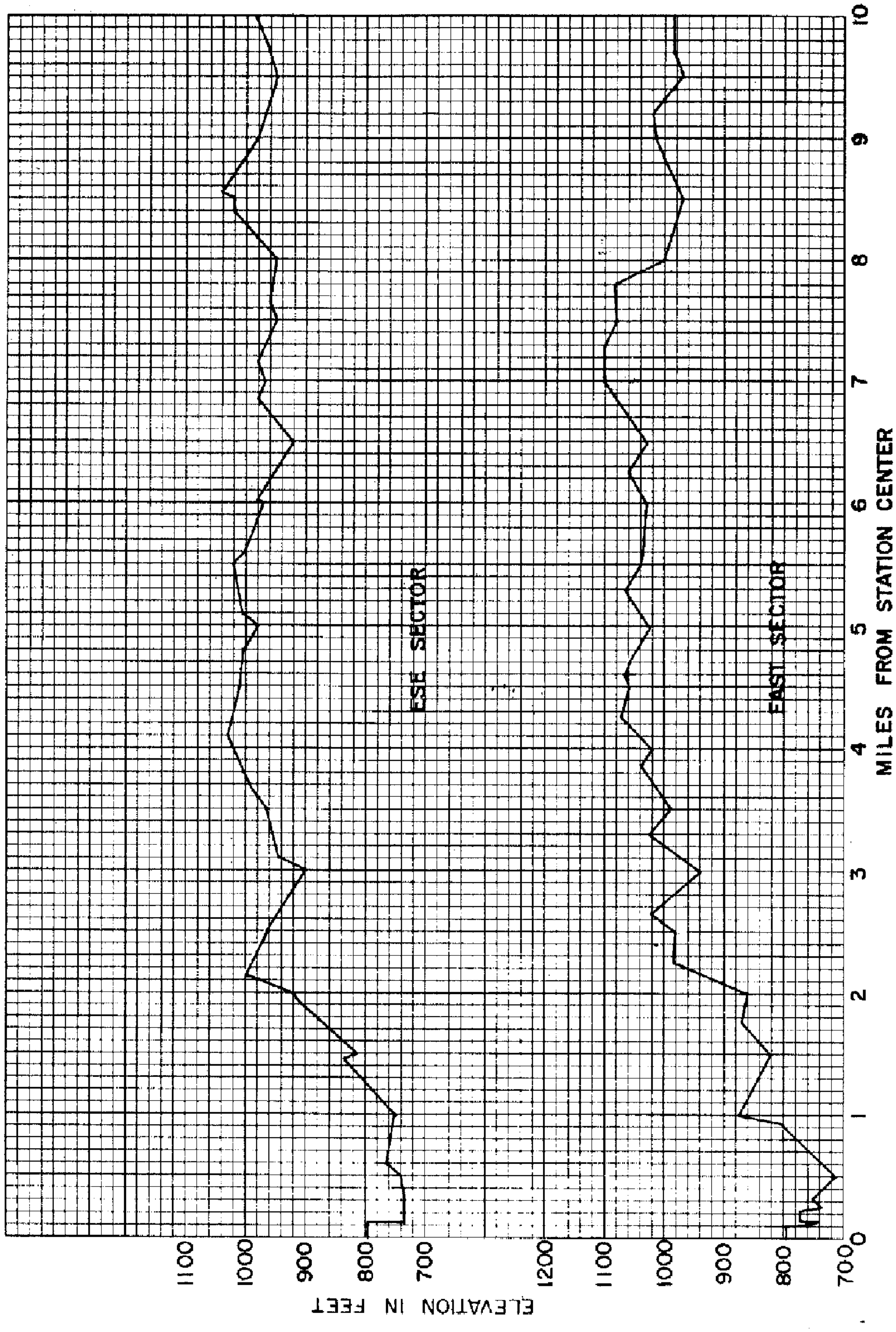


Figure 2-18. Maximum Topographic Elevation versus Distance (SSE and SE sectors)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

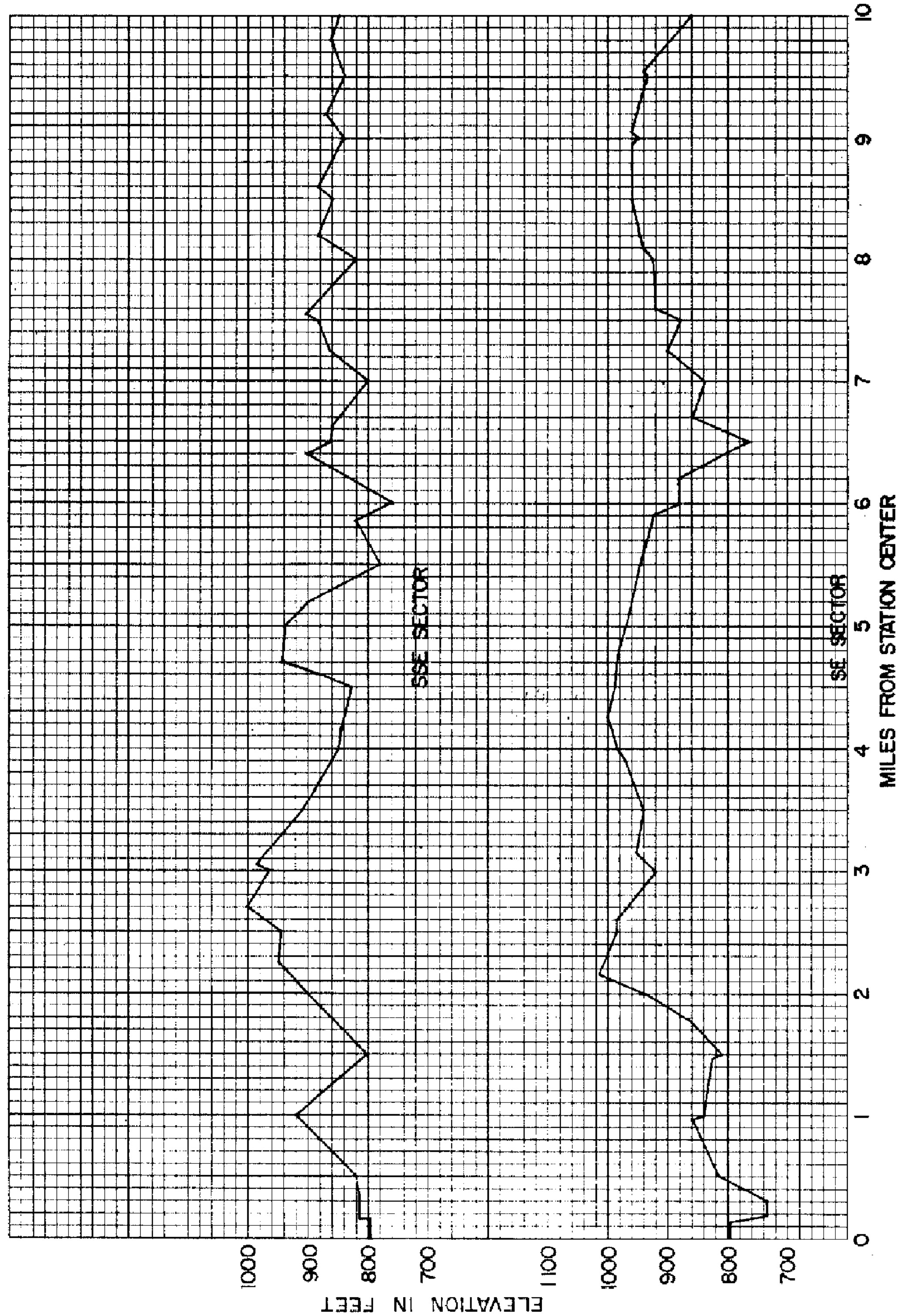


Figure 2-19. Maximum Topographic Elevation versus Distance (SSW and S sectors)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

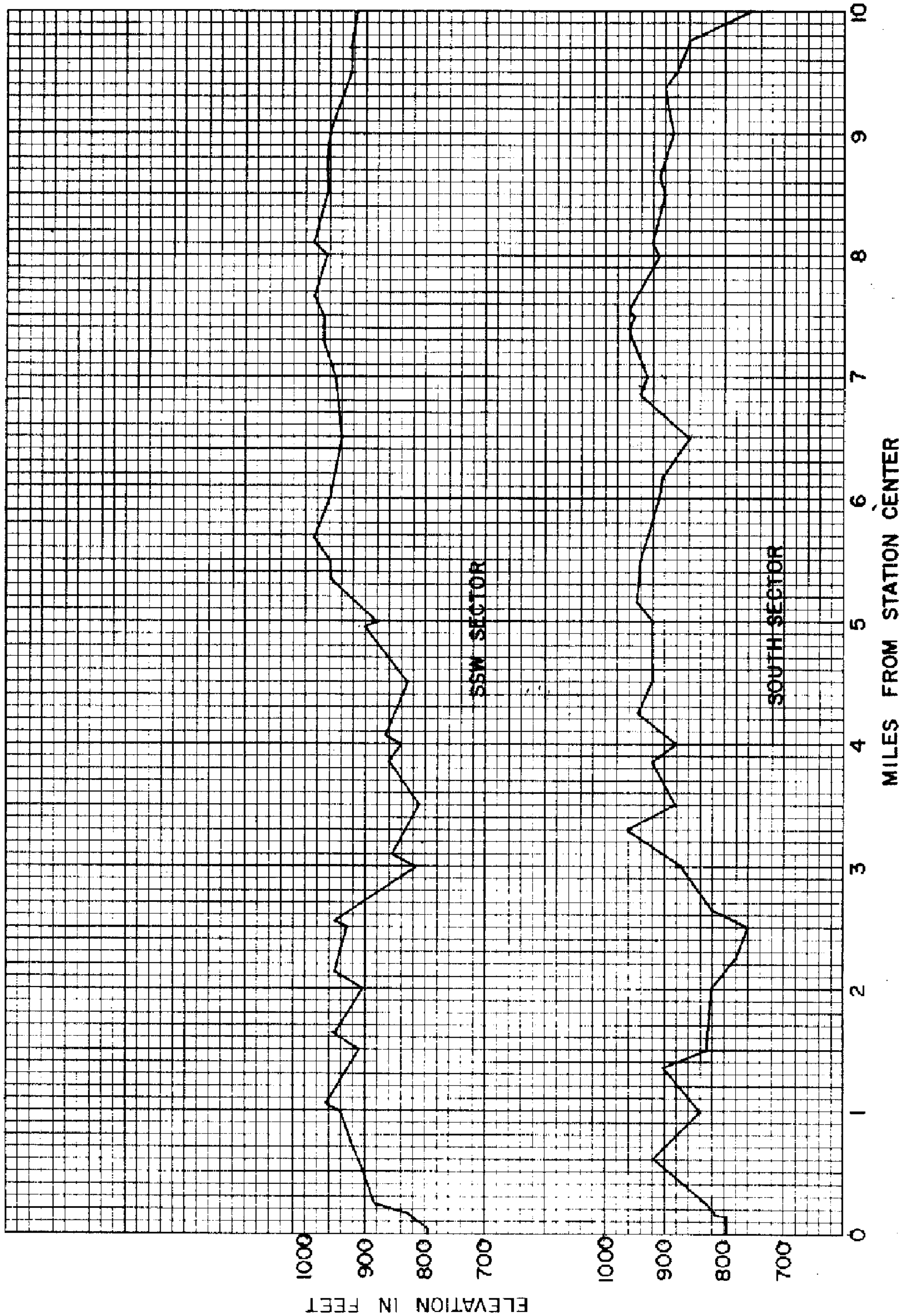


Figure 2-20. Maximum Topographic Elevation versus Distance (WSW and SW sectors)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

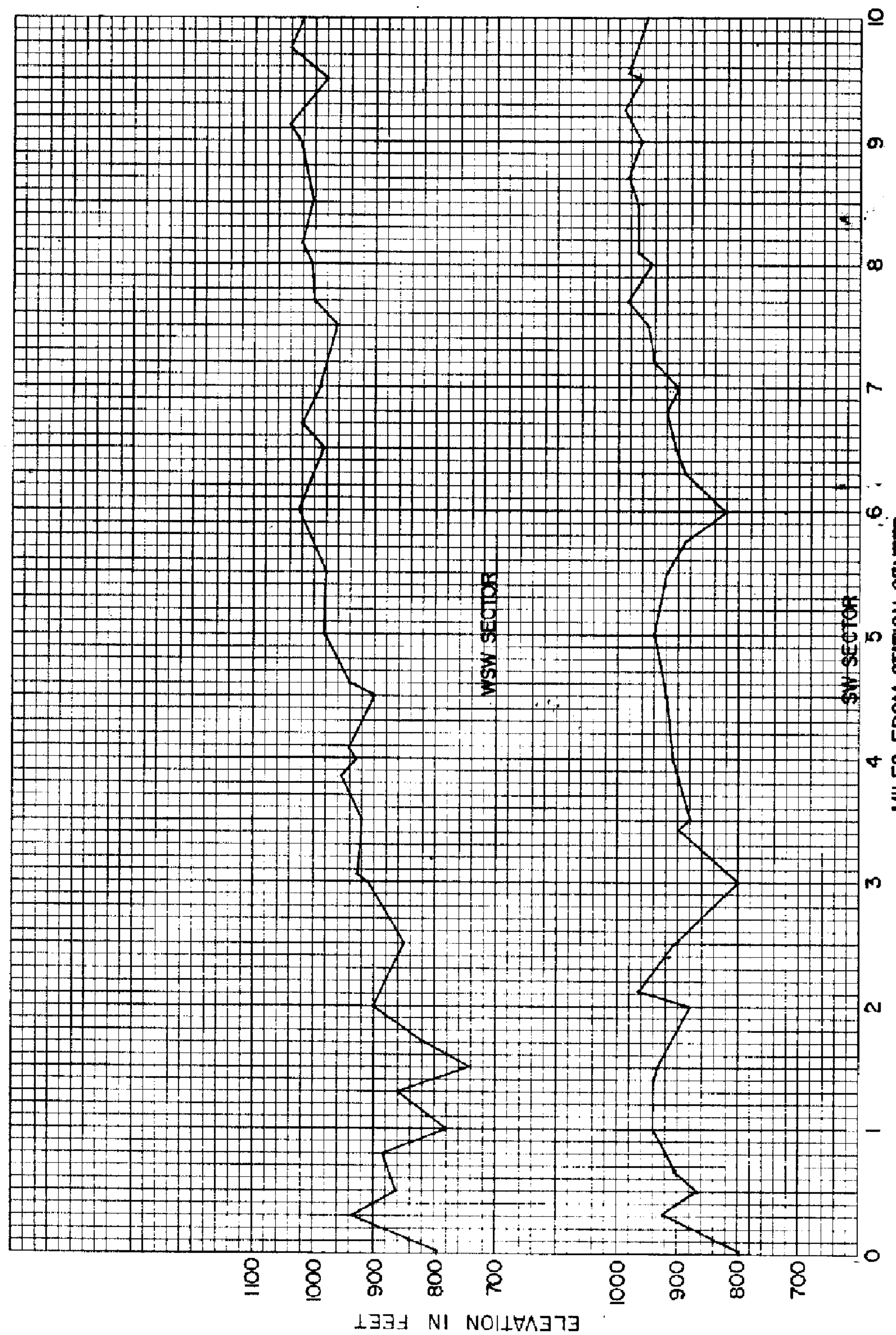


Figure 2-21. Maximum Topographic Elevation versus Distance (WNW and W sectors)

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

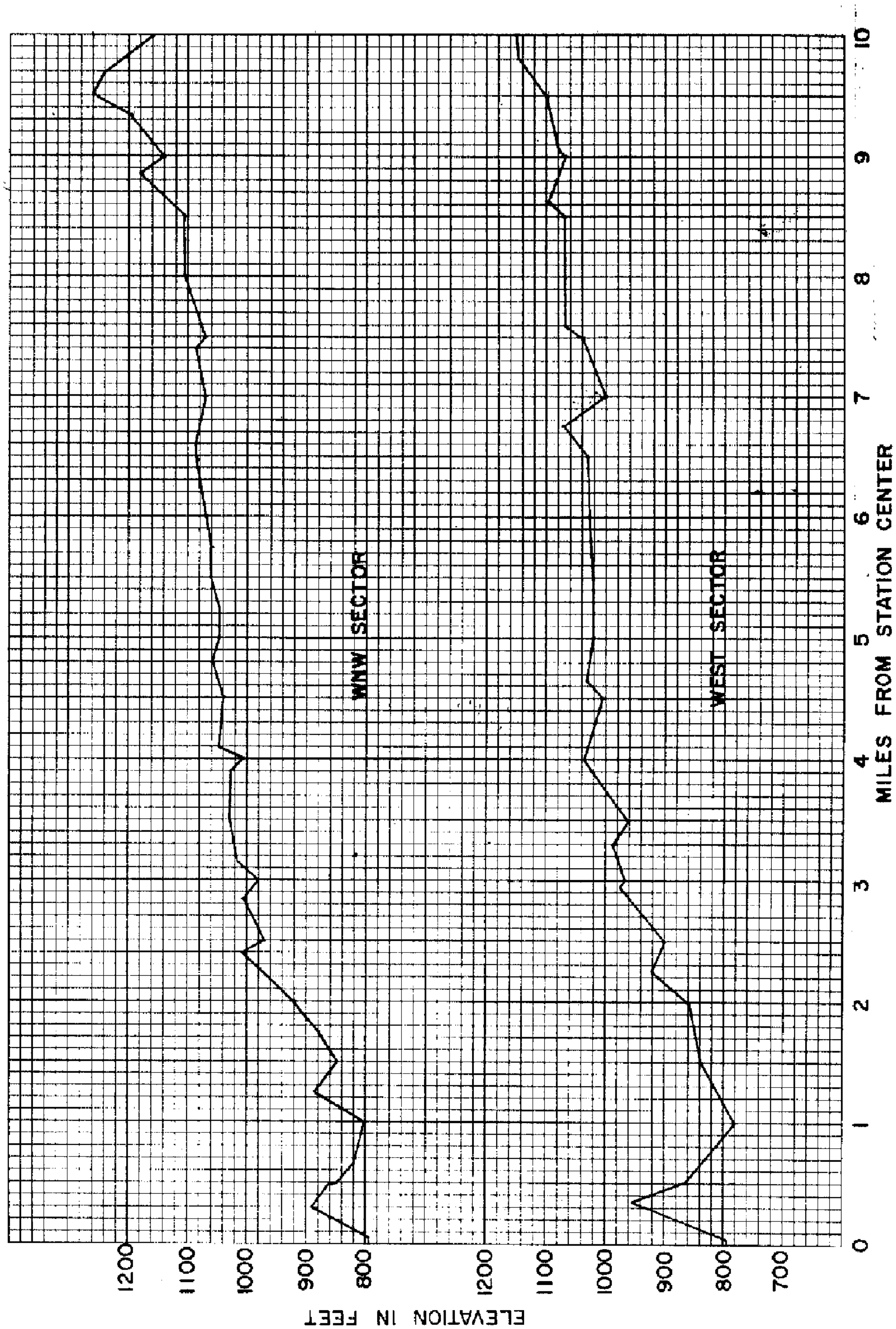


Figure 2-22. Maximum Topographic Elevation versus Distance (NW sector)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

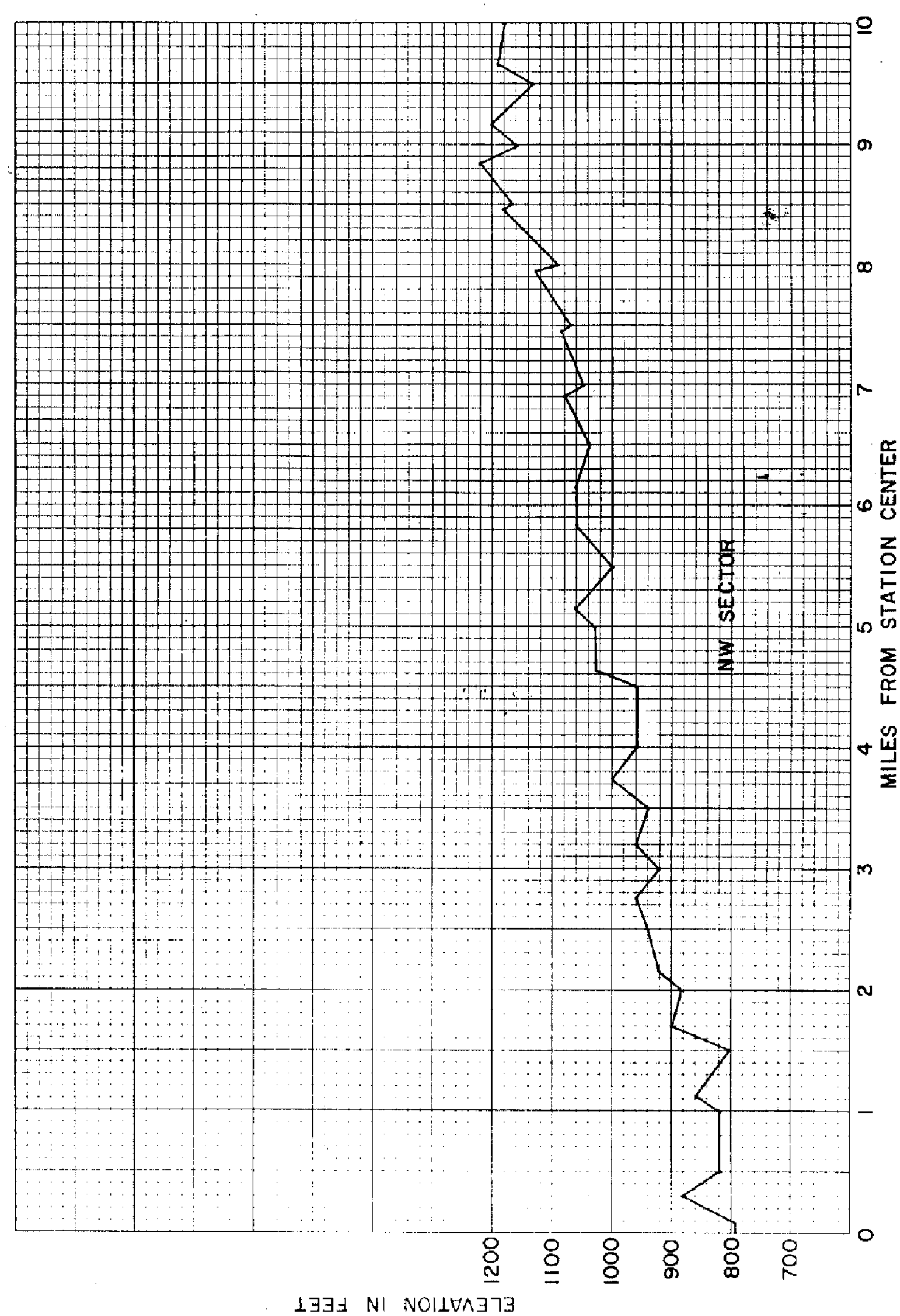


Figure 2-23. Maximum Topographic Elevation versus Distance (NWW sector)

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

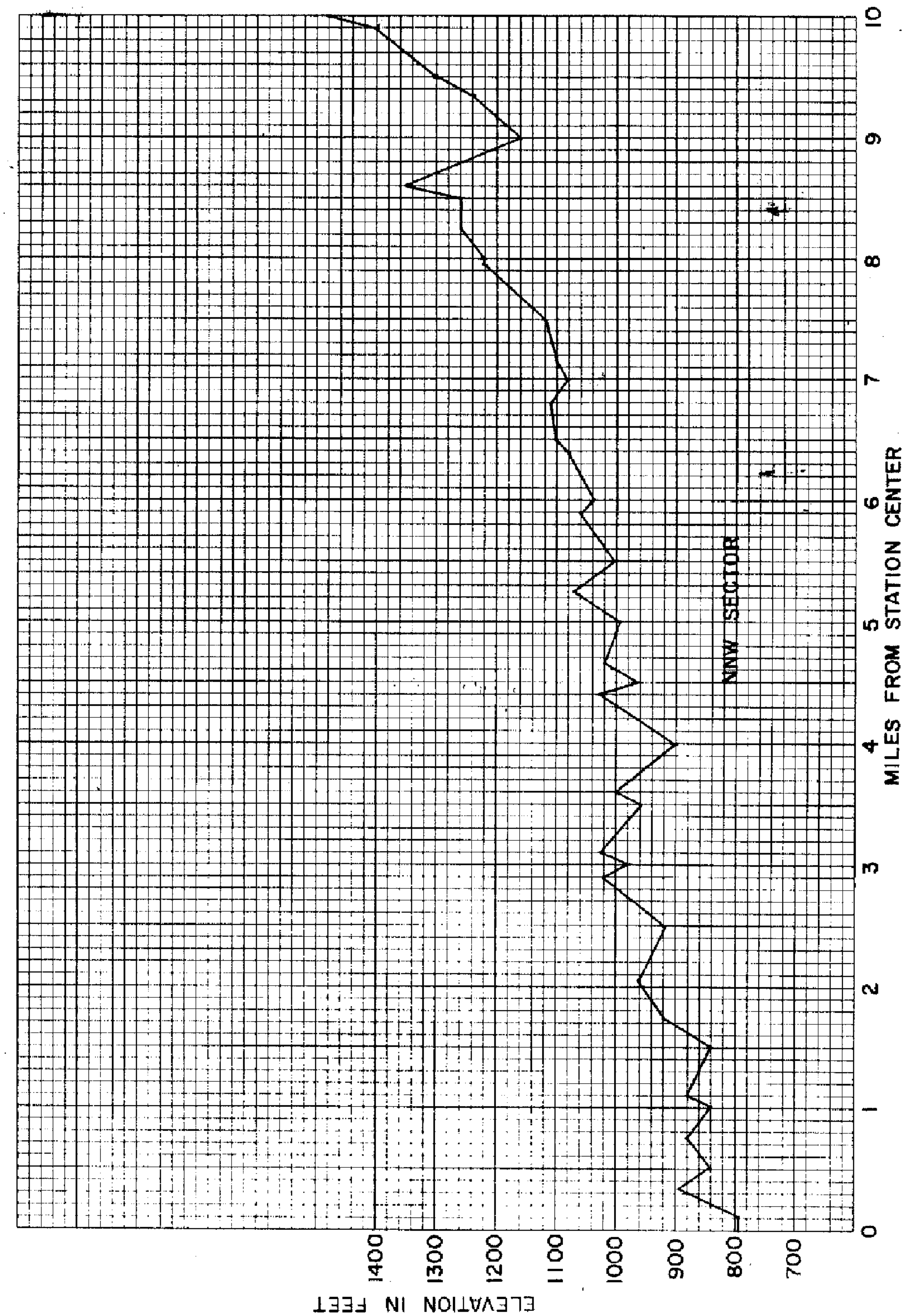
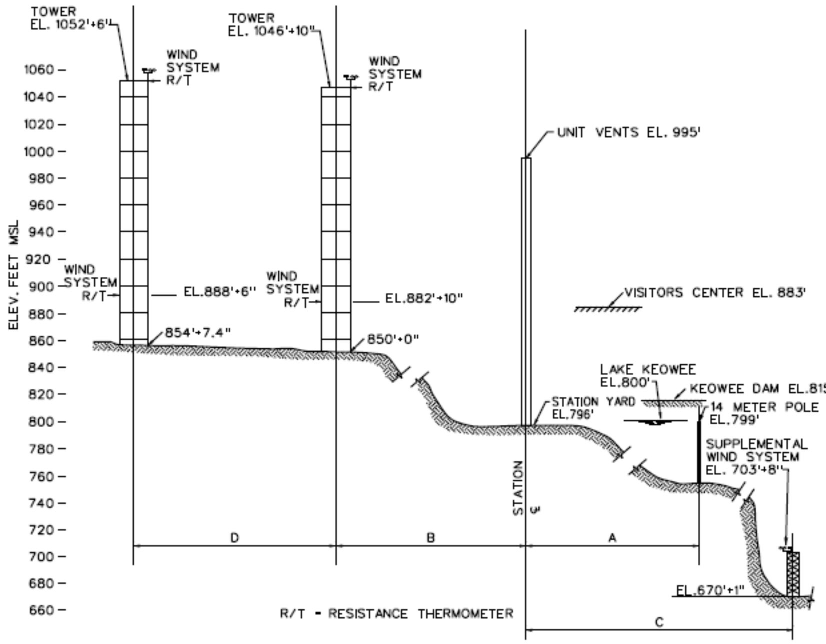


Figure 2-24. Relative Elevations of Meteorological



A. METEOROLOGICAL SURVEY #1 (MID OCT 1966 - LATE OCT 1967) 14m POLE WITH WS-101 SYSTEM (PACKARD BELL ELECTRONICS CORP.) LOCATED APPROX. ±1250 FT SE OF STATION CENTER FOR NEAR-GROUND STUDIES.

B. METEOROLOGICAL SURVEY #2 (JUNE 1967 - APRIL 1988) AS PRIMARY MET TOWER LOCATED APPROX. ±525 FT WNW OF STATION CENTER. 46m MICROWAVE TOWER MOUNTED WITH METEOROLOGICAL INSTRUMENTS, FIRST WITH ANALOG SYSTEM (THROUGH APRIL 16, 1984) AND THEN UPGRADED TO DIGITAL SYSTEM (APRIL 17, 1984 THRU APRIL 22, 1988). (46m MICROWAVE TOWER REMOVED PER EC416601)

C. SUPPLEMENTAL KEOWEE RIVER 10m METEOROLOGICAL TOWER LOCATED APPROX. ±3950 FT EAST OF STATION CENTER, BEGAN OPERATION JAN. 30, 1981. RAIN GAUGE MOVED FROM MICROWAVE TOWER TO KEOWEE RIVER SITE ON NOV. 15, 1981. (MICROWAVE TOWER REMOVED PER EC416601)

D. CURRENT 60m METEOROLOGICAL TOWER (PRIMARY SYSTEM) IS LOCATED APPROX. ±2375 FT WNW OF STATION CENTER AND BEGAN OPERATION APRIL 22, 1988.

Figure 2-25. Annual Surface Wind Rose (October 19, 1966 - October 31, 1967)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

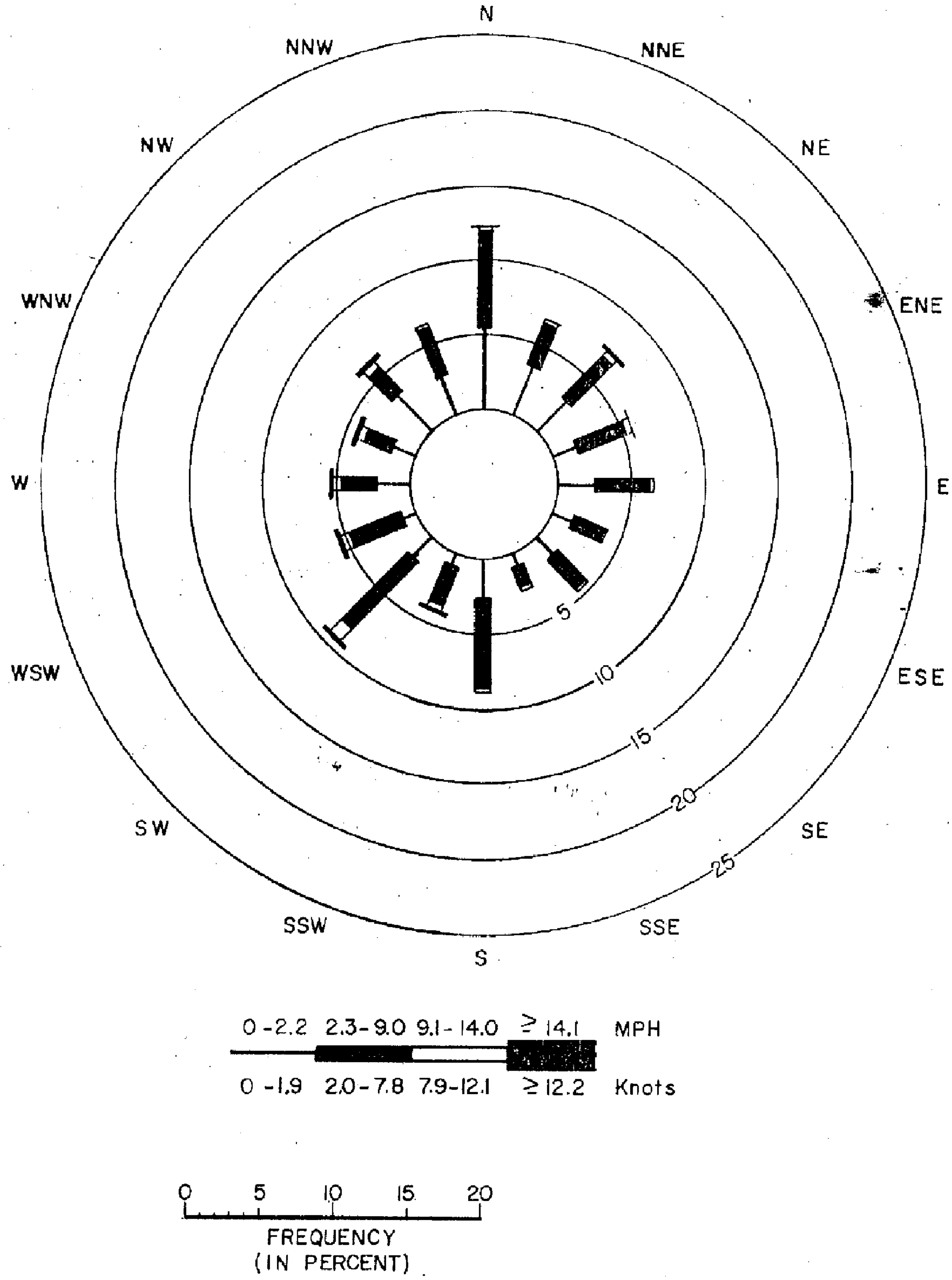


Figure 2-26. Precipitation Surface Wind Rose (October 19, 1966 - October 31, 1967)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

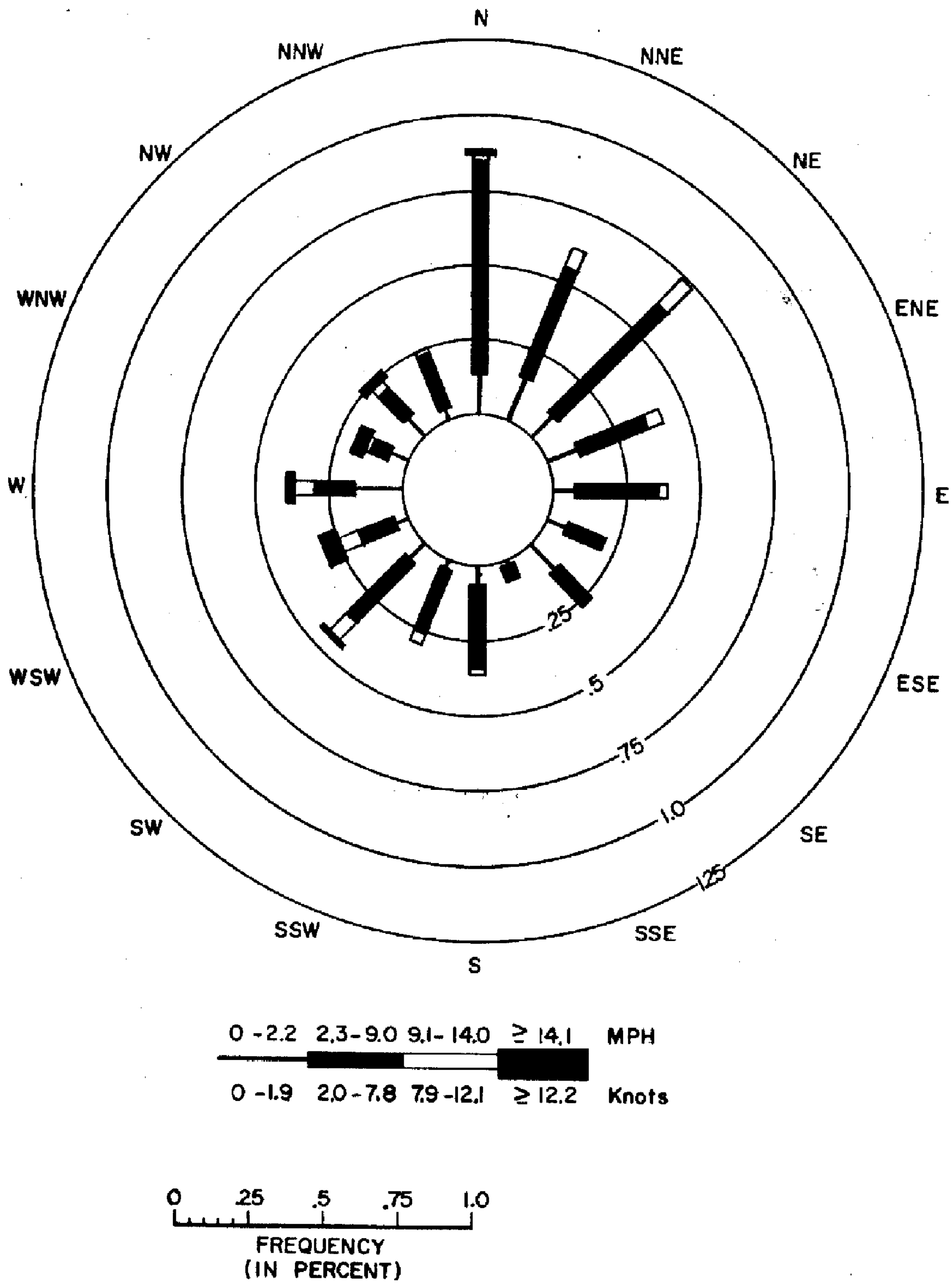


Figure 2-27. Surface Wind Frequency Distribution during Low-Level Temperature Inversion Conditions (October 19, 1966 - October 31, 1967)

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

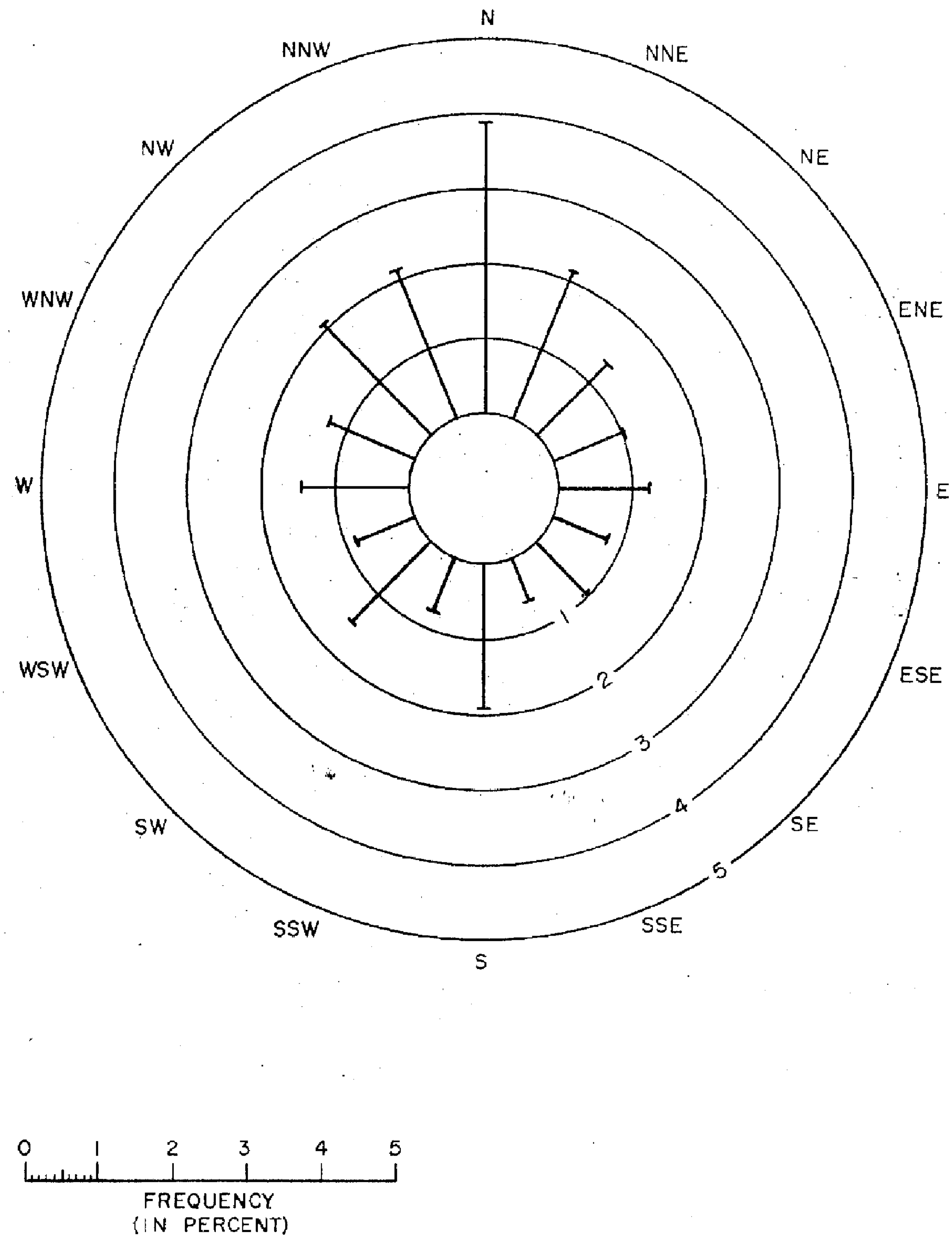


Figure 2-28. Wind Rose for Tower Winds (June 19, 1967 - May 31, 1968)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

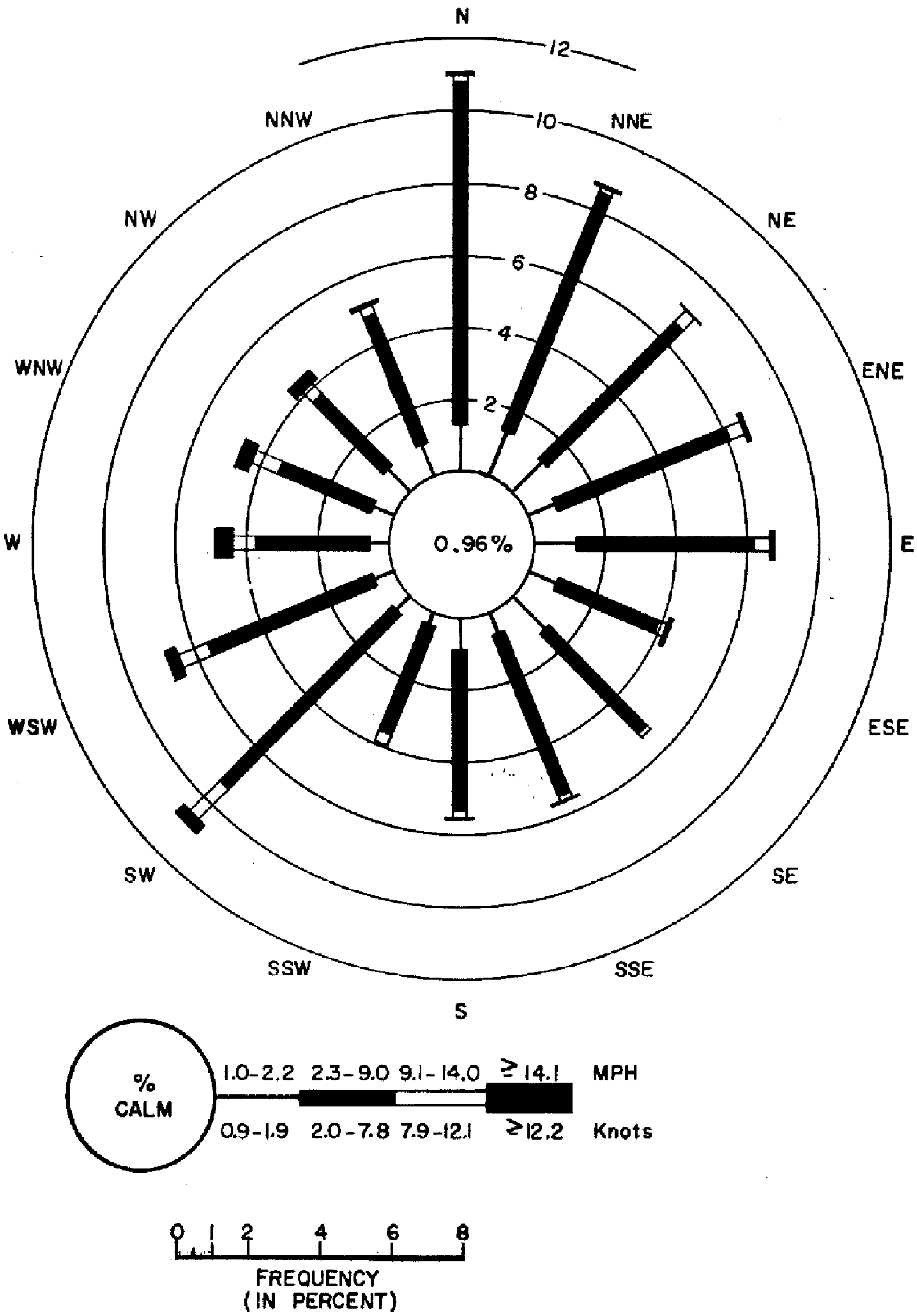


Figure 2-29. Frequency Distribution for Tower Winds During Low-Level Temperature Inversion Conditions (June 19, 1967 - May 31, 1968)

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

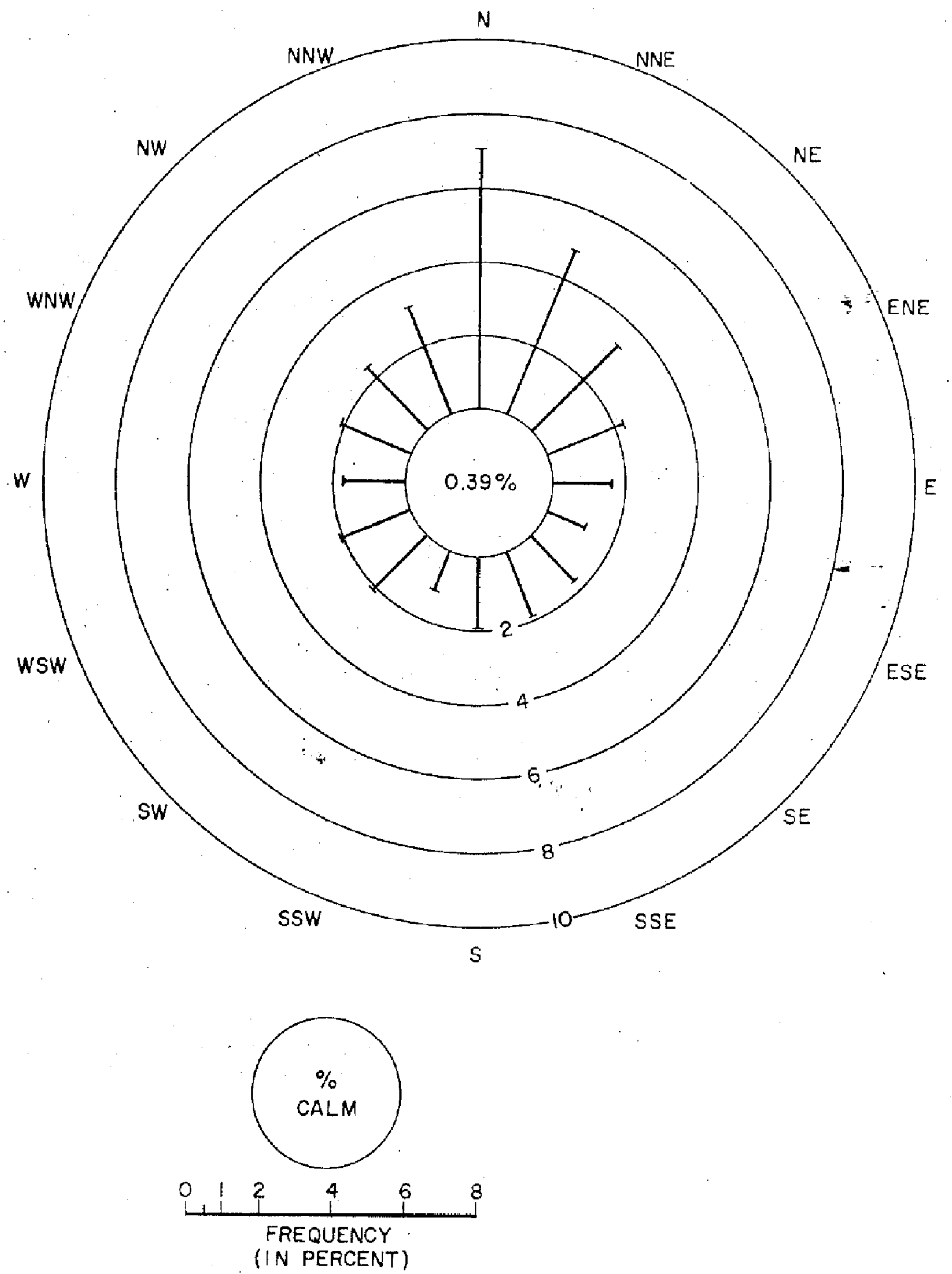


Figure 2-30. Precipitation Wind Rose for Tower Winds (June 19, 1967 - May 31, 1968)
["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

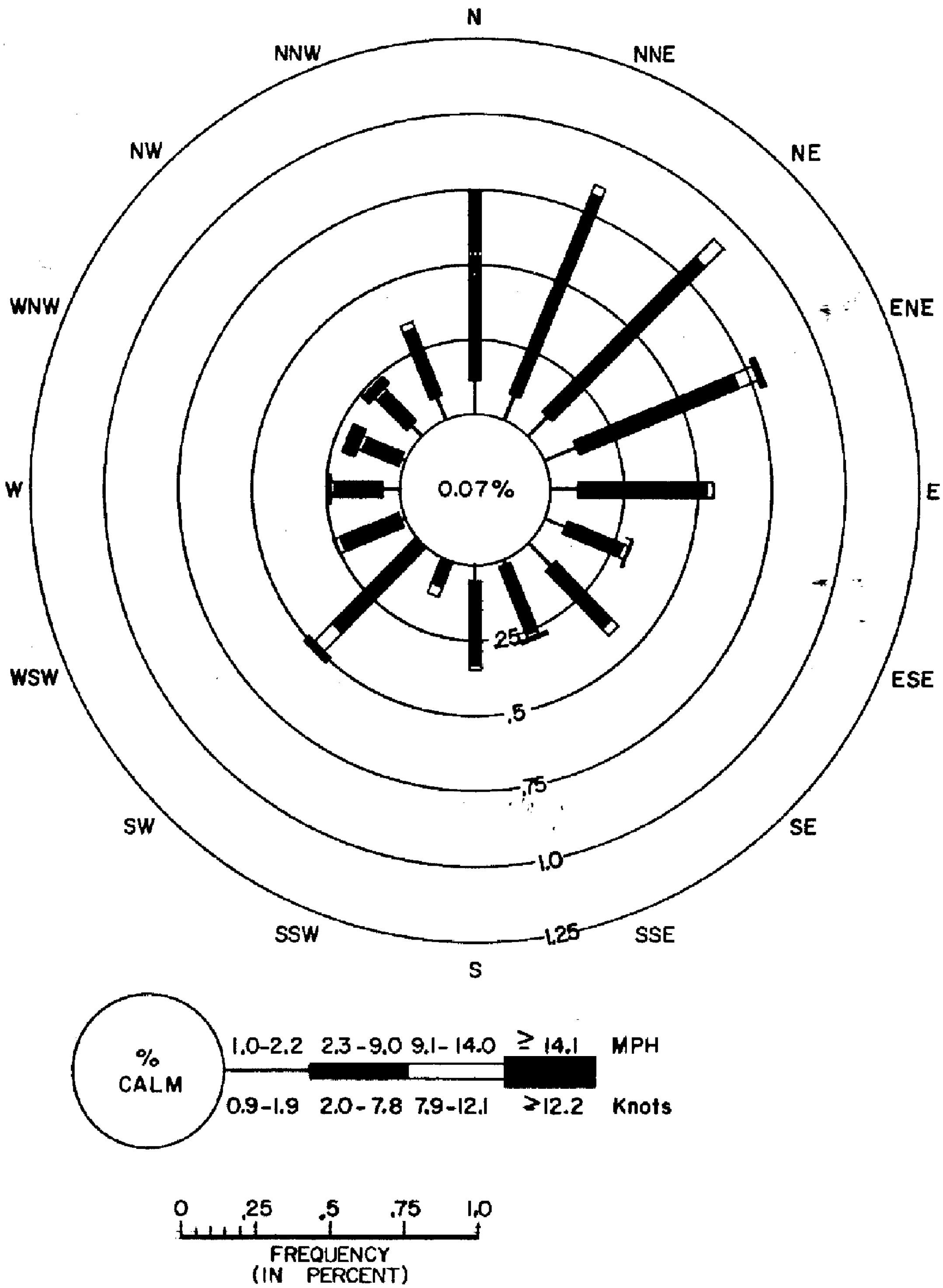
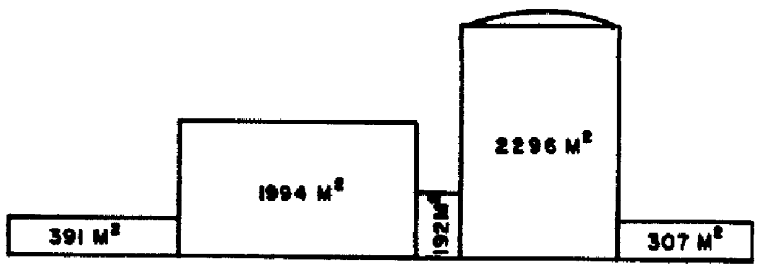
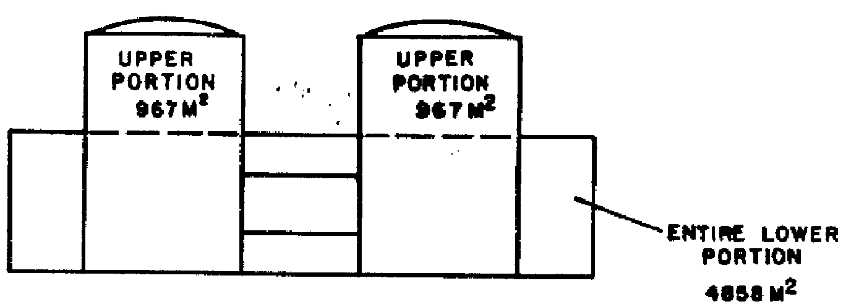


Figure 2-31. General Building Arrangements

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]



GENERAL BUILDING ARRANGEMENT — SIDE VIEW
CROSS-SECTIONAL AREAS
TOTAL AREA 5180 M^2



GENERAL BUILDING ARRANGEMENT — FRONT VIEW
CROSS SECTIONAL AREAS
TOTAL AREA 6792 M^2

Figure 2-32. Plot Plan and Site Boundary During Early Meteorological Studies

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

Figure 2-33. SF_6 Gas Tracer Test Background Sample Points

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

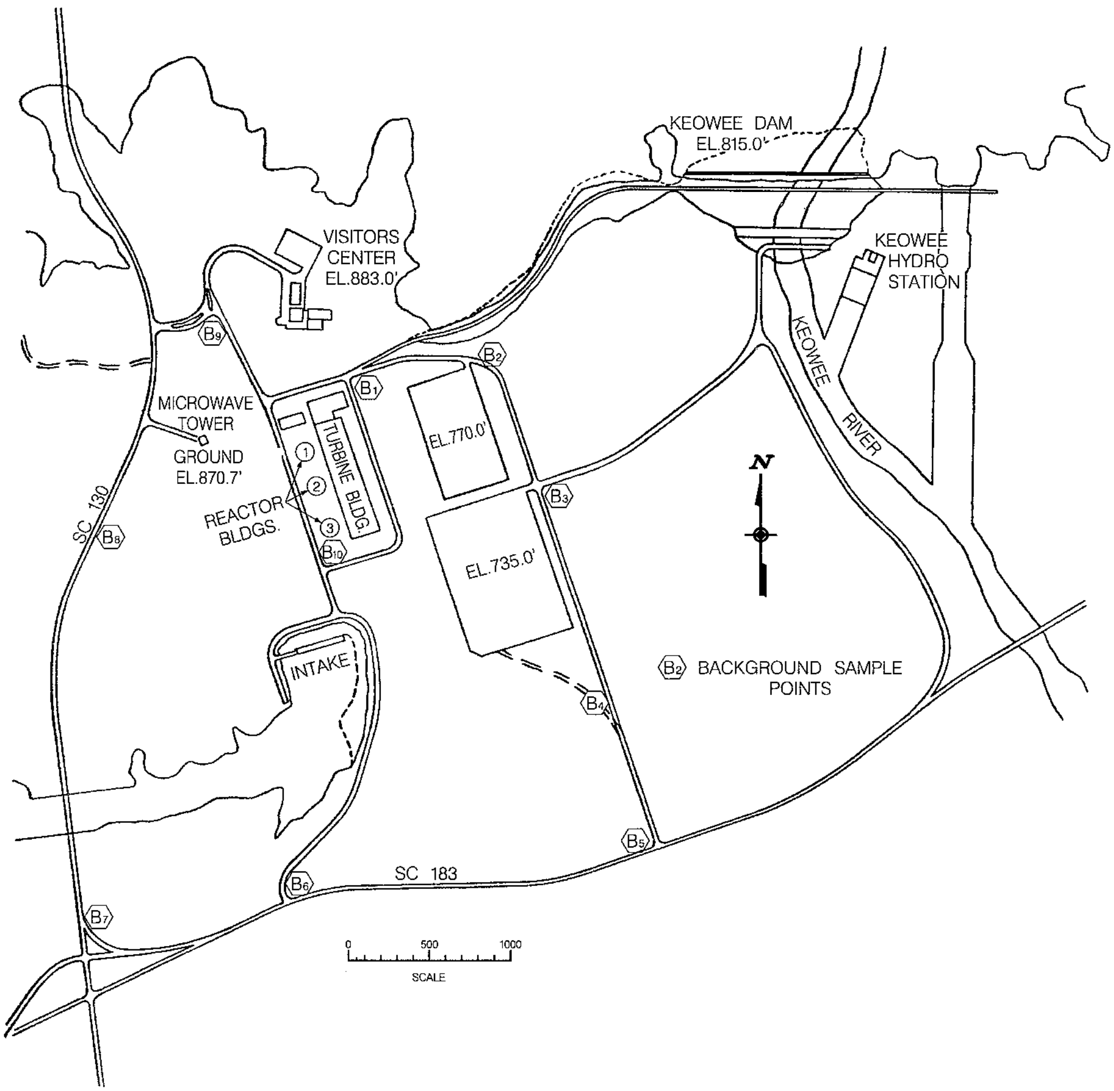


Figure 2-34. SF_6 Gas Tracer Test Release Point

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

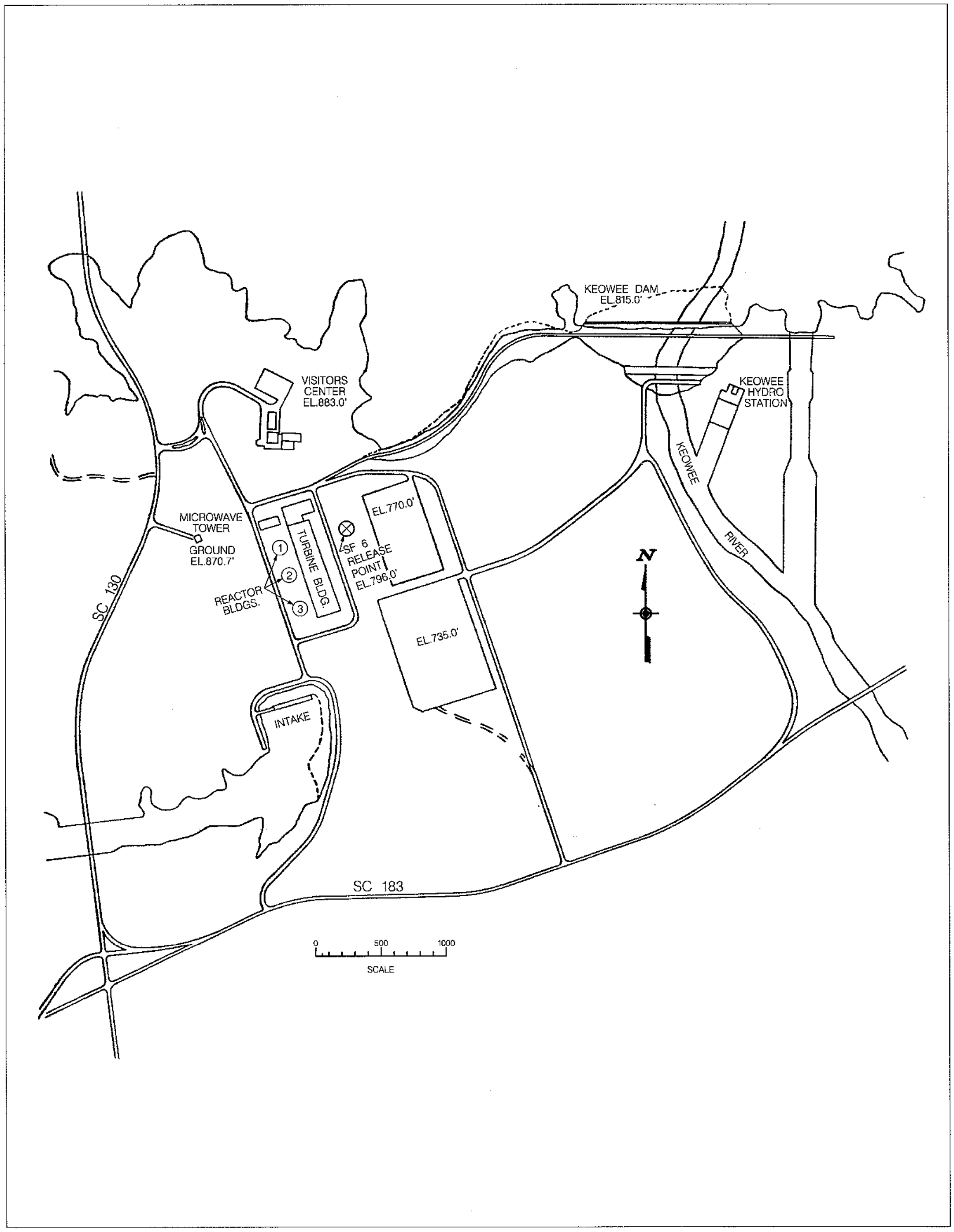


Figure 2-35. Deleted per 2008 Update

Figure 2-36. Deleted per 2008 Update

Figure 2-37. SF_6 Gas Tracer Test Release and Sample Stations. Figure is representative of the 1/15/70 SF6 Test only. See Original FSAR Appendix 2A Figure 2A-5 for the release and sample station lay outs for the other SF6 Tests.

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

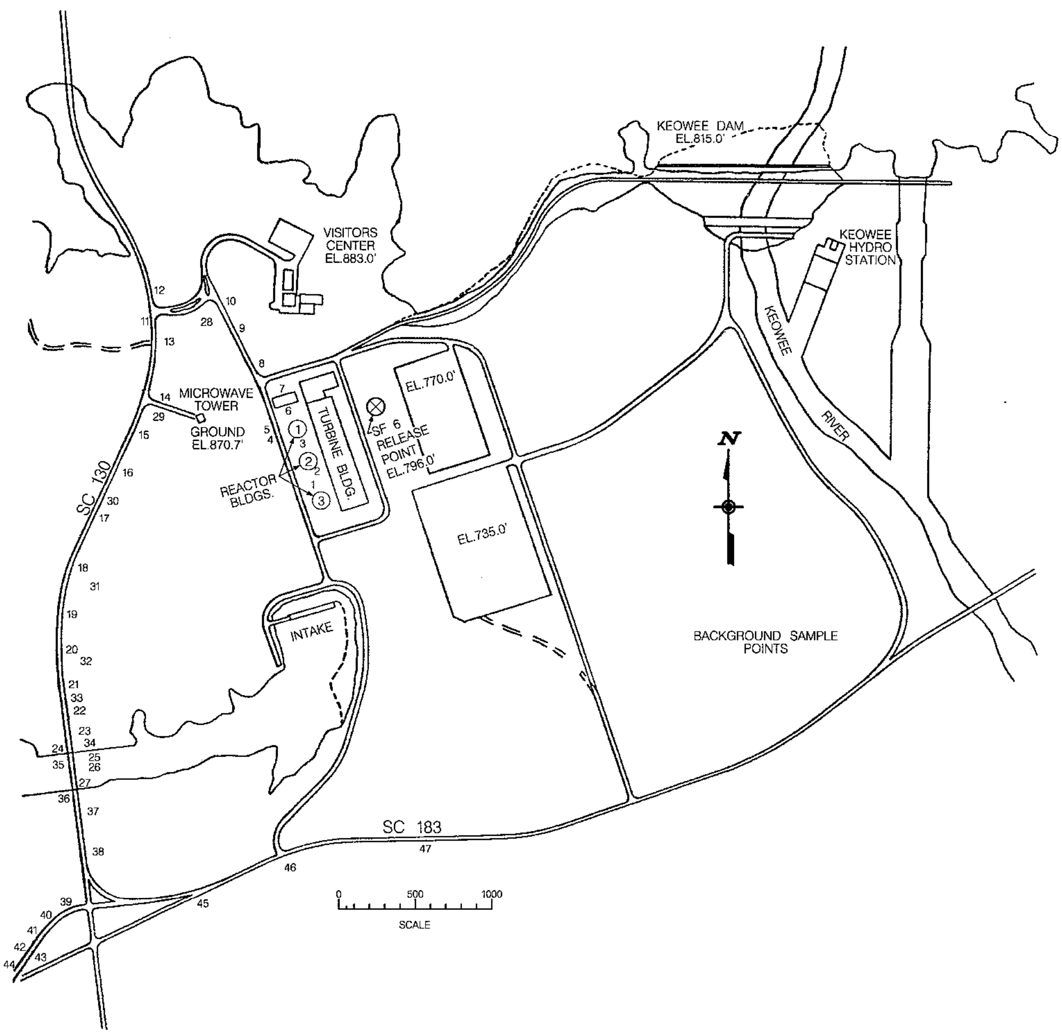


Figure 2-38. Approximate Terrain at Nuclear Site

["HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"]

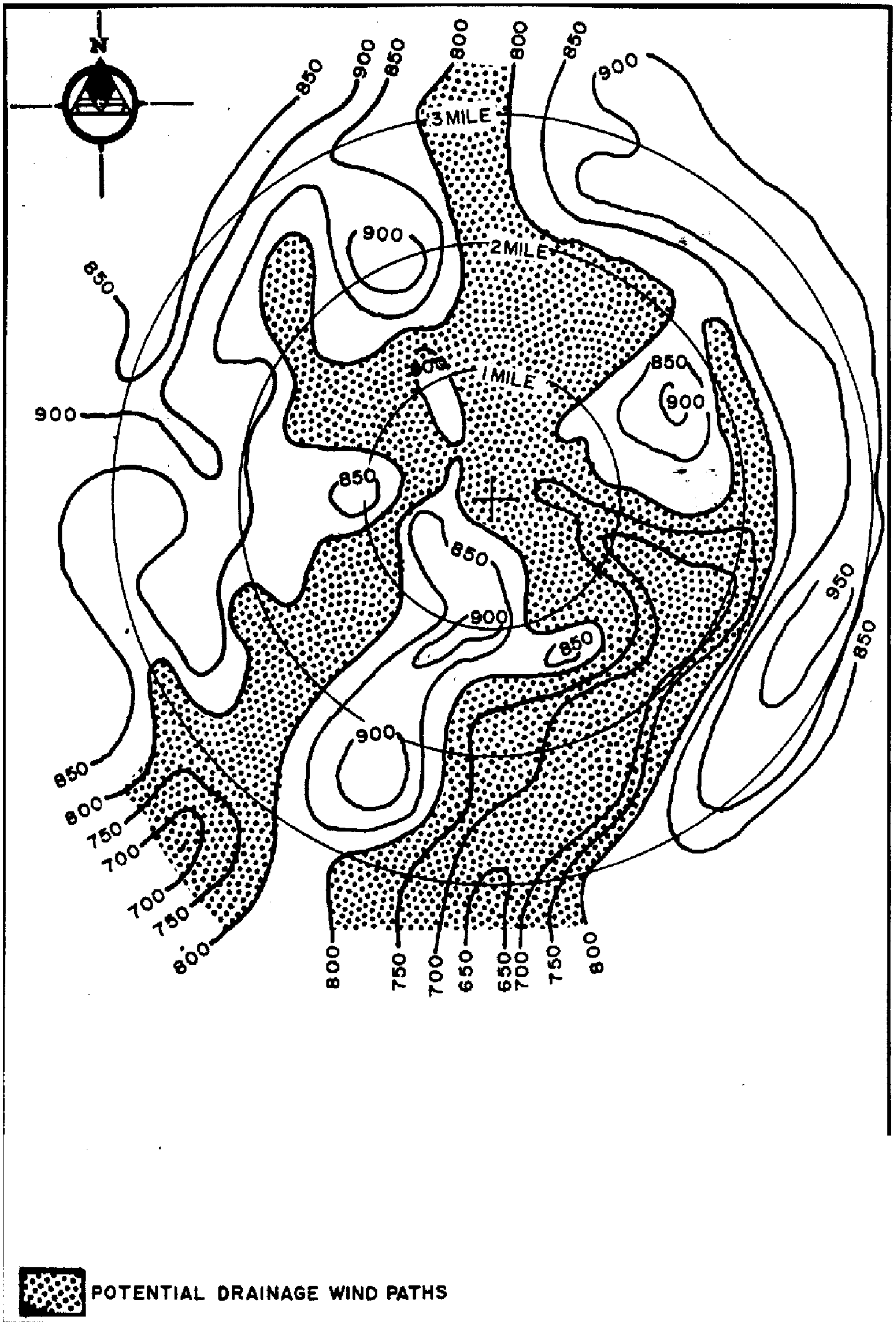


Figure 2-39. Location of Municipal Water Supply Intakes

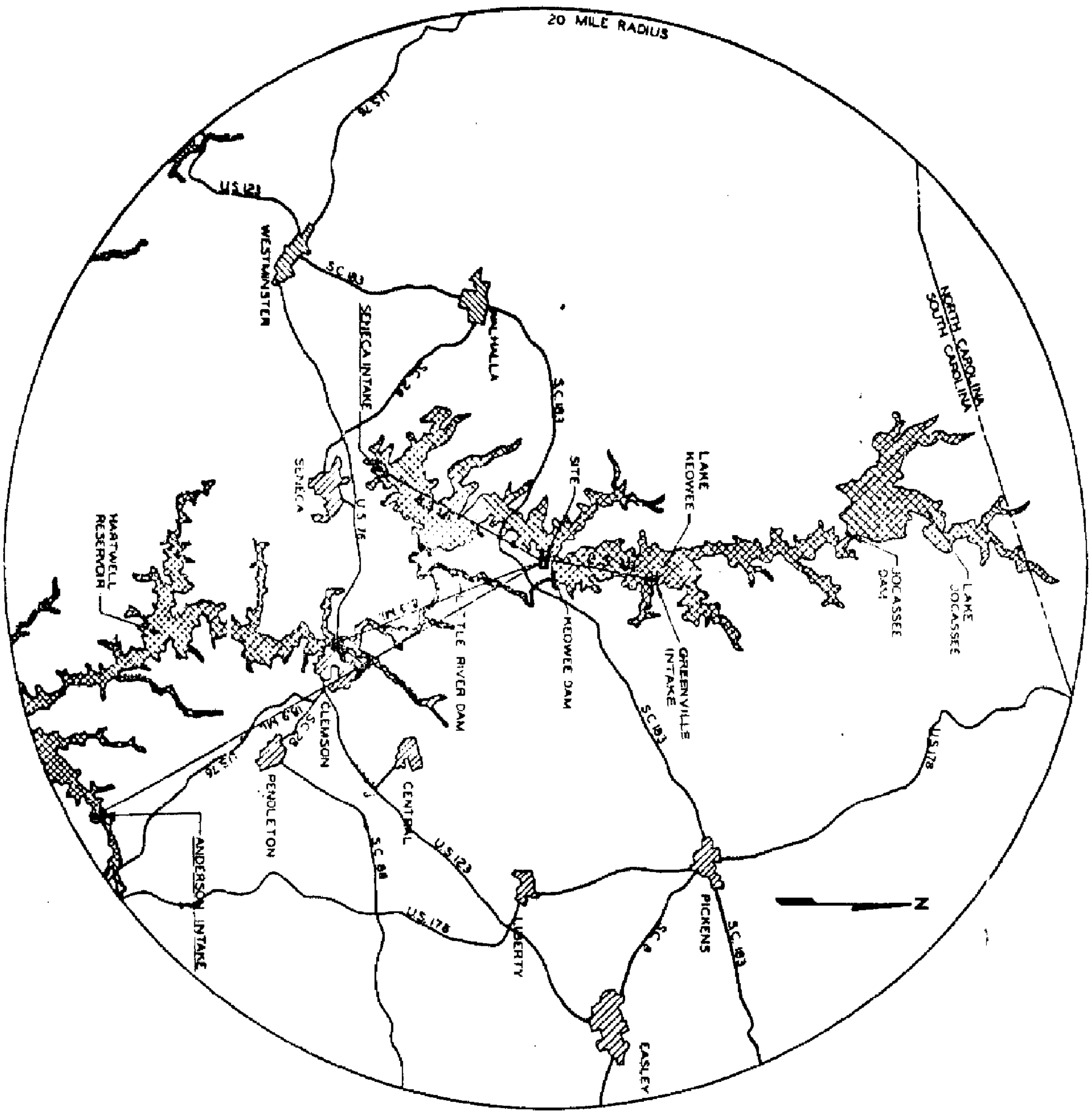


Figure 2-40. Areal Groundwater Survey

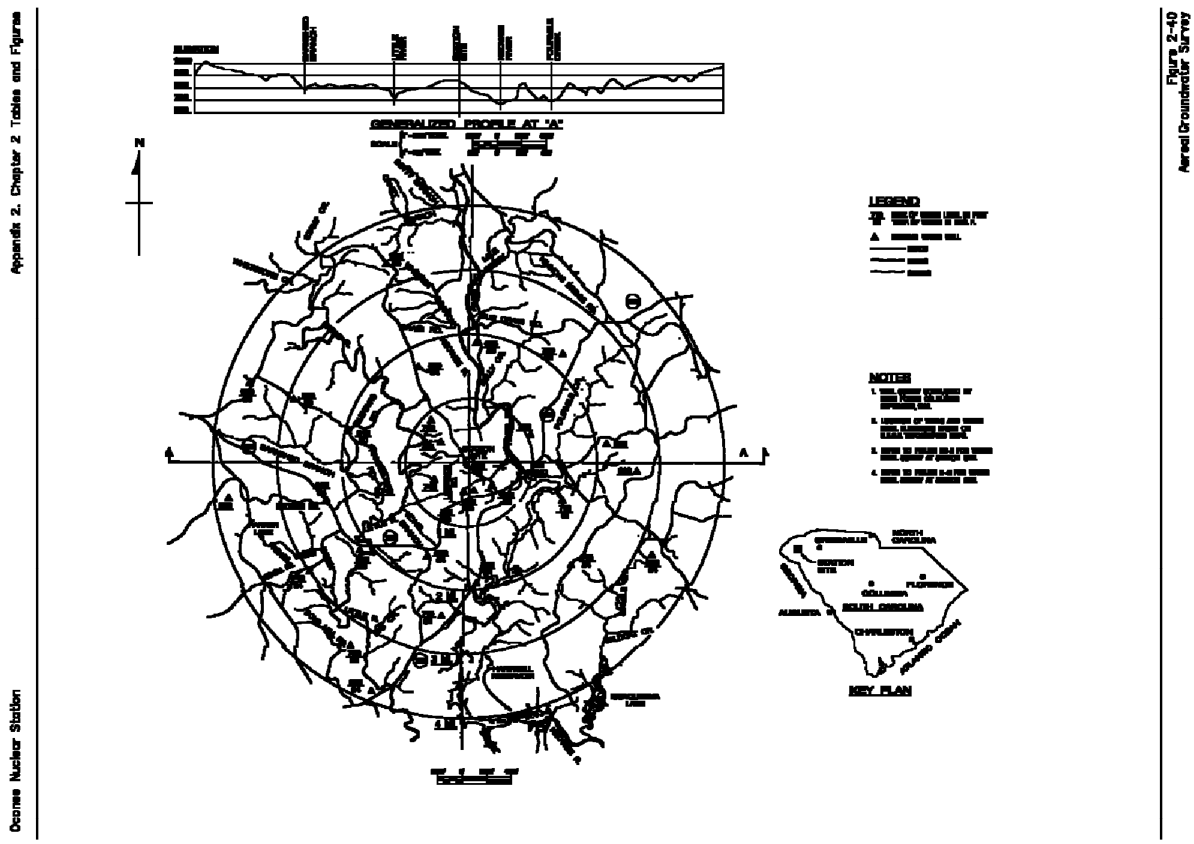
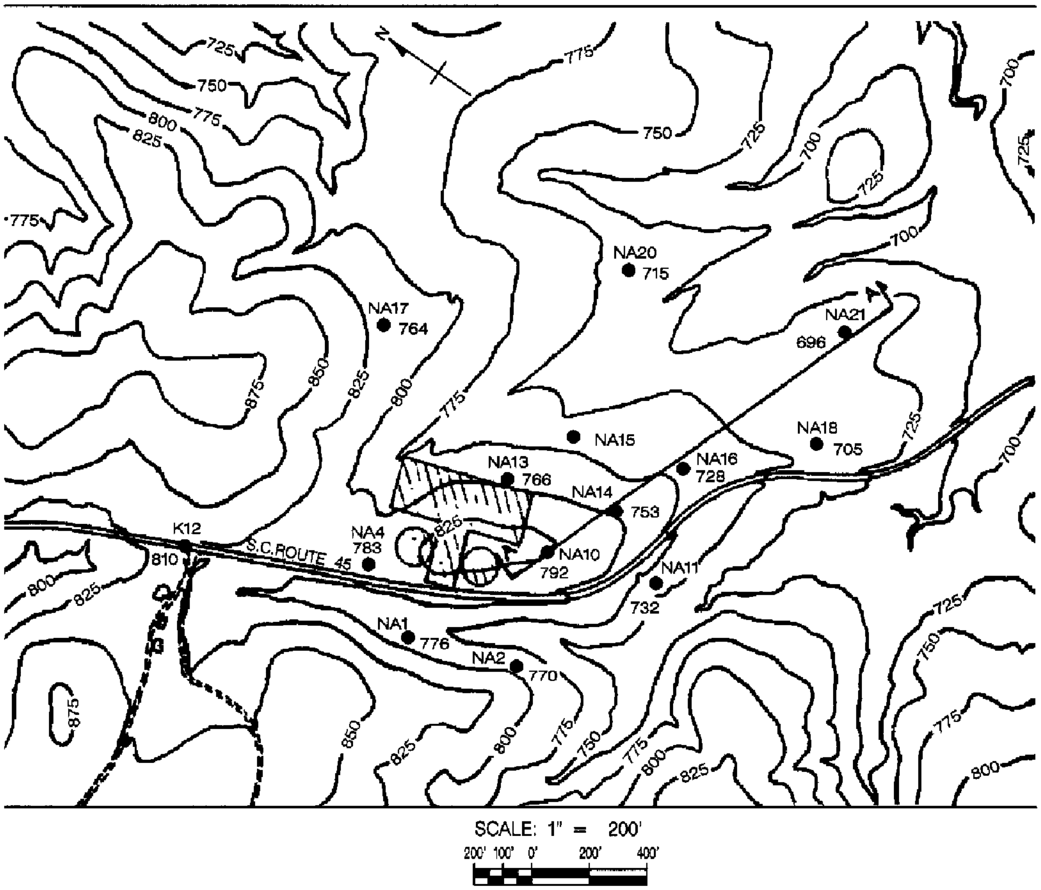


Figure 2-41. Groundwater Survey at Station Site



PROFILE AT "A"

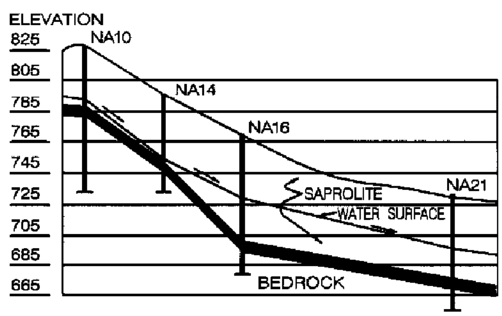
SCALE { 1" = 200' HORIZ. 200' 100' 0' 200' 400'
1" = 40' VERT. 40' 20' 0' 40' 80' }

LEGEND

NA1 ● EXPLORATORY DRILL HOLE BY LAW ENGINEERING TESTING CO., 1966

K12 ● EXPLORATORY DRILL HOLE BY LAW ENGINEERING TESTING CO., 1965

732 ELEV. OF WATER LEVEL IN DRILLED HOLE



NOTES

1. WATER LEVELS IN "NA" HOLES MEASURED DURING SEPTEMBER, 1966 AND K12 MEASURED DURING DECEMBER, 1965.
2. REFER TO FIGURE 2-40 FOR GENERAL LOCATION AND AREAL GROUNDWATER SURVEY.

Figure 2-42. Well Permeameter Test Apparatus

FIELD PERMEABILITY TESTING

The tests were run according to the Bureau of Reclamation's Field Permeability Tests, Designation E-19. The immediate vicinity of each of the exploratory borings were selected as the locations for the wells: NA-4, NA-11A, NA-13 and NA-15 (Figure 2-65). Two 8 in. diameter holes were drilled at each location, to the refusal of the auger used. The NA-4 test wells were drilled with a 27 in. auger. Generally, the test wells were within 20 ft. of the exploratory borings.

The wells were prepared with care in order to cause as little disturbance to the surrounding soil as possible. No water was encountered in any of the wells. After the wells were excavated, the sides and bottoms were lightly cleaned where necessary, and the loose soil was removed from the bottom.

After cleaning, all wells were backfilled with 3/8 in. to Number 4 size crushed stone and covered with plastic sheets until time of testing. The equipment used for these permeability tests is shown to the right. each 50 gallon drum was calibrated in increments of 1/16 of an inch change in water level which corresponds to 0.0142 cubic feet of water.

For each test the permeability equipment, as shown, was set up, the crushed stone was removed to a depth of approximately 1 ft. in the well from the ground surface and the Robert's Type valve float bob was adjusted so that a water level would be maintained constant at about a 6 in. depth. All depths from the ground surface were measured from a baseline string stretched across the hole at ground level. The drum was filled with water and the test started. Water and ground temperatures were taken and recorded at varied time intervals. Readings of water level (to the nearest 1/16 of an inch) and time (to the nearest minute) were taken throughout the test. Plots of cumulative water volume versus time were prepared during each test. In general, the dry soil at the start of the test absorbed water at a comparatively high rate, but as the soil below the test became saturated, the rate decreased to a point where it was practically constant. When this occurred, as evidenced by the plotted points on the curve falling on practically a straight line for several hours, the tests were discontinued. This data is available but has not been included on the test summary. The slope of the straight line gave the rate of flow to be used in computations of coefficient of permeability, k. Figure 2-43 shows the formulas used for determining the coefficient of permeability, k and Table 2-83 summarizes the results of the test.

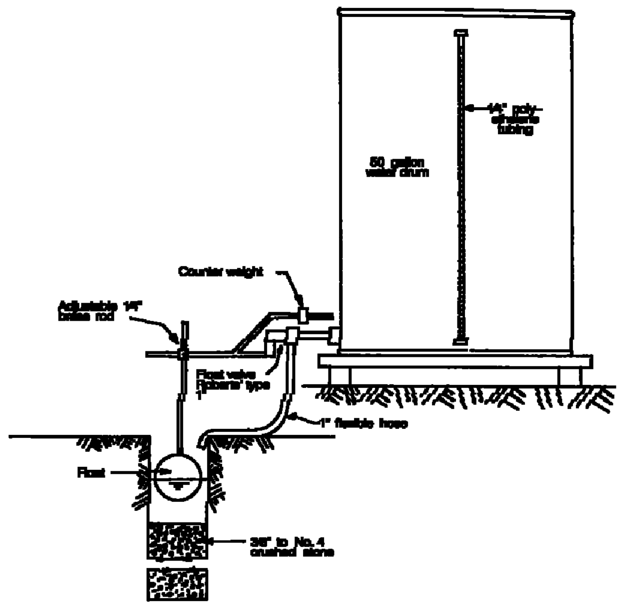
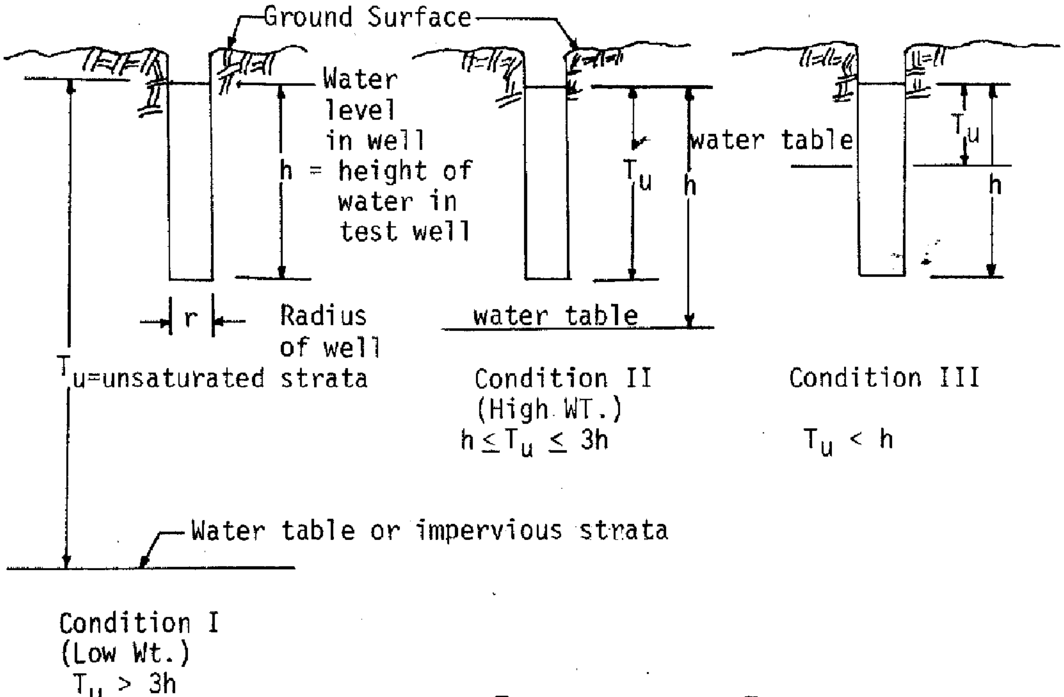


Figure 2-42
Well Permeameter Test Apparatus

Figure 2-43. Formulae for Determining Permeability



Condition I: $$k_{20} = 525{,}600\ \frac{\left[\sinh^{-1}\ \frac{h}{r}\ - 1\right]\frac{Q}{2\pi}}{h^2}\left(\frac{\mu_T}{\mu_{20}}\right)$$

Condition II: $$k_{20} = \frac{525{,}600\ \log_e \frac{h}{r}\ \overset{h^2}{\frac{Q}{2\pi}}}{h^2\left[\frac{1}{6}+\frac{1}{3}\left(\frac{h}{T_u}\right)^{-1}\right]}\left(\frac{\mu_T}{\mu_{20}}\right)$$

k_{20} = coefficient of permeability, feet per year

h = height of water in the well, feet

r = radius of well, feet

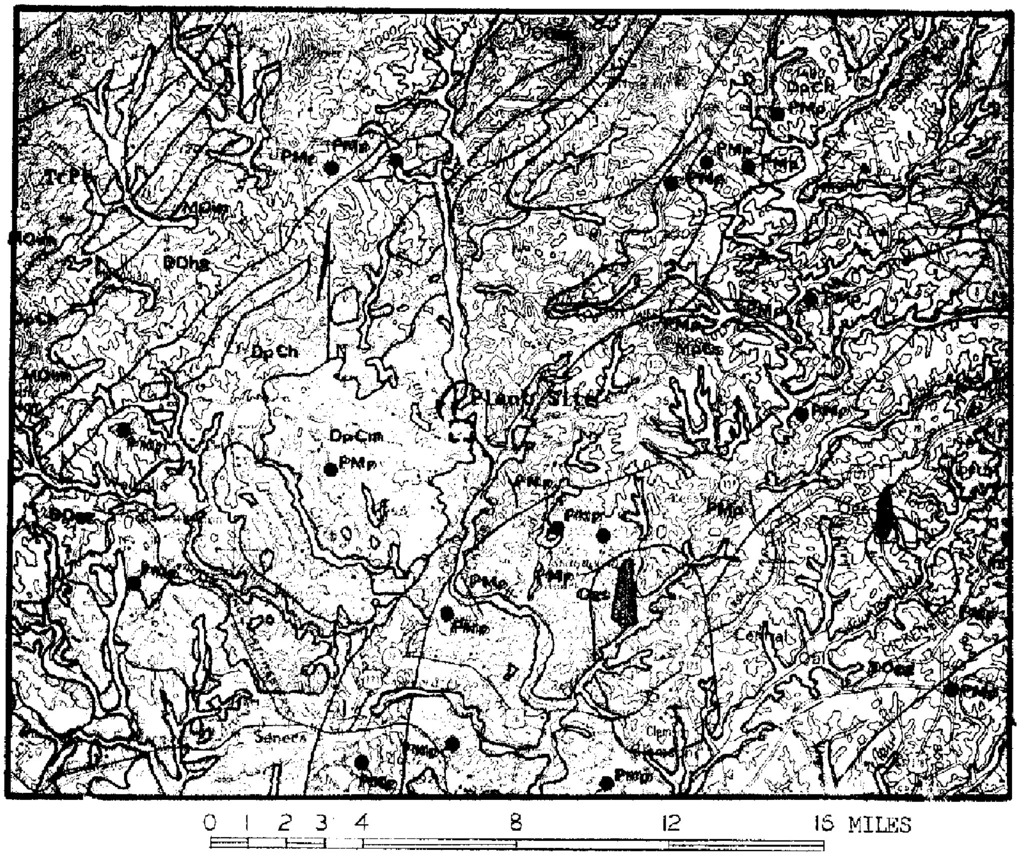
Q = discharge rate of water from the well for steady state condition, ft^3/min.

μ_T = viscosity of water at temperature T

μ_{20} = viscosity of water at 20°-C

T_u = unsaturated distance between the water surface in the well and the water table, feet

Figure 2-44. Regional Geologic Map



REGIONAL GEOLOGIC MAP
Scale 1" = 4 miles
OCONEE NUCLEAR STATION

SYMBOL	EXPLANATION	AGE
Qal	Alluvium	Quaternary
TrPb	Brevard Belt	Permian - Triassic (?)
PMp	Muscovite Pegmatite Dikes	Permian (?)
DOgg	Biotite Granite Gneiss	Ordovician to Devonian
DOhg	Henderson Gneiss	
Ogs	Gabbro and Soapstone	Ordovician
MOim	Quartzite	
DpCh	Hornblende Gneiss	Upper Precambrian to Devonian
DpCm	Biotite Gneiss and Migmatite	

From Geological Map of the Crystalline Rocks of South Carolina
by
William C. Overstreet and Henry Bell, III
Miscellaneous Geologic Investigations Map I - 413

Figure 2-45. Topographic Map of Area

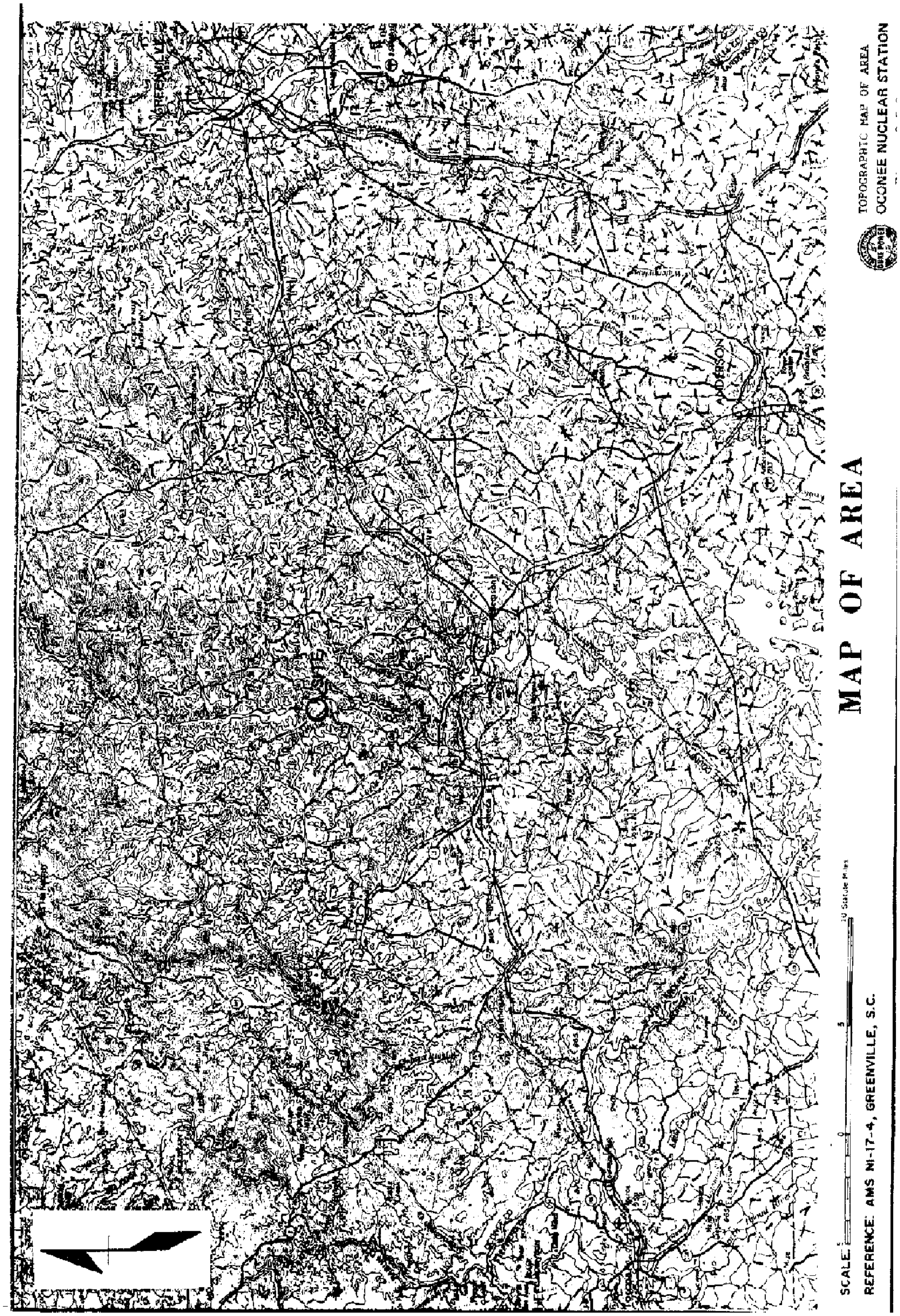


Figure 2-46. Location and Topographic Map

LOCATION AND TOPOGRAPHIC MAP

OCONEE NUCLEAR STATION

DUKE POWER COMPANY

From Old Pickens, South Carolina Quadrangle, 1961. Mapped, edited, and published by the United States Geological Survey.

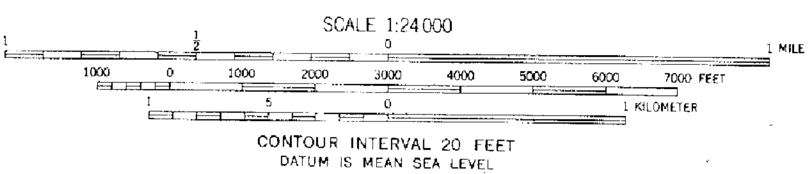


Figure 2-47. Strike and Dip of Joint Pattern

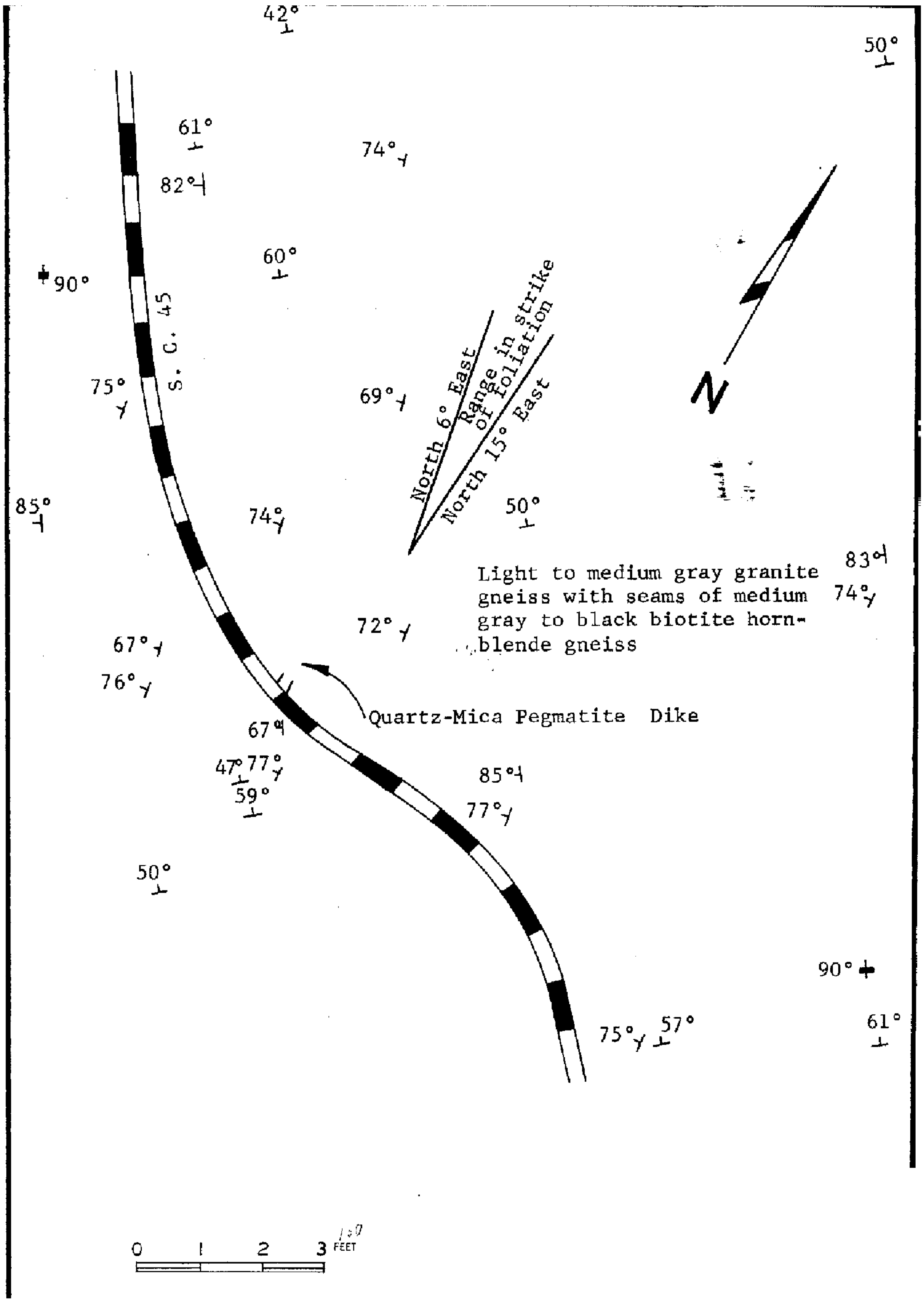


Figure 2-48. Earthquake Epicenters

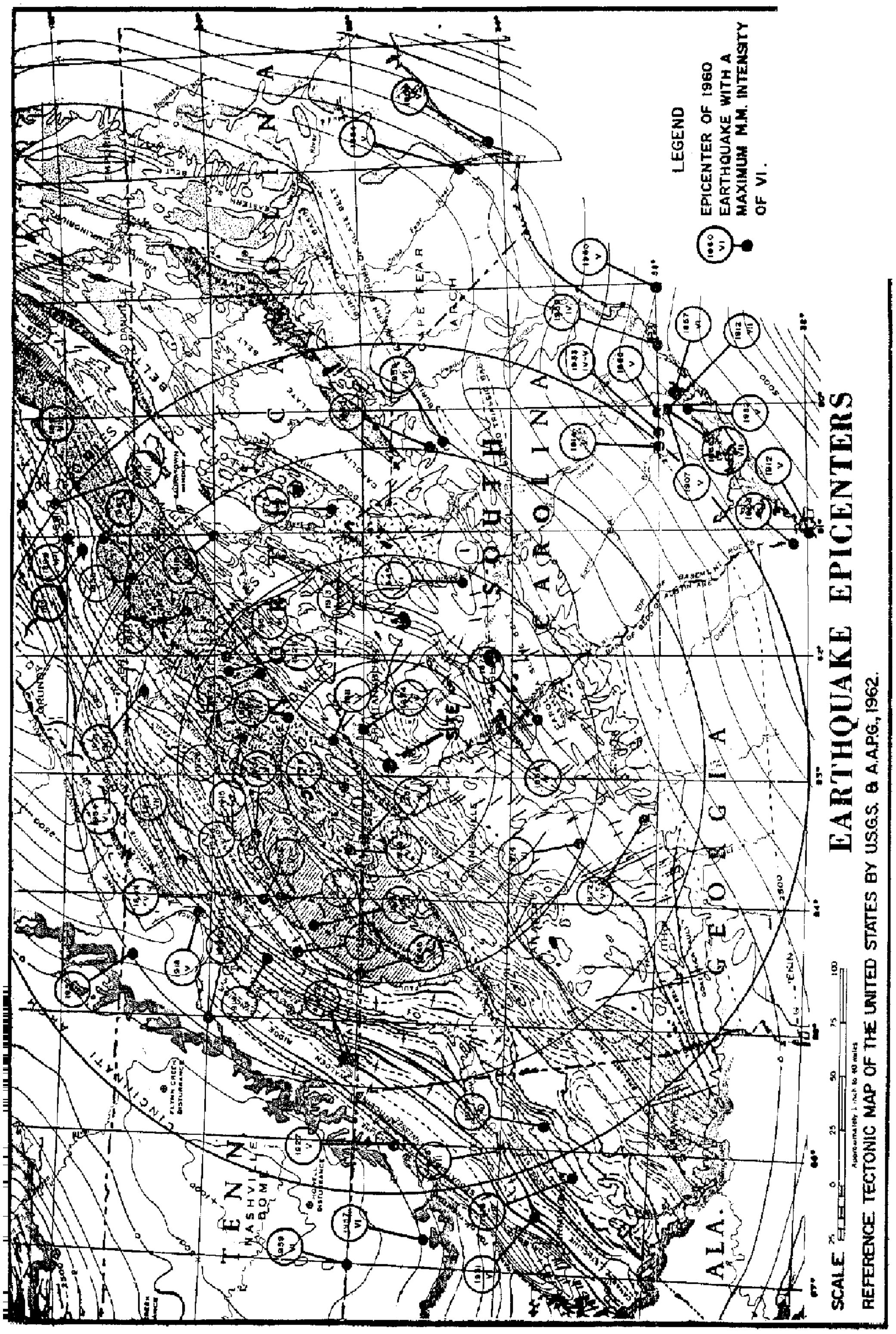


Figure 2-49. Regional Techtonics

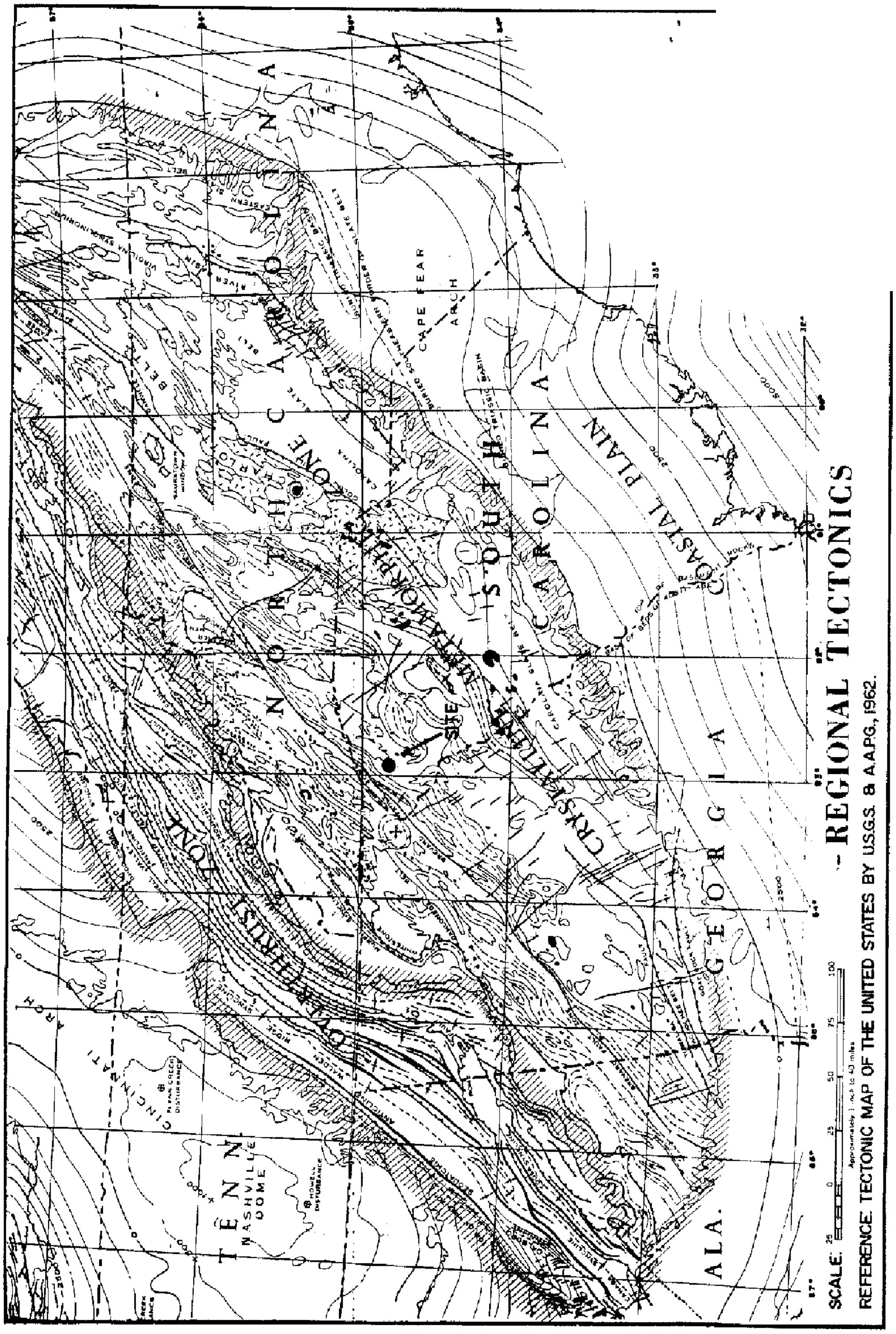
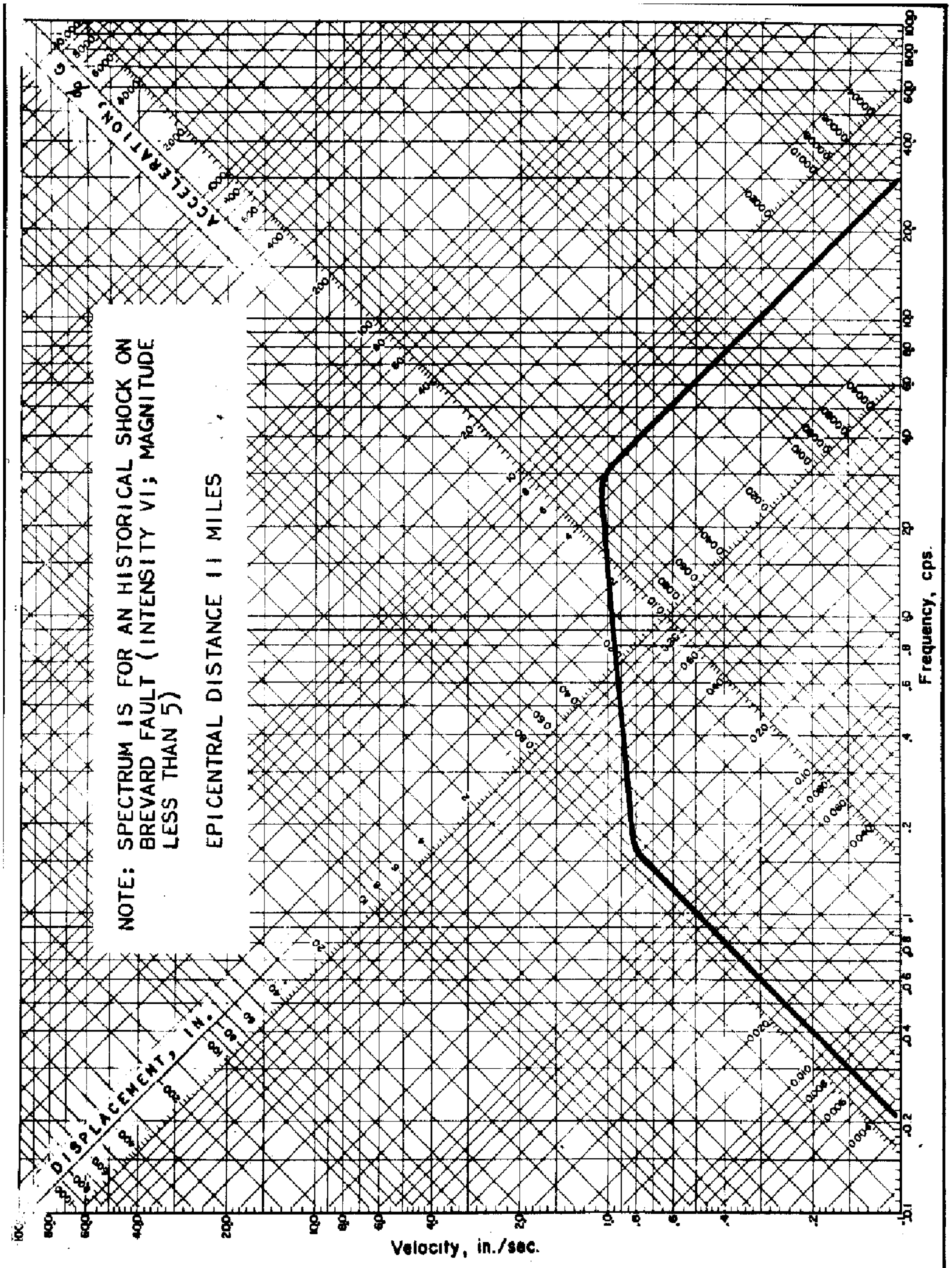
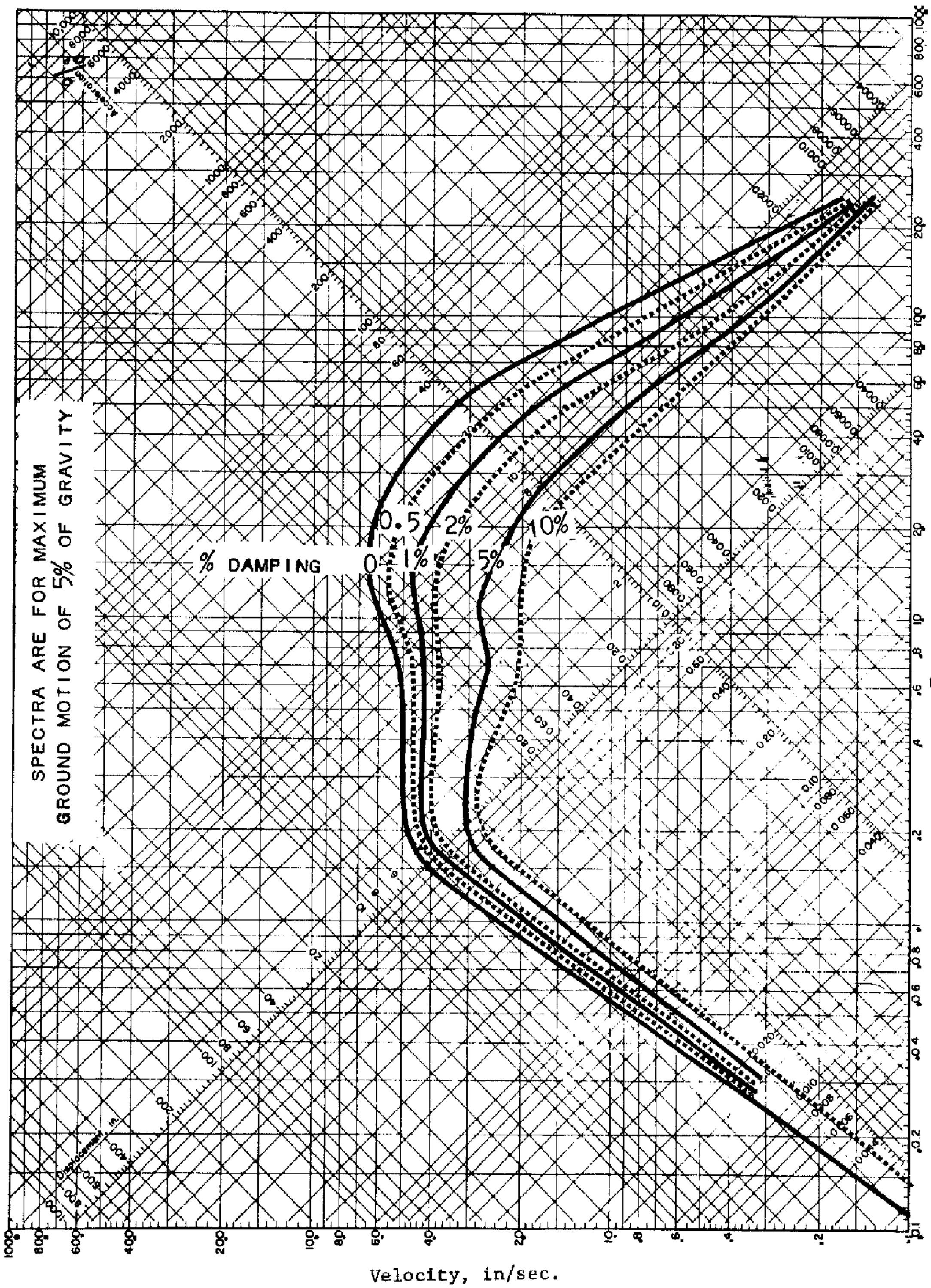


Figure 2-50. Ground Motion Spectra



RECOMMENDED GROUND MOTION SPECTRUM

Figure 2-51. Recommended Response Spectra



RECOMMENDED RESPONSE SPECTRA

Figure 2-52. Ground Motion Spectra

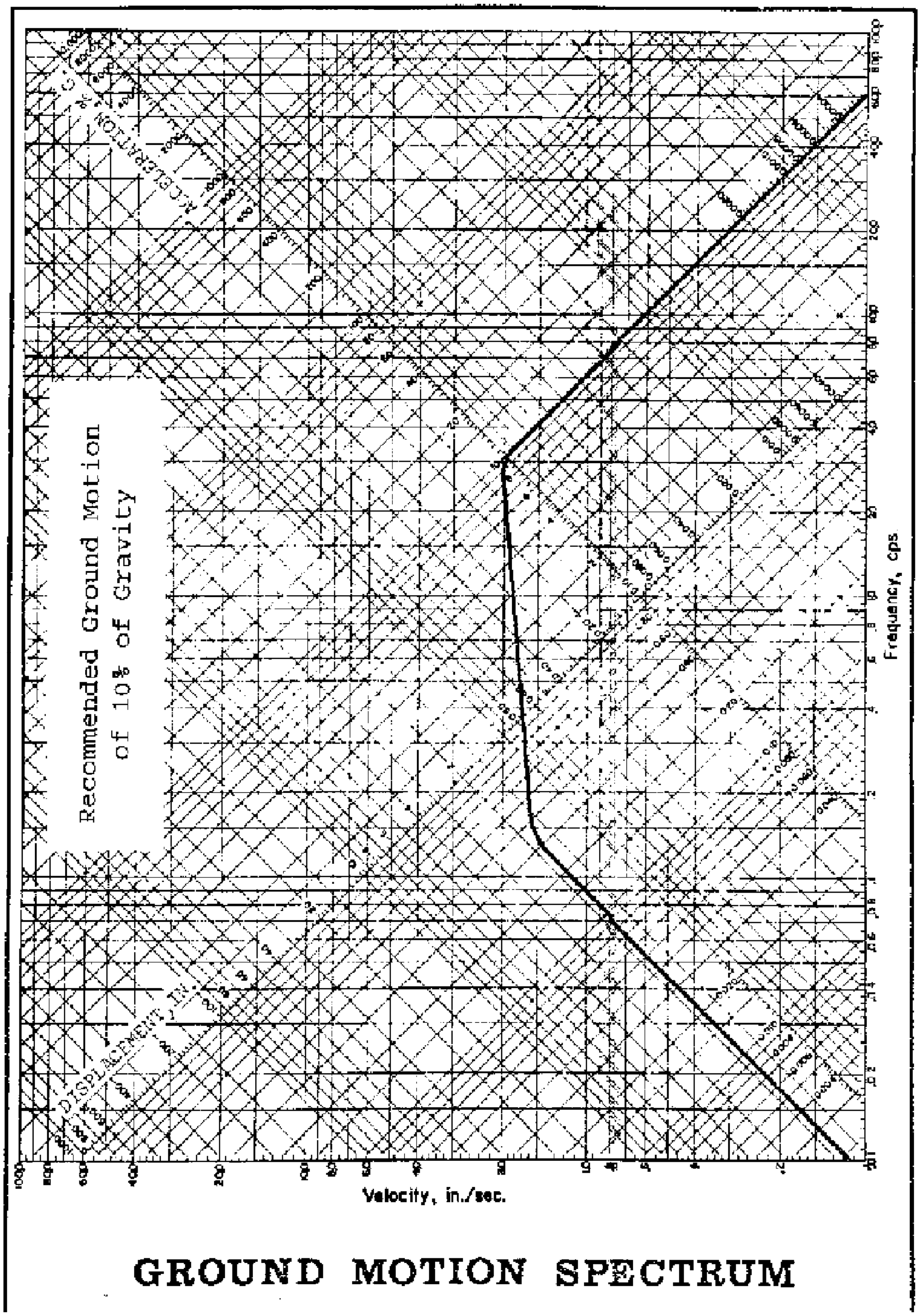
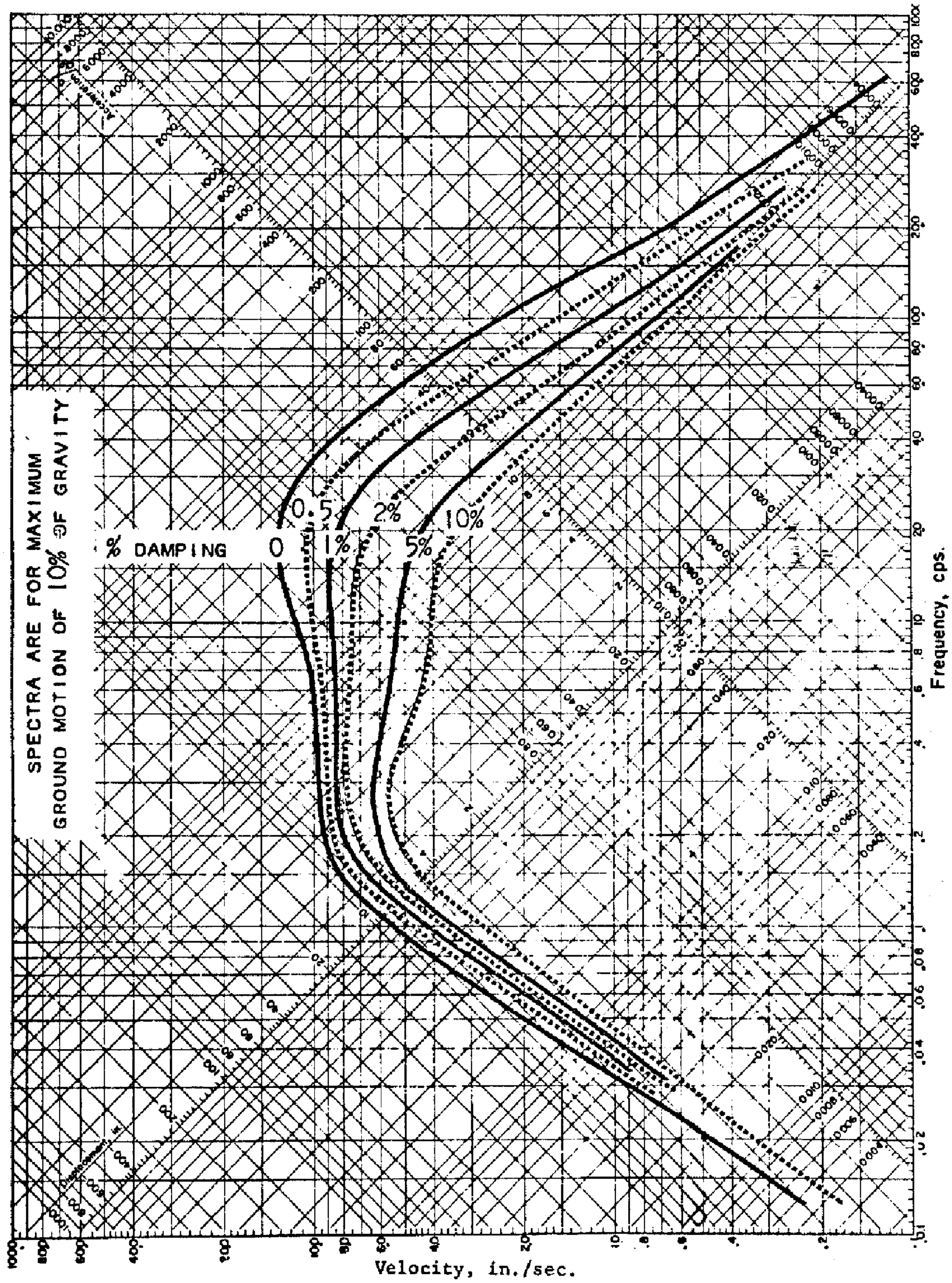


Figure 2-53. Recommended Response Spectra



RECOMMENDED RESPONSE SPECTRA

Figure 2-54. Ground Motion Spectra

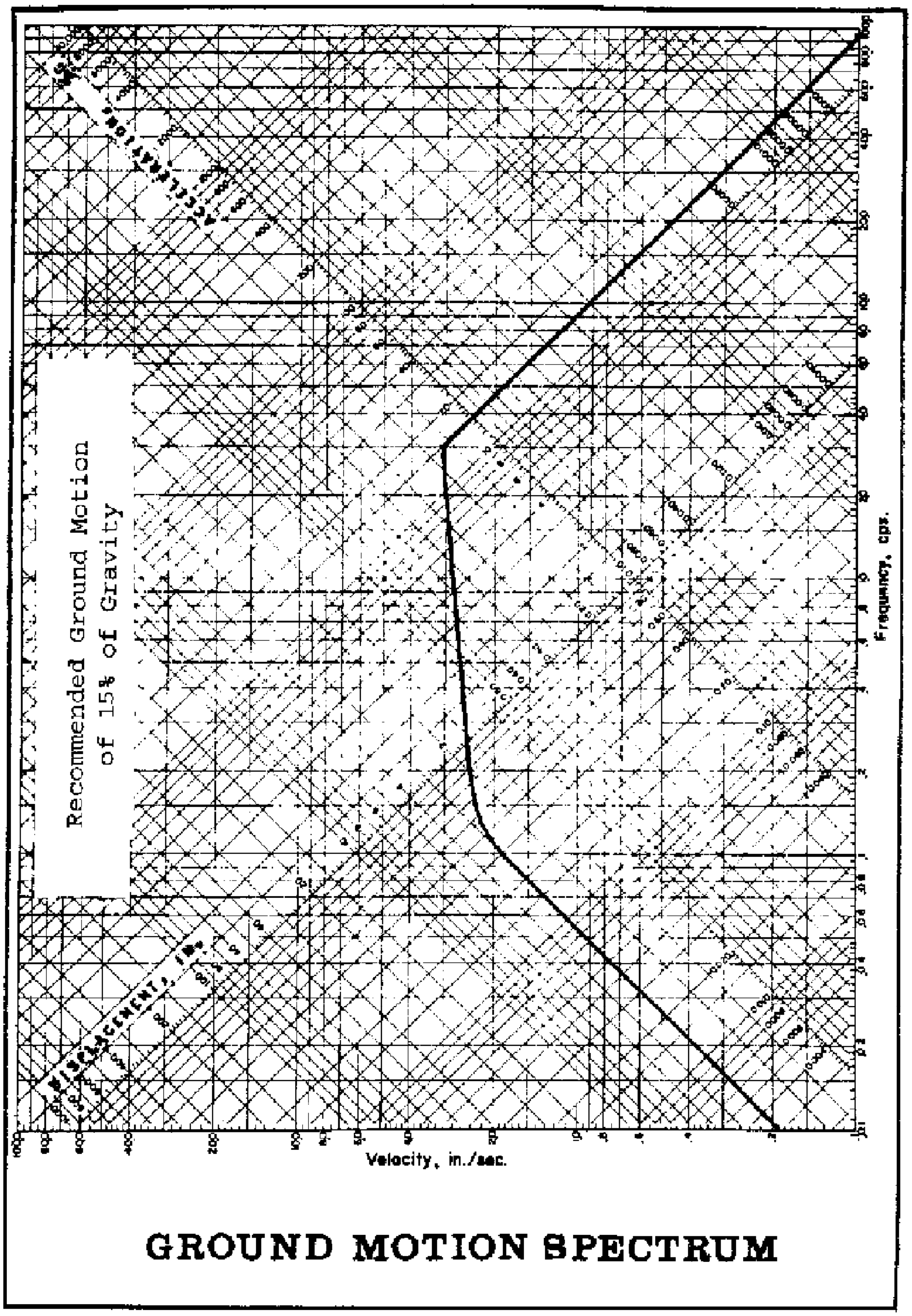
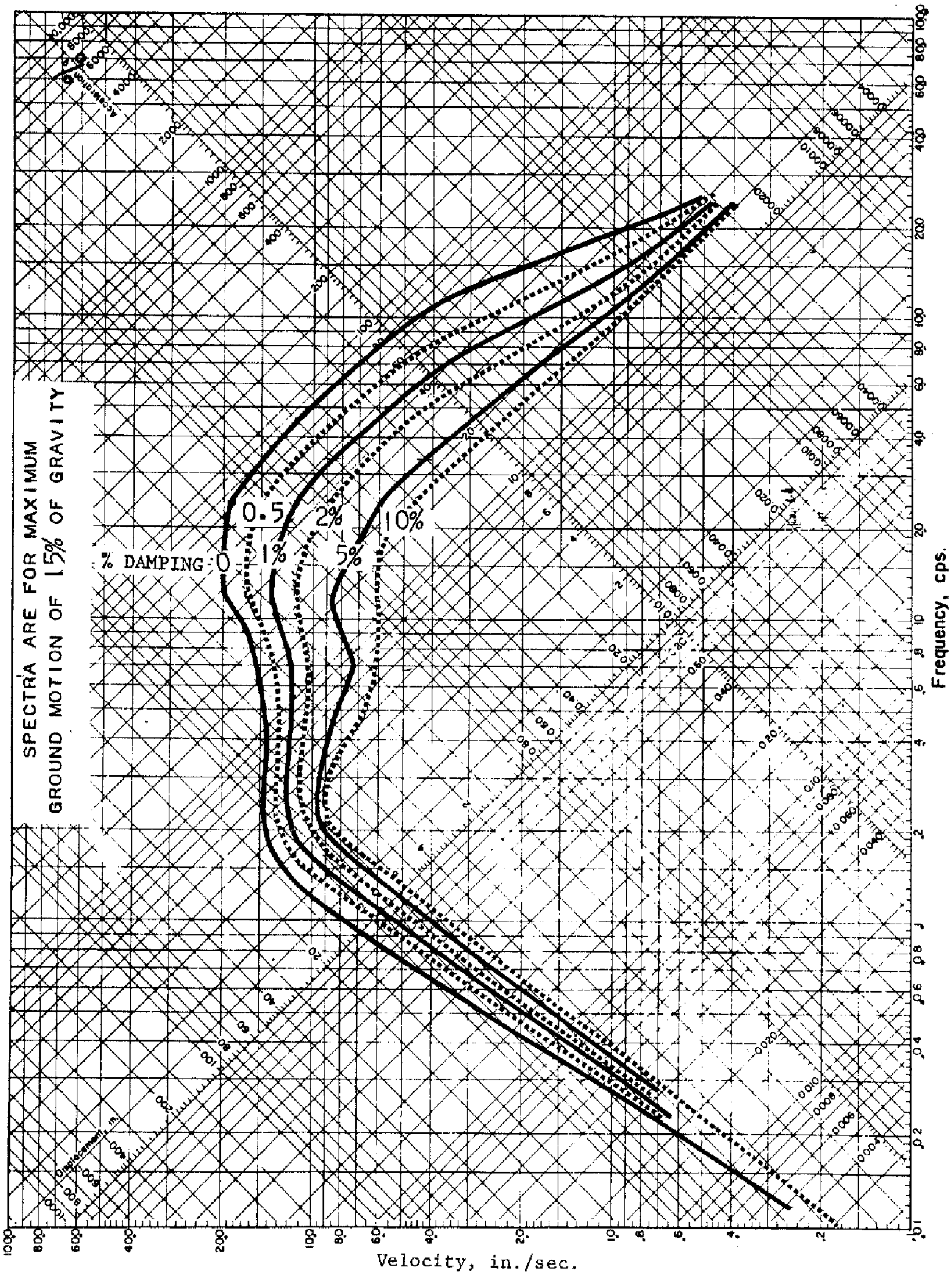


Figure 2-55. Recommended Response Spectra



RECOMMENDED RESPONSE SPECTRA

Figure 2-56. Subsurface Profile

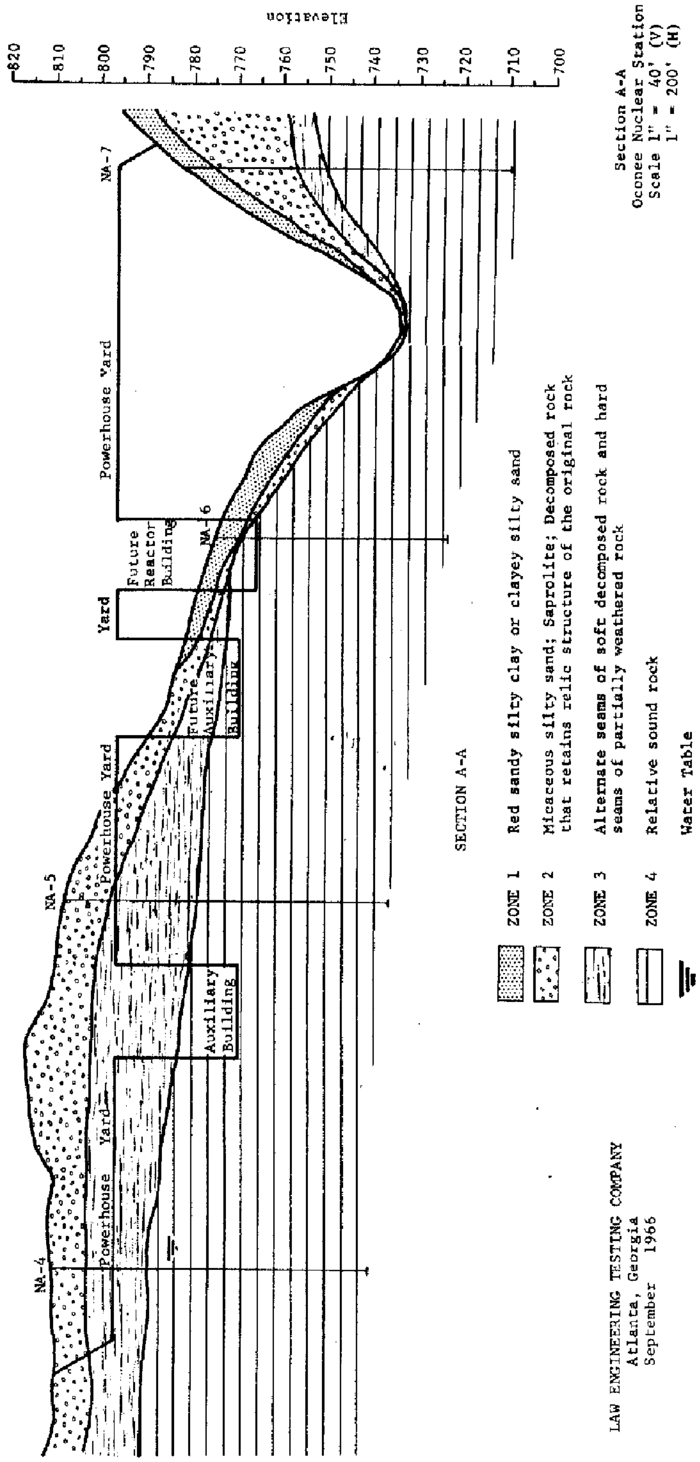


Figure 2-57. Subsurface Profile

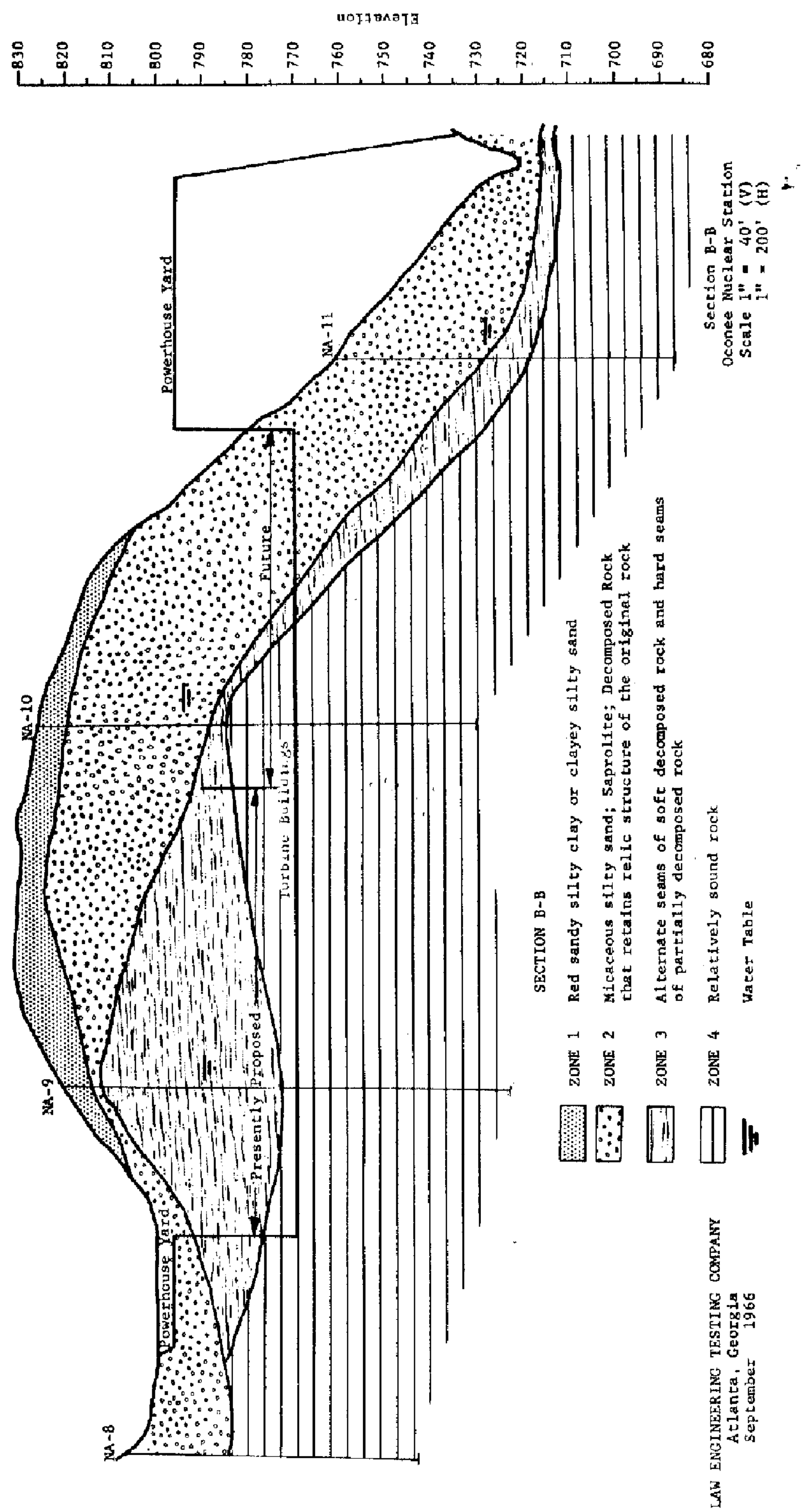


Figure 2-58. Subsurface Profile

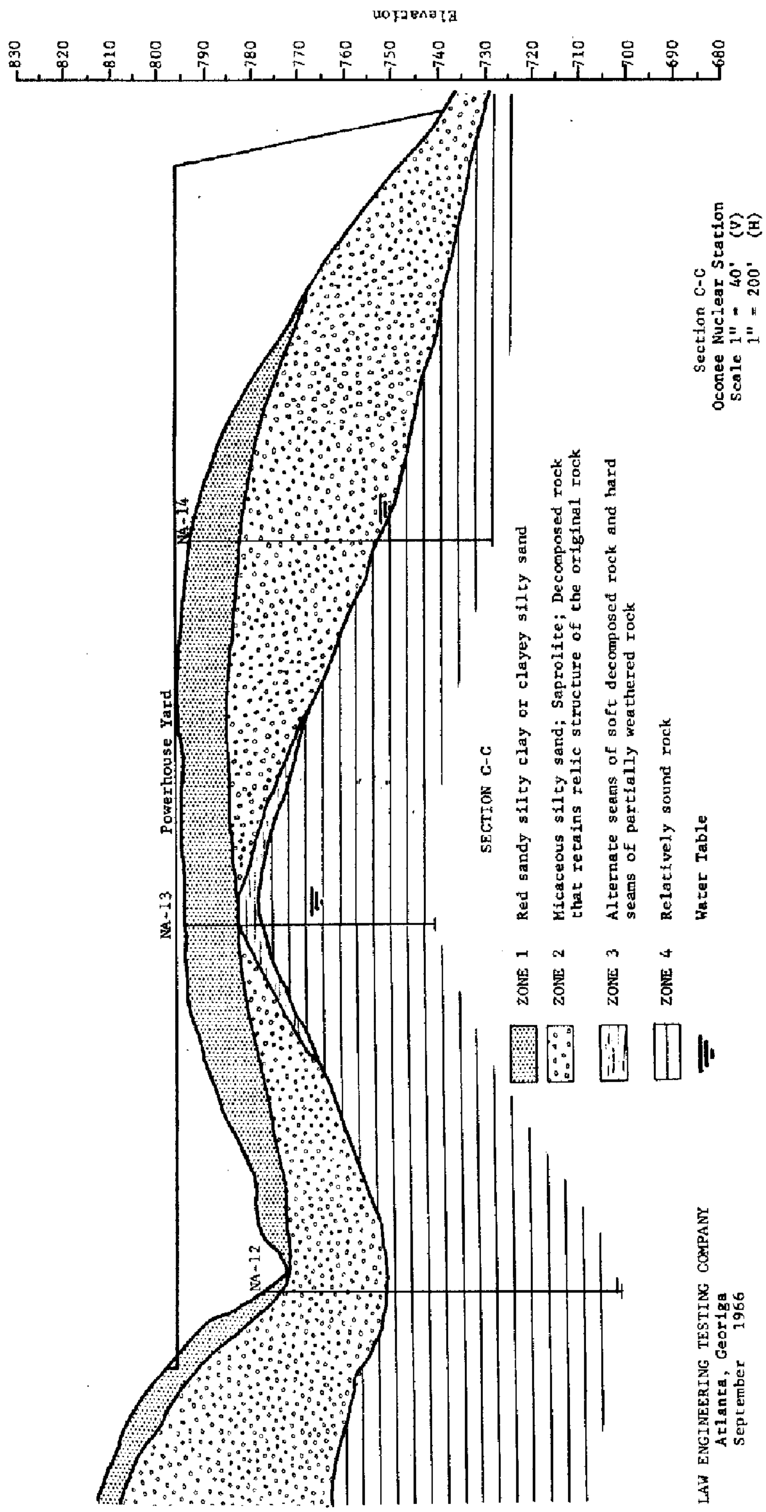


Figure 2-59. Subsurface Profile

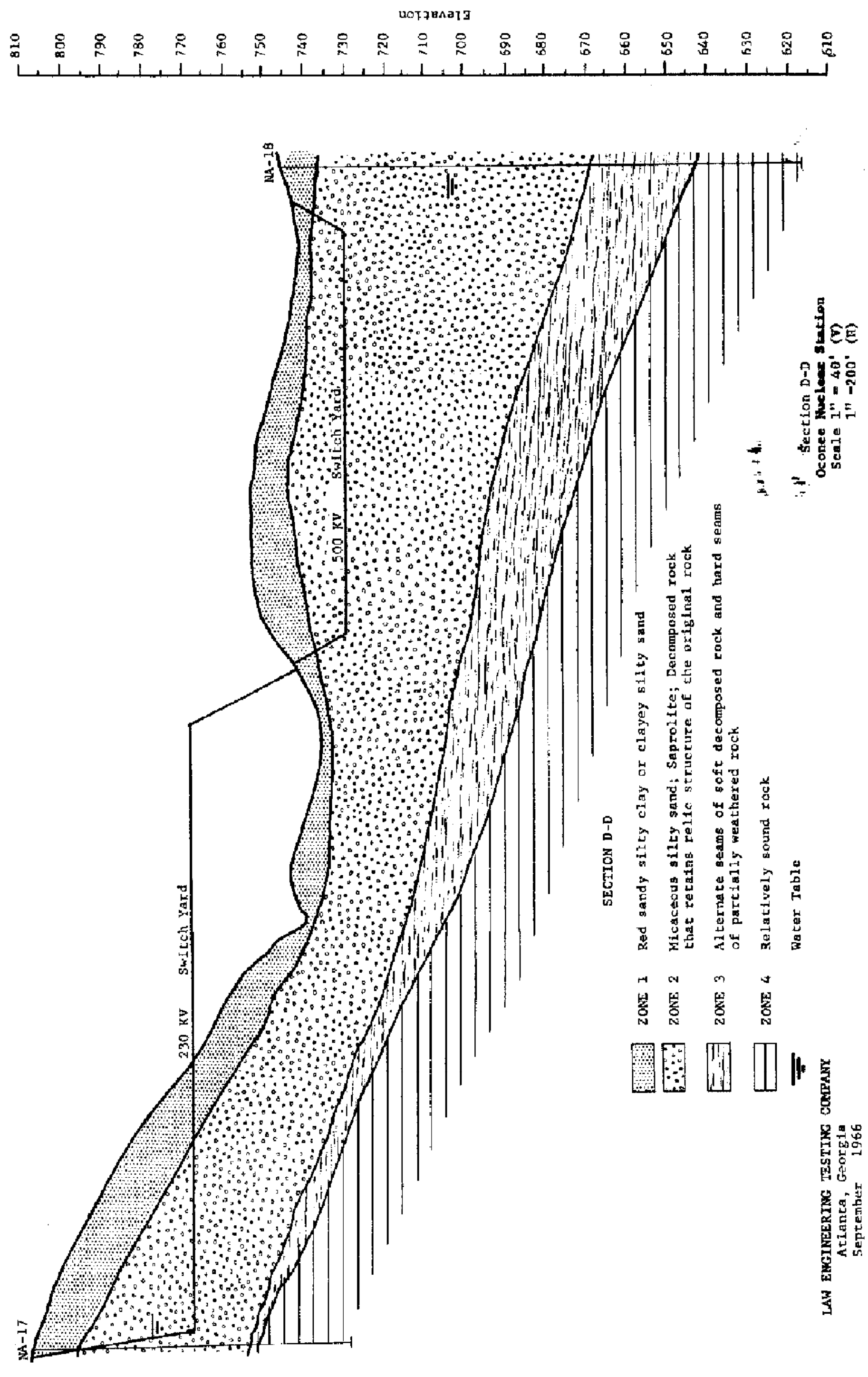


Figure 2-60. Subsurface Profile

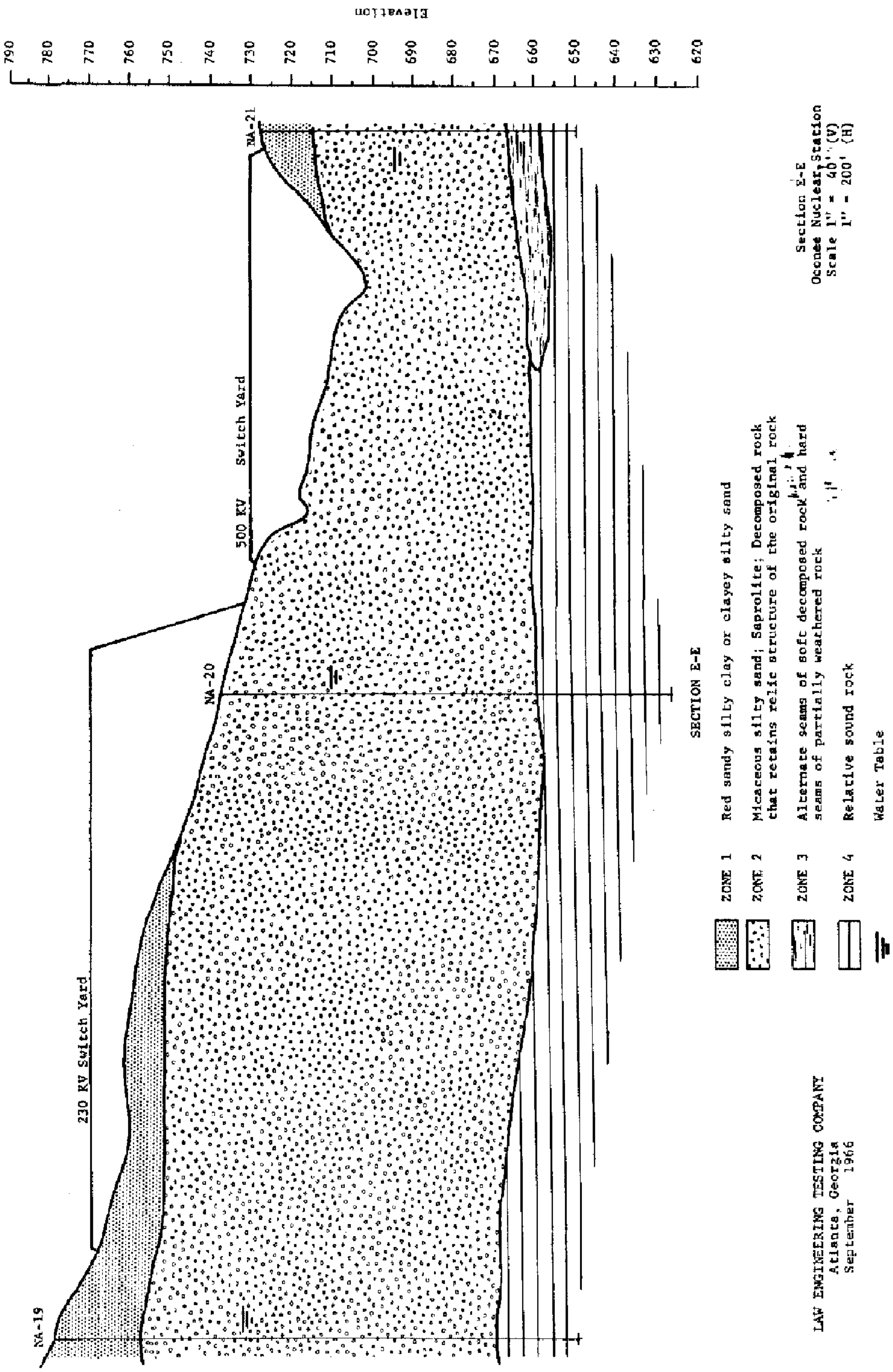


Figure 2-61. Subsurface Profile

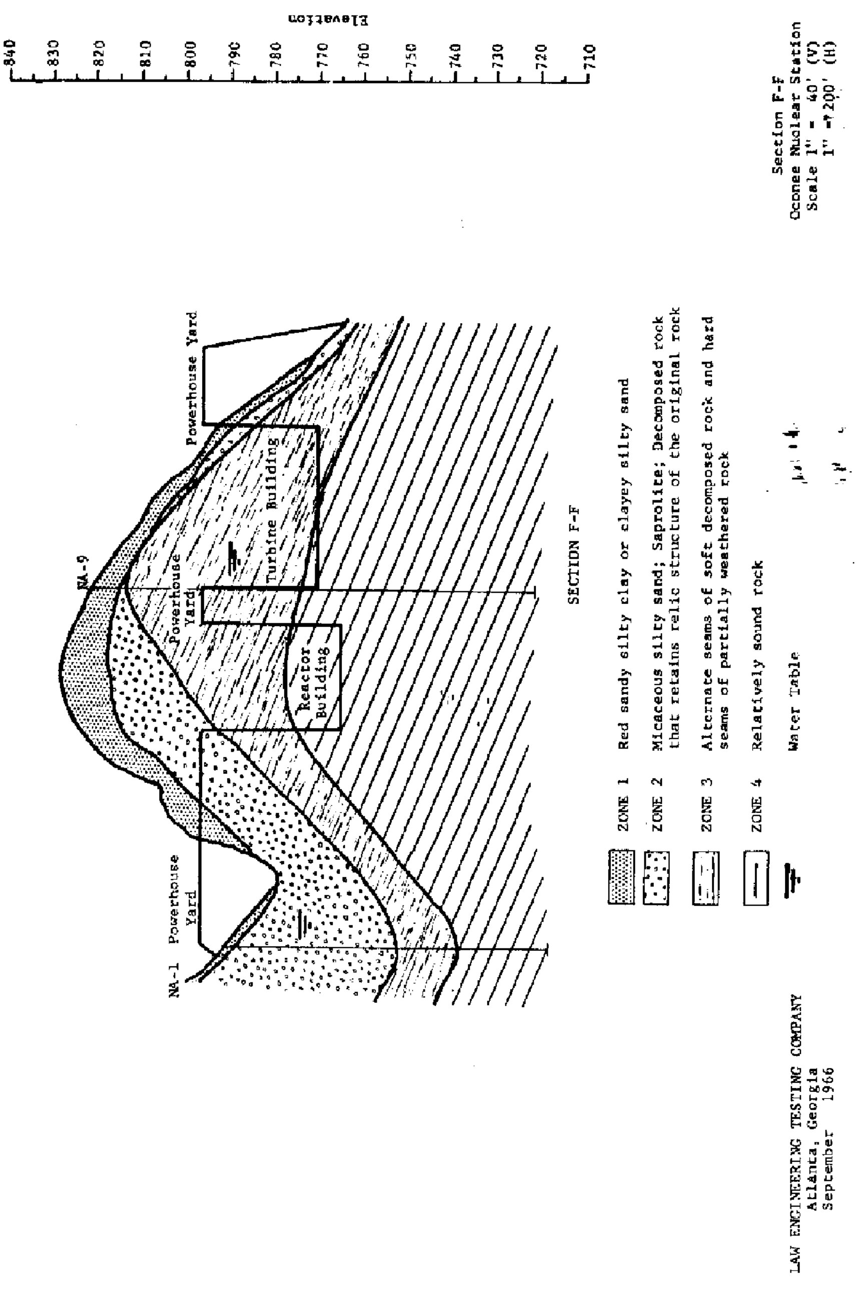


Figure 2-62. Subsurface Profile

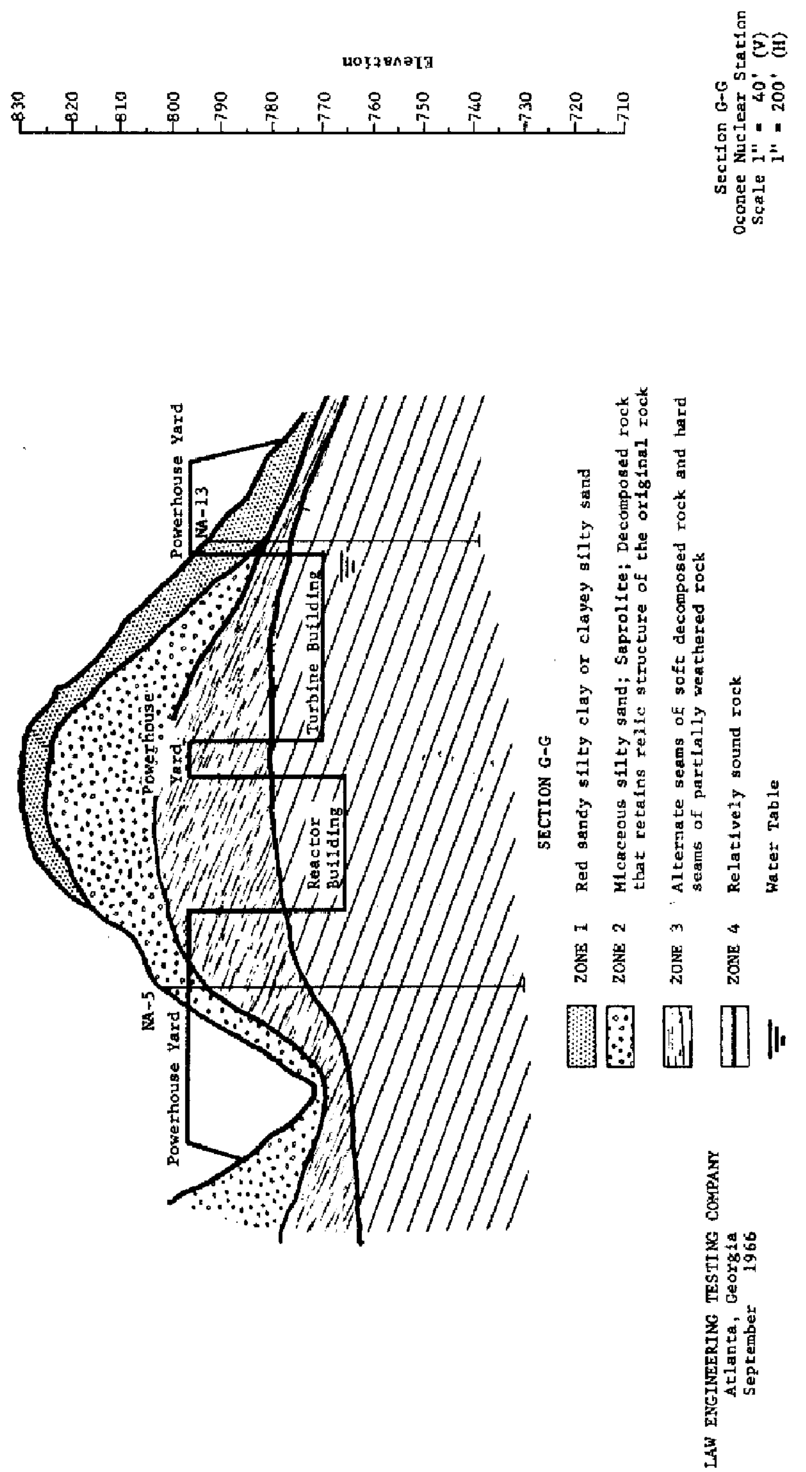


Figure 2-63. Subsurface Profile

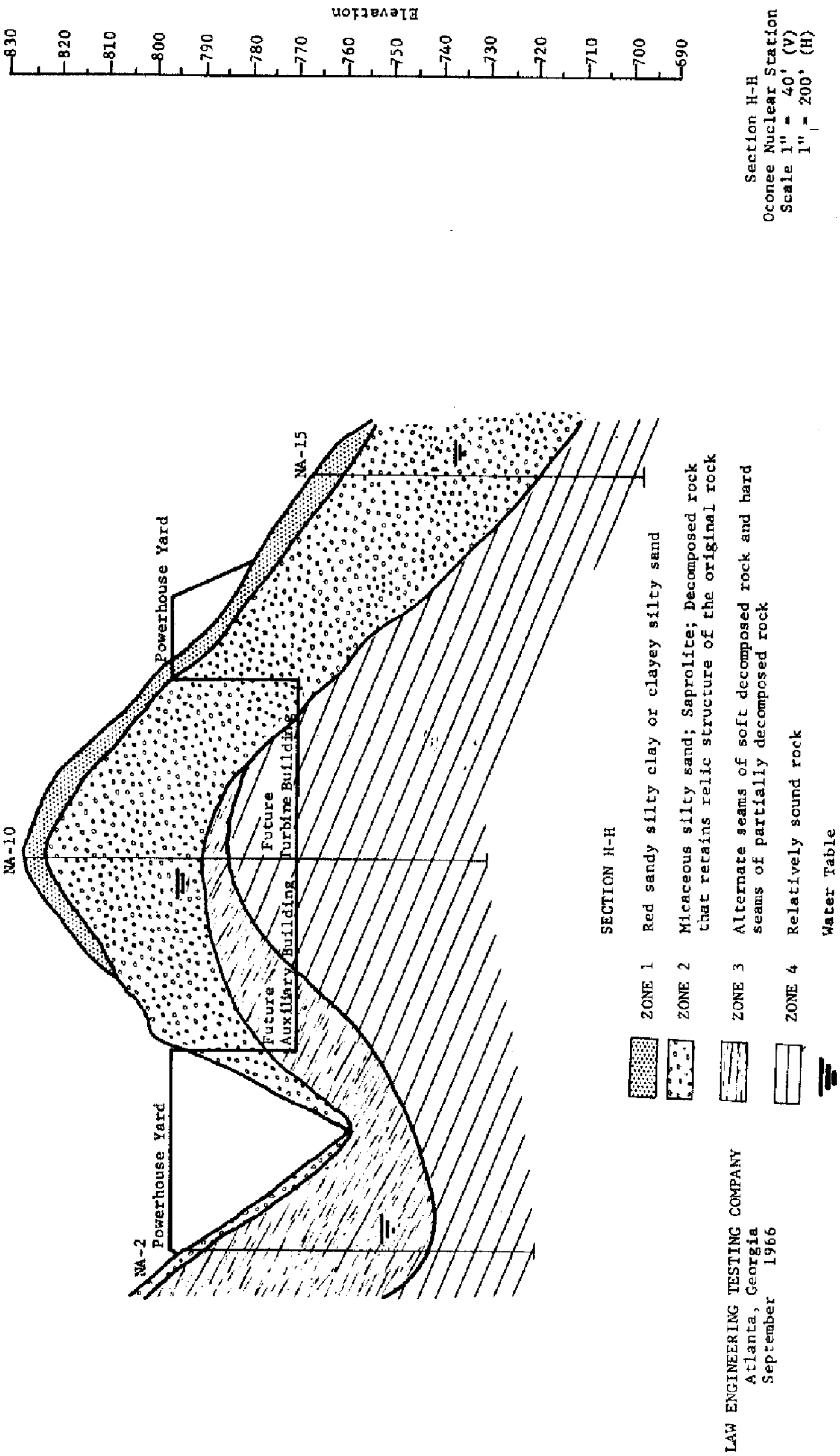


Figure 2-64. Subsurface Profile

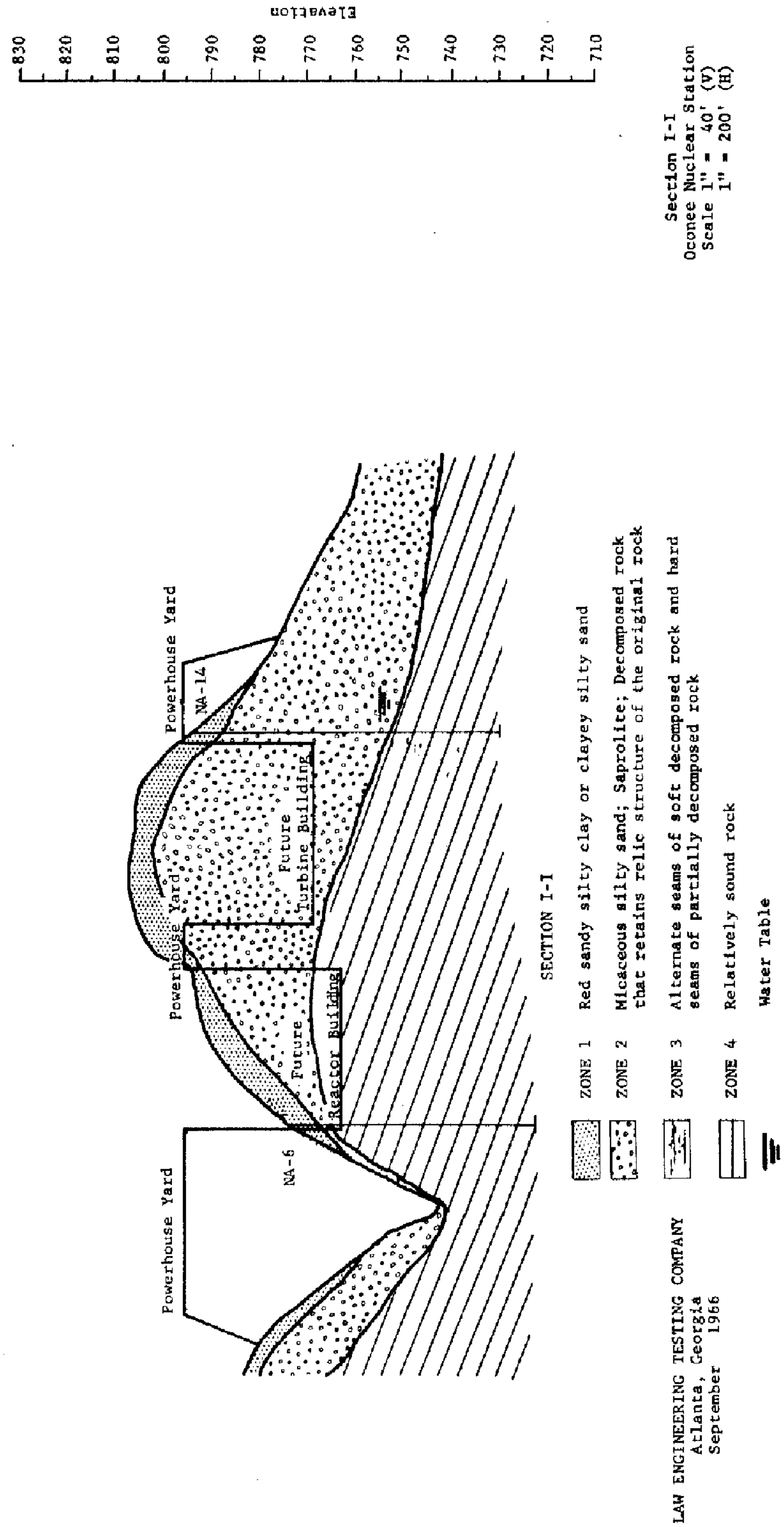


Figure 2-65. Boring Plan

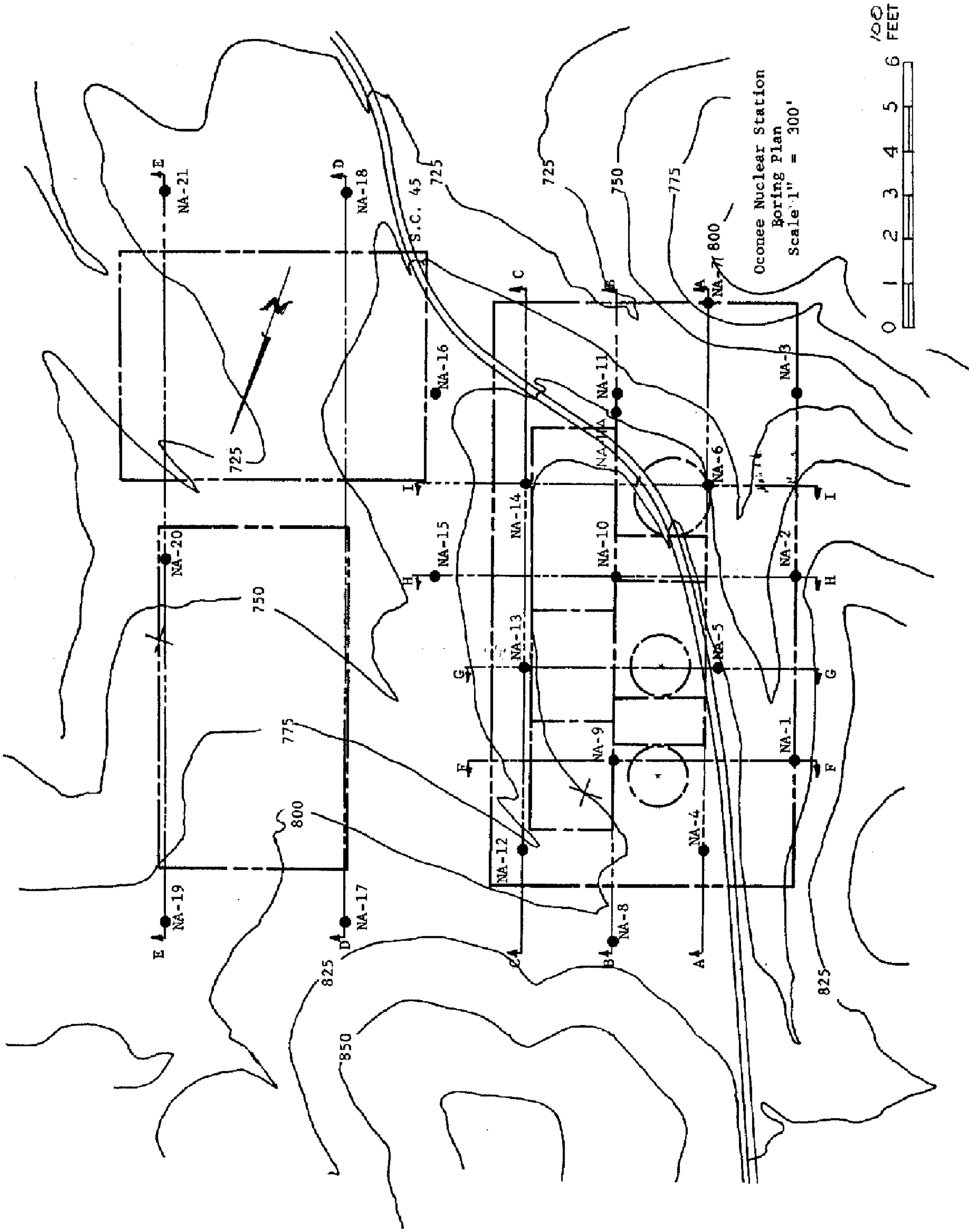


Figure 2-66. Core Boring Record, Boring Log NA-1

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
0				794.1	
	RED MICACEOUS SANDY CLAYEY SILT				
3.6	STIFF TO VERY STIFF RED YELLOW BROWN MICACEOUS FINE TO MEDIUM SANDY SILT			789.1	N = 11
					Undisturbed Sample 4.0 to 5.0 feet.
				784.1	N = 20
				779.1	N = 26
18.0	VERY STIFF TO HARD GRAY BROWN MICACEOUS FINE TO MEDIUM SANDY SILT			774.1	N = 28
				769.1	N = 38
28.0	VERY DENSE GRAY BROWN BLACK MICACEOUS SILTY FINE TO COARSE SAND			764.1	N = 50
32.0	VERY DENSE YELLOW BROWN MICACEOUS SILTY FINE TO COARSE SAND			759.1	N = 65
40.0				754.1	

LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

End of Boring

WATER TABLE

Figure 2-67. Core Boring Record, Boring Log NA-1

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0				754.1	
44.9	SOFT GRAY AND BROWN GRANITE GNEISS	75%		749.1	
45.6	MOD HD LI GY GN	93%			
45.8	SOFT DK GY BROWN BI HO GN				28° Foliation Plane at 45.1 Feet
46.0	MOD LI GY GRAN GN		NX		
47.3	MOD HD DK GY BROWN BI HO GN				
48.2	SOFT LI GY BROWN GRAN GN				
48.5	SOFT DK GY BROWN BI HO GN				
52.7	SOFT AND MOD HD ALTERNATING LAYERS LI GY BROWN GRAN GN			744.1	
53.6	HARD LI GY QUARTZ SEAM				
58.5	HD LI GY GRAN GN	100%		739.1	Vertical Joint at 50 Feet
58.8	HD DK GY BI HO GN				
60.9	HD LI GY GRAN GN			734.1	
61.1	HD DK GY BI HO GN				
63.4	HD LI GY GRAN GN		BX		
64.1	HD DK GY BI HO GN				
66.2	HD LI GY GRAN GN WITH INCLUSIONS OF HORNBLENDE CONCENTRATIONS			729.1	
67.4	MOD HD DK GY BK BI HO GN	100%			
67.9	HD LI GY GRAN GN				
68.2	HD DK GY BI HO GN				
70.1	HD LI GY GRAN GN			724.1	
70.3	HD DK GY BI HO GN				
73.8	HD LI GY GRAN GN WITH THIN HD GN SEAMS			720.3	
	CORING TERMINATED			719.1	

WATER TABLE

Figure 2-68. Core Boring Record, Boring Log NA-2

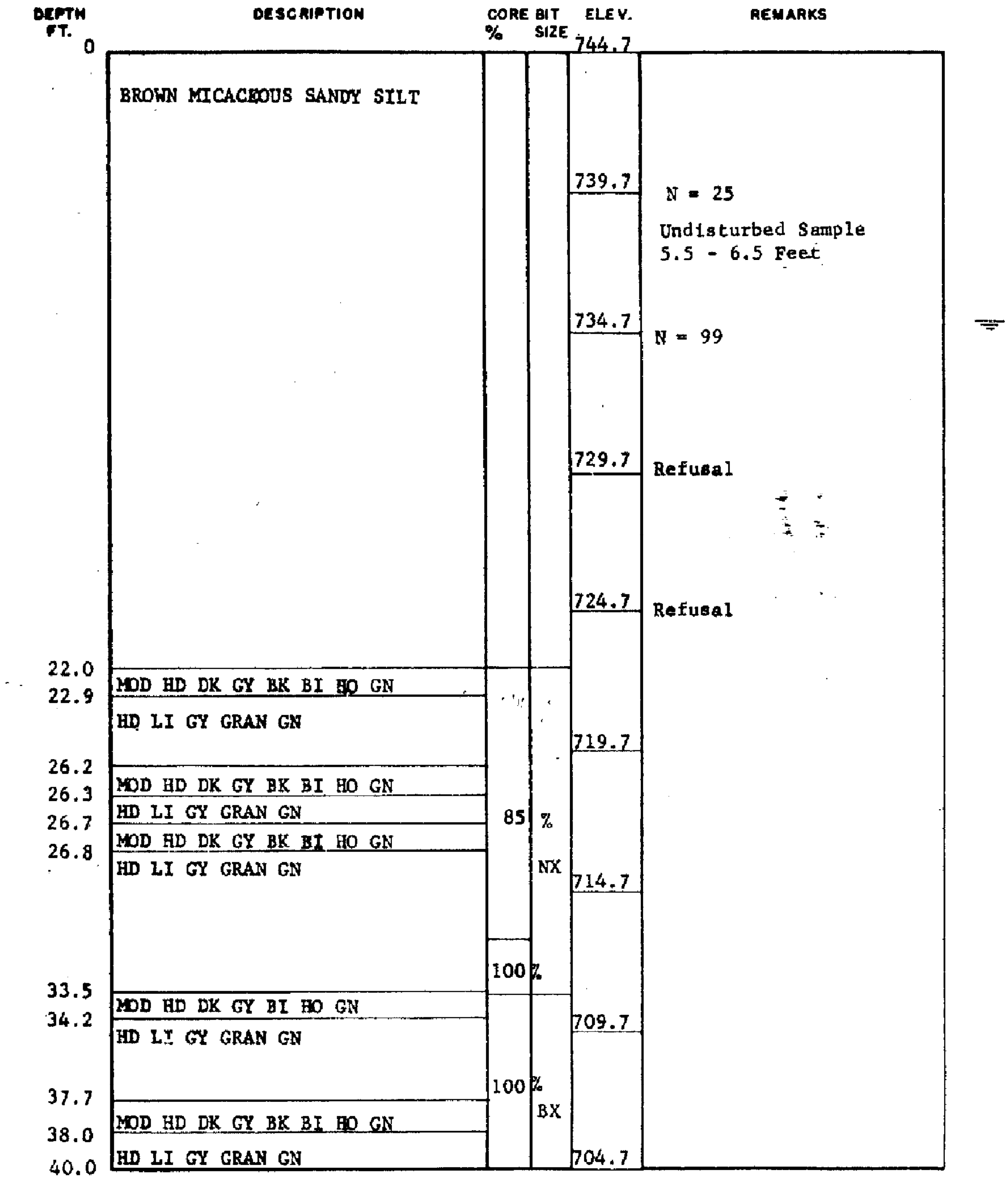
DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
0	BROWN MICACEOUS SANDY SILT			812.5	
3.8	MOD HD LI GY BROWN GRAN GN	36%	NX		
4.9	VERY SOFT GRAN GN AND BROWN SANDY SILT			807.5 802.5	
10.5	MOD HD LI GY BROWN GRAN GN WITH SOIL SEAMS	86%		797.5	
18.8	VERY SOFT LI GY GRAN GN WITH THIN LAYERS OF MOD HD GRAN GN	50% 28%		792.5 787.5 782.5 777.5	
38.8	HD LI GY GRAN GN	65%		772.5	
40.0					

LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

Figure 2-69. Core Boring Record, Boring Log NA-2

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0	HD LI GY GRAN GN	65% 78%	NX	772.5 767.5	80° Joint at 46.0 - 47.5 Feet
48.7	SOFT DK GY BROWN BI HO GN			762.5	
50.9	HD LI GY GRAN GN	85%	BX	757.5	
58.3	MOD HD DK GY BI HO GN				
59.3	HD LI GY GRAN GN	100%		752.5	
63.2	HD DK GY BK BI HO GN				
63.5	HD LI GY GRAN GN			747.5	
65.1	HD DK GY BK BI HO GN				
68.2	HD LI GY GRAN GN	100%		742.5 739.7	
72.8	CORING TERMINATED			737.5	

Figure 2-70. Core Boring Record, Boring Log NA-3



LI - Light
DK - Dark
GY - Gray
BK - Black
MOD - Moderately
MED - Medium
HD - Hard
BI - Biotite
HO - Hornblende
GRAN - Granite
GN - Gneiss

Figure 2-71. Core Boring Record, Boring Log NA-3

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0				704.7	
	HD LI GY GRAN GN	100%	BX	702.7	
42.0	CORING TERMINATED			699.7	

Figure 2-72. Core Boring Record, Boring Log NA-4

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
0	VERY STIFF YELLOW BROWN MICACEOUS FINE TO MEDIUM SANDY SILT			810.42 805.42	N = 32
7.8	MOD HD LI GY GRAN GN	96%		800.42	Lost Water 9.9 Feet 82° Joint at 11.8 Feet 82° Joint at 12.2 Feet 81° Joint at 13.2 Feet 54° Joint at 14.0 Feet
15.6	SOFT LI GY GRAN GN	60%	NX	795.42	
17.9	MOD HD LI GY GRAN GN			790.42	
21.1	SOFT DK GY BK BI HO GN	90%			
21.7	HD LI GY GRAN GN	100 %		785.42	
26.5	HD DK GY BI HO GN				
26.7	HD LI GY GRAN GN	100 %		780.42	
30.8	HD DK GY BK BI HO GN	100 %	BX		
34.1	HD LI GY GRAN GN			775.42	
34.4	HD DK GY BK BI HO GN				23° Foliation Plane at 36 Feet
36.6	HD LI GY GRAN GN	100 %			
39.3	HD LI GY QUARTZ PEGMATITE			770.43	
40.0					

31.0 Feet of 2" Plastic Pipe left in hole

LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

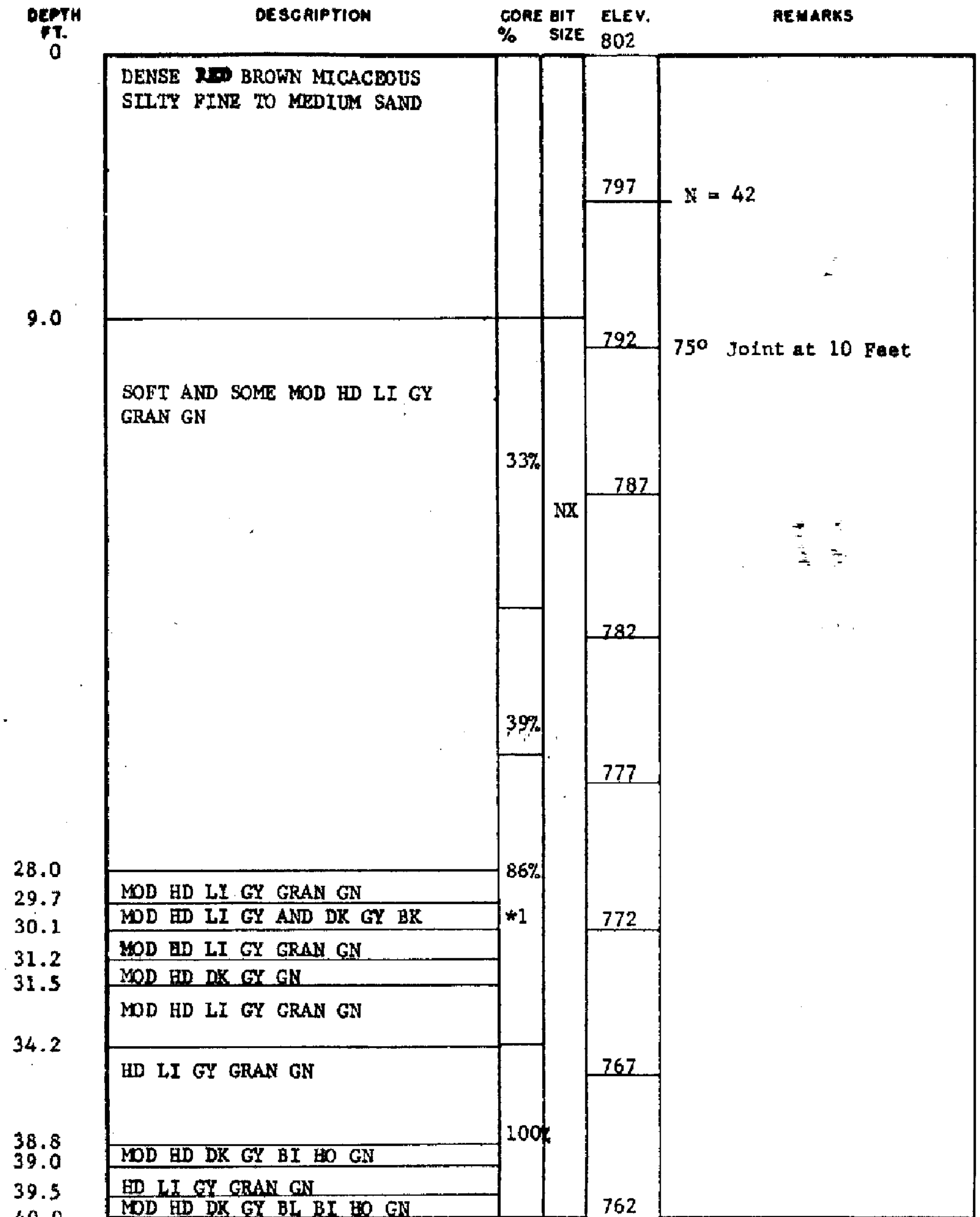
WATER TABLE

Figure 2-73. Core Boring Record, Boring Log NA-4

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0	HD LI GY QUARTZ PEGMATITE	100%		770.42	
43.0	HD LI GY GRAN GN	100 %		765.42	
47.6	HD DK GY BI HO GN				
48.1	HD DK GY GRAN GN	100 %		760.42	
50.9	HD DK GY BI HO GN		BX		
51.1	HD LI GY GRAN GN	100 %		755.42	
56.8	HD DK GY BK BI HO GN				
57.3	HD LI GY GRAN GN				
58.0	HD DK GY BK BI HO GN				
58.2	HD LI GY GRAN GN			750.42	
58.7	HD DK GY BK BI HO GN	100 %			
58.9	HD LI GY GRAN GN				
59.3	HD . . BK BI HO GN				
59.7	HD LI GY GRAN GN	100 %		745.42	
		95%		740.02	
70.4	CORING TERMINATED			735.42	

Not to scale

Figure 2-74. Core Boring Record, Boring Log NA-5



*1 ALTERNATING THIN LAYERS OF GRAN GN AND BI HO GN

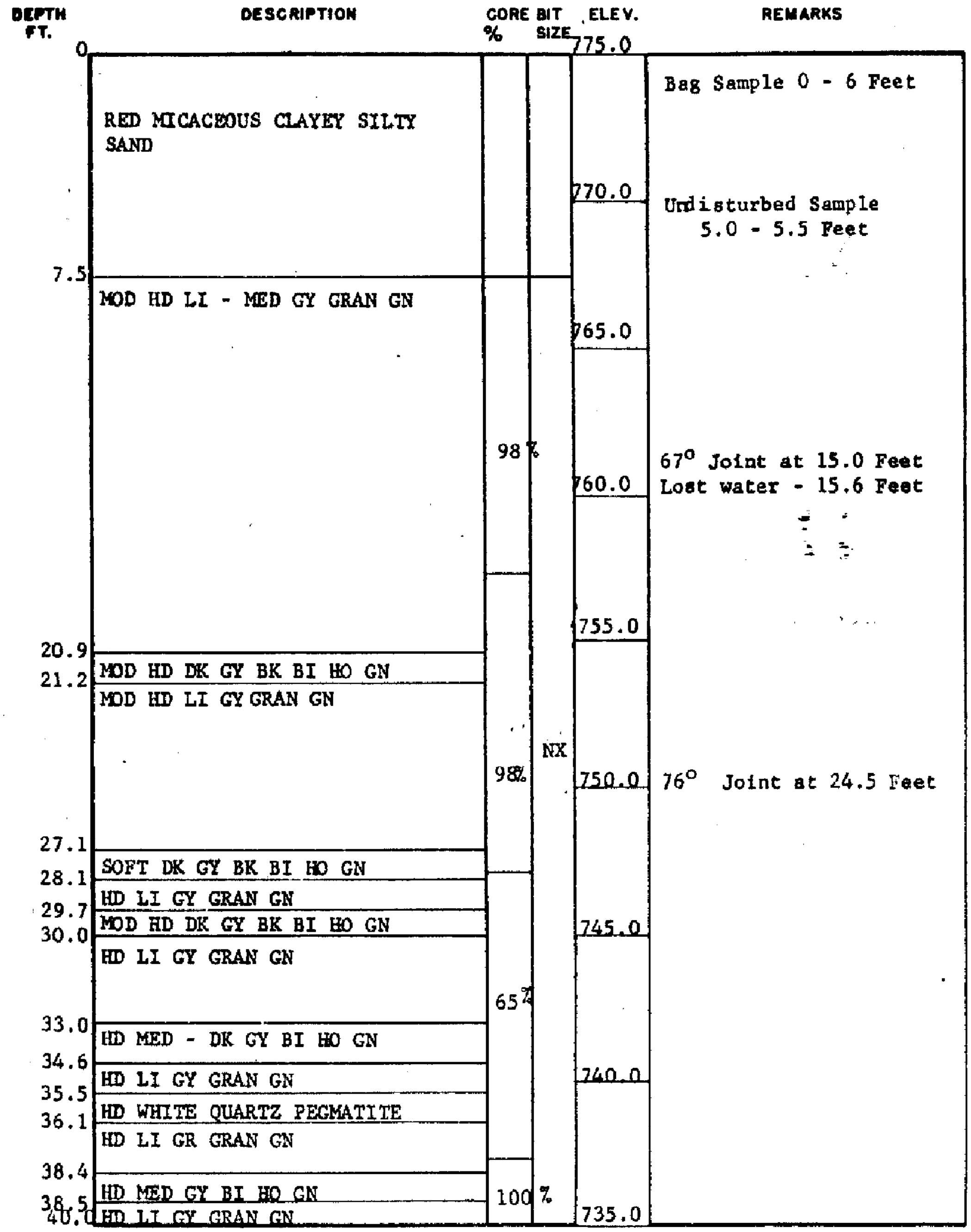
LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

No Water Encountered

Figure 2-75. Core Boring Record, Boring Log NA-5

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0	MOD HD DK GY BK BI HO GN			762	
40.7	HD LI GY GRAN GN	92%			
44.5	MOD HD DK GY BK BI HO GN				
44.8	HD LI GY GRAN GN			757	
45.8	MOD HD DK GY BK BI HO GN	86%			
47.8	HD LI GY GRAN GN			752	
51.8	MOD HD DK GY BK BI HO GN	98%	NX		
52.5	HD LI GY GRAN GN			747	
57.3	HD DK GY BI HO GN				
58.2	HD LI GY GRAN GN				
58.8	HD DK GY BI HO GN			742	
58.9	HD LI GY GRAN GN				
61.5	HD DK GY BK BI HO GN				
63.2	HD LI GY GRAN GN	100%			
64.2	HD DK GY BK BI HO GN			737	
64.4	HD LI GY GRAN GN	99%			
67.1	HD DK GY BI HO GN				
68.1	HD LI GY GRAN GN				
68.9	HD DK GY BI HO GN		BX	732	
69.3	HD LI GY GRAN GN			731.2	
70.8	CORING TERMINATED			727	

Figure 2-76. Core Boring Record, Boring Log NA-6



LI - Light
DK - Dark
GY - Gray
BK - Black
MOD - Moderately
MED - Medium

HD - Hard
BI - Biotite
HO - Hornblende
GRAN - Granite
GN - Gneiss

Not to scale

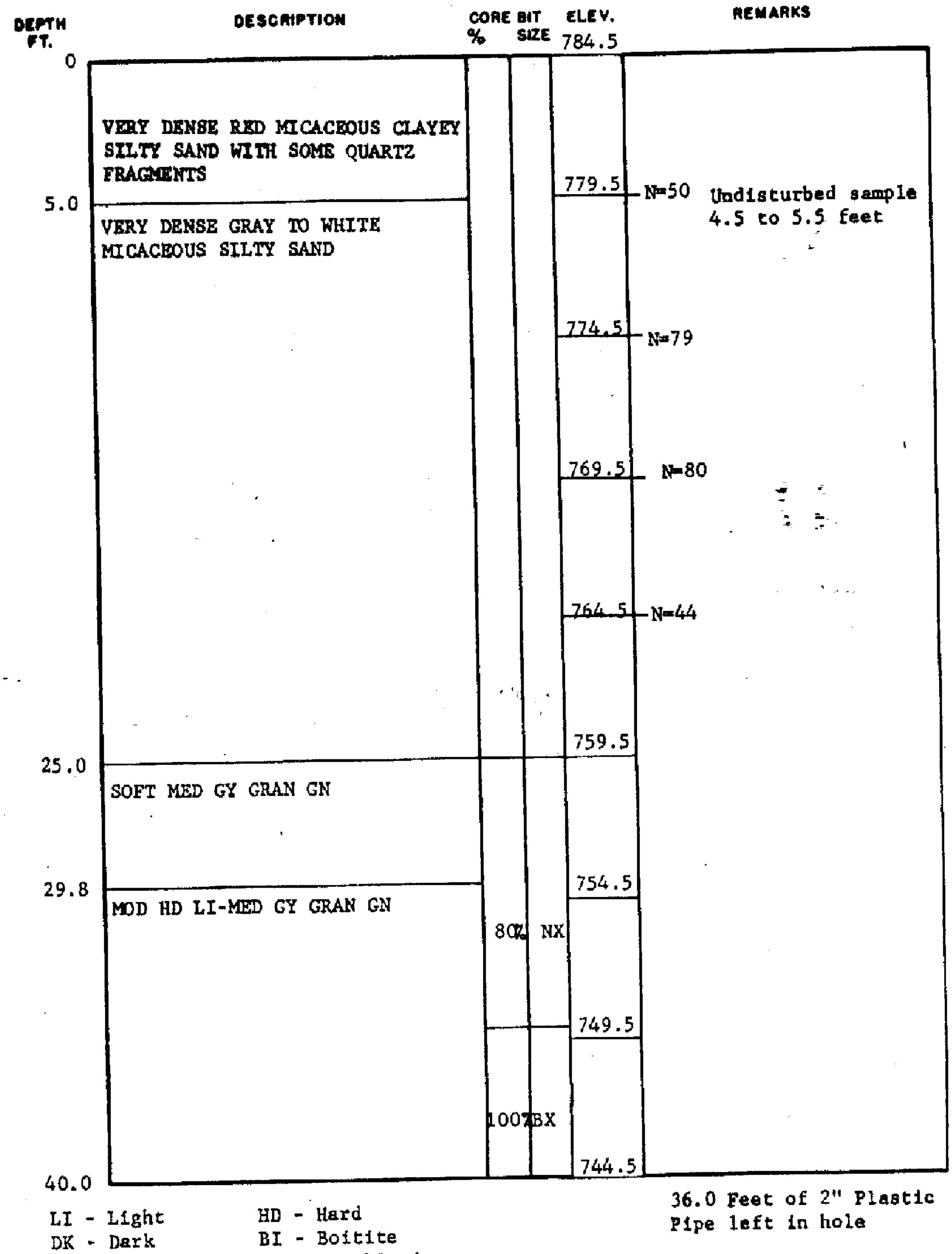
Figure 2-77. Core Boring Record, Boring Log NA-6

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0–40.7	HD LI GY GRAN GN			735.0	
40.7–40.8	HD MED GY BI HO GN				
40.8–43.7	HD LI GY GRAN GY				
43.7–44.7	HD LI-DK GY ALTERNATING LAYERS*1	100 %		730.0	
44.7–45.6	HD LI GY GRAN GN				
45.6–45.9	HD MED GY BI HO GN		NX		
45.9–46.6	HD LI GY GRAN GN				
46.6–46.7	HD MED GY BI HO GN				
46.7–47.0	HD LI GY GRAN GN				
47.0–47.1	HD DK GY BK BI HO GN				
47.1–50.3	HD LI GY GRAN GN	100 %		725.0	
50.3–50.9	HD MED-DK GY BI HO GN				
50.9–51.6	HD LI GY GRAN GN				
51.6–51.7	HD MED DK GY BI HO GN			723.3	
	CORING TERMINATED				

*1 OF BI HO GN AND GRAN GN

Not to scale

Figure 2-78. Core Boring Record, Boring Log NA-7



LI - Light
DK - Dark
GY - Gray
BK - Black
MOD - Moderately
MED - Medium
HD - Hard
BI - Boitite
HO - Hornblende
GRAN - Granite
GN - Gneiss

Figure 2-79. Core Boring Record, Boring Log NA-7

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0				744.5	
40.1	MOD HD LI-MED GY GRAN GN				
	MOD HD DK GY BK BI HO GN	100%			50° Joint at 42.7 Feet 50o Joint at 43.5 Feet
44.8	MOD HD LI GY GRAN GN			739.5	
46.5	MOD HD DK GY BK BI HO GN	100%			
46.6	MOD HD LI GY GRAN GN				
47.7	MOD HD DK GY BK BI HO GN				
47.8	MOD HD LI GY GRAN GN				
49.2	MOD HD DK GY BI HO GN				
49.3	MOD HD LI GY GRAN GN				
49.6	MOD HD DK GY BI HO GN				
49.8	MOD HD LI GY GRAN GN		BX	734.5	
50.5	HD WHITE QUARTZ PEGMATITE	98%			
53.0	HD LI GY GRAN GN				
54.0	HD WHITE QUARTZ PEGMATITE			729.5	
55.2	HD LI GY GRAN GN				
58.0	MOD HD DK GY BI HO GN				
58.1	HD LI GY GRAN GN				
59.5	HD WHITE QUARTZ PEGMATITE	100%		724.5	
60.7	HD LI GY GRAN GN				
63.7	SOFT LI-MED GY GRAN GN			719.5	
64.7	HD LI GY QUARTZ PEGMATITE				
65.3	HD LI GY GRAN GN				
66.0	HD WHITE QUARTZ PEGMATITE	100%			
66.7	HD LI GY GRAN GN				
69.3	MOD HD LI-MED GY GRAN GN			713.5	
70.4	MOD HD DK GY GK BI HO GN				
70.9	MOD HD LI-MED GY GRAN GN			713.2	
71.3	CORING TERMINATED			709.5	

Not to scale

Figure 2-80. Core Boring Record, Boring Log NA-8

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE
0 – 22.0	VERY DENSE BROWN GRAY WHITE MICACEOUS SILTY SAND		
22.0 – 25.7	HD LI GY GRAN GN		
25.7 – 27.0	MOD HD MED GY GRAN GN		
27.0 – 29.5	HD LI GY GRAN GN	92%	
29.5 – 30.0	MOD HD DK GY BK BI HO GN		
30.0 – 30.3	MOD HD LI GY GRAN GN		
30.3 – 32.0	MOD HD DK GY BK BI HO GN		NX
32.0 – 32.5	SOFT DK GY BK BI HO GN		
32.5 – 34.7	HD LI GY GRAN GN		
34.7 – 35.4	MOD HD DK GY BK BI HO GN		
35.4 – 37.0	HD LI GY GRAN GN	100%	
37.0 – 38.3	SOFT DK GY BK BI HO GN		
38.3 – 40.0	HD LI GY GRAN GN		

ELEV.	REMARKS
800.9	
795.9	N = 42
790.9	N = 42
785.9	N= 41
780.9	N= 50/3"
775.9	
770.9	
765.9	
760.9	

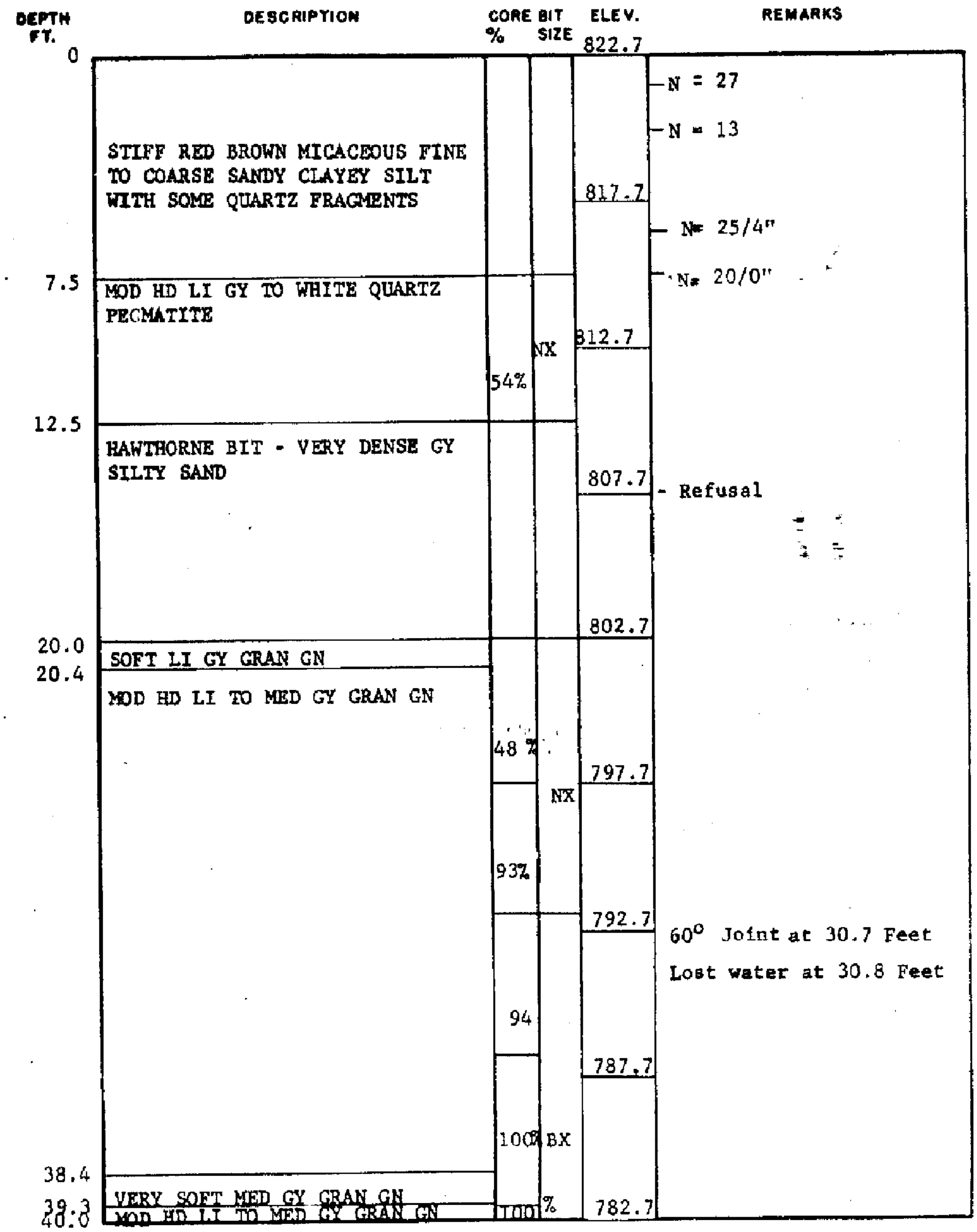
LI - Light
DK - Dark
GY - Gray
BK - Black
MOD - Moderately
MED - Medium
HD - Hard
BI - Biotite
HO - Hornblende
GRAN - Granite
GN - Gneiss

Figure 2-81. Core Boring Record, Boring Log NA-8

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0	HD LI GY GRAN GN	100 %	NX	760.9	42° Joint at 40.8 Feet
40.9	MOD HD DK GY BK BI HO GN				
41.7	MOD HD LI-MED GY GRAN GN			755.9	
46.7		100	%		
46.8	MOD HD DK GY BK BI HO GN				
47.1	MOD HD LI GY GRAN GN				
47.2	MOD HD DK GY BK BI HO GN		BX	750.9	
50.0	HD LI GY GRAN GN				
50.2	HD DK GY BK BI HO GN				
	HD LI GY GRAN GN				
53.4					
54.4	HD DK GY BK BI HO GN			745.9	
	HD LI GY GRAN GN	100	%		
56.0	HD DK GY BK BI HO GN				
57.7	HD LI GY GRAN GN				
58.2	HD DK GY BK BI HO GN			740.9	
58.7	HD LI GY GRAN GN				
61.1	HD DK GY BK BI HO GN				
61.5	HD LI GY GRAN GN				
61.6	HD DK GY BK BI HO GN	100	%		
62.1	HD LI GY GRAN GN			736.4	
64.5	CORING TERMINATED			735.9	

Not to scale

Figure 2-82. Core Boring Record, Boring Log NA-9



31.0 Feet of 2" Plastic Pipe left in hole

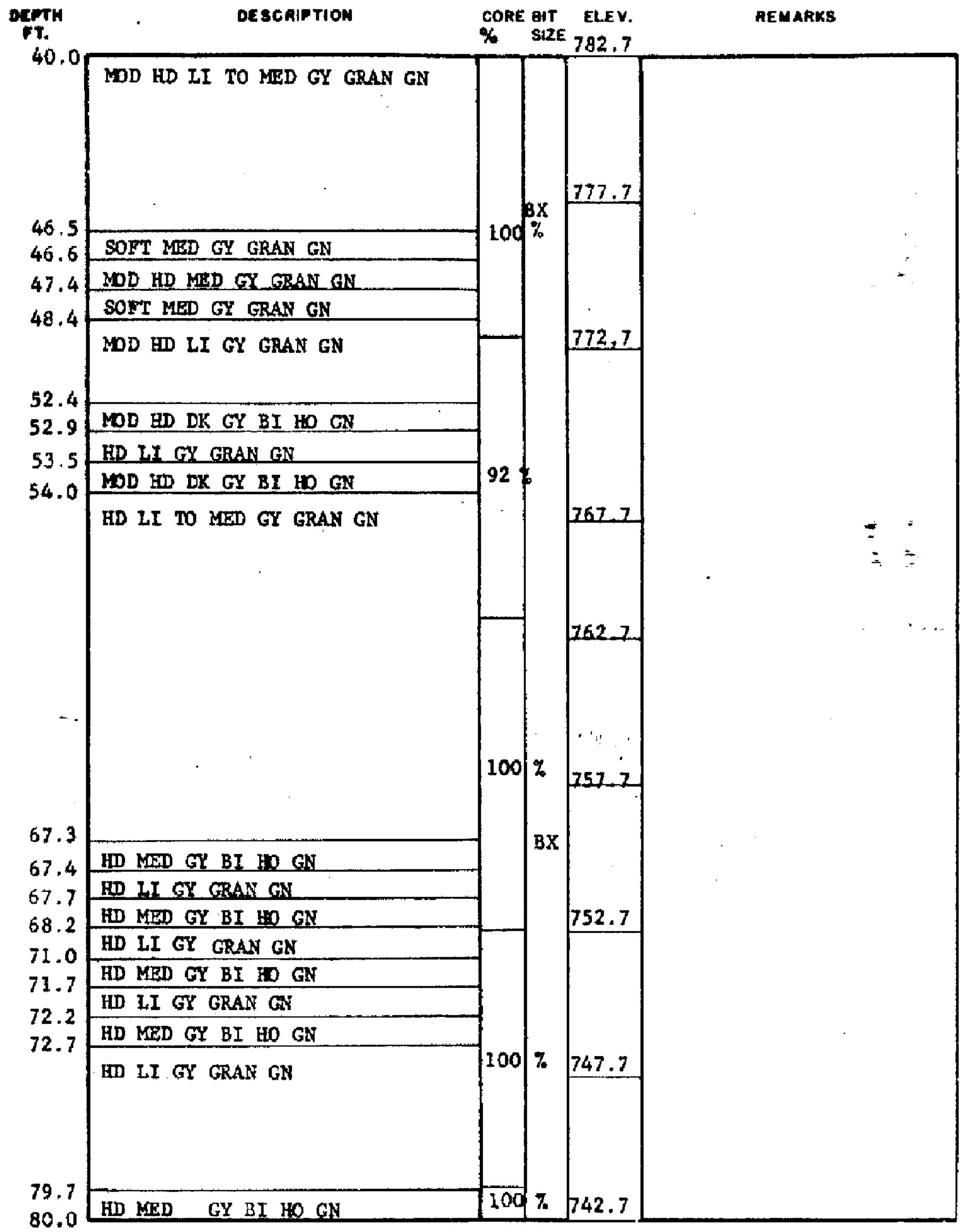
LI - Light
DK - Dark
GY - Gray
BK - Black
MOD - Moderately
MED - Medium

HD - Hard
BI - Biotite
HO - Hornblende
GRAN - Granite
GN - Gneiss

bjs

WATER TABLE

Figure 2-83. Core Boring Record, Boring Log NA-9



Not to scale

bjs

WATER TABLE

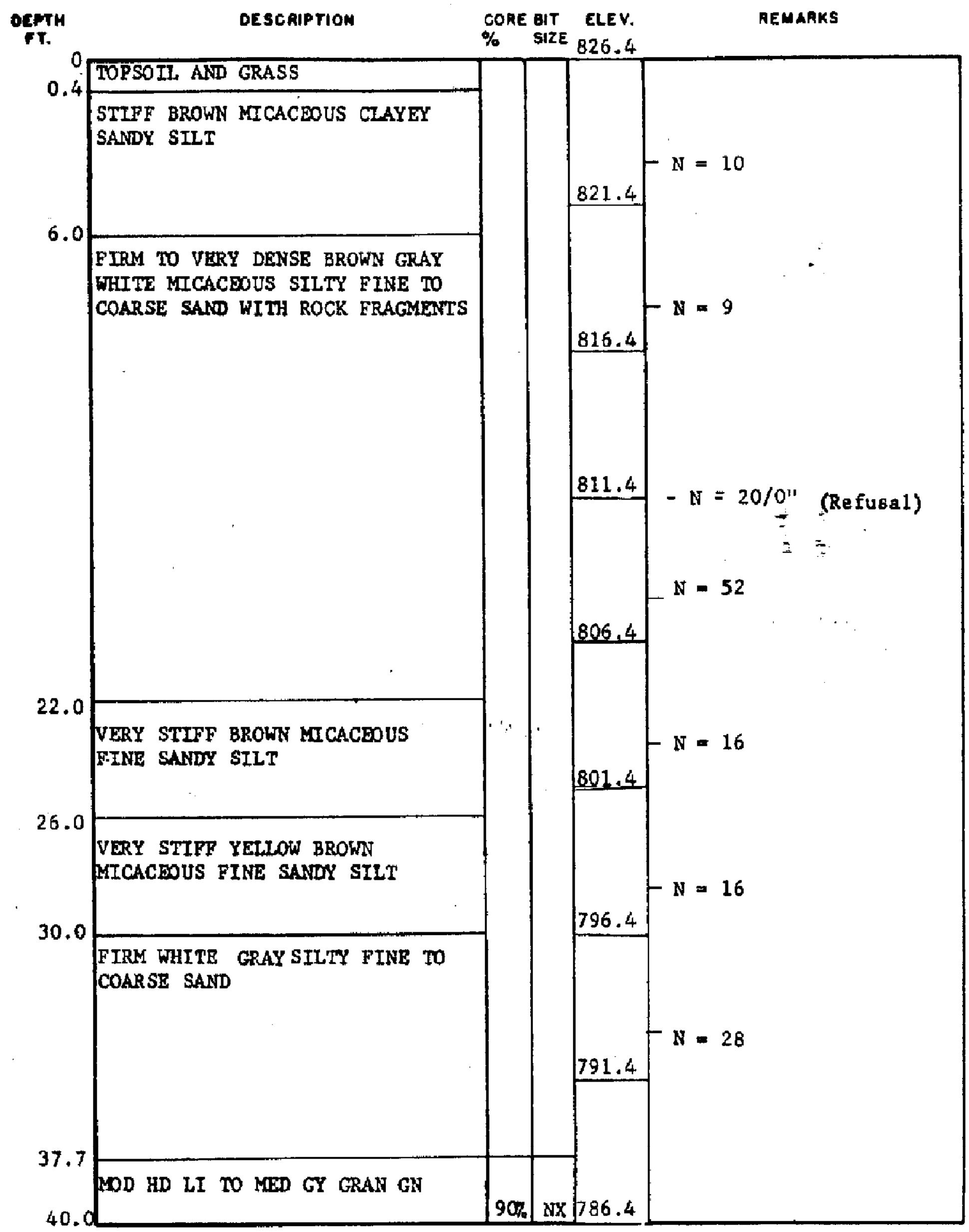
Figure 2-84. Core Boring Record, Boring Log NA-9

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
80.0				742.7	
80.2	HD MED GY BI HO GN				
81.0	HD LI GY GRAN GN				
81.3	MOD HD DK GY BI HO GN				
82.0	HD LI GY GRAN GN				
83.0	HD MED GY BI HO GN				
83.7	HD LI GY GRAN GN				
83.9	HD DK GY BI HO GN	100			
84.3	HD LI GY GRAN GN				
84.7	HD MED TO DK GY BI HO GN				
87.2	HD LI GY GRAN GN		BX	737.7	
87.5	HD MED GY BI HO GN				
88.1	HD WHITE QUARTZ PEGMATITE			732.7	
92.8	HD LI GY GRAN GN				
93.4	HD DK GY BI HO GN				
94.0	HD LI GY GRAN GN				
94.4	HD MED TO DARK GY BI HO GN				
95.7	HD LI GY GRAN GN	98		727.7	
96.5	HD MED GY BI HO GN				
96.8	HD LI GY GRAN GN				
97.3	HD MED GY BI HO GN				
99.2	HD LI GY GRAN GN			723.5	
	CORING TERMINATED				

Not to scale

WATER TABLE

Figure 2-85. Core Boring Record, Boring Log NA-10



LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

WATER TABLE

Figure 2-86. Core Boring Record, Boring Log NA-10

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0	MOD HD LI TO MED GY GRAN GN	90%		786.4	74° Joint at 40.0 Feet
40.1	SOFT MED GY BROWN GRAN GN				
41.6	MOD HD LI TO MED GY GRAN GN				
42.8	HD LI GY GRAN GN	94%	NX	781.4	
46.0	MOD HD LI TO MED GY GRAN GN				
46.8	MOD HD DK GY BK BI HO GN				
48.5	HD LI GY GRAN GN	100%			
48.9	MOD HD DK GY BK BI HO GN			776.4	
49.5	HD LI GY GRAN GN	100%		771.4	
59.4	HD DK GY BK BI HO GN			766.4	
62.5	HD LI GY GRAN GN				
63.2	HD DK GY BI HO GN				
63.8	HD LI GY GRAN GN		BX		
64.7	HD DK GY BI HO GN	100	%		
64.9	HD LI TO DK GY ALTERNATING THIN	*1		761.4	
65.5	HD DK GY BI HO GN				
65.7	HD LI GY GRAN GN				
65.9	HD DK GY BI HO GN				
66.1	HD LI TO DK GY ALTERNATING	*1			
66.7	HD DK GY BI HO GN				
66.9	HD LI GY GRAN GN	100%		756.4 / 751.4	
78.7	HD DK GY BI HO GN				
78.9	HD LI GY GRAN GN				
80.0				746.4	

*1 LAYERS OF BI HO GN AND GRAN GN

WATER TABLE

Figure 2-87. Core Boring Record, Boring Log NA-10

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
80.0	HD LI GY GRAN GN	100 100	BX	746.4	
85.0	HD WHITE QUARTZ PEGMATITE			741.4	
88.0	HD DK GY BI HO GN				
88.6	HD LI GY GRAN GN	96%		736.4	
92.4	HD DK GY BI HO GN				
92.5	HD LI GY GRAN GN				
93.0	HD DK GY BI HO GN				
94.2	HD LI GY GRAN GN			731.4	
96.7	CORING TERMINATED			729.7 726.4	

Not to scale

WATER TABLE

Figure 2-88. Core Boring Record, Boring Log NA-11

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
0				763.85	
	LOOSE RED BROWN SILTY MICACEOUS FINE TO MEDIUM SAND			758.85	N = 9
8.0	STIFF TO VERY STIFF GRAY BROWN MICACEOUS FINE TO MEDIUM SANDY SILT			753.85	N = 12
				748.85	N = 14
				743.85	N = 26
23.0	DENSE BROWN MICACEOUS SILTY FINE SAND			738.85	N = 31
				733.85	N = 30
32.0	WEATHERED ROCK FRAGMENTS				
35.0	VERY SOFT DK BROWN GRAN GN AND BI HO GN	49%	NX	728.85	77° Joint at 35.5 Feet 47° Joint at 36.6 Feet
40.0				723.85	

LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

End of Boring

WATER TABLE

Figure 2-89. Core Boring Record, Boring Log NA-11

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0	VERY SOFT DK BROWN GY GRAN GN AND BI HO GN			723.85	
42.5	SOFT TO MEDIUM GY GRAN GN	49%			46° Joint at 43.0 Feet (Recemented)
43.6	MOD HD LI GY GRAN GN	80%		718.85 713.85	
55.0	MOD HD DK GY BK BI HO GN			708.85	58° Joint at 55.3 Feet 59° Joint at 55.9 Feet
56.4	HD LI GY GRAN GN	99%	NX		64° Joint at 57.Feet
57.6	HD DK GY BK BI HO GN				
58.8	HD LI GY GRAN GN			703.85	
61.4	HD DK GY BI HO GN				
62.1	HD LI GY GRAN GN			698.85	
64.5	HD DK GY BI HO GN				
67.3	HD LI GY QUARTZ PEGMATITE	92%			60° Joint at 67.8 Feet
68.4	HD LI GY GRAN GN			693.85	
73.0	HD LI GY GRAN GN AND BI HO GN			688.85	
75.0	CORING TERMINATED				
80.0					

WATER TABLE

Figure 2-90. Core Boring Record, Boring Log NA-12

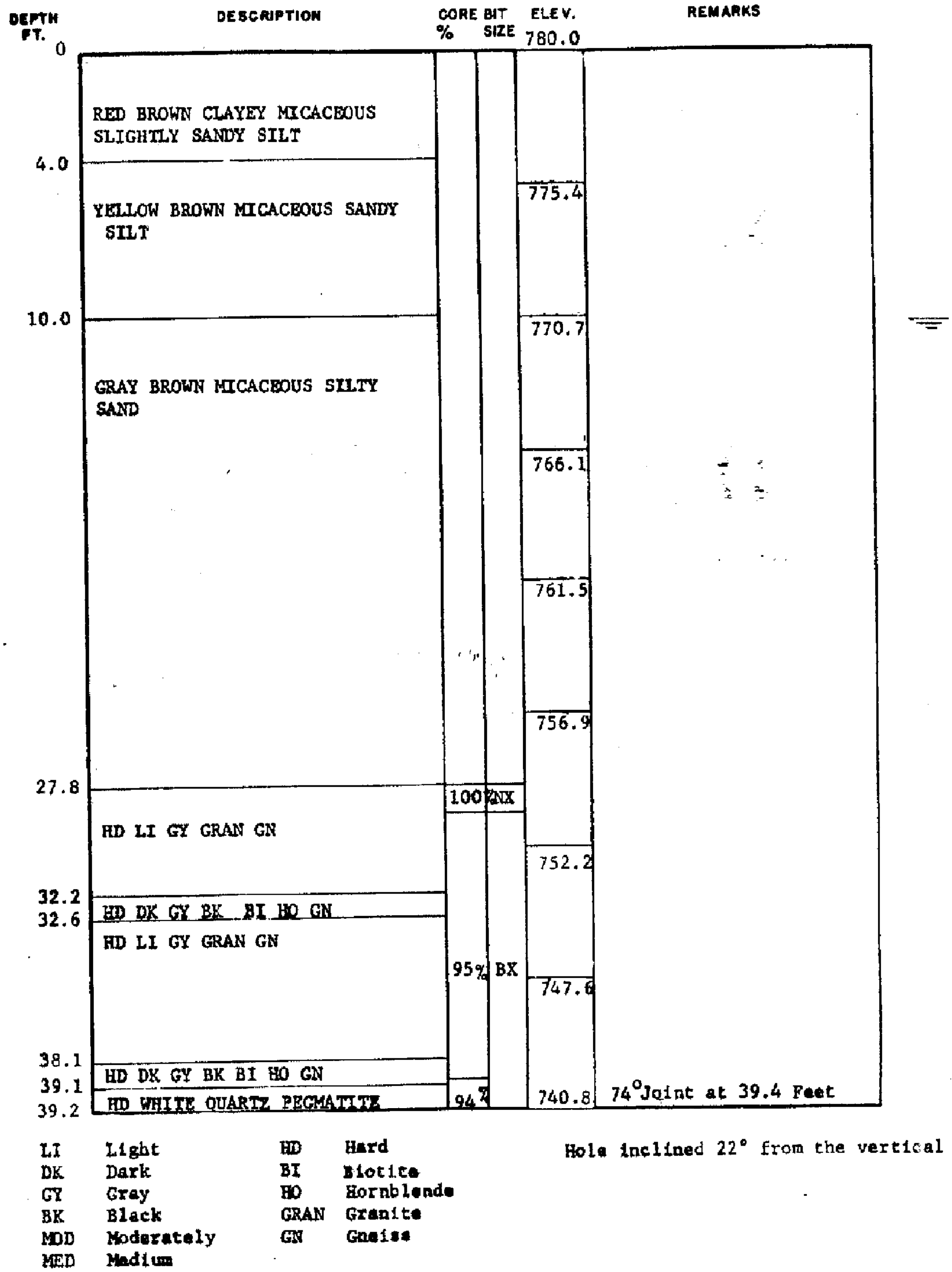


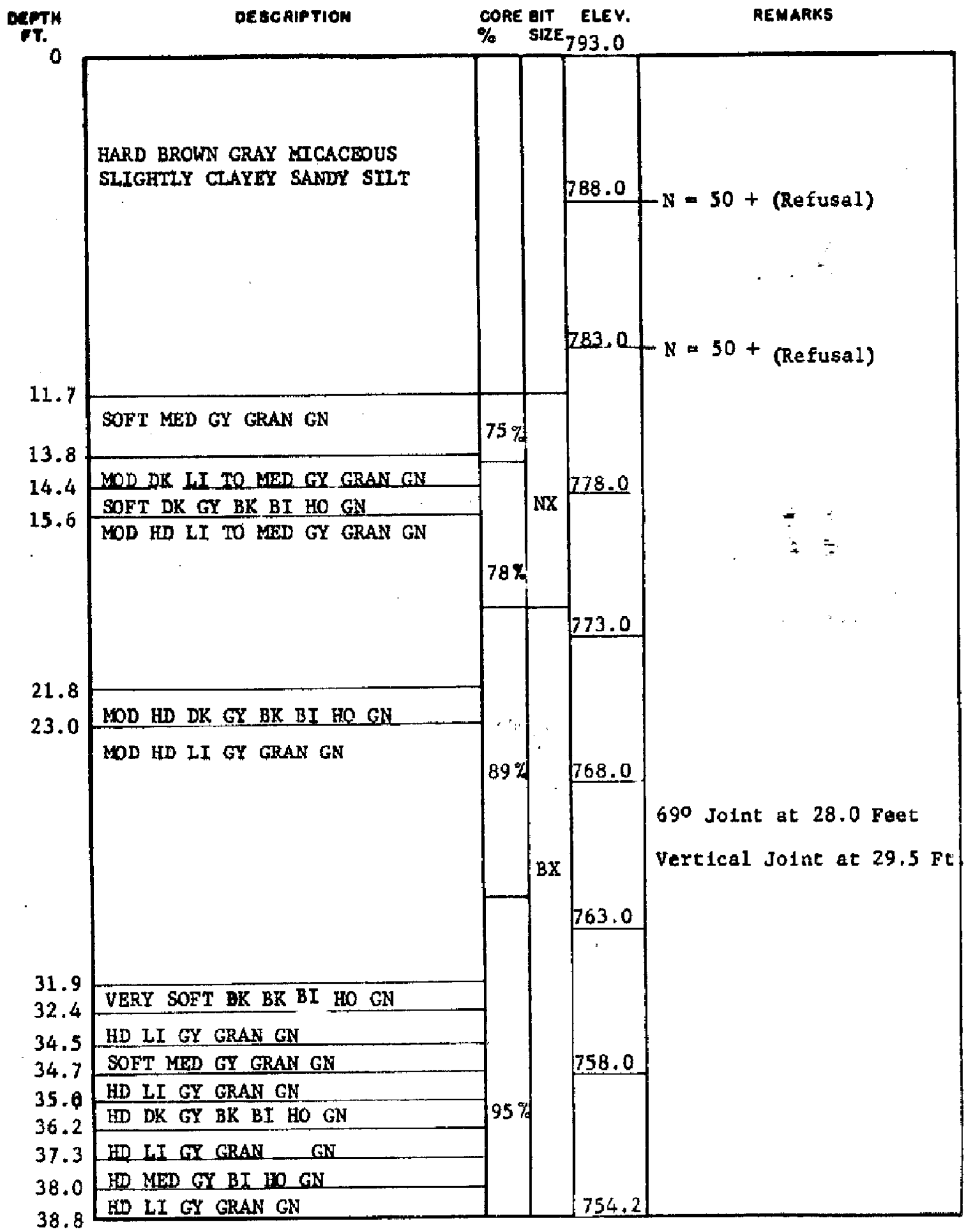
Figure 2-91. Core Boring Record, Boring Log NA-12

DEPTH FT.	DESCRIPTION
39.2	
39.7	HD DK GY BK BI HO GN
39.9	SOFT DK GY BK BI HO GN
40.3	HD DK GY BK BI HO GN
42.5	HD LI GY GRAN GN
43.0	HD DK GY BK BI HO GN
46.0	HD LI GY GRAN GN
46.4	HD DK GY BK BI HO GN
46.5	HD WHITE QUARTZ PEGMATITE
46.8	HD DK GY BK BI HO GN
	HD LI GY GRAN GN
71.9	
72.2	HD DK GY BK BI HO GN
72.8	HD LI GY GRAN GN
73.2	HD DK GY BK BI HO GN
	HD LI GY GRAN GN
77.7	
	CORING TERMINATED

CORE %	BIT SIZE	ELEV.	REMARKS
		740.8	
94%	BX	742.9	
		738.3	
100 %		733.7	
		729.1	
100%		724.4	
		719.8	
98%		715.2	
		710.5	
		702.3	
		705.9	

Not to scale

Figure 2-92. Core Boring Record, Boring Log NA-13



LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

11.0 feet of 2" plastic pipe left in hole

Not to scale

WATER TABLE

Figure 2-93. Core Boring Record, Boring Log NA-13

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
38.8	HD MED TO DK GY BI HO GN	95%		754.2	
39.5	HD LI GY GRAN GN	100	%	753.0	
43.8	MOD HD DK GY BK BI HO GN				
44.0	HD LI GY GRAN GN			748.0	
47.5	HD DK GY BK BI HO GN				
47.7	HD WHITE QUARTZ PEGMATITE		BX		
48.1	HD LI GY GRAN GN	100	%		
48.6	HD DK GY BK BI HO GN				
49.0	HD LI GY GRAN GN				
49.3	HD MOD DK GY BI HO GN			743.0	
49.7	HD LI GY GRAN GN				
52.3	HD WHITE QUARTZ PEGMATITE				
53.5	HD LI DK GY ALTERNATING LAYERS	*1		739.0	
54.0	CORING TERMINATED			738.0	

*1 OF BI HO GN AND GRAN GN

Not to scale

WATER TABLE

Figure 2-94. Core Boring Record, Boring Log NA-14

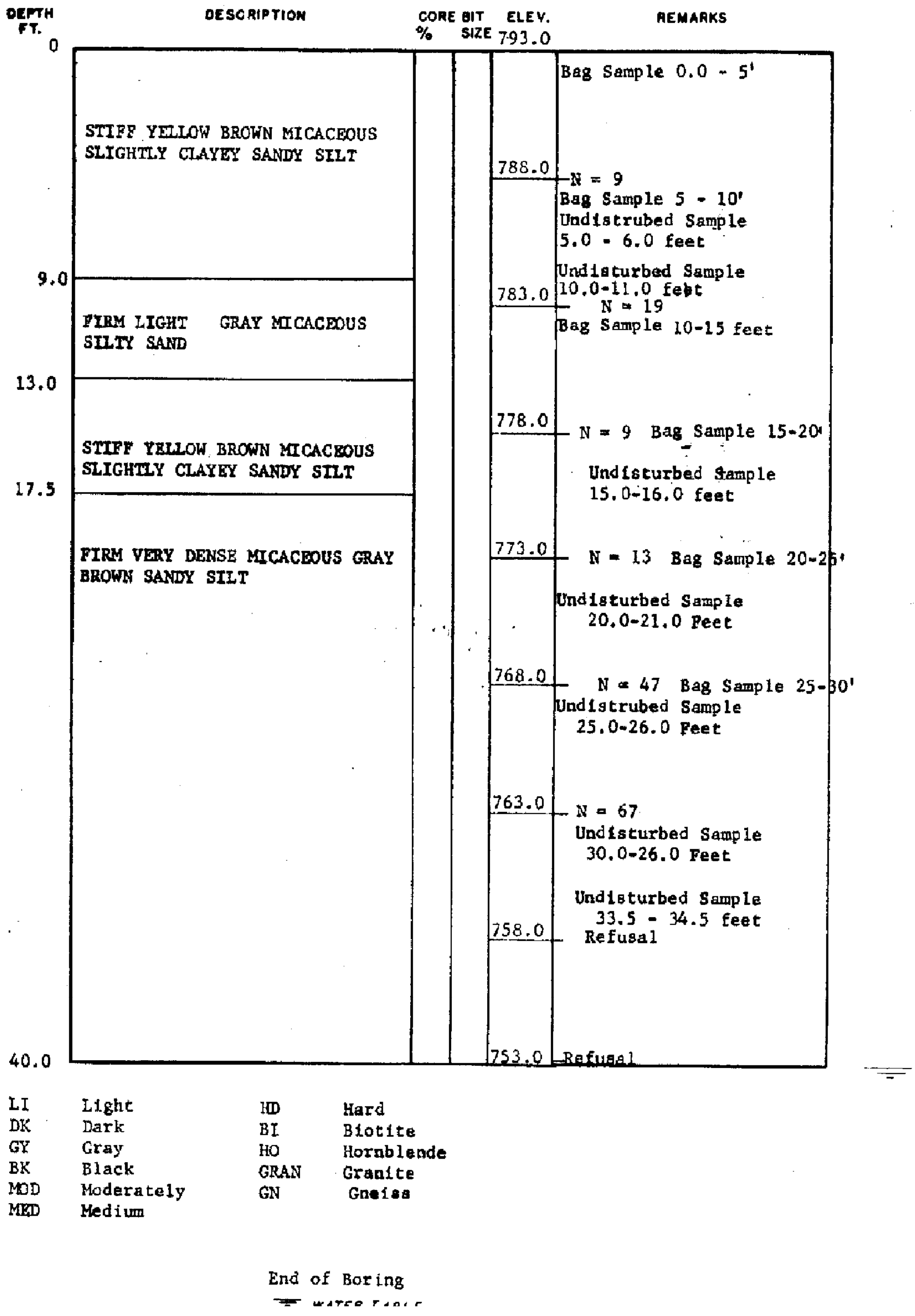


Figure 2-95. Core Boring Record, Boring Log NA-14

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0				753.0	
41.0	FIRM-VERY DENSE GRAY BROWN SANDY	*1			
	MOD HD LI TO MED GY GRAN GN	75	NX		
44.7	MOD HD DK GY BK BI HO GN	87			
44.8	HD LI GY GRAN GN			748.0	
				743.0	
51.5	HD LI GY WHITE QUARTZ PEGMATITE		BX		
54.5	HD LI GY GRAN GN	100		738.0	72° Joint at 53.0 Feet
56.7	HD DK GY BK BI HO GN				
57.8	HD LI GY GRAN GN				
58.1	HD DK GY BK BI HO GN				
58.4	HD LI GY GRAN GN				
59.0	HD DK GY BK BI HO GN	100		733.0	
59.5	HD LI GY GRAN GN				
61.9	HD DK GY BK BI HO GN				
62.1	HD LI GY GRAN GN				
63.4	HD DK GY BK BI HO GN			729.2	
63.8	CORING TERMINATED			728.0	

*1 SILT

Not to scale

End of Boring
WATER TABLE

Figure 2-96. Core Boring Record, Boring Log NA-15

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE
0 – 0.3	TOPSOIL		
0.3 – 7.0	VERY STIFF BROWN CLAYEY MICACEOUS FINE TO MEDIUM SANDY SILT		
7.0 – 12.0	STIFF BROWN FINE TO MEDIUM SANDY MICACEOUS SILT		
12.0 – 27.0	FIRM TO HARD BROWN GRAY MICACEOUS FINE TO MEDIUM SANDY SILT		
27.0 – 32.0	VERY STIFF BROWN GRAY WHITE MICACEOUS FINE TO COARSE SANDY SILT		
32.0 – 40.0	VERY DENSE BROWN GRAY WHITE MICACEOUS SILTY FINE TO COARSE SAND		

ELEV.	REMARKS
766.1	
	N = 22
761.1	
	N = 9"
756.1	
	N = 6"
751.1	
	N = 7"
746.1	
	N = 40/3"
741.1	
	N = 19
736.1	
	N = 20/0"
731.1	
	N = 40/3"
726.1	

36.0 Feet of 2" plastic pipe left in hole

LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

WATER TABLE

Figure 2-97. Core Boring Record, Boring Log NA-15

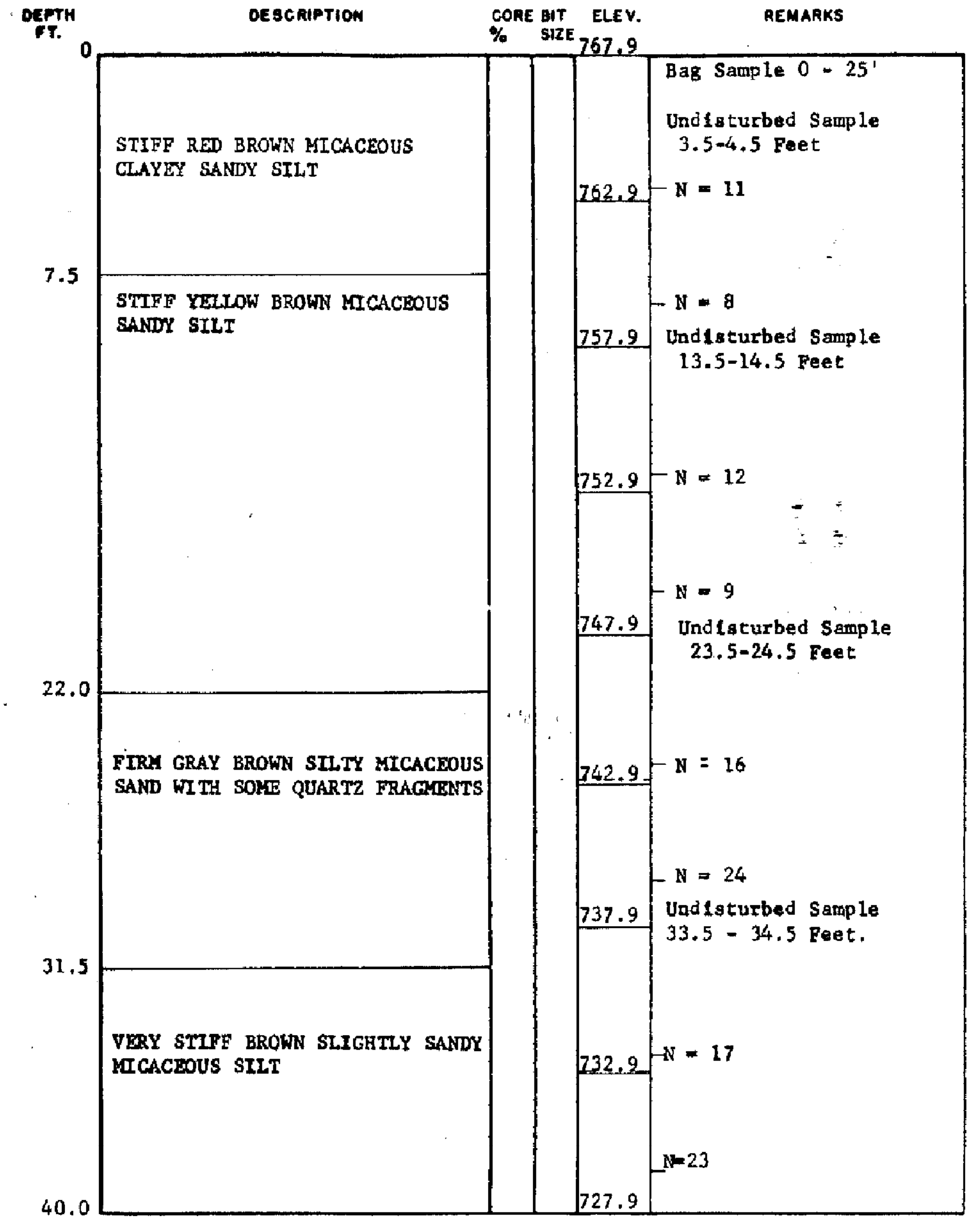
DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0	VERY DENSE BROWN GRAY WHITE MICACEOUS SILTY FINE TO COARSE SAND			726.1	
				721.1	N = Refusal
49.5	MOD HD LI GY GRAN GN			716.1	50° Joint at 50.4 Feet
50.8	MOD HD DK GY BI HO GN				
51.0	MOD HD LI GY GRAN GN				
51.6	MOD HD DK GY BI HO GN	100			
55.6	HD LI GY GRAN GN			711.1	
57.2	MOD HD DK GY BI HO GN	100	NX		
57.6	HD LI GY GRAN GN				
58.9	MOD HD DK GY BI HO GN				
59.2	HD LI GY GRAN GN				
59.6	HD DK GY BI HO GN			706.1	
60.0	HD LI GY GRAN GN				
61.1	MOD HD DK GY BK BI HO GN	100			
61.4	HD LI GY GRAN GN				
62.2	HD DK GY BI HO GN				
62.5	HD LI GY GRAN GN			701.1	
67.3	MOD HD DK GY BI HO GN				
67.5	HD LI GY GRAN GN	100			
67.6	MOD HD DK GY BI HO GN				
67.8	HD LI GY GRAN GN			696.6	
69.5	CORING TERMINATED			696.1	

Not to scale

Page 2 of 2

WATER TABLE

Figure 2-98. Core Boring Record, Boring Log NA-16



85.0 Feet of 2" Plastic pipe left in hole

LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

Figure 2-99. Core Boring Record, Boring Log NA-16

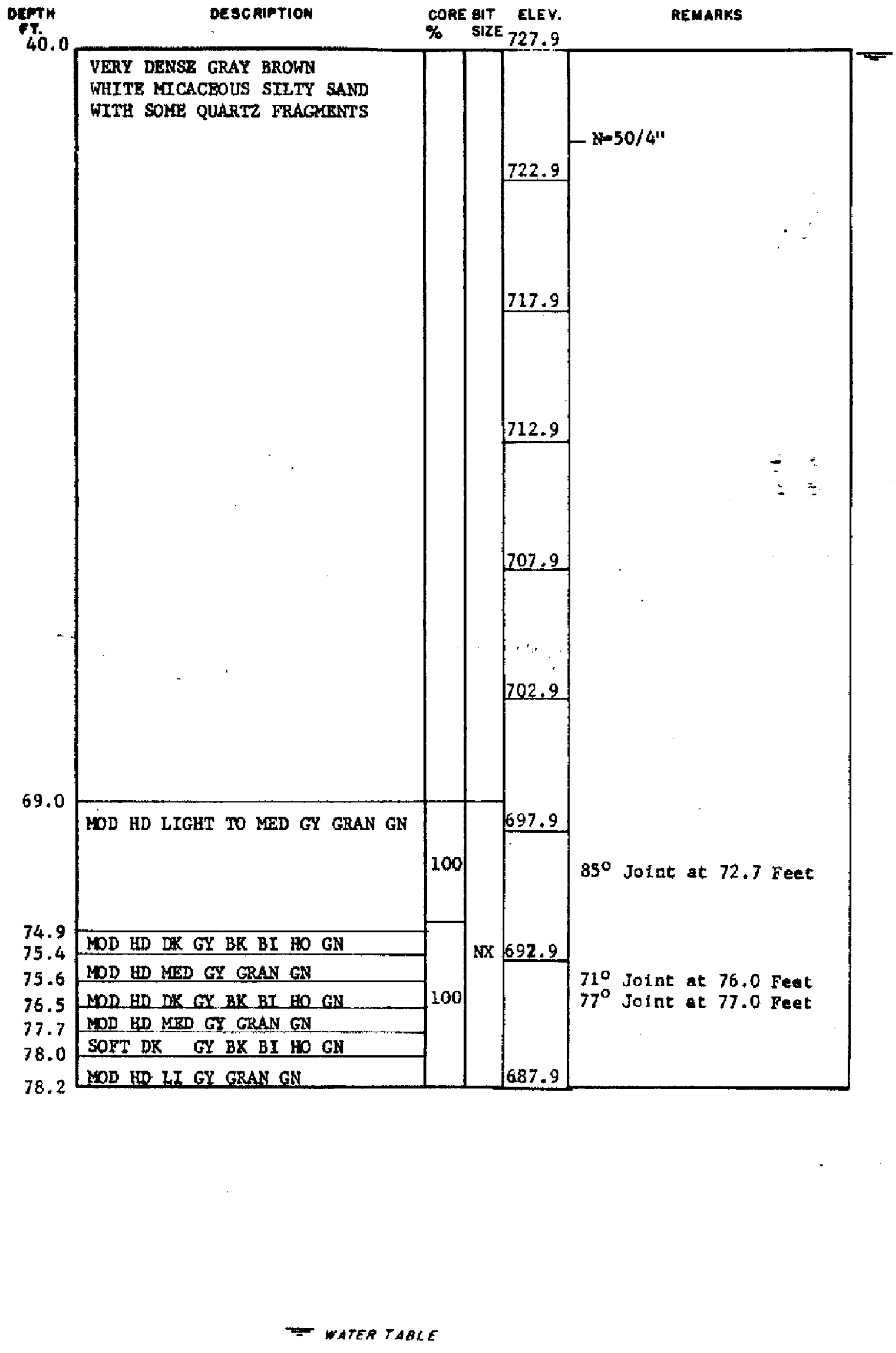


Figure 2-100. Core Boring Record, Boring Log NA-16

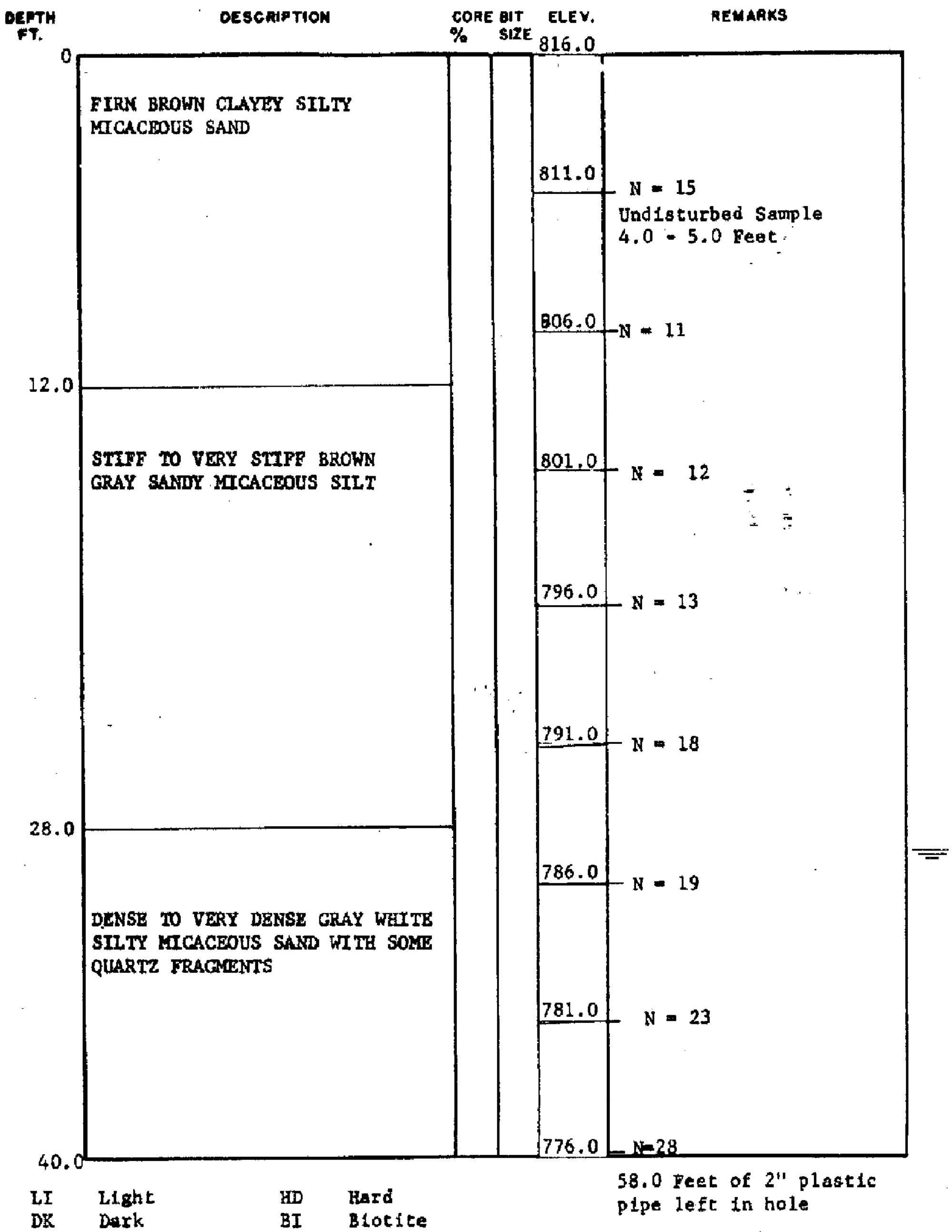
DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
78.2				687.9	
79.1	MOD HD DK GY BK BI HO GN	100			
79.6	MOD HD MED GY GRAN GN				
79.7	SOFT DK GY BK BI HO GN				
80.0	MOD HD LI GY GRAN GN			682.9	
80.2	SOFT DK BY BK BI HO GN				
81.3	MOD HD LI GY GRAN GN	100			
82.1	MOD HD MED TO DK GY BI HO GN		NX		
84.0	MOD HD LI GY GRAN GN				
84.5	HD LI GY GRAN GN				
84.7	MOD HD DK GY BK BI HO GN				
86.0	HD LI GY GRAN GN				
86.3	SOFT DK GY BK BI HO GN	100			
87.3	HD LI GY GRAN GN				
89.0	MOD HD LI TO DK GY ALTERNATE	*1		678.9	
	CORING TERMINATED			672.9	

*1 LAYERS OF BI HO GN AND GRAN GN

Not to scale

WATER TABLE

Figure 2-101. Core Boring Record, Boring Log NA-17



LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

End of Boring

WATER TABLE

Figure 2-102. Core Boring Record, Boring Log NA-17

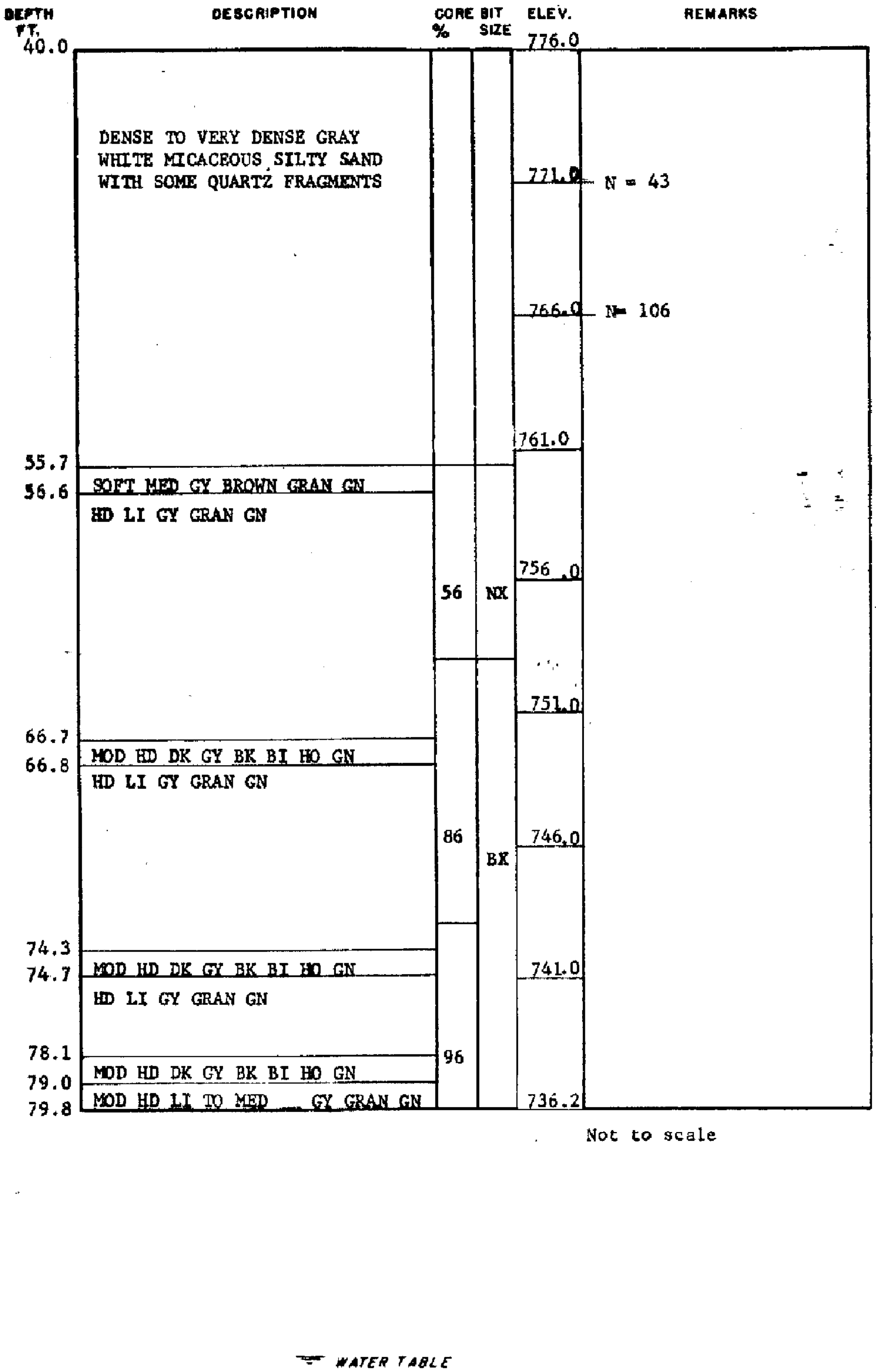
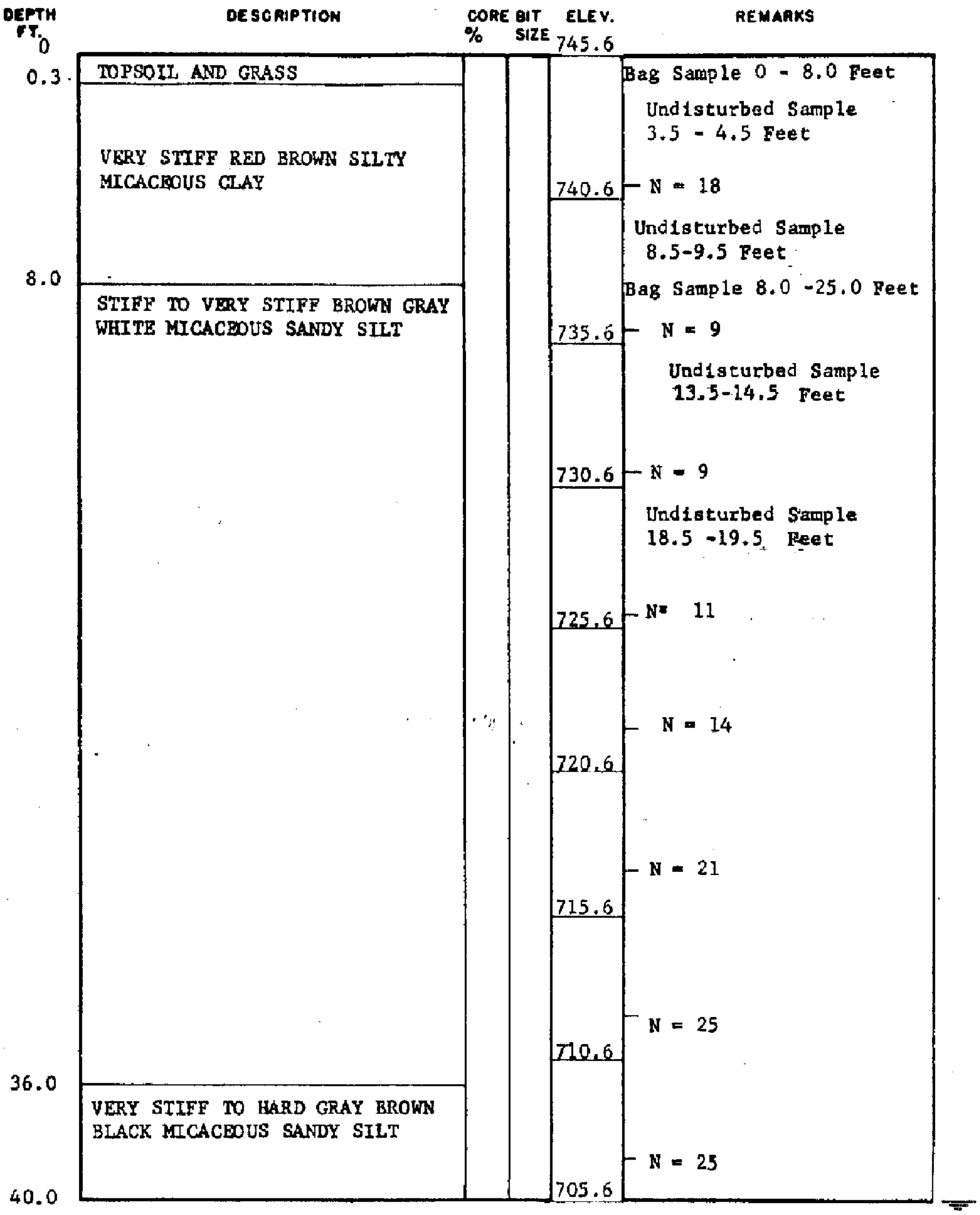


Figure 2-103. Core Boring Record, Boring Log NA-17

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
79.8				736.2	
80.1	MOD HD DK GY BK BI HO GN			736.0	
	HD LI TO MED GY GRAN GN	96	BX	732.8	
83.2	CORING TERMINATED			731.0	

WATER TABLE

Figure 2-104. Core Boring Record, Boring Log NA-18



LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

WATER TABLE

Figure 2-105. Core Boring Record, Boring Log NA-18

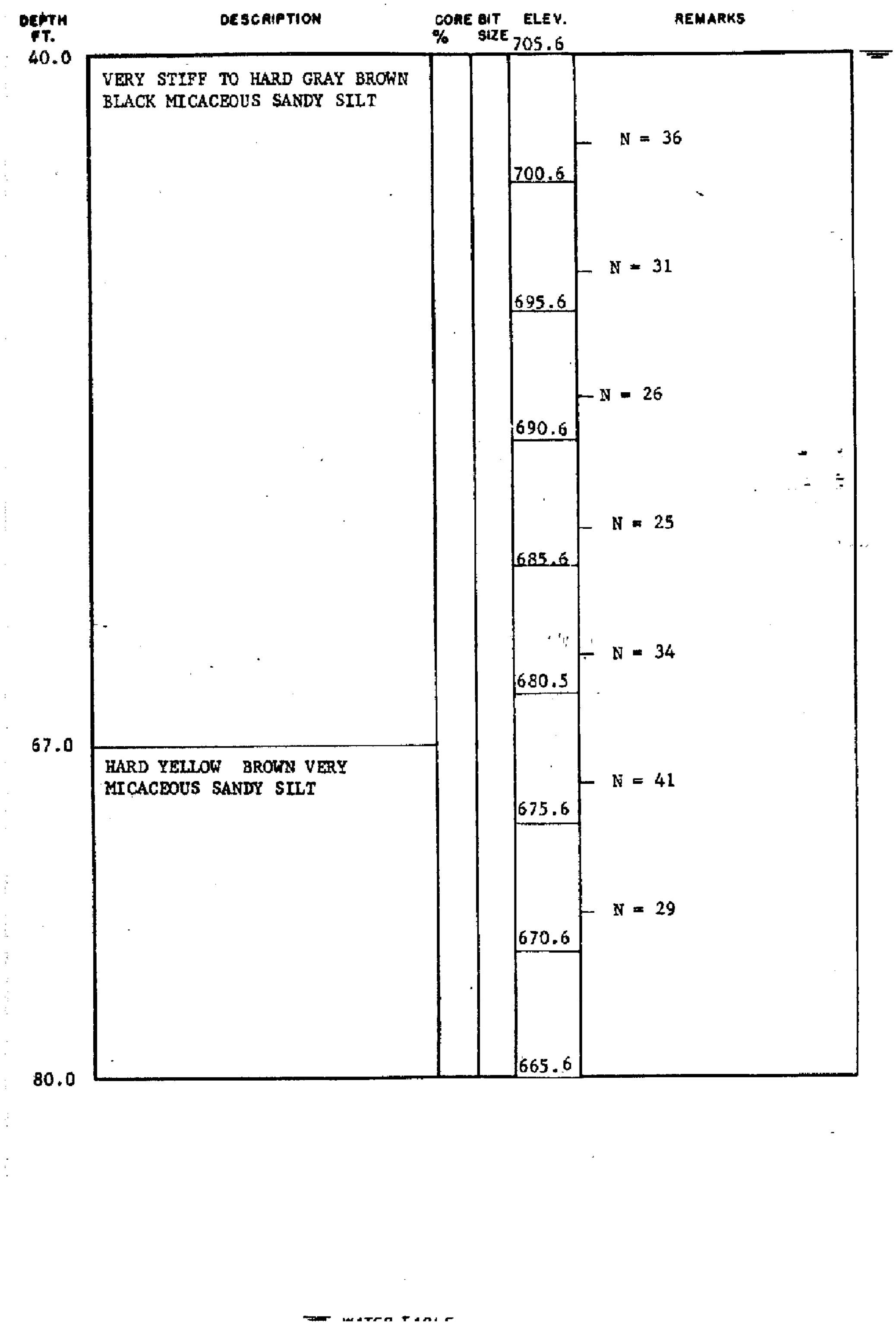


Figure 2-106. Core Boring Record, Boring Log NA-18

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
80.0	VERY SOFT ROCK (NO RECOVERY)	0	BX	665.6	
84.0	SOFT MED GY AND BR GRAN GN	60		660.6, 655.6	74^{o} Joint at 86.0 Feet
90.0	HAWTHORNE BIT - VERY DENSE GY SILTY SAND			650.6, 645.6	
104.0	QUARTZ VEIN	66	BX	640.6	
104.5	VERY SOFT GY GRAN GN				
108.0	MOD HD MED GY AND BR GRAN GN			635.6	
115.7	MOD HD DK GY BK BI HO GN	80		630.6	75^{o} Joint at 115.7 Feet
115.9	MOD HD LI TO MED GY GRAN GN				
116.1	SOFT DK GY BK BI HO GN				
118.0	MOD HD LI TO MED GY GRAN GN				
120.0				625.6	

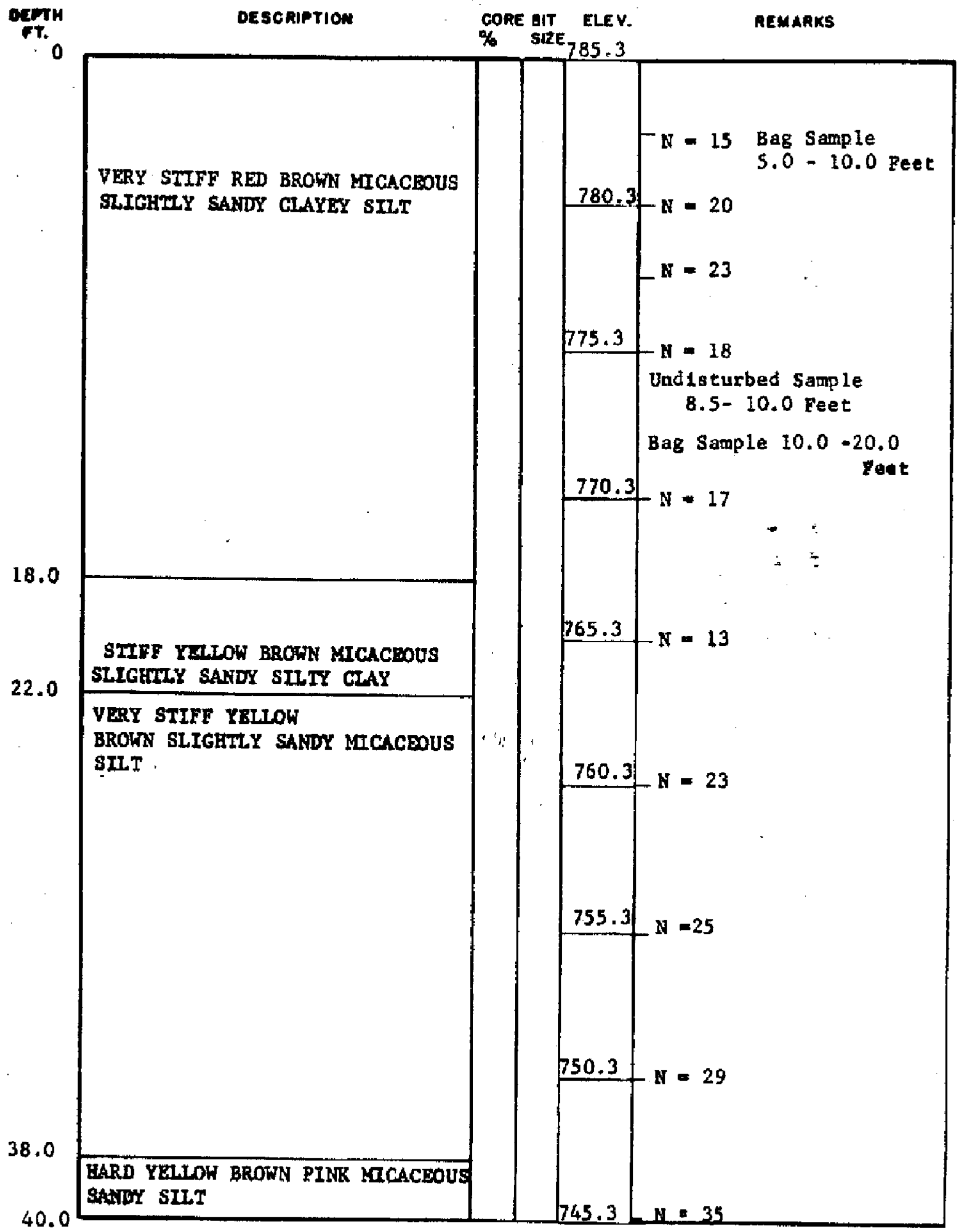
WATER TABLE

Figure 2-107. Core Boring Record, Boring Log NA-18

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
120.0	MOD HD LI TO MED GY GRAN GN			625.6	
122.2	SOFT DK GY BK BI HO GN	80			
123.1	MOD HD LI TO MED GY GRAN GN			620.6	78° Joint at 123.0 Feet
125.3	VERY SOFT MED GY GRAN GN	38	BX		57° Joint at 124.0 Feet
130.0	CORING TERMINATED			615.6	

WATER TABLE

Figure 2-108. Core Boring Record, Boring Log NA-19



LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	BLACK	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

WATER TABLE

Figure 2-109. Core Boring Record, Boring Log NA-19

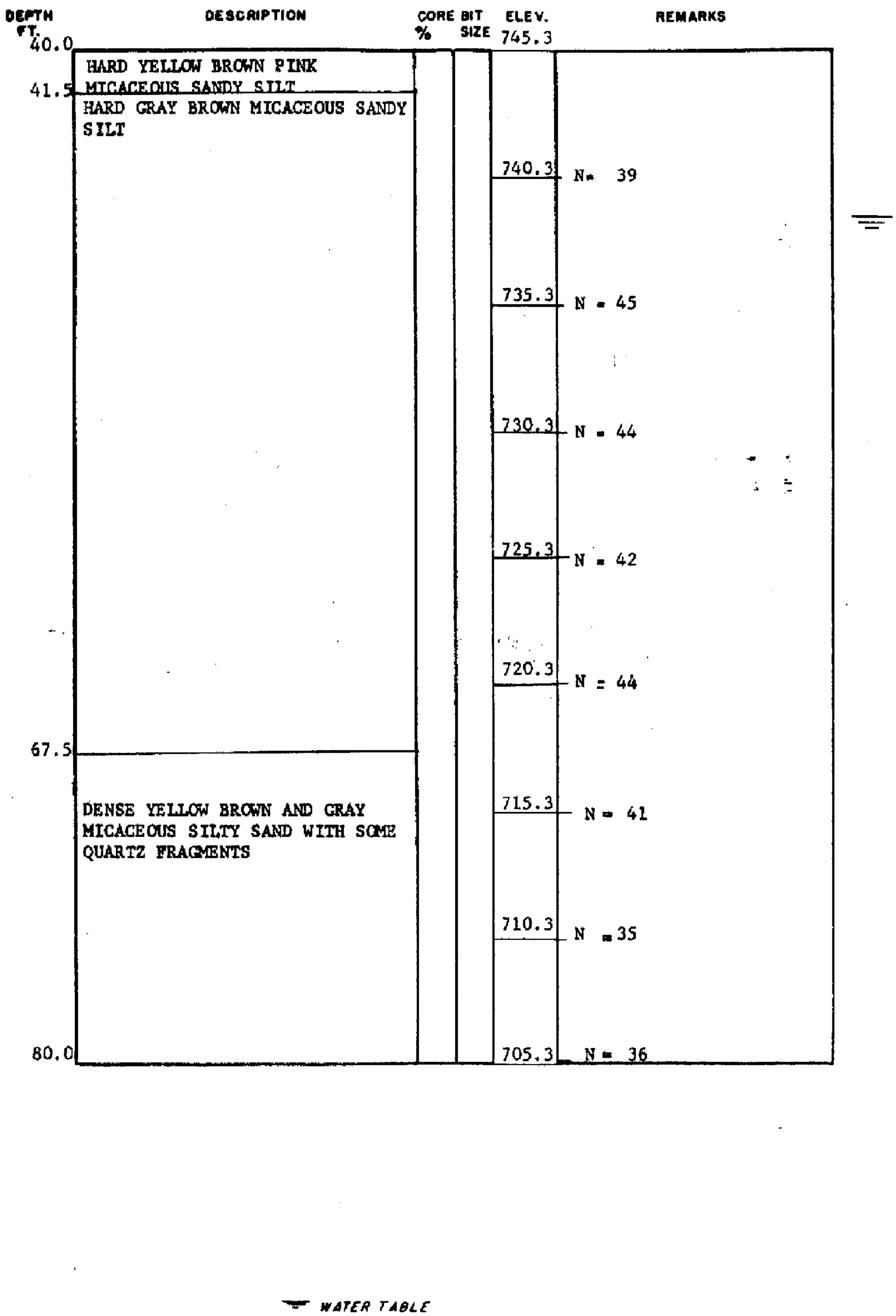


Figure 2-110. Core Boring Record, Boring Log NA-19

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
80.0				705.3	
	DENSE YELLOW BROWN AND GRAY MICACEOUS SILTY SAND WITH SOME QUARTZ FRAGMENTS			700.3	N = 40
				695.3	
				690.3	
				685.3	
101.0	DENSE SILTY SAND WITH THIN LAYERS OF QUARTZ			680.3	
105.3	DENSE YELLOW BROWN AND GRAY SILTY SAND WITH SOME QUARTZ FRAGMENTS			675.3	
110.0	HD LI GY GRAN GN				
112.3	MOD HD MED GY BK BI HO GN				50° Joint at 112.0 Feet
112.8	HD LI GY GRAN GN			670.3	
115.5	MOD HD DK GY BK BI HO GN	100	BX		
118.3	LD LI GY GRAN GN				
120.0				665.3	

WATER TABLE

Figure 2-111. Core Boring Record, Boring Log NA-19

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
120.0	HD LI GY GRAN GN	100	BX	665.3	
125.0	MOD HD LI GY GRAN GN			660.3	
130.0	CORING TERMINATED			655.3	

WATER TABLE

Figure 2-112. Core Boring Record, Boring Log NA-20

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
0				742.6	
0.3	TOPSOIL AND GRASS				Bag Sample 0 - 4.0 Feet
	STIFF BROWN MICACEOUS SANDY SILT				Undisturbed Sample 3.5 -4.5 feet
				737.6	N = 8
					Bag Sample 4.0 -25.0 Feet
7.0	FIRM TO VERY STIFF BROWN GRAY WHITE MICACEOUS SANDY SILT				
				732.6	N = 6 Undisturbed Sample 8.5-9.5 Feet
				727.6	N = 12 Undisturbed Sample 13.5-14.5 Feet
					Undisturbed Sample 18.5-19.5 Feet
				722.6	N = 13
					Undisturbed Sample 23.5-24.5 Feet
				717.6	N = 15
					N = 17
				717.6	
					N = 16
				707.6	
37.0	DENSE BROWN GRAY WHITE MICACEOUS SILTY FINE TO MEDIUM SAND				N = 31
40.0				702.6	

36.0 Feet of 2" Plastic Pipe left in hole

LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

WATER TABLE

Figure 2-113. Core Boring Record, Boring Log NA-20

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0				702.6	
41.0	DENSE BROWN GRAY WHITE	*1			
	HARD BROWN GRAY VERY MICACEOUS SANDY SILT				N = 70
				697.6	
					N = 40/3" (refusal)
				692.6	
					N = Refusal
				687.6	
					N = Refusal
				682.6	
					N = Refusal
				677.6	
					N= Refusal
				672.6	
					N = Refusal
				667.6	
77.0	MOD HD LI TO MED GY GRAN GN	100	NX		½ inch shear displacement
79.6					
80.0	MOD HD DK GY BK BI HO GN			662.6	

*1 MICACEOUS SILTY FINE TO MEDIUM SAND

WATER TABLE

Figure 2-114. Core Boring Record, Boring Log NA-20

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
80.0	MOD HD LI TO MED GY GRAN GN	100		662.6	82° Joint at 80.0 Feet 85° Joint at 82.3 Feet
83.7	MOD HD DK GY BK BI HO GN				
83.9	MOD HD LI GY AND BR GRAN GN	100		657.6	
88.6	MOD HD DK GY BK BI HO GN				
88.8	MOD HD LI TO MED GY &BR GRAN GN	100		652.6	
89.4	MOD HD DK GY BK BI HO GN				
90.1	MOD HD LI TO MED GY GRAN GN				
92.0	SOFT DK GY BR BI HO GN				
92.2	MOD HD LI GY GRAN GN	100		647.6	
97.0	MOD HD DK GY BK BI HO GN				74° Joint at 97.0 Feet
97.5	MOD HD LI GY GRAN GN			642.6	
99.8	MOD HD DK GY BK BI HO GN				
100.3	MOD HD LI GY GRAN GN	100	NX		
104.6	MOD HD LI TO MED GY BI HO GN			637.6	73° Joint at 104.7 feet
105.7	MOD HD LI GY GRAN GN				
106.1	MOD HD DK GY BK BI HO GN	95			
106.9	MOD HD LI TO MED GY GRAN GN	93			
109.6	SOFT DK GY BK BI HO GN			632.6	
110.0	MOD HD LI GY GRAN GN				
110.2	MOD HD DK GY BK BI HO GN				
110.4	MOD HD LI GY GRAN GN			630.6	
112.0	CORING TERMINATED			627.6	

Figure 2-115. Core Boring Record, Boring Log NA-21

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
0				728.9	
0.4	TOPSOIL				
	VERY STIFF RED BROWN MICACEOUS FINE SANDY SILTY CLAY			723.9	N = 21 Undisturbed Sample 3.5-4.5 Feet
8.0	VERY STIFF BROWN MICACEOUS FINE SANDY SILT			718.9	N = 16 Undisturbed Sample 8.5-9.5 Feet
12.0	LOOSE BROWN GRAY MICACEOUS SILT FINE SAND			713.9	Undisturbed Sample 13.5-14.5 Feet N = 4
17.5	STIFF BROWN GRAY WHITE MICACEOUS FINE TO MEDIUM SANDY SILT			708.9	Undisturbed Sample 18.5-19.5 Feet N = 10 Undisturbed Sample 23.5-24.5 Feet
21.0	VERY STIFF TO HARD MICACEOUS BROWN GRAY WHITE SILTY FINE TO COARSE SAND			703.9	N = 17
				698.9	N = 45
				693.9	N = 60
36.0	HARD DARK GRAY BLACK AND WHITE FINE SANDY SILT			688.9	N = 30/1" (Refusal)
40.0					

LI	Light	HD	Hard
DK	Dark	BI	Biotite
GY	Gray	HO	Hornblende
BK	Black	GRAN	Granite
MOD	Moderately	GN	Gneiss
MED	Medium		

WATER TABLE

Figure 2-116. Core Boring Record, Boring Log NA-21

DEPTH FT.	DESCRIPTION	CORE %	BIT SIZE	ELEV.	REMARKS
40.0	HARD DARK GRAY BLACK AND WHITE FINE SANDY SILT (DECOMPOSED HORNBLENDE GNEISS)			688.9 683.9 678.9	N = 20/0" (Refusal) N = Refusal
53.5	MOD HD LI TO MED GY GRAN GN			673.9	
55.1	SOFT MED GY GRAN GN				
55.5	VERY SOFT DK GY BK BI HO GN				
56.0	MOD HD LI TO MED GY GRAN GN				Vertical Joint at 57.5 Feet
59.9	VERY SOFT DK GY BK BI HO GN			668.9	
60.2	MOD HD LI TO MED GY GRAN GN	100			
61.7	MOD HD DK GY BI HO GN				
62.1	VERY SOFT DK GY BI HO GN				
62.2	SOFT MED GY GRAN GN		NX		
62.4	SOFT DK GY BI HO GN				
62.7	SOFT MED GY GRAN GN				
63.0	MOD HD LI TO MED GY GRAN GN				
63.5	SOFT DK GY BI HO GN				
63.8	SOFT LI TO MED GY GRAN GN				
64.0	MOD HD DR GY BI HO GN			663.9	
64.2	MOD HD LI TO MED GY GRAN GN				61° Joint at 65.0 Feet
68.8	MOD HD DK GY BK BI HO GN				
70.6	MOD HD LI TO MED GY GRAN GN	100			
71.4	VERY SOFT MED GY GRAN GN				
71.5	MOD HD LI TO MED GY GRAN GN			655.4	
73.5	CORING TERMINATED			658.9	

Not to scale

WATER TABLE

Figure 2-117. Seismic Field Work Location Map

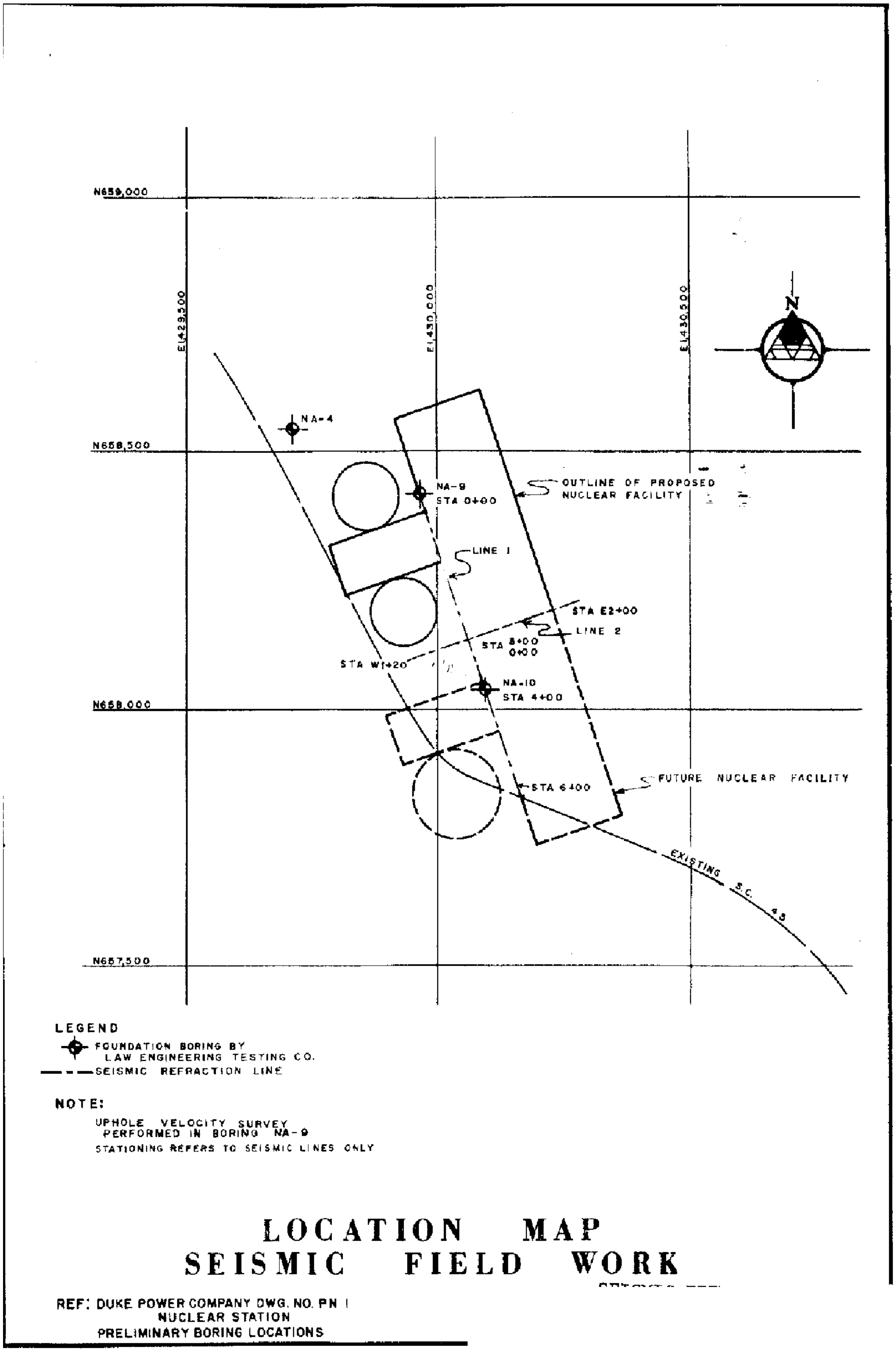


Figure 2-118. Diagrammatic Cross Section through Seismic Lines

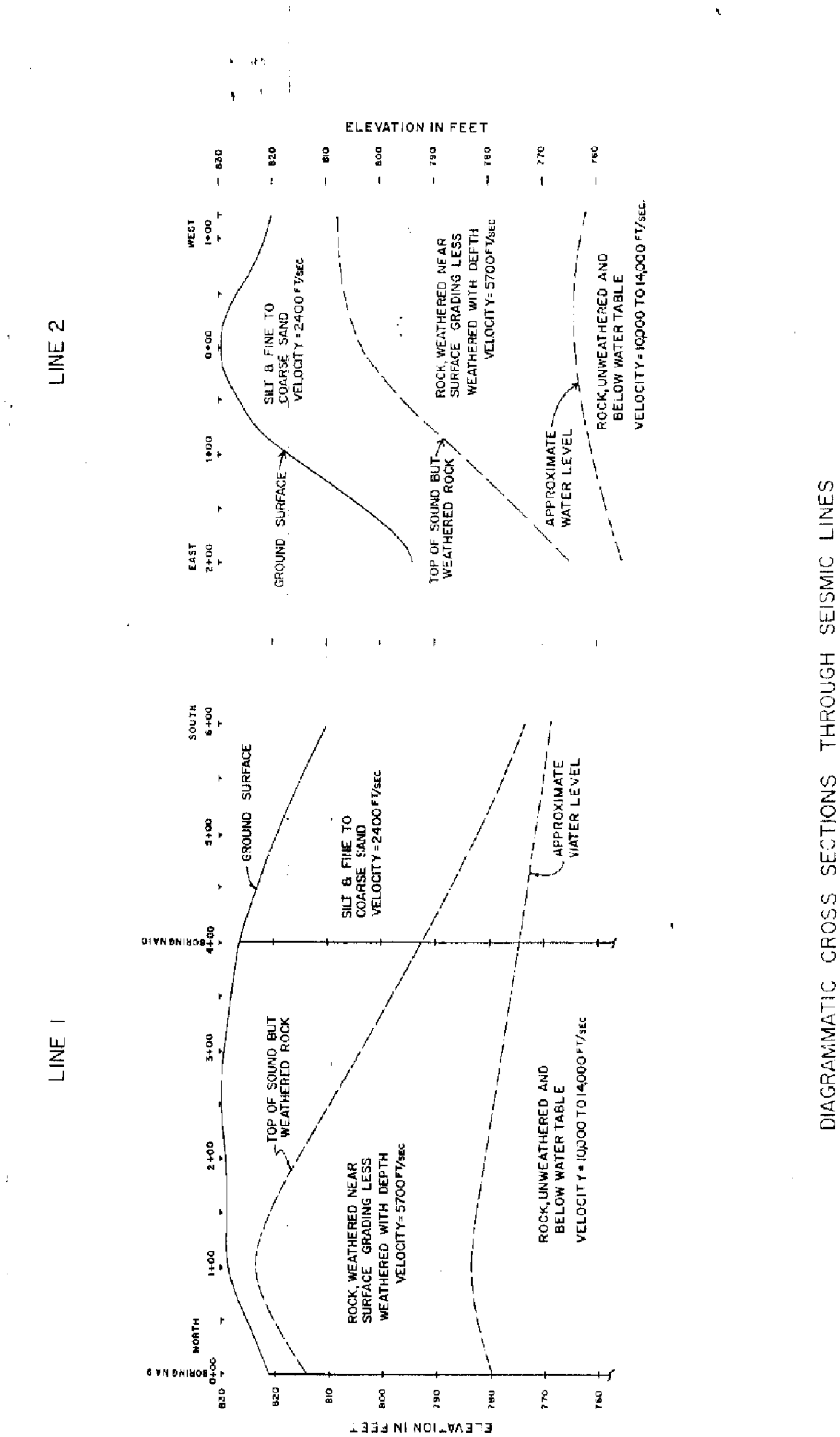


Table of Contents

List of Tables

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List of Figures

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3.0 Design of Structures, Components, Equipment, and Systems

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3.1 Conformance with NRC General Design Criteria

Deleted Paragraph(s) per 2009 Update

The principal design criteria for Oconee 1, 2 and 3 were developed in consideration of the seventy General Design Criteria for Nuclear Power Plant Construction Permits proposed by the AEC in a proposed rule-making published for 10CFR Part 50 in the Federal Register of July 11, 1967. Listed below are the seventy criteria proposed by the AEC, together with the applicant's response indicating the applicant's interpretation of an agreement with the intent of each criterion. The criteria (were) categorized as Category A or Category B. Experience (had) shown that more definitive information (was) needed at the construction permit stage for the items listed in Category A than for those in Category B. In the discussion of each criterion, sections of the report containing more detailed information are referenced.

3.1.1 Criterion 1 - Quality Standards (Category A)

Those systems and components of reactor facilities which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes or standards on design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance levels to be used shall be identified. A showing of sufficiency and applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance levels used is required.

Discussion

1. Essential Systems and Components

   The integrity of systems, structures, and components (SSCs) essential to accident prevention and to mitigation of accident consequences has been included in the reactor design evaluations. These systems, structures, and components are:

   a. Reactor Coolant System

   b. Reactor vessel internals

   c. Reactor Building

   d. Engineered Safeguards System

   e. Electric emergency power sources

2. Codes and Standards

The following table references applicable sections where codes, quality control, and testing are included in the FSAR. The Quality Assurance program is discussed in detail in Chapter 17.

Item	Codes	Quality Control	Testing
Reactor Coolant System	Section 5.2.2	Section 5.2.3.11	Sections 5.2.3.11; 4.4.4
Reactor Vessel Internals	Section 4.5.1	Section 4.5.4	Section 4.5.4
Reactor Building	Sections 3.8.1.2; 3.8.3; 3.8.1.4; 3.8.1.5	Section 3.8.1.6	Section 3.8.1.7
Engineered Safeguards System	Sections 6.2.2.2.2; 6.0; 6.3.2.4	Sections 6.0; 6.6	Sections 6.3.4; 6.4.3; 6.5.1.4; 6.2.2.4; 6.2.4
Electric Emergency Power Sources			Section 8.3.1.1.6

3.1.1.1 Oconee QA-1 Program

To meet the requirements of 10CFR50 Appendix B, Oconee has defined its QA-1 program. The QA-1 program shall be applied to the "essential systems and components" listed above. The scope of these systems and components is provided in greater detail below. The QA-1 program shall also be applied to the Reactor Protective System, and shall be applied to any systems and components committed to the NRC as being classified as QA-1 per any correspondence subsequent to the orginal QA-1 licensing basis.

Therefore, the general criteria used to determine if a SSC is QA-1 is divided into two categories:

First category - provides general QA-1 criteria based on the original licensing basis of ONS, and

Second Category - provides general criteria for SSCs that were added to the QA-1 licensing basis after issuance of the original operating licenses for ONS.

First Category, Original Oconee QA-1 Licensing Basis

This first category includes the integrity of SSCs essential to prevention and mitigation of the Large Break LOCA coincident with loss of offsite power for the following five SSCs: 1) Reactor Coolant System, 2) Reactor Vessel Internals, 3) Reactor Building, 4) Engineered Safeguards System, and 5) Emergency Electric Power Sources. In addition, 6) Reactor Protective System, another system not addressed in FSAR Section 3.1.1, was interpreted to be included in the QA-1 scope, even though not listed.

Clarification regarding the six SSCs identified above is provided below.

1. Reactor Coolant System

   From a quality assurance perspective, the Reactor Coolant System consists of all connecting piping, valve bodies, pump casings, heat exchangers, or vessels out to and including the first isolation valve. The integrity of the pressure boundary of the connecting piping, valve bodies, pump casings, heat exchangers, or vessels is the function which determines applicability of the quality assurance program.

2. Reactor Vessel Internals

The Reactor Vessel Internals consist of the plenum assembly and the core support assembly. The core support assembly consists of the core support shield, vent valves, core barrel, lower grid, flow distributor, incore instrument guide tubes, thermal shield, and surveillance holder tubes. The plenum assembly consists of the upper grid plate, the control rod guide assemblies, and a turnaround baffle for the outlet flow.

Reactor vessel internals do not include fuel assemblies, control rod assemblies, surveillance specimen assemblies, or incore instrumentation.

3. Reactor Building

The Reactor Building consists of the following:

a. The structure which consists of a post-tensioned reinforced concrete cylinder and dome connected to and supported by a massive reinforced concreted foundation slab.

b. The entire interior surface of the structure (a steel plate liner).

c. Welded steel penetrations through which numerous mechanical and electrical systems pass into the Reactor Building.

d. Access openings to the Reactor Building.

4. Engineered Safeguards System

The Engineered Safeguards System consists of structure, systems, or components necessary to:

a. Provide emergency cooling to assure structural integrity of the core:

High Pressure Injection System

Low Pressure Injection System

Core Flooding System

b. Maintain the integrity of the Reactor Building

Reactor Building Spray System

Reactor Building Cooling System

Reactor Building Isolation System (this includes all piping penetration isolation paths)

c. Provide for the collection and control of Reactor Building penetration leakage:

Penetration Room Ventilation System

d. In addition, support systems necessary to ensure that the above systems can perform their intended safety functions are considered QA-1. These systems are:

Low Pressure Service Water portions necessary to supply cooling water to:

1) Reactor Building Cooling Units

2) Decay Heat Removal Coolers

3) High Pressure Injection Pump Motors

Keowee emergency start, load shed, and emergency power switching logic

Analog and Digital ES Channels and DC Power to support operability of these channels

5. Emergency Electric Power Sources

The following power sources and distribution systems are QA-1.

a. Keowee Hydroelectric Units 1 and 2, including:

Keowee Hydro-Generator and Emergency Start Circuits,

Keowee 600/208/120 VAC Auxiliary Power System, and

Keowee 125 VDC Power System.

The following mechanical Keowee SSCs:

1) Governor Oil System
2) Governor Air System
3) Guide Bearing Oil System
4) Turbine Sump System
5) Cooling Water System

b. Underground Emergency Power Path, including:

Underground cable,

Transformer CT4, and

Standby Busses.

c. Overhead Emergency Power Path, including:

Keowee Main Step-Up Transformer,

Associated Tranmission and 230KV Switchyard Components (e.g., transmission lines and power circuit breakers),

230 KV Switchyard Yellow Bus,

230 KV Switchyard 125 VDC Power System, and

Unit Start-up Transformers (CT1, CT2, and CT3).

d. Unit Main Feeder Busses

e. 4160 VAC Safety Auxiliary Power System

f. 600/208 VAC Safety Auxiliary Power System

g. 120 VAC Vital I&C Power System

h. 125 VDC Vital I&C Power System

6. Reactor Protective System

The Reactor Protective System (RPS) is not covered by the equipment categories identified in FSAR Section 3.1.1. However, the RPS was listed in Section 1.41 of the PSAR and subsequently in FSAR Appendix 1B. The RPS is required for LBLOCA/LOOP mitigation and has always been QA-1. Therefore DPC believes that it warrants inclusion into the category of "original QA-1 licensing basis."

Second Category, Oconee QA-1 SSCs Added To The Original Licensing Basis.

In this category DPC includes any commitments to the NRC to treat other SSCs as QA-1 per correspondence subsequent to the original Oconee QA-1 licensing basis.

These commitments are as follows:

1. The following portions of the emergency feedwater (EFW) systems are QA-1.
    a. the motor-driven (MD) EFW pumps
    b. the piping from the MD EFW pumps to the steam generators
    c. the EFW flow control valves (excluding the operators)
    d. the power supply to the MD EFW pumps and controls
    e. piping from the upper surge tanks (USTs) to the MD EFW pumps
    f. UST level monitoring circuitry and associated solenoid valves
    g. EFW flow transmitters upstream of the flow control valves
    h. MD and turbine-driven EFW low steam generator water level and Main Feedwater pump low hydraulic oil pressure pump initiation signals
2. The anticipatory reactor trips on (1) loss of main feedwater and (2) turbine trip are QA-1.
3. The following instruments are QA-1 per the Duke response to Regulatory Guide 1.97:
    a. Two channels of wide range Reactor Coolant System (RCS) pressure
    b. 24 core exit thermocouples (12 per train)
    c. Two channels of pressurizer level (one per train)
    d. Two channels of saturation margin (one monitoring loop A and the core, the other monitoring loop B and the core)
    e. Two channels of steam generator (SG) level per SG (O-388" range)
    f. Two channels of SG pressure per SG
    g. Three channels of borated water storage tank level
    h. Two channels of high pressure injection (HPI) flow
    i. Two channels of low pressure injection (LPI) flow
    j. Two channels of Reactor Building spray flow
    k. Two channels of Reactor Building hydrogen concentration
    l. Two channels of upper surge tank level (one per tank)
    m. Two channels of full range neutron flux
    n. Two channels of wide range RCS hot leg temperature (one per loop)
    o. Two channels of reactor vessel head level
    p. Two channels of hot leg level (one per loop)
    q. Two channels of wide range Reactor Building sump level
    r. Two channels of Reactor Building pressure
    s. One channel of valve position for each electrically-controlled Reactor Building isolation valve
    t. Two channels of high range Reactor Building radiation level
    u. Two channels of EFW flow per SG

   v. One channel of low pressure service water (LPSW) flow to the LPI coolers (per cooler)

4. The RCS hot leg and reactor vessel high point vents (piping, valves, and power supplies) are QA-1.

5. Duke has made explicit QA-1 commitments for the following portions of the Standby Shutdown Facility:

   a. SSF reactor coolant emergency makeup piping and components

   b. SSF auxiliary service water piping and components

   c. SSF cooling water piping for the diesel generator and HVAC

   The SSF equipment required for mitigation of a Turbine Building flood shall be QA-1, with the exception of plant equipment used for the SSF function that was not QA-1 prior to the construction of the SSF (e.g., pressurizer heaters) and the SSF Portable Pumping System.

6. The Control Rod Drive System AC breakers and associated undervoltage devices are QA-1.

7. The power supplies and position indications for valves 2LP-3 and 3LP-3 are QA-1.

8. The equipment installed for the automatic Keowee auxiliary load center transfer modification is QA-1.

9. The 230 kV Degraded Grid Protection System (DGPS) and the CT-5 DGPS are QA-1.

10. The suction source for the Low Pressure Service Water (LPSW) System is QA-1. This includes:

    a. Emergency Condenser Circulating Water System first siphon which provides suction to the Low Pressure Service Water System following a LOOP event. This includes the pressure boundary of the Condenser Circulating Water pumps, pump discharge valves and piping from the intake up to and including the 42 inch crossover header

    b. Essential Siphon Vacuum System

11. The instrument tubing on the systems that comprise the ECCS are to be reclassified as QA-1.

12. The pressure transmitters, logic circuitry, and power sources for the Automatic Feedwater Isolation System (AFIS) and components used to terminate EFW flow to a faulted steam generator are QA-1.

13. The maintenance and test procedures for certain 6.9 kV and 4 kV switchgear breakers are QA-1. Components that are used in future maintenance on these breakers that may impact the ability to shed non-safety loads are also QA-1.

14. The hydrogen recombiner interfacing piping systems shall be QA-1

15. No regulatory commitment exists for Duke to treat Oconee Class F piping as QA-1 solely on the basis of its Class F designation. However, Duke has always and expects to continue to treat Oconee Class F piping as QA-1 in the future. This explicit clarification is noted here, for it has been the cause of some confusion both within Duke and for the NRC.

16. The LPSW RB Waterhammer Prevention System

17. The Protected Service Water (PSW) System is QA-1 with limited exceptions, e.g., fire detection components, some HVAC equipment, building lighting, etc. (Note: Components that receive backup power from PSW or systems that connect to PSW retain their existing seismic and quality classifications).

3.1.1.2 Oconee QA-5 Program

The Oconee QA Condition 5 program is a voluntary program. Program elements have not been specified to the NRC and are not subjected to a formal NRC review and approval process. The QA-5 program itself is not a commitment to the NRC, but Duke has committed to the NRC to include certain equipment within the scope of this voluntary QA-5 program.

The QA-5 program was conceived in response to the recognition that there are some SSCs that were not covered in the original Oconee QA-1 Licensing Basis or deemed appropriate for the expanded QA-1 Licensing Basis that are however credited for prevention and mitigation of design basis and other selected events. The significance of these components warranted an augmented quality assurance program. To that end, Duke created the voluntary QA-5 Program, described in Attachments 4, 4a and 4b of Reference 1 in Section 3.1.1.3 and accepted by the NRC in Reference 2, to apply selected 10CFR 50 Appendix B criteria to such SSCs. The QA-5 classification designates those SSCs for testing and maintenance under selected Appendix B criteria while not requiring that they be procured per Appendix B criteria. Replacement parts for these SSCs will be procured “equal or better in quality” based on engineering judgment.

To determine the population of SSCs to which this classification would apply, a list of accidents and events in the Oconee licensing basis was made, excluding those accidents or events that did not require a safety-related function or were design criteria only. For each remaining accident or event, the primary critical safety functions and primary supporting functions were identified. The SSCs that performed those functions were then evaluated.

The QA-5 classification applies to that equipment which meets the criteria described in References 1 and 2 in Section 3.1.1.3.

The QA-5 program is not a design program or design criteria. Its inclusion here is to clarify the reasoning for excluding certain equipment from the QA-1 program. The QA-5 program clarifies the delineation between safety-related (QA-1) and non-safety-related equipment. Furthermore, the augmented maintenance and testing of the QA-5 Program improves equipment reliability for non-safety-related equipment.

The QA-5 Program was created by the Oconee Safety Related Designation Clarification (OSDRC) program. It addresses NRC concerns regarding a lack of quality assurance for non-safety components that were relied upon to mitigate design basis events. One such concern and how the QA-5 program addressed it are detailed in the (CLOSED) URI 50-269, 270, 287/98-03-09 in Reference 3 in Section 3.1.1.3.

3.1.1.3 Reference

1. Oconee QA-1 Licensing Basis and Generic Letter 83-28, Section 2.2.1, Subpart 1 Supplemental Response, submitted by J.W. Hampton (Duke) letter dated April 12, 1995 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.
2. GENERIC LETTER 83-28 SUPPLEMENTAL RESPONSE – OCONEE UNITS 1, 2, AND 3 (TAC NOS. M92023, M92024, AND M92025), submitted by Leonard A. Wiens (NRC, Office of Nuclear Reactor Regulation) dated August 3, 1995 to Mr. J.W. Hampton, Vice President, Oconee Site, Docket Nos. 50-269, 50-270 and 50-287.
3. OCONEE NUCLEAR STATION – NRC INSPECTION REPORT NOS. 50-269/00-12, 50-270/00-12, AND 50-287/00-12, submitted by Charles R. Ogle, Chief (NRC, Engineering Branch, Division of Reactor Safety) dated December 12, 2000 to Mr. W.R. McCollum, Vice President, Oconee Site, Docket Nos. 50-269, 50-270 and 50-287, License No: DPR-38 DPR-47, DPR-55.

3.1.2 Criterion 2 - Performance Standards (Category A)

Those systems and components of reactor facilities which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences shall be designed, fabricated and erected to performance standards that will enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes, tornadoes, flooding conditions, winds, ice, and other local site effects. The design bases so established shall reflect: a) appropriate consideration of the most severe of these natural phenomena that have been recorded for the site and the surrounding area and, b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.

Discussion

1. Essential Systems and Components

   The integrity of systems, structures, and components essential to accident prevention and to mitigation of accident consequences has been included in the reactor design evaluations. These systems, structures, and components are:

   a. Reactor Coolant System

   b. Reactor vessel internals

   c. Reactor Building

   d. Engineered Safeguards Systems

   e. Electric emergency power sources.

2. Natural Phenomena

   These essential systems and components have been designed, fabricated, and erected to performance standards that will enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena. The designs are based upon the most severe of the natural phenomena recorded for the vicinity of the site, with an appropriate margin to account for uncertainties in the historical data.

   These natural phenomena are listed below. Design bases are presented elsewhere in this report where specific systems, structures, and components are discussed.

   a. Earthquake

   b. Tornado - See details in Section 3.2.2

   c. Ground Water and Flood

   d. Wind and Hurricane

   e. Snow and Ice

   f. Other Local Site Effects

3.1.3 Criterion 3 - Fire Protection (Category A)

The reactor facility shall be designed: 1) to minimize the probability of events such as fires and explosions and, 2) to minimize the potential effects of such events to safety. Noncombustible and fire-resistant materials shall be used whenever practical throughout the facility, particularly in areas containing critical portions of the facility such as containment, control room, and components of engineered safety features.

Discussion

The reactor facility is designed to minimize the probability of fire and explosion. Noncombustibles and fire-resistant materials were used whenever practical throughout the facility.

The control rooms are constructed and furnished with non-flammable equipment. Adequate fire extinguishers are supplied, and combustible materials, such as records, are kept to a minimum as indicated in Section 7.7.5. The control rooms are equipped with emergency breathing apparatus to permit continuous occupancy in the unlikely event of a fire.

Electrical distribution equipment will be physically located to reduce vulnerability of vital circuits to physical damage as a result of accidents. Locations to achieve this result are described in Section 8.3.1.4.

3.1.4 Criterion 4 - Sharing of Systems (Category A)

Reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing.

Discussion

Portions of the following systems are shared as indicated. Where sharing between Oconee 1 and 2 is indicated, a separate system is provided for Oconee 3. Safety is not impaired by the sharing.

System	Shared by Units	Reference
Chemical Addition and Sampling	1, 2	9.3.2
Spent Fuel Cooling	1, 2	9.1.3
Reverse Osmosis System	1, 2	9.1.3
Liquid Waste Disposal	1, 2, 3	11.2.2
Gaseous Waste Disposal	1, 2	11.3.2
Solid Waste Disposal	1, 2, 3	11.4.1.2
Coolant Treatment	1, 2, 3	9.3.5
Recirculated Cooling Water	1, 2, 3	9.2.2.2.4
Low Pressure Service Water	1, 2	9.2.2.2.3
High Pressure Service Water	1, 2, 3	9.2.2.2.2
Control Room Ventilation	1, 2	9.4.1
Auxiliary Building Ventilation	1, 2	9.4.3
Turbine Building Ventilation	1, 2, 3	9.4.4
Area Radiation Monitoring	1, 2	12.3.3
Process Radiation Monitoring	1, 2	11.5
4.16 kV Standby Power Buses	1, 2, 3	8.3.1.1.3

System	Shared by Units	Reference
125/250 Volt DC Power System	1, 2, 3	8.3.2.1.2
120 Volt AC Vital Power System	1, 2, 3	8.3.2.1.4
120 Volt Regulated Power System	1, 2, 3	8.3.2.1.6
Auxiliary Steam System	1, 2, 3	10.3.2
Standby Shutdown Facility	1, 2, 3	9.6.1
Protected Service Water	1, 2, 3	9.7

3.1.5 Criterion 5 - Records Requirements (Category A)

Records of the design, fabrication, and construction of essential components of the plant shall be maintained by the reactor operator or under his control throughout the life of the reactor.

Discussion

Duke Power Company will have under its control or will have access to all records of major essential components for the life of the plant. Records maintained by Duke Power Company will include:

1. A complete set of as-built facility plans and systems diagrams which will include general arrangement plans, system diagrams, major structural plans, and technical manuals of major installed equipment.
2. A set of completed test procedures as associated data for all plant testing outlined in Chapter 14.
3. Quality assurance data generated during fabrication and erection of the essential components of the plant as defined by the quality assurance program within the scope of Section 3.1.1.

3.1.6 Criterion 6 - Reactor Core Design (Category A)

The reactor core shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core design, together with reliable process and decay heat removal systems, shall provide for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and for transient situations which can be anticipated, including the effects of the loss of power to recirculation pumps, tripping out of a turbine generator set, isolation of the reactor from its primary heat sink, and loss of all off-site power.

Discussion

The reactor is designed with the necessary margins to accommodate, without fuel damage, expected transients from steady-state operation including the transients given in the criterion. Fuel clad integrity is ensured under all normal and abnormal modes of anticipated operation by avoiding clad overstressing and overheating. The evaluation of clad stresses includes the effects of internal and external pressures, temperature gradients and changes, clad-fuel interactions, vibrations, and earthquake effects. Clad fatigue due to power and pressure cycling is minimized by pre-pressurizing with helium all fuel rods except those in the low burnup region of Core I, Oconee 1. The free-standing clad design prevents collapse at the end volume region of the fuel rod and provides sufficient radial and end void volume to accommodate clad-fuel interactions and internal gas pressures (Section 4.2.2).

Clad overheating is prevented by satisfying the core thermal and hydraulic criteria shown in (Section 4.4.1).

The design margins allow for deviations of temperature, pressure, flow, reactor power, and reactor-turbine power mismatch. Above 15 percent power, the reactor is operated at a constant average coolant temperature and has a negative power coefficient to damp the effects of power transients. The Reactor Control System will maintain the reactor operating parameters within preset limits, and the Reactor Protective System will shut down the reactor if normal operating limits are exceeded by preset amounts (Section 7.2).

Reactor decay heat will be removed through the steam generators until the reactor coolant system is cooled to 250°F. Steam generated by decay heat will supply the steam-driven main feedwater pump turbine and can also be vented to atmosphere and/or bypassed to the condenser. The steam generators are supplied feedwater from either the main steam-driven feedwater pumps, the motor-driven emergency feedwater pumps, or from a steam-driven emergency feed pump, sized at 7.5 percent of full feedwater flow.

The main feedwater pumps supply the steam generators with water contained in the feedwater train and the condensate storage tank. The emergency feed pumps take suction from the upper surge tank or from the condenser hotwell. These sources provide sufficient coolant to remove decay heat for about one day after reactor shutdown with the primary heat sink (condenser) isolated. The condenser is normally available so that water inventory is not depleted (Chapter 10), even in the event of loss of electrical power.

The reactor coolant pumps are provided with sufficient inertia to maintain adequate flow to prevent fuel damage if power to all pumps is lost. Natural circulation coolant flow will provide adequate core cooling after the pump energy has been dissipated (Section 15.6).

3.1.7 Criterion 7 - Suppression of Power Oscillations (Category B)

The core design, together with reliable controls, shall ensure that power oscillations which could cause damage in excess of acceptable fuel damage limits are not possible or can be readily suppressed.

Discussion

Power oscillations resulting from variations of coolant temperature are minimized by constant average coolant temperature when the reactor is operated above 15 percent power. Power oscillations from spatial xenon effects are minimized by the large negative power coefficient and axial power shaping rod assemblies.

The ability of the reactor control and protective system to control the oscillations resulting from variation of coolant temperature within the control system dead band and from spatial xenon oscillations has been analyzed. Variations in average coolant temperature provide negative feedback and enhance reactor stability during that portion of core life in which the moderator temperature coefficient is negative. When the moderator temperature coefficient is positive, rod motion will compensate for the positive feedback. The maximum rate of power change resulting from temperature oscillations within the control system dead band has been calculated to be less than 1 percent/minute. Since the unit has been designed to follow ramp load changes of 10 percent/minute, this is well within the capability of the control system (Section 7.6.1).

Control flexibility, with respect to xenon transients, is provided by the combination of control rods and nuclear instrumentation. Axial, radial, or azimuthal neutron flux changes will be detected by the nuclear instrumentation. Individual control rods or groups of control rods can be positioned to suppress and/or correct flux changes (Section 4.3.2.2). The analysis of xenon-related power effects is presented in BAW-10010, "Stability Margin for Xenon Oscillation."

3.1.8 Criterion 8 - Overall Power Coefficient (Category B)

The reactor shall be designed so that the overall power coefficient in the power operating range shall not be positive.

Discussion

The overall power coefficient is negative in the power operating range (Section 4.3.1).

3.1.9 Criterion 9 - Reactor Coolant Pressure Boundary (Category A)

The reactor coolant pressure boundary shall be designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage throughout its design lifetime.

Discussion

The Reactor Coolant System pressure boundary meets the criterion through the following:

1. Material selection, design, fabrication, inspection, testing, and certification in accordance with ASME codes for all components excluding piping, which is done in accordance with the USAS B31.1 and B31.7 codes. The piping was redesigned to the 1983 ASME Code during the Steam Generator replacement project.
2. Manufacture and erection in accordance with approved procedures.
3. Inspection in accordance with code requirements plus additional requirements imposed by the manufacturer.
4. System analysis to account for cyclic effects of thermal transients, mechanical shock, seismic loadings, and vibratory loadings.
5. Selection of reactor vessel material properties to give due consideration to neutron flux effects and the resultant increase of the nil ductility transition temperature.

The materials, codes, cyclic loadings, and non-destructive testing are discussed further in Chapter 5.

3.1.10 Criterion 10 - Containment (Category A)

Containment shall be provided. The containment structure shall be designed to sustain the initial effects of gross equipment failures, such as a large coolant boundary break, without loss of required integrity, and, together with other engineering safety features as may be necessary, to retain for as long as the situation requires the functional capability to protect the public.

Discussion

Containment is provided by the Reactor Building. The Reactor Building has the capability to sustain, without loss of integrity, the effects of gross equipment failures, including the transient peak pressure associated with a hypothetical rupture of any pipe in the Reactor Coolant System including the effects of metal-water reactions described in Section 15.14.

The design parameters for the Reactor Building are tabulated in Section 3.8 and Engineered Safety Systems have been evaluated for various combinations of credible energy releases as discussed in Section 15.14. Sufficient redundancy is provided both in equipment and control to ensure the functional availability and capability of systems required to protect the public.

3.1.11 Criterion 11 - Control Room (Category B)

The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit access, even under accident conditions, to equipment in the control room or other areas as necessary to shut down and maintain safe control of the facility without radiation exposures of personnel in excess of 10CFR20 limits. It shall be possible to shut the reactor down and maintain it in a safe condition if access to the control room is lost due to fire or other cause.

Discussion

The reactors and associated equipment are controlled from panels located in the control rooms. The control rooms are designed to permit continuous occupancy following a maximum hypothetical accident (MHA) (Section 7.7.5).

All controls and instrumentation required to monitor and operate the reactors and electric power generating equipment are located within the control rooms. This includes indication of power level; process variables such as temperatures, pressures, and flows; valve positions; and control rod positions.

All Engineered Safety Systems equipment are controlled and monitored from the control rooms. The status of all dynamic equipment (pumps, valves, etc.)--as well as pertinent pressures, temperatures, and flows--is displayed. The Radiation Monitoring System has provisions for alarms and for display of instrumentation readouts in the control room.

The concrete Reactor Buildings and control room walls and roofs are designed to provide adequate protection against direct radiation to control room personnel at all times. Post-accident dose to control room personnel following the MHA is addressed in UFSAR Section 15.15.

The control rooms are provided with independent ventilation and filtration systems to minimize ingress of airborne radioactive contaminants escaping from the Reactor Building. The details of the control room ventilation system and its operation following an accident are described in Section 9.4.1.

The control rooms are constructed and furnished with non-flammable equipment. Adequate fire extinguishers are supplied and combustible materials, such as records, are kept to a minimum as per Section 7.7.5. Emergency breathing apparatus is provided in the control room to permit occupancy in the unlikely event of a fire.

Adequate instrumentation and controls are provided to maintain the reactor in Mode 3 (with T_{ave} ≥ 525°F) from outside the control room if access to the control room is lost or if the room must be evacuated temporarily in the unlikely event of a fire or other causes.

3.1.12 Criterion 12 - Instrumentation and Control Systems (Category B)

Instrumentation and controls shall be provided as required to monitor and maintain variables within prescribed operating ranges.

Discussion

Reactor regulation is based upon the use of movable control rods and a chemical neutron absorber (boron in the form of boric acid) dissolved in the reactor coolant. Input signals to the reactor controls include reactor coolant average temperature, core thermal power demand, and reactor power. The reactor controls are designed to maintain a constant average reactor coolant temperature over the load range from approximately 15 to 100 percent of rated power. The steam system operates at constant pressure for all loads. Adequate instrumentation and controls are provided to maintain operating variables within their prescribed ranges (Section 7.7.2).

The non-nuclear instrumentation measures temperatures, pressures, flows, and levels in the Reactor Coolant System, Steam System, and Auxiliary Reactor Systems, and maintains these variables within prescribed limits (Section 7.4.2).

3.1.13 Criterion 13 - Fission Process Monitors and controls (Category B)

Means shall be provided for monitoring and maintaining control over the fission process throughout core life and for all conditions that can reasonably be anticipated to cause variations in reactivity of the core, such as indication of position of control rods and concentration of soluble reactivity control poisons.

Discussion

This criterion is met by reactivity control means and control room display. Reactivity control is by movable control rods and by chemical neutron absorber (in the form of boric acid) dissolved in the reactor coolant. The position of each control rod will be displayed in the control room. Changes in the reactivity status due to soluble boron will be indicated by changes in the position of the control rods. Actual boron concentration in the reactor coolant is determined periodically by sampling and analysis (Sections 7.7.1 and 9.3.3.2).

3.1.14 Criterion 14 - Core Protection Systems (Category B)

Core protective systems, together with associated equipment, shall be designed to act automatically to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

Discussion

The reactor design meets this criterion by reactor trip provisions and engineered safety features. The Reactor Protective System is designed to limit reactor power which might result from unexpected reactivity changes, and provides an automatic reactor trip to prevent exceeding acceptable fuel damage limits. In a loss-of-coolant accident, the Engineered Safeguards System automatically actuates the High-Pressure and Low-Pressure Injection Systems. The core flooding tanks are self-actuating. Certain long-term operations in the emergency Core Cooling Systems which do not require immediate actuation are performed manually by the operator, such as remote switching of the low-pressure injection pumps to the recirculation mode and sampling of the recirculated coolant (Sections 7.2 and 7.3).

3.1.15 Criterion 15 - Engineered Safety Features Protection Systems (Category B)

Protective systems shall be provided for sensing accident situations and initiating the operation of necessary engineered safety features.

Discussion

The Engineered Safeguards Protective System senses Reactor Coolant System pressure and Reactor Building pressure and initiates Emergency Core Cooling, Reactor Building isolation, and Reactor Building cooling at the appropriate levels. It also initiates starting of the Standby Emergency Power Sources (Sections 6.3.2 and 8.3.1.1.3).

3.1.16 Criterion 16 - Monitoring Reactor Coolant Pressure Boundary (Category B)

Means shall be provided for monitoring the reactor coolant pressure boundary to detect leakage.

Discussion

Reactor coolant pressure boundary integrity can be continuously monitored in the control room by surveillance of variation from normal conditions for the following:

1. Reactor Building temperature and sump level.
2. Reactor Building radioactivity levels.
3. Condenser off-gas radioactivity levels and main steam line monitors (to detect steam generator tube leakage).
4. Decreasing letdown storage tank water level (indicating system leakage).

Gross leakage from the reactor coolant boundary will also be indicated by a decrease in pressurizer water level and a rapid increase in the Reactor Building sump water level (Section 5.2.3.8).

3.1.17 Criterion 17 - Monitoring Radioactivity Releases (Category B)

Means shall be provided for monitoring the containment atmosphere, the facility effluent discharge paths and the facility environs for radioactivity that could be released from normal operations, from anticipated transients and from accident conditions.

Discussion

Various process radiation monitoring system detectors are used to measure airborne gaseous and particulate radioactivity, including iodine, in the Reactor Buildings; in releases from Waste Gas Tanks; and in effluent activity in the vent stacks (Section 11.5). These detectors have extended ranges to cover anticipated levels during normal operation, transient and accident conditions. They are also shielded against the background radiation levels expected to exist during an accident so that their readings will be valid under these conditions. Detectors are also located on the radioactive liquid waste discharge line which are interlocked to close the discharge valve on high activity. These instruments have been calibrated and have individual built-in secondary calibration sources of long half-life. Batch samples can also be collected for laboratory analysis and counting prior to the release of liquid and gaseous effluents. Service water, main steam lines, and turbine air ejector off-gas are also monitored to detect leakage of radioactivity in operation.

As part of the Environmental Radioactivity Monitoring Program, several sampling locations will be located within the Exclusion Area. One of these is located where the highest annual ground level concentrations of radioactivity from unit vent releases is expected to exist based on site meteorological studies. Another location is downstream of the liquid waste discharge point. Dosimeters are located at numerous points along the site boundary fence. Vegetation, surface water, shoreline sediment, fish, and integrated dose are monitored (Section 12.4).

In addition, environmental monitoring locations have been established in various populated areas and towns surrounding the site at distances up to 12 miles.

3.1.18 Criterion 18 - Monitoring Fuel and Waste Storage (Category B)

Monitoring and alarm instrumentation shall be provided for fuel and waste storage and handling areas for conditions that might contribute to loss of continuity in decay heat removal and to radiation exposures.

Discussion

All refueling operations will be carried out with the fuel under borated water to provide cooling for fuel assemblies and shielding for personnel.

Level indicators are provided to alarm low water level in the spent fuel storage pool. Penetrations of the pool liner are arranged to prevent accidental drainage of the pool (Section 9.1.4.2.3)

Temperature sensors and flow monitors in the spent fuel pool cooling loop alarm on high temperature or loss of flow (Section 9.1.3).

Radiation monitors and alarms are provided in the Reactor Building, in all refueling areas, and in the waste storage and processing areas to warn operating personnel of excessive radiation levels (Section 12.3.3).

3.1.19 Criterion 19 - Protection Systems Reliability (Category B)

Protective systems shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed.

Discussion

The Protective Systems design meets this criterion by specific instrument location, component redundancy, and in-service testing capability. The major design criteria stated below have been applied to the design of the instrumentation.

1. No single component failure shall prevent the protective systems from fulfilling their protective function when action is required.
2. No single component failure shall initiate unnecessary protective system action, provided implementation does not conflict with the criterion above.

Test connections and capabilities are built into the protective systems to provide for:

1. Pre-operational testing to give assurance that the protective systems can fulfill their required functions.
2. On-line testing to assure availability and operability (Section 7.1.2.1).

3.1.20 Criterion 20 - Protection Systems Redundancy and Independence (Category B)

Redundancy and independence designed into Protective Systems shall be sufficient to assure that no single failure or removal from service of any component or channel of a system will result in loss of the protective function. The redundancy provided shall include, as a minimum, two channels of protection for each protective function to be served. Different principles shall be used where necessary to achieve true independence of redundant instrumentation components.

Discussion

Reactor protection is by four channels with 2/4 coincidence, and engineered safeguards features are by three channels with 2/3 coincidence. All Protective System functions are implemented by redundant sensors, instrument strings, logic, and action devices that combine to form the protective channels. Redundant protective channels and their associated elements are electrically independent and packaged to provide physical separation.

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The Reactor Protective System will determine action to be taken based on the type of module removed. These actions could range from indication of trouble within the system to a protective channel trip.

3.1.21 Criterion 21 - Single Failure Definition (Category B)

Multiple failures resulting from a single event shall be treated as a single failure.

Discussion

The Protective Systems meet this criterion in that the instrumentation is designed so that a single event cannot result in multiple failures that would prevent the required protective action (Section 7.3).

3.1.22 Criterion 22 - Separation of Protection and Control Instrumentation Systems (Category B)

Protective Systems shall be separated from control instrumentation systems to the extent that failure or removal from service of any control instrumentation system component or channel, or of those common to control instrumentation and protective circuitry, leaves intact a system satisfying all requirements for the protective channels.

Discussion

The Protective Systems' input channels are electrically and physically independent. Shared instrumentation for protective and control functions satisfies the single failure criteria by the employment of isolation techniques to the multiple outputs of various instrument strings.

3.1.23 Criterion 23 - Protection against Multiple Disability for Protection Systems (Category B)

The effects of adverse conditions to which redundant channels or Protective Systems might be exposed in common, either under normal conditions or those of an accident, shall not result in a loss of the protective function.

Discussion

The Protective Systems are designed to extreme ambient conditions. The Protective Systems' instrumentation will operate from 40°F to 140°F and sustain the loss-of-coolant building environmental conditions, including 100 percent relative humidity, without loss of operability. Out-of-core neutron detectors, however, will withstand 90 percent relative humidity. The Protective Systems' instrumentation will be subject to environmental (qualification) testing as required by the proposed IEEE “Criteria for Nuclear Power Plant Protection Systems,” IEEE No. 279, dated August, 1968. Protective equipment outside the Reactor Building (control room and cable room) is designed for continuous operation in an ambient temperature and relative humidity representative of loss-of-coolant accident conditions (Section 7.1.2.1). The RPS / ESPS systems are also subject to IEEE Std 603-1998 “IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations”.

3.1.24 Criterion 24 - Emergency Power for Protection Systems (Category B)

In the event of loss of all off-site power, sufficient alternate sources of power shall be provided to permit the required functioning of the Protective Systems.

Discussion

In the event of loss of all off-site power to all units at Oconee or to any unit alone, sufficient power for operation of the Protective Systems of any unit will be available from either of two on-site independent hydroelectric generators. Details of the Emergency Power Generation System are described in Section 8.3.1.1.1.

Redundant battery power is provided for vital instrumentation and control.

3.1.25 Criterion 25 - Demonstration of Functional Operability of Protection Systems (Category B)

Means shall be included for testing Protective Systems while the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

Discussion

Test circuits are supplied which utilize the redundant, independent, and coincidence features of the Protective Systems. This makes it possible to manually initiate on-line trip signals in any single protective channel in order to test trip capability in each channel without affecting the other channels (Section 7.3).

3.1.26 Criterion 26 - Protection Systems Fail-Safe Design (Category B)

The Protective Systems shall be designed to fail into a safe state or into a state established as tolerable on a defined bases if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water), are experienced.

Discussion

The Reactor Protective System will trip the reactor on loss of power. The Engineered Safeguards Protective System is supplied with multiple sources of electric power for control and valve action.

A total loss of power will not result in a trip condition. The loss of the affected channel signals will be indicated to the remaining channels and will not cause any trip condition on the system.

The system is designed for continuous operation under adverse environments, as described in the discussion of Criterion 23 (Sections 7.1.2.1 and 7.2).

Redundant instrument channels are provided for the Reactor Protective and Engineered Safeguards Protective Systems. Loss of power to each individual reactor protective channel will trip that individual channel. Loss of all instrument power will trip the Reactor Protective System and activate the Engineered Safeguards System instrumentation (with the exception of the Reactor Building spray valves).

Manual reactor trip is designed so that failure of the automatic reactor trip circuitry will not prohibit or negate the manual trip. The same is true with respect to manual operation of the engineered safeguards equipment.

3.1.27 Criterion 27 - Redundancy of Reactivity Control (Category A)

At least two independent Reactivity Control Systems, preferably of different principles, shall be provided.

Discussion

This criterion is met by movable control rods Section 4.3.2, Section 7.6.1.1 and soluble boron poison (Section 4.3.2).

3.1.28 Criterion 28 - Reactivity Hot Shutdown Capability (Category A)

At least two of the reactivity control systems provided shall independently be capable of making and holding the core subcritical from any hot standby or hot operating condition, including those resulting from power changes, sufficiently fast to prevent exceeding acceptable fuel damage limits.

Discussion

A single reactivity control system consisting of 61 control rods is provided to rapidly make the core subcritical upon a trip signal. Trip levels are set to protect the core from damage due to the effects of any operating transient. The soluble absorber reactivity control system can add negative reactivity to make the reactor subcritical. However, its action is slow and its ability to protect the core from the damage, which might result from rapid load changes such as a full load turbine trip, is not a design criterion for this system. The high degree of redundancy in the Control Rod Drive System is considered sufficient to meet the intent of this criterion (Section 4.3.2 Section 7.6.1.1).

3.1.29 Criterion 29 - Reactivity Shutdown Capability (Category A)

At least one of the Reactivity Control Systems provided shall be capable of making the core subcritical under any conditions (including anticipated operation transients), sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margins greater than the maximum worth of the most effective control rod when fully withdrawn shall be provided.

Discussion

The reactor design meets this criterion both under normal operating conditions and under the accident conditions set forth in Chapter 15. The reactor is designed with the capability of providing a shutdown margin of at least 1 percent $\Delta k/k$ with the single most reactive control rod fully withdrawn at any point in core life with the reactor at a hot, zero power power condition. (Section 4.3.2.3). Table 4-6 illustrates a shutdown margin calculation for a sample Oconee fuel cycle.

3.1.30 Criterion 30 - Reactivity Holdown Capability (Category B)

At least one of the Reactivity Control Systems provided shall be capable of making and holding the core subcritical under any conditions with appropriate margins for contingencies.

Discussion

The reactor meets this criterion with control rods for hot shutdown under normal operating conditions and for shutdown under the accident conditions set forth in Chapter 15 except for the Steam Line Break Analysis. For details of this analysis refer to Section 15.13.

Reactor Shutdown margin is maintained during cooldown by increasing soluble boron concentration. The rate of reactivity compensation from boron addition is greater than the reactivity change associated with the reactor cooldown rate of 100°F/hour. Thus, subcriticality can be maintained during cooldown with the most reactive control rod totally unavailable (Section 4.3.2).

3.1.31 Criterion 31 - Reactivity Control Systems Malfunction (Category B)

The Reactivity Control Systems shall be capable of sustaining any single malfunction, such as unplanned continuous withdrawal (not ejection) of a control rod, without causing a reactivity transient which could result in exceeding acceptable fuel damage limits.

Discussion

The reactor design meets the intent of this criterion. A reactor trip will protect against any single malfunction of the reactivity control system. This conclusion is based on the analysis for a continuous rod group withdrawal accident (Section 15.3).

> **Note:** Design Criterion 31 implies by example that an unplanned continuous single rod withdrawal accident analysis may be performed. ONS did not perform a single rod withdrawal accident analysis in order to meet this design criterion. A single rod withdrawal accident cannot occur with a single reactivity control systems malfunction under any normal conditions of plant startup, shutdown, or operation. In addition, the NRC reviewed and approved the concept of using a group rod withdrawal accident analysis as the basis for meeting this design criterion.

3.1.32 Criterion 32 - Maximum Reactivity Worth of Control Rods (Category A)

Limits, which include considerable margin, shall be placed on the maximum reactivity worth of control rods or elements, and on rates at which reactivity can be increased to insure that the potential effects of a sudden or large change of reactivity cannot: a) rupture the reactor coolant pressure boundary or b) disrupt the core, its support structures, or other vessel internals sufficiently to impair the effectiveness of emergency core cooling.

Discussion

The reactor design meets this criterion by safety features which limit the maximum reactivity insertion rate. These include rod-group withdrawal interlocks, soluble boron concentration reduction interlock, maximum rate of dilution water addition, and dilution-time cutoff (Section 15.4). In addition, the rod drives and their controls have an inherent feature that limits overspeed in the event of malfunctions (Section 4.5.3). Ejection of the maximum-worth control rod will not lead to further coolant boundary rupture or to internals damage which would interfere with emergency core cooling (Section 15.12).

3.1.33 Criterion 33 - Reactor Coolant Pressure Boundary Capability (Category A)

The reactor coolant pressure boundary shall be capable of accommodating without rupture, and with only limited allowance for energy absorption through plastic deformation, the static and dynamic loads imposed on any boundary component as a result of any inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition.

Discussion

The reactor design meets this criterion. There are no credible mechanisms whereby damaging energy releases are liberated to the reactor coolant. Ejection of the maximum worth control rod will not lead to further coolant boundary rupture (Section 15.12).

3.1.34 Criterion 34 - Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention (Category A)

The reactor coolant pressure boundary shall be designed to minimize the probability of rapidly propagating type failures. Consideration shall be given a) to the notch-toughness properties of materials extending to the upper shelf of the Charpy transition curve, b) to the state of stress of materials under static and transient loadings, c) to the quality control specified for materials and component fabrication to limit flaw sizes, and d) to the provisions for control over service temperature and irradiation effects which may required operation restrictions.

Discussion

The reactor coolant pressure boundary design meets this criterion by the following:

1. Development of reactor vessel plate material properties opposite the core to a specified Charpy-V-notch test result of 30 ft/lb or greater at a nominal low NDTT.
2. Determination of the fatigue usage factor resulting from expected static and transient loading during detailed design and stress analysis.
3. Quality control procedures including permanent identification of materials and non-destructive testing.
4. Operating restrictions to prevent failure towards the end of design vessel life resulting from increase in the nil-ductility transition temperature (NDTT) due to neutron irradiation, as predicted by a material irradiation surveillance program (Section 5.2.3.13).

3.1.35 Criterion 35 - Reactor Coolant Pressure Boundary Brittle Fracture Prevention (Category A)

Under conditions where Reactor Coolant Pressure Boundary System components constructed of ferritic materials may be subjected to potential loadings, such as a reactivity-induced loading, service temperature shall be at least 120°F above the nil ductility transition (NDT) temperature of the component material if the resulting energy release is expected to be absorbed by plastic deformation or 60°F above the NDT temperature of the component material if the resulting energy release is expected to be absorbed within the elastic strain energy range.

Discussion

The reactor vessel is the only Reactor Coolant System component exposed to a significant level of neutron irradiation and is, therefore, the only component subject to material irradiation damage. Unit operating procedures will limit the operating pressure to 20 percent of the design pressure when the Reactor Coolant System temperature is below NDTT +60°F throughout unit life. Analysis has shown no potential reactivity-induced conditions which will result in energy release to the primary system in the range expected to be absorbed by plastic deformation (Section 5.2.3.3).

3.1.36 Criterion 36 - Reactor Coolant Pressure Boundary Surveillance (Category A)

Reactor coolant pressure boundary components shall have provisions for inspection, testing, and surveillance by appropriate means to assess the structural and leak-tight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with ASTM-E-185-66 shall be provided.

Discussion

The reactor coolant pressure boundary components meet this criterion. Space is provided for non-destructive testing during plant shutdown. A reactor pressure vessel material surveillance program conforming to ASTM-E-185-66 has been established (Section 5.2.3.13).

3.1.37 Criterion 37 - Engineered Safety Features Basis for Design (Category A)

Engineered safety features shall be provided in the facility to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems. As a minimum, such engineered safety features shall be designed to cope with any size reactor coolant pressure boundary break up to and including the circumferential rupture of any pipe in that boundary assuming unobstructed discharge from both ends.

Discussion

The reactor design meets this criterion. The Emergency Core Cooling Systems can protect the reactor for any size leak up to and including the circumferential rupture of the largest reactor coolant pipe (Section 15.14).

3.1.38 Criterion 38 - Reliability and Testability of Engineered Safety Features (Category A)

All engineered safety features shall be designed to provide high functional reliability and ready testability. In determining the suitability of a facility for a proposed site, the degree of reliance upon and acceptance of the inherent and engineered safety afforded by the systems, including engineered safety features, will be influenced by the known and the demonstrated performance capability and reliability of the systems, and by the extent to which the operability of such systems can be tested and inspected where appropriate during the life of the plant.

Discussion

All Engineered Safeguards Systems are designed so that a single failure of an active component in a system will not prevent operation of that system or reduce its capacity below that required to maintain a safe condition. Two independent Reactor Building Cooling Systems, each having full heat removal capacity, are provided to prevent overpressurization (Section 7.3).

The High-Pressure Injection, Core-Flooding, and Low-Pressure Injection Systems have separate equipment and instrumentation strings to ensure availability of capacity.

Some portions of the Engineered Safeguards Systems have both a normal and an emergency function, thereby providing nearly continuous demonstration of operability. During normal operation, the standby and operating units will be rotated into service on a scheduled basis.

Engineered Safeguards Systems equipment piping that is not fully projected against LOCA missile damage utilizes dual lines to preclude loss of the protective function as a result of the secondary failure.

Testing and inspection of the Engineered Safeguards Systems is further described in Chapter 6.

3.1.39 Criterion 39 - Emergency Power for Engineered Safety Features (Category A)

Alternate power systems shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the on-site power system and the off-site power system shall each, independently, provide this capacity assuming a failure of a single active component in each power system.

Discussion

The electrical systems meet the intent of the criterion as discussed in Chapter 8.

Three alternate emergency electric power supplies are provided for the station from which power to the engineered safety feature buses of each unit can be supplied. These are the 230 KV switching station with multiple off-site interconnections and two on-site independent 87,500 KVA hydroelectric generating units. Each nuclear unit can receive emergency power from the 230 KV switching station through its start-up transformer as a preferred source. Each unit can receive emergency power from one hydroelectric generating unit through a 13.8 KV underground connection to standby transformer CT4. The other hydroelectric generating unit serves as a standby emergency power source and can supply power to each unit's startup transformer when required. Both on-site hydroelectric generating units will start automatically upon loss of all normal power or upon an engineered safety feature action.

Two additional sources of alternate power are available, as each nuclear unit is capable of supplying any other unit through the 230 KV switching station. In addition, a connection to the 100 KV transmission network is provided as an alternate source of emergency power whenever both hydroelectric generating units are unavailable.

3.1.40 Criterion 40 - Missile Protection (Category A)

Protection for engineered safety features shall be provided against dynamic effects and missiles that might result from plant equipment failures.

Discussion

Engineered safety features are defined as Engineered Safeguards Systems. Engineered Safeguards System features are redundant. Engineered Safeguards Systems at Oconee are protected against dynamic effects and missiles resulting from hypothesized plant equipment failures. In general, missile protection for Oconee is described in Section 3.5. Two basic categories of plant equipment failure are hypothesized and considered in the Oconee design:

1. Missiles generated inside Containment - Assumptions and design requirments for missiles generated inside containment are described in Section 3.5.1.1.
2. Missiles generated by a main turbine failure - Assumptions and design requirements for missiles generated by a main turbine failure are described in Section 3.5.1.2.

3.1.41 Criterion 41 - Engineered Safety Features Performance Capability (Category A)

Engineered safety features such as Emergency Core Cooling and Containment Heat Removal Systems shall provide sufficient performance capability to accommodate partial loss of installed capacity and still fulfill the required safety function. As a minimum, each engineered safety feature shall provide this required safety function assuming a failure of a single active component.

Discussion

All Engineered Safeguards Systems are designed so that a single failure of an active component will not prevent operation of that system or reduce the system capacity below that required to maintain a safe condition. Redundancy is provided in equipment and piping so that the failure of a single active component of any system will not impair the required safety function of that system (Section 7.3).

3.1.42 Criterion 42 - Engineered Safety Features Components Capability (Category A)

Engineered safety features shall be designed so that the capability of each component and system to perform its required function is not impaired by the effects of a loss-of-coolant accident.

Discussion

The Engineered Safeguards System design meets this criterion. A single-failure analysis of the Emergency Core Cooling Systems (Section 6.3.2.6) and the Reactor Building Heat Removal Systems (Sections 6.2; 6.2.2) demonstrates that these systems have sufficient redundancy to perform their design functions.

The core flooding tanks contain check valves which operate to permit flow of emergency coolant from the tanks to the reactor vessel. These valves are self-actuating and need no external signal or external supplied energy to make them operate. Accordingly, it is not considered credible that they would fail to operate when needed.

The engineered safeguards features are designed to function in the unlikely event of a loss of coolant accident with no impairment of function due to the effects of the accident.

3.1.43 Criterion 43 - Accident Aggravation Prevention (Category A)

Engineered safety features shall be designed so that any action of the engineered safety features which might accentuate the adverse after-effects of the loss of normal cooling is avoided.

Discussion

The Engineered Safeguards Systems are designed to meet this criterion. The water injected to ensure core cooling is sufficiently borated to ensure core subcriticality. Water sources that are not required to mitigate the consequences of an accident inside the Reactor Building are automatically isolated to prevent dilution of the borated coolant. Sources of necessary post-accident cooling waters are monitored for boron concentration to prevent additions which may lead to dilution of boron content. An analysis has been made to demonstrate that the injection of cold water on the Hot Reactor Coolant System surfaces will not lead to further failure. The design of the equipment and its actuating system ensures that water injection will occur in a sufficiently short time period to preclude significant metal-water reactions and consequent energy release to the Reactor Building (Section 15.14).

3.1.44 Criterion 44 - Emergency Core Cooling Systems Capability (Category A)

At least two Emergency Core Cooling Systems, preferably of different design principles, each with a capability for accomplishing abundant emergency core cooling, shall be provided. Each Emergency Core Cooling System and the core shall be designed to prevent fuel and clad damage that would interfere with the emergency core cooling function and to limit the clad metal-water reaction to negligible amounts for all sizes of breaks in the reactor coolant pressure boundary, including the double-ended rupture of the largest pipe. The performance of each Emergency Core Cooling System shall be evaluated conservatively in each area of uncertainty. The systems shall not share active components and shall not share other features or components unless it can be demonstrated that: a) the capability of the shared feature or component to perform its required function can be readily ascertained during reactor operation, b) failure of the shared feature or component does not initiate a loss-of-coolant accident, and c) capability of the shared feature or component to perform its required function is not impaired by the effects of a loss-of-coolant accident and is not lost during the entire period this function is required following the accident.

Discussion

Emergency core cooling is provided by pumped injection and pressurized core flooding tanks. Pumped injection is subdivided in such a way that there are two separate and independent strings, each including both high pressure and low pressure coolant injection, and each capable of providing 100 percent of the necessary core injection with the core flooding tanks. There is no sharing of active components between the two subsystems in the post-accident operating mode. The core flooding tanks are passive components which are needed for only a short period of time after the accident, thereby assuring 100 percent availability when needed. This equipment prevents clad melting for the entire spectrum of Reactor Coolant System failures ranging from the smallest leak to the complete severance of the largest reactor coolant pipe (Section 15.14).

3.1.45 Criterion 45 - Inspection of Emergency Core Cooling Systems (Category A)

Design provisions shall be made to facilitate physical inspection of all critical parts of the Emergency Core Cooling System including reactor vessel internals and water injection nozzles.

Discussion

All critical parts of the Emergency Core Cooling Systems, including the reactor vessel internals, can be inspected during plant shutdown (Section 5.2.3.12).

3.1.46 Criterion 46 - Testing of Emergency Core Cooling Systems Components (Category A)

Design provisions shall be made so that active components of the Emergency Core Cooling Systems, such as pumps and valves, can be tested periodically for operability and required functional performance.

Discussion

The design of Emergency Core Cooling Systems and components has incorporated adequate test and operational features to permit periodic testing of active components to assure operability and functional capability. Core flooding tank functional performance will be demonstrated only in pre-operational testing.

3.1.47 Criterion 47 - Testing of Emergency Core Cooling Systems (Category A)

A capability shall be provided to test periodically the delivery capability of the Emergency Core Cooling Systems at a location as close to the core as is practical.

Discussion

The High-Pressure (makeup water) and Low-Pressure (decay-heat removal) Injection Systems are included as part of Normal Service Systems. Consequently, the active components can be tested periodically for delivery capability. The Core Flooding System delivery capability will be demonstrated during startup testing. In addition, all valves required to ensure delivery capability will be periodically cycled to ensure operability. With these provisions, the delivery capability of the Emergency Core Cooling Systems can be periodically demonstrated (Section 6.3.4).

3.1.48 Criterion 48 - Testing of Operational Sequence of Emergency Core Cooling Systems (Category A)

A capability shall be provided to test, under conditions as close to design as practical, the full operational sequence that would bring the Emergency Core Cooling Systems into action, including the transfer to alternate power sources.

Discussion

The operational sequence that would bring the Emergency Core Cooling Systems into action, including transfer to alternate power sources, can be tested in parts (Sections 6.3.4 and 7.3).

3.1.49 Criterion 49 - Containment Design Basis (Category A)

The containment structure, including access openings and penetrations, and any necessary containment heat removal systems shall be designed so that the containment structure can accommodate without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of Emergency Core Cooling Systems.

Discussion

The Reactor Building, access openings and penetrations, have been designed to accommodate a pressure of 59 psig at 286°F (Section 6.2.1). As described in Section 15.14 these conditions exceed the greatest transient peak pressure associated with a hypothetical rupture of a pipe in the Reactor Coolant System, including the margin for the effects of metal-water reactions. The capacity of each Reactor Building Cooling System (Sections 6.2 and 6.2.2) is designed to remove heat from the Reactor Building to reduce pressure following a loss-of-coolant accident.

Components of the Reactor Building Cooling System - including electric motors and valves, which function within the Reactor Building during accident conditions - are capable of operation as required to accomplish the safeguards function.

3.1.50 Criterion 50 - NDT Requirement for Containment Material (Category A)

Principle load-carrying components of ferritic materials exposed to the external environment shall be selected so that their temperatures under normal operating and testing conditions are not less than 30°F above nil-ductility transition (NDT) temperature.

Discussion

The Reactor Building liner has been designed so that it is not susceptible to a low temperature brittle fracture.

All principal load-carrying components of ferritic materials for the containment vessel exposed to the external environment have been selected and tested to confirm that their ductile-to-brittle-transition (NDT) temperature is at least 30°F below the minimum service metal temperature. The ferritic materials exposed to the external environment consist of the penetrations and large openings (equipment access hatch and personnel locks), for which materials have been selected to conform with ASME Boiler and Pressure Vessel Code, Section III, for Class “B” Vessels. Material specifications for the penetrations are more completely described in Section 3.8.1.1.

3.1.51 Criterion 51 - Reactor Coolant Pressure Boundary outside Containment (Category A)

If part of the reactor coolant pressure boundary is outside the containment, appropriate features, as necessary, shall be provided to protect the health and safety of the Public in case of an accidental rupture in that part. Determination of the appropriateness of features, such as isolation valves and additional containment, shall include consideration of the environmental and population conditions surrounding the site.

Discussion

The reactor coolant pressure boundary is defined as those piping systems or components which contain reactor coolant at high pressure and temperature. With the exception of the normal reactor coolant sampling line and the reactor coolant post accident liquid sample line, the reactor coolant pressure boundary, as defined above, is located entirely within the Reactor Building. These sampling lines are provided with remotely operated valves for isolation. The normal reactor coolant sampling line is used only during actual sampling operations. The reactor coolant post accident liquid sample line is used during performance testing of the post accident liquid sampling system and/or actual sampling operations (Section 9.3.6). No significant environmental dose would result from these sources (Sections 6.2.3, 11.2.2.)

3.1.52 Criterion 52 - Containment Heat Removal Systems (Category A)

Where active heat removal systems are needed under accident conditions to prevent exceeding containment design pressure, at least two systems, preferably of different principles, each with full capacity, shall be provided.

Discussion

Two systems of different principles are provided to remove heat from each Reactor Building following an accident. The systems are discussed in Sections 6.2 and 6.2.2. Analysis of peak accident pressure in containment following an accident is addressed in Sections 6.2.1.3 and 6.2.1.4 respectively. The analysis shows containment to be capable of withstanding peak accident pressure without the Reactor Building Spray System, or Reactor Building Cooling System.

The Reactor Building Cooling System removes heat by circulating building atmosphere over cooling coils.

The Reactor Building Spray System supplies droplets of cool, borated water which absorb sensible and latent heat from the containment atmosphere.

3.1.53 Criterion 53 - Containment Isolation Valves (Category A)

Penetrations that require closure for the containment function shall be protected with redundant valving and associated apparatus.

Discussion

Piping penetrations that require closure under accident conditions are provided with double barriers so that no single credible failure or malfunction could result in a loss of isolation. Valves are manually, electrically or pneumatically operated. Check valves are used in certain applications. All isolation valves inside the Reactor Building requiring remote operation are electrically operated. As an alternative to valves, other types of apparatus which provide a suitable barrier for containment isolation may be utilized. Examples of such mechanisms include, but are not limited to flanges and closed loop piping systems that are designed to remain intact when containment isolation is required.

3.1.54 Criterion 54 - Containment Leakage Rate Testing (Category A)

Containment shall be designed so that an integrated leakage rate testing can be conducted at design pressure after completion and installation of all penetrations and the leakage rate measured over a sufficient period to verify its conformance with required performance.

Discussion

The Reactor Buildings are designed so that leakage rate can be determined at design pressure after completion and installation of all penetrations. The leak-rate test will verify that the maximum integrated leak rate does not exceed the design leakage rate (Section 3.8.1.7.3).

3.1.55 Criterion 55 - Containment Periodic Leakage Rate Testing (Category A)

The containment shall be designed so that integrated leakage rate testing can be done periodically at design pressure during plant lifetime.

Discussion

The Reactor Building has been structurally designed to permit integrated leakage rate testing at design pressure (Section 3.8.1.7.4).

3.1.56 Criterion 56 - Provisions for Testing of Penetrations (Category A)

Provisions shall be made for testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at design pressure at any time.

Discussion

All Reactor Building penetrations with resilient seals or expansion bellows are constructed so that they may be pressurized to design pressure for leak tests at any time (Section 3.8.1.7.4 and Section 3.8.1.5.4).

3.1.57 Criterion 57 - Provisions for Testing of Isolation Valves (Category A)

Capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valves leakage does not exceed acceptable limits.

Discussion

All remotely operated valves serving an Engineered Safeguards function have the capability for testing their functional operability. These tests can be conducted from the control rooms.

Isolation valves that are required to be closed from an Engineered Safeguards signal have test provisions for leak testing (Table 6-7).

3.1.58 Criterion 58 - Inspection of Containment Pressure - Reducing Systems (Category A)

Design provisions shall be made to facilitate the periodic physical inspection of all important components of the containment pressure-reducing systems, such as pumps, valves, spray nozzles, torus, and sumps.

Discussion

Provision is made to permit periodic physical inspection of components of the two containment pressure-reducing systems, the Reactor Building Spray System and the Reactor Building Cooling System. The Reactor Building spray pumps and the valves and operators associated with piping in each of these systems are located outside the Reactor Building, permitting the inspection of these components. The fan units of the Reactor Building cooling units are located so that physical inspection is possible during normal operation.

The cooling coils of the Reactor Building cooling units can be inspected during shutdown. The spray header and nozzles of the Reactor Building Spray System, located in the dome of the Reactor Building, can be inspected visually during shutdown. The sumps can be inspected and the strainers cleaned during shutdown.

3.1.59 Criterion 59 - Testing of Containment Pressure-Reducing System Components (Category A)

The containment pressure-reducing systems shall be designed so that active components, such as pumps and valves can be tested periodically for operability and required functional performance.

Discussion

The containment pressure-reducing systems have the capability of being periodically tested as follows:

1. Reactor Building Cooling Units
    a. The air fans can be individually tested for low speed operation.
    b. The cooling coil low pressure service water valves can be operated through their full travel with resulting flow alarm indication.
    c. The stand-by low pressure service water pumps can be tested for automatic starting.
2. Reactor Building Spray System
    a. The operation of the spray pumps can be tested by recirculating to the borated water storage tank through a test line.
    b. The building spray isolation valves can be operated through their full travel.

3.1.60 Criterion 60 - Testing of Containment Spray Systems (Category A)

A capability shall be provided to periodically test the delivery capability of the Containment Spray System at a position as close to the spray nozzles as is practical.

Discussion

The delivery capability of the spray nozzles will be tested by blowing low pressure air through the system and verifying flow through the nozzles.

The delivery capability of the pumps will be tested by recirculating to the borated water storage tank and monitoring the resultant flow.

3.1.61 Criterion 61 - Testing of Operational Sequence of Containment Pressure Reducing Systems

A capability shall be provided to test, under conditions as close to the design as practical, the full operational sequence that would bring the containment pressure-reducing systems into action including the transfer to alternate power sources.

Discussion

Each of the three redundant 4 kV switchgear buses supplying power to essential loads receives its power from two 4 kV main feeder buses. These main feeder buses are supplied by: 1) the main unit auxiliary transformers, 2) the startup transformer, and 3) the underground feeder from Keowee Hydro plant. Each main feeder bus is fed from each of the three sources above. In normal operation the two main feeders will be supplied through breakers from the unit auxiliary transformer and the breakers from the start-up transformer and the underground feeder will be open.

To test the transfer to alternate power source, the three breakers associated with one of the main feeders will be placed in test position with the normal breaker closed and the two alternate power sources breakers open. A low voltage simulation will be used to trip the normal breaker and close the start-up breaker. A low voltage and an Engineered Safeguards (ESG) simulation will be used to trip the start-up breaker and close the underground feeder breaker. In making these tests, the automatic dropping of load will not take place.

Testing the two independent channels for the Reactor Building Cooling System and the Building Spray System by inserting an analog signal can be accomplished without placing the systems in operation.

3.1.62 Criterion 62 - Inspection of Air Cleanup Systems

Design provisions shall be made to facilitate physical inspection of all critical parts of containment air cleanup systems such as ducts, filters, fans, and dampers.

Discussion

The Penetration Room Ventilation System (PRVS) was originally addressed by this design criterion. Due to the adoption of the Alternate Source Term, PRVS is no longer required and this design criterion no longer applies.

3.1.63 Criterion 63 - Testing of Air Cleanup System Components

Design provisions shall be made so that active components of the Air Cleanup Systems, such as fans and dampers, can be tested periodically for operability and required functional performance.

Discussion

The Penetration Room Ventilation System (PRVS) was originally addressed by this design criterion. Due to the adoption of the Alternate Source Term, PRVS is no longer required and this design criterion no longer applies.

The Control Room Ventilation System (CRVS) was not originally addressed by this design criterion. Operation and Maintenance of CRVS is addressed by the QA 5 program. Testing of CRVS is addressed by the Ventilation Filter Test Program.

3.1.64 Criterion 64 - Testing of Air Cleanup Systems

A capability shall be provided for in situ periodic testing and surveillance of the Air Cleanup Systems to ensure; a) filter bypass paths have not developed and, b) filter and trapping materials have not deteriorated beyond acceptable limits.

Discussion

The Penetration Room Ventilation System (PRVS) was originally addressed by this design criterion. Due to the adoption of the Alternate Source Term, PRVS is no longer required and this design criterion no longer applies.

The Control Room Ventilation System (CRVS) was not originally addressed by this design criterion. Operation and Maintenance of CRVS is addressed by the QA 5 program. Testing of CRVS is addressed by the Ventilation Filter Test Program.

3.1.65 Criterion 65 - Testing of Operational Sequence of Air Cleanup Systems (Category A)

A capability shall be provided to test under conditions as close to design as practical the full operational sequence that would bring the Air Cleanup Systems into action including the transfer to alternate power sources and the design air flow delivery capability.

Discussion

The Penetration Room Ventilation System (PRVS) was originally addressed by this design criterion. Due to the adoption of the Alternate Source Term, PRVS is no longer required and this design criterion no longer applies.

The Control Room Ventilation System (CRVS) was not originally addressed by this design criterion. Operation and Maintenance of CRVS is addressed by the QA 5 program. Testing of CRVS is addressed by the Ventilation Filter Test Program.

3.1.66 Criterion 66 - Prevention of Fuel Storage Criticality (Category B)

Criticality in new and spent fuel storage shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls.

Discussion

Criticality of new or spent fuel is prevented by limiting the fuel assembly array size and limiting assembly interaction by fixing the mimimum separation between assemblies. Fuel assemblies cannot be placed in other than the prescribed locations (Section 9.1.2).

3.1.67 Criterion 67 - Fuel and Waste Storage Decay Heat (Category B)

Reliable Decay Heat Removal Systems shall be designed to prevent damage to the fuel in storage facilities that could result in radioactivity release to plant operating areas or the public environs.

Discussion

This criterion is met by the Spent Fuel Cooling System which incorporates provisions to maintain water cleanliness, temperature, and water level. Three pumps and three coolers will be adequate to maintain the spent fuel pool temperature within acceptable limits. The pumps in the system can be operated from the standby bus in case of loss of outside power to provide continuous cooling capability in the fuel storage facility (Section 9.1.3). The above discussion of Spent Fuel Cooling is for the permanently installed systems and not for the temporary Supplemental SFP Cooling System (Section 9.1.3.1.3) used to improve the SFP area environment.

3.1.68 Criterion 68 - Fuel and Waste Storage Radiation Shielding (Category B)

Shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities to meet the requirements of 10CFR20.

Discussion

Shielding meeting the requirements of 10CFR 20 is provided for protection of operating personnel:

1. During all phases of spent fuel removal and storage (Section 12.3.2).
2. From radioactive waste holdup tanks and other containers containing potentially radioactive solutions, resins, or gases (Section 12.3.2).

3.1.69 Criterion 69 - Protection against Radioactivity Release from Spent Fuel and Waste Storage (Category B)

Containment of fuel and waste storage shall be provided if accidents could lead to release of undue amounts of radioactivity to the public environs.

Discussion

Analyses in Chapter 15 have demonstrated that accidental release of the maximum activity content of a tank containing waste gases or liquids will not cause excessive off-site doses. The fuel handling accident, analyzed in Chapter 15 does not result in excessive off-site doses.

3.1.70 Criterion 70 - Control of Releases of Radioactivity to the Environment (Category B)

The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified: a) on the basis of 10CFR 20 requirements for normal operations and for any transient situation that might reasonably be anticipated to occur and b) on the basis of 10CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence except that reduction of the recommended dosage levels may be required where high population densities or very large cities can be affected by the radioactive effluents.

Discussion

The waste disposal system is designed to insure that station personnel and the general public are protected against excessive exposure to radioactive material in accordance with the regulations of 10CFR 20 and 10CFR 50 Appendix I.

The gaseous, liquid, and solid waste storage facilities are discussed in Chapter 11 where it is demonstrated that adequate holdup capacity is provided. Gaseous and liquid wastes will be sampled before release and will be monitored for activity level at all times during release, or independent sampling and analysis will be performed prior to release when the appropriate monitor is out of service.

Control of leakage following a reactor accident is accomplished by the Reactor Building. Experience has shown that Reactor Building leakage is more likely at penetrations than in liner plates or weld joints. Prior to the adoption of the alternate source term, the Penetration Room Ventilation system was required to collect and process post-accident Reactor Building leakage by establishing a vacuum in the Penetration Rooms and processiong the leakage through a prefilter, an absolute filter, and a carbon filter prior to release by way of the unit vent. This system is still available but no longer required to serve an accident mitigation function.

The release of radioactive materials produced by a reactor accident or waste gas tank failure are within the guidelines set by 10CFR 100.

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3.2 Classification of Structures, Components, and Systems

3.2.1 Seismic Classification

3.2.1.1 Structures

The design bases for normal operating conditions are governed by the applicable building design codes. The basic design criterion for the worst loss-of-coolant accident and seismic conditions is that there shall be no loss of function if that function is related to public safety.

AEC publication TID 7024, "Nuclear Reactors and Earthquake," as amplified in Chapter 3 is used as the basic design guide for seismic analysis.

The design basis earthquake ground acceleration at the site is 0.05g. The maximum hypothetical earthquake ground acceleration is 0.10g. and 0.15g for Class 1 structures founded on bedrock and overburden respectively.

The plant structures are classified as one of three classes according to their function and the degree of integrity required to protect the public.

3.2.1.1.1 Class 1

Class 1 structures are those which prevent uncontrolled release of radioactivity and are designed to withstand all loadings without loss of function. Class 1 structures include the following:

Portions of the Auxiliary Building that house engineered safeguards systems, control room, fuel storage facilities and radioactive materials.

Reactor Building and its penetrations.

CT4 Transformer and 4KV Switchgear Enclosures (Blockhouses) (Reference Section 8.3.1.4.1.)

Unit Vent.

Standby Shutdown Facility (SSF) (Reference Section 9.6.3.4.1.)

Protected Service Water (PSW) Building (Reference Section 9.7.3.5).

Note: From the license renewal review, it was determined that Class 1 civil structures are included in the scope for license renewal.

3.2.1.1.2 Class 2

Class 2 structures are those whose limited damage would not result in a release of radioactivity and would permit a controlled plant shutdown but could interrupt power generation. Class 2 structures include the following:

Oconee Intake Structure
Oconee Turbine and Auxiliary Buildings, except as included in Class 1
Oconee Intake Canal Dike
Oconee Intake Underwater Weir
Keowee Powerhouse
Keowee Spillway
Keowee Service Bay Substructure

Keowee Breaker Vault
Keowee Intake Structure
Keowee Power and Penstock Tunnels
Keowee Dam
CCW Intake Piping
CCW Discharge Piping
ECCW Piping (Structural Portion outside of Turbine Building)
Little River Dam and Dikes
Essential Siphon Vacuum System Intake Dike Trench
Essential Siphon Vacuum Cable Trench
Essential Siphon Vacuum Building
230 kV Switchyard QA-1 component bases and support structures
230 kV Relay House
230 kV Switchyard cable trench
Overhead Power Path component bases (including KHU MSU, CT1, CT2 and CT3 bases) and support structures
Overhead Power Path transmission towers and bases

Note: From the license renewal, it was determined that Class 2 civil structures are included in the scope for license renewal.

3.2.1.1.3 Class 3

Class 3 structures are those whose failure could inconvenience operation, but which are not essential to power generation, orderly shutdown or maintenance of the reactor in a safe condition. They include all structures not included in Classes I and 2.

3.2.1.2 Components and Systems

Capability is provided to shutdown safely all three units in the event of a maximum hypothetical earthquake. Major equipment and portions of systems that can withstand the maximum hypothetical earthquake are identified in Section 3.2.2.

3.2.1.3 Seismic Loading Conditions

The design basis earthquake ground acceleration at the site is 0.05g. The maximum hypothetical earthquake ground acceleration is 0.10g. and 0.15g for Class 1 structures founded on bedrock and overburden respectively.

The terms Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE) are sometimes referred to within the UFSAR.

Operating Basis Earthquake (OBE) is equivalent to Design Basis Earthquake (DBE).

Safe Shutdown Earthquake (SSE) is equivalent to Maximum Hypothetical Earthquake (MHE).

3.2.2 System Quality Group Classification

This section defines the design criteria used with respect to the loss-of-coolant accident (LOCA), and natural phenomena and also explains the division of components and piping into classifications related to design and function. These criteria are as follows:

A maximum hypothetical earthquake will not result in a loss-of-coolant accident (LOCA), but the simultaneous occurrence of these events will not result in loss of function to vital safety related components or systems. The simultaneous occurrence of the maximum hypothetical earthquake and a LOCA is only a design criteria. A LOCA is not postulated to occur simultaneously with a maximum hypothetical earthquake during accident analysis. In addition, pipe failures during a maximum hypothetical earthquake are not postulated as part of the accident analysis.

A tornado will not be allowed to cause a LOCA.

A tornado does not occur simultaneously with or following a LOCA.

A tornado and earthquake do not occur simultaneously.

An earthquake can occur simultaneously with a loss of offsite power.

A turbine missile will not be allowed to cause a LOCA.

A turbine missile does not occur simultaneously with a LOCA.

The following design objectives result from consideration of the design criteria:

1. Loss-of-Coolant Accident

   Capability is provided to assure necessary protective actions, including reactor trip and operation of the Emergency Core Cooling System, to protect the public during a LOCA, even in the event of a simultaneously occurring maximum hypothetical earthquake.

2. Turbine Missile Accident

   The Reactor Coolant System will not be damaged by a turbine missile. Capability is provided to safely shutdown the affected units.

3. Earthquake

   Major equipment and portions of systems that can withstand the maximum hypothetical earthquake include the following:

   a. Reactor Coolant System.

   b. Borated water storage tank and piping to high pressure and low pressure injection pumps and Reactor Building spray pumps.

   c. HP injection pumps and piping to Reactor Coolant System.

   d. LP injection pumps, LP injection coolers and piping to both Reactor Coolant System and Reactor Building spray pumps.

   e. Core flood tanks and piping to Reactor Coolant System.

   f. Reactor Building spray pumps, piping to spray headers, and the spray headers.

   g. Reactor Building coolers.

   h. Low pressure service water (LPSW) pumps, LPSW piping to LP injection coolers and Reactor Building coolers and LPSW piping from these coolers to the condenser circulating water (CCW) discharge.

   i. CCW intake structure, CCW pumps, pump motors, CCW intake piping to the LPSW pumps, also through the condenser and emergency CCW discharge piping and CCW discharge piping.

   j. Upper surge tanks, and piping to the emergency feedwater pump.

k. Emergency feedwater pump and turbine and auxiliary feedwater piping to the steam generators.

l. Main steam lines to and including turbine stop valves. Turbine bypass system up thru Main Steam System isolation valves, and steam supply lines to the emergency feedwater pump turbine.

m. Penetration Room Ventilation System. (not required to operate for accident mitigation due to adoption of alternate source terms) (Reference 3)

n. Reactor Building penetrations and piping through isolation valves.

o. Siphon Seal Water System.

p. Essential Siphon Vacuum System.

q. Electric power for above.

r. Nitrogen supply to the EFW control valves FDW-315 and FDW-316.

Information relating to the seismic design of SSF systems and components is contained in Section 9.6.4.1 and 9.6.4.3. Information relating to the seismic design of the PSW System and its components are contained in Section 9.7.

4. Tornado

For Units where the revised tornado mitigation strategies as discussed in Reference 5 have not been implemented:

The Reactor Coolant System will not be damaged by a tornado. A loss of Reactor Coolant Pump (RCP) seal integrity was not postulated as part of the tornado design basis. Capability is provided to shutdown safely all three units.

The Reactor Coolant System, by virtue of its location within the Reactor Building, is protected from tornado damage. A sufficient supply of secondary side cooling water for safe shutdown is assured by Protected Service Water Pumps located in the Auxiliary Building and taking suction from Oconee 2 CCW intake piping. Redundant and diverse sources of secondary makeup water are credited for tornado mitigation. These include: 1) the other units' EFW Systems, 2) the PSW pumps, and 3) the SSF ASW pump.

Protected or physically separated lines are used to supply cooling water to each steam generator. The sources of power to the PSW pumps are the Keowee Hydro Station and the Central Tie Switchyard via a 100 kV transmission line to a 100/13.8 kV substation.

An external source of cooling water is not immediately required due to the large quantities of water stored underground in the intake and discharge CCW piping. The stored volume of water in the intake and discharge lines below elevation 791ft would provide sufficient cooling water for all three units for at least 30 days after trip of the three reactors.

Although not fully protected from tornadoes, the following sources provide reasonable assurance that a sufficient supply of primary side makeup water is available during a tornado initiated loss of offsite power.

a. The SSF Reactor Coolant Makeup Pump can take suction from the Spent Fuel Pool. The pump can be supplied power from the SSF Diesel.

b. A High Pressure Injection Pump can take suction from either the Borated Water Storage Tank or the Spent Fuel Pool. Either the “A” or “B” High Pressure Injection Pump can be powered from the PSW Switchgear.

Protection against tornado is an Oconee design criteria, similar to the criteria to protect against earthquakes, wind, snow, or other natural phenomena described in UFSAR section 3.1.2. A specific occurrence of these phenomena is not postulated, nor is all equipment that would be used to bring the plant to safe shutdown comprehensively listed. The statement, “Capability is provided to shutdown safely all three units” is intended to be a qualitative assessment that, after a tornado, normal shutdown systems will remain available or alternate systems will be available to allow shutdown of the plant. It was not intended to imply that specific systems should be tornado-proof. As part of the original FSAR development, specific accident analyses were not performed to prove this judgement, nor were they requested by the NRC. Subsequent probabilistic studies have confirmed that the original qualitative assessments were correct. The risk of not being able to achieve safe shutdown after a tornado is sufficiently small that additional protection is not required.

In addition, there was considerable correspondence between Duke and NRC in the years post-TMI discussing Oconee's ability to survive tornado generated missiles. Based upon the probability of failure of the EFW and Station ASW systems combined with the protection against tornado missiles afforded by the SSF ASW system, the NRC concluded that the secondary side decay heat removal function complied with the criterion for protection against tornadoes.

For Units where the revised tornado mitigation strategies as discussed in Reference 5 have been implemented:

The Reactor Coolant System, by virtue of its location within the Reactor Building, will not be damaged by a tornado. Capability is provided to shutdown safely all three units. Tornado is not considered a design basis event (DBE) or transient for Oconee. Protection against tornado is an Oconee design criterion, similar to the criteria to protect against earthquakes, wind, snow, or other natural phenomena described in UFSAR Section 3.1.2. A specific occurrence of these phenomena is not postulated.

The statement, “Capability is provided to shutdown safely all three units” was intended to be a qualitative assessment that, after a tornado, normal shutdown systems would remain available or alternate systems would be available to allow shutdown of the plant. It was not intended to imply that specific systems should be tornado proof. As part of the original FSAR development, specific accident analyses were not performed to prove this judgment, nor were they requested by the NRC. Subsequent probabilistic studies confirmed that the original qualitative assessments were correct. The risk of not being able to achieve safe shutdown after a tornado was sufficiently small that additional protection was not required.

In an effort to ensure the risk of not being able to achieve safe shutdown after a tornado is maintained sufficiently small, design criteria are applied to the SSF through physical protection and TORMIS to establish its capability to mitigate a tornado. The overall tornado mitigation strategy utilizes the deterministically tornado protected SSF for secondary side decay heat removal (SSDHR) and reactor coolant makeup (RCMU) following a postulated loss of all normal and emergency systems which usually provide these safety functions.

Successful mitigation of a tornado condition at Oconee is defined in UFSAR Section 9.6, SSF. The SSF and its related equipment have been physically protected to meet tornado requirements or have been evaluated using TORMIS.

In addition to the SSF deterministic capability to mitigate a tornado, the inherent plant design of system redundancy, independence, and diversity is maintained for reasonable assurance that sufficient primary and secondary makeup is available following a tornado. Though all features of the inherent plant design are not tornado proof, their collective capabilities result in high availability and reliability to ensure that system functions are not reliant on any single feature of the design. As such, the high availability and reliability provided by the inherent design of the plant which includes redundancy, independence, and diversity ensures defense in depth is maintained if the SSF and related components become unavailable either prior to or during a tornado. The sources of secondary makeup include: 1) the Emergency Feedwater system including the capability to cross connect from another unit, 2) the PSW system, and 3) the SSF ASW system capable of being powered by the SSF diesel. The sources of primary makeup include: 1) the SSF Reactor Coolant Makeup Pump supplied from the Spent Fuel Pool and capable of being powered from the SSF diesel and 2) A High Pressure Injection (HPI) pump supplied from the Borated Water Storage Tank. Note that in addition to their normal and emergency power sources, the “A” and “B” HPI pumps can be powered from the PSW switchgear.

The revised tornado mitigation strategies will be implemented when the SSF letdown line, SSF control room QA-1 instrumentation upgrade, and SSF diesel fuel oil tank fill/vent missile protection conforming modifications are completed.

An external source of cooling water is not immediately required due to the large quantities of water stored underground in the intake and discharge CCW piping. The stored volume of water in the intake and discharge lines below elevation 791 ft would provide sufficient cooling water for all three units for at least 30 days after trip of the three reactors.

3.2.2.1 System Classifications

Plant piping systems, or portions of systems, are classified according to their function in meeting design objectives. The systems are further segregated depending on the nature of the contained fluid. For those systems which normally contain radioactive fluids or gases, the Nuclear Power Piping Code, USAS B31.7 and Power Piping Code USAS, B31.1.0 are used to define material, fabrication, and inspection requirements.

Diagrams for each system are included in the FSAR sections where each system is described.

Fabrication and erection of piping, fittings, and valves are in accordance with the rules for their respective classes. Welds between classes of systems (Class I to II, I to III, or II to III) are performed and inspected in accordance with the rules for the higher class. This preceding sentence does not apply to valves where the class break has been determined to occur at the valve seat, and to pipe with 1" nominal diameter and less.

In-line instrument components such as turbine meters, flow nozzle assemblies, and control valves, etc. are classified with their associated piping unless their penetration area is equal to or less than that of a I inch i.d. pipe of appropriate schedule for the system design temperature and pressure, in which case they are placed in Class III. Definitions of the three classes are listed below:

<u>Class I</u>

This class is limited to the Reactor Coolant System (RCS) and Reactor Coolant Branch lines, as described herein. The Reactor Coolant Branch lines include connecting piping out to and including the first isolation valve. This section of piping is Class I in material, fabrication, erection, and supports and restraints. A Class I analysis of the piping to the first isolation valve has been completed for the following systems:

1. High Pressure Injection (Emergency Injection)
2. High Pressure Injection (Normal Injection)
3. High Pressure Injection (Letdown)
4. Low Pressure Injection (Decay Heat Removal Drop-line)

5. Low Pressure Injection (Core Flood)
6. Reactor Coolant Drain Lines
7. Pressurizer Spray
8. Pressurizer Relief Valve Nozzles

Modifications that affect the Reactor Coolant System and the Class I portion of the branch lines must demonstrate that the impact on the Class I piping is acceptable. The impact may be assessed by performing a Class I analysis or by other conservative techniques to assure Class I allowable limits are not exceeded. Isolation valves can be either stop, relief, or check valves. Piping 1 inch and less is excluded from Class I.

Class II

Class II systems, or portions of systems, are those whose loss or failure could cause a hazard to plant personnel but would represent no hazard to the public. Class II systems normally contain radioactive fluid whose temperature is above 212°F, and in addition, those portions of Engineered Safeguards Systems outside the Reactor Building which may see recirculated reactor building sump water following a LOCA. Piping I inch and less is excluded.

Class III

Class III systems, or portions of systems, are those which would normally be Class II except that the contained fluid is less than 212°F. Valves, piping, instrument fittings and thermowells with a penetration area equal to or less than a 1 inch i.d. pipe or less (all schedules) are placed in Class III regardless of system temperature or pressure, when such equipment is connected to Class I, II, or III systems.

3.2.2.2 System Piping Classifications

System piping is divided into eight classes, depending on the required function of the system or portion of a system. These eight piping classes result from the combination of the preceding system classifications with and without design for seismic loading, as indicated in Table 3-1. Piping classes A through C meet the intent of USAS B31.7 Nuclear Power Piping Code (February 1968) and Addenda (June 1968) with the exception of those portions of the code which lack adequate definition for complete application. The Class I RCS piping was redesigned to the 1983 ASME Code (No Addenda) during the Steam Generator replacement project.

Code Applicability: Due to the numerous code references located throughout this UFSAR, no attempt is made to revise these references as Codes are amended, superseded or substituted. Consequently, the station piping specifications should be relied upon to determine applicable codes. The existing Code references are the basis for design and materials; however, it is Duke Power Company's intent to comply with portions of, or all of, the latest versions of existing Codes unless material and/or design commitments have progressed to a stage of completion such that it is not practical to make a change. When only portions of Code Addenda are utilized, the appropriate engineering review of the entire addenda will be made to assure that the overall intent of the Code is still maintained. Detailed information for each station unit and code applicability with respect to design, material procurement, fabrication techniques, Nondestructive Testing (NDT) requirements and material traceability for each piping system class is described in the station piping specifications.

Table 3-1 applies uniformly to all piping except auxiliary systems in the Reactor Building. Due to schedule commitments, and concern over lack of definitive design guidance in B31.7, it was decided to use B31.1 and applicable nuclear cases in the Reactor Building, but the materials were bought, erected, and inspected to the standards set down in B31.7. The Reactor Coolant System was designed to B31.7, Class I. The Class I portion of the connecting piping to the RCS will have Class I analyses completed by August 31, 1999 (See Section 3.2.2.1). The Class I RCS piping was redesigned to the 1983 ASME Code (No Addenda) during the Steam Generator replacement project.

Oconee has a number of systems that were designed to USAS B31.7 Class II and Class III and to USAS B31.1.0 requirements [Reference Table 3-1]. Piping analyses for these systems include stress range reduction factors to provide conservatism in the design to account for thermal cyclic operations. Thermal fatigue of mechanical systems designed to USAS B31.7 Class II and Class III and to USAS B31.1 is considered to be a time-limited aging analysis because all six of the criteria contained in Section 54.3 of Reference 4 Section 3.12.1 are satisfied.

From the license renewal review, it was determined that the existing analyses of thermal fatigue of these mechanical systems are valid for the period of extended operation.

3.2.2.3 System Valve Classifications

In the absence of definitive codes, the non-destructive testing criteria applied to system valves are consistent with the intent of Par. 1-724 of USAS B31.7 Nuclear Power Piping Code (Feb. 1968) and the piping classification applicable to that portion of the system which includes the valve. On this basis, valves are grouped into the same eight classes as shown for piping in Table 3-1, and a valve is in the same class as the portion of system piping which includes the valve.

Code Applicability: Due to the numerous code references located throughout this UFSAR, no attempt is made to revise these references as Codes are amended, superseded, or substituted. Consequently, the station specifications applicable to a given valve should be relied upon to determine applicable codes.

3.2.2.4 System Component Classification

In the absence of definitive codes, the design criteria applied to pressure retaining system components are generally consistent with the intent of Sections III and VIII of the ASME Boiler and Pressure Vessel Code, the piping system classification applicable to that portion of the system which includes the component, and the required function of the component. Atmospheric water storage tanks important to safety conform to American Waterworks Association Standard for Steel Tanks, Standpipes, Reservoirs and Elevated Tanks for Water Storage, D100, or equivalent.

Components are listed by system in Table 3-2. This tabulation shows the code to which the component was designed, whether the component was designed to withstand the seismic load imposed by the maximum hypothetical earthquake, and the analytical technique employed in seismic analysis.

Code Applicability: Due to the numerous code references located throughout the UFSAR, no attempt is made to revise these references as codes are amended, superseded, or substituted. Consequently, the station specifications applicable to a given component should be relied upon to determine appplicable codes.

3.2.3 Reference

1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3*, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

2. NUREG-1723, Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.
3. License Amendment No. 338, 339, and 339 (date of issuance - June 1, 2004); Adoption of Alternate Source Term.
4. License Amendment No. 386, 388, and 387 (date of issuance - August 13, 2014); Implementation of the Protected Service Water System.
5. License Amendments Nos. 415, 417, and 416 (date of issuance – October 31, 2019); Tornado Mitigation.

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3.3 Wind and Tornado Loadings

All Class 1 structures, except those structures not exposed to wind, are designed to withstand the effects of wind and tornado loadings, without loss of capability of the systems to perform their safety functions.

3.3.1 Wind Loadings

3.3.1.1 Design Wind Velocity

The design wind velocity for all Class 1 structures is 95 mph. This is the largest wind velocity for a 100-year occurrence as shown in Figure 1(b) of Reference 1.

3.3.1.2 Determination of Applied Forces

The applied wind pressures are computed by the means outlined in ASCE Paper 3269 which states that the equivalent static force on a building is equal to the dynamic pressure (q) times the drag coefficient (C_D) multiplied by the elevation area. The dynamic pressure is the product of one-half the air density and the square of the velocity (the kinetic energy per unit volume of moving air). For air at 15° C at 760 mm Hg: $q = 0.002558\ V^2$ with q in psf and V in mph. The drag coefficient is based on test data and tabulated in Reference 1. For these high wind velocities, this equation may be excessively conservative, but no credit is taken for this possible pressure reduction.

3.3.2 Tornado Loadings

All Class 1 structures, except those structures not exposed to wind, are designed for tornado loads.

3.3.2.1 Applicable Design Parameters

Simultaneous external loadings used in the tornado design of Class I structures, with the exception of the Standby Shutdown Facility, are:

a. Differential pressure of 3 psi developed over 5 seconds.

b. External wind forces resulting from a tornado having a velocity of 300 mph.

The spectrum and characteristics of tornado-generated missiles is covered in Section 3.5.1.3.

Tornado loading parameters for the Standby Shutdown Facility are described in Section 9.6.3.1.

Revision 1 to Regulatory Guide 1.76, “Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants,” was released in March 2007. Revision 1 to Regulatory Guide 1.76 was incorporated into the plant’s licensing basis in the 4th quarter of 2007. The design of new systems (and their associated components and/or structures) that are required to resist tornado loadings will conform to the tornado wind, differential pressure, and missile criteria specified in Regulatory Guide 1.76, Revision 1 or be evaluated by TORMIS on Units where the revised tornado mitigation strategies as described in Section 3.2.2 have been implemented.

3.3.2.2 Determination of Forces on Structures

Tornado wind loadings are calculated in accordance with Section 3.3.1.2, using the tornado wind velocities given in Section 3.3.2.1. The tornado loading combination used for design of Class 1 structures is:

$$Y = \frac{1}{\phi}(1.0D + 1.0W_t + 1.0P_i)$$

Where Y, ϕ, and D are as defined in Table 3-14.

W_t	=	Stress induced by design tornado wind velocity (drag, lift and torsion)
P_i	=	Stress due to differential pressure

Shape factors will be applied in accordance with ASCE Paper 3269. No height or gust factors will be used with tornado loadings.

3.3.2.3 Effect of Failure of Structures or Components Not Designed for Tornado Loads

This information is described in Section 3.2.2

3.3.2.4 Wind Loading for Class 2 and 3 Structures

The wind loads are determined from the largest wind velocity for a 100-year occurrence as shown in Figure 1(b) of Reference 1. This is 95 mph at the site.

3.3.3 References

1. *Wind Forces on Structures*, Task Committee on Wind Forces, ASCE Paper No. 3269.
2. Regulatory Guide 1.76, "Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants," Revision 1.
3. License Amendments Nos. 415, 417, and 416 (date of issuance – October 31, 2019); Tornado Mitigation.

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3.4 Water Level (Flood) Design

3.4.1 Flood Protection

3.4.1.1 Flood Protection Measures for Seismic Class 1 Structures

The plant yard elevation is 796.0 ft. msl. All of the man-made dikes and dams forming the Keowee Reservoir rise to an elevation of 815.0 ft. msl with a full pond elevation of 800.0 ft. msl. See Section 2.4.2.2 for exceptions to the elevation of 815.0 ft. However, Class 1 structures and components are not subject to flooding since the Probable Maximum Flood (PMF) would be contained by the Keowee Reservoir. The minimum external access elevation for the Auxiliary, Turbine, and Service Buildings is 796.5 ft. msl which provides a 6 inch water sill. Also, the plant site is provided with a surface water drainage system that protects the plants facilities from local precipitation.

3.4.1.1.1 Current Flood Protection Measures for the Turbine and Auxiliary Buildings

The following information describes internal flood attributes beneficial to the management of flooding, but not required for the design basis flood. Many of these attributes have been considered in the Probabilistic Risk Assessment.

In the current Turbine Building flood handling analysis, it was found that there exists a remote possibility of flooding in the Turbine Building at the basement level due to failure of expansion joints in the Condenser Circulating Water System near the condenser water box inlet or outlet nozzles.

Condenser circulating water intake and discharge pipes are embedded in the Turbine Building substructure mat at points immediately below the inlet or outlet connections on the condenser inlet and outlet water boxes. At each waterbox connection, a 78 inch steel pipe is turned up and projected above the basement level and connected to a butterfly valve. A rubber expansion joint is located between each valve and waterbox connection. The rubber joint spans across a 4¼ inch physical gap in the 78 inch intake pipe and across a 2 inch physical gap in the 78 inch discharge. At maximum flow conditions through any condenser, a complete rupture of the 4¼ inch intake pipe point (all rubber removed) would result in a 235 cfs leak into the Turbine Building basement area. This is the worst case leak condition due to the higher head and wider possible gap situation that exists on the intake side of the condenser.

Each foot of depth in this 202 feet wide by 790 feet long structure contains a volume of 160,000 cubic feet. Therefore, a joint rupture would fill the Turbine Building at the rate of 0.088 feet per minute until the water surface reaches the height of the rupture and a reduced rate thereafter due to reduced differential head conditions, provided all flood water could be contained in the Turbine Building.

Deleted paragraph(s) per 2010 update.

Early licensing correspondences documented that possible Turbine Building floods could be isolated by the operators before safety related equipment was impacted. (See References 6 and 7.) ONS installed curbs and TB sump level alarms to provide operators adequate time to isolate the flood and contain the water in the TB. Subsequently, the Standby Shutdown Facility (SSF) was installed and became the licensed method for mitigating a TB Flood. See Section 9.6

To prevent transmission of flood water from the Turbine Building to the Auxiliary Building, the Turbine/Auxiliary Building wall along column line "N" is capable of withstanding a flood to a depth of 20 ft. above elevation 775 + 0. Six doors originally located on this wall have been made flood barriers. Three of the doors are permanently sealed while the remaining three have been replaced with "submarine type" flood doors. All other penetrations through the wall to elevation 795 + 0 have been sealed.

A Turbine Building Flood Statalarm is provided in the Unit 1 and 2 control room to indicate flood conditions in the Turbine Building basement. This alarm has a 2 out of 4 logic. The emergency procedure is entered immediately upon receipt of a turbine building flood "emergency high" alarm from the detectors mounted at elevation 775 ft. 6 inches (6 inches above the floor). Immediate actions include tripping all three units and stopping all CCW pumps.

A push button in each control room provides capability to close the Condenser Circulating Water (CCW) pump discharge valves to protect against CCW siphoning into the turbine building basement. This flood mitigation station modification has been installed pursuant to the recommendations made in the Oconee Probabilistic Risk Assessment Study.

It is desirable to allow a limited amount of backflow from the CCW discharge through the condensate coolers during a flood to provide suction for Low Pressure Service Water (LPSW) pumps and the Standby Shutdown Facility Auxiliary Service Water (SSF ASW) pump. Temperature control valves 2CCW-84 and 3CCW-84 have had their air supplies disconnected and clamps have been installed on the valves, effectively failing them in the open position (See Figure 9-9). This does not apply to Unit 1 since there are no service water or SSF suction requirements on the Unit 1 system.

The Auxiliary Building could be subject to flooding from a single break in any one of the following non-seismic sources:

- High pressure service water system (source for fire protection),
- Non-seismic portions of the low pressure service water system (the ventilation cooling water),
- Plant drinking water system,
- Non-seismic portions of the Reverse Osmosis System when it is connected to the Unit 1 and 2 spent fuel pool or the Unit 1 or Unit 2 borated water storage tank, and the Supplemental Spent Fuel Pool Cooling System when it is connected to the Unit 1 & 2 spent fuel pool supporting full core off-load evolutions,
- Non-seismic portions of the coolant storage system,
- Demineralized water system and
- Filtered water system.

The high pressure service water Unit 1, 2, and 3 hatch and Unit 1 drumming station sprinkler systems are not considered flood sources based on the results of realistic seismic analyses that demonstrate the pipes and supports will not fail during a seismic event. The remaining portions of the non-seismic high pressure service system, the non-seismic portions of the low pressure service water system, coolant storage system, demineralized water system, filtered water system, and the plant drinking water system are isolated or flow limited to allow operators sufficient time to identify and isolate the source. The Reverse Osmosis System and the Supplemental Spent Fuel Pool Cooling System can be isolated in time to prevent loss of safety-related equipment when aligned to the Unit 1 & 2 spent fuel pool or the Unit 1 or Unit 2 borated water storage tank. Operator actions are directed by abnormal operating procedures. Operator response times were tested to ensure flood mitigation can occur before safety related equipment is adversely affected. Flooding by these sources will be detected through the procedural response to a seismic event or high level alarm sensors (non-seismic) in the auxiliary building sumps.

Several water systems with non-seismic piping in the Auxiliary Building have a limited water volume and cannot flood safety related equipment. Examples include the Component Cooling Water System, Recirculated Water Cooling System, and the Chilled Water Systems.

3.4.1.1.2 Flood Protection Measures Inside Containment

The primary means for detecting leakage in the Reactor Building is the level indication for the normal sump. This indication has a range of 0-to-30 inches, with a statalarm occurring at 8 inches increasing level and a computer alarm at approximately 10 inches. These alarms would alert the operators in the control room such that appropriate actions could be taken. In addition to the alarms, sump level is input to the plant computer and is logged to the alarm log. Level is also recorded on a trend recorder in each control room. Safety related redundant level transmitters with a range of 3 inches to 24 inches are also provided in the normal sump. Both transmitter levels are indicated in the control room on receiver gauges and one train is recorded. Thus, the operators have several methods for monitoring changes in sump level.

The sump fill rate is routinely measured to determine leakage rate. The sump capacity is 15 gallons per inch of height below embedded piping and each graduation on the indicator level indicates 1.5 gallons of leakage into the sump. A 1 gal/min leak would therefore be detectable within less than 10 minutes.

In addition to the normal sump level, indication of the emergency sump level is also provided by redundant safety related systems with a range of 0 to 3 feet. Both trains of instrumentation are indicated on receiver gauges in the control room and one train is recorded. This indication can be used in conjunction with the normal sump level indication to detect abnormal leakage in the Reactor Building. Two additional trains of containment level transmitters are installed in each Reactor Building to provide wide range level indication and recording with a range of 0 to 15 feet.

The normal sump is routinely pumped to the miscellaneous waste holdup tanks whenever the alarm point (8 inches) is reached. Pumping of the sump water is started manually, but terminates automatically when the sump level has dropped to 1 inch (which clears the statalarm). Each time the sump is pumped, it is recorded in the Unit Reactor Operator's Log Book. During pumping, a decreasing sump level indication and/or increasing miscellaneous waste holdup tank level indication can be used to verify flow from the normal sump. The flow rate from the sump can be determined using the rate of change in sump level.

In order to provide periodic monitoring of sump levels, the recording of normal and emergency sump levels is done daily. Daily monitoring of level indications is useful in confirming that level instrumentation are operable, while verifying the sump pumps are operable and maintaining the sump level at or below the alarm point. Calibration of the normal and emergency sump indications is performed during refueling.

In the event of increased leakage to the Reactor Building, sampling may be performed to determine the origin of the leakage (e.g., LPSW, feedwater, component cooling, or RC system).

Leakage from the LPSW system in containment can also be detected by the monitoring of other parameters. For example, the inlet and outlet LPSW flows for each Reactor Building Cooling Unit (RBCU) are monitored for any differences which could be indicative of a cooler leak. If a flow difference is detected, an alarm is provided to the control room. The operator can then promptly isolate the affected cooler by closing remote operated valves.

The Reactor Coolant Pump (RCP) motor parameters are also continuously monitored. A leak in the motor stator winding cooler would be alarmed in the control room. A leak in either of the motor bearing oil coolers could be detected by changing motor temperature in conjunction with increasing sump level. The pump could then be stopped and the cooling water isolated from the control room.

The component cooling system is designed to provide cooling water for various inside containment components. In-leakage of reactor coolant is detected by a radiation monitor and an increase in surge tank level which will be annunciated. Out-leakage from the system will result in a decreasing surge tank level which is annunciated. Volume of the surge tank is 50 ft^3 and allows relatively small volumes of in-leakage or out-leakage to be observed.

3.4.2 References

1. Elevations taken from Figure 2-2 of FSAR and Oconee FSAR 2.2.6.
2. Response to Question of Effects of Failure of Non-Category I Equipment, Oconee FSAR, Supplement 13 of January 29, 1973, Item No. 7347. Information received from Steam Department.
3. Response to Bulletin 80-24 on Cooling Systems Inside Containment, Attachment to Mr. W. O. Parker, Jr.'s letter of January 6, 1981, Item No. 760. Information received from Steam Department.
4. Deleted Per 2001 Update.
5. Deleted Per 2019 Update.
6. Letter from AEC to Duke Energy, dated September 26, 1972, requesting that Oconee evaluate failures similar to Quad Cities expansion joint failure.
7. Letter from Duke Energy to AEC, dated October 24, 1972, responding to the Quad Cities expansion joint failure.

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3.5 Missile Protection

3.5.1 Missile Selection and Description

3.5.1.1 Internally Generated Missiles (Inside Containment)

The major components including reactor vessel, reactor coolant piping, reactor coolant pumps, steam generators, and the pressurizer are located within three shielded cubicles. Each of two cubicles contain one steam generator, two coolant pumps, and associated piping. One of the cubicles also contains the pressurizer. The reactor vessel is located within the third cubicle or primary shield. The reactor vessel head and control rod drives extend into the fuel transfer canal.

Penetrations in the generators, piping, and the pressurizer are located such that missiles which may be generated, such as valves, valve bonnets, valve stems, or reactor coolant temperature sensors will not escape the cubicles or possess sufficient energy to damage the Reactor Building liner plate.

Openings are provided in the lower shield walls to provide vent area. To assure that no missile will impact on the Reactor Building liner plate, concrete shielding is provided for the liner plate area opposite the openings. The shielding extends beyond the openings so that any missile will impact on the shields.

Pipe lines carrying high pressure injection water are routed outside the shield walls entering only when connecting to the loop. Missiles which may be generated in one cubicle cannot rupture high pressure injection lines for the other loop. Low pressure injection lines and core flooding lines are routed outside of the shield walls, behind missile shield walls, and through the primary shield where they enter the reactor vessel. They are, thus, protected from missiles which might be generated in either cubicle.

A concrete missile shield is located above the control rod drives to stop a control rod drive should it become a missile. The shield is removed during refueling.

The reactor cavity annulus seal ring and biological shield plugs are analyzed as potential missiles following a postulated Core Flood Line pipe rupture inside the reactor vessel cavity. The analysis indicates that the seal ring and plugs will not reach a sufficient height to become destructive missiles. Breaks of the RCS inside the reactor vessel cavity are not considered in the missile evaluation due to the successful application of a Leak-Before-Break analysis.

Items that could become missiles are oriented so they impinge on concrete surfaces.

Analysis of the missile penetration is based on the methods described in Nav. Docks P-51, Design of Protective Structures by Amirikan (Bureau of Yards and Docks, August 1950).

The penetration formulae are:

$$D = kApV'$$

where:

$$V' = \log_{10} 1 + \frac{V^2}{215000}$$

$$K = \frac{D^1}{D} = 1 + e^{-4(a^1 - 2)}$$

where:

$$a^1 = \frac{T}{D}$$

where:

D	=	Penetration in a slab of infinite thickness (ft.)
D^1	=	Penetration in a slab of thickness “T” (ft.)
T	=	Thickness of slab (ft.)
Ap	=	Sectional pressure, obtained by dividing the weight of missile by its cross sectional area (psf)
V	=	Velocity of missile (fps)
k	=	Material's coefficient, in our case, $k=2.30 \times 10^{-3}$ for reinforced concrete

Formulae for determining energy loss due to drag:

$$\frac{Ti}{Tc} = \frac{1}{1 + \frac{2Tc}{WL}};$$

$$L = 2\frac{W}{SAC_d}$$

Note: The above equation was revised in 1995 update.

where:

A	=	Average area
C_d	=	Drag coefficient (Cd=1.0 in our case)
Ti	=	Kinetic energy on impact
Tc	=	Kinetic energy after leaving casing
W	=	Weight in lbs.
S	=	Air density = 0.074 $\#/ft^3$

In addition to the penetration calculation, the overall structural strength of the removable concrete slabs, its supports and anchors are analyzed based on the research paper “Impact Effect of Fragments Striking Structural Elements” by R. A. Williamson and R. R. Alvy.

The following three missiles are used to design the removable concrete slabs:

Description	Wt. Lbs.	Imp. Area In^2	Velocity FPS	Kin. Energy Ft-lbs.
C. R. Drive Assembly	1500	64.0	254	1.49×10^6
CRD Vent Cap w/Valve	55	13.4	546	0.12×10^6

Description	Wt. Lbs.	Imp. Area In^2	Velocity FPS	Kin. Energy Ft-lbs.
CRD Motor and Clutch Assem.	750	47.0	483	1.35×10^6

The properties of other missiles postulated by the Nuclear Steam System Supply (NSSS) vendor are given in Table 3-3 to Table 3-9.

Missile protection is provided to comply with the following criteria:

1. The Reactor Building and liner are protected from loss of function due to damage by such missiles as might be generated in a loss-of-coolant accident for break sizes up to and including the double-ended severance of a main coolant pipe.
2. The engineered safeguards system and components required to maintain Reactor Building integrity are protected against loss of function due to damage by the missiles defined below.

During the detailed plant design, the missile protection necessary to meet the above criteria was developed and implemented using the following methods:

1. Components of the Reactor Coolant System are examined to identify and to classify missiles according to size, shape and kinetic energy for purposes of analyzing their effects.
2. Missile velocities are calculated considering both fluid and mechanical driving forces which can act during missile generation.
3. The Reactor Coolant System is surrounded by reinforced concrete and steel structures designed to withstand the forces associated with double-ended rupture of a main coolant pipe and designed to stop missiles.
4. The structural design of the missile shielding takes into account both static and impact loads and is based upon the state of the art of missile penetration data.

The types of missiles for which missile protection is provided are:

1. Valve stems.
2. Valve bonnets.
3. Instrument thimbles.
4. Various types and sizes of nuts and bolts.

Protection is not provided for certain types of missiles for which postulated accidents are considered incredible because of the material characteristics, inspections, quality control during fabrication, and conservative design as applied to the particular component. Included in this category are missiles caused by massive, rapid failure of the reactor vessel, steam generator, pressurizer, main coolant pump casings and drives.

3.5.1.2 Turbine Missiles

The turbine-generator supplier has made a study of failure of rotating elements of steam turbines and generators. The postulated types of failures are: (1) failure of rotating components operating at or near normal operating speed and, (2) failure of components that control admission of steam to the turbine resulting in destructive shaft rotational speed.

3.5.1.2.1 Failure at or Near Operating Speed

All of the known turbine and generator rotor failures at near rated speed resulted from the combination of severe strain concentrations in relatively brittle materials. New alloys and processes have been developed and adopted to minimize the probability of brittle fracture in rotors, wheels, and shafts. Careful control of chemistry and detailed heat treating cycles have greatly improved the mechanical properties of all of these components. Transition temperatures (the temperature at which the character of the fracture in the steel changes from brittle to ductile, often identified as FATT) have been reduced on the low temperature wheel and rotor applications for nuclear units to well below startup temperatures. Improved steel mill practices in vacuum pouring and alloy addition have resulted in forgings which are much more uniform and defect free than ever before. More comprehensive vendor and manufacturer tests involving improved ultrasonic and magnetic particle testing techniques are better able to discover surface and internal defects than in the past. Laboratory investigation has revealed some of the basic relationships between structure strength, material strength, FATT and defect size, and location so that the reliability of the rotor as a structure has been significantly improved over the past few years.

New starting and loading instructions have been developed to reduce the severity of surface and bore thermal stress cycles incurred during service. The new practices include:

1. Better temperature sensors.
2. Better control devices for acceleration and loading.
3. Better guidance for station operators in the control speed, acceleration, and loading rates to minimize rotor stresses.

Progress in design, better materials and quality control, more rigorous acceptance criteria, and improved machine operation have substantially reduced the likelihood of burst failures of turbine-generator rotors operating at or near rated speed.

The brittle fracture failure mode in rotors with shrunk on wheels is due to the initiation and growth of stress corrosion cracks (SCC) to critical size in the exposed wheel keyway surfaces. The replacement low pressure turbine rotors are of monoblock construction (manufactured from a single piece) and do not have shrunk on wheels. Therefore, the formerly dominate inside-out SSC brittle fracture failure mechanism is eliminated for these design type rotors.

3.5.1.2.2 Failure at Destructive Shaft Rotational Speeds

Improvements of rotor quality discussed above, while reducing the chance of failures at operating speed, tend to increase the hazard level associated with unlimited overspeed because of higher bursting speed. Therefore, turbine overspeed protection systems have been evaluated as follows:

1. Main and secondary steam inlets have the following valves in series:
    a. Control valves - controlled by the speed governor and tripped closed by emergency governor and backup overspeed trip, thus providing three levels of control redundancy.
    b. Stop valves or trip throttle valve - actuated by the emergency governor and backup overspeed trip, thus providing two levels of control redundancy.

    Since 1948 there have been over 650 turbines, of over 10,000 kw each, placed in service by the Oconee turbine supplier with no report of main stop valves failing to close when required to protect the turbine. Impending sticking has been disclosed by means of the fully closed test feature so that a planned shutdown could be made to make the necessary correction. This almost always involves the removal of the oxide layer which builds up on the stem and bushing and which would not occur on a low temperature nuclear application.

c. Combined stop and intercept valves in cross around systems - these are actuated by the speed governor, emergency, and backup overspeed trips. These valves also include the testing features described above.

The speed sensing devices for the governor and emergency governor are separate from each other, thus providing two independent lines of defense.

2. Uncontrolled Extraction Lines to Feedwater Heaters

If the energy stored in an uncontrolled extraction line is sufficient to cause a dangerous overspeed, two positive closing nonreturn valves are provided, to be actuated by the emergency governor and backup overspeed trip. These are designed for remote manual periodic tests to assure proper operation. The station piping, heater, and check valve system are reviewed during the design stages to make sure the entrained steam cannot overspeed the unit beyond safe limits.

Special field tests are made of new components to obtain design information and to confirm proper operation. These include the capability of controls to prevent excessive overspeed on loss of load.

Careful analysis of all past failures has led to design, inspection, and testing procedures to substantially eliminate destructive overspeed as a possible cause of failure in modern design units.

The study of postulated ruptures made by the turbine-generator supplier concludes that the missile having the highest combination of weight, size, and energy is the last stage wheel for both shrunk on wheel and monoblock rotor designs. The properties of this missile are summarized in Table 3-10. Initial velocities and energies shown in the table are based on 180 percent overspeed. As the missile penetrates the casing, 50 percent of the initial energy is considered absorbed in the casing.

Analysis of the above missile is based on calculations using methods presented in Reference 1 to determine the depth to which this missile would penetrate the concrete Reactor Building. Conservatively, no reduction of missile energy is made for penetration of the Turbine Building and/or impact with intervening equipment and structural components after leaving turbine shell. The energy loss from 23.25 x 10^6 ft-lbs to 18.0 x 10^6 ft-lbs is caused by air friction. This effect has been calculated by using a drag coefficient of 1.0. Since the offset between the Turbine and Reactor Buildings is relatively short, about 170 feet, no account has been taken for air friction losses for the case in which the missile is ejected nearly horizontally to strike the cylinder wall. Following are results of analysis:

Case I:

“Side on” impact. Missile could penetrate the concrete cylinder wall to a depth of approximately 6 inches and the dome to a depth of approximately 5½ inches. The tendons will not be damaged since they are protected to a depth of 7 3/4 inches in the cylinder wall and 8 inches in the dome.

Case II:

“End on” impact. In this case the missile could penetrate the concrete cylinder wall to a depth of approximately 13 3/4 inches and the dome to a depth of approximately 12¼ inches. The tendon arrangement is such that the missile could strike two adjacent tendons in the dome or a maximum of three horizontal and one vertical tendons in the cylinder wall. The local effect on the tendons could be one of either partial deflection or possible severance. However, analysis of the structure indicates that the structure can withstand the loss of three horizontal and three vertical tendons in the cylinder wall or five adjacent tendons in the dome without loss of function and a greater number of tendons without building failure.

Case III:

As a final analysis, an extreme case is considered in which none of the initial kinetic energy of the missile is absorbed by its penetration through the turbine casing. The total initial energy of 46.5×10^6 ft-lbs is available for penetration of the cylinder wall and 29.3×10^6 ft-lbs for penetration of dome where the reduction is due to air friction only. The maximum depth of penetration of cylinder wall is 35½ inches and the dome is 25 inches. The missile can strike five tendons in the dome or three horizontal and one vertical tendons in the cylinder wall. The local effect in the impact area would be as described in Case II above even though the depth of penetration is greater.

Depths of penetration of Reactor Building wall are summarized in Table 3-11.

Since the thicknesses of the cylinder wall and dome are 45 inches and 39 inches respectively, it can be seen that the turbine missile, even under extreme assumptions, does not penetrate the Reactor Building.

3.5.1.2.3 Application of Turbine Missile Design to Engineered Safeguards Systems

Low Trajectory Turbine Missiles

1. If the engineered safety feature is located outside of the missile strike zone as defined in Reg. Guide 1.115 Revision 1, no additional protection is required.
2. If the engineered safety feature is located within the missile strike zone, evaluate the probability of the engineered safety feature being struck and damaged by an equipment failure per Regulatory Guide 1.115 Revision 1, "Protection against Low-Trajectory Turbine Missiles", and NUREG 0800, Revision 2, "Standard Review Plan", Section 3.5.1.3. Should the probability of that particular engineered safety feature being struck and damaged be less than that specified, no protection would be required or provided.
3. Should the probability of the engineered safety feature being struck and damaged be greater than that specified, protection would be provided in the form of physical separation or shielding. A minimum of seven feet of separation, as viewed from the missile generation point on the turbine, constitutes adequate physical separation for low trajectory turbine missiles.

High Trajectory Turbine Missiles

High trajectory turbine missiles are characterized by their nearly vertical trajectories. Missiles ejected more than a few degrees from the vertical, either have sufficient speed such that they land offsite, or their speeds are low enough so that their impact on most plant structures is not a significant hazard.

1. The probability of a high trajectory turbine missile landing within a few hundred feet from the turbine is on the order of 10^{-7} per square foot of horizontal surface area. Consequently the risk from high trajectory turbine missiles is insignificant unless the vulnerable target area is on the order of 10^4 square feet or more.
2. Should the probability of the engineered safety feature being struck and damaged be greater than that specified, protection would be provided in the form of physical separation

or shielding. A minimum of seven feet of separation, as shown in the plan view, constitutes adequate physical separation for high trajectory turbine missiles.

3.5.1.3 Missiles Generated by Natural Phenomena

For an analysis of missiles created by a tornado having maximum wind speeds of 300 mph, two missiles are considered. One is a missile equivalent to a 12 foot long piece of wood 8 inches in diameter traveling end on at a speed of 250 mph. The second is a 2000 pound automobile with a minimum impact area of 20 square feet traveling at a speed of 100 mph.

For the wood missile, calculations based on energy principle indicate that because the impact pressure exceeds the ultimate compressive strength of wood by a factor of about four, the wood would crush due to impact. However, this could cause a secondary source of missiles if the impact force is sufficiently large to cause spalling of the free (inside) face. The compressive shock wave which propagates inward from the impact area generates a tensile pulse, if it is large enough, will cause spalling of concrete as it moves back from the free (inside) surface. This spalled piece moves off with some velocity due to energy trapped in the material. Successive pieces will spall until a plane is reached where the tensile pulse becomes smaller than the tensile strength of concrete. From the effects of impact of the 8 inch diameter by 12 foot long wood missile, this plane in a conventionally reinforced concrete section would be located approximately 3 inches from the free (inside) surface. However, since the Reactor Building is prestressed, there will be residual compression in the free face, as the tensile pulse moves out and spalling will not occur. Calculations indicate that in the impact area a 2 inch or 3 inch deep crushing of concrete should be expected due to excessive bearing stress due to impact.

For the automobile missile, using the same methods as in the turbine failure analysis, the calculated depth of penetration is ¼ inch and for all practical purposes the effect of impact on the Reactor Building is negligible.

From the above, it can be seen that the tornado generated missiles neither penetrate the Reactor Building wall nor endanger the structural integrity of the Reactor Building or any components of the Reactor Coolant System.

Additional tornado missile requirements were subsequently imposed by NRC post-TMI on Emergency Feedwater Systems. ONS met these requirements based upon the probability of failure of the EFW and station ASW Systems combined with the protection against tornado missiles afforded the SSF ASW System. Subsequently, PSW replaced station ASW relative to this function. See UFSAR Sections 3.2.2 and 10.4.7.3.6 for additional information.

Revision 1 to Regulatory Guide 1.76, “Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants,” was released in March 2007. Revision 1 to Regulatory Guide 1.76 was incorporated into the plant’s licensing basis in the 4th quarter of 2007. The design of new systems (and their associated components and/or structures) that are required to resist tornado loadings will conform to the tornado wind, differential pressure, and missile criteria specified in Regulatory Guide 1.76, Revision 1 or be evaluated by TORMIS on Units where the revised tornado mitigation strategies as described in Section 3.2.2 have been implemented.

3.5.1.3.1 TORMIS Methodology

The following is applicable on Units where the revised tornado mitigation strategies as described in Section 3.2.2 have been implemented.

The TORMIS methodology provides an approach to demonstrate adequate protection for existing SSCs that were originally required to be protected from tornado missiles in accordance with the plant design basis but that are not adequately protected due to some oversight. The approved methodology does not allow TORMIS analysis to be used to temporarily or permanently eliminate existing barriers that are credited for providing tornado missile protection.

The TORMIS acceptance criteria are based on the cumulative damage frequency of tornado missile damage to all safety-related SSCs that are not provided positive protection. Therefore, the impacts of all non-conforming items are combined so that the total missile damage frequency is evaluated against the acceptance criterion of 1E-06 per year. If additional new non-conforming SSCs are identified in the future, TORMIS analysis may be used to evaluate these specific plant features and combine their damage impacts with the impacts of SSCs that were previously analyzed using the TORMIS methodology to determine if adequate protection is maintained.

The TORMIS computer code is used to determine the frequency of a damaging tornado missile strike on unprotected plant SSCs that are used to mitigate a tornado. The TORMIS code is an updated version of the original TORMIS code developed for the Electric Power Research Institute (EPRI). The methodologies used in the code to evaluate the frequency of damaging tornado missile strikes are documented in References 9, 10, 11, and 12.

The TORMIS code accounts for the frequency and severity of tornadoes that could strike the plant site, performs aerodynamic calculations to predict the transport of potential missiles around the site, and assesses the annual frequency of these missiles striking and damaging structures and other targets of interest.

The analysis requires the development of input data in three broad areas:

1. Development of site tornado hazard information.
2. Development of site missile characteristics.
3. Development of target size, location, and physical properties.

<u>TORMIS Model Inputs</u>

The TORMIS methodology seeks to demonstrate that the annual probability of a radioactive release in excess of 10 CFR 100 resulting from tornado missile damage to unprotected SSCs used to mitigate a tornado is less than the acceptance criterion of 1E-06/rx-yr [reactor-year]. This means that the unprotected SSCs are evaluated collectively against the acceptance criterion rather than individually. For a multi-unit site such as Oconee, this criterion is applied to each unit individually.

For this evaluation, the prevention of a “release in excess of 10 CFR 100” is accomplished by establishing SSD conditions following a tornado strike and maintaining these conditions for up to 72 hours. The following safety functions are required:

- Secondary Side Decay Heat Removal.
- Reactor Coolant Makeup.
- Reactor Coolant System pressure boundary integrity.

Through a process of plant walkdowns and reviews of plant drawings, calculations, and other information, a detailed list of structures and equipment lacking deterministic protection was developed that meets the scope of the TORMIS safety targets described above.

<u>TORMIS Results</u>

A site specific analysis of vulnerable tornado mitigation equipment (SSCs) has been conducted using the TORMIS analysis methodology. This includes a characterization of the site tornado hazard and potential tornado generated missiles developed in a manner consistent with the requirements of the TORMIS User's Manual and other TORMIS reference materials.

For each Oconee unit, the mean annual frequency of a damaging tornado missile strike resulting in a radiological release in excess of 10 CFR 100 limits was determined to be less than the acceptance criteria of 1E-06 per year. The analysis was performed in a manner consistent with the requirements of the EPRI topical reports and with the requirements set forth in the NRC's SER (Reference 14) and Regulatory Issue Summary 2008-14 (Reference 15).

3.5.2 Barrier Design Procedures

The Reactor Building and Engineered Safeguards Systems components are protected by barriers from all credible missiles which might be generated from the primary system. Local yielding or erosion of barriers is permissible due to jet or missile impact provided there is no general failure.

The final design of missile barrier and equipment support structures inside the Reactor Building is reviewed to assure that they can withstand applicable pressure loads, jet forces, pipe reactions and earthquake loads without loss of function. The deflections or deformations of structures and supports are checked to assure that the functions of the Reactor Building and engineered safeguards equipment are not impaired. Missile barriers are designed on the basis of absorbing energy by plastic yielding.

3.5.3 References

1. Amirikian, A., Design of Protective Structures, Bureau of Yards and Docks, Department of the Navy, *NAVDOCKS P-51*, 1950.
2. Alvy, R. R., and Willimson, R. A., "Impact Effect of Fragments Striking Structural Elements."
3. Regulatory Guide 1.115, Revision 1, "Protection Against Low-Trajectory Turbine Missiles, dated July 1977.
4. Internal Duke Memorandum from Robert E. Miller to P.N. Hall et al, titled "Turbine Missile Properties", dated June 3, 1970.
5. NUREG 0800, Revision 2, "Standard Review Plan", Section 3.5.1.3, dated July 1981.
6. Letter from D. W. Montgomery (B&W) to W. H. Owen (Duke) regarding Potential Reactor Building Missiles, dated November 14, 1967.
7. Calculation BWC-006K-B932 (OSC-8433), Weight, Impact Area and Velocity, and Kinetic Energy of ROTSG Missiles, May 20, 2004, Rev.0.
8. Regulatory Guide 1.76, “Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants,” Revision 1.
9. Electric Power Research Institute Report – EPRI NP-768 and NP-769, “Tornado Missile Risk Analysis,” dated May 1978.
10. Electric Power Research Institute Report – EPRI NP-2005 Volumes 1 and 2, “Tornado Missile Risk Evaluation Methodology,” dated August 1981.
11. Applied Research Associates, Inc., Project 5313, “TORMIS95 User's Manual: Tornado Missile Risk Methodology,” dated December 1995.
12. License Amendments Nos. 415, 417, and 416 (date of issuance – October 31, 2019); Tornado Mitigation.

13. Regulatory Issue Summary 2015-06, “Tornado Missile Protection,” dated June 10, 2015.

14. Rubenstein, L.S. “Safety Evaluation Report – Electric Power Research Institute (EPRI) Topical Reports Concerning Tornado Missile Probabilistic Risk Assessment (PRA) Methodology,” U.S. Nuclear Regulatory Commission letter to F. J. Miraglia, dated October 26, 1983.

15. Regulatory Issue Summary 2008-14, “Use of TORMIS Computer Code for Assessment of Tornado Missile Protection,” dated June 16, 2008.

16. OM 200-203.001, “I/B – (Viewable) Steam Turbine – Low Pressure Turbine (LPT) Monoblock Rotor Manual”

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3.6 Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping

For units with the HELB Mitigation Strategy (Reference 16) implemented, Main Steam High Energy Line Breaks (MS HELBs) are not synonymous with Main Steam Line Breaks (MSLBs). The analyses and the treatment of MSLBs as described in UFSAR Chapter 15 were required as part of the initial licensing of the Oconee Nuclear Station (ONS) units. The analyses were completed to evaluate the reactor core response to the resulting overcooling following the MSLB. The postulated break locations for the MSLB analyses described in Chapter 15 were not specified, and as such, damage from the MSLB was not considered. The Giambusso/Schwencer letters (References 9 and 15) were released as construction of Unit 1 was nearing completion. These letters required that licensees consider damage following a postulated break, including those postulated in the MS system. These breaks were considered for different purposes using different assumptions and acceptance criteria. In cases where the potential damage postulated for a MS HELB was similar to the inputs and assumptions used in the MSLB analyses described in UFSAR Sections 15.13 and 15.17, those analyses were used as surrogates for the MS HELB analyses. In a similar manner, a Main Feedwater (MFDW) HELB is not synonymous with a Main Feedwater Line Break (MFLB). The analyses for a MFLB as discussed in UFSAR Section 10.4.7 were completed to evaluate the reactor core response to the overheating caused by the MFLB. The postulated break locations of the MFLBs described in Chapter 10 were not specified and damage from the MFLBs was not considered. However, for MFDW HELBs, the Giambusso/Schwencer letters required evaluation of specific locations and the potential damage.

3.6.1 Postulated Piping Failures in Fluid Systems Inside Containment

3.6.1.1 Design Bases

The basic design criteria for pipe whip protection is as follows:

1. All penetrations are designed to maintain containment integrity for any loss of coolant accident combination of containment pressures and temperatures.
2. All penetrations are designed to withstand line rupture forces and moments generated by their own rupture as based on their respective design pressures and temperatures.
3. All primary penetrations, and all secondary penetrations that would be damaged by a primary break, are designed to maintain containment integrity.
4. All secondary lines whose break could damage a primary line and also breach containment are designed to maintain containment integrity.

Pipe whip restraints, jet impingement shields and other protective devices do not have to be installed to protect against an instantaneous double ended rupture of a large RCS pipe based on LBB analyses and technology. Per References 4 and 5, the NRC has approved the use of the LBB approach to eliminate the need to protect against the dynamic effects of large bore pipe breaks, as established in previous topical report submittals in References 6, 7, and 8.

3.6.1.2 Description

The major components including reactor vessel, reactor coolant piping, reactor coolant pumps, steam generators, and the pressurizer are located within three shielded cubicles. Each of two cubicles contain one steam generator, two coolant pumps, and associated piping. One of the cubicles also contains the pressurizer. The reactor vessel is located within the third cubicle or primary shield. The reactor vessel head and control rod drives extend into the fuel transfer canal.

Openings are provided in the lower shield walls to provide vent area. Pipe lines carrying high pressure injection water are routed outside the shield walls entering only when connecting to the loop.

3.6.1.2.1 Core Flood/Low Pressure Injection System

After implementation of the passive Low Pressure Injection (LPI) cross connect modification on each Oconee Unit, the pipe rupture design basis of Core Flood (CF) / LPI system inside containment is based on the system function during full power operations. The CF section (defined as the “A” and “B” train piping downstream of LP-176 and LP-177 respectively) qualifies as high energy during full power operations. For this CF piping, up to but not including the CF / Reactor Vessel nozzles, Leak Before Break technology was employed to eliminate the dynamic effects associated with postulated breaks (Refer to Section 5.2.1.9). For the LPI section of the system (defined as the “A” and “B” train piping upstream of LP-176 and LP-177 to their respective Reactor Building penetrations, and including the cross connect piping between the “A” and “B” trains), USNRC Standard Review Plan Section 3.6.2 Branch Technical Position MEB 3-1 (Reference 3) was used for treatment of postulated pipe ruptures.

3.6.1.3 Protected Service Water (PSW) System

For units without the HELB Mitigation Strategy (Reference 16) implemented, the PSW System is designed as a standby system for use under emergency conditions. With the exception of testing of the system, the system is not normally pressurized. Testing of the system is infrequent, typically every quarter. In addition, the duration of the test configuration is short, compared to the total plant (unit) operating time. Due to the combination of the infrequent testing and the short duration of the test, pipe ruptures are not postulated or evaluated for the PSW System.

3.6.1.4 Safety Evaluation

Note: Section 3.6.1.4 applies to units without the HELB Mitigation Strategy (Reference 16) implemented.

The analysis of effects resulting from postulated piping breaks outside containment is contained in Duke Power MDS Report No. OS-73.2, dated April 25, 1973 including revisions through supplement 2.

An evaluation of potential non-safety grade control system interactions during design basis high energy line break accidents is contained in the Duke Power/Babcock and Wilcox Report dated October 5, 1979.

An exception to report OS-73.2, extending the time allowed to align HPI after certain secondary piping breaks from 30 minutes to 1 hour, has been evaluated as acceptable.

The Reverse Osmosis Unit was added after MDS Report No. OS-73.2 was completed. It contains high energy piping that has been evaluated to have acceptable results.

3.6.2 Postulated Piping Failures in Fluid Systems Outside Containment

Note: Section 3.6.2 applies to units with the HELB Mitigation Strategy (Reference 16) implemented.

The purpose of this description is to provide a comprehensive strategy for mitigating the potential adverse interactions caused by the ONS postulated HELBs. The strategy provides an evaluation of the ONS postulated HELBs and describes the (as modified) ONS configuration for the identified HELBs. It also supersedes the analysis provided in the original 1973 ONS HELB analysis (References 1 and 9). The strategy identifies and describes the pathway to a safe shutdown (SSD) condition for any postulated HELB in any unit. HELBs are only postulated to occur during the normal operating configuration of the system with the unit operating at 100% rated thermal power level (full power).

The revised HELB mitigation strategies will be implemented when the following conforming actions are completed: installation of a new standby shutdown facility (SSF) letdown line, installation/upgrade of SSF control room QA-1 instrumentation, upgrade of inlet isolation valves to the Unit 1 letdown coolers, upgrade to the heating, ventilation, and air conditioning ducting impacting the control complex, upgrade of turbine building (TB) structural support columns, upgrade of suction valves to the Unit 2A & 2B High Pressure Injection (HPI) pumps, elimination of the Control Rod Drive (CRD) cross connect between units, environmentally qualify SSF related components located in each Unit's auxiliary building (AB), provide HELB protected isolation for Alternate Reactor Building Cooling (RBC) System return piping alignment, and Time Critical Operator Actions (TCA) validation.

3.6.2.1 Identification of High Energy Lines

The following criteria are used to identify the high energy piping and the boundaries of the high energy portions of the systems:

- The high energy (piping) lines are those lines that during initial operating conditions, the fluid inside of the pipe has either or both of the following conditions:
  1. A normal operating temperature greater than 200°F.
  2. A normal operating pressure greater than 275 psig.
- The high energy section of any piping run shall extend from component to component. The high energy portion shall not terminate unless there is a termination at a vessel, a pump, a closed valve, or equivalent boundary.
- Piping downstream of a normally closed valve, that is the high energy boundary for a high energy piping run, is not postulated to be high energy due to potential leakage across the closed valve.
- High energy line boundaries are based upon the normal operating configuration of the system with the unit at 100% rated thermal power level (full power).
- Gas Systems (e.g. Nitrogen) and oil systems (e.g. Electro Hydraulic Control) are not identified as high energy systems because those systems possess limited energy.

3.6.2.2 Identification of High Energy Line Break Locations

The following criteria are used to identify the high energy piping break locations:

- HELBs of any type are not postulated on high energy piping that has a nominal size of (1) inch or less.
- HELBs and critical cracks are not postulated on high energy lines that operate at high energy conditions less than approximately 2% of the total system operating time.

- HELBs and critical cracks are not postulated on high energy lines that operate at high energy conditions less than 1% of the total plant (unit) operating time (Normal Plant Conditions).
- HELBs are postulated at the Terminal Ends of high energy piping runs.
- There is no American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section III, Division 1-Class 1 equivalent piping outside of the containment building.
- For ASME B&PV, Section III-Class 2 and Class 3 equivalent piping that is seismically analyzed, HELBs are postulated at axial locations, where the calculated longitudinal stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceeds $0.8(S_a + S_h)$.
- For ASME B&PV, Section III-Class 2 and Class 3 equivalent piping that is seismically analyzed, critical cracks are postulated at axial locations where the calculated stress for the applicable load cases exceed $0.4(S_a + S_h)$. Applicable load cases include internal pressure, dead weight (gravity), thermal, and seismic (OBE). Critical cracks are not postulated at locations of terminal end or intermediate breaks.
- For branch connections where the branch line is included in the seismic stress analysis of the piping run, the stress criteria for seismically analyzed piping lines is used to determine HELBs.
- Breaks and critical cracks at closed valves are postulated as follows. The postulation of terminal end breaks at the first normally closed valve(s) separating portions of a system maintained pressurized during normal operations and portions of a system not maintained pressurized depends on whether the system has a seismic analysis that is continuous across the valve. For systems or portions of systems that are not seismically analyzed, breaks are postulated to occur at all piping girth welds in the system including those that attach to normally closed valves. For systems or portions of systems that are seismically analyzed, and the analysis is continuous across the normally closed valve, such that stresses can be accurately determined, break and crack locations are determined based on comparison to the intermediate break and crack stress thresholds.
- For piping that is not rigorously analyzed or does not include seismic loadings, HELBs are postulated at intermediate break locations as provided in BTP MEB 3-1, Section B.1.c.(2)(b)(i).
- For branches where both the main and branch runs are unanalyzed or where the stress at the branch connection is not accurately known, break locations are postulated on the branch and run sides of the connection.
- For piping that is not rigorously analyzed or does not included seismic loadings, critical cracks are not postulated since the effects of postulated HELBs on these piping runs will bound the effects from critical cracks.
- Actual stresses used for comparison to the break and crack thresholds are calculated in accordance with the ONS piping code of record, USAS B31.1.0 (1967 Edition). Allowable stress values S_a and S_h are determined in accordance with USAS B31.1.0 or or the USAS B31.7 (February 1968 draft edition with errata) code as appropriate.
- Moderate energy line breaks are not postulated. The HELB requirements for ONS only require compliance to the Giambusso/Schwencer letters. The requirements contained therein do not include postulation of moderate energy line breaks.

- High Energy Piping lines with an internal pressure at atmospheric or below (≤ 0 psig) are excluded from damage assessments due to insufficient energy to create pipe whip or jet impingement forces.
- For the MS penetrations into the containment structure, MS HELBs are postulated to occur at the outside face of the concrete containment structure.
- For the MFDW penetrations into the containment structure, MFDW HELBs are postulated to occur on the outside of the containment structure side of the Main Feedwater terminal/rupture/guard pipe restraint.
- For all other ASME B&PV, Section III-Class 2 equivalent piping penetrations into the containment structure, HELBs are postulated to occur at the outside face of the concrete containment structure.

3.6.2.3 Identification of High Energy Break Types

The following criteria are used to identify the high energy break types, required to be postulated at the identified break location in ONS. There are three (3) types of HELBs at ONS. They are circumferential breaks, longitudinal breaks, and critical cracks. The criteria for each break type are as follows:

- Circumferential Breaks are postulated in high energy lines that exceed one (1) inch nominal pipe size.
- Only circumferential breaks are postulated at terminal ends of high energy piping runs. (Longitudinal breaks are not postulated at terminal ends).
- Longitudinal breaks are postulated in high energy lines that have a nominal pipe size of four (4) inches or greater.
- Circumferential and longitudinal breaks are not postulated to occur concurrently.
- Longitudinal breaks are not postulated at branch connections.
- Longitudinal breaks are postulated only at intermediate break locations.
- Longitudinal breaks are postulated parallel to the pipe axis and orientated at all points on the pipe circumference.
- The break area of a longitudinal break is equal to the effective cross-sectional flow area of the pipe immediately upstream of the break location.
- Critical Cracks are postulated on seismically analyzed high energy piping that exceeds one (1) inch in nominal pipe size.

3.6.2.4 Shutdown Sequence Evaluation Criteria

The following criteria are used to identify the systems and components necessary for HELB mitigation and/or unit shutdown to the cold shutdown condition:

- Equipment used to mitigate postulated HELBs includes those systems and components that are used for detection and isolation of specified HELBs. Equipment that is used for the detection and isolation for an identified HELB is the only detection and isolation equipment required to be targets of that specific HELB.
- Equipment used to meet any of the following shutdown objectives are considered a target of postulated HELBs:

  - Reactivity Control
  - RCS Inventory Control
  - RCS Pressure Control
  - RCS Heat Removal Control
  - Reactor Building (Boundary) Integrity
  - Control Room Habitability (long term)
  - Plant Cooldown

- Both primary and back-up systems, used to achieve the shutdown objectives described above, are included as shutdown equipment and targets of the postulated HELBs.
- Piping, orifices, relief valves, and check valves, are considered passive type components in that they do not require an external power source or manual action to perform their intended function, and these components perform their intended function regardless of the environmental conditions. These components are not identified as required in the shutdown sequence, because they are not subject to single active failures (SAFs). They are, however, HELB targets.
- A SAF is postulated in systems used to mitigate the consequences of the postulated HELBs and Critical Cracks or those systems used to achieve a shutdown objective of the unit. The single active component failure is assumed to occur in addition to those components damaged by the postulated pipe break.
- No SAFs are postulated during the “Plant Cooldown” phase and the “Plant Cooldown to the Cold Shutdown Condition” phase.
- All available systems, including those actuated by operator actions, may be employed to mitigate the consequences of a postulated HELB or critical crack.
- In determining the systems and components available to mitigate the consequences of postulated HELBs, all Shutdown Equipment is assumed to be operable and available at the start of the postulated HELB sequence. It is not necessary to postulate that any systems or components are out of service for maintenance.
- Although a postulated HELB outside of the containment building may ultimately require a cold shutdown, holding at hot standby/shutdown is allowed in order that plant personnel assess the situation and make any necessary repairs to allow the unit to reach cold shutdown.

3.6.2.5 Interaction Evaluation Criteria

The following criteria are used to determine the interactions that occur as a result of postulated HELBs with shutdown equipment and the criteria for determining the pathway to cold shutdown for a given postulated HELB:

- The targets of the postulated HELBs are those systems and components required to mitigate the consequences of postulated HELBs and/or are used during the shutdown sequence to safely bring the unit to the cold shutdown condition.
- SSD, Cold Shutdown, and HELB mitigation systems and components directly impacted by a specific postulated HELB are considered to be unavailable to support the Shutdown Objectives for that specific HELB, unless documented otherwise.

- Movement of a ruptured high energy pipe (i.e. pipe whip) is considered for potential interactions. The pipe whip is assumed to occur in the plane defined by the piping geometry.
- The energy level in whipping pipes may be considered insufficient to rupture an impacted pipe of equal or greater nominal pipe size and equal or heavier wall thickness.
- No secondary pipe breaks are postulated due to jet impingement from the source pipe (pipe with postulated HELB).
- The Jet Impingement Forces, Jet Impingement Cone Geometry, and the Jet Impingement Effective Length are determined in accordance with NUREG/CR-2913, "Two Phase Jet Loads," subject to the pressure and temperature limitations given in the NUREG (i.e. stagnation pressures from 870 psia to 2465 psia, 0 to 126°F sub-cooling, 0 to 75% steam quality). For jets consisting of steam or subcooled liquid water falling outside of the NUREG limitations, the effective length of the jet is 10 pipe diameters (ID). Similarly, jet lengths from Critical Cracks are limited to 5 pipe diameters (ID).
- Thrust loads for evaluating potential interactions between postulated HELBs and the TB structural components are determined in accordance with ANSI 58.2 (Rev. 2).
- Systems and components, whose only function is to support the cooldown of the unit from an RCS temperature of approximately 250°F to the cold shutdown condition, need not be protected from postulated HELBs.
- A "Loss of Offsite Power" (LOOP) is not postulated unless the initiating break directly causes a LOOP.
- HELB interactions with cables result in the affected component(s) failing in the most undesired state or are evaluated for the effects of the interaction. However, the following exceptions apply. If an electric Load Center (LC) or Motor Control Center (MCC) is affected by interactions, the LC or MCC is considered to be de-energized. Components receiving power from this LC or MCC are considered de-energized and unable to function unless alternate power supplies are available. Valves directly powered from an affected MCC fail "as is" regardless of other interactions.
- The Reactor Trip Breakers and the CRD system can be excluded from the list of Shutdown Equipment components and potential HELB targets because the unit trip function can be considered to be completed prior to any potential degradation of the system due to any gradual adverse environmental effects caused by postulated HELBs.

3.6.2.6 Determination of Safe Shutdown Systems

3.6.2.6.1 HELB Mitigation Strategy

The HELB Mitigation Strategy addresses the level of protection provided to systems, structures, and components (SSCs) necessary to reach SSD from the direct effects (pipe whip and jet impingement) and indirect effects (environmental and flooding) of a given HELB outside of the containment building. The major points of the strategy are as follows:

- Required SSCs located in the TB are not impacted by HELBs postulated to occur in the AB or in the yard.
- Required SSCs located in the AB are not impacted by HELBs postulated to occur in the TB.

- SAFs are imposed for those components required for initial mitigation.
- SAFs are not imposed for those components required to initiate a cooldown of the plant.
- HELBs resulting in the loss of plant systems inside the TB needed for SSD are mitigated by the Protected Service Water (PSW) system (see UFSAR Section 9.7).
- Should the PSW system be unavailable, the SSF (see UFSAR Section 9.6) is credited as an alternate means of achieving and maintaining SSD following HELBs that disable plant systems inside the TB.
- HELBs resulting in the loss of plant systems inside the AB needed for SSD are mitigated by normal plant systems or the SSF.
- As applicable, NUREG/CR-2913 is used for the determination of jet impingement effects following HELBs and critical cracks.
- Exclusion of systems whose operating time at high energy conditions is less than 1% of the total unit operating time.
- Exclusion of systems whose operating time at high energy conditions is less than approximately 2% of the total system operating time.
- Elimination of arbitrary intermediate breaks in ASME B&PV Section III-Class 2 and Class 3 equivalent piping. Intermediate breaks are postulated where calculated longitudinal stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceed $0.8(S_a + S_h)$.
- Intermediate breaks in non-rigorously analyzed piping are postulated in accordance with BTP MEB 3-1, Section B.1.c(2)(b)(i).
- Elimination of critical cracks at the most adverse location in ASME B&PV Section III-Class 2 and Class 3 equivalent piping. Critical cracks are postulated at axial locations where the calculated stress for the applicable load cases (internal pressure, dead weight (gravity), thermal, and seismic (OBE) conditions) exceed $0.4(S_a + S_h)$. Critical cracks are not postulated at locations of terminal ends.
- Elimination of critical cracks at the most adverse location in non-rigorously analyzed piping. The effects of the postulated intermediate breaks bound the effects from critical cracks.
- HELBs occurring outside of the TB and AB are mitigated by normal plant systems.

3.6.2.6.2 Shutdown Objectives

HELBs outside of the containment building may or may not result in consequences that require an automatic trip of the reactor and main turbine. The operator may elect to trip the reactor and main turbine for personnel and equipment protection. The objective for each shutdown interval is provided below.

The shutdown sequence is divided into four intervals:

1. Shutdown of the Reactor and Main Turbine

   The objective is to place the reactor in a subcritical state to protect the core. The main turbine must be tripped to prevent excessive RCS cooling. With the exception of the MS supply to the turbine driven emergency feedwater pump (TDEFWP), the tripping of the main turbine also separates the MS lines from one another by closure of the main turbine stop valves.

2. Establishment of stable RCS conditions

   The objective is to balance the heat generation in the RCS with the heat being removed by the Steam Generators (SGs) such that RCS temperatures can be controlled. This is accomplished by maintaining RCS inventory control and establishing RCS pressure control such that coupling with the SGs can be restored or maintained. Secondly, feeding and/or steaming of the SGs are controlled in a manner such that the amount of heat generated by core decay heat and Reactor Coolant Pump (RCP) heat (if still running) is balanced with the heat removal from the SGs. Finally, a source of borated water sufficient to maintain the reactor in a subcritical condition is aligned and used to supply the RCS. Depending on the extent of damage from the HELB and the strategy used for mitigation, stable RCS conditions may be maintained up to 72 hours before plant cooldown would be initiated.

3. Initiation of RCS cooldown to approx. 250°F

   The objective of this phase is to initiate a plant cool-down from the point where RCS conditions are stabilized to LPI entry conditions. The SGs are utilized for plant cooldown from normal post reactor trip conditions to approximately 250°F. Typically, plant cooldown would be via forced circulation using any RCP. If all of the RCPs are unavailable, procedures are provided to initiate a natural circulation cooldown.

4. Establishment of the cold shutdown condition (RCS temperature < 200°F)

   The objective of this phase of post-HELB operations is to transition from decay heat removal using the SGs to removing core decay heat using the LPI system. The LPI system, in conjunction with the low pressure service water system, is utilized to cool the RCS from approximately 250°F to less than 200°F.

3.6.2.6.3 Functions to Meet Safe Shutdown Objectives

This section describes the functions needed to satisfy the shutdown objectives following a postulated HELB outside of the containment building. HELBs outside of the containment building can be divided into three categories: those that result in a loss of heat transfer (loss of SG feedwater), those that result in excessive heat transfer (loss of MS pressure boundary control), and those that result in loss of reactor coolant inventory (letdown line break). Loss of heat transfer scenarios result in a mismatch where more heat is generated in the core than is removed by the secondary system. These scenarios lead to an increase in RCS temperature and pressure. Excessive heat transfer scenarios result in a mismatch where more heat is removed by the secondary system than is generated in the core. These scenarios lead to a decrease in RCS temperature, pressure, and water level (due to reactor coolant shrinkage). Loss of inventory scenarios have a minor effect on the RCS due to the insignificant amount of inventory lost. The systems necessary to reach SSD were selected based on meeting the following Shutdown functions for the categories of HELB:

- Reactivity Control
- RCS Inventory Control
- RCS Pressure Control
- RCS Heat Removal Control
- Reactor Building (Boundary) Integrity

- Control Room Habitability (long term)
- Plant Cooldown
- Process Monitoring
- Support Functions

3.6.3 Safety Evaluation

Note: Section 3.6.3 applies to units with the HELB Mitigation Strategy (Reference 16) implemented.

Normal plant systems, the PSW system, and the SSF are credited for the mitigation of HELBs outside containment. MFDW HELBs result in overheating transients. MS HELBs result in overcooling transients.

The safety analysis acceptance criteria for each HELB transient are as follows:

Overheating Analysis

- The core must remain intact and in a coolable geometry.
- Minimum departure from nucleate boiling ratio (DNBR) meets specified acceptable fuel design limits.
- RCS pressure must not exceed 2750 psig (110% of design).

Overcooling Analysis

In addition to the criteria specified above, the following criteria are applicable (validated) for the most limiting overcooling analyses:

- The SG tubes remain intact.
- RCS remains within acceptable pressure and temperature limits.

The bounding overheating transient is a MFDW HELB in the TB resulting in a loss of all 4160 VAC power to normal plant systems. The bounding overcooling transient is a double MS HELB in the TB resulting in a loss of all 4160 VAC power to normal plant systems.

The PSW system is credited for the mitigation of HELBs inside the TB when a HELB results in the loss of plant systems needed for SSD. The SSF is credited as an alternate means for mitigation of HELBs inside the TB when a HELB results in the loss of plant systems needed for SSD.

3.6.3.1 PSW Response Following a MFDW HELB in the TB

The transient begins with an immediate and complete loss of MFDW from hot full power (HFP) conditions with an initial core power level of 102% of 2568 MW, as well as a loss of the 4160 VAC switchgear. This causes an immediate reactor trip and turbine trip due to the loss of power. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, or 3 minutes after a loss of RCP seal cooling. The motor driven emergency feedwater pumps (MDEFWP) are powered from the 4160 VAC switchgear and are not available. The TDEFWP is assumed to be unavailable.

Since portions of the integrated control system (ICS) are unprotected from HELB damage, the pressurizer power operated relief valve (PORV) is assumed to be unavailable. The combination of high end of cycle decay heat and delayed PSW flow to the SGs causes a large overheating transient in the primary system and a rapid increase in RCS pressure. RCS pressure increases to the pressurizer safety valve (PSV) lift setting, and the PSVs cycle to control RCS pressure until operators establish PSW flow 14 minutes into the event. PSW is assumed to be available at 14 minutes in the overheating analysis to prevent liquid relief through the PSVs. The peak RCS pressure in the overheating analysis is defined by the pressurizer safety relief valve characteristics since the PORV is not available. With an immediate reactor trip, the rate of RCS pressurization is such that maximum pressure occurs during the first PSV lift. The maximum pressure observed remains below the 2750 psig limit. Thus, the peak RCS pressure results obtained are not contingent on the timing of PSW flow.

Successful mitigation of a HELB condition at ONS shall be defined as ensuring that the integrity of the fuel and RCS remains unchallenged. For the overheating analysis the fuel integrity is ensured by the reactivity added via control rod insertion and maintaining the core covered. A minimum DNBR evaluation is not required for this analysis since the transient does not include a return to power and the DNBR at reactor trip is bounded by the existing UFSAR Chapter 15 analyses. RCS integrity is demonstrated by verifying the RCS pressure remains below the 2750 psig limit.

In summary, the results of the analysis demonstrate that PSW is capable of ensuring peak RCS pressure remains below the 2750 psig limit. Additionally, the results demonstrate there is sufficient decay heat removal (DHR) and primary coolant makeup to keep the core covered and maintain the RCS in Mode 3 for the duration of the scenario.

3.6.3.2 SSF Response Following a MFDW HELB in the TB

The transient begins with an immediate and complete loss of MFDW from HFP conditions with an initial core power level of 102% of 2568 MW, as well as a loss of the 4160 VAC switchgear. This causes an immediate reactor trip and turbine trip due to the loss of power. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loff of indicated subcooled margin, or 3 minutes after loss of RCP seal cooling. The MDEFWPs are powered from the 4160 VAC switchgear and are not available due to the loss of power. The TDEFWP is assumed to be unavailable.

Since portions of the ICS are unprotected from HELB damage, the pressurizer PORV is assumed to be unavailable. The combination of high end of cycle decay heat and delayed SSF auxiliary service water (ASW) flow to the SGs cause a large overheating transient in the primary system and a rapid increase in RCS pressure. RCS pressure increases to the PSV lift setting, and the PSVs cycle to control RCS pressure until operators establish SSF ASW flow 14 minutes into the event. The peak RCS pressure in the overheating analysis is defined by the pressurizer safety relief valve characteristics since the PORV is not available. With an immediate reactor trip, the rate of RCS pressurization is such that the maximum pressure occurs during the first PSV lift. The maximum pressure observed remains below the 2750 psig limit. Thus, the peak RCS pressure results obtained are not contingent on the timing of SSF ASW flow.

Successful mitigation of a HELB shall be defined as ensuring that the integrity of the fuel and RCS remains unchallenged. For the overheating analysis the fuel integrity is ensured by the reactivity added via control rod insertion and maintaining the core covered. A minimum DNBR evaluation is not required for this analysis since the transient does not include a return to power and the DNBR at reactor trip is bounded by the existing UFSAR Chapter 15 analyses. RCS integrity is demonstrated by verifying the RCS pressure remains below the 2750 psig limit.

In summary, the results of the analysis demonstrate that the SSF is capable of ensuring peak RCS pressure remains below the 2750 psig limit. Additionally, the results demonstrate there is sufficient DHR and primary coolant makeup to keep the core covered and maintain the RCS in Mode 3 for the duration of the scenario.

3.6.3.3 PSW Response Following a Double MS HELB in the TB

This analysis determines the plant transient response to a double MS HELB mitigated with PSW equipment and without credit for the automatic feedwater isolation system (AFIS). This analysis assumes an initial core power level of 102% of 2568 MW at HFP conditions. The initiating event causes double MS HELB, an immediate loss of 4160 VAC power, a reactor trip, a turbine trip, and a trip of all condensate and MFDW pumps. The RCPs continue to operate until operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, or 3 minutes after a loss of RCP seal cooling. The MDEFWPs are not available due to the loss of 4160 VAC power. To maximize the overcooling, the TDEFWP is assumed to automatically start and run without being throttled until the contents of the upper surge tank (UST) are delivered to the SGs. This scenario is intended to bound the consequences resulting from a double MS HELB.

The primary objective of this analysis is to demonstrate that the minimum DNBR is acceptable and that the plant will achieve a steady state condition where the RCS is in natural circulation flow conditions with PSW providing a heat sink, a PSW powered HPI pump providing seal injection flow, RCS pressure being maintained with the PSW powered pressurizer heaters, and pressurizer level being controlled by operation of the loop high point vents and/or PSW flow. This assures that the core remains intact and in a coolable geometry.

The double MS HELB causes the RCS to depressurize and shrink. As RCS pressure decreases the two CFTs inject additional borated inventory into the RCS. The core remains covered throughout the overcooling transient. The sustained overcooling in the affected loop is not sufficient to result in a return to criticality. The core remains subcritical after the rods insert for the duration of the transient. The core remains covered and cooled for the duration of the transient. The PSW powered HPI pump is started to restore RCP seal cooling and makeup to the RCS. PSW flow is available at 14 minutes, but not delivering flow to the SGs at this time due to the overcooling. The overcooling continues until shortly after the TDEFWP stops feeding the SGs.

After the overcooling has terminated, the RCS begins to slowly reheat and swell, pressurizer level returns on scale, and the PSW powered pressurizer heaters are manually energized. PSW flow is established to the SGs to stabilize RCS temperature and pressurizer level. Saturated conditions are established in the pressurizer and pressurizer heaters are then cycled to maintain RCS pressure stable. Stable subcooled natural circulation conditions are achieved approximately three hours into the transient.

Successful mitigation of a HELB condition at ONS shall be defined as ensuring that the integrity of the fuel and RCS remains unchallenged. For the overcooling analysis the fuel integrity is confirmed by the DNBR analysis.

RCS integrity is demonstrated by determining the limiting SG tube compressive and tensile stresses remain within design limits, and that the RCS pressure and temperature remains within the acceptable cooldown limits during the transient evolution. The time dependent SG tube and SG shell temperatures are determined using a linear average to determine if the temperature differences remain within the SG design limits. The results indicate the SG tube stress remains well within the established limits for the duration of the transient. The cooldown performed through operator control of PSW to below 350°F will provide margin to prevent tube deformation.

This analysis demonstrates that a double MS HELB can be mitigated using PSW equipment. In summary, the overcooling analysis demonstrates that for a double MS HELB scenario, the following acceptance criteria are satisfied:

- The core remains intact and in a coolable geometry,
- Minimum DNBR meets specified acceptable fuel design limits,
- The SG tubes remain intact,
- RCS pressure does not exceed 2750 psig, and
- RCS remains within acceptable pressure and temperature limits.

3.6.3.4 SSF Response Following a Double MS HELB in the TB

This analysis determines the plant transient response to a double MS HELB mitigated with SSF equipment and without credit for AFIS. This analysis assumes an initial core power level of 102% of 2568 MW at HFP conditions. The initiating event causes either a single or double MS HELB, an immediate loss of 4160 VAC power, a reactor trip, a turbine trip, and a trip of all condensate and MFDW pumps. The RCPs continue to operate until operator action is taken to trip them either 2 minutes after a loss of indicated subcooled margin, or 3 minutes after a loss of RCP seal cooling. The MDEFWPs are not available due to the loss of 4160 VAC power. To maximize the overcooling, the TDEFWP is assumed to automatically start and run without being throttled until the contents of the UST are delivered to the SGs. This scenario is intended to bound the consequences resulting from a MS HELB.

The primary objective of this analysis is to demonstrate that the minimum DNBR is acceptable and that the plant will achieve a steady state condition where the RCS is in natural circulation flow conditions with SSF ASW providing a heat sink, SSF reactor coolant makeup (RCMU) flow providing seal injection flow, RCS pressure being maintained with the SSF powered pressurizer heaters, and pressurizer level being controlled by operation of the SSF letdown line and/or SSF ASW. This assures that the core remains intact and in a coolable geometry.

The double MS HELB causes the RCS to depressurize and shrink. As RCS pressure decreases, the two CFTs inject additional borated inventory into the RCS. The core remains covered throughout the overcooling transient. While a brief recriticality is indicated, the resulting fission power obtained is not significant (less than one watt). The SSF RCMU pump is started to restore RCP seal cooling and makeup to the RCS. SSF ASW flow is available at 14 minutes, but not delivering flow to the SGs at this time due to the overcooling. The overcooling continues until shortly after the TDEFWP stops feeding the SGs.

After the overcooling has terminated, the RCS begins to slowly reheat and swell, pressurizer level returns on scale, and the SSF powered pressurizer heaters are manually energized. SSF ASW flow is established to the SGs to stabilize RCS temperature and pressurizer level. Saturated conditions are established in the pressurizer and pressurizer heaters are then cycled to maintain RCS pressure stable. Stable subcooled natural circulation conditions are achieved approximately three hours into the transient.

Successful mitigation of a HELB condition at ONS shall be defined as ensuring that the integrity of the fuel and RCS remains unchallenged. For the overcooling analysis the fuel integrity is demonstrated by the DNBR analysis.

RCS integrity is demonstrated by determining the limiting SG tube compressive and tensile stresses remain within design limits, and that the RCS pressure and temperature remains within the acceptable cooldown limits during the transient evolution. The time dependent SG tube and

SG shell temperatures are determined using a linear average to determine if the temperature differences remain within the SG design limits. The results indicate the SG tube stress remains well within the established limits for the duration of the scenario. The cooldown performed through operator control of SSF ASW to below 350°F will provide margin to prevent tube deformation.

To validate that RCS pressure and temperature remain within limits, these parameters are plotted versus each other to examine the time dependent response. These results indicate significant margin is maintained to the acceptable cooldown limits during the scenario.

This analysis demonstrates that a double MS HELB can be mitigated using SSF equipment. In summary, the overcooling analysis demonstrates that for a double MS HELB scenario, the following acceptance criteria are satisfied:

- The core remains intact and in a coolable geometry,
- Minimum DNBR meets specified acceptable fuel design limits,
- The SG tubes remain intact,
- RCS pressure does not exceed 2750 psig, and
- RCS remains within acceptable pressure and temperature limits.

3.6.4 References

1. Duke Power MDS Report No. OS-73.2, dated April 25, 1973 including revisions through supplement 2.
2. USNRC Standard Review Plan (NUREG 0800) Section 3.6.1 Branch Technical Position ASB 3-1.
3. USNRC Standard Review Plan (NUREG 0800) Section 3.6.2 Branch Technical Position MEB 3-1.
4. NRC Safety Evaluation of B&W Owners Group Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops, dated December 12, 1985.
5. NRC Safety Evaluation Relating To Elimination of Dynamic Effects of Postulated Primary Loop Pipe Ruptures from Design Basis in Regard to TMI-1, dated November 5, 1987.
6. B&W Topical Report BAW-1847, Revision 1, “Leak-Before-Break Evaluation of Margin Against Full Break for RCS Primary Piping of B&W Designed NSS,” September 1985.
7. B&W Topical Report BAW-1889P, “Piping Material Properties for Leak-Before-Break Analysis,” October 1985.
8. B&W Topical Report BAW-1999, “TMI-1 Nuclear Power Plant Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping”, April 1987.
9. Clarification Letter (related to the 15 December 1972 letter), dated 17 January 1973, from A. Schwencer (AEC) to A. C. Thies (DPC).
10. HELB Outside Containment Walkdown Criteria & Requirements, ONS, Units 1, 2, & 3.
11. Calculation OSC-8385 – Normal Operating Conditions for High Energy Line Break (HELB) Analysis (ONS Units 1, 2, & 3).
12. OSS-0254.00-00-4017 – Design Basis Specification for the “Pipe Rupture” – ONS Units 1, 2, & 3.

13. NRC Generic Letter 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements (Rev. 2 of BTP MEB 3-1), June 19, 1987.
14. Duke Energy Calculation, OSC-11769, Analysis of Postulated HELBs Outside of Containment.
15. Letter from A. Giambusso (AEC) to A.C. Thies (Duke Power Company), "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment," dated December 15, 1972.
16. License Amendment No. 421, 423, and 422 (date of issuance – March 15, 2021); HELB Mitigation.
17. Duke Power/B&W Report, Oconee Nuclear Station, "Evaluation of Potentially Adverse Environmental Effects on Non-Safety Grade Control Systems," dated October 5, 1979.

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3.7 Seismic Design

3.7.1 Seismic Input

3.7.1.1 Design Response Spectra

The design response spectra curves for the 0.05g Design Base Earthquake (DBE), the 0.10g Maximum Hypothetical Earthquake (MHE) for Class 1 Structures founded on rock, and the 0.15g Maximum Hypothetical Earthquake (MHE) for structures founded on overburden are given in Figure 2-51, Figure 2-53, Figure 2-55, respectively.

3.7.1.2 Design Time History

The Time History record of the N-S, May 1940 El Centro earthquake is used (vertical and N-S horizontal components).

3.7.1.3 Critical Damping Values

Deleted row(s) per 2004 update.

The following damping values are used for the seismic design of Class 1 structures:

	Percent of Critical Damping		
Item	**OBE**	**SSE**	**LOCA**
Welded carbon and stainless steel assemblies (This includes reactor internals, supports and similar weldments.)	1	1	4
Steel frame structures (Both welded and high strength bolted)	2	2	7
Reinforced concrete equipment supports	2	2	7
Reinforced concrete frames and buildings	5	5	7
Prestressed concrete structures under earthquake forces	2	5	5
Vital piping	0.5	0.5	3

3.7.1.4 Supporting Media for Seismic Class 1 Structures

The supporting media for each seismic Class 1 structure are defined in Section 2.5.

3.7.1.5 Response to Generic Letter 87-02

Generic Letter 87-02, “Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46,” was issued because the NRC concluded that the seismic adequacy of certain equipment in operating plants must be reviewed against seismic criteria developed during the resolution of Unresolved Safety Issue (USI) A-46. The concern was that equipment in nuclear plants with construction permit applications docket before 1972 may not be adequately qualified to ensure its survival and functionality in the event of a safe shutdown earthquake (SSE) because the equipment was not reviewed against current licensing criteria for seismic equalification of equipment (Regulatory Guide 1.100, IEEE 344-

1975, and NUREG-0800). This is a backfit seismic evaluation under 10 CFR.50.109 since the current criteria was not in use when the plants were licensed

The NRC determined that it is not feasible to require older operating plants to meet new licensing requirements that were not in use when plants were licensed. Threfore, an alternative method was selected to verify the seismic capability of equipment. This alternative method used a compilation of existing earthquake experience data supplemented by test data as the basis to verify the seismic capability of equipment. Generic Letter 87-02 allowed the seismic verification to be accomplished by utilities through a generic program, and the Seismic Qualification Utility Group (SQUG) was formed. The SQUG developed a Generic Implementation Procedure (GIP) that documents the seismic verification process, procedures, and methodologies for verifying the seismic qualification of equipment and resolving USI A-46. Supplement 1 of Generic Letter 87-02 (Reference 11) endorsed use of the GIP for the seismic qualification process and contained revised licensee actions.

Oconee performed the seismic qualification process in accordance with the NRC endorsed version of the GIP. In a Safety Evaluation Report (Reference 12), the NRC concluded that Oconee met the purpose and intent of the seismic qualification process and that the corrective actions and modifications provide sufficient basis to close the USI A-46 review at Oconee.

Additional discussions related to Generic Letter 87-02 can be found in seismic qualification discussions in Sections 3.9.2.2, 3.10.1, 3.10.2, 8.3.1.4.6.1, and 10.4.7.1. The seismic verification process is considered part of the seismic licensing basis for Oconee, so the seismic qualification criteria developed by the SQUG in response to Generic Letter 87-02 must be considered during mechanical and electrical equipment modifications

3.7.2 Seismic System Analysis

3.7.2.1 Seismic Analysis Methods

3.7.2.1.1 Reactor Building

Seismic loading of the structure controls in all cases over that of tornado or wind loading. The seismic analysis is conducted in the following manner: The loads on the Reactor Building caused by earthquake are determined by a dynamic analysis of the structure. The dynamic analysis is made on an idealized structure of lumped masses and weightless elastic columns acting as spring restraints. The analysis is performed in two stages: the determination of the natural frequencies of the structure and its mode shapes, and the response of these modes to the earthquake by the spectrum response method.

3.7.2.1.2 Auxiliary Building

In determining the response of the building to the earthquake the spectrum response technique is utilized. For this technique the earthquake is described by spectrum response curves presented in Figure 2-51 and Figure 2-53. From the curves, acceleration levels are determined as associated with the natural frequency and damping value of each mode. The standard spectrum response technique uses these values to determine inertial forces, shears, moments, and displacements per mode. These results are then combined on the basis of the absolute sum to obtain the structural response. The process is accomplished by the Bechtel computer program, CE641.

3.7.2.1.3 Turbine Building

Seismic analysis of Turbine Building is discussed in Section 3.8.5.4.

3.7.2.2 Natural Frequencies and Response Loads

3.7.2.2.1 Reactor Building

The natural frequencies and mode shapes are computed using the matrix equation of motion shown below for a lumped mass system. The form of the equation is:

$$(\mathrm{K})(\Delta) = \omega^2 (\mathrm{M})(\Delta)$$

K = matrix of stiffness coefficients including the combined effects of shear, flexure, rotation, and horizontal translation.

M = matrix of concentrated masses.

Δ = matrix of mode shape

ω = angular frequency of vibration.

The results of this computation are the several values of ω_n and mode shapes Δ_n for n = 1, 2, 3, . . . m, where m is the number or degrees of freedom (i.e., lumped masses) assumed in an idealized structure.

3.7.2.2.2 Auxiliary Building

The natural frequencies and mode shapes of the structure are obtained by the Bechtel computer program, CE617. This program utilizes the flexibility coefficients and lumped weights of the model. The flexibility coefficients are formulated into a matrix and inverted to form a stiffness matrix. The program then uses the technique of diagonalization by successive rotations to obtain the natural frequencies and mode shapes. The results are shown in Figure 3-1.

3.7.2.3 Procedure Used for Modeling

3.7.2.3.1 Reactor Building

The modeling of the Reactor Building is discussed in Section 3.7.2.4.

3.7.2.3.2 Auxiliary Building

The mathematical model of the structure is constructed in terms of lumped masses and stiffness coefficients. At appropriate locations within the building, points are chosen to lump the weights of the structure. Between these locations properties are calculated for moments of inertia, cross sectional areas, effective shear areas, and lengths. A sketch of the model is shown on Figure 3-3. The properties of the model are utilized in the IBM computer program, STRESS, along with unit loads to obtain the flexibility coefficients of the building at the mass locations. In Figure 3-4 are presented the moments, shears, displacements, and accelerations for the model subjected to 0.05 g ground motion and 5 percent damping.

3.7.2.3.3 Turbine Building

This information is outlined in Section 3.8.5.4.

3.7.2.4 Development of Floor Response Spectra

3.7.2.4.1 Reactor Building

The actual structural system is idealized as a mathematical model in form of a lumped mass system interconnected by elastic members. Lumped masses, which are a summation of structure and equipment masses, are located at pertinent floor levels and at other levels where response spectra are desired. These other levels would include equipment support elevations, pipe support elevations, etc.

In the case of the Reactor Building, two mathematical models are generated to describe the complete Reactor Building. The first model represents the Reactor Building shell, and the second model represents the internal structure. Modifications to each model are required to determine response from ground motions. After these models are developed, the following procedure is employed for all the models:

The flexibility matrix of the structural system is determined by using Bechtel program CE309. The procedure for each loading condition is to apply a unit load at each mass point and determine the deflection at all mass points.

The mode shapes and frequencies for the lumped mass systems are obtained by means of either of two Bechtel computer programs; CE548, "Symbolic Matric Interpretive System" or CE617, "Diagonalization Method for Eigenvalues and Eigenvectors".

The Time-History record of the N-S, May 1940 El Centro earthquake is used (vertical and N-S horizontal components). Using the mode shapes and frequencies and the time history (time vs. acceleration record), properly scaled, the time history of the accelerations, velocities and displacements of the lumped masses are obtained. Bechtel program CE611 is utilized for this computation.

The acceleration time-history is applied at the base of a single degree of freedom system. Initially the system is set with specific values for its natural frequency and damping. The time-history response of the mass is determined and examined for the value of maximum acceleration. The same process is repeated over a range of natural frequencies. The resulting maximum G levels and frequencies are tabulated and plotted into the spectrum curve for a single structure elevation. The resulting curve is labeled with the damping value. The process is repeated for required structure elevations and damping values. Bechtel computer program CE591, "Spectral Analysis", is used to obtain the acceleration and velocity response spectra at each floor for each percentage of damping required.

A sample of the acceleration spectrum curves at different floor levels of a building is shown in Figure 3-6. For these curves, the horizontal axis is logarithmic in cycles per second and the vertical axis is linear in G's. The curves are for 1½ percent of critical damping. The building has natural frequencies of 4.8 cps at the first mode and 10 cps at the second mode. Thus maximum accelerations occur between 1.0 cps and 10.0 cps. At the far right end, the curve converges on the peak value of the input earthquake as the single degree of freedom system becomes rigid, relative to the seismic excitation. At progressively higher locations, the building amplifies the input earthquake, especially in the vicinity of its natural frequencies. Note the sharp peak in each curve at the natural frequency of the building.

When using response curves for piping systems which are located at different elevations, it is necessary to superimpose several curves and plot the envelope curve for the system inputs. At the maximum acceleration peak of each specific curve used for the envelope curve, the envelope has a plateau of approximately ±10 percent to avoid the condition where a small change in frequency could result in a significant change in acceleration. Through the ME 601 program, the natural frequency and mode shapes of the pipe are found and combined with the spectrum curves to find the seismic forces on the pipe.

3.7.2.4.2 Auxiliary Building

The spectrum response curves for equipment inside the building are generated by the time history technique of seismic analysis. The sample earthquake utilized is that recorded at El Centro, California, N-S, May 18, 1940. Essentially the curves are generated by applying the recorded earthquake to the structure and obtaining the time history at selected mass points. Each of these time histories is then applied to a single degree of freedom system of which the values for damping and natural frequency are varied. The curves for Units 1 and 2 Auxiliary Buildings are accomplished by the Bechtel program, CE611. The curves for Unit 3 Auxiliary Building are generated by Duke. The spectrum curves were generated for both directions (East-West and North-South). At the high frequency end of the curve, the acceleration levels converge to the value of the location inside the building.

Digital computer program, CE 617, CE 641, CE 611, and CE 591 are proprietary programs of the Bechtel Corporation.

3.7.2.5 Components of Earthquake Motion

Seismic forces are applied in the vertical and in any horizontal direction. The horizontal and vertical components of ground motion are applied simultaneously.

3.7.2.6 Combination of Modal Responses

3.7.2.6.1 Reactor Building

The response of each mode of vibration to the design earthquake computed by the response spectrum technique, as follows:

1. The base shear contribution of the n[th] mode $V_n = W_n S_{an}(\omega_n \Upsilon)$ where:

   W_n = effective weight of the structure in the n[th] mode.

   $$W_n = \frac{\left(\sum_x \Delta_{xn} w_x\right)^2}{\sum_x \left(\Delta_{xn}\right)^2 w_x}$$

   where the subscript x refers to levels throughout the height of the structure, and w_x is the weight of the lumped mass at level x.

   ω_n = angular frequency of the n[th] mode.

   $S_{an}(\omega_n \Upsilon)$ = spectral acceleration of a single degree of freedom system with a damping coefficient of Υ, obtained from the response system.

2. The horizontal load distribution for the n[th] mode is computed as:

   $$F_x = V_n \frac{(\Delta_{xn} w_x)}{\sum_x \Delta_{xn} w_x}$$

   Note: The above equation was revised in 1995 update.

The several mode contributions are then combined to give the final response of the structure to the design earthquake.

3. The number of modes to be considered in the analysis is determined to adequately represent the structure being analyzed. The analytical model and results for the 0.05 g earthquake and 2 percent damping and for the 0.1 g earthquake and 5 percent damping are shown in Figure 3-7.

3.7.2.6.2 Auxiliary Building

For description of combining of modal responses, see Section 3.7.2.1.

3.7.2.7 Method Used to Account for Torsional Effects

Torsional modes are not considered in the seismic analysis. Insignificant torsional shear stresses exist, assuming a minimum of 10 percent eccentricity, based on "Torsion in Symmetrical Buildings," N. M. Newmark.

3.7.2.8 Methods for Seismic Analysis of Dams

The methods for the seismic analysis of dams are defined in Section 2.5.6.5.2.

3.7.2.9 Determination of Seismic Class 1 Structure Overturning Moments

The safety factor against overturning for the Reactor Building due to maximum hypothetical earthquake moment is 3.6.

3.7.2.10 Analysis Procedure for Damping

Damping values for the structural system are selected based upon evaluation of the materials and mode shapes. Appropriate damping values of individual materials are presented in Section 3.7.1.3. Evaluation of the mode shapes makes possible the selection of damping values to be associated with each mode.

3.7.3 Seismic Subsystem Analysis

3.7.3.1 Seismic Analysis Methods

The criteria for determining whether systems or portions of systems require a seismic analysis is defined in Section 3.2.1. Piping is further classified according to the required function of the system or portion of a system as shown in Table 3-1.

Two analytical techniques are employed in the seismic analyses: dynamic and static methods. The results obtained by the Section 3.7.3.3 static method are more conservative than the results calculated by the dynamic analysis. The use of the static analysis procedure is limited to piping systems which are not considered complex and where the anticipated seismic effects are minimal.

A special realistic seismic analysis has been used exclusively to qualify the auxiliary building HPSW sprinkler piping in the Units 1, 2 and 3 personnel hatch areas and Unit 1 drumming station to prevent auxiliary building flooding in the event of an earthquake. This method takes exception to some of the criteria specified in the UFSAR for seismic qualification such as the computer code used for analysis, damping values and allowable stresses. See Section 3.7.5, Reference 13

All seismically designed systems penetrating the Reactor Building wall are designed as follows: Within the Reactor Building, a dynamic analysis is performed except where noted below. As each penetration serves as an anchor to the system passing through the Reactor Building wall, a separate analysis is run on the piping outside the Reactor Building.

The design of the B, C, and F Systems outside the Reactor Building is based on a static analysis using a 0.5 g design acceleration. However, subsequent floor response spectra presented in Bechtel "Seismic Analysis Auxiliary Building" report dated January, 1970 and subsequent floor response spectra for Turbine Building developed by Duke Power Company show that there are peak accelerations greater than 0.5 g. Consequently, additional analysis is done to ensure that either (1) span lengths are reduced to avoid fundamental frequencies corresponding to accelerations above 0.5 g or (2) piping stresses and restraint load capabilities are reviewed for adequacy for the appropriate accelerations. Conservative manual methods will be used to determine span frequencies. Also, piping spans will be kept simple to avoid the necessity for modal analysis. Where this technique cannot be applied with confidence, a dynamic analysis will be performed.

Seismically designed systems which penetrate the Reactor Building with a very minor portion of the system inside the Reactor Building (i.e., from the penetration point to the inside isolation valve) are statically analyzed. These systems are as follows:

Reactor Building Purge System

Coolant Storage System

Liquid Waste Disposal System

Miscellaneous Non-Nuclear Service Systems; i.e., Service Air, Nitrogen, Demineralized Water, etc.

Although there is not a seismic classification type interface, the Reactor Coolant System is a B&W Duke system interface.

The scope of NRC Inspection and Enforcement Bulletin 79-14 was defined as all piping that was computer analyzed for seismic loadings and all piping greater than or equal to 2½" diameter that was seismically analyzed using criteria methods. The design inputs for the IEB 79-14 seismic analysis have been reconciled with the as-built. A rigorous computer analysis has been performed for all pipe reanalyzed for IEB 79-14.

Each pipe is idealized as a mathematical model consisting of lumped masses connected by elastic members. Lumped masses are located at carefully selected points in order to adequately represent the dynamic and elastic characteristics of the pipe system. Using the elastic properties of the pipe, the flexibility matrix for the pipe is determined. The flexibility calculations include the effects of torsional, bending, shear, and axial deformations. In addition, for curved members, the stiffness is decreased in accordance with USAS B31.1-1967, Code for Power Piping.

Once the flexibility and mass matrices of the mathematical model are calculated, the frequencies and mode shapes for all significant modes of vibration are determined. All modes having a period greater than 0.05 seconds are used in the analysis. The mode shapes and frequencies are solved in accordance with the following equation:

$$(K - w_n^2 M)\phi_n = 0$$

in which:

K = square stiffness matrix of the pipe

M = mass matrix for the pipe

w_n = frequency for the n[th] mode

ϕ_n = mode shape matrix of the n[th] mode

After the frequency is determined for each mode, the corresponding spectral acceleration is read from the appropriate response spectrum for the pipe. Using these spectral accelerations, the response for each mode is found by solving the following equation:

$$Y_n \max = \frac{R_n Sa_n D}{M_n w_n^2}$$

in which:

$Y_n\max$ = response of the n[th] mode

R_n = participation factor for the n[th] mode = $\Sigma M_i \phi_{in}$

Sa_n = spectral acceleration for the n[th] mode

D = earthquake direction matrix

M = generalized mass matrix for the n[th] mode = $\Sigma M_i \phi^2{}_{in}$

Using these results, the maximum displacements for each mode are calculated for each mass point in accordance with the following equation:

$$V_{in} = \phi_{in} Y_n \max$$

in which:

V_{in} = maximum displacement of mass i for mode n

The total displacement for each mass is determined by taking the square root of the sum of the squares of the maximum deflection for each mode:

$$V_i = \sqrt{\Sigma V_{in}^2}$$

in which:

V_i = maximum displacement of mass i due to all modes calculated

The inertia forces for each direction of earthquake for each mode are then determined from:

$$Q_n = KV$$

in which:

Q_n = inertia force matrix for mode n

V = displacement matrix corresponding to Q_n

Each mode's contribution to the total displacements, internal forces, moments, and stresses are determined from standard structural analysis methods using the inertia forces for each mode as an external loading condition. The total combined results are obtained by taking the square root of the sum of the squares of each parameter under consideration, in a manner similar to that done for displacements.

The computer program PISOL, used for original Oconee piping analysis performed by Duke, was provided and maintained by EDS Nuclear of San Francisco, California. Subsequent revision piping analyses on Oconee have been performed by Duke using updated versions of PISOL and SUPERPIPE, by the NUS Corporation, and by Nuclear Power Services (NPS) of Secaucus, New Jersey using their proprietary program.

Both EDS and NPS have reviewed their programs and have verified that the algebraic summation methods were not used in either the earthquake co-directional responses or in the inter-modal responses per IE Bulletin 79-07.

Certain piping analyses on Oconee were performed by Bechtel Corporation, Gaithersburg, Maryland. Bechtel has verified that algebraic summation methods, as noted above, were not used in the piping analysis performed for Duke on Oconee. Bechtel's analysis was performed by EDS on EDS programs.

The verification of computer programs was done in a combination of ways. Due to the non-existence of the ASME benchmark problems during the time of the original analyses, original versions of programs were verified with hand calculated results. As more and more programs became commercially available, comparisons were made with these programs and with the ASME problems.

Specifically, EDS has used a combination of any or all of the following methods:

1. Comparison to ASME Benchmark Problem #1
2. Benchmark Problems Utilizing EDS Programs and Other Industry Programs (PIPESD, NUPIPE, ADLPIPE, ME-101).
3. Comparison to Hand Calculations.
4. Comparison Between EDS Programs and Updated Versions.

NPS has verified its program against PIPESD and ANSYS.

Deleted paragraph(s) per 2004 update.

3.7.3.1.1 Replacement Steam Generator Seismic Analysis

Framatome ANP analyzed the RCS loop model using the certified program BWSPAN. BWSPAN has been certified by comparison to STALUM and T3PIPE, as well as problems generated by Brookhaven National Laboratories and by hand calculations. BWSPAN was reviewed and approved by the NRC (Reference 7 and 8).

The model used to evaluate the effects of the RSG on the RCS contains the reactor vessel, steam generators, pump and pressurizer, as well as the system piping and the interior concrete structures.

Two seismic loadcases were analyzed:

1. Operating Basis Earthquake (OBE), also known as Design Basis Earthquake (DBE). OBE - X+Y Direction, OBE - Y+Z Direction
2. Safe Shutdown Earthquake (SSE), also known as Maximum Hypothetical Earthquake (MHE). SSE - X+Y Direction, SSE - Y+Z Direction

The seismic analyses consider modes up to the cutoff frequency of 33 Hertz. The contribution of those modes beyond the cutoff frequency is accounted for using the technique outlined in Standard Review Plan 3.7.2 of NUREG 0800.

Orthogonal modal damping was used in the seismic analyses. In this method, each section in the mathematical model is assigned a frequency dependent damping value based on information found in Section 3.7.1.3.

Composite damping for each mode is calculated by relating it to the bar strain energy of each of the model sections as described in Section N-1233.2 of Appendix N to the 1983 Section III Division 1 ASME B+PV Code. Once the composite damping for a mode is calculated, the spectral acceleration to be applied at the fixed support nodes is interpolated from the appropriate input spectra curves. Note that the seismic analyses are performed as enveloped spectra analyses with the basemat response spectra applied at all support points at the basemat elevation. The three response spectra acting in the directions of the global coordinate axes are input at several damping values. If the damping for a mode falls between two of the input spectra curves (as is the case most often) the bounding spectra curves are interpolated to get the correct spectral acceleration. The modal results are combined by taking the SRSS of all the modes per Section 3.7.3.1. The model responses to the directional earthquake input (applied response spectra) are combined two-dimensionally for the X+Y and Y+Z directions.

3.7.3.2 Procedure Used for Modeling

A general description of the modeling for the specific programs used for seismic analysis is included in Section 3.7.3.1. The following figures are isometric drawings of typical piping models:

1.	System 01A	Figure 3-9	Main Steam System – West Generator
	Problem #1-01-08		
2.	Systems 53A and 59	Figure 3-10	Core Flooding Tank 1A
	Problem #1-53-9	Figure 3-11	Low Pressure Injection System - West
3.	Systems 51A and 59	Figure 3-12	Reactor Coolant Pump Piping to High
	Problem #1-55-3	Figure 3-13	Pressure Injection Letdown Coolers
		Figure 3-14	
		Figure 3-15	

The practice of overlapping analysis problems was used in the original analytical work performed for the Oconee Nuclear Station piping systems. This approach was utilized to avoid erecting in-line pipe anchors for the sole purpose of defining piping analysis problems. In the reanalysis work required for IE Bulletin 79-14, every effort was made to reduce the number of problems with overlap regions. This was done by combining individual analysis problems into one larger problem. However, this could not be accomplished for all problems due to computer capacity limitations.

When necessary to separate analysis problems the models will be "overlapped" to obtain adequate boundary conditions. The overlap region (pipe modeled in both problems) shall be selected based on engineering judgement, considering the specific geometry to be modeled, to give acceptably accurate results at the problem boundary. As a minimum, the overlap region must include five effective restraints in each of three orthogonal directions. One axial restraint is effective for the entire run between changes of direction. The overlap region should be located in the most rigid portion of the pipe to obtain maximum isolation between problems.

In the overlap region, S/R loads from both problems will be enveloped to obtain a conservative design load.

3.7.3.3 Use of Equivalent Static Load Method of Analysis of Piping Systems

3.7.3.3.1 Piping

Duke Engineering Design Report, Static Method of Seismic Analysis of Piping Systems for Oconee 1, 2, 3, File #OS-27-B, dated June 5, 1970, describes the approach and a sample problem for seismic piping.

The original method for determining seismic response based on static analysis for Reactor Building piping is as follows:

The envelope of response curve(s) developed for the dynamic analysis are used for the static analysis which is based on the assumption that the natural frequency of the piping system is at the critical frequency.

Static loads at points of support are determined by utilizing the computer program ME553-Piping Flexibility Analysis - to perform a modified weight analysis which is based on applying the maximum horizontal forces in the positive X or Z directions simultaneously with the maximum, vertical force.

The horizontal forces are obtained by using the maximum acceleration peak from the appropriate envelope curves as the multiplier to convert uniform pipe weight into forces. The vertical force is obtained from the pipe weight density multiplied by the vertical peak acceleration.

The valves and special fittings on the system are mathematically expressed in the analysis as equivalent pipe of the same weight as the valve or fitting.

The combination of all maximum forces in the positive directions produces resulting static loads of greater magnitude than the dynamic analysis.

Reactor Building Pipe Stress analyses revised subsequent to original analysis are based on the "Duke Engineering Design Report" discussed above.

3.7.3.3.2 Components

The seismic analysis of the component coolers shown in Figure 3-16, Figure 3-17, and Figure 3-18 is an example of the static analysis applied to components in Class B, C, and F Systems outside the Reactor Building.

3.7.3.4 Components of Earthquake Motion

Seismic forces are applied in the vertical and in any horizontal direction. The horizontal and vertical components of ground motion are applied simultaneously.

3.7.3.5 Combination of Modal Response

This information is addressed in Section 3.7.3.1.

3.7.3.6 Analytical Procedures for Piping

General Analytical Procedures are discussed in Section 3.7.3.1.

3.7.3.7 Multiple Supported Equipment and Components with Distinct Inputs

Floor response spectra developed as discussed in Section 3.7.2.5 are used as input for the piping analysis. When the pipe is supported from more than one elevation or structure, the response spectra for all support levels are enveloped and the envelope spectra are used in the analysis, except when the Independent Support Motion technique is used. In certain instances where one group of supports attach to a structure and another group of supports attach to a structure with a definite distinction in structural seismic response, ISM methods have been used in the qualification of existing pipe and supports during reanalysis for IEB 79-14 to mitigate the consequences and excessive conservatism of the total enveloped spectra method. Such consequences may include undue radiation exposure to personnel or undue hardship in implementing field modifications.

For piping passing from one building into another building, the maximum movements of the two buildings (deflections produced by earthquake) are summed absolutely and the piping system is subjected to these movements through the piping system restraints. The stresses produced in the piping by the building movements are considered additive to the stresses resulting from accelerations or thermal expansion.

Rocking of the turbine support structure has been considered with respect to the Main Steam System analysis and movements of the turbine support are negligible as compared to other design movements of the main turbine piping leads attached to the main steam stop valve and control valve assembly.

3.7.3.8 Buried Piping Tunnels Designed for Seismic Conditions

The CCW intake piping furnishing water to the LPSW pumps is placed on concrete bedding which rests on bed rock at the point of entry into the station. There will not be any differential movement at the piping-structural interface with the rock base, thereby precluding any stress problems. Except for the CCW piping described above, other seismically designed safety-related buried lines for the Oconee Project are the 48" emergency discharge CCW pipe and CCW discharge piping, and the SSF Auxiliary Service Water pump discharge line, the Siphon Seal Water line, and the Essential Siphon Vacuum lines.

3.7.3.9 Interaction of other Piping with Piping Designed for Seismic Conditions

The interaction between seismic/non-seismic lines are considered and safety system integrity is assured by the following methods:

Seismic/non-seismic lines are physically separated insofar as possible such that failure of a non-seismic line has no effect on safety-related piping.

Seismic/non-seismic boundaries are established by valves which are designed to meet the seismic design criteria. Failure in the non-seismic portion of the system cannot cause loss of function to the safety system in that automatic or remote manual-operated valves are used for valves normally open during Reactor Operation. A variation of this case is where the seismic/non-seismic boundary is beyond the automatic or remote-manual valve. (For example, LPSW piping to and from the Reactor Building Auxiliary Coolers have Seismic Category I/Seismic Category II boundaries inside containment at normally open manual valves. For containment isolation purposes in this particular case, the Seismic Category II piping, although it has structural seismic integrity, the piping is treated as non-seismic, from a piping pressure boundary perspective, since it is non QA Condition 1. The containment isolation valves associated with the penetrations are located outside containment. Closure of the containment isolation valves mitigates the effects of failure of the non-seismic piping. The boundary is extended past the containment isolation valves since the seismic boundary is part of those particular containment penetrations. Seismic Category I and Seismic Category II are defined in Regulatory Guide 1.29, Seismic Design Classification.)

Deleted paragraph per Revision 29 update.

Automatic or remote manual-operated valves are not required for seismic/non-seismic boundaries that are normally open during reactor operation, provided that an analysis has demonstrated that a seismically-induced failure of the piping would not cause loss of system safety function. Such analysis shall assume only a single pipe break during a seismic event, and the analysis shall determine the effect on the safety-related portion of the system from the most limiting single pipe break.

Automatic or remote manual-operated valves are not required on the Spent Fuel (SF) Cooling system seismic/non-seismic boundary drain lines off the Fuel Transfer Canal and Incore Instrument Handling Tank that are normally open during reactor operation. Flooding is not a concern during reactor operation since these flow paths would channel flow from other systems to the Reactor Building sumps (i.e. act as funnels and are not sources of water). (Reference 6)

The seismic/non-seismic boundary valve is protected from seismic effects by restraining or anchoring the non-seismic portion of the system downstream of the valve.

3.7.3.10 Seismic Analysis of Reactor Internals

The core support structure is designed as a Class I structure, as defined in Section 3.2 to resist the effects of seismic disturbances. The basic design guide for the seismic analysis is AEC publication TID-7024, "Nuclear Reactors and Earthquakes."

Lateral deflection and torsional rotation of the lower end of the core support assembly is limited in order to prevent excessive deformation resulting from seismic disturbance thereby assuring insertion of control rod assemblies (CRA). Core drop in the event of failure of the normal supports is limited by guide lugs so that the CRA do not disengage from the fuel assembly guide tubes. Additional information on design of the Reactor Internals is included in Section 3.9.2.

3.7.3.11 Analysis Procedures for Damping

A 0.5 percent critical damping value is used for vital piping analysis (see Section 3.7.1.3).

3.7.4 Seismic Instrumentation Program

3.7.4.1 Location and Description of Instrumentation

Earthquake instrumentation being provided is a strong motion accelerograph designated SMA-3 and manufactured by Kinemetrics, Inc., of Pasadena, CA. This system consists of a central recording system, control panel, one TS-3 triaxial seismic trigger package, and two force-balance triaxial accelerometer packages.

The operations sequence is as follows:

> The seismic trigger senses the initial earthquake ground motion with a normal setting of 0.01g and actuates the SMA-3 to full operation in less than 0.1 second.

The SMA-3 operates for as long as the trigger detects the earthquake, plus an additional 10 seconds.

The accelerograph can thus record a single earthquake or a sequence of earthquakes and aftershocks lasting as long as 30 minutes.

The output of each triaxial sensor is recorded using frequency modulation on a single four track cassette tape. Three of the tracks on the tape are the data tracks; the fourth is a reference track used for tape speed and amplitude compensation.

The Seismic Trigger and one Force Balance accelerometer of the SMA-3 system are located in the Unit 1 Tendon Gallery. Also, a second Force Balance accelerometer is located directly above at elevation 797' + 6" in the Oconee 1 Reactor Building. The recorder for the system is located in the Unit 1 Cable Room.

Also, a seismic trigger/switch is located in the Unit 1 tendon gallery. The Kinemetrics Model TS-3A has a preset acceleration threshold of 0.05g which activates the statalarm in Units 1 and 3 control rooms, when design conditions occur.

Six 2g peak recording accelorometers, manufactured by Engdahl-Model PAR 400, are also installed at various locations within the Oconee 1 Reactor Building. The instruments will provide post-seismic data for the following locations or items:

1. Adjacent to the strong motion accelerograph located in Tendon Access Gallery.
2. Support of the pressurizer vessel.
3. Support of Core Flood Tank 1A.
4. Main steam line pipe hanger.
5. Feedwater line pipe hanger.
6. Core flood injection line pipe hanger.

The major Class 1 structures, Reactor Building and Auxiliary Buildings, will be founded on a common rock foundation and will have similar base motions. The dynamic structural properties and responses of these structures are generated using similar assumptions and analytical techniques. Therefore, the response of these structures can be determined based upon the instrumentation in one structure.

Top of soil (free field) responses will not provide useful analytical data for the evaluation of major Class 1 structures founded on rock. Therefore, it is felt that free field instrumentation will not contribute to the evaluation of these structures.

3.7.4.2 Comparison of Measured and Predicted Responses

In the event of an earthquake, the data will be analyzed to determine the magnitude of the earthquake. If the design earthquake is exceeded, the units would be shut down and structures, systems, and equipment thoroughly investigated. Responses from instruments located on selected structures, systems and components will be compared to calculated responses for those structures, systems and components at the respective location when subjected to the same base response.

The recorded seismic data will be used for comparison and verification of seismic analysis assumptions, damping characteristics, and the analytical model used for the plant seismic design.

3.7.5 References

1. Bechtel Report, "Seismic Analysis Auxiliary Building", January, 1970.
2. Duke Power Engineering Design Report, "Static Method of Seismic Analysis of Piping Systems for Oconee 1, 2 and 3", File OS-27-B, June 6, 1970.
3. AEC Report TID-7024, "Nuclear Reactors and Earthquakes".
4. Newmark, N. M., "Torsion in Symmetrical Buildings".
5. Deleted Per 2000 Update
6. OSC-7462, Rev. 0, “Spent Fuel Cooling System – Normally Open Seismic Boundary Valves.”
7. Letter dated July 26, 2001 from W. R. McCollum, Jr. to NRC, requesting NRC review and approval of the methodology that will be used for the re-analysis of the reactor coolant loop as a part of steam generator replacement.
8. Letter dated September 6, 2001 from Dave E. LaBarge transmitting the NRC’s SER for the proposed methodology for the analysis of the reactor coolant loop in support of steam generator replacement.
9. Calculation OSC-7835, Steam Generator Replacement Project; ONS Unit 1 Reactor Coolant Structural Analysis for ROTSG’s.
10. Calculation OSC-7836, Steam Generator Replacement Project; ONS Units 2 and 3 Reactor Coolant Loop Structural Analysis for ROTSG’s.
11. Supplement No. 1 to Generic Letter 87-02 that Transmits Supplemental Safety Evaluation Report No. 2 (SSER No. 2) on SQUG Generic Implementation Procedure, Revision2, as Corrected On February 14, 1992 (GIP-2).
12. Letter dated September 9, 1999 from David E. Labarge to W. R. McCollum, Jr Transmitting Oconee Plant Specific Safety Evaluation Report for Unresolved Safety Issue A-46 Program Implementation, Including Keowee Hydro Station and Switchyard.
13. Letter dated November 14, 2007 from Leonard N. Olshan, Sr. transmitting the NRC's SER for the realistic seismic analysis of the auxiliary building HPSW sprinkler piping.

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3.8 Design of Structures

Class 1 structures are those which prevent uncontrolled release of radioactivity and are designed to withstand all loadings without loss of function.

Class 2 structures are those whose limited damage would not result in a release of radioactivity and would permit a controlled plant shutdown but could interrupt power generation.

Class 3 structures are those whose failure could inconvenience operation, but which are not essential to power generation, orderly shutdown or maintenance of the reactor in a safe condition.

Note: From the license renewal review, it was determined that Class 1 and Class 2 civil structures only are included in the scope for license renewal.

3.8.1 Concrete Containment

The concrete/steel containment is analyzed as a free standing structure and is referred to as the Reactor Building. It is constructed of reinforced concrete and structural liner plate steel with no separation between the two.

3.8.1.1 Description of the Containment

The structure consists of a post-tensioned reinforced concrete cylinder and dome connected to and supported by a massive reinforced concrete foundation slab as shown in Figure 3-19. The entire interior surface of the structure is lined with a ¼ inch thick welded ASTM A36 steel plate to assure a high degree of leak tightness. Numerous mechanical and electrical systems penetrate the Reactor Building wall through welded steel penetrations as shown in Figure 3-20 and Figure 3-21. The mechanical penetrations and access openings are design, fabricated, inspected, and installed in accordance with Subsection B, Section III, of the ASME Pressure Vessel Code.

Principal dimensions are as follows:

"These values are historical and for descriptive purposes only."

Inside Diameter	116 ft
Inside Height (Including Dome)	208½ ft
Vertical Wall Thickness	3-3/4 ft
Dome Thickness	3-¼ ft
Foundation Slab Thickness	8-½ ft
Liner Plate Thickness	¼ in.
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The Reactor Building is shown in Figure 1-2 through Figure 1-9.

In the concept of a post-tensioned Reactor Building, the internal pressure load is balanced by the application of an opposing external pressure type load on the structure. Sufficient post-tensioning is used on the cylinder and dome to more than balance the internal pressure so that a margin of external pressure exists beyond that required to resist the design accident pressure. Nominal, bonded reinforcing steel is also provided to distribute strains due to shrinkage and temperature. Additional bonded reinforcing steel is used at penetrations and discontinuities to resist local moments and shears.

The internal pressure loads on the foundation slab are resisted by both the external bearing pressure due to dead load and the strength of the reinforced concrete slab. Thus, post-tensioning is not required to exert an external pressure for this portion of the structure.

The post-tensioning system consists of:

1. Three groups of 54 dome tendons oriented at 120° to each other for a total of 162 tendons anchored at the vertical face of the dome ring girder.
2. 176 vertical tendons anchored at the top surface of the ring girder and at the bottom of the base slab.
3. Six groups of 105 hoop tendons plus two additional tendons enclosing 120° of arc for a total of 632 tendons anchored at the six vertical buttresses.

Each tendon consists of ninety ¼ inch diameter wires with buttonheaded BBRV type anchorages, furnished by The Prescon Corporation. Replacement tendons installed during steam generator replacement were furnished by PSC. The tendons are housed in spiral wrapped corrugated thin wall sheathing. After fabrication, the tendon is shop dipped in a petroleum corrosion protection material, bagged and shipped. After installation, the tendon sheathing is filled with a corrosion preventive grease.

Ends of all tendons are covered with pressure tight grease filled caps for corrosion protection.

ASTM A615, Grade 60 reinforcing steel, mechanically spliced with T-series CADWELDS, is used throughout the foundation slab and around the large penetrations. A615, Grade 40 steel is used for the bonded reinforcing throughout the cylinder and dome as crack control reinforcing. At areas of discontinuities where additional steel is used, such steel is generally A615, Grade 60 to provide an additional margin of elastic strain capability. ASTM A615, Grade 60 was also used as necessary for the repaired area following steam generator replacement.

The ¼ inch thick liner plate is attached to the concrete by means of an angle grid system stitch welded to the liner plate and embedded in the concrete. The details of the anchoring system are provided in Figure 3-19. The frequent anchoring is designed to prevent significant distortion of the liner plate during accident conditions and to insure that the liner maintains its leak tight integrity. The design of the liner anchoring system also considers the various erection tolerances and their effect on its performance. The liner plate was coated during construction for corrosion protection. See Table 3-12 for Reactor Building coatings. There is no paint on the side in contact with concrete.

The concrete used in the original construction of the structure is made with crushed marble aggregate obtained from Blacksburg, South Carolina. Such aggregate produces an excellent high strength, dense, sound concrete. The design strengths are 5000 psi at 28 days for the shell and foundation slab. A 5000 psi high early strength, non-shrink or slightly expansive mix was used for repairing the temporary construction opening following steam generator replacement.

Personnel and equipment access to the structure is provided by a double door personnel hatch with double seals on the outer door and by a 19 ft. - 0 in. clear diameter double gasketed single door equipment hatch as shown in Figure 3-21. A double door emergency personnel escape hatch is also provided. These hatches are designed and fabricated of A516, Grade 70 firebox quality steel made to A3000 specification, Charpy V-notch impact tested to 0°F in accordance with Section III of the ASME Pressure Vessel Code. All piping penetrations are furnished to the same requirements.

Structural brackets provided for the Reactor Building polar crane runway are fabricated of A36 steel shapes and A516, Grade 70 insert plates (Figure 3-19). Structural brackets and thickened plates are shop fabricated, stress relieved and shipped to the jobsite for welding into the ¼ inch liner plate similar to the penetration assemblies.

3.8.1.1.1 Coating Materials

The original coating materials applied to all structures within the containment during plant construction were qualified by withstanding autoclave tests designed to simulate LOCA conditions. The qualification testing of Service Level I substitute coatings now used for new applications or repair/replacement activities inside containment was in accordance with ANSI N 101.2 for LOCA conditions and radiation tolerance. The substitute coatings when used for maintenance over the original coatings were tested, with appropriate documentation, to demonstrate a qualified coating system.

The original, maintenance, and new coating systems defining surface preparation, type of coating, and dry film thickness are tabulated in Table 3-12 (Containment Coatings).

The elements of the Oconee Coatings Program are documented in a Nuclear System Directive. The Oconee Coatings Program includes periodic condition assessments of Service Level I coatings used inside containment. As localized areas of degraded coatings are identified, those areas are evaluated for repair or replacement, as necessary.

3.8.1.2 Applicable Codes, Standards, and Specifications

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

The following codes, standards, and specifications were used during the design, construction, testing and inservice inspection of Class 1 Structures:

ACI 301	-	*Specification for Structural Concrete for Buildings*
ACI 318-63	-	*Building Code Requirements for Reinforced Concrete*
ACI 347	-	*Recommended Practice for Concrete Framework*
ACI 605	-	*Recommended Practice for Hot Weather Concreting*
ACI 613	-	*Recommended Practice for Selecting Proportions for Concrete*
ACI 614	-	*Recommended Practice for Measuring, Mixing and Placing Concrete*
ACI 315	-	*Manual of Standard Practice for Detailing Reinforced Concrete Structures*
ASME-1965	-	*Boiler and Pressure Vessel Code, Sections III, VIII, and IX*
AISC	-	*Steel Construction Manual, 6th ed* [1]
PCI	-	*Inspection Manual*
ACI 505	-	*Specification for Design and Construction of Reinforced Concrete Chimneys*
ACI	-	*American Concrete Institute*

ASME	-	*American Society of Mechanical Engineers*
AISC	-	*American Institute of Steel Construction*
PCI	-	*Prestressed Concrete Institute*

Notes:

1. For visual inspections of structural welds, reference the "Visual Weld Acceptance Criteria for Structural Welding at Nuclear Power Plants", NCIG-01, Rev. 2 dated 5/7/85.

3.8.1.3 Loads and Load Combinations

3.8.1.3.1 Loads Prior to Prestressing

Under this condition the structure is designed as a conventionally reinforced concrete structure. It is designed for dead load, live loads (including construction loads), and a reduced wind load. Allowable stresses are according to ACI 318-63.

3.8.1.3.2 Loads at Transfer of Prestress

The Reactor Building is checked for prestress loads and the stresses compared with those allowed by ACI 318-63 with the following exceptions: ACI 318-63, Chapter 26, allows concrete stress of $0.60f'_{ci}$ at initial transfer. In order to limit creep deformations, the membrane compression stress is limited to $0.30f'_{ci}$; whereas, in combination with flexural compression, the maximum allowable stress will be limited to $0.60f'_{ci}$ per ACI 318-63.

For local stress concentrations with nonlinear stress distribution as predicted by the finite element analysis, $0.75f'_{ci}$ is permitted when local reinforcing is included to distribute and control these localized strains. These high local stresses are present in every structure but they are seldom identified because of simplifications made in design analysis. These high stresses are allowed because they occur in a very small percentage of the cross section, are confined by material at lower stress and would have to be considerably greater than the values allowed before significant local plastic yielding would result. Bonded reinforcing is added to distribute and control these local strains.

Membrane tension and flexural tension are permitted provided they do not jeopardize the integrity of liner plate. Membrane tension is permitted to occur during the post-tensioning sequence but will be limited to $1.0\sqrt{f'_{ci}}$. When there is flexural tension but no membrane tension, the section is designed in accordance with Section 2605(a) of the ACI Code. The stress in the liner plate due to combined membrane tension and flexural tension is limited to 0.5 fy.

Shear criteria are in accordance with the ACI 318-63 Code, Chapter 26, as modified by the equations in Section 3.8.1.3.6 using a load factor of 1.5 for shear loads.

3.8.1.3.3 Loads Under Sustained Prestress

The conditions for design and the allowable stresses for this case are the same as above except that the allowable tensile stress in nonprestressed reinforcing is limited to 0.5 fy. ACI 318-63 limits the concrete compression to $0.45f'_c$ for sustained prestress load. Values of $0.30f'_c$ and $0.60f'_c$ are used as described above which bracket the ACI allowable value. However, with these same limits for concrete stress at transfer of prestress, the stresses under sustained load are reduced due to creep.

3.8.1.3.4 Service Loads

This loading case is the basic "working stress" design. The Reactor Building is designed for the loading cases shown in Table 3-13.

Sufficient prestressing is provided in the cylindrical and dome portions of the vessel to eliminate membrane tensile stress (tensile stress across the entire wall thickness) under design loads. Flexural tensile cracking is permitted but is controlled by bonded reinforcing steel.

Under the design loads the same performance limits stated in Section 3.8.1.3.2 apply with the following exceptions:

1. If the net membrane compression is below 100 psi, it is neglected and a cracked section is assumed in the computation of flexural bonded reinforcing steel. The allowable tensile stresses in bonded reinforcing are 0.5 fy.

2. When the maximum flexural stress does not exceed $6\sqrt{f'_c}$ and the extent of the tensions zone is not more than 1/3 the depth of the section, bonded reinforcing steel is provided to carry the entire tension in the tension block. Otherwise, the bonded reinforcing steel is designed assuming a cracked section. When the bending moment tension is additive to the thermal tension, the allowable tensile stress in the bonded reinforcing steel is 0.5 fy minus the stress in reinforcing due to the thermal gradient as determined in accordance with the method of ACI-505.

3. The problem of shear and diagonal tension in a prestressed concrete structure should be considered in two parts: membrane principal tension and flexural principal tension. Since sufficient prestressing is used to eliminate membrane tensile stress, membrane principal tension is not critical at design loads. Membrane principal tension due to combined membrane tension and membrane shear is considered under Section 3.8.1.3.6.

   Flexural principal tension is the tension associated with bending in planes perpendicular to the surface of the shell and shear stress normal to the shell (radial shear stress). The present ACI 318-63 provisions of Chapter 26 for shear are adequate for design purposes with proper modifications as discussed under Section 3.8.1.3.6 using a load factor 1.5 for shear loads.

Crack control in the concrete is accomplished by adhering to the ACI and American Society of Civil Engineers Code Committee standards for the use of reinforcing steel. These criteria are based upon a recommendation of the Prestressed Concrete Institute and are as follows:

0.25 percent reinforcing shall be provided at the tension face for small members

0.20 percent for medium size members

0.15 percent for large members

A minimum of 0.15 percent bonded steel reinforcing is provided in two perpendicular directions on the exterior faces of the wall and dome for proper crack control.

The liner plate is attached on the inside faces of the wall and dome. Since, in general, there is no tensile stress due to temperature on the inside faces, bonded reinforcing steel is not necessary at the inside faces.

The Reactor Building shell is also designed for the following loads:

1. Dead load
2. Prestress forces
3. Live load including allowances for piping, ductwork and cable trays
4. Wind, including tornado
5. Earthquake
6. Thermal expansion of pipes attached to the Reactor Building wall

The external design pressure of the Reactor Building shell is 3 psig. This value is approximately 0.5 psig beyond the maximum external pressure that could be developed if the Reactor Building were sealed during a period of low barometric pressure and high temperature and, subsequently, the Reactor Building atmosphere were cooled with a concurrent rise in barometric pressure. Vacuum breakers are not provided.

3.8.1.3.5 Loadings Common to all Structures

Ice or Snow Loading

A uniform distributed live load of 20 pounds per square foot is considered for roofs as stated in Section 1203.2 of the Southern Standard Building Code.

3.8.1.3.6 Loads Necessary to Cause Structural Yielding

The structure is checked for the factored loads and load combinations that will cause structural yielding.

The load factors are the ratio by which loads will be multiplied for design purposes to assure that the load/deformation behavior of the structure is one of elastic, low-strain behavior. The load factor approach is being used in this design as a means of making a rational evaluation of the isolated factors which must be considered in assuring an adequate safety margin for the structure. This approach permits the designer to place the greatest conservatism on those loads most subject to variation and which most directly control the overall safety of the structure. It also places minimum emphasis on the fixed gravity loads and maximum emphasis on accident and earthquake or wind loads. The final design of the Reactor Building satisfies the loading combinations and factors tabulated in Table 3-14.

The load combinations, considering load factors referenced above, are less than the yield strength of the structure. The yield strength of the structure is defined as the upper limit of elastic behavior of the effective load carrying structural materials. For steels (both prestress and nonprestress), this limit is taken to be the guaranteed minimum yield given in the appropriate ASTM specification. For concrete, it is the ultimate values of shear (as a measure of diagonal tension) and bond per ACI 318-63 and the 28-day ultimate compressive strength for concrete in flexure (f'_c). The ultimate strength assumptions of the CI Code for concrete beams in flexure are not allowed; that is, the concrete stress is not allowed to go beyond yield and redistribute at a strain of three or four times that which causes yielding.

The maximum strain due to secondary moments, membrane loads and local loads exclusive of thermal loads is limited to that corresponding to the ultimate stress divided by the modulus of elasticity (f'_c/E_c) and a straight-line distribution from there to the neutral axis assumed.

For the loads combined with thermal loads, the peak strain is limited to 0.003 inch/inch. For concrete membrane compression, the yield strength is assumed to be $0.85f'_c$ to allow for local irregularities in accordance with the ACI approach. The reinforcing steel forming part of the load carrying system is allowed to go to, but not to exceed, yield as is allowed for ACI ultimate strength design.

A further definition of yielding is the deformation of the structure which causes strains in the steel liner plate to exceed 0.005 inch/inch. The yielding of nonprestress reinforcing steel is allowed, either in tension or compression, if the above restrictions are not violated. Yielding of the prestress tendons is not allowed under any circumstances.

Principal concrete tension due to combined membrane tension and membrane shear, excluding flexural tension due to bending moments or thermal gradients, is limited to $3\sqrt{f'_c}$. Principal concrete tension due to combined membrane tension, membrane shear, and flexural tension due to bending moments or thermal gradients is limited to $6\sqrt{f'_c}$. When the principal concrete tension exceeds the limit of $6\sqrt{f'_c}$, bonded reinforcing steel is provided in the following manner:

1. <u>Thermal Flexural Tension</u> - Bonded reinforcing steel is provided in accordance with the methods of ACI-505. The minimum area of steel provided is 0.15 percent in each direction.
2. <u>Bending Moment Tension</u> - Sufficient bonded reinforcing steel is provided to resist the moment on the basis of cracked section theory using the yield stresses stated above with the following exception: When the bending moment tension is additive to the thermal tension, the allowable tensile stress in the reinforcing steel is fy minus the stress in reinforcing due to the thermal gradient as determined in accordance with the methods of ACI-505.

Shear stress limits and shear reinforcing for radial shear are in accordance with Chapter 26 of ACI 318-63 with the following exceptions: Formula 26-12 of the code shall be replaced by

$$V_{ci} = Kb'd\sqrt{f'_c} + M_{cr}\left(\frac{V}{M'}\right) + V_i$$

Where:

$$K = [1.75 - \frac{0.036}{np'} + 4.0\,np']$$

but not less than 0.6 for $p' \geq 0.003$.

For $p' < 0.003$, the value of K shall be zero.

$$M_{cr} = \frac{I}{Y}[6\sqrt{f'_c} + f_{pe} + f_n + f_i]$$

f_{pe}	=	Compressive stress in concrete due to prestress applied normal to the cross section after all losses (including the stress due to any secondary moment) at the extreme fiber of the section at which tension stresses are caused by live loads.
f_n	=	Stress due to axial applied loads (f_n shall be negative for tension stress and positive for compression stress).
f_i	=	Stress due to initial loads at the extreme fiber of a section at which tension stresses are caused by applied loads (including the stress due to any secondary moment). f_i shall be negative for tension stress and positive for compression stress.

n	=	$\frac{505}{\sqrt{f'_c}}$
p′	=	$\frac{A'_s}{bd}$
V	=	Shear at the section under consideration due to the applied loads.
M′	=	Moment at a distance d/2 from the section under consideration, measured in the direction of decreasing moment, due to applied loads.
V_i	=	Shear due to initial loads (positive when initial shear is in the same direction as the shear due to applied loads).

Lower limit placed by ACI 318-63 on V_{ci} as $1.7b'd\sqrt{f'_c}$ is not applied.

Formula 26-13 of the Code shall be replaced by

$$V_{cw} = 3.5b'd\sqrt{f'_c} \qquad \sqrt{1 + \frac{f_{pc} + f_n}{3.5\sqrt{f'_c}}}$$

The term f_n is as defined on the previous page. All other notations are in accordance with Chapter 26, ACI 318-63.

1. This formula is based on the tests and work done by Dr. A. H. Mattock of the University of Washington.
2. This formula is based on the commentary for proposal redraft of Section 2610, ACI-318, by Dr. A. H. Mattock, dated December 1962.

When the above-mentioned equations show that allowable shear in concrete is zero, radial horizontal shear ties are provided to resist all the calculated shear.

3.8.1.4 Design and Analysis Procedures

The strength of the Reactor Building at working stress and overall yielding is compared to various loading combinations to assure safety. The Reactor Building is examined with respect to strength, the nature and the amount of cracking, the magnitude of deformation, and the extent of corrosion to assure proper performance. The structure is designed and constructed in accordance with design criteria based upon ACI 318-63, ACI 301, and ASME Pressure Vessel Code, Sections III, VIII, and IX to meet the performance and strength requirements prior to prestressing, at transfer of prestress, under sustained prestress, at design loads and at yield loads.

It is the intent of the criteria to provide a structure of unquestionable integrity that will meet the postulated design conditions with a low strain elastic response. The Oconee Reactor Building meets these criteria because:

1. The design criteria are, in general, based on the proven stress, strain, and minimum proportioning requirements of the ACI or ASME Codes. Where departures or additions from these codes have been made, they have been done in the following manner:

   a. The environmental conditions of severity of load cycling, weather, corrosion conditions, maintenance, and inspection for this structure have been compared and evaluated with those for code structures to determine the appropriateness of the modifications.

   b. The consultant firm of T. Y. Lin, Kulka, Yang and Associates was retained to assist in the development of the criteria. In addition to assisting with the criteria submitted in the PSAR, they have been involved in the continuing updating of the criteria and the review of design methods to assure that the criteria were being implemented as intended.

   c. Dr. Alan H. Mattock of the University of Washington was retained to assist in developing the proper design criteria from combined shear, bending, and axial load.

   d. All criteria, specifications, and details relating to the liner plate and penetrations, and corrosion protection have been referred to Bechtel's Metallurgy and Quality Control Department. This department maintains a staff to advise the corporation on problems of welding, quality control, metallurgy, and corrosion protection.

   e. The design of the Oconee Reactor Building was continually reviewed as the criteria were improved for successive license applications to assure that this structure does meet the latest criteria.

2. The primary membrane integrity of the structure is provided by the unbonded post-tensioning tendons, each one of which is stressed to 80 percent of ultimate strength during installation and performs at approximately 50 percent - 60 percent during the life of the structure. Thus, the main strength elements are individually proof-tested prior to operation of the plant.

3. 970 such post-tensioning elements have been provided, 162 in the dome, and 176 vertical and 632 hoop tendons in the cylinder. Any three adjacent tendons in any of these groups can be lost without significantly affecting the strength of the structure due to the load redistribution capabilities of the shell structure. The bonded reinforcing steel provided for crack control assures that this redistribution capability exists.

4. The unbonded tendons are continuous from anchorage to anchorage, being deflected around penetrations and isolated from secondary strains of the shell. Thus, the membrane integrity of the shell can be assured regardless of conditions of high local strains.

5. The unbonded tendons exist in the structure at a slightly ever-decreasing stress due to relaxation of the tendon and creep of the concrete and, even during pressurization, are subject to a stress change of very small magnitude (2 percent to 3 percent of ultimate strength). Thus, the main structural system is never subject to large changes in load, even during accident conditions.

6. The concrete portion of the structure, similar to the tendons, is subject to the highest state of stress during the initial post-tensioning. During pressurization, it is subject to a large change in load (or state of stress) but the change is, in general, a decrease in load. The large membrane compressive forces are diminished, and replaced, by relatively small radial pressures and stresses.

7. The deformations of the structure during plant operation, or due to accident conditions, are relatively minor due to the low strain behavior of the concrete. The largest deformations occur at the time of initial post-tensioning and shortly, thereafter, prior to operation. This low strain behavior, and the inherent strength of the structure, permit the anchoring of all piping penetrating the structure directly to the shell. Such details (see Figure 3-21) eliminate the use of expansion bellow seals and significantly reduce the likelihood of leaks developing at the penetrations.

The analysis for the Reactor Building falls into two parts, axisymmetric and nonaxisymmetric. The axisymmetric analysis is performed through the use of a finite element computer program for the individual loading cases of dead load, live load, temperature, prestress, and pressure, as described in Section 3.8.1.4.1. The axisymmetric finite element approximation of the Reactor Building shell does not consider the buttresses, penetrations, brackets, and anchors. These items of configuration, the lateral loads due to seismic or wind, and concentrated loads are considered in the nonaxisymmetric analysis described in Section 3.8.1.4.2.

This section discusses analytical techniques, references and design philosophy. The results of these analyses are discussed in Section 3.8.1.5. The design criteria and analysis have been reviewed by Bechtel's consultants, T. Y. Lin, Kulka, Yang and Associates.

3.8.1.4.1 Axisymmetric Techniques

The finite element technique is a general method of structural analysis in which the continuous structure is replaced by a system of elements (members) connected at a finite number of nodal points (joints). Conventional analysis of frames and trusses can be considered to be examples of the finite element method. In the application of the method to an axisymmetric solid (e.g., a concrete Reactor Building), the continuous structure is replaced by a system or rings of quadrilateral cross section which are interconnected along circumferential joints. Based on energy principles, work equilibrium equations are formed in which the radial and axial displacements at the circumferential joints are unknowns of the system. The results of the solution of this set of equations are the deformation of the structure under the given loading conditions. For the output, the stresses are computed knowing the strain and stiffness of each element.

The finite element mesh used to describe the structure is shown in Figure 3-22. The upper portion and lower portion of the structure were analyzed independently to permit a greater number of elements to be used for those areas of the structure of major interest such as the ring girder area and the base of the cylinder. The finite element mesh of the structure base slab was extended down into the foundation material to take into consideration the elastic nature of the foundation material and its effect upon the behavior of the base slab. The tendon access gallery is separated from the Reactor Building base slab by 3 in. compressible material. No moments or forces are transmitted from the base slab to the tendon access gallery. The maximum vertical elastic displacement of the base slab is one inch due to the maximum loading combinations. The tendon access gallery was designed as a separate structure with no reactions being generated from the bedrock to the ring shaped gallery structure.

The finite element mesh for the Reactor Building does not include the interior structure. The interior structure was included in the finite element input as a lump weight. The finite elements provide stresses for axisymmetric loads. The stresses from the eccentric interior structure loads and earthquake loads are superimposed analytically to the finite element stresses. The final algebraic summation of all stresses was used to design the base slab.

Stresses for Axisymmetric Loads	Stresses with Non-Axisymmetric Loads
11.0 kips/sq.ft.	26.0 kips/sq.ft.

The use of the finite element computer program permitted an accurate estimate of the stress pattern at various locations of the structure. The following material properties were used in the program for the various loading conditions:

	Load Conditions	
	D, F, T_O, T_A	P
$E_{concrete}$, Foundation (psi)	3.0×10^6	3.0×10^6
$E_{concrete}$, Shell (psi)	3.0×10^6	3.0×10^6
$\mu_{concrete}$ (Poisson's Ratio)	0.17	0.17
$\alpha_{concrete}$ (Coefficient of Expansion)	0.55×10^{-5}	–
$E_{subgrade}$ (psi)	4.5×10^6	4.5×10^6
E_{liner} (psi)	29×10^6	29×10^6
$f_{y\ liner}$ (psi)	36,000	36,000

The major benefit of the program is the capability to predict shears and moments due to internal restraint and the interaction of the foundation slab relative to the subgrade. The structure is analyzed assuming an uncracked homogeneous material. This is conservative because the decreased relative stiffness of a cracked section would result in smaller secondary shears and moments.

In arriving at the tabulated values of E, the effect of creep is included by using the following equation for long-term loads such as thermal load, dead load and prestress:

$$E_{cs} = E_{ci}(\varepsilon_i / (\varepsilon_s + \varepsilon_i))$$

Where:

E_{cs}	=	sustained modulus of elasticity of concrete.
E_{ci}	=	instantaneous modulus of elasticity of concrete.
ε_i	=	instantaneous strain, inch/inch per psi.
ε_s	=	creep strain, inch/inch per psi.

The thermal gradients used for design are shown in Figure 3-24. The gradients for both the design accident condition and the factored load condition are based on the temperature associated with the factored pressure (factored loads are described in Section 3.8.1.3.6). The design pressure and temperature of 59 psig and 286°F became 88.5 pisg and 286°F at factored conditions.

The upper stress limit for a linear stress-strain relationship was assumed to be 3000 psi (0.6 f'_c) for use with analyses made by the use of the axisymmetric finite element analytical method. (The analyses referred to considered the concrete as uncracked and the analytical model is the entire containment.) However, the maximum predicted compressive stress was about 2559 psi. The load combination considered was $0.95D+F+P+E'+T_A$ and the location for the predicted stress was for Section EF in ring girder (see Table 3-16). Therefore, only the linear portion of the stress strain curve was used in the analyses that used the entire containment structure as a model.

The compressive stress and strain level is the highest (after the LOCA when temperature is still relatively high, 200°F, and pressure is dropping rapidly) at the inside face of the concrete at the edge of openings and also under the liner plate anchors. Neither concentration is a result of what may be considered a real load. In the case of an opening, the real stress is a result of prestress, reduced pressure and dead load. Applying stress concentration factors to these loads still keeps the concrete in essentially the elastic range. When the strain and resulting stress from the thermal gradient are also multiplied by a stress concentration factor, the total strain and resulting stress will be above the linear stress range determined as by a uniaxial compression test. The relatively high stress level is not of real concern due to the following:

1. The concrete affected is completely surrounded by either other concrete or the penetration nozzle and liner reinforcing plate. This confinement puts the concrete in triaxial compression and gives it the ability to resist forces far in excess of that indicated by a uniaxial compression test.

2. The high state of stress and strain exist at a very local area and really have no effect on the overall containment integrity.

However, to be conservative, reinforcing steel was placed in these areas, and also, the penetration nozzle will function as compressive reinforcement.

The concrete under the liner plate anchors has some limited yielding in order to get the necessary stress distribution required to resist the liner plate self-relieving loads.

The thermal loads are a result of the temperature differential within the structure.

The liner plate is not included in the model. The strains at the inner face of the concrete surface are taken as the strains in the liner plate.

Figure 3-22 shows the inclusion of the liner plate in the finite element mesh.

Under the design accident condition or factored load condition, cracking of the concrete at the outside face would be expected. The value of the sustained modulus of elasticity of concrete, E_{cs}, was used in ACI Code 505-54 to find the stresses in concrete, reinforcing steel and liner plate from the predicted design accident thermal loads and factored accident loads.

The isostress plots shown in Figure 3-25 and Figure 3-26 do not consider the concrete cracked. The thermal stresses are combined from the individual isostress output for the cases of D + F + T and D + F + 1.5P + T. The first case is critical for concrete stresses and occurs after depressurization of the Reactor Building; the second case is critical for the reinforcing stresses and it occurs when pressure and thermal loads are combined and cause cracking at the outside face. The loading cases for isostress plots shown in Figure 3-25 are D + F + 1.15P on Sheet 1, 0.95D + F + 1.5P + T on Sheet 2, D + F on Sheet 3, and T on Sheet 4. The loading cases for isostress Plots shown in Figure 3-26 are D on Sheet 1, F on Sheet 2, T on Sheet 3, 0.95D + T on Sheet 4, F + 1.15P on Sheet 5, and F + 1.5P on Sheet 6.

The general approach of determining stresses in the concrete and reinforcement required the evaluation of the stress blocks of the cross section being analyzed.

The value of stresses was taken from the computer output in case of axisymmetric loading and from analytical solutions in case of nonaxisymmetric loading. Both computations were based on homogeneous materials; therefore, some adjustment was necessary to evaluate the true stress-strain conditions when cracks develop in the tensile zone of the concrete.

An equilibrium equation can be written considering the tension force in the reinforcement, the compressive force in the concrete and the axial force acting on the section. In this manner, the neutral axis is shifted from the position defined by the computer analyses into a position which is the function of the amount of reinforcement, the modulus ratio, and the acting axial forces.

Large axial compressive force might prevent the existence of any tension stresses, as in the loading condition D + F + T; therefore, no self-relieving action exists; the stresses are taken directly from the computer output, except at the buttresses where analysis showed tensile stress in the concrete exceeded the modulus of rapture.

In the case of D + F + 1.5P + T, the development of cracks in the concrete decreases the thermal moment and this effect was considered; but the self-relieving properties of other loadings were not taken into account, even in places where they do exist, such as at discontinuities, e.g., the cylinder-base slab connection. This means that in analyzing the section, a reduced thermal moment was added to the unreduced moment caused by other loadings.

The thermal stresses in the containment are comparable to those developed in a reinforced concrete slab, which is restrained from rotation. The temperature varies linearly across the slab. The concrete will crack in tension and the neutral axis will be shifted toward the compressive extreme fiber. The cracking will reduce the compression at the extreme fiber and increase the tensile stress in reinforcing steel.

The following analysis is based on the equilibrium of normal forces; therefore, any normal force acting on the section must be added to the normal forces resulting from the stress diagram. The effects of Poisson's ratio are considered while the reinforcement is considered to be identical in both directions.

Stress - Strain relationship in compressed region of concrete:

$$E_c\Sigma_x = \sigma_x - \nu_c\sigma_y \qquad \text{Equation 1}$$

$$E_c\Sigma_y = -\nu_c\sigma_x + \sigma_y \qquad \text{Equation 2}$$

From the above equations (1) and (2):

$$\sigma_x = E_c\frac{\Sigma_x + \Sigma_y\nu}{1-\nu_c{}^2} \qquad \text{Equation 3}$$

$$\sigma_y = E_c\frac{\Sigma_y + \Sigma_x\nu}{1-\nu_c{}^2} \qquad \text{Equation 4}$$

Substituting,

$\sigma_x = \sigma_y = \sigma_c \text{and}\, \Sigma_x = \Sigma_y = \Sigma_c$ into equations (3) and (4)

$$\sigma_c = E_c\Sigma_c\frac{1}{1-\nu_c} = 1.205E_c\Sigma_c(\text{if}\nu_c = .17)$$

The reinforcement is acting in one direction, independently from the reinforcement in the perpendicular direction.

Example: If $E_c = 3 \times 10^6$ and $E_s = 29 \times 10^6$

$$n_R = \frac{29}{1.205 \text{ x } 3} = 8.02$$

The liner plate is acting in two directions, similar to the concrete except for the difference caused by the Poisson's ratios:

$$\sigma_L = E_s \Sigma_s \frac{1}{1 - \nu_L} = 1.35 E_s \Sigma_s \qquad \nu_L = .25$$

$$n_L = \frac{1.35 \text{ x } 29}{1.205 \text{ x } 3} = 10.83 \qquad \nu_c = .17$$

The following is an example of the use of the analytical method derived for D + F + P + T_A + E (See Table 3-16).

The concrete and reinforcement stresses are calculated by conventional methods, from the moment caused by loading other than thermal. The analyses assume homogeneous concrete sections. Those concrete and reinforcing steel stresses are then added to the thermal stresses as obtained by the method described.

Data:

E_c = 3 x 10^6 psi ν_L = 0.25

E_s = 29 x 10^6 psi n_R = 8.02

ν_c = 0.17 n_L = 10.83

Notation:

E_c Modulus of elasticity of concrete.

E_s Modulus of elasticity of steel.

n_L Modular ratio of liner plate-concrete.

n_R Modular ratio of reinforcement-concrete.

$^{\Delta}\sigma c$ Reduction of concrete compressive stress, considering cracking.

Σ_c Concrete strain.

Σ_s Steel strain.

Σ_x Concrete strain in X direction.

Σ_y Concrete strain in Y direction.

ν_c Poisson's ratio of concrete.

ν_L Poisson's ratio of liner plate.

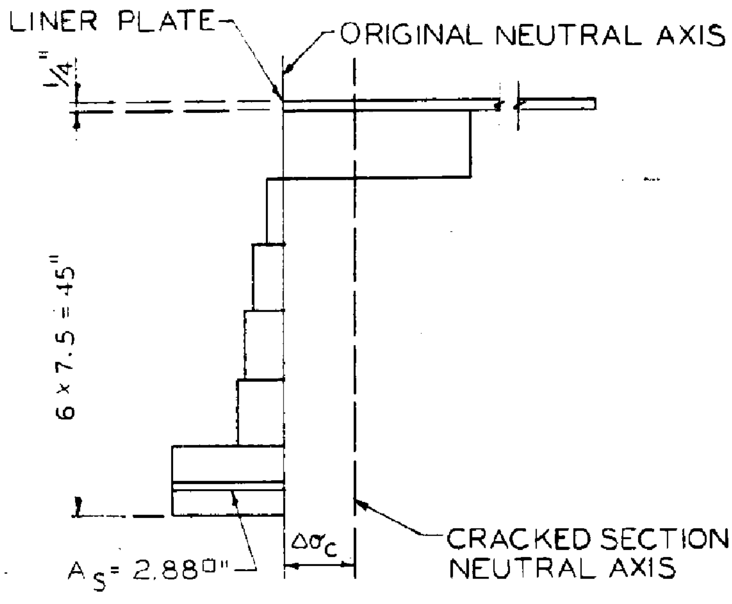
σ_c Stress in concrete.

σ_L Stress in liner plate.

σ_R Stress in reinforcement.

σ_x Stress in concrete in direction X.

STRESS BLOCK FROM THE COMPUTER OUTPUT



SECTION G-H
(ELEMENT 333-339)

(Thermal) Stresses (Psi)	(Thermal) Forces (K/Ft.) Resultant
-36000	- 108.0
- 1997	- 179.7
+ 277	+ 24.9
+ 529	+47.6
+ 595	+ 53.5
+ 666	+ 60.0
+ 1467	+ 132.0

EQUILIBRIUM AFTER CRACKING

$2.88\ (1467+{}^{\Delta}\sigma c)\ 8.02 - (179.7+108)\ 1000 + {}^{\Delta}\sigma c\ (12x7.5+3x10.83) = N = -102{,}000$

$33884 + 23.1\ {}^{\Delta}\sigma c - 287700 + 124.5\ {}^{\Delta}\sigma c + 102{,}000 = 0$

$$147.6\ {}^{\Delta}\sigma c = 151{,}816$$

$${}^{\Delta}\sigma c = 1028.6$$

ASSUMED POSITION OF N. A. is O.K.

$${}^{\Delta}\sigma c = 1029 \text{ Psi}$$

σ_s(After Cracking) = (1467 + 1029) 8.02 = 20018 Psi

σ_c = -1997 + 1029 = -968 Psi

σ_R = σ_{D+F+P} + σ_T + σ_E

= -503 + 20018 ± 96 = 19611 (Tensile)

σ_c = σ_{D+F+P} + σ_T + σ_E

= 61 - 968 ± 11 = -918 (Compression)

3.8.1.4.2 Nonaxisymmetric Analysis

The nonaxisymmetric aspects of configuration or loading required various methods of analysis. The description of the methods used as applied to different parts of the containment is given below.

1. Buttresses

   The buttresses and tendon anchorage zones are defined as Class 1 elements and were designed in accordance with the general design criteria for the Reactor Building structure and with the applicable provisions of ACI 318-63, Chapter 26.

   The buttresses were analyzed for two effects, nonaxisymmetric and anchorage zone stresses. Both effects are shown in the results of a two-dimensional plane strain finite element analysis with loads acting in the plane of the coordinate system (Figure 3-27).

   At each buttress, the hoop tendons are alternately either continuous or spliced by being mutually anchored on the opposite faces of the buttress. Between the opposite anchorages, the compressive force exerted by the spliced tendon is twice as much as elsewhere. This value combined with the effect of the tendon which is not spliced will be 1.5 times the prestressing force acting outside of the buttresses. The cross-sectional area at the buttress is about 1.5 times that of the wall, so the hoop stresses as well as the hoop strains and radial displacements can be considered as being nearly constant all around the structure. Isostress plots of the plane strain analysis, Figure 3-28, confirm this.

   The vertical stresses and strains, caused by the vertical post-tensioning, become constant at a short distance away from the anchorages because of the stiffness of the cylindrical shell. Since the stresses and strains remain nearly axisymmetric despite the presence of the buttresses, their effect on the overall analysis is negligible when the structure is under dead load or prestressing loads.

   When an increasing internal pressure acts upon the structure, combined with a thermal gradient (Figure 3-29) such as at the design accident condition, the resultant forces being axisymmetric, the stiffness variation caused by the buttresses will decrease as the concrete develops cracks. The structure will then tend to shape itself to follow the direction of the acting axisymmetric resultant forces even more closely. Thus, the buttress effect is more axisymmetric at yield loads, which include factored pressure, than at design loads including pressure. This fact, combined with the design provision that alternate horizontal tendons terminate in a single buttress, indicates that the buttresses will not reduce the margins of safety available in the structure.

   The analysis of the anchorage zone stresses at the buttresses has been determined to be the most critical of all the various types of anchorage areas of the shell. The local stress distribution in the immediate vicinity of the bearing plates has been derived by the following three analysis procedures:

a. The Guyon equivalent prism method: This method is based on experimental photoelastic results as well as on equilibrium considerations of homogeneous and continuous media. It should be noted that the relative bearing plate dimensions are considered.

b. In order to include biaxial stress effects, use has been made of the experimental test results presented by S. J. Taylor at the March 1967 London Conference of the Institution of Civil Engineers (Group H, Paper 49). This paper compares test results with most of the currently used approaches (such as Guyon's equivalent prism method). It also investigates the effect of the rigid trumpet welded to the bearing plate.

c. The finite element method, assuming homogeneous and elastic material, was used in a plane strain analysis. The mesh and results are shown in Figure 3-27 and Figure 3-28.

The Guyon method yields the following results for a loading ratio (a′/a)[1] = 0.9 Maximum compressive stress under the bearing plate:

σ_c = -2400 psi

Maximum tensile stress in spalling zone:

σ spalling = +2400 psi = $-\sigma_c$

Maximum tensile stress in bursting zones:

σ maximum bursting = 0.04 P = +96 psi

S. J. Taylor's experimental results indicate that the anchor plate will give rise to a similar stress distribution pattern as Guyon's method; the main difference lies in the fact that the central bursting zone has a tensile stress peak of twice Guyon's value:

σ maximum bursting = +192 psi

By finite element analysis, the symmetric buttress loading yields a tensile peak stress in the bursting zone very close to S. J. Taylor's value:

s maximum bursting = +114 psi

A state of biaxial tension in the concrete will appear on the outside face under the loading case 1.05D + 1.5P + 1.0T_A + 1.0F. The superposition of the corresponding state of stress with the local anchor stresses reduces the load carrying capacity of the anchorage unit and caused a reduction in the maximum tensile strain to cracking.

On the other hand, the uniform compressive state of stress (vertical prestress) applied to the anchorage zone increases the load carrying capacity of the anchorage unit, with the maximum tensile strain to cracking being increased.

The design of the buttress anchor zones considered such additional vertical stresses, leading to a state of pseudo biaxial stress, the second direction being radial through the thickness.

For the above-mentioned case, 1.05D + 1.5P + 1.0T_A + 1.0F, the averaged vertical (meridional) stress component is:

$$f_a \simeq +400\text{psi}$$

[1] Ratio of width of bearing plate to width of concrete under bearing plate.

The compressive bearing plate stress at 10 inches depth below the bearing plate is:

$$f_c \simeq -1500\text{psi}$$

(Note: The steel trumpet carries 7.2 percent of the prestress force.)

Thus, the two values introduced in the biaxial stress envelopes proposed in S. J. Taylor's article:

$$f_c / f_c' = 1500/1500 = 0.3$$

$$f_c / f_c' = 400/5000 = 0.08$$

show that failure could occur if vertical reinforcing were not provided. In fact, the maximum allowable vertical averaged tensile stress according to Taylor's interaction curve is $f_a / f_c' = 0.03$; therefore, $f_a = +150$ psi.

The three dimensional stress distribution in the anchor zones was analyzed in sufficient detail to permit the rational evaluation of stress concentrations. A conical wedge segment was used as the basic design element and the radial splitting tension was determined as a tangential distribution function. The summation of splitting stresses through the entire volume of the lead-in zone established the value of the splitting force. This force is a function of the a/b ratio and the cone angle and/or, a/b and h. Several different combinations of the values were analyzed and the most critical values selected. A system analysis for the vertical splitting force was carried out based on statics and the magnitude of vertical and spalling forces were also determined.

The most unfavorable loads and load combinations were considered in the analysis of the anchorage zone and stresses based on transient thermal gradients were used in all cases where the use of a steady state gradient under-estimated the stresses and strains and were superimposed on the bursting stresses determined from the triaxial stress calculations. The computed stresses are less than the ACI allowable values. The design of the concrete reinforcement is based on this conservative analysis to provide a margin of safety similar to the other components of the Reactor Building structure and to control cracking in the anchorage zone. As a result, there is no danger of delayed rupture of the concrete under sustained load, due to local overstress and microcracking.

The reinforcing details, including the method for anchoring and splicing the reinforcing, are shown on Figure 3-30.

The reinforcement required has been designed primarily to resist tensile forces and has been located such that it will efficiently resist the tensile forces. The reinforcement was provided for load cases which create the maximum tensile forces and for other load cases the relevant shear forces or stresses were superimposed.

The possibility of the concrete breaking along shear planes was considered at the intersection of (1) the buttress with the cylinder and (2) the cylinder with the base slab.

a. Buttress - Cylinder Intersection

   An increase in the compression force at the buttress corresponds to an increase in the concrete area of the same magnitude.

b. Cylinder - Base Slab Intersection

   An analysis for the most critical radial shear conditions was performed. The difference in shear stiffness between the shell and the buttress and the remainder of the shell was included as a shear amplification factor. The reinforcing required was less than the reinforcing provided.

The possibility of concrete breaking along a shear plane is excluded by providing ample reinforcing. In other locations, breakage along the shear plane has been excluded by the opposition of prestressing and anchor forces.

The following three sources of information were also considered in the design of the anchorage zone reinforcing:

a. Full-scale load tests of the anchorage on the same concrete mix used in the structure and review of prior uses of the anchorage.

b. The post-tensioning supplier's recommendations of anchorage reinforcing requirements.

c. Review of the final details of the combined reinforcing by the consulting firm of T. Y. Lin, Kulka, Yang, and Associates.

2. Large Opening (Equipment Hatch and Personnel Lock Opening)

The primary loads considered in the design of the equipment hatch and personnel lock opening, as for any part of the structure, were dead load, prestress, pressure, earthquake, and thermal loads. The secondary loads considered were the following effects caused by the above primary loads:

a. The deflection of tendons around the opening.

b. The curvature of the shell at the opening.

c. The thickening around the opening.

The primary loads listed are mainly membrane loads with exception of the thermal loads. In addition to membrane loads, accident pressure also produces punching shear around the edge of the opening. The values of these loads for design purposes were the magnitudes of these loads at the center of the opening. These are fairly simple to establish knowing the values of hoop and vertical prestressing, accident pressure, and the geometry and location of the opening.

Secondary loads were predicted by the following methods:

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

a. The membrane stress concentration factors and effect of the deflection of the tendons around the equipment hatch were analyzed for a flat plate by the finite element method. The stresses predicted by conventional stress concentration factors, compared with those values found from above-mentioned finite element computer program, demonstrated that the deflection of the tendons does not significantly affect the stress concentrations. This is a plane stress analysis and does not include the effect of the curvature of the shell. However, it gives an assurance of the correctness of the assumed membrane stress pattern caused by the prestressing around the opening. Results of this analysis are shown in Figure 3-31.

b. With the help of *Reference 1*, stress resultants around the large opening were found for various loading cases. Comparison of the results found from this reference, with the results of a flat plate of uniform thickness with a circular hole, showed the effect of the cylindrical curvature on stress concentrations around the opening.

Normal shear forces (relative to opening) were modified to account for the effect of twisting moments as shown in *Reference 1*. These modified shear forces are called

Kirschoff's shear forces. Horizontal wall ties were provided to resist a portion of these shear forces.

c. The effect of the thickening on the outside face around the large opening was considered using several methods. *Reference 2* was used to evaluate the effect of thickening on the stress concentration factors for membrane stress. A separate axisymmetric finite element computer analysis for a flat plate with anticipated thickening on the outside face was prepared to handle both axisymmetric and nonaxisymmetric loads to predict the effect of the concentration of hoop tendons, with respect to the Reactor Building at the top and bottom of the opening.

For the analysis of the thermal stresses around the opening, the same method was used as for the other loadings. At the edge of the opening, a uniformly distributed moment, equal but opposite to the thermal moment existing on the rest of the shell, was applied and evaluated using the methods of the preceding *Reference 1*. The effects were then superimposed on the stresses calculated for the other loads and effects.

In the case of accident temperature, after the accident pressure has already been decreased, very little or no tension develops on the outside, so thermal strains will exist without the relieving effect of the cracks. However, the liner plate will reach a high strain level and so will the concrete at the inside corner of the penetration, thereby relieving the very high stresses, but still carrying a high moment in the state of redistribution stresses.

In the case of 1.5P (prestress fully neutralized) + $1.0T_A$ (accident temperature), the cracked concrete with highly strained tension reinforcement constitutes a shell with stiffness decreased but still essentially constant in all directions. In order to control the increased hoop moment around the opening, the hoop reinforcement is about twice that of the radial reinforcement. See Figure 3-21.

The equipment hatch opening was thickened for the following reasons:

1) To reduce the larger than acceptable predicted membrane stresses around the opening.
2) To accommodate tendon placement.
3) To accommodate bonded steel reinforcing placement.
4) To compensate for the reduction in the overall shell stiffness due to the opening.

The working stress method (elastic analysis) was applied to both the load combinations for design loads, as well as for yield loads, for the analytical procedures described above. The only difference is the higher allowable stresses under yield conditions. The various factored load combinations and capacity reduction factors are specified in Section 3.8.1.3.6 and were used for the yield load combinations using the working stress design method. The design assumption of straight line variation of stresses was maintained under yield conditions.

The governing design condition for the sides of the equipment hatch opening at the outside edge of the opening is the accident condition. Under this condition, approximately 60 percent of the total bonded reinforcing steel needed at the edge of the opening at the outside face is required for the thermal load.

Excluding thermal load, the remaining stress (equivalent to approximately 40 percent of the total load including thermal) at the edge of the outside face is the sum of the following stress resultants:

1) Normal stresses resulting from membrane forces, including the effect of thickening, contribute approximately minus 35 percent (minus 14 percent of total).

2) Flexural stresses resulting from the moments caused by thickening on the outside face contribute approximately 150 percent (60 percent of total).

3) Normal and flexural stresses resulting from membrane forces and moments caused by the effect of cylindrical curvature contribute approximately minus 15 percent (minus 6 percent of total).

3. Penetrations

Analysis of the Reactor Building penetrations falls into three parts: (1) the concrete shell, (2) the liner plate reinforcement and closure to the pipe, and (3) the thermal gradients and protection requirements at the high-temperature penetrations. The three categories will be discussed separately.

a. Concrete Shell

In general, special design consideration is given to all openings in the Reactor Building. Analysis of the various openings has indicated that the degree of attention required depends upon the penetration size. Small penetrations are considered to be those with a diameter smaller than 2-½ times the shell thickness: i.e., approximately 8 feet in diameter or less. Reference 1 indicates that, for openings of 8-foot diameter or less, the curvature effect of the shell is negligible. In general, the typical concrete wall thickness has been found to be capable of taking the imposed stresses using bonded reinforcement, and the thickness is increased only as required to provide space requirements for radially deflected tendons. The induced stresses, due to normal thermal gradients and postulated rupture conditions, distribute rapidly and are of a minor nature compared to the numerous loading conditions for which the shell must be designed. The small penetrations are analyzed as holes in a plane sheet. Applied piping restraint loads due to thermal expansion or accident forces are assumed to distribute in the cylinder as stated in Reference 3. Typical details associated with these openings are indicated in Figure 3-20.

b. Liner Plate Closure

The stress concentrations around openings in the liner plate were calculated using the theory of elasticity. The stress concentrations were then reduced by the use of a thickened plate around the opening. In the case of a penetration with no appreciable external load, stud bolts are used to maintain strain compatibility between the liner plate and the concrete. Inward displacement of the liner plate at the penetration is also controlled by the stud bolts.

In the case of a pipe penetration in which significant external operating loads are imposed upon the penetration, the stress level from the external loads is limited to the design stress intensity values, S_m, given in the ASME Boiler and Pressure Vessel Code, Section III, Article 4. The stress level in the stud bolts from external loads is in accordance with the AISC Code.

The combining of stresses from all effects is performed using the methods outlined in the ASME Boiler and Pressure Vessel Code, Section III, Article 4, Figure N-414. The maximum stress intensity is the value from Figure N-415 (A) of the previously referenced code. Figure 3-32 shows a typical penetration and the applied loads.

Design stresses for the effects of pipe loads, pressure loads, dead load, and earthquake were calculated and the stress intensity kept below S_m.

The stresses from the remaining effects were combined with the above-calculated stresses and the stress intensity kept below S_a.

c. Thermal Gradient

The only high temperature lines penetrating the Reactor Building shell are the main steam and feedwater. Cooling fans and stacks are provided for the Main Steam penetrations. The feedwater penetrations rely on natural ventilation for cooling.

4. Liner Plate

There are no design conditions under which the liner plate is relied upon to assist the concrete in maintaining the integrity of the structure even though the liner will, at times, provide assistance in order to maintain deformation compatibility.

Loads are transmitted to the liner plate through the anchorage system and direct contact with the concrete and vice versa. Loads may be, at times, also transmitted by bond and/or friction with the concrete. These loads cause, or are caused by, liner strain. The liner is designed to withstand the predicted strains.

Possible cracking of concrete has been considered and reinforcing steel is provided to control the width and spacing of the cracks. In addition, the design is made such that total structural deformation remains small during the loading conditions, and that any cracking will be orders of magnitude less than that sustained in the repeated attempts to fail the prestressed concrete reactor vessel “Model 1,” and even smaller than the concrete strains of overpressure tests of “Model 2” (both at General Atomic). See Reference 4 and Reference 5.

As described, the structural integrity consequences of concrete cracking are limited by the bonded reinforcing and unbonded tendons provided in accordance with the design criteria. The effect of concrete cracking on the liner plate has also been considered. The anchor spacing and other design criteria are such that the liner will sustain orders of magnitude of strain, for example, less than did the liner of Model 1 at General Atomic (Reference 4) without tensile failure.

5. Liner Plate Anchors

The liner plate anchors were designed to preclude failure when subjected to the worst possible loading combinations. The anchors were also designed such that, in the event of a missing or failed anchor, the total integrity of the anchorage system would not be jeopardized by the failure of adjacent anchors.

The following loading conditions were considered in the design of the anchorage system:

a. Prestress

b. Internal Pressure

c. Shrinkage and Creep of Concrete

d. Thermal Gradients

e. Dead Load

f. Earthquake

g. Wind or Tornado

h. Vacuum

The following factors were considered in the design of the anchorage system:

a. Initial inward curvature of the liner plate between anchors due to fabrication and erection inaccuracies.

b. Variation of anchor spacing.

c. Misalignment of liner plate seams.

d. Variation of plate thickness.

e. Variation of liner plate material yield stress.

f. Variation of Poisson's ratio for liner plate material.

g. Cracking of concrete in anchor zone.

h. Variation of the anchor stiffness.

The anchorage system satisfies the following conditions:

a. The anchor has sufficient strength and ductility so that its energy absorbing capability is sufficient to restrain the maximum force and displacement resulting from the condition where a panel with initial outward curvature is adjacent to a panel with initial inward curvature.

b. The anchor has sufficient flexural strength to resist the bending moment which would result from Condition 5a.

c. The anchor has sufficient strength to resist radial pull-out force.

When the liner plate moves inward radially as shown in Figure 3-33, the sections will develop membrane stress due to the fact that the anchors have moved closer together. Due to initial inward curvature, the section between 1 and 4 will deflect inward giving a longer length than adjacent sections and some relaxation of membrane stress will occur. It should be noted here that section 1-4 cannot reach an unstable condition due to the manner in which it is loaded.

The first part of the solution for the liner plate and anchorage system is to calculate the amount of relaxation that occurs in section 1-4, since this value is also the force across anchor 1 if it is infinitely stiff. This solution was obtained by solving the general differential equation for beams and the use of calculus to simulate relaxation or the lengthening of section 1-4. Figure 3-33 shows the symbols for the forces that result from the first step in the solution.

Using the model shown in Figure 3-34 and evaluating the necessary spring constants, the anchor was allowed to displace.

The solution yielded a force and displacement at anchor 1, but the force in section 1-2 was (N) - $K_{R(Plate)}S_1$ and anchor 2 was no longer in force equilibrium.

The model shown in Figure 3-34 was used to allow anchor 2 to displace and then to evaluate the effects on anchor 1.

The displacement of anchor 1 was $S_1 + S'_1$ and the force on anchor 1 was $K_c(S_1 + S'_1)$. Then anchor 3 is not in force equilibrium and the solution continued to the next anchor.

After the solution was found for displacing anchor 2 and anchor 3, the pattern was established with respect to the effect on anchor 1 and by inspection, the solution considering an infinite amount of anchors was obtained in the form of a series solution.

The preceding solution yielded all necessary results. The most important results were the displacement and force on anchor 1.

Various patterns of welds attaching the angle anchors to the liner plate have been tested for ductility and strength when subjected to a transverse shear load such as N and are shown in Figure 3-35.

Using the results from these tests together with data from tests made for the Fort St. Vrain PSAR, Amendment No. 2 and Oldbury vessels, Reference 6, a range of possible spring constants was evaluated for the Oconee liner. By using the solution previously obtained together with a chosen spring constant, the amount of energy required to be absorbed by the anchor was evaluated.

By dividing the amount of energy that the system will absorb by the most probable maximum energy, the result then yielded the factor of safety.

By considering the worst possible loading condition which resulted from the listed loading conditions and conditions stated below, the results in Table 3-15 were obtained.

Case I	– Simulates a plate with a yield stress of 36 Ksi and no variation in other parameters.
Case II	– Simulates a 1.25 increase in yield stress and no variation in any other parameters.
Case III	– Simulates a 1.25 increase in yield stress, a 1.16 increase in plate thickness and a 1.08 increase for all other parameters.
Case IV	– Simulates a 1.88 increase in yield stress with no variation of any other parameters.
Case V	– Is the same as Case III except the anchor spacing has been doubled to simulate what happens if an anchor is missing or has failed.

6. Supports

In designing for structural bracket loads applied perpendicular to the plane of the liner plate, or loads transferred through the thickness of the liner plate, the following criteria and methods have been used:

a. The liner plate was thickened to reduce the predicted stress level in the plane of the liner plate. The thickened plate with the corresponding thicker weld attaching the bracket to the plate will also reduce the probability of the occurrence of a leak at this location.

b. Under the application of a real tensile load applied perpendicular to the plane of the liner plate, no yielding is to occur in the perpendicular direction. By limiting the predicted strain to 90 percent of the minimum guaranteed yield value, this criterion was satisfied.

c. The allowable stress in the perpendicular direction was calculated using the allowable predicted strain in the perpendicular direction together with the predicted stresses in the plane of the liner plate.

d. In setting the above criteria, the reduced strength and strain ability of the material perpendicular to the direction of rolling (in plane of plate) was also considered in the bracket did not penetrate the liner thickened plate. In this case, the major stress is normal to the plane of the liner plate. The allowable stresses were reduced to 75 percent of the stress permitted in Item (3) above.

e. The necessary plate characteristics were assured by ultrasonic examination of the thickened plates for lamination defects.

3.8.1.4.3 Analysis of the Reactor Building for Steam Generator Replacement

Replacement of the steam generators required the creation of a construction opening in the shell wall of the reactor buildings. The structural analysis required to accomplish this task consisted of a finite element model which explicitly represented the vertical tendons, hoop tendons, and opening geometry. The model represented 180 degrees of the structure with the symmetry plan placed along the 0 to 180 degree azimuth of the building. The ANSYS computer program was used for this analysis.

The structure was analyzed for the load combinations given in the UFSAR and farther delineated by Oconee calculation OSC-6728. Additional load combinations were added, per ACI 318-63, that describe the structural loadings while the containment opening is in place. Each load combination was applied to the model in twelve load steps. Each step represents a significant point of change as the building is undergoing opening creation and repair.

3.8.1.5 Structural Acceptance Criteria

This section documents the manner in which the structural acceptance criteria were met by the designer.

Section 3.8.1.5.1 consists of isostress plots and tabulations of predicted stresses for the various materials. The isostress plots of the homogeneous uncracked concrete structure indicate the general stress pattern for the structure as a whole, under various loading conditions. More specific documentation is made of the predicted stresses for all materials in the structure. In these tabulations, the predicted stress is compared with the allowable to permit an easy comparison and evaluation of the adequacy of the design.

Sections 3.8.1.5.3 and 3.8.1.5.4 illustrate the actual details used in the design to implement the criteria.

3.8.1.5.1 Results of Analysis

The isostress plots, Figure 3-25 and Figure 3-26, show the three principal stresses and the direction of the principal stresses normal to the hoop direction. The principal stresses are the most significant information about the behavior of the structure under the various conditions and were a valuable aid for the final design.

The plots were prepared by a cathode-ray tube plotter. The data for plotting were taken from the stress output of the finite element computer program for the following design load cases:

$D + F$

$D + F + 1.15P$

$D + F + 1.5P + T_A$

$D + F + T_A$

The above axisymmetric loading conditions have been found to be governing in the design since they result in highest stresses at various locations in the structure.

The containment stress analysis results for structural concrete and liner plate, including shear stresses, are shown in Table 3-16.

3.8.1.5.2 Prestress Losses

In accordance with the ACI Code 318-63, the design provides for prestress losses caused by the following effects:

1. Seating of anchorage.
2. Elastic shortening of concrete.
3. Creep of concrete.
4. Shrinkage of concrete.
5. Relaxation of prestressing steel stress.
6. Frictional loss due to intended or unintended curvature in the tendons.

All of the above losses can be predicted with sufficient accuracy.

The environment of the prestress system and concrete is not appreciably different, in this case, from that found in numerous bridge and building applications. Considerable research has been done to evaluate the above items and is available to designers in assigning the allowances. Building code authorities consider it acceptable practice to develop permanent designs based on these allowances.

The following categories and values of prestress losses have been considered in the design:

Type of Loss	Assumed Value
Seating of Anchorage	None
Elastic Shortening	$\frac{f_{cpi}}{3.0\text{x}10^6}$ Inch/Inch
Creep of Concrete	$0.222 \times 10^{-7} \times \ln(t+1)$ Inch/Inch/psi
Shrinkage of Concrete	100×10^{-6} Inch/Inch
Relaxation of Prestressing Steel	
Hoop & Vertical	14.6% of $0.65f_s$ = 22.82 Ksi
Dome	16.04% of $0.65f_s$ = 25.06 Ksi
Frictional Loss	K = 0.0003, μ = 0.156

There is no allowance for the seating of the BBRV anchor since no slippage occurs in the anchor during transfer of the tendon load into the structure. Sample lift-off readings will be taken to confirm that any seating loss is negligible.

The loss of tendon stress due to elastic shortening was based on the change in the initial tendon relative to the last tendon stressed.

The concrete properties study conducted at Clemson University indicated an acutal creep value of 0.222×10^{-7} inch/inch/psi. Conversion of the unit creep data to hoop, vertical and dome stress gives these values of stress loss in the tendons:

	Hoop	-9.8 Ksi
	Vertical	-4.65 Ksi
	Dome	-5.60

The value used for shrinkage loss represents only that shrinkage that could occur after stressing. Since the concrete is, in general, well aged at the time of stress, little shrinkage is left to occur and add to prestress loss.

The value of relaxation loss is based on the information furnished by the tendon system vendor, The Prescon Corporation.

Frictional loss parameters for unintentional curvature (K) and intentional curvature (μ) are based on full-scale friction test data. This data indicates actual values of K = 0.0003 and μ = 0.125 versus the design values of K = 0.0003 and μ = 0.156.

Assuming that the jacking stress for tendons is 0.80 f'_s of 192,000 psi and using the above prestress loss parameters, the following tabulation shows the magnitude of the design losses and the final effective prestress at end of 40 years for a typical dome, hoop and vertical tendon.

	Dome (Ksi)	**Hoop (Ksi)**	**Vertical (Ksi)**
Jacking Stress	175.2	174.6	175.2
Friction Loss	13.3	12.26	10.4
Seating Loss	0	0	0
Elastic Loss	6.6	7.6	2.86
Creep Loss	5.6	9.8	4.65
Shrinkage Loss	2.9	2.9	2.9
Relaxation Loss	25.1	22.8	22.8
Final Effective Stress[1]	121.7	119.2	131.6

Note:

1. This force does not include the effect of pressurization which increases the prestress force.

To provide assurance of achievement of the desired level of Final Effective Prestress and that ACI 318-63 requirements are met, a written procedure was prepared for guidance of post-tensioning work. The procedures provided nominal values for end anchor forces in terms of pressure gauge readings for calibrated jack-gauge combinations. Force measurements were made at the end anchor, of course, since that is the only practical location for such measurements.

The procedure required the measured temporary jacking force, for a single tendon, to approach but not exceed 850 kips (0.8f'_s). Thus, the limits set by ACI 318-63 2606 (a) 1, and of the prestressing system supplier, were observed. Additionally, benefits were obtained by in place testing of the tendon to provide final assurance that the force capability exceeded that required by design. During the increase in force, measurements were required of elongation changes and force changes in order to allow documentation of compliance with ACI 318-63 2621 (a).

The procedures required that the prestressing steel be installed in the sheath before stressing for a sufficient time period that the temperatures of the prestressing steel and concrete reach essential equilibrium, to establish conformance with ACI 318-63 2621 (e). The jacking force of $0.8f'_s$ further provided for a means of equalizing the force in individual wires of a tendon to establish compliance with ACI 318-63 2621 (b). The procedures required compliance with ACI 318-63 such that, if broken wires resulted from the post-tensioning sequence, compliance with section 2621 (d) was documented. Each of the above procedures contributed to assurance that the desired level of Final Effective Prestress would be achieved.

The requirements of ACI 318-63 2606 (a) 2 state that f_s should not exceed $0.7f'_s$ for "post-tensioning" tendons immediately after anchoring.

Industry has been considering rewriting that requirement such that it has only one interpretation rather than the several now possible. Consideration is also being given to raising the value of $0.7f'_s$ or eliminating the requirement entirely and, instead, retaining the $0.8f'_s$ or some other limitation on temporary jacking force.

Paragraph 2606 (a) 2 of ACI 318-63 refers to "tendons" rather than to an individual tendon. Further, the paragraph does not refer to the location to be considered for the determination of f_s in the manner, for example, of the "temporary jacking force" referred to in 2606 (a) 1.

Two interpretations were therefore required. Both interpretations had to consider the effect of the resultant actions on both the prestressing system and structure.

The first interpretation was that the location for measurement of the seating force, used in calculating f'_s was at the end anchor and just subsequent to the measurement of the "temporary jacking force" referred to in ACI 318-63 2606 (a) 1. The advantages of this location are several. One is that it is a practical one and thus the possibility for achieving valid measurements is greater. The second is that it is the same location used for measuring the "temporary jacking force" and measurements could be made without the added complexity of additional measuring devices. The third advantage is that measurements at this location provide assurance that the calculated f'_s does not anywhere exceed the maximum f'_s to which that tendon has been subjected.

Several possible cases were considered for the second interpretation so as to allow anchoring of an individual tendon without exceeding the requirement stated for "tendons" collectively in ACI 318-63 2606 (a) 2. One such case assumed that the anchoring force for the typical tendon was that for a tendon anchored midway through the prestressing sequence. It further assumed that the losses to be assumed were one-half of the sum of elastic losses, and of the creep, shrinkage, and relaxation predicted to occur during the entire prestressing sequence. This interpretation, however, was not considered to be practical nor enforceable since it resulted in changing the seating forces as the actual (as compared to the schedule) time length of the prestressing period was dictated by weather and manpower availability.

Another case considered was that of anchoring each tendon at a measured force of 850 kips ($0.8f'_s$). Although there was no apparent detrimental effect to the prestressing system or structure, insertion of shims would be almost impossible. Further, it was concluded that this case would not establish compliance with ACI 318-63.

The case adopted was to seat each tendon with a measured "pressure" reading for the jack, at "lift-off" of the end anchor, of 775 kips (between 0.72 and 0.73 f'_s). This procedure has several advantages.

One advantage was that the force on the containment and the tendon was within the bounds of those for which it had been tested and resulted in no known detrimental effects. The second advantage was that the stressing procedure was simplified since the stressing crews did not have to accommodate a large number of different anchoring force requirements. The third advantage was that, at the completion of stressing the last tendon, the expected losses were such that the average f'_s at the end anchors of the tendons would be less than 0.7 f'_s, thus establishing compliance with ACI 318-63 2606 (a) 1 and 2. The fourth advantage was that the percentage loss of prestressing force was less than would be the case if the tendons were anchored in such a manner the calculated value of f'_s nowhere exceeded 0.7 f'_s.

The latter advantage deserves special mention since it plays a strong role in assuring that the Final Effective Prestress equalled or exceeded the desired value. For example, if the f'_s at anchorage of the tendons were 0.1 f'_s, creep and shrinkage of concrete could result in the loss of almost all of the prestressing force. Assuming that the total losses due to creep, shrinkage, and elastic shortening equals 0.1 f'_s, then the Final Effective Prestress would be 20 percent percent of an initial prestress equivalent to 0.5 f'_s. If the initial prestress were equivalent to 0.7 f'_s, the Final Effective Prestress, neglecting relaxation for the moment, would be about 86 percent of the initial prestress. Clearly, the assurance (that the concrete creep and shrinkage losses have been properly accounted for) increases as the f'_s for the anchored tendons and tendon increases. However, this design was committed to meeting the ACI 318-63 requirement and the anchorage force for the tendons was kept at or below 0.7 f'_s in accordance with the interpretation described.

Loss of prestress in the post-tensioning system is due to material strain occurring under constant stress. Loss of prestress over time is accounted for in the design and is a time-limited aging analysis requiring review for license renewal.

In accordance with ACI 318-63 the design of the Oconee Containment post-tensioning system provides for prestress losses caused by the following:

1. Elastic shortening of concrete
2. Creep of concrete
3. Shrinkage of concrete
4. Relaxation of prestressing steel stress
5. Frictional loss due to curvature in the tendons and contact with tendon conduit.

No allowance is provided for seating of the anchor since no slippage occurs in the anchor during transfer of the tendon load into the structure.

By assuming an appropriate initial stress from tensile loading and using appropriate prestress loss parameters, the magnitude of the design losses and the final effective prestress at the end of 40 years for typical dome, vertical, and hoop tendons was calculated at the time of initial licensing.

Containment post-tensioning system surveillance will be performed in accordance with Oconee Improved Technical Specification SR 3.6.1.3. Acceptance criteria for tendon surveillance are given in terms of Prescribed Lower Limits and Minimum Required Values. Oconee Sele`cted Licensee Commitment, Oconee UFSAR, SLC 16.6.2 provides the required prescribed lower limits and minimum required values in Appendix 16.6-2, Figures 1, 2, and 3. Each prescribed lower limit line has been extended to 60 years of plant operation and remains above the minimum required values for all three tendon groups.

From the license renewal review, it was determined that the loss of prestress analysis is valid for the period of extended operation and will continue to be managed by the Containment Inservice Inspection Plan.

3.8.1.5.3 Liner Plate

The design criteria which are applied to the Reactor Building liner to assure that the specified leak rate is not exceeded under accident conditions are as follows:

1. That the liner be protected against damage by missiles (see Section 3.5.1.2).
2. That the liner plate strains be limited to allowable values that have been shown to result in leak tight vessels or pressure piping.
3. That the liner plate be prevented from developing significant distortion.
4. That all discontinuities and openings be well anchored to accommodate the forces exerted by the restrained liner plate, and that careful attention be paid to details of corners and connections to minimize the effects of discontinuities.

The most appropriate basis for establishing allowable liner plate strains is considered to be the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Article 4. Specifically, the following sections have been adopted as guides in establishing allowable strain limits:

Paragraph N-412 (m)	Thermal Stress (2)
Paragraph N-414.5	Peak Stress Intensity Table N-413 Figure N-414, N-415 (A)
Paragraph N-412 (n)	
Paragraph N-415.1	

Implementation of the ASME design criteria requires that the liner material be prevented from experiencing significant distortion due to thermal load and that the stresses be considered from a fatigue standpoint (Paragraph N-412 (m) (2)).

The following fatigue loads are considered in the design on the liner plate:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 40 cycles for the plant life of 40 years.
2. Thermal cycling due to Reactor Building interior temperature varying during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500 cycles.
3. Thermal cycling due to the loss-of-coolant accident will be assumed to be one cycle. Thermal load cycles in the piping systems are somewhat isolated from the liner plate penetrations by the concentric sleeves between the pipe and the liner plate. The attachment sleeve is designed in accordance with ASME Section III fatigue considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the plant life.

The thermal stresses in the liner plate fall into the categories considered in Article 4, Section III, Nuclear Vessels of the ASME Boiler and Pressure Vessel Code. The allowable stresses in

Figure N-415 (A) are for alternating stress intensity for carbon steel and temperatures not exceeding 700°F.

In accordance with ASME Code, Paragraph 412 (m) (2), the liner plate is restrained against significant distortion by continuous angle anchors and never exceeds the temperature limitation of 700°F and also satisfies the criteria for limiting strains on the basis of fatigue consideration.

Paragraph 412 (n), Figure N-415 (A) of the ASME Code has been developed as a result of research, industry experience, and the proven performance of code vessels, and it is a part of a recognized design code. Figure N-415 (A) and its appropriate limitations have been used as a basis for establishing allowable liner plate strains. Since the graph in Figure N-415 (A) does not extend below ten cycles, ten cycles are being used for a loss-of-coolant accident instead of one cycle.

The maximum compressive strains are caused by accident pressure, thermal loading prestress, shrinkage and creep. The maximum strains do not exceed 0.0025 inch/inch and the liner plate always remains in a stable condition.

At all penetrations the liner plate is thickened to reduce stress concentrations in accordance with the ASME Boiler and Pressure Vessel Code 1965, Section III, Nuclear Vessels.

The liner plate is anchored as shown in Figure 3-19 with anchorage in both the longitudinal and hoop direction. The anchor spacing and welds were designed to preclude failure of an individual anchor. The load deformation tests referred to in Section 3.8.1.4.2 indicate that the alternate stitch fillet weld used to secure the anchor to the liner plate would first fail in the weld and not jeopardize the liner plate leak tight integrity.

Offsets at liner plate seams are controlled in accordance with ASME Section III Code, which allows 1/16 inch misalignment for ¼ inch plate. The flexural strains due to the moment resulting from the misalignment were added to calculate the total strain in the liner plate.

The liner plate plus structural shapes to support the liner are ASTM A36 or ASTM A516 steel. The selection of this material complies with “Safety Standard for Design, Fabrication and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors” prepared by Subcommittee N6.2, Containment, of ASA Sectional Committee N6, Reactor Safety Standards.

The interior surface of the Containment is lined with welded steel plate to provide an essentially leak tight barrier. At all penetrations, the liner plate is thickened to reduce stress concentrations. Design criteria are applied to the liner to assure that the specified leak rate is not exceeded under design basis accident conditions. The following fatigue loads were considered in the design of the liner plate and are considered to be time-limited aging analyses for the purposes of license renewal:

(a) Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 40 cycles for the plant life of 40 years.

(b) The combined loading of thermal cycling due to Reactor Building interior temperature varying during the startup and shutdown of the Reactor Coolant System and Type A integrated leak rate tests required by 10 CFR 50, Appendix J, including any Type A tests that may be performed if major modifications or repairs are made to the Containment pressure boundary. The number of cycles for this combined loading is assumed to be 500 cycles.

(c) Thermal cycling due to the loss-of-coolant accident will be assumed to be one cycle.

(d) Thermal load cycles in the piping systems are somewhat isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner plate. The attachment sleeve is designed in accordance with ASME Section III considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the plant life.

From the license renewal review, it was determined that the existing analyses of thermal fatigue for the Containment penetrations are valid for the period of extended operation.

3.8.1.5.4 Penetrations

Penetrations conform to the applicable sections of ASA N6.2-1965, "Safety Standard for the Design, Fabrication and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors." Piping penetrations 25, 26, 27, 28, 63 and 64 conform to the requirements of ASME Section III, Subsections NE and NC, 1992 Edition, including all 1992 Addenda. Subsection NC applies only to the piping portion of the penetration. All personnel locks and any portion of the equipment access door extending beyond the concrete shell conform in all respects to the requirements of ASME Section III, Nuclear Vessels Code.

The basis for limiting strains in the penetration steel is the ASME Boiler and Pressure Vessel Code for Nuclear Vessels, Section III, Article 4, 1965, and therefore, the penetration structural and leak tightness integrity are maintained. Local heating of the concrete immediately around the penetration will develop compressive stress in the concrete adjacent to the penetration and a negligible amount of tensile stress over a large area. The mild steel reinforcing added around penetrations distributes local compressive stresses for overall structural integrity.

Horizontal and vertical bonded reinforcement is provided to help resist membrane and flexural loads at the penetrations. This reinforcement was located on both the inside and outside face of the concrete. Stirrups were also used to assist in resisting shear loads.

Local crushing of the concrete due to deflection of the reinforcing or tendons is precluded by the following details:

1. The surface reinforcements either have a very large radius such as hoop bars concentric with the penetration or are practically straight, having only standard hooks as anchorages where necessary.
2. The tendons are bent around penetrations at a minimum radius of approximately 20 feet. Maximum tendon force at initial prestress is 850 kips, which results in a bearing stress of about 880 psi on the concrete.

It is also important to note that the deflected tendons are continuous past the openings and are isolated from the local effects of stress concentrations by virtue of being unbonded.

In accordance with ASME Section III, piping penetration reinforcing plates and the weldment of the pipe closure to it are stress relieved. This code requirement and the grouping of penetrations into large shop assemblies permit a minimum of field welding at penetrations.

The personnel hatch consists of a steel cylinder with 3 ft-6 in. x 6 ft-8 in. doors at each end interlocked so that only one door can be open at any time. The hatch is designed to withstand all Reactor Building design conditions with either or both doors closed and locked. Doors open toward the center of the Reactor Building and are thus sealed under Reactor Building pressure. Design live load on the hatch floor is 200 psf.

Operation of the hatch is normally manual, that is, without power assist. Interlocks will prevent opening both doors at once.

Double gaskets are provided on the outer door to permit periodic pressurizing of the space between the gaskets from outside the Reactor Building. The hatch barrel may be pressurized to demonstrate its leak tightness without pressurizing the Reactor Building. Auxiliary restraint beams are attached to the inner door in this case to help the locking bars to resist internal lock pressure, which is greatly in excess of the Reactor Building design external pressure of 3 psig. The personnel hatch was pneumatically shop tested for pressure and leakage.

Figure 3-21 shows the principal features of the personnel hatch.

An emergency hatch is provided with 30 inch diameter doors. Its features are identical to the personnel hatch.

In order to support outage work activities during refueling operations, a temporary cover plate can be placed in the emergency hatch. The cover plate provides emergency hatch closure during refueling operations and is considered to be closed when a visual inspection shows no obvious leakage path.

The cover plate is approximately 36-inches in diameter and approximately 1-inch thick. The cover plate has multiple penetrations through it of various diameters. These penetrations have sleeves of varying lengths inserted through them and welded in place. The cover plate is installed and sealed against the inner emergency hatch door flange gasket. Positive sealing of the cover plate is accomplished by the use of RTV sealants. The cover plate is visually inspected to ensure that no gaps exist. All cables and hoses routed through the sleeves on the cover plate will also be installed and sealed. The sleeves will also be inspected to ensure that no gaps exist. Leak testing is not required prior to beginning fuel handling operations. Therefore, visual inspection of the cover plate over the emergency hatch satisfies the requirement that the emergency hatch be closed.

A 19-foot diameter equipment hatch opening to the outside provides the movement of large items into and out of the Reactor Building. The door is secured by bolts on the inside of the Reactor Building wall and can be opened only from inside the Reactor Building. It is opened only when the reactor is subcritical. Double gaskets on the door permit the seals to be pressurized from outside the Reactor Building to check the integrity of the seals. During operation, the space between the double gaskets is vented to the penetration room.

Figure 3-21 shows the principal features of the equipment hatch.

1. Piping and Ventilation Penetrations

   All piping and ventilation penetrations are of the rigid welded type and are solidly anchored to the Reactor Building wall or foundation slab, thus precluding any requirements for expansion bellows. All penetrations and anchorages are designed for the forces and moments resulting from operating conditions. External guides and stops are provided as required to limit motions, bending and torsional moments to prevent rupture of the penetrations and the adjacent liner plate for postulated pipe rupture. Piping and ventilation penetrations have no provision for individual testing since they are of all-welded construction.

   For typical details of piping penetrations, see Figure 3-20.

2. Electrical Penetrations

   Medium voltage penetrations for reactor coolant pump power shown on Figure 3-20 are canister type using glass sealed bushings for conductor seals. The canisters are filled to a positive pressure with an inert gas. The assemblies are bolted to mating flanges which incorporate double “0” ring seals with a test port between as a means of verifying seal integrity.

Low voltage power, control and instrumentation assemblies are shown on Figure 3-20. These assemblies are designed to bolt to mating flanges mounted inside the Reactor Building. Electrical penetrations are designed to maintain containment integrity; thus, reliable environmental seals must be maintained. To accomplish the required reactor building environment seals, the interface between the mounting flange and the penetration header plate must be sealed and also the interfaces between the header plate and individual penetration feedthrough conductors must be sealed.

Dual “O” rings are used to complete the seal between the mating flange and the penetration header plate. The mating flange is welded to the penetration nozzle. The space between the “O” ring seals is charged with an inert gas. The charged gas space is piped to a charging valve located outside of the Reactor Building, which allows leakage around the “O” ring seals to be detected.

Depending upon the type of penetration utilized in a particular application, two different schemes are used to accomplish the seals between the header plate and the penetration feedthrough conductors. One scheme accomplishes the seal by utilizing two header plates to which are welded glass to metal sealed conductors. Another scheme accomplishes the feedthrough seals by use of polysulfide to metal sealed conductors. In both schemes, the space between the seals is also charged with an inert gas. The charged gas space is piped to a pressure gauge and a charging valve located outside of the Reactor Building, which allows leakage to be tested.

3.8.1.5.5 Miscellaneous Considerations

In various cases, it has been the designer's decision to provide structural adequacy beyond that required by the design criteria. Those cases are as follows:

1. Section 3.8.1.3.4 requires a minimum of 0.15 percent bonded reinforcing steel in two perpendicular directions on the exterior faces of the wall and dome for proper crack control. Due to the weather exposure, a minimum of approximately 0.5 percent was provided.
2. Section 3.8.1.3.4 requires a minimum of 0.15 percent bonded steel reinforcing (as stated above) for any location. At the base of the cylinder, the controlling design case requires 0.25 percent vertical reinforcing. As a result of pursuing the recommendation of the AEC Staff to further investigate current research on shear in concrete, several steps were taken:
    a. The work of Dr. Alan H. Mattock was reviewed and he was retained as a consultant on the implementation of the current research being conducted under his direction. The criteria has been updated in accordance with his recommendations.
    b. Concurrently with reviewing Dr. Mattock's work, the firm of T. Y. Lin, Kulka, Yang and Associates was consulted to review the detailed design of the cylinder to slab connection. It was their recommendation to use approximately 0.5 percent reinforcing rather than the 0.25 percent reinforcing indicated by the detailed design analysis for the vertical wall dowels. This increase would assure that there was sufficient flexural steel to place the section within the lower limits of Mattock's test data (approximately 0.3 percent) to prevent flexural cracking from adversely affecting the shear capability of the section.

    Additional information concerning structural acceptance criteria for liner plate, penetrations, supports, and buttresses can be found in Section 3.8.1.4.2.

3.8.1.6 Materials, Quality Control, and Special Construction Techniques

Test, code, and cleanliness requirements accompanied each specification or purchase order for materials and equipment. Hydrostatic, leak, metallurgical, electrical, and other tests to be performed by the supplying manufacturers are enumerated in the specifications together with the requirements, if any, for test witnessing by an inspector. Fabrication and cleanliness standards, including final cleaning and sealing, are described together with shipping procedures. Standards and tests are specified in accordance with applicable regulations, recognized technical society codes and current industrial practices. Inspection is performed in the shops of vendors and subcontractors as necessary to verify compliance with specifications.

3.8.1.6.1 Concrete

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

An experienced full-time concrete inspector continuously checked concrete batching and placing operations.

Concrete mixes were designed and the associated tests run by the concrete testing laboratory at Clemson University in accordance with ACI 613. During construction, the field inspection personnel made minor modifications that were necessitated by variations in aggregate gradation or moisture content.

In determining the design mixes; air content, slump, and bleeding tests were run in accordance with the appropriate ASTM Specifications.

The concrete ingredients consist of Type II Cement (ASTM C-150), Solar 25 air entraining agent (ASTM C-260), Plastiment water reducing agent (ASTM C-494), Aggregate (ASTM C-33), and water that was free from injurious amounts of chlorides, sulphates, oil, acid, alkali, organic matter, or other deleterious substances.

Fine aggregate consists of clean, sharp, washed sand of uniform gradation from Becker County Hagood Quarry. Coarse aggregate consists of washed crushed rock having hard, strong, durable pieces of Gaffney marble from Campbell Limestone Company. The acceptability of the aggregate was based on Los Angeles Abrasion, Clay Lumps Natural Aggregates, Material Finer Number 200 Sieve, Organic impurities effect on Mortar, Organic impurities - Sands, Potential Reactivity, Seive Analysis, Soundness, Specific Gravity and Absorption, and Petrographic tests based on the appropriate ASTM Specifications.

Acceptability of aggregates is based on the following ASTM tests. These are performed by a qualified testing laboratory.

Test	***ASTM***
LA Abrasion	*C131*
Clay Lumps Natural Aggregate	*C142*
Material Finer No. 200 Sieve	*C117*
Mortar making properties	*C87*
Organic impurities	*C40*
Potential Reactivity (chemical)	*C289*
Potential Reactivity (mortar bar)	*C227*
Sieve Analysis	*C136*

Test	*ASTM*
Soundness	*C88*
Specific Gravity and Absorption Coarse	*C127*
Specific Gravity and Absorption Fine	*C128*

3.8.1.6.1.1 Cement

Cement conforms to ASTM C150 and tested to ASTM C114.

The manufacturer submits certified copies of mill test reports showing the chemical composition and certifying that the cement complies with the specification on each shipment delivered to the site. In addition to the manufacturer's tests, cement is sampled periodically at the site and tested to ascertain conformance with ASTM Specification C150.

3.8.1.6.1.2 Water

Water is potable and does not contain impurities in amounts that will cause a change of more than 25 percent in setting time for the Portland Cement, nor a reduction in the compressive strength of mortar of more than 5 percent as compared with results obtained using distilled water.

3.8.1.6.1.3 Admixtures

Admixtures, as to be determined by detailed mix design, conform to applicable ASTM Specification covering such materials and their testing.

3.8.1.6.1.4 Concrete Test Cylinders

Concrete cylinders for compression testing are made and stripped within 24 hours after casting, and marked and stored in the curing room. These cylinders are made in accordance with ASTM C31, “Making and Curing Concrete Compression and Flexure Test Specimens in the Field.”

Slump, air content, and temperature are taken when cylinders are cast and for each 35 yards of concrete placed. Slump tests are performed in accordance with ASTM C143, “Standard Method of Test for Slump of Portland Cement Concrete.” Air tests are performed in accordance with ASTM C231, “Standard Method of Test of Air Content of Freshly Mixed Concrete by the Pressure Method.” Compressive strength tests are made in accordance with ASTM C39, “Method of Test for Compressive Strength of Molded Concrete Cylinders.”

Six standard test cylinders are obtained and molded for concrete placed in excess of 10 cubic yards in any one day, with 6 additional cylinders for each successive 100 cubic yards placed. Two cylinders are tested at the age of 7, 28, and 90 days.

Concrete mixes are designed in accordance with “Recommended Practice for Selecting Proportions for Concrete” (ACI 613), using materials qualified and accepted for the work; and the strength, workability, and other characteristics of the mixes are ascertained before placement. Duke Power's concrete control laboratory is set up on the Oconee site. A batch-plant inspector is provided, and testing as shown below is performed. Field control is in accordance with the “Manual of Concrete Inspection” as reported by ACI Committee 611.

3.8.1.6.1.5 Mix Design

Only those mixes meeting the design requirements specified for Reactor Building concrete are used. Trial mixes are tested in accordance with the applicable ASTM Codes as follows:

Test	ASTM
Air Content	C231
Slump	C143
Bleeding	C232
Making and Curing Cylinders in Laboratory	C192
Compressive Strength Tests	C39

Six cylinders are cast from each design mix for two tests on each of the following days: 7, 28, and 90.

Test cylinders are cast from the mix proportions selected for construction and the following concrete properties determined:

Uniaxial creep

Modulus of elasticity and Poisson's Ratio

Autogenous shrinkage

Thermal diffusivity

Thermal coefficient of expansion

Compressive strength

3.8.1.6.1.6 Aggregates

Aggregate testing is performed as follows:

1. Sand sample for gradation (ASTM C33 Fine Aggregate)
2. Organic test on sand (ASTM C40)
3. 3/4" sample for gradation (ASTM C33, Size No. 67)
4. 1-½ inch sample for gradation (ASTM C33, Size No. 4)
5. Check for proportion of flat and elongated particles.

3.8.1.6.1.7 Concrete Construction

Cast-in-place concrete was used to construct the Reactor Building shell. The base slab construction was performed in seven pours utilizing large block pours. After the completion of the base slab steel liner erection and testing, an additional concrete slab was placed to provide protection for the floor liner.

The concrete placement in the walls was done in 10 ft high lifts with vertical joints at the radial center line of each of six buttresses. Cantilevered jump forms on the exterior face and interior steel wall liner served as the forms for the wall concrete.

The dome liner plate, temporarily supported by 18 radial steel trusses and purlins, served as an inner form for the initial 8 inch thick pour in the dome. The weight of the subsequent pour was supported in turn by the initial 8 inch pour. The trusses were lowered away from the liner plate after the initial 8 inches of concrete had reached design strength, but prior to the placing of the balance of the dome concrete.

The standards or specifications on quality control and tests of concrete during construction are equal to or better than requirements of ACI 301. Some of the areas where quality control exceeds the requirements of ACI 301 are as follows:

1. Requirements for water quality.
2. Placing temperature of concrete.
3. Requirements for aggregate acceptability.
4. Requirements for test cylinders.

Horizontal construction joints are prepared for receiving the next lift by blasting with compressed air. Surface set retardant compounds are not used.

Horizontal surfaces are wetted and covered with a coating of mortar of the same cement-sand ratio as used in the concrete immediately before the concrete is placed.

Vertical joints are also blasted with compressed air, cleaned, and wetted before placing concrete.

Vertical joints are placed at the center of each buttress to take advantage of the 50 percent additional horizontal prestress due to the overlapping of the anchored hoop tendons.

Horizontal joints between buttresses are at the same elevation. These joints are prepared as stated above to provide maximum possible bond. Principal tension in the membrane is limited to $3\sqrt{f'_c}$.

3.8.1.6.1.8 Construction Opening for Steam Generator Replacement

Replacement concrete for the construction opening was developed through an exhaustive testing program developed especially for the purpose. The details are delineated in Specification SGRP-SPEC-C-003, Reactor Building – SGRP Construction Opening Concrete Work. The testing regiment covers all the original requirements for reactor building concrete plus testing to verify the shrinkage characteristics of the mix. The development efforts insure that the repair mix is compatible with the existing concrete and performs acceptability over the life of the building.

3.8.1.6.2 Prestressing

These instructions and methods describe the quality control standards and measures applied in the control, manufacture, and field installation of the prestressing phase of construction of the Reactor Building.

The BBRV post-tensioning system furnished by The Prescon Corporation was used. Tendons replaced during the steam generator replacement are by PSC. Each tendon consists of ninety ¼ inch diameter wires conforming with ASTM A-421-65T, two anchor heads and two sets of shims conforming with American Iron and Steel Institute (AISI) C-1045 HR. The tendon sheathing system consists of spirally wound carbon steel tubing connecting to a trumplate (bearing plate and trumpet) at each end. A513 Type 5 carbon steel tube was used for the replacement tendon sheathing in closing the construction opening following steam generator replacement. The bearing plates were fabricated from steel plate conforming with AISI C-1045 HR and the trumpets from AISI C-1010 HREW material.

The C-1045 HR material used for the stressing washers, dead-end washers, shims, and bearing plates was modified by the addition of silicon to obtain a finer grain structure and cleaner steel than unmodified C-1045. The average depth of the heat affected zone resulting from flame cutting is approximately 1/16 inch and the improved general ductility of modified C-1045 material should increase resistance to cracks starting in heat affected zones and decrease the probability of crack propagation. However, a cracked plate could continue to perform its function without loss of structural integrity and should be evaluated in terms of actual functional ability.

Flame cutting is limited to sizing the bearing plate and making the center hole. All other holes in the bearing plate are drilled. The dead-end washer is flame cut to size and drilled for the tendon wires. No flame cutting is performed on the stressing washer.

3.8.1.6.2.1 Control

Supervision

The subcontractor furnishes competent, experienced supervision of the tendon installation and tensioning operation until completion of post-tensioning. The above individual exercises a close check and rigid control of all post-tensioning operations, as necessary, for full compliance with specifications.

Inspection of Duke's Work

The subcontractor is responsible for the inspection of Duke's handling and installation of tendon sheaths and bearing plates. To this end, he provides a competent technical representative to check the installation of these items by Duke. If any of Duke's work or actions jeopardize the subcontractor's work, he notifies Duke's Resident Engineer in writing. Failure to do this constitutes acceptance of Duke's work as it affects subcontractor's responsibilities.

Arrangement of Prestressing Tendons

The configuration of the tendons in the dome is based on a three-way tendon system consisting of three groups of tendons oriented at 120 degrees with respect to each other. The vertical cylinder wall is provided with a system of vertical and horizontal (hoop) tendons. Hoop tendons are placed in a 120 degree system in which three tendons form a complete ring. Six buttresses are used as anchorages.

3.8.1.6.2.2 Detail Shop Drawings

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

Subcontractor

Upon award of the contract, Duke furnished engineering design drawings which were issued for construction of the prestressing work providing information required for the preparation of shop detail drawings by the subcontractor. The subcontractor furnished the following detail drawings and erection drawings to Duke:

1. *Outside dimensions of sheathing proposed for the tendon.*
2. *Complete details of the post-tensioned wall and dome including dimensional locations of the tendons and necessary equipment and materials to place the tendons.*
3. *Tendon characteristics indicating the A_s, F'_s, f_{sy}, and a typical stress-strain curve for the tendon used, as well as tendon force capability.*

4. *Details of anchorages, bearing plates, and other accessories pertinent to the post-tensioning system.*
5. *Erection drawings showing clearly the marking and positioning of tendons, anchorages, and sheaths, and details showing alignment and setting tolerances required.*
6. *Stressing sequence drawings.*

3.8.1.6.2.3 Prestressing Steel

Materials and Fabrication

High strength steel wires are in accordance with ASTM A416 or A421 as a minimum requirement.

Wire materials used for steam generator replacement: ASTM A421 Type BA, 0.25” diameter and guaranteed ultimate strength of 240 ksi.

Shim materials used for steam generator replacement are: ASTM A656, Type 7, Grade 80; ASTM A656, Type 7, Grade 70; ASTM A737, Grade C or ASTM A633, Grade E.

Wires are to be straightened if necessary to produce equal stress in all wires or wire groups that are to be stressed simultaneously or when necessary to insure proper positioning in sheaths. However, wires showing a permanent set are not to be straightened or installed if the bend exceeds 60 degrees and the radius is less than 1.25 inches.

Tests were made on wire bent to 30, 60, and 90 degrees with a bend radius of 1.25 inches (5 times wire diameter) and wire bent to 30 and 60 degrees with a zero radius. The test specimens were from two different heats of ¼ inch diameter wire. All specimens within one test series were from the same heat and coil. In the sequence of cutting, every sixth specimen fell into the same group. The first group consisted of straight specimens for comparison.

Specimens were cut to a length of 15-½ inches, bent to the prescribed angle and radius in a bend-tester, and straightened. The specimens were button headed on each end and tensile tested to failure. The test results presented in Table 3-22 show that the strength of prestressing wire is not affected by bending the wire 60 degrees around a 1.25 inch radius pin.

The button head is cold formed to a nominal diameter of 3/8 inch symmetrically about the axis of the wires. If splitting is consistent and appears in all heads or if there are more than two splits in which the opening exceeds 0.06 inch per head, the wire is rejected. No forming process is used that caused indentation in the wire. Wires showing indentations are rejected. Wires showing fabrication defects, wires having welds or joints made during manufacture, or broken wires are removed and replaced.

The BBR Bureau Standard for button head splits is a maximum number of two splits with a width of 0.06 inch. The Prescon Corporation has run tests on button heads with splits; and based on an evaluation of the test results, the BBR Bureau Standard is acceptable.

Protection

Prestressing steel is protected from mechanical damage and corrosion during shipment, storage, installation, and tensioning. A thin film of No-Ox-Id (R) 500, as manufactured by Dearborn Chemical Company or Visconorust 1601, manufactured by Viscosity Oil Company, is applied to the prestressing steel after fabrication in accordance with the manufacturer's instructions. The steel is then wrapped before shipment to the site. The steel is not handled, shipped, or stored in a manner that will cause a permanent set or notch, change its material properties, or expose it to inclement weather or injurious agents such as chloride containing solutions. Damaged or corroded tendons are rejected.

Installation

The tendon installation prestressing procedure was carried out as follows:

1. To assure a clear passage for the tendons, a "sheathing Rabbit" was run through the sheathing both prior to and following placement of the concrete.
2. Tendons were uncoiled and pulled through the sheathing unfinished end first.
3. The unfinished end of the tendons was pulled out with enough length exposed so that field attachment of the anchor head and buttonheading could be performed. To allow this operation, trumplates on the opposite end had an enlarged diameter to permit pulling the shop finished ends with their anchor heads.
4. The anchor heads were attached and the tendon wires buttonheaded.
5. The shop finished end of the tendon was pulled back and the stressing jack attached.
6. The post-tensioning was done by jacking to the permissible overstressing force to compensate for friction and placing the shims precut to lengths corresponding to the calculated elongation. Proper tendon stress was achieved by comparing both jack pressure and tendon elongation against previously calculated values. The vertical tendons were prestressed from either one or both ends, while the horizontal and dome tendons were prestressed from both ends.
7. The grease caps were bolted onto anchorages at both ends and made ready for pumping the tendon sheathing filler material.
8. The tendon sheaths and grease caps were filled with sheathing filler and sealed. The sheathing filler material had limitations specified for deleterious water soluble salts.

   Corrosion protection of the tendons and interior surface of sheathing was applied prior to shipment.

   Tendon sheaths mark 24H34, 31H34 and 34V14 on Oconee 1, 31H21 on Oconee 2, 34V13 and 34V25 on Oconee 3 were plugged. The location of the plugged sheaths are shown in Figure 3-36.

3.8.1.6.2.4 Anchorages and Bearing Plates

Anchorages

Anchorages will develop the minimum guaranteed ultimate strength of the tendon and the minimum elongation of the tendon material as required by the applicable ASTM specification.

Bearing Plates

Bearing plates are capable of developing the ultimate strength of the tendon and distributing the bearing load over the bearing surface of the concrete. Bearing plates conform to the following requirements:

1. The transfer unit compressive stress on the concrete directly underneath the plate or assembly is in conformance with the ACI Code 318-63, latest edition.
2. Bending stresses in the plates induced by the pull of the prestressing steel shall not exceed 22,000 psi for structural steel and 15,000 psi for cast steel, except as experimental data may indicate that higher stresses are satisfactory.

3. Materials shall meet requirements of ASTM A36 for structural shapes or ASTM A148, Grade 80-40 for cast steel, or higher quality materials approved by Duke to meet strain requirements.
4. Design, fabrication, and erection shall meet the requirements of the latest AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings."

3.8.1.6.2.4.1 Tendons Installed During Steam Generator Replacement

New tendons installed during the SGR are of the BBRV system type currently existing in the structure, however they are manufactured in accordance with the Inryco design instead of the Prescon system currently used. The differences in these two systems are minor, head material is AISI 4140 and the wire button heads are slightly larger, which allows the use of the current maintenance equipment and ISI procedures.

Anchor Head Materials:

ITEM	VALUE
Material	AISI 4140
Yield	89 KSI
Ultimate	118 KSI
Elongation	12%
R/A	20%
Hardness	Rc 29 TO 33
Heat Treatment	As Needed for Performance to Spec.

Wire Materials:

ASTM A421 Type BA, 0.25" diameter, and Guaranteed ultimate strength of 240ksi

Shim Materials:

ASTM A656, type 7 Grade 80,

ASTM A656, type 7, Grade 70,

ASTM A737, Grade C, or

ASTM A633, Grade E.

3.8.1.6.2.5 Sheaths

Materials

Sheaths for post-tensioning tendons are ungalvanized corrugated articulated tubing and meet the following requirements:

1. The internal diameter is adequate to allow insertion of prestressing steel after concrete placement.
2. The sheaths will withstand the placing of concrete at a pour rate of two feet per hour (with mechanical vibration) without ovalling or changing alignment.
3. Sheaths are protected from corrosion during storage.

A513 Type 5 carbon steel tube was used for replacement tendon sheathing in closing the construction opening following steam generator replacement.

Sheath Fabrication

The sheaths are cut to length and bent to shape. The bending is accomplished without wrinkling the metal. Dented or wrinkled sheaths are replaced. Finished bent or straight dimensions are in accordance with approved drawings.

Installation (by Duke)

Sheaths are accurately installed in the forms at the location shown on the drawings to a tolerance of ± one-half (½) inch, except as otherwise indicated on the drawings. The sheaths are supported in such a manner as to prevent displacement during concrete placement. The sheath is supported at the ends and at such intervals as are in accordance with the drawings. Damaged or improperly bent sheaths are rejected.

Cleaning and Venting

Just prior to insertion of the tendon, the sheath is cleaned by the use of compressed air or other suitable means.

3.8.1.6.2.6 Corrosion Protective Grease

Corrosion protection is provided by grease injected into the sheaths under pressure. Grease will be Visconorust 2090P or 2090P-4 manufactured by Viscosity Oil Company.

The grease is sampled and laboratory tested for chemical analysis to establish conformance with specifications and for deleterious substances such as water soluble chlorides, nitrates, and sulfides.

Visconorust Casing Filler is a petroleum base corrosion preventive designed for bulk application and extended protection.

It has:

1. A three phase protective system starting with a polar agent preferentially wetting the wires and displacing any moisture, rust preventive additives molecularly attached to the wetting agent and a petroleum barrier completing the resistant coating.
2. The property to emulsify any moisture picked up in the system while being pumped through the casing and either carrying it out the other end or nullifying its rusting ability if the moisture is trapped in the casing.
3. Reserve Alkalinity - The basic formulation of Visconorust casing fillers are very stable and resistant to exterior moisture encroachment as well as mild acids and alkali. However, because of the probability of picking up moisture as the rust preventive is pumped through the tendons, an additional safety factor, besides the barrier action, is available to neutralize any acids that might form between the interface of the moisture and rust preventive.

   Tests have been run using volatile acids, such as Hydro Bromic Acid, in an attempt to penetrate the Visconorust casing filler film and cause corrosion without success.
4. Only a trace amount of water soluble chlorides, sulfides, or nitrates.
5. A plugging agent designed to supplement the natural tendency of the microwax crystals and amorphus solid components to form a filter cake bridging any hair line cracks in the concrete, with which the casing filler might come in contact.

6. Self-healing qualities at the ambient temperature expected during operation, to take care of any voids created by wire movement.
7. Thixotropic properties that provide pumpability below 50°F.
8. Radiation Resistance:

   Visconorust casing fillers have been subjected to 1 x 10^6 rads/(min). Results show that the Gamma rays did not have any material effect on either the physical or chemical structure (as noted by a negligible change in base number).

   Corroboration of the test results is readily noted in extensive literature on this subject, a few of which are listed below:

   Bibliography:

   a. The Lubrication of Nuclear Power Plants by R. S. Barnett - NLGI - October 1960.
   b. How Radiation Affects Petroleum Lubricants - Power, Vol. 100 December 1956, Page 164.
   c. Conventional Lubricants Are Sufficiently Radiation Resistant for Most Nuclear Power Reactor Applications by E. D. Reeves SAE Journal Vol. 66, May, 1956, Page 56-57.
   d. Organic Lubricants and Polymers for Nuclear Power Plants by Bolt and Carroll.

   The amount of nitrate found in the 90,000 gallons of Nuclear Grade material made for Palisades, Point Beach, and Turkey Point plants, so far, was “0” and practically, in order to keep the trace amounts allowed, be it 2 or 4, the amounts must be kept at zero. However, the refinery requires the use of 4 parts per million figure as a maximum.

   Infra-red spectographic analysis shows Visconorust 2090P and NO-OX-ID CM to be quite similar with approximately the same amounts of wetting agents and rust preventives in the petroleum carriers.

PERFORMANCE DATA

Item	NO-OX-ID	Visconorust 2090P	ASTM Method	2090P-4
Weight Per Gal.	7.2 - 7.5 lbs.	7.3 - 7.6 lbs.	--	7.3-7.4
Pour Point	110° - 120°F	--	D-97	
Flash Point (coc)	400°F	385°F	D-92	420°F
Viscosity @ 150°F	125 - 150 SSU	116 SSU	D-88	
Viscosity @ 210°F	55 - 75 SSU	59 SSU	D-88	150 - 300°F
Spec. Grav @ 60°F	0.88 - 0.90	0.88 - 0.91	D-287/1298	0.88 - 0.94
Pene. (cone) @ 77°F	325 – 370	370	D-937	170 - 200
Water Sol Chlorides	1 PPM	1 PPM	D-512	2 PPM

PERFORMANCE DATA				
Item	**NO-OX-ID**	**Visconorust 2090P**	**ASTM Method**	**2090P-4**
Water Sol Nitrates	2 PPM	4 PPM	D-1255/992-78	4 PPM
Water Sol Sulfides	1 PPM	1 PPM	D-992/APHA 4500S	2 PPM
Phenoloc Bodies (As Phenol)	1 PPM	1 PPM	--	--
Shrinkage Factor (150°F to 70°F)	3.5 - 4.5%	3.5 - 4.5%	--	--
Total Base Number	--	3	D-974	35

3.8.1.6.2.7 Tensioning Schedule

Prestressing begins after the concrete in the walls and the dome has reached the specified f′c. The dome and the hoop tendons are tensioned from both ends, and the vertical tendons are tensioned from either the top end or from both ends. Six jacks are used throughout the post-tensioning operations.

Phase 1

Twelve hoop tendons above elevation 943 feet + 6 inches on buttresses at 90 degrees, 210 degrees, and 330 degrees.

Phase 2

Thirty-six dome tendons in the periphery of the dome.

Phase 3

Twelve hoop tendons above elevation 943 feet + 6 inches on buttresses at 30 degrees, 150 degrees, and 270 degrees.

Phase 4

Remaining 126 dome tendons.

Phase 5

One hundred and forty-one hoop tendons from elevation 865 feet + 0 inches to elevation 943 feet + 6 inches on buttresses at 30 degrees, 150 degrees, and 270 degrees.

Phase 6

Close the construction opening if not closed prior to Phase 6.

Phase 7

One hundred and fifty-three hoop tendons from elevation 775 feet + 0 inches to elevation 865 feet + 0 inches on buttresses at 30 degrees, 150 degrees, and 270 degrees.

Phase 8

Forty-two hoop tendons from elevation 776 feet + 0 inches to elevation 801 feet + 6 inches on buttresses at 90 degrees, 210 degrees, and 330 degrees.

Phase 9

One hundred and seventy-six vertical tendons.

Phase 10

Two hundred and fifty-two hoop tendons from elevation 801 feet + 6 inches to elevation 943 feet + 6 inches on buttresses at 90 degrees, 210 degrees, and 330 degrees.

Phase 11

Ten hoop tendons above elevation 949 feet + 10-2/3 inches on buttresses at 90 degrees, 210 degrees, and 330 degrees.

Phase 12

Ten hoop tendons above elevation 949 feet + 10-2/3 inches on buttresses at 30 degrees, 150 degrees, and 270 degrees.

Force and Stress Measurements

Force and stress measurements are made by measurement of elongation of the prestressing steel after taking up initial slack and comparing it with the force indicated by the jack-dynamometer or pressure gauge. Force jack pressure gauge or dynamometer combinations are calibrated against known precise standards before application of prestressing force. All gauges are calibrated on a dead weight calibration apparatus. The presence of two gauges, one gauge on the pump and one gauge on the jack, provides a means to maintain a constant check of the calibration of the gauges. Based on the actual calibration tests of the stressing equipment, it was concluded that the pump efficiency does not influence the equipment accuracy and that the stressing accuracy depends only on the ram efficiency. Therefore, any combination of ram, gauge, and pump may be used interchangeably. During stressing, records are made of elongations as well as pressures obtained. Jack dynamometer or gauge combinations are checked against elongation of the tendon and any discrepancy exceeding plus or minus 5 percent will be evaluated by Design Engineering. The measured elongation will differ from the calculated elongation because of the following:

1. The statistical modulus of elasticity of 29.3 million psi for straight, untwisted wire.
2. The actual length and location of the tendon sheath will vary from the theoretical position due to approved placing tolerances.
3. All wires in a tendon are equal in length and the tendon is twisted to compensate for the difference in actual arc lengths. The twisting forms a wire cable configuration which does not follow the sheath centerline and which has a modified modulus of elasticity value.
4. The friction factor used in calculations is an average value based on experience. The true influence of friction on each tendon can be significantly different from the average value used in calculations.
5. The permissible tolerance in pressure gauge accuracy combined with the possible variables in stressing techniques such as reading the gauges and scales can constitute a significant difference.

Calibration of the pressure gauges are maintained accurate within the following limits:

0 to 2500 psi - Accuracy limit of the gauge, plus or minus 50 psi.

2500 to 7030 psi - Plus or minus 2 percent of gauge reading.

Pressure gauges are recalibrated after each stressing cycle on Oconee 3 and, as requested by Duke Power, during and at the end of the tensioning operations on Oconee 1 and 2.

Strain Gauge Installation and Protection

Strain or force gauging devices are installed on certain tendon areas prior to and/or during installation. These strain devices are monitored during the tensioning operation and used during subsequent pressure testing. Approximately 4 tendon sets are instrumented with load cells.

Tests, Samples, Inspections

Sampling and testing conforms to ASTM Standard A421 and as specified herein.

Each size of wire from each mill heat shipped to the site is assigned an individual lot number and tagged in such a manner that each such lot can be accurately identified at the job site. Anchorage assemblies are likewise identified. All unidentified prestressing steel or anchorage assemblies received at the job site are rejected.

Random samples as specified in the ASTM Standard stated above are taken from each lot of prestressing steel used in the work. With each sample of prestressing steel wire that is tested, there is submitted a certificate stating the manufacturer's minimum guaranteed ultimate tensile strength of the sample tested.

For the prefabricated tendons, one completely fabricated prestressing test specimen tendon 5 feet in length, including anchorage assemblies, is tested for each size of tendon contained in individual shipping release.

No prefabricated tendon is shipped to the site without first having been released by Duke, and each tendon is tagged before shipment for identification purposes. The release of any material by Duke does not preclude subsequent rejection if the material is damaged in transit or later damaged or found to be defective.

Duke shop inspects the prefabricated tendons prior to being shipped to the job site.

The anchorages and tendons are inspected at the job site for corrosion and mechanical damage during shipment, storage, installation, and tensioning. Damaged or corroded tendons and anchorages are rejected.

Acceptance

The Reactor Building has been analyzed based on missing tendons for the various loading conditions including missiles. The stresses for the various loading conditions were within the allowable design stresses. The missing tendons will not have any affect on the structure to withstand turbine and tornado generated missiles without loss of function. The missing tendons are located on the northwest face and shielded by location from a direct turbine missile strike. However, as stated in Section 3.5.1.3, the structure can withstand the loss of three horizontal and three vertical tendons in the cylinder wall without loss of function. The depth of penetration from tornado generated missiles as stated in Section 3.5.1.3 is less than the tendon concrete cover and will not endanger the structural integrity of the Reactor Building.

Final acceptance for warranty purposes is the successful completion of the pressure testing of the Reactor Building.

3.8.1.6.2.7.1 Steam Generator Replacement Tensioning Schedule

During steam generator replacement, tendons in the temporary construction opening were relaxed and/or removed. At the completion of the outage, the tendons were re-tensioned in accordance with specification SGRP-SPEC-C-002.

3.8.1.6.3 Reinforcing Steel

The concrete inspector visually inspected the shop fabricated reinforcing steel for compliance with drawings and specifications. Intermediate grade reinforcing steel conformed with ASTM A615, Grade 40 and high strength reinforcing steel conformed with ASTM A615, Grade 60. Mill test reports are submitted for engineering review and approval. Metallurgical inspection and testing of the reinforcing steel is done in accordance with the ACI Code 318-63, Chapter 8.

Reinforcing steel is inspected at delivery as well as at erection. The condition of the material must meet all of the requirements of ACI 318-63, as well as any additional requirements made by the inspector.

Number 14S and 18S reinforcing steel for which the ACI Code required welded or mechanical splices is spliced by the CADWELD process using full tensile strength “T” series connections. Quality control is maintained by qualification testing of the individual splicing crews, visual inspection of each completed connection, and random sampling and tensile testing of splices.

Prior to splicing operations, bar ends were inspected for damaged deformations and were power brushed to remove all loose mill scale, rust, and other foreign material. Immediately before the splice sleeve positioning, bar ends were preheated to assure complete absence of moisture.

Prior to making any production splices, each individual splicing crew prepares sample splices for tensile testing covering each bar size and position used in production to qualify. The sample splices must be properly filled, free of porous metal and meet the minimum requirement for tensile strength as stated below.

All splices are subjected to visual inspection and must meet the following standards:

1. Sound, nonporous filler metal must be visible at both ends of the splice sleeve and at the tap hole in the center of the splice sleeve. Filler metal is usually recessed ¼ inch from the end of the sleeve due to the packing material, and is not considered a poor fill.
2. Splices which contain slag or porous metal in the riser, tap hole, or at the ends of the sleeves (general porosity) are rejected. A single shrinkage bubble present below the riser is not detrimental and should be distinguished from general porosity as described above.

In addition to the above, random splices are subjected to mechanical tests and must meet the following standards:

1. The strength of 95 percent of the CADWELD splices tested will be greater than 125 percent of the specified minimum yield strength for the particular bar size and ASTM specification.
2. The strength of the average of all the splices tested will be equal to or greater than the minimum ultimate strength for the particular bar size and ASTM specification.
3. No failures of CADWELD splices below the required minimum yield strength are expected. In the unlikely event that one should occur, it would be sent to a testing laboratory for analysis of failure. Based on the testing laboratory's report, additional samples would be taken to insure that there are no other defective welds.

Tests are made in accordance with the following schedule for each position, bar size and grade of bar:

1 out of first 10 splices

3 out of next 100 splices

2 out of next 100 and each subsequent 100 splices

Test splices are made by having test bars of 3 feet length spliced in sequence with the production bars. In addition, two production splices are cut out and tested for each 100 test splices.

The inspections and tests are performed by individuals thoroughly trained by the CADWELD manufacturer.

For reinforcing steel of size 11 and under, lap splices are permitted in accordance with ACI 318-63, Chapter 8.

3.8.1.6.3.1 Steam Generator Replacement Reinforcing Steel

All new reinforcing steel, including replacement bars, are ASTM A615 Grade 60. The existing bars within the opening are A615 Grade 40. Mechanical splicing of bars will be accomplished through the use of BarSplice BPI XI swaged couplers. These devices are in compliance with ASME Section III, Division 2, Subsection CC and are capable of developing not less than of 125% of the specified yield strength of the bars in question.

Splice testing is in compliance with the UFSAR.

Where mechanical splices could not be used, direct-butt fusion welded splices were used. These splices were welded and inspected in accordance with AWS D1.4-98, Structural Welding Code – Reinforcing Steel.

3.8.1.6.4 Liner Plate

Construction of the liner plate conformed to the applicable portions of Part UW of Section VIII of the ASME Code. In addition, the qualification of all welding procedures and welders was performed in accordance with Part A of Section IX of the ASME Code. All liner angle welding was visually inspected prior to, during, and after welding to insure that quality and general workmanship met the requirements of the applicable welding procedure specification.

The erection of the liner plate was as follows:

After the floor plate embedments in the foundation slab had been placed and welded, and concrete was poured flush, the wall liner plates were erected in 60 degree segments and 10 feet high courses. This pattern was followed to the dome spring line and then the steel dome erection trusses were placed. During the period of erection o: wall liner plates, the floor liner plate was placed and welded.

The tolerances for liner plate erection were as follows:

1. The location of any point on the liner plate shall not vary from the design diameter by more than ± 3 inches.
2. Maximum inward deflection (toward the center of the structure) of the ¼ inch liner plate between the angle stiffeners of 1/8 inch, when measured with a 15 inch straightedge placed horizontally.

3.8.1.6.4.1 Steam Generator Replacement Liner Plate Repair and Fabrication

The liner plate and stiffeners removed to facilitate generator removal will be reused or replaced with new materials of the same grade as the existing. Fabrication of the new materials will be per ASME Boiler and Pressure Vessel Code, Section VIII, 1998 Edition with 1998 Addenda. Testing will be per ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWL, IWE, and IWA of the 1992 Edition with 1992 Addenda. The actual repair was in accordance with the original liner plate specification.

3.8.1.6.5 Field Welding

This section outlines the general requirements for welding quality control to assure that all field welding is performed in full compliance with the applicable job specification. These requirements include the use of qualified welding inspectors and nondestructive testing technicians and the assurance that field welding is performed only by qualified welders using qualified procedures.

3.8.1.6.5.1 Qualifications for Welding Inspectors

Duke Power welding inspectors are qualified in accordance with the quality assurance requirements outlined in Chapter 17.

3.8.1.6.5.2 Instructions for Field Welding Inspectors

Quality Control procedures are in accordance with the quality assurance requirements outlined in Chapter 17. Visual inspection is performed after welding in accordance with Duke Power Company procedures, which reference ASME Sections III and VIII and NCIG-01.

3.8.1.6.5.3 Qualifications for Nondestructive Examination Inspectors.

Duke Power NDE inspectors are trained, qualified, and certified in accordance with the quality assurance requirements outlined in Chapter 17.

1. A technician will have a thorough knowledge of the type of testing he is to conduct. He will also be familiar with the welding procedure specification for the field welds he is inspecting.
2. The technician is properly certified in accordance with Duke Power Company procedures that incorporate the Society for Nondestructive Testing Recommended Practice No. SNT-TC.1A, as applicable.

3.8.1.6.5.4 Instructions for Nondestructive Examination Inspectors

NDE procedures are in accordance with the quality assurance requirements outlined in Chapter 17.

3.8.1.6.5.5 Welding Procedures

All welding is in strict accordance with approved welding procedure specifications.

Welder Qualification

All welders and welding operators who are to make welds under a code or standard which requires qualification of welders are tested and qualified accordingly before beginning production welding. Duke Power Company is responsible for testing and qualifying its own welders. The welding inspector is responsible in all cases for determining that the welders have passed the necessary qualification tests.

3.8.1.6.5.6 Steam Generator Replacement Field Welding of Liner Plate

Field welding, inspection, and welder qualifications are per ASME Boiler and Pressure Vessel Code, Section VIII, 1998 Edition with 1998 Addenda.

ASME Boiler and Pressure Vessel Code, Section VIII, 1998 Edition with 1998 Addenda.

3.8.1.7 Testing and Inservice Inspection Requirements

3.8.1.7.1 Structural Test

Each of the three Reactor Buildings will be pressurized to 115 percent of design pressure for one hour following completion of construction to establish the structural integrity of the building. The structural integrity test of each building will be conducted in accordance with a written procedure. Operating units will remain in operation during the structural test of another unit. Personnel access limitations included in the written procedures will designate areas of limited access during specific periods of the test. Except for personnel access restrictions, the operation of one unit will not be affected by a building being tested.

The structural integrity test of each building will verify the workmanship involved; in addition, the test of the Oconee 1 Reactor Building will verify the design and workmanship. The response of the Oconee 1 building will be compared with the calculated behavior to confirm the design by means of instrumentation.

3.8.1.7.1.1 Test Objectives

1. To provide direct verification that the structural integrity as a whole is equal to or greater than necessary to sustain the forces imposed by two different and large loading conditions.
2. To provide direct verification that the in-place tendons (the major strength elements) have a strength of at least 80 percent of guaranteed ultimate tensile strength and that the concrete has the strength needed to sustain a strain range from high initial average concrete compression when unpressurized to low average concrete compression when pressurized.
3. To acquire detailed strain data which will be compared with the analytical predictions.

To achieve objectives, data will be acquired and evaluated to determine the response of the structure during and immediately after post-tensioning to determine any indication of unanticipated and continued deformation under load. A quality assurance program was instituted. In addition, each individual tendon is tensioned in place to 80 percent of the guaranteed ultimate tensile strength and then anchored at a lower load that is still in excess of those predicted to exist at test pressure levels. During pressurization of the structure, the structure's response will be measured at selected pressure levels with the highest being 1.15 times the design pressure. An indication that the structure is capable of withstanding internal pressure will result from these tests. The strain measuring program is described in Section 3.8.1.7.2.

Individual test values which fall outside the predicted range will not be considered as necessarily indicative of a lack of adequate structural integrity. Structural integrity cannot be judged on the data acquired from only one sensor since such precise devices may malfunction.

3.8.1.7.1.2 Steam Generator Replacement Structural Testing

At the completion of the repair process the structure will undergo post modification testing. The building will be pressurized to the design pressure, Pa = 59 psig. This test will provide verification of the integrity of the reactor building. The test will be performed in conjunction with a Type A Integrated Leak Rate Test.

3.8.1.7.2 Instrumentation

The structural response of the building will be assessed by comparing the theoretical analysis to test results of strains and deformations at boundaries, points of stress concentration, openings, areas of maximum creep, and at sections representing typical stress conditions.

The following instruments were installed in the first Reactor Building:

118	Two element strain rosette, waterproofed BLH Company designation FAET-12-12-S6, to be attached to the reinforcing bars.
9	Linear element, electric resistance strain gauges, BLH designation AS9-1 (Valore Type) to be attached to the surface of the concrete. Taut wire system for measuring building deformation.
6	Electric resistance strain gauge, Budd Company designation CP-1101 EX to be attached to the surface of the concrete for measuring crack propagation.
1	Cement Paint (Figure 3-37) to observe cracks in concrete.
7	Load cells each containing strain gauges to be attached to the tendons.
18	Three element rosette, electric resistance strain gauges BLH Company designation FAER-25-12-(60)S6, to be attached to the inside and outside face of the liner and penetration nozzles.
26	Two element strain rosette, BLH Company designation FAET-25-12-S6 to be attached to the inside face and outside face of the liner and penetration nozzles.

The instrument layout is shown on Figure 3-37, sheets 1, 2, and 3. The types and locations of the gauges are described in the legend on the figure. Because of the well-known vulnerability of the bonded resistance gauges to moisture, special care is taken in bonding and waterproofing of the gauges.

In order to reduce the possibilities of faulty preparation of the gauges in the field, the gauges are encapsulated and the wires soldered to the gauge leads and then waterproofed in the shop.

Bonding and waterproofing materials such as BLH EPY150 Cement, Epoxylite 222 and Microcrystalline Wax are used to install the gauges.

Gauges were calibrated in accordance with the manufacturer's instructions and set at zero reading during installation.

The final procedures in sequence of structural proof testing are as follows:

1. Test strain gauges immediately after installation.
2. Test strain gauges immediately after pouring concrete.
3. Record strains and deflections and observe cracking at three intervals suitably spaced during prestressing and immediately after all prestressing is completed.
4. After prestressing and before testing, a certain number of readings will be taken to determine the effects of creep and shrinkage.

5. Record measurements at increments of 10 psi up to 40 psi and then at increments of 5 psi up to proof-test pressure.
6. Record measurements at 15 psi increments during depressurization.
7. Observe the development of cracks during load application. Measurement of cracks with mechanical dial gauges will be made when deemed pertinent by the test engineer.

The Reactor Building air temperature is monitored by resistance thermometers and the dewpoint temperature is monitored by a dewpoint sensor. Using the Reactor Building coolers and electric heaters, the temperature is maintained between 60° and 100°F and above the dewpoint temperature.

The status of gauges on November 28, 1970 was as follows:

Gauge Mark	Number Inoperative	Number Operative	Number Being Replaced
SGA-1	114	4	(See 2 below)
SGE-2	7	2	(See 2 below)
SGC-3	0	6	–
SGR-4	7	11	6
SFT-5	7	19	6
LC (Load Cell)	1	6	(See 4 below)
Taut Wire System	0	–	–

Since a significant number of embedded gauges are inoperative, we believe it prudent to verify the design by (a) utilizing test results from Palisades and, (b) continuing with the Oconee Structural Test, as noted below:

1. The design and construction of Palisades and Oconee Reactor Buildings are very similar. The Palisades' structural instrumentation program was successful and permitted a detailed comparison between design calculations and observed response.
2. At Oconee, the taut wire system (building deformation) will permit verification that the structural response is consistent with the predicted behavior. In addition, twenty-six Carlson SAIOS strain gauges will be surface mounted on the Reactor Building to obtain concrete strains for comparison with Palisades and those predicted for Oconee as shown on Figure 3-37, Sheet 4.
3. Six inoperative gauges mark SGR-4 and SFT-5 are accessible and will be replaced to obtain data for comparison with Palisades and predicted strains for Oconee.
4. Load cells that are inoperative will be repaired or supplemented with prestress rams that have been modified with 20 psi division gauges to measure tendon forces. Prestress rams were used at Palisades and performed satisfactory. Results of measured forces can than be compared with those predicted.

The taut wire system consists of linear potentiometers (infinite resolution type) as the transducer element. Movement of the linear pontentiometers will be actuated by invar wires attached at one end to the point of measurement and at the other end to a reference point. Approximately 35 linear potentiometers will be used to measure building deformations during the structural test.

Oconee 2 and 3 Reactor Buildings are instrumented with the taut wire system for measuring building deformations as described above for Oconee 1. Displacement measurements are made at the following locations:

Dome	– Four points
Cylinder Wall	– Seven elevations at approximately 20 foot intervals at a buttress section and a wall section
Equipment Hatch	– Nine points with six of the points on the horizontal centerline and three of the points on the vertical centerline above the hatch
Vertical	– Two points

The above locations were selected so that deformation measurements could be compared with Oconee 1 measurements.

Concrete crack patterns are recorded at the base-wall intersection, cylinder wall mid-height, springline, equipment hatch opening, buttress-cylinder wall intersection, cylinder wall-ring girder intersection, and top of ring girder. Each inspection area consisted of approximately 40 square feet. Cracks that exceed 0.01 inch in width are mapped.

3.8.1.7.2.1 Reactor Building Structural Instrumentation for Steam Generator Replacement

Instrumentation will consist of a Laser Tracker Metrology System used to acquire the measurements on the outside of the Reactor Building by placing/adhering semi-permanent Spherical Mounted Retro-Reflector (SMR) Nests to the outside concrete in the area of the repair. The Laser Tracker combines the linear distance of the interferometer or Absolute Distance Measurement (ADM) with a position angle of the elevation and azimuth axes to derive a target's three dimensional (3-D) coordinate position. The 3-D coordinates are acquired by tracking the laser beam to SMR's and recording the data via wireless remote or keyboard entry. The expected accuracy in the volume of this scope is 0.006 of an inch. The Tracker will be positioned on a stable platform at ground level and the adhered targets will be acquired for a baseline. SMR's will be placed in each nest for continuous monitoring during the pressure test. A working coordinate system will be established to aid in interpretation of the displaced measurements.

3.8.1.7.3 Initial Leakage Tests

Following completion of the Reactor Buildings and prior to the hot functional tests and fueling of the reactors, integrated leakage rate tests will be performed on the containment systems. One test will be performed at or above the maximum calculated peak accident pressure. A second test will be performed at a pressure of not less than 50 percent of maximum calculated peak accident pressure.

The absolute pressure-temperature and/or the reference vessel method will be used for these tests. The objectives of these tests are:

1. To determine the initial integrated leakage rate for comparison with the design leakage rate.
2. To establish representative leakage characteristics of the containment system to permit retesting at reduced pressures.
3. To establish a performance history summary of the integrated leakage rate tests.

4. To establish a test method and the equipment to be used for subsequent retesting.

The leakage rate will be measured by integrating the leakage rate for a period of not less than 24 hours. This integrated leakage will be verified by the "pump-back" method and/or introduction of a known leak rate. The necessary instrumentation will be installed to provide accurate data for calculating the leakage rate. It will be demonstrated that the total Reactor Building leakage rate to the environment will maintain public exposure below 10CFR100 limits in the event of an accident.

3.8.1.7.3.1 Steam Generator Replacement Leakage Testing

Following the steam generator replacement a Type A Intergrated Leakage Test, (ILRT), will be performed in accordance with the requirements of 10 CFR 50.app J. This test will not be materially different from current station requirements.

3.8.1.7.4 Leakage Monitoring

A program of testing and surveillance of each of the three duplicate Reactor Buildings has been developed to provide assurance, during service, of the capability of each containment system to perform its intended safety function. This program consists of tests defined as follows:

Overall integrated leak rate tests of the Reactor Buildings and systems which under post accident conditions become an extension of the containment boundary.

Local leak detection tests of components having resilient seals, gaskets, or sealant compounds that penetrate or seal the boundary of the containment system. Components included in this category are:

1. Personnel Hatches
2. Emergency Hatches
3. Equipment Hatches
4. Fuel Transfer Tube Covers
5. Electrical Penetrations
6. Leak Rate Test Pressurization/Exhaust Penetration

Local leak detection and operability tests of containment isolation valves in systems that vent directly to the Reactor Building atmosphere or the Reactor Coolant system that must close upon receiving an isolation signal and seal the containment under accident conditions.

Operability tests of engineered safeguards systems which under post accident conditions are relied upon to limit or reduce leakage from the containment. Included in these tests are:

1. Reactor Building Spray Systems
2. Reactor Building Penetration Room Ventilation Systems (not required for accident mitigation due to adoption of alternate source term), Reference 34.
3. Reactor Building Cooling Systems
4. Reactor Building Isolation Valves not covered above

Following the integrated leakage rate tests, performed as a part of the preoperational testing, subsequent tests will be performed at the maximum calculated peak accident pressure or greater. The tests will be performed on schedule based on the following considerations:

1. There are three Reactor Buildings each having the same design. Information pertaining to deterioration in performance obtained in the testing of one Reactor Building is therefore applicable to the other Reactor Buildings.
2. Local leak detection tests will be performed on a more frequent basis than the integrated tests to detect and correct excessive leakage at containment penetrations. Where feasible, these tests will be performed during operation; otherwise, they will be performed during refueling outages and/or major maintenance outages. These tests will be performed at or above the maximum calculated peak accident pressure.
3. The engineered safeguards tests will also be performed at more frequent intervals than the integrated leak rate tests to verify the functional capability of these systems which are relied upon to limit or reduce leakage from the containment buildings in the case their service is required. These tests will be performed during outages for refueling and/or major maintenance outages.

The schedule of testing, type of test, and components to be tested are as follows:

Integrated Leak Rate Tests

Integrated leak rate tests shall be performed as follows:

1. Each Reactor Building shall be tested at the calculated peak accident pressure of 59 psig and at one-half this pressure prior to the initial fuel loading.
2. After the initial preoperational leakage rate test, integrated leakage rate tests shall be performed on each Reactor Building at intervals in accordance with 10CFR50 Appendix J Option B. These tests shall be conducted at or above peak accident pressure (P_t).

   Visual examinations of containment pressure retaining metallic surfaces shall be performed at least three times every 10 years and only those examinations performed in conjunction with each Type A test need to be performed during shutdown. When possible, these general visual examinations are to be performed concurrently with general visual examinations required by ASME Code Subsection IWE, Table IWE-2500-1, Examination Category E-A, Item 1.11 during each ISI interval.

Local Leak Detection and Operability Tests (Resilient Seals)

Local leak detection and operability tests shall be performed as required by the Technical Specifications.

The barrier to leakage in the Reactor Building is the one-quarter inch steel liner plate. All penetrations are continuously welded to the liner plate before the concrete in which they are embedded is placed. The penetrations, shown on Figure 3-20 and Figure 3-21, become an integral part of the liner and are so designed, installed, and tested.

The steel liner plate is securely attached to the prestressed concrete Reactor Building and is an integral part of this structure. This Reactor Building is conservatively designed and rigorously analyzed for the extreme loading conditions of a highly improbable hypothetical accident, as well as for all other types of loading conditions which could be experienced. Thorough control is maintained over the quality of all materials and workmanship during all stages of fabrication and erection of the liner plate and penetrations and during construction of the entire Reactor Building.

During construction, the entire length of every seam weld in the liner plate was leak tested. Individual penetration assemblies were shop tested. Welded connections between penetration assemblies and the liner plate were individually leak tested after installation. Following completion of construction, the entire Reactor Building, the liner, and all its penetrations were tested at 115 percent of the design pressure to establish structural integrity. The initial leak rate tests of the entire Reactor Building were conducted at the maximum calculated peak accident pressure and one-half this pressure to demonstrate vapor tightness and to establish a reference for periodic leak testing for the life of the station. Multiple and redundant systems based on different engineering principles are provided as described in Chapter 6, to provide a very high degree of assurance that the accident conditions will never be exceeded and that the vapor barrier of the containment will never be jeopardized.

Under all normal operating conditions and under accidental conditions short of the worst loss-of-coolant accident, virtually no possibility exists that any leakage could occur or that the integrity of the vapor barrier could be violated in any way that would be significant to the public health and safety or to that of the station personnel. Adequate administrative controls are enforced to minimize the possibility of human error. Station operators are trained and licensed in accordance with regulations. Safety analyses are presented in Chapter 15.

Penetrations such as the personnel access and emergency hatches cannot be opened except by deliberate action and are interlocked and alarmed by failsafe devices such that the Reactor Building will not be breached unintentionally. The liner plate over the foundation slab is protected by cover concrete. Wherever access to the liner plate is blocked by interior concrete, means are provided so that weld seams can be tested for leakage. The liner plate is protected against corrosion by suitable coatings. Walls and floors for biological and missile shielding, and for access and operating purposes, also provide compartmentation which constitutes protection for the liner during operating as well as accident conditions.

Once the adequacy of the liner has been established initially, there is no reason to anticipate progressive deterioration during the life of the station which would reduce the effectiveness of the liner as a vapor barrier. Inside the Reactor Building, the atmosphere is subject to a high degree of temperature control. The outside of the liner is protected by 3-3/4 feet of prestressed concrete which is exceptionally resistant to all weather conditions.

Inspection on a periodic basis, as necessary, will be conducted in all spaces accessible under full power operation. Biological shielding is provided to reduce radiation to limits which make occupancy of spaces adjacent to the liner permissible.

All penetrations except those described in Section 6.5.1.2, are grouped within or vented to the penetration room. Any leakage that might occur from these penetrations will be collected and discharged through high efficiency particulare air (HEPA) filters and charcoal filters to the unit vent as described in Section 6.5. In this manner, leakage which might occur from these penetrations will be isolated from leakage which might occur through the Reactor Building itself.

Individual major penetrations or groups of penetrations will be tested by means of permanently installed pressure connections or temporarily installed pressure or vacuum boxes. If necessary, liner plate weld seams will be tested by the vacuum box soap bubble method, where accessible, or by means of the permanently installed backup channels and angles where inaccessible.

In any event, sources of excessive leakage will be located and such corrective action as necessary will be taken. This will consist of repair or replacement. Appropriate action will also be taken to minimize the possibility of recurrence of excessive leakage, including such redesign as might prove to be necessary to protect public health and safety. Leak testing will be continued until a satisfactory leak rate has again been demonstrated.

A considerable background of operation experience is being accumulated on containments and penetrations. Full advantage of this knowledge has been taken in all phases of design, fabrication, installation, inspection, and testing. Practical improvements in design and details have been incorporated as they are developed, where applicable.

The steel-lined Reactor Building is self-sufficient, and other than valves and hatch doors, there are no operating parts. The containment boundary is extended only by listed penetrations and further described and tabulated in Section 6.2.3.

3.8.1.7.5 Engineered Safeguards Tests

The Reactor Building Spray, Penetration Room Ventilation, Reactor Building Cooling Systems, and the Reactor Building Isolation Valves will be tested periodically to provide assurance of system reliability. These tests will include:

1. Reactor Building Cooling System.

   This system is operated periodically during normal operating periods. This normal operator initiated operation of this system provides verification of the operability. In addition to this normal operation, testing of this system in the engineered safeguards mode will be performed as indicated in the Improved Technical Specifications. This test will be initiated by inserting a simulated engineered safeguards signal as would occur during an accident situation. Verification of the proper operation of the components of this system will be determined and a record of the test results made a part of the permanent plant records.

2. Reactor Building Spray System.

   The Reactor Building Spray System will be tested in a similar manner as the system above, with some exceptions. The ES testing for this system will be performed on a refueling frequency. It will test only the initiation control circuitry, and will not actually start the Reactor Building Spray Pumps. The pump breaker will be positioned to "test" position, allowing the verification that the signal reaches the breaker and the breaker actuates, but the pump does not receive power. Separate testing is performed to verify the functional readiness of the pumps and valves on a quarterly frequency. For the pump tests, the headers are isolated to prevent spray water from entering the spray headers. A special test connection is provided ahead of the Reactor Building isolation valves so that the portion of the system outside the Reactor Building may be operated in recirculation alignment to the Borated Water Storage Tank. Following activities which could cause nozzle blockage, compressed air will be blown through each of the spray headers in the Reactor Building through special test connections to verify that spray water would be directed into the Reactor Building under accident conditions. Proper operation of the various components of this system will be verified and a record of the test results made a part of the plant records.

3. Penetration Room Ventilation System

   The Penetration Room Ventilation system is no longer required to operate for accident mitigation due to the adoption of the alternate source term, Reference 34. However, it will continue to be operated periodically during normal operation to verify the system functions properly. In addition to this normal operation, testing in the engineered safeguards mode will be performed by inserting a simulated engineered safeguards signal as would occur during an accident situation. Verification of proper system operation will be determined and record of the test results made a part of permanent plant records.

4. Reactor Building Isolation Valves

   Proper operability of the Reactor Building isolation valves not covered in the other tests will be verified by inserting a simulated engineered safeguards signal to initiate operation of these valves. The valves in the reactor building purge flow path are required to be maintained closed in Modes where the engineered safeguards system is required operable.

This is a requirement of NUREG 0737, Item II.E.4.2.6. Therefore Engineered Safeguards system testing of these reactor building purge valves is not required.

3.8.1.7.6 Post-Tensioning System

A surveillance program for the Reactor Building post-tensioning system, is executed in order to assure the continued quality of the system. The program consists of periodic inspections of randomly selected tendons - for symptoms of material deterioration or excessive pre-stress force reduction. The program assesses the condition and functional capability of the system and, therefore, verifies the adequacy of the system and provides an opportunity to take proper corrective action should adverse conditions be detected.

An end anchorage concrete surveillance program for the post-tensioning system is implemented to assure the continued structural integrity of the Reactor Buildings. The program consists of periodic inspections of end anchorages and adjacent concrete surfaces.

3.8.1.7.7 Liner Plate

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

A surveillance program for the Reactor Building liner plate was implemented to assure continued integrity of the liner plate. The initial surveillance was conducted in conjunction with the initial Reactor Building Structural Integrity Test. The building was pressurized to 67.8 psig during the surveillance test to check the inward displacement of the liner plate. This program was completed for Oconee 1 on January 2, 1974.

Liner plate inspection now is conducted in accordance with 10CFR 50, Appendix J requirements.

3.8.2 Steel Containment

The Reactor Building does not have a steel containment vessel separate from the concrete shell. The description of the steel liner plate and all applicable supporting data is found in Section 3.8.1.

3.8.3 Concrete and Structural Steel Internal Structures of Containment

3.8.3.1 Description of the Internal Structures

The Reactor Building interior structure consists of (1) the reactor cavity, (2) two steam generator compartments, and (3) a refueling pool which is located between the steam generator compartments and above the reactor cavity.

The reactor cavity houses the reactor vessels and serves as a biological shield wall. The reactor cavity is also designed to contain core flooding water up to the level of the reactor nozzle.

Additional descriptive information can be found in Section 3.8.1.

3.8.3.2 Applicable Codes, Standards, and Specifications

The interior structures are designed in accordance with the applicable codes and specifications listed in Section 3.8.1.2.

3.8.3.3 Loads and Load Combinations

The loads and load combinations considered for the design of the interior structures are described in Section 3.8.1.3.

3.8.3.4 Design and Analysis Procedures

The Reactor Building interior structures are designed using conventional structural analytical techniques. Some of the provisions of the design are described below:

The primary functions of the steam generator compartment walls are to serve as secondary shield walls and to resist the pressure and jet loads.

The foundations for all NSSS equipment including the reactor vessel, the steam generators, and the pressurizer are designed to remain within the elastic range during rupture of any pipe combined with the “maximum earthquake”.

The design pressure differential across walls and slabs of enclosed compartments in the internal structure are as follows:

Reactor Cavity–	208 psi
East Steam Generator Compartment–	15 psi
West Steam Generator Compartment–	15 psi

In addition to the peak differentials, the steam generator compartment walls are designed for simultaneous action of a single jet impingement load and the safe shutdown earthquake.

Pipe whipping restraints are provided for the main steam, feedwater, and other high-pressure piping.

3.8.3.5 Structural Acceptance Criteria

The Reactor Building interior structure (comprising all elements inside the Reactor Building shell) is a Seismic Class 1 structure and is designed on the following bases:

1. The stresses in any portion of the structure under the action of dead load, live load, and design seismic load will be below the allowable stresses given by either the ACI Building Code, ACI 318-1963 except as noted in Section 3.8.1.3.6, and the AISC Manual of Steel Construction, 6th Edition.
2. The stresses in any portion of the structure under the action of dead load, and thermal load will be below 133 percent of the allowable stresses given in (1).
3. The capability to safely shut down the plant will be maintained under the combined action of dead load, maximum seismic load, pressure and jet impingement load. The latter two loads are based on the rupture of one pipe in the primary loop. The deflections of structures and supports under these combined loads would be such that the functioning of engineered safeguards equipment would not be impaired. The yield load equations in Section 3.8.1.3.6 are adhered to except that local yielding is permitted for pipe, jet or missile barriers provided there is no general failure.
4. Under the combined action of dead load and maximum seismic load, reinforced concrete structures shall be designed in accordance with the requirements of Table 3-14. Structural steel structures shall be designed in accordance with the provisions of the AISC Manual of

Steel Construction except that normal allowable stresses may be increased by 150%, not to exceed 0.9 yield.

5. The maximum allowable concrete temperature at penetrations in the Primary Shield Wall shall not exceed 400°F.

3.8.3.6 Materials, Quality Control, and Special Construction Techniques

The materials used for the structural elements are as follows:

Structural Steel	– ASTM A36
Concrete	– f'_c = 4000 psi at 28 days
	– f'_c = 5000 psi at 28 days (for steam generator bases, reactor foundation, and primary shield wall).
Reinforcing	– ASTM A615, Grade 40 for Bars #11 and under ASTM A615, Grade 60 for Bars larger than #11.

Additional materials, quality control, and construction techniques and described in Section 3.8.1.6.

3.8.3.7 Testing and Inservice Surveillance Requirements

Testing and inservice surveillance requirements are outlined in Section 3.8.1.7.

3.8.4 AUXILIARY BUILDING

3.8.4.1 Description of the Structure

The Auxiliary Building was constructed on a 5.00 foot thick reinforced concrete mat foundation. Below grade, the building consists of reinforced concrete walls and slabs. Above grade, the building consists principally of reinforced concrete columns, beams, and slabs, with the slabs acting as diaphragms.

The following facilities related to the Nuclear Steam Supply System are located in the Auxiliary Building:

1. New and Spent Fuel Handling, Storage, and Shipment
2. Control Rooms
3. Waste Disposal System
4. Chemical Addition and Sampling System
5. Component Cooling System
6. Reactor Building Spray Systems
7. High and Low Pressure injection System
8. Spent Fuel Cooling System
9. Electrical Distribution System

3.8.4.2 Applicable Codes, Standards, and Specifications

The Class 1 Structure is designed according to the applicable codes and specifications listed in Section 3.8.1.2.

3.8.4.3 Loads and Load Combinations

The loads and load combinations considered for the design of the Auxiliary Building are listed in Table 3-23. The final design of the Auxiliary Building satisfies the loading combinations and factors tabulated in Table 3-14.

3.8.4.4 Design and Analysis Procedures

The design of the Auxiliary Building is performed using conventional structural analytical techniques. The provisions of the design for the Spent Fuel Pool are described below: The ultimate strength assumptions of the ACI Code for concrete beams in flexure are not allowed; that is, the concrete strain is not allowed to go beyond yield.

The Spent Fuel Pool Walls were analyzed for thermal loads in accordance with methods presented in ACI 505. The exterior wall temperature was assumed to be 60°F for areas enclosed by the Auxiliary Building and 0°F for exposed areas.

Under normal conditions, the interior wall temperature was 150°F and the maximum calculated thermal stress was 996 psi for concrete and 11,410 psi for reinforcing steel.

After prolonged outage of the cooling system, the interior wall temperature could reach 212°F and the maximum calculated thermal stress was 1681 psi for concrete and 25,600 psi for reinforcing steel. Reinforcing steel conforming with ASTM A516, Grade 60, was used.

A minimum of 0.30 percent reinforcing was used in the spent fuel pool walls to control concrete cracking. Also, a ¼ inch thick steel liner was used on the inside face of the pool for leak tightness.

The Spent Fuel Pool Slab was designed for the postulated cask drop accident. Fill concrete was placed from sound rock to the bottom of the fuel pool slab in the area covered by the cask crane to prevent the shearing of a large plug from the pool slab in the event the cask was accidentally dropped.

The SFP concrete floor slab is designed to withstand the 100 ton cask drop. However, localized concrete could be crushed and the steel liner plate punctured in the area of dry storage cask impact. For the purpose of analyzing the event, a gap of 1/64 inch for a perimeter of 308 inches in the liner plate was assumed. The calculated leakage of pool water through the gap is 21.3 gallons per day. This amount of water loss is within the capability of the SFP makeup sources.

3.8.4.5 Structural Acceptance Criteria

The areas of the Auxiliary Building housing the facilities listed in Section 3.8.4.1 have been designed for the loads and conditions as shown in Table 3-23 with maximum allowable stresses as follows:

Loading Condition	Maximum Allowable Stress
A	Stresses in accordance with ACI and AISC Codes
B, D	For Reinforced Concrete Design:

Loading Condition	Maximum Allowable Stress
	fc = 0.85 f'_c for Flexure
	fc = 0.70 f'_c for tied compression members
	Shear = $1.1\sqrt{f'_c}x1.33$ for beams with no web reinforcing
	fs = 0.90 fy for Flexure
	fs = 0.90 fy for web reinforcing
	fs = 0.85 fy for reinforcing steel with lap or mechanical splices
	Bond = $\frac{3.4\sqrt{f'_c}}{D}$ x 1.33 for top bars
	= $\frac{4.8\sqrt{f'_c}}{D}$ x 1.33 other than top bars
	For Structural Steel Design:
	AISC Code allowable stresses x 150%, not to exceed 0.9 Fy
C, E	Analyzed on basis of Reference 7

3.8.4.6 Materials, Quality Control, and Special Construction Techniques

This information is outlined in applicable portions of Section 3.8.1.6.

During the Unit 1 Steam Generator Replacement Outage, a portion of the Auxiliary Building roof was removed and repaired. The replacement reinforcing steel information is outlined in the applicable portions of Section 3.8.1.6.3.1.

3.8.4.7 Concrete Masonry Walls

The masonry walls are in-fill panels serving as partitions with some walls having pressure, fire and radiation barrier applications. The walls are single or multiple wythe and constructed of hollow or grouted concrete blocks or solid concrete blocks or bricks. All masonry walls are non-structural and constructed on a structural support system.

Pursuant to I.E. Bulletin 80-11, a safety re-evaluation of all masonry walls was undertaken by Duke. As a result of this reevaluation effort certain masonry walls were modified to meet minimum factors of safety.

Certain masonry walls that are part of the Units 1, 2, and 3 Auxiliary Buildings that house equipment needed to mitigate the adverse effects of a tornado were evaluated for tornado-induced differential pressure loading per Reference 41. Beginning in 2011, these walls were subsequently strengthened to meet these loads using a fiber-reinforced polymer (FRP) system. Per References 42 and 49, masonry walls constructed of concrete block and solid concrete brick strengthened by the FRP System have been found to be acceptable by the NRC Staff in resisting tornado-induced differential pressure.

3.8.4.7.1 Applicable Codes and Standards

The criteria used for the re-evaluation of masonry walls pursuant to I.E. Bulletin 80-11 are contained in Attachment 4 of Reference 14 and Reference 16. The criteria in Reference 14 use the American Concrete Institute "Building Code Requirements for Concrete Masonry Structures," ACI 531-79, as the governing code with supplemental allowables specified for cases not directly addressed in the code. The criterion in Reference 16 is the Arching Action Theory for Masonry Walls.

The criteria used for the re-evaluation of masonry walls to resist tornado-induced differential pressure loadings are contained in References 37, 38, 39, 40, 43, 44, 45, 46, 47, and 48 as approved by the NRC Staff in References 42, 49, 50 and 51. These criteria specify ACI 531-79 as the governing code for this evaluation with supplemental working stress allowables specified for the fiber-reinforced polymer (FRP) system.

3.8.4.7.2 Loads and Load Combinations

The design loadings for the masonry walls at Oconee are those specified in portions of Section 3.8.4. The only thermal effects which a masonry wall experiences are those pertinent to normal operation, and these are not considered a significant design consideration.

In addition, the design differential pressure for masonry walls evaluated for tornado-induced loadings is contained in Section 3.3.2.1. The load combinations for tornado-induced loadings, which include the differential pressure loading for which the fiber-reinforced polymer (FRP) system was used to mitigate, are contained in NUREG-0800, Standard Review Plan, Section 3.8.4, “Other Seismic Category I Structures”, Rev. 1 - July 1981.

3.8.4.7.3 Upgrade and Modification of Masonry Walls

A program of repairs was performed on selected masonry walls pursuant to I.E. Bulletin 80-11. The walls included in this program were not found to be unsafe in their original configuration; however, an added margin of safety was desired for these walls. The repairs provide increased factors of safety by either upgrading the walls to meet the allowable stresses set forth in the re-evaluation criteria or by shielding the safety related equipment located in proximity of the walls from damage, assuming the masonry walls were to collapse. References 12 through 24 and References 35 and 36 pertain to I.E. Bulletin 80-11.

Certain masonry walls that are part of the Units 1, 2, and 3 Auxiliary Buildings were modified beginning in 2011 to resist tornado-induced differential pressure loading (References 42 and 49). These walls were strengthened using a fiber-reinforced polymer (FRP) system.

3.8.5 Nonclass 1 Structures

The Turbine Building, the condenser circulating water structures, the Essential Siphon Vacuum System Intake Dike Trench, the Essential Siphon Vacuum Cable Trench, the Essential Siphon Vacuum Building, 230 kV Switchyard Structures and Overhead Power Path Structures and the Keowee structures as listed in Section 3.2.1.1.2 are Class 2 structures.

Class 3 structures include all structures not included in Class 1 and 2.

3.8.5.1 Description of the Structures

1. Turbine Building

   The building was constructed of reinforced concrete below grade consisting of substructure walls and a mat foundation. Above grade, the building consists of structural steel with metal siding.

2. Keowee Structures

   The Keowee Structures considered are Powerhouse, Power and Penstock Tunnels, Spillway, Service Bay Substructure, Breaker Vault, and Intake Structure.

3. Dams and Dikes

   The Keowee Dam, the Little River Dam and Dikes, and the Oconee Intake Canal Dike impound the waters of Lake Keowee to provide the source of flowing water for the Keowee hydroelectric power plant.

4. Oconee Intake Structure

   The intake structure supports the CCW pumps, intake screens, and inlets of the CCW pipes.

5. Oconee Intake Underwater Weir

   The underwater weir retains an emergency water supply in the event that the waters of Lake Keowee are released by the failure of a dam or dike.

6. CCW Intake Piping

   The CCW Intake Piping conveys water from the CCW pumps on the intake structure to the condenser, supplies water to the LPSW Pumps, and serves as the reservoir for the SSF Auxiliary Service Water System and the Protected Service Water System.

7. CCW Discharge Piping

   The CCW Discharge Piping conveys water from the condenser to the discharge structure and supplements the CCW intake piping as a reservoir for the Protected Service Water System.

8. ECCW Piping

   The ECCW Piping serves two different functions. 1) It can siphon the Condenser Circulating Water through the Condenser to be discharged at the treatment pond. 2) It can be used for recirculation of the Condenser Circulating Water back to the Intake Canal.

9. Essential Siphon Vacuum System Intake Dike Trench

   The Essential Siphon Vaccum (ESV) System Intake Dike Trench is constructed of reinforced concrete (bottom and walls). The covers for the trench are steel plate except at the roadway crossing. The covers at the roadway are removable reinforced concrete slabs.

   The Essential Siphon Vaccum (ESV) System Intake Dike Trench routes the ESV piping, the Siphon Seal Water (SSW) piping, electrical heat trace cables, and electrical instrumentation cables within the FERC boundary without reducing the integrity of the Oconee Intake Dike.

10. Essential Siphon Vacuum System Building

    The ESV Building is constructed of a reinforced concrete mat foundation and rigid structural steel frame with metal siding.

The ESV Building encloses the ESV System's pumps, motors and associated equipment, providing protection (from weather & freezing) for that equipment and providing a suitable environment for maintenance activities.

11. Essential Siphon Vacuum System Cable Trench

    The essential Siphon Vacuum (ESV) System Intake Cable Trench is constructed of reinforced concrete (bottom and walls). The covers for the trench are steel plate except at the traffic crossing. The covers at the crossing are removable reinforced concrete slabs.

    The ESV System Cable Trench routes the cables associated with the ESV System and SSW System from the Radwaste Trench to the ESV Building.

12. 230 KV Switchyard Structures and Overhead Power Path Structures

    The primary purpose of these structures is to support or protect the electrical equipment and transmission lines in the 230 KV Switchyard and the overhead power path.

3.8.5.2 Applicable Codes, Standards, and Specifications

Class 2 structures are designed in accordance with the following codes:

ACI 318-63	- Building Code Requirements for Reinforced Concrete
AISC	- Steel Construction Manual, 6th edition and 9th edition (The 9th ed. is for the Essential Siphon Vacuum Building only)

The working stress design method will be used for normal and seismic conditions and stress will be in accordance with above codes, including the 33% increase for wind or earthquake leads. Class 2 structures are qualified for the Design Base Earthquake (DBE). All Keowee Structures necessary for Emergency Power Generation, the Oconee Turbine and Auxiliary Buildings (except as included in Class 1), the Oconee Intake Structure, the CCW Intake Piping, the CCW Discharge Piping, ECCW Piping (structural portion), the Oconee Intake Canal Dike, and the Essential Siphon Vacuum System Intake Dike Trench, the Essential Siphon Vacuum Cable Trench, and the Essential Siphon Vacuum Building are designed for Maximum Hypothetical Earthquake (MHE).

3.8.5.3 Loads and Load Combinations

3.8.5.3.1 Turbine Building

1. Transverse Loading

   The loadings were applied as follows:

Dead Loads - Roof		- 50 psf, reduced to 25 psf when the type of roof construction was finalized.
	Floors	- Grating Areas - 20 psf.

Concrete Areas

a. Operating Floor - 11-1/2 in. - 170 psf.

b. Mezzanine Floor - 8 in. - 115 psf.

c. Upper Surge Tank Floor - 4 in. - 65 psf plus tank at normal operating condition.

Crane Columns and Girders - Calculated weights.

Live Loads - Roof - 50 psf.

Grating Areas - 100 psf.

Operating Floor

a. Turbine Bay - 600 psf. *

b. -Heater Bay - 400 psf. *

* Includes an allowance for undefined equipment and normal loads – known S/Rs (supports/restraints)

Mezzanine Floor

a. General Area - 250 psf *

b. Moisture Separator Tube Pull Area - 400 psf *

c. Moisture Separator Lay Down Area - 30 kip concentrated load @ c/l of collector beams

*Includes an allowance for undefined equipment and normal loads – known S/Rs (supports/restraints)

Upper Surge Tank Floor - 100 psf (all areas except those between column lines 28 & 29 and 44 & 45 - 250 psf) **

**Includes an allowance for normal tank reactions and values for normal loads – known S/Rs (supports/restraints)

Cranes - 180 Ton and 80 Ton Cranes fully loaded, lifted load and lateral force arranged to produce maximum stresses. The lateral forces were reduced to 15 percent of the sum of the weights of the lifted load and the crane trolleys.

Wind load - 30 psf.

Seismic Loading No. 1 - (Load Combinations)

a. Critical Damping - 2%

b. Maximum Ground Motion Acceleration - 5% of gravity

c. Maximum Acceleration for Design - 12% of gravity (This is the maximum value of the acceleration response curve for 2% damping.)

d. Loadings - Roof - 50 psf, reduced to 25 psf when the type of roof construction was finalized.

e. Operating Floor - dead load of floor plus equipment load. (Equipment load estimated at 250 psf.)

f. Mezzanine Floor - dead load of floor plus equipment load. (Equipment load estimated at 150 psf.)

g. Upper Surge Tank and Floor - 65 psf plus tank at normal operating condition.

h. Crane - 180 Ton Crane, fully loaded, at center of bay.

i. Crane Columns and Girders - Calculated weights.

Seismic Loading No. 2 - (Load Combinations)

a. Critical Damping = 2%

b. Maximum Ground Motion Acceleration - 10% of gravity

c. Maximum Acceleration for Design - 22% of gravity (This is the maximum value of the acceleration response curve for 2% damping.)

   Loadings - Roof - 25 psf.

d. Operating Floor - dead load of floor plus equipment load. (Equipment load estimated at 200 psf.)

e. Mezzanine Floor - dead load of floor plus equipment load. (Equipment load estimated at 125 psf.)

f. Upper Surge Tank and Floor - 65 psf plus tank at normal operating condition.

g. Cranes - 180 Ton Crane and 80 Ton Crane at rest and in unloaded condition.

h. Crane Columns and Girders - Calculated weights.

i. Loading for Dynamic Seismic Analysis - (Load Combinations)

j. Critical Damping = 2%

k. Maximum Ground Motion Acceleration - 10% of gravity.

l. Reference subsection "Dynamic Seismic Analysis" in Section 3.8.5.4.1 for design accelerations.

Loadings:

a. Roof - 25 psf

b. Operating Floor - dead load of floor plus equipment load. (Equipment load estimated at 150 psf)

c. Mezzanine Floor - dead load of floor plus equipment load. (Equipment load estimated at 150 psf)

d. Upper Surge Tank and Floor - 65 psf plus tank at normal operating condition.

e. Cranes - 180 Ton and 80 Ton Capacity Cranes at rest and in unloaded condition.

f. Crane Columns and Girders - calculated weights.

Seismic Loading No. 2 was introduced approximately six months after the building was analyzed for Seismic Loading No. 1. With more complete information, it was apparent that the equipment loads assumed for the Operating and Mezzanine Floors were too conservative. Therefore, the equipment loads were reduced for the analysis for Seismic Loading No. 2.

2. <u>Longitudinal Loading</u>

The loadings were applied as follows:

Wind Load	- 30 psf.
Crane Load	- 10% of Maximum wheel load.
Seismic Loading No. 1	- Same as Seismic Loading No. 1 for Transverse Analysis with the following exceptions:
Loadings	- Operating Floor - Equipment load estimated at 130 psf.
	Mezzanine Floor - Equipment load estimated at 110 psf.

Seismic Loading No. 2 - Same as Seismic Loading No. 2 for Transverse Analysis with the following exceptions:

Loadings - Operating Floor	- Equipment load estimated at 130 psf.
Mezzanine Floor	- Equipment load estimated at 110 psf.

Loading for Dynamic Seismic Analysis - Same as loading for dynamic seismic analysis for transverse direction.

3. Loading Combinations and Factors

$S = 1.0\ D + 1.0\ L$

$1.33S = 1.0\ D + 1.0\ L + 1.0\ W$

$1.33S = 1.0\ D + 1.0\ E$

$1.64S = 1.0\ D + 1.0\ E'$

S = Allowable stress due to normal loading - from AISC specifications

D = Dead Loads (Equipment loads included in the case of seismic loadings)

L = Live Loads

W = Wind Loads

E = Loads from Seismic Loading No. 1

E' = Loads from Seismic Loading No. 2

3.8.5.3.2 Keowee Structures

1. Powerhouse

A typical reinforced concrete frame was investigated for the following loading conditions using a static type analysis:

a. Dead load plus live load (1000 lbs per square foot) using allowable stresses in accordance with ACI Code. The maximum calculated stresses were f_s = 18,590 psi and f_c = 1122 psi.

b. Dead load plus live load (1000 lbs per square foot) plus seismic load equal to 0.10g times the dead load. The maximum calculated stresses were f_s = 19,120 psi and f_c = 1189 psi. Allowable stresses were $f_s = 0.9\ f_y$ = 36,000 psi and $f_c = 0.85\ f'c$ = 2550 psi.

c. Dead load plus live load (1000 lbs per square foot) plus seismic load equal to 0.20g times the dead load. The maximum calculated stresses were f_s = 19,700 psi and f_c = 1229 psi.

The large live loading of 1000 lbs per square foot was included to allow for heavy equipment loads expected during construction and maintenance. Therefore, to be conservative, the 1000 lbs per square foot was included to b and c above but with seismic loadings added as a function of dead load only.

2. Spillway

A typical spillway pier was investigated for the following loading conditions:

a. Dead load plus hydrostatic load with allowable stresses in accordance with ACI Code. The maximum calculated stresses were f_s = 0 and f_c = 61.7 psi.

b. Dead load plus hydrostatic load plus seismic load equal to 0.10 times dead load. The maximum calculated stresses were f_s = 7760 psi and f_c = 173 psi. The allowable stresses were f_s = 0.9 f_y = 36,000 psi and f_c = 0.85 $f'c$[2] = 3400 psi.

1) Same as b except seismic load equal to 0.20 times dead load. The maximum calculated stresses were f_s = 16,350 psi and f_c = 227 psi.

In addition, the taintor gate thrust girder was investigated for the following loading conditions:

a. Dead load plus hydrostatic load with allowable stresses in accordance with AISC Code. The maximum calculated stress was f_s = 23,300 psi.

b. Dead load plus hydrostatic load plus seismic load equal to 0.10 times dead load with allowable stress = 0.9 f_y = 32,500 psi. The maximu[2]m calculated stress was f_s = 25,000 psi.

c. Same as b except seismic load equal to 0.20 times dead load. The maximum calculated stress was f_s = 28,800 psi.

3. Service Bay Substructure

The Service Bay substructure contains the Control Room, Cable Room, Equipment Room, and Battery Room areas. The substructure was investigated for the following loading conditions:

a. Dead load plus live load with allowable stresses in accordance with ACI Code. The maximum calculated stresses were f_s = 19,700 psi and f_c = 1160 psi.

b. Dead load plus live load plus seismic load equal to 0.15 times the combined dead-live load. The allowable stresses were f_s = 0.9 f_y = 36,000 psi and f_c = 0.85 $f'c$ = 2550 psi. The maximum calculated stresses were f_s = 24,000 psi and f_c = 1410 psi. It is apparent that the seismic loads could be substantially increased with resulting stresses being well below those allowable.

4. Breaker Vault

[2] $f'c$ = 4000 psi in piers.

The Breaker Vault is located on the Operating Floor level of the Keowee Powerhouse and was designed primarily to afford tornado protection for electrical equipment. The controlling case was dead load plus equipment loads plus tornado wind and missile. Resulting stresses for this case were f_s = 38,000 psi and f_c = 2190 psi.

These compare to the allowable f_s = 0.9 f_y = 36,000 psi and f_c = 0.85 f′c = 2550 psi. The actual steel stresses were about 5-½ percent over the allowable stresses but 5-½ percent below the guaranteed minimum yield stress and are considered satisfactory for this severe loading combination.

A second case considered dead load plus seismic loads equal to 0.15 times the combined dead-live loads plus normal wind load. By inspection, it was found that this would result in substantially lower stresses than the loading combination above. Therefore, a detailed design check was not made.

5. Intake Structure

Three design cases were considered:

a. Construction condition (dead load plus wind load) with no water and allowable stresses being within the ACI and AISC Code. The resulting stresses were extremely low.

b. Structure unwatered and stop logs in place. Allowable stresses were based on ACI and AISC Code. Calculated stresses were found to be well within the code limits.

c. The third case considered the cylinder gate open, dead loads and seismic loads equal to 0.15 times the dead load. Maximum calculated stresses were f_s = 39,700 psi and f_c = 2050 psi.

The resulting steel stresses are marginally below the guaranteed minimum yield stress and are considered satisfactory for the severe loading combination.

3.8.5.4 Design and Analysis Procedures

3.8.5.4.1 Turbine Building

Based on the basic criteria and general arrangement drawings of the Turbine Building, design studies were made to determine building dimensions, type of steel, member sizes, and shapes. A computer program, “Stress”, was used in the analysis of the bents.

Transverse Analysis

Each bent consisted of the three main crane columns, on lines D, J, and M, the roof girders, the columns of lines K and L and the operating and mezzanine floor framing. Where continuity of framing was not interrupted by the turbine-generator support, the short columns and operating and mezzanine floor framing were included as a part of the rigid frame. See Figure 3-38 for typical Turbine Building cross-section.

Longitudinal Analysis

Column lines B, D, J, and M were braced with diagonal members. For lines D, J, and M, this bracing took the form of two members for each brace with batten plates and angle lacing tying them together.

Dynamic Seismic Analysis

A dynamic seismic analysis of the building was performed consisting of a three mass system. Section 3.8.5.3.1 describes loading conditions for the dynamic seismic analysis. Maximum accelerations in the transverse direction were taken as the absolute sum of the accelerations associated with the first three mode shapes and were 0.47 g at the roof, 0.20 g at the Operating floor, and 0.16 g at the Mezzanine floor. Maximum accelerations in the longitudinal direction were taken as the absolute sum of the accelerations associated with the first three mode shapes and were 0.57 g at the roof, 0.24 g at the Operating floor, and 0.18 g at the Mezzanine floor. It is considered that the absolute sum is a conservative value. The structure was analyzed using these accelerations and stresses were found to be within design criteria. Typical stress values, shown as percentage of allowable, are as follows:

Location	Normal Load	Seismic Load #2 (Static Analysis)	Seismic Load Dynamic Analysis)
Col. D at basement	83%	68%	44%
Col. D at roof	94%	36%	28%
Col. J below oper. floor	81%	51%	67%
Col. J above oper. floor	78%	37%	48%
Col. J at roof	88%	54%	59%
Col. M below oper. floor	89%	72%	75%
Col. M at oper. floor	84%	36%	47%
Col. M at roof	90%	56%	48%

3.8.5.4.2 Keowee Structures

The Keowee structures are designed using conventional structural analytical techniques.

3.8.5.4.3 Class 3 Structures

Class 3 structures are designed in accordance with design methods of accepted standards and codes insofar as they are applicable.

3.8.5.5 Structural Acceptance Criteria

The load combinations used in the design of the Turbine Building and Keowee structures and section strengths required to resist those load combinations are given in Section 3.8.5.3.

3.8.5.6 Materials, Quality Control, and Special Construction Techniques

Keowee Structures

All structures utilize concrete with a minimum compressive strength of 3000 psi, 40,000 psi reinforcing steel and A36 structural steel.

3.8.6 Foundations

The foundation for the Reactor Building is described in Section 3.8.1.1.

Foundation descriptions for Auxiliary and Turbine Buildings are given in Section 3.8.4.1 and Section 3.8.5.1, respectively.

3.8.7 References

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41. Regulatory Guide 1.76, Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants, Revision 1.
42. Letter from U. S. Nuclear Regulatory Commission to Duke Power Company, LLC, "Oconee Nuclear Station, Units 1, 2, and 3, Issuance of Amendments Regarding Use of Fiber-Reinforced Polymer (FRP) (TAC Nos. MD2129, MD2130, and MD2131)," dated February 21, 2008.
43. Letter from Duke Energy Carolinas, LLC to U. S. Nuclear Regulatory Commission, "Oconee Nuclear Station, Units 1, 2, and 3, Docket Numbers 50-269, 50-270, and 50-287, License Amendment Request to Incorporate Use of Fiber-Reinforced Polymer System to Strengthen Existing Auxiliary Building Masonry Brick Walls for Tornado Loadings, - License Amendment Request No. 2009-05," dated June 29, 2009.
44. Letter from Duke Energy Carolinas, LLC to U.S. Nuclear Regulatory Commission, "Oconee Nuclear Station, Units 1, 2, and 3, Docket Numbers 50-269, 50-270, and 50-287, Renewed Operating Licenses DPR-38, DPR-47, and DPR-55, Revision to Tornado/HELB Mitigation Strategies and Regulatory Commitments," dated May 18, 2010.
45. Letter from Duke Energy Carolinas, LLC to U. S. Nuclear Regulatory Commission, "Oconee Nuclear Station, Units 1, 2, and 3, Docket Numbers 50-269, 50-270, and 50-287, Renewed Operating Licenses DPR-38, DPR-47, and DPR-55, Tornado Mitigation License Amendment Request - Response to Request for Additional Information," dated June 24, 2010.
46. Letter From Duke Energy Carolinas, LLC to U. S. Nuclear Regulatory Commission, "Oconee Nuclear Station, Units 1, 2, and 3, Docket Numbers 50-269, 50-270, and 50-287, Renewed Operating Licenses DPR-38, DPR-47, and DPR-55, License Amendment Request to Incorporate Use of Fiber-Reinforced Polymer System to Strengthen Existing Auxiliary Building Masonry Brick Walls for Tornado Loadings - Response to Request for Additional Information," dated February 15, 2011.
47. Letter form Duke Energy Carolinas, LLC to U. S. Nuclear Regulatory Commission, "Oconee Nuclear Station, Units 1, 2, and 3, Docket Numbers 50-269, 50-270, and 50-287, Renewed Operating Licenses DPR-38, DPR-47, and DPR-55, License Amendment Request to Incorporate Use of Fiber-Reinforced Polymer System to Strengthen Existing Auxiliary Building Masonry Brick Walls for Tornado Loadings - Response to Request for Additional Information," dated June 6, 2011.
48. Letter form Duke Energy Carolinas, LLC to U. S. Nuclear Regulatory Commission, "Oconee Nuclear Station, Units 1, 2, and 3, Docket Numbers 50-269, 50-270, and 50-287, Renewed Operating Licenses DPR-38, DPR-47, and DPR-55, License Amendment Request to

Incorporate Use of Fiber-Reinforced Polymer System to Strengthen Existing Auxiliary Building Masonry Brick Walls for Tornado Loadings - Response to Request for Additional Information," dated June 15, 2011.

49. Letter from U. S. Nuclear Regulatory Commission to Duke Energy Carolinas, LLC, "Oconee Nuclear Station, Units 1, 2, and 3, Issuance of Amendments Regarding Authorizing a Change to the Updated Final Safety Analysis Report Allowing the Use of Fiber Reinforced Polymer on Masonry Brick Walls for the Mitigation of Differential Pressure Created by High Winds (TAC NOS. ME1710, ME1711, and ME1712)", dated June 27, 2011.

50. Letter from U. S. Nuclear Regulatory Commission to Duke Energy Carolinas, LLC, "Oconee Nuclear Station, Units 1, 2, and 3, Request for Withholding Information from Public Disclosure Regarding Installation of Fiber-Reinforced Polymer on Masonry Brick Walls for the Mitigation of Differential Pressure Created by High Winds (TAC NOS. ME1710, ME1711, AND ME1712)", dated June 27, 2011.

51. Letter from U. S. Nuclear Regulatory Commission to Duke Energy Carolinas, LLC, "Oconee Nuclear Station, Units 1, 2, and 3, Correction Letter for Amendment Nos. 373, 375, and 374 Regarding Authorizing a Change to the Updated Final Safety Analysis Report (UFSAR) Allowing the Use of Fiber Reinforced Polymer on Masonry Brick Walls for the Mitigation of Differential Pressure Created by High Winds (TAC NOS. ME1710, ME1711, and ME 1712)", dated January 11, 2012.

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3.9 Mechanical Systems and Components

3.9.1 Special Topics for Mechanical Components

3.9.1.1 Design Transients

All Reactor Coolant System components are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. Design transient cycles for the Reactor Coolant System are shown in Table 5-2 and the design transient cycles for the Pressurizer Surge Line Piping are shown in Table 5-23. Both sets of design cycles are documented in Reference 31.

As a result of NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification, a reanalysis of the Pressurizer Surge Line (PSL) piping was performed in accordance with the 1986 ASME Code and documented in BAW-2127 (Ref. 34) and its Supplement 2 (Ref. 35). The new surge line design transients are based on actual operating transients and are used for the PSL piping analysis and are summarized in the Pressurizer Surge Line Functional Specification (BAW Document 18-1202139-000), Reference 22 of Section 5.2.4. The PSL Functional Specification is contained in Reference 31.

3.9.1.2 Computer Programs Used in Analysis1

Computer programs used to perform the code calculations on the casing for the reactor coolant pump are described in Section 5.4.1.2.

Additional computer programs used in analysis are given in Section 3.7.3.1.

3.9.1.3 Deleted Per 2004 Update

3.9.1.4 Considerations for the Evaluation of the Faulted Condition

The analytical method used for the evaluation of faulted conditions is elastic analysis. Stress limits for the faulted conditions are established in Section 3.9.3.1.

Faulted operating conditions were not applied to any components that were not a part of the reactor coolant pressure boundary.

The design stress limits for components comparable to the ASME Code Class 2 and 3 did not allow inelastic deformation.

3.9.2 Dynamic Testing and Analysis

3.9.2.1 Piping Vibration, Thermal Expansion, and Dynamic Effects

The following paragraphs describe the actions taken during the initial startup to address piping vibrations, thermal expansion and dynamic effects. It was Duke's normal practice and a startup procedure consideration to put essential and safety related systems through all of their normal and emergency modes of operation, visually observing the system for excessive movement and/or vibration. Based on operational reports indicating possible excessive movement and/or vibration, the Steam Production Department requested Design Engineering review of each case. Design Engineering observed the system making necessary measurements, readings, etc., as required to analyze the problem against existing design stress analysis and design criteria. Based on this analysis, Design Engineering either approved the system as satisfactory or required additional design consideration. Additional supports or suppressors were designed to accommodate the effects of valve closures, pump trips, safety valve operations, and operational vibrations as required. Any problems defined for any unit were reviewed and corrected for all three units as required.

Although not required for the Oconee project, Duke conducted prior to initial station startup the following monitoring programs which are typical of Design Engineering reviews as discussed above for the purpose of comparing results with design analysis.

1. Thermal Movement Monitoring Program for the Reactor Coolant System Piping (Data was taken on Oconee 1 only; however, the report was qualified for all three units).
2. Thrust Movement Monitoring Program for the Main Steam Bypass to Condenser Piping (Data was taken on Oconee 1 only; however, the report was qualified for all three units).
3. Hanger and Restraint Setting Monitoring Program for the LP Injection System (Data was taken on Oconee 1 only; however, the report was qualified for all three units).

   Dynamic analysis is further described in Section 3.9.3.1.

3.9.2.2 Seismic Qualification Testing of Safety-Related Mechanical Equipment

When the response spectra at each elevation in the building has been determined, the G-loadings imposed on a component may then be determined. These loads are evaluated by the equipment supplier and in the case of complex components such as a heat exchanger, the design calculations performed by the supplier are reviewed by B&W Engineering or Duke, as applicable. The supplier has the freedom to use either of two alternate analytical methods to evaluate the equipment or he may choose to test it. Components may be tested by either shaker or impact tests and a certification of the test results are required. In a few cases, a manufacturer's certification that the equipment would withstand seismic conditions is acceptable based on tests of similar equipment, an example of this would be similar type pumps. Analytically the evaluation can be made by calculating the natural frequency of the component, entering the appropriate damping curve and determining the amplification factor from the response spectrum curve. The equipment is then evaluated using these G-loadings. As an alternate, the component may be evaluated without calculating the natural frequency by using the peak amplification factor from the appropriate damping curve to determine the equipment loads. This latter approach is conservative.

Special attention is given to foundation and nozzle loadings for equipment such as tanks, pumps, heat exchangers, demineralizers and filters. Loads imposed by connecting piping on a given component are included and in some cases, component nozzles have had to be reinforced to accommodate these loads. Components which are most likely to require special reinforcement due to seismic loads are long horizontal, saddle mounted tanks, vertical tanks mounted on legs, and stacked heat exchangers. These have all been evaluated and appropriately designed for the seismic conditions.

An alternate method of seismic qualification for mechanical equipment (within the applicable equipment classes) would be an experienced based approach. Seismic adequacy can be established using methods described in the Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment, Revision 3A, developed by the Seismic Qualification Utility Group (SQUG). This method is also commonly known as SQUG.

3.9.2.3 Pre-operational Flow-induced Vibration Testing of Reactor Internals

The test program developed to measure vibration of the reactor internals at Oconee 1 during hot functional testing is described in Topical Report *BAW-10038* (Reference 18).

The main objective of the testing program is to obtain measurements of flow-induced vibration to confirm the structural adequacy of the internals. The components to be instrumented were selected on the basis of an evaluation of the distressed areas in the Oconee 1 reactor internals during previous hot functional testing and of the regions with high flow velocities. Another objective of the program is to confirm current analytical methods.

BAW-10038 presents the documentation required by Safety Guide 20 to qualify the Oconee 1 internals as the prototype design for B&W's 177-fuel-assembly plant. Described therein are the instrumentation used on the internals and reactor vessel, the data acquisition system, the test conditions, the on-line analysis of data, the predicted component responses, the test acceptance criteria, and the inspection program.

3.9.2.3.1 Pre-Operational Testing

First-of-a-kind instrumentation which will measure flow induced vibrations at special locations during pre-operational testing was installed on the Oconee I internals. Confirmatory measurements were made on Oconee 2 and Oconee 3 internals.

General

The directions and velocities of the coolant flow are controlled by the design of the reactor internals and are primary criteria used to determine what internal components should not be measured. Consequently, a brief description of the coolant flow through the reactor as indicated in Figure 3-57 is given below.

Coolant for the core enters through the four reactor inlet nozzles. It is then directed downward in an outside annulus defined by the inside surface of the vessel, the core support shield, and the thermal shield. Approximately 99.6 percent of the downward flow enters an outside annulus at approximately 23 ft/sec. The remaining 0.4 percent enters an inside annulus between the inside surface of the thermal shield and the outside surface of the core barrel. The flow velocity in this annulus is limited to less than 1 ft/sec by orifices located in the bottom of the core barrel cylinder.

Flow in the outside annulus enters the plenum region in the bottom of the vessel, turns and then flows upward through the core. Approximately 1.5 percent of the upward flow passes through an annulus between the core barrel inside surface and the back side of the baffle plates. Velocity in this annulus is also limited to less than 1 ft/sec.

As the coolant exits from the core, it enters the plenum assembly. The plenum cylinder maintains the coolant flow parallel to the outside of the guide tube assemblies. Flow passes from the plenum to the two outlet nozzles through 34 inch and 22 inch diameter holes in the upper section of the plenum. The maximum flow velocity across the guide tube assemblies adjacent to the plenum outlets is approximately 19 ft/sec. At the two locations where a small amount of outlet flow passes through a cluster of twenty four 3-inch diameter holes, the flow across the adjacent guide tube assemblies is only 8 ft/sec.

The flow direction and velocity control where chosen to reduce the possibility of developing forces which would result in damaging vibrations in all regions of the core. The resulting velocities are low enough to preclude the necessity of measuring motions of the core barrel, control rod guide tube assembly (a part of the plenum assembly), and other upper plenum assembly components, as can be seen from the following:

1. The 19 ft/sec. flow velocity across the guide tube assemblies adjacent to the outlets in the plenum results in a vortex shedding frequency of only 6 cps. Since this shedding frequency is much lower than the 50 cps fundamental of the guide tube assembly, it was concluded that the assemblies will not have significant vibratory motion from the cross flow.
2. The flow velocity in the annulus between the core barrel and the thermal shield is less than 1 ft/sec. At this extremely small velocity, the vibratory motion of the shell modes will be negligible. Beam type motions of the core barrel can be measured by the upper accelerometer in the surveillance holder tube assembly. (The accelerometer instrumentation is described later.)
3. The plenum cover assembly is an extremely stiff assembly. Flow across the plenum cover occurs only at the outer edge of the assembly at a low velocity of 5 ft/sec. The force on the assembly due to flow is insignificant.
4. Since the coolant at 100 percent power operation is subcooled at the discharge of the fuel assembly, no steam bubbles exist which might induce vibration of the control rod guide tubes, plenum cylinder, or plenum cover assembly.

Pre-operational testing will yield results which are comparable to or more conservative than during operation for the following reasons:

1. The total flow is slightly greater during hot functional testing when the reactor core is not in place than during operation. This is particularly true for pump combinations of less than four pumps.
2. The velocities in areas of concern are not significantly influenced by the flow differences with or without the core.

Oconee 1

Instrumentation

The internal components which will be measured during pre-operational testing are the surveillance specimen holder tube, the thermal shield and the plenum cylinder. Details of the instrumentation follow.

A set of two accelerometer assemblies will be installed in each of two surveillance specimen holder tubes. The location of the holder tubes is shown in Figure 3-58. The accelerometer transducers will be located in the perforated section of the holder tube assembly as shown in Figure 3-59. In addition, two weights which simulate the surveillance capsules will be installed in each perforated tube.

The location of the lower accelerometer was selected to measure the midspan vibratory motions of the perforated tube. The perforated section of the surveillance holder tube is expected to have the largest flow induced vibratory amplitudes relative to the other sections of the holder tube assembly.

The upper end of the perforated tube is connected to the thermal shield. Consequently, the upper accelerometer will measure the thermal shield mid-plane vibratory amplitudes.

The 1-inch penetrations in the reactor vessel head permit the addition of three accelerometers to measure the shell mode vibrations of the plenum cylinder. One accelerometer will be located at the lower end of each of three tubes which are welded to the outside of the cylinder adjacent to the outlet holes as shown in Figure 3-60.

Each of the four accelerometers in the surveillance holder tube is biaxial. Therefore, there will be eight separate channels, four channels for measuring the acceleration amplitudes of the lower section of the surveillance holder tube and four channels for detecting the accelerations of the thermal shield. The uniaxial accelerometers for the plenum cylinder will provide three channels for measuring the acceleration amplitudes of the cylinder.

The accelerometers, specially designed for the components, will be capable of measuring the frequency of the components over a range of 2 to 300 Hz at acceleration up to 30g's.

Analysis

The acceleration signals from the various components will be recorded on tape by a FM tape recorder. After the signals are recorded, the information on the tape will be digitized by use of a mini-computer which samples the data at preset time intervals. The digitized time history record will then be used as input to a computer program which will analyze the record.

A B&W proprietary computer program will be used to plot the time history of the fluctuating accelerations, determine the predominant frequencies, the autocorrelation of the signal and phase differences between signals.

Cyclic stress values will be determined from the measured acceleration amplitudes, frequency and mode shapes. These dynamic stresses will be combined with normal operational stresses. The combined stresses will be judged acceptable if they are less than the endurance limit for the materials used to manufacture the components.

Oconee 2 & 3

The reactor vessels and internals designed for Oconee 2 and 3 are essentially identical to Oconee 1. To confirm that the fabrication process has not altered the characteristics of the internals, one surveillance holder tube for Oconee 2 and one for Oconee 3 will be instrumented like Oconee 1. Measurements will be made as described for Oconee 1. The instrument cables will go through a control rod nozzle (requiring the removal of a control rod drive mechanism) because the reactor vessel heads for these units do not have the 1-inch penetrations. The results from each of these tests will be compared to those for Oconee I to confirm that the vibration characteristics are similar.

3.9.2.4 Dynamic System Analysis of the Reactor Internals Under Faulted Conditions (Reference 19)

FCF (AREVA) identified a calculation inconsistency between the Mark-B fuel assembly horizontal faulted condition analyses and Emergency Core Cooling System (ECCS) calculations specific to the requirements of 10CFR50.46 (Reference 20). FCF re-analyzed this condition and found all B&W designed plants (with skirt-supported and nozzle supported reactor vessels) fueled with Framatome Mark-B type fuel assemblies conform to the requirements of 10CFR50.46 with adequate margin of safety. Leak before-break (LBB) analyses are used to establish the design breaks and the resulting reactor internals loads and displacement time histories, and fuel assembly impact loads. The results are applicable to Oconee Nuclear Station for any Mark-B type fuel assembly.

3.9.2.4.1 Background

The existing Mark-B fuel assembly horizontal faulted analyses, i.e., Loss-of-Coolant Accident (LOCA) and combined LOCA and Safe Shutdown Earthquake (SSE), showed minor grid deformations on outer and inner fuel assemblies within the core. These deformations were shown for both the Mark-B and Mark-BZ fuel assemblies. (The Mark-B fuel assembly design comprises Inconel spacer grids; the Mark-BZ fuel assembly comprises zircaloy intermediate grids. Currently, Oconee Units are refueled with Mark-BZ type fuel assemblies). Review of the existing ECCS calculation bases identified that no grid plastic deformation was considered for core interior fuel assemblies. Only grid plastic deformation for core periphery fuel assemblies was evaluated. Therefore, resolution of the inconsistency between the fuel assembly structural and ECCS calculation bases was necessary to ensure that the criteria set forth in 10CFR 50.46 are met.

The current Mark-B/BZ fuel assembly faulted condition analyses for horizontal fuel loadings embody substantial conservatism in the imposed forcing function (i.e. the pipe break selection). The current Mark-B/BZ fuel assembly faulted condition analyses apply reactor internals displacement time histories from large-bore pipe rupture loadings to determine fuel assembly grid loads and deformations. Highly conservative double-sided guillotine breaks at the hot leg and cold leg nozzle are evaluated in the existing Mark-B/BZ fuel assembly faulted condition analyses. Undue conservatisms are removed by using the LBB design breaks to establish the reactor internal structural loads and displacements for use in the fuel assembly structural evaluation.

Per References 21 and 27, the NRC staff has approved the use of the LBB to eliminate the large bore breaks from the design basis for structural evaluations of all BWOG plants, as established in previous topical report submittals per References 22, 23, and 28. Use of the remaining attachment line break loads is within the fuel assembly faulted structural guidelines set forth in NUREG-0800, Section 4.2, Appendix A. As such the RCS attachment line breaks are considered in the revised fuel assembly faulted structural analyses presented herein. Resulting fuel assembly spacer grid loads show that no plastic deformation occurs on any fuel assembly, thus the existing ECCS calculations conform to the requirements of 10CFR50.46.

3.9.2.4.1.1 Deleted per 1996 Revision

3.9.2.4.1.2 Deleted per 1996 Revision

3.9.2.4.1.3 Deleted per 1996 Revision

3.9.2.4.2 Postulated Loss-Of-Coolant Accidents

For reactor vessel skirt-supported plants, such as Oconee, the following postulated RCS attachment line LOCA breaks are evaluated: core flood line, decay heat line, and surge line. Note that the decay heat line break envelopes the surge line break as discussed in section 3.9.2.4.3.4.

3.9.2.4.3 Reactor Internals Analysis

The approach used to determine the core plate motions for the given attachment line breaks differs based on whether the plant is skirt-supported or nozzle-supported. Core plate motions are used as input for the fuel assembly faulted structural analysis.

3.9.2.4.3.1 RV Skirt Supported Plants

For skirt supported plants, such as the Oconee Units, the core plate motions are determined for the attachment break response by utilizing the same methodologies as used in BAW-1621 (Reference 24) for the large-bore pipe break analyses. The analyses are described below:

3.9.2.4.3.2 RV Internals Hydraulics Analysis

The hydraulic model of the RV internals and RCS loop representative of the RV skirt supported plants was retrieved and verified to be the same as that used in BAW-1621. The model was then modified to represent the three attachment line breaks (core flood line, decay heat line, and surge line). The analysis was executed using the same computer code as was done in BAW-1621 for the large-bore pipe breaks. The pressure output time-for-time was post-processed to determine the loadings on the RV and internals.

3.9.2.4.3.3 RV Asymmetric Cavity Pressure Analysis

For a postulated core flood line break (attached directly to the RV inside the RV cavity), mass and energy release from the break pressurizes the RV cavity and exerts asymmetric type loadings on the RV. Using the primary break cavity loadings as a guide, FCF determined that the Oconee cavity represented the bounding cavity for all of its RV skirt-supported plants. Hence, the Oconee RV cavity model was retrieved and verified to be the same as used in BAW-1621. Mass and energy data from the bounding core flood line break was in the computer code analysis of the cavity as was done in BAW-1621 for the large-bore pipe breaks. The pressure output time-for-time was post-processed to determine the loadings on the RV.

3.9.2.4.3.4 RV Internals Structural Analysis

The reactor vessel and internals model used for the RV skirt-supported plants in BAW-1621 was retrieved and verified. For the core flood line break, the RV internal hydraulics loadings, cavity pressure loadings, and thrust loadings were applied to the model. Upper and lower core plate motions were determined for use in the detailed fuel assembly model. For the surge line and decay heat line breaks, RV internal hydraulic loadings and thrust loads were applied to the model. These breaks have no cavity pressure, since they are attached to the primary piping outside the RV cavity. Comparison of results indicated that the decay heat line enveloped the surge line results. Core plate motions for the decay heat line break have been used in the detailed fuel assembly model.

3.9.2.4.4 Fuel Assembly Analysis

The horizontal displacement time histories for the reactor vessel lower core plate, upper core plate and the core baffle under the postulated loss-of-coolant loadings, as specified above, were used as input into the fuel assembly faulted structural analysis. A non-linear dynamic analysis was performed to calculate fuel assembly loadings and grid impact loads. The method and models of analysis were per NRC approved Topical Report BAW-10133, Revision 1 (Reference 25). For the horizontal analysis, two orthogonal directions were evaluated, namely X and Y. The detailed fuel assembly mathematical model used was applicable to the RV skirt-supported plants.

3.9.2.4.4.1 LOCA Analysis

Core Flood Line Guillotine - RV Skirt Supported Plant

FCF determined that the grid impact loads were less than the allowable spacer grid elastic load limit. This load limit is the 95/95 confidence level buckling load determined by impact tests performed on production grids at reactor operating temperatures. Tests were performed as described in BAW-10133P, Rev. 1. Therefore, the fuel assembly spacer grids will remain elastic, and the coolable geometry will be maintained during the postulated Core Flood Line break.

Decay Heat Line Guillotine - RV Skirt-Supported Plant

FCF results show no grid impact forces, i.e., no fuel assembly grid contact is made. Therefore, the coolable geometry will be maintained during the postulated Decay Heat Line break. These results are also applicable for the Surge Line break, since it is bounded by the Decay Heat Line break.

3.9.2.4.4.2 Combined Seismic and LOCA Analysis

The loads for LOCA and seismic conditions were combined by the square-root-of-sum-of-squares method (SRSS) as discussed and accepted by the NRC in NUREG-0800, Standard Review Plan 4.2 (Reference 26). The maximum grid impact forces for the seismic analyses were obtained from the existing seismic analysis performed for the Mark-BZ fuel assembly. The seismic input at the core supports, that envelope the seismic input for Oconee, was used in the fuel assembly seismic analysis.

FCF determined the maximum impact force for the Safe Shutdown Earthquake (SSE) condition and the combined SSE and LOCA condition. The impact force is less than the spacer grid elastic load limit. The empirical method for determining the spacer grid elastic load limit is as described in BAW-10133P, Rev. 1. Hence, the spacer grids will remain elastic for all loads from postulated breaks coupled with seismic excitation. Therefore, the requirement to maintain a coolable geometry is met for all fuel assemblies within the core.

3.9.2.4.5 Conclusion

The LBB licensing basis allows the most limiting breaks in RCS attachment lines to be used in evaluating RCS components for LOCA integrity. The use of the RCS attachment line breaks is thereby incorporated into the design basis for the evaluation of the dynamic effects of LOCA events on Mark-B/BZ fuel assemblies.

The spacer grid impact loads for all the faulted conditions with the LBB licensing basis are within the spacer grid elastic load limit. Therefore, no permanent grid deformation is predicted and the coolable geometry requirements are met for all fuel assemblies within the core.

FCF determined that substantial margin exists between the applied load and the grid elastic load limit (control rod insertion will not be hindered under any faulted condition); therefore, control rod insertability is ensured and the requirements of 10CFR50.46 are met.

3.9.2.4.5.1 Deleted per 1996 Revision

3.9.2.4.5.2 Deleted per 1996 Revision

3.9.2.4.5.2.1 Deleted per 1996 Revision

3.9.2.4.5.2.2 Deleted per 1996 Revision

3.9.2.4.5.2.3 Deleted per 1996 Revision

3.9.2.5 Deleted per 1996 Revision

3.9.2.5.1 Deleted per 1996 Revision

3.9.2.5.2 Deleted per 1996 Revision

3.9.2.5.3 Deleted per 1996 Revision

3.9.3 ASME Code Class 1, 2, 3 Components, Component Supports, and Core Support Structures

3.9.3.1 Load Combinations, Design Transients and Stress Limits

3.9.3.1.1 Reactor Coolant System

The Reactor Coolant System is designed structurally for 2,500 psig and 650°F. The system will normally operate at 2,155 psig and 604°F. The design transients are defined in Section 3.9.1.1.

The number of transient cycles specified in Table 5-2 and Table 5-23 for the fatigue analysis is conservative.

Reactor Coolant System components are designated as Class 1 equipment and are designed to maintain their functional integrity during an earthquake. Design is in accordance with the seismic design bases shown below. The loading combinations and corresponding design stress criteria for internals and pressure boundaries of vessels and piping are given in the section. These are summarized in Table 3-26. A discussion of each of the cases of loading combinations follows:

Case I - Design Loads Plus Operating Basis Earthquake (OBE) Loads - For this combination, the reactor must be capable of continued operation; therefore, all components excluding piping are designed to Section III of the ASME Code for Reactor Vessels. The primary piping is designed according to the requirements of USAS B31.1 and B31.7. The S_m values for all components, excluding bolting, are those specified in Table N-421 of the ASME Code. The S_m value for bolts are those specified in Table N-422 of the ASME Code. The primary system piping was redesigned to the 1983 ASME Code (No Addenda) during the steam generator replacement project.

Case II - Design Loads Plus Safe Shutdown Earthquake (SSE) Loads - In establishing stress levels for this case, a "no-loss-of-function" criterion applies, and higher stress values than in Case I can be allowed. The multiplying factor of (1.2) has been selected in order to increase the code-based stress limits and still insure that for the primary structural materials, i.e., 304 SST, 316 SST, SA302B, SA212B, and SA106C, an acceptable margin of safety will always exist. A more detailed discussion of the adequacy of these margins of safety is given in B&W Topical Report BAW-10008, Part 1, "Reactor Internals Stress & Deflection Due to LOCA and Maximum Hypothetical Earthquake (MHE)". Note that the MHE is equivalent to the SSE. The S_m values for all components are those specified in Table N-421 of the ASME Code.

The load cases for consideration of the faulted condition are defined below.

A loss-of-coolant accident coincident with a seismic disturbance has been analyzed to assure that no loss of function occurs. In this case, primary attention is focused on the ability to initiate and maintain reactor shutdown and emerg`ency core cooling. Two additional cases are considered as follows:

<u>Case III - Design Loads Plus Pipe Rupture Loads</u> - For this combination of loads, the stress limits for Case II are imposed for those components, systems, and equipment necessary for reactor shutdown and emergency core cooling.

<u>Case IV - Design Loads Plus Safe Shutdown Earthquake (SSE) Loads Plus Pipe Rupture Loads</u> - Two thirds of the ultimate strength has been selected as the stress limit for the simultaneous occurrence of safe shutdown earthquake and reactor coolant pipe rupture. As in Case III, the primary concern is to maintain the ability to shut the reactor down and to cool the reactor core. This limit assures that a materials strength margin of safety of 50 percent will always exist.

The design allowable stress of Case IV loads is given in B&W Topical Report BAW-10008 for 304 stainless steel. This curve is used for all reactor vessel internals including bolts. It is based on adjusting the ultimate strength curves published by U. S. Steel to minimum ultimate strength values by using the ratio of ultimate strength given by Table N-421 of Section III of the ASME Code at room temperature to the room temperature strength given by U. S. Steel.

In Cases II, III and IV, secondary stresses were neglected, since they are self-limiting. Design stress limits in most cases are in the plastic region, and local yielding would occur. Thus, the conditions that caused the stresses are assumed to have been satisfied. See B&W Topical Report BAW-10008, Part 1, for a more extensive discussion of the margin of safety, the effects of using elastic equations, and the use of limit design curves for reactor internals.

3.9.3.1.1.1 Deleted Per 2004 Update

3.9.3.1.1.1.1 Deleted Per 2004 Update

3.9.3.1.1.1.2 Deleted Per 2004 Update

3.9.3.1.1.1.3 Deleted Per 2004 Update

3.9.3.1.1.1.4 Deleted Per 2004 Updatel

3.9.3.1.1.1.5 Deleted Per 2004 Update

3.9.3.1.1.1.6 Deleted Per 2004 Update

3.9.3.1.1.1.7 Deleted Per 2004 Update

3.9.3.1.1.1.8 Deleted Per 2004 Update

3.9.3.1.1.1.9 Deleted Per 2004 Update

3.9.3.1.1.2 Steam Generator Replacement Analysis of the Reactor Coolant System

This section contains the following categories of information.

1. Pertinent information on the seismic design of the Reactor Coolant System.
2. A description of the type and location of each major component support analyzed, its design, and the seismic amplification associated with the location in the support building.
3. A correlation between a free-standing spacial analysis of the Nuclear Steam System and a planar analysis considering building-loop inter action.

3.9.3.1.1.2.1 Scope of Analysis

The Reactor Coolant System consists of the reactor vessel, coolant pumps, steam generators, pressurizer, and interconnecting piping. For the purpose of seismic analysis the Reactor Coolant System consists of all of the above components in addition to the pressurizer support steel, surge line snubbers, and the reactor coolant pump snubbers.

3.9.3.1.1.2.2 Description of Analytical Models

Seismic Analysis

See Section 3.7.3.1.1 for a description of the RCS seismic analysis for replacement steam generators.

Consistent mass is used to represent the Reactor Coolant Loop piping and the majority of the component weights. Lumped mass is used to represent the Control Rods, the Main and Auxiliary Feedwater Headers, the Pump assemblies, the Snubber's weight on the Pumps, the Pressurizer's whip restraint, and the Hot Legs' whip restraint. The torsional mass moment of inertia is included for the Reactor Vessel, Control Rod Drive mechanisms, Service Support structure, Pressurizer, and the Steam Generators since the analysis code does not calculate this term for those model sections having their cross sections modeled as pipe. Additionally, a portion of the "bending" mass moment of inertia, which represents the difference between a slender rod and a circular cylinder, is included for above components.

Dead Load Analysis

Input into the dead load analysis consists of three parts:

1. Material and Water Densities: These densities represent piping and support steel weight as well as piping water weight. Except for some cases where lumped masses are used to represent the weight.
2. Distributed (Linear) Weights: These weights represent component shells and heads, internals, entrained water and insulation and in the case of the Reactor Coolant Pumps they represent the motor and motor stand weight.
3. Applied Forces: These forces represent component head weights and attachment weights (supports and whip restraints, CRDM's, etc.). These applied forces are used to include the weights that are included as lumped masses.

Thermal Expansion

In order to consider all of the possible normal and upset operating conditions and perform a fatigue analysis, five thermal expansion load cases will be run. 0% power is used, as it is the highest power level where the hot leg and cold leg are at the same temperature (532° F). It is used mostly in the fatigue analyses and is often subtracted from other power levels when considering an operating cycle. 8% power is used in the fatigue analyses, as it is the maximum power level for transients 1A and 1B (heatup/cooldown). 15% power is the maximum normal operating cold leg temperature (575° F). This power level typically gives the maximum cold leg loads during the entire heatup. 100% power is used in the fatigue analysis as the maximum normal power level. The Trip 8/11 is a combined loadcase developed to determine the maximum hot and cold leg loads for any of the normal/upset transients included in the Reactor Coolant System Functional Spec (Reference 31).

Trip 8/11 Material Properties

The Trip 8/11 thermal condition is an envelop of all of the transients included in the RCS Functional Specification. It used in fatigue analysis and gives the worst case thermal expansion stresses for the piping and component nozzles. Review of that document showed that the highest hot leg temperature was 650° F and occurred with transient 8A (Reference 31) (Figure 8-1). The highest cold leg temperatures was 592° F and occurred with transient 11 (Reference 31) (Figure 11-1). Since the Steam Generator has a fixed base, the hot leg and cold leg are nearly isolated structurally. Therefore, choosing the highest temperature from all transients is a conservative method of enveloping the transients. It should be noted that the cold leg temperature used from transient 11 occurs over a very short period of time. Heat transfer analysis considering the actual temperature time history would show that the average through wall temperature of the cold leg would never reach this temperature during the actual transient. Therefore, this analysis is very conservative for the cold leg.

Transient 8A occurs at 100% power while transient 11 occurs at 15% power. Since the growth of the Steam Generator has more effect on the hot leg, the hot leg transient (Transient 8A) will be used for the Steam Generator. According to the Functional Spec for Transient 8A (Reference 31, Figure 8-1), the Steam Generator reaches a temperature of about 548° F in about 1 minute and the feedwater and steam flow drop to about 0 lbm/sec. Therefore, 548° F will be used for the Steam Generator shell, excluding the upper and lower heads, support stool, and tubesheets. The outlet nozzles will be considered at the same temperature as the rest of the cold leg (592° F) as they do not affect the hot leg but have significant effect on the cold leg.

3.9.3.1.1.2.3 Stress Analysis of Reactor Coolant Piping

Stress calculations made at various locations throughout the piping system are done in accordance with subsection NB of Section III of the 1983 Edition of the ASME Boiler and Pressure Vessel Code, (no addenda). Stress calculations were performed using the pipe stress equations found in Article NB-3600 of the 19893 Code. Primary and primary plus secondary stresses were calculated at each location and comparison made to 1.5 S_m and 3 S_m respectively. The primary stresses are calculated using equation 9 in subsection NB-3652 of section III of the 1983 edition of the ASME Code, and the primary plus secondary stresses are calculated using equation 10 in subsection NB-3653 of the ASME code. The highest primary stress at any location was found to be 20,580 psi, which is below the allowable value of 58,200 psi. The loads used to calculate the faulted primary stresses are combined in the following manner. The seismic and LOCA conditions are combined using SRSS, then added to operating pressure and deadweight.

3.9.3.1.1.2.4 Stress Evaluation of the Reactor Vessel

Stress evaluation of the reactor vessel is discussed in Section 5.2.3.3.1.

3.9.3.1.1.2.5 Stress Evaluation of Steam Generators

The stress evaluation of the replacement steam generators is included in the Base Design Condition Report (BWC-006K-SR-01) (Reference 29) and the Transient Analysis Stress Report (BWC-006K-SR-02) (Reference 30).

3.9.3.1.1.2.6 Stress Evaluation of the Reactor Coolant Pumps

The reactor coolant pump casings are designed, fabricated, inspected and tested to meet the intent of the ASME Boiler and Pressure Vessel Code, Section III, for Class A vessels, but are not code stamped.

The reactor coolant pump casing has been completely analyzed including a dynamic analysis separately from the loop to insure that the stresses throughout the casing are below the allowable for all design conditions.

An analysis in accordance with Paragraph N-415.1 of the ASME Code was performed to determine if the pump casing required a fatigue analysis for the number of design cycles specified. This analysis showed that the pump casing bowl met all the requirements of Paragraph N-415.1. Thus a fatigue analysis was not required. However, a fatigue analysis was performed on the pump casing cover in which the worst possible stress combination was considered at the two most critical points in the cover. It was found from this analysis, with this very conservative approach, that the maximum cumulative usage factor is only 0.125 for design cycles specified for this plant.

See Section 5.4.1.2 for a discussion of the code allowables and maximum calculated stresses for the reactor coolant pumps.

The casing cover analysis indicates that the thermal stresses and pressure stresses on the cover are within the Section III code allowables.

There are no deviations from the applicable ASME Code requirements in the design and fabrication of the pump casings other than code stamping.

To accommodate for the different reactor coolant pumps, the reactor coolant loops for Unit 1 and Units 2, 3 were analyzed separately for Deadweight, Thermal, Seismic, and Loss of Coolant Accidents for the replacement steam generator analysis (Reference 32 and 33). The replacement steam generators do not change the overall structural performance of the reactor coolant pumps for Units 1, 2, and 3. The RCPs remain qualified using the applicable ASME Code requirements.

3.9.3.1.1.2.7 Stress Analysis of Pressurizer Surge Line Piping

Stress calculations made at various locations throughout the Surge Line were performed in accordance with the ASME Code, Section III, Subarticle NB-3600. Pursuant to the code, seismic, thermal, pressure and cyclic loadings were considered in the analysis. The results indicate that the subject pipe meets all design criteria.

Stress calculations were made at various locations throughout the surge line piping in the replacement steam generator analysis in accordance with applicable ASME Code requirements. The replacement steam generators do not impact the qualification of the surge line piping.

3.9.3.1.1.2.8 Summary and Conclusion

The replacement steam generator analysis for Units 1, 2, and 3 was used to generate forces and moments for normal, seismic and LOCA conditions at critical locations throughout the reactor coolant system. These loads or the stresses resulting from them were compared to the allowable loads and stresses for each of the individual component locations. The replacement steam generator analysis found that there is no impact to the qualification of the reactor coolant system.

3.9.3.1.2 Other Duke Class A, B, and C Piping

Piping which is Class A, B, or C is defined in Section 3.2. The applicable Code requirements are established in Section 3.2. The seismic requirements for this piping are defined in Section 3.2. The seismic analysis techniques are defined in Section 3.7.3.

3.9.3.1.3 Field Routed Piping and Instrumentation

Duke's practice is to detail the routing of all safety-related and non safety related process lines regardless of size, except as follows:

1. Process piping - All main run process piping in Duke System Classification A, B, C, D, and F is detailed on engineering drawings; however, items such as vents, drains, valve bypass warming lines, and pump seal water for all systems are “field run”. Class E piping not meeting the limitations of Specification OSS-0027.00-00-0003 is detailed on engineering drawings.

   Instrument impulse lines - end points and specific routing requirements of any safety-related and non-safety-related instrument tubing lines are established per instrumentation and Controls Field Installation Standards, Specification OSS-0060.00-00-0001.

   Class E, G & H piping can be field routed and supported with certain limitations per Specification OSS-0027.00-00-0003.

2. It is not practical to limit “field run” piping to an extent greater than this for the following reasons:

   a. Obstruction to desirable routing would be difficult to determine and documentation of a precisely designed path would be lengthy, difficult to prepare, and difficult to follow.

   b. Revision to major process piping would cause changes in routing of small lines, resulting in many drawing changes without significant improvement in the final result.

   c. Sloping of impulse lines would be difficult to accomplish and document.

   Thus, field routing of small lines results in a superior job since obstruction and other revisions are clearly visible and easier to consider while meeting design requirements as established by OSS-0060.00-00-0001.

3. The special rigorous quality assurance measures and performance tests that will be conducted to assure satisfactory installation of field run piping and instrument tubing lines are as follows:

   a. All field engineered lines are schematically shown either on a diagrammatic, an instrumentation detail or a piping drawing such that mistakes in valving, connection termination points and materials are virtually eliminated.

   b. Requirements for seismic design for field run piping and tubing is established prior installation.

c. Except for very low pressure lines downstream of vent and drain valves and instrument impulse lines, all “field run” piping is hydrostatically tested in accordance with the requirements of the main process system.

d. Prior to erection, engineering specifies requirements for interaction of seismically designed with non seismically designed structures. After erection, QA/QC reviews all safety-related and non-safety-related piping and tubing in the area to assure that appropriate criteria have been followed.

e. Instrument impulse line installation is inspected by site QA/QC prior to turnover of the system to operations.

f. Instrumentation testing programs are well defined by Duke test procedures. These tests document conclusively that the instrument loops are correctly installed and operate properly.

This practice of “controlled field routing” of small piping and instrument tubing lines produces the best possible overall results. It is not practical to limit “field run” piping to a greater extent.

3.9.3.2 Pump and Valve Operability Assurance

Equipment pre-operational test programs are described in Section 14.2.

The NRC issued IE Bullentin 88-04, "Potential Safety-Related Pump Loss," on May 5, 1988. The purpose of this bulletin was to request licensee investigation and correction, as applicable, of two miniflow design concerns for plant safety-related pumps. The first concern involved the potential for dead-heading of one or more pumps in safety-related systems that have a miniflow line common to two or more pumps or other piping configurations that do not precluded pump-to-pump interaction during miniflow operations. The second concern was whether or not the installed miniflow capacity is adequate for even a single safety-related pump in operation. Final evaluations and operability justifications per the requirements of this bulletin were presented in response to the NRC by letter on January 15, 1990 (letter form H.B. Tucker to the NRC, dated January 15, 1990). Futher programmatic enhancements and long-term corrective actions committed to in this response were verified complete/closed out in the letter from M.S. Tuckman to the NRC, dated January 10, 1991.

The NRC issued Generic Letter 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," onAugust 17, 1995, to request that licensees take actions to identify safety-related power-operated gate valves that are susceptible to pressure locking or thermal binding, and ensure that they are capable of performing their safety functions. Evaluations of the valves within this category were completed with responses to the NRC submitted in References 37, 38, 39, and 40. The responses included commitments to replace specific valves, modify specific valves, and test specific valves during future outages. The NRC accepted the actions and closed this issue in Reference 41. Valve operators are designed to actuate the valves with the maximum system pressure drop across the valve plus packing friction forces and potential pressure locking and thermal binding forces. Where possible, power-operated gate valves are of the parallel disc design or the flexible wedge design, which release the mechanical holding force during the first increment of travel so that the operator works only against the frictional component of the hydraulic imbalance and the packing box friction.

3.9.3.3 Design and Installation Details for Mounting of Pressure Relief Devices

Design analysis and installation criteria for safety and relief valves located within the reactor coolant and main steam (thru main stop valves) pressure boundaries are as follows:

1. Piping and its Support-Restraint System are designed to accommodate and/or restrain the piping for both dynamic and static loadings as applicable such that stresses produced are within code allowables for the following:
   a. Dead weight effect
   b. Thermal loads and movements
   c. Seismic loads and deflections - movements
   d. Safety valve thrust and moment
   e. Maximum absolute differential movement between structures

   Applicable loadings are combined and considered as described in Section 3.2.
2. Nozzles are analyzed and appropriate reinforcement added such that code allowables stresses are maintained for:
   a. Internal pressure
   b. Safety valve thrust
   c. Safety valve moment

In particular, for the main steam lines outside the Containment, pressure relief is accomplished through the use of sufficient safety relief valves to meet code requirements. The safety valves are set for progressive relief in intermediate steps of pressure within the allowed range of pressure settings to prevent all valves actuating simultaneously. Valves are located on a horizontal run of pipe and are oriented in a manner that will produce torsion and bending in the main pipe during operation of the valves. The valves are staggered on opposite sides of the main steam line and set to relieve progressively to counterbalance the torque produced. But the valves could be within the allowed range and the maximum net torque on the piping system could result from four valves. The piping system is designed to accept the net torque resulting from four safety valves operating simultaneously on the same side of the line. The piping support and restraint system is designed using shock suppressors and rigid stops to limit piping system stresses within code allowables as discussed above.

Dynamic thrust effects were analyzed for the Reactor Coolant System pressurizer relief discharge line to the Quench Tank, constituting a closed system. Stresses produced by the thrust effects were within the established Code allowables for the station. No other safety-related closed systems exist for Oconee.

3.9.3.4 Component Supports

3.9.3.4.1 Reactor Coolant System Component Supports

3.9.3.4.1.1 Description of Supports

The reactor vessel is supported by a cylindrical skirt and the replacement steam generators by a conical stool. These supports are rigidly attached to the vessels and bolted to the foundation by means of an integral base plate. The skirts and stool are designed in accordance with ASME Section III and criteria stated in Section 3.9.3.1.1. Lateral support is provided for the steam generator at the upper tube sheet level by means of a structural tie to the secondary shield wall.

The pressurizer is supported by 8 support pads spaced symmetrically around the circumference of the vessel. The pads are designed in accordance with Section III and criteria stated in Section 3.9.3.1.1 of this report.

The reactor coolant piping is self-supporting with respect to dead weight, seismic, and thermal loading. The reactor coolant pumps are partially supported by hanger rods which are designed to support the dead weight of the pump motor, with the remainder of the dead weight of the pump being supported by the piping. To reduce seismic deflection, the pumps are supported laterally at the motor by means of hydraulic suppressors connected to the secondary shield wall.

3.9.3.4.1.2 Method of Analysis

3.9.3.4.1.2.1 Calculation of Foundation Loads for Reactor Vessel and Replacement Steam Generator

Deleted paragraph(s) per 2004 update

The reactor coolant system with the replacement steam generators was modeled using a three dimensional analysis. Consistent mass is used to represent the Reactor Coolant Loop piping and the majority of the component weights. Lumped mass is used to represent the Control Rods, the Main and Auxiliary Feedwater Headers, the Pump assemblies, the Snubber's weight on the Pumps, the Pressurizer's whip restraint, and the Hot Legs' whip restraint. The torsional mass moment of inertia is included for the Reactor Vessel, Control Rod Drive Mechanisms, Support Service Structure, Pressurizer, and the Steam Generators since the analysis code does not calculate this term for those model sections having their cross sections modeled as pipe. Additionally, a portion of the "bending" mass moment of inertia, which represents the difference between a slender rod and a circular cylinder, is included for above components. The reactor vessel support is modeled using rotational springs at the base to represent the flexibility of the anchor bolts and concrete foundation beneath the vessel. Similar modeling approach is completed for the replacement steam generator base support.

3.9.3.4.1.2.2 Calculation of Foundation Loads for Pressurizer

Deleted paragraph(s) per 2004 update

The pressurizer and its support frame were included in the reactor coolant loop model. Seismic and LOCA loads were generated by dynamic analysis. Loads due to the thermal expansion of the piping were included as well as the dead weight of the vessel at normal operating conditions.

The vessel wall was analyzed for local loading, from the attached support, by means of a method developed by P. P. Bijlaard. The resulting stress intensities were compared to stress allowables specified in ASME Section III and criteria stated in Section 3.9.3.1.1.

3.9.3.4.1.2.3 Analysis of Reactor Vessel and Steam Generator Supports

The reactor vessel support skirt and support skirt flange is designed and analyzed using procedures described in Chapter 10, Section 1, of Reference 15. That procedure is used to determine the tensile stress in the anchor bolts, the bearing stress on the support skirt flange and the location of the neutral axis of bending on the bolt-flange mechanism.

The skirt-flange mechanism was statically analyzed for the applied forces and moments due to seismic loading on the vessel, considering a free-standing vessel.

The support skirt flange and foundation is assumed to be rigid. In regard to the reactor vessel, effects of anchor bolt pretension on the bending moment capacity of the support skirt were evaluated. With no anchor bolt pretension, the location of the neutral axis is found by trial and error methods so that the difference between the first moment of the bolt tension area and first moment of the flange compression area about the neutral axis is less than 5 percent of the smaller value. Increasing values of applied anchor bolt pretension result in less shift of the neutral axis.

The anchor pretension load necessary to prevent any separation of the support skirt flange from the foundation is the required load which will result in no shift of the neutral axis. In that case the neutral axis is located on the centerline of the vessel flange.

For a typical seismic load condition on the vessel, the support skirt flange was analyzed for flange bearing stress, anchor bolt loads, and location of neutral axis. Once the neutral axis was located, giving consideration to anchor bolt pretension loads, the flange, skirt, gusset mechanism was analyzed for applied tensile, compressive, and shear loads resulting from bending using methods from engineering mechanics.

The allowable stress criterion specified in Section 3.9.3.1.1 of this report was used where applicable. Finite element method is employed to analyze the replacement steam generator base support stool and flange for the applied forces and moments due to deadweight, thermal, seismic and LOCA. In the finite element model, the concrete foundation and the anchor bolts are represented by appropriate compressive-only and tensile-only elements, respectively, such that bearing stress on the concrete and tensile stress on the bolts can be calculated. The analysis is documented in the Base Design Condition Report (BWC-006K-SR-01) (Reference 29).

3.9.3.4.2 Supports for Other Duke Class A, B, C and F Piping

3.9.3.4.2.1 Allowable Stress Criteria

3.9.3.4.2.1.1 Structural Members

Allowable stresses are as follows:

1. <u>Tension</u>

Normal	Ft = 0.6 Fy
Upset	Ft = (1.33) (.6 Fy) = .8 Fy
Faulted	Ft = Fy

2. <u>Bending in Structural Members</u>

   (Laterally Supported to preclude local compressive instability)[2]

Normal	Fb = 0.6 Fy
Upset	Fb = (1.33) (0.6 Fy) = .8 Fy
Faulted	Fb = Fy

3. <u>Bending in Base Plates</u>

Normal	Fb = 0.75 Fy
Upset	Fb = (1.33) (0.75 Fy) = Fy
Faulted	Fb = Fy

4. <u>Shear</u>

Normal	$Fv = 0.4\ Fy$
Upset	$Fv = (1.33)\ (0.4\ Fy) = 0.533\ Fy$
Faulted	$Fv = (1.5)\ (0.4\ Fy) = 0.6\ Fy$

5. Compression

Normal	$Fc = Fa^1$
Upset	$Fc = 1.33\ Fa$
Faulted	$Fc = [1.67 - (\frac{0.33(K1/r)}{Cc^1})]Fa,$
	For $K1/r < Cc$
	$Fc = 1.33\ Fa$, for $K1/r > Cc$

Note:

1. See Section 1.5.1.3 AISC 6th Edition for definition.
2. See Section 1.5.1.4 AISC 6th Edition for allowable extreme fiber compressive stress in bending for rolled shapes, built-up members, channels, etc., when full lateral support is not provided.

3.9.3.4.2.1.2 Allowable Stresses for ASTM A36 Materials

Allowable Stress (Ksi)

Loading	**Normal**	**Upset**	**Faulted**
Tension	21.6	28.8	36.0
Bending			
a. Members	21.6	28.8	36.0
b. Base Plates	27.0	36.0	36.0
Shear	14.4	19.2	21.6

Note:

1. Stress allowables for normal and upset load conditions are derived from the AISC Manual of Steel Construction, 6th Edition. Stress allowables for faulted load conditions are established by factoring AISC, 6th Edition allowables.
2. For stress conditions not covered in Section 3.9.3.4.2.1.1, the AISC allowables are utilized for normal loadings, and 133 percent of the AISC allowables shall be utilized for upset loadings.
3. No increase in stress allowables is permitted for material strain hardening and/or strain rate effects due to dynamic loadings.

The specified minimum yield stress (Fy) for ASTM A501 and ASTM A500, Grade B structural tubing is as defined in the 7th Edition of the AISC Manual of Steel Construction.

3.9.3.4.2.1.3 Weld Stresses

1. Tension, bending, compression, and shear on effective throat of complete penetration groove welds and normal compression and shear on effective throat of partial-penetration groove welds permissible allowables are the same as the base material.
2. All other shear:

Normal	Fv = 18.0 ksi
Upset	Fv = (1.33) (18.0) = 24.0 ksi
Faulted	Fv = (1.5) (18.0) = 27.0 ksi

Note:

1. The above shear allowables are based upon the use of E60XX electrodes. The normal allowable is taken from AWS Standard AWS D1.0-69 and Table 1.5.3 in the 7th Edition of the AISC Manual. The normal allowable is higher (18 ksi vs. 13.6 ksi) than the allowable given in the 6th Edition of the AISC Manual. For electrodes other than E60XX, the normal allowable is taken from Table 1.5.3 in the 7th Edition of the AISC Manual. The corresponding upset and faulted allowable is obtained by multiplying the normal allowable by 1.33 and 1.50 respectively.

   The normal weld allowables were increased 33 percent by AWS and AISC in 1969 to eliminate over conservatism required by the AISC 6th Edition. This over-conservatism was present due to design criteria for welds which were inconsistent with the remainder of the AISC Code and lack of test data. Changes in procedures or materials were not a consideration in this change. It is therefore considered appropriate to utilize the AISC 7th Edition weld allowables on Oconee Nuclear Station.

3.9.3.4.2.1.4 Standard Components

All standard components shall be limited by the recommended allowable load specified in either manufacturer's Hanger Standards, manufacturer's Load Capacity Data Sheets (LCD's) or Qualified Product Load Ratings.

3.9.3.4.2.1.5 Combined Stresses In Structural Members

Members subjected to both axial compression and uniaxial bending stresses shall comply with Section 1.6 of the AISC Manual, 6th Edition.

Members subjected to both axial tension and bending stresses shall comply with Section 1.6 of the AISC Manual, 6th Edition.

Members subjected to biaxial bending coincident with axial tension or compression shall be proportioned to satisfy the requirements of Section 1.6 of the AISC Manual, 6th Edition, in accordance with the guidance provided by Section 1.6 of the Commentary in the AISC Manual, 6th Edition.

3.9.3.4.2.1.6 Bolts and Threaded Parts

All allowable stresses are *based on unthreaded body area* of bolts and threaded parts.

A307 BOLTS

1. Tension

Normal = 14 ksi

Upset = 1.33 (14) = 18.6 ksi

Faulted = 1.67 (14) = 23.4 ksi

2. Shear

Normal = 10 ksi

Upset = 1.33 (10) = 13.3 ksi

Faulted = 1.5 (10) = 15 ksi

Threaded Parts of Other Steels

1. Tension

Normal = .4 Fy

Upset = 1.33 (.4 Fy) = .53 Fy

Faulted = 1.67 (.4 Fy) = .67 Fy

2. Shear

Normal = .3 Fy

Upset = 1.33 (.3 Fy) = .4 Fy

Faulted = 1.5 (.3 Fy) = .45 Fy

Stress allowables for other bolts are given in Section 1.5.2, Table 1.5.2.1 of the AISC Manual, 6th Edition. The following factors shall be applied to normal allowable stresses:

	Tension	Shear
Normal	1.0	1.0
Upset	1.33	1.33
Faulted	1.67	1.5

For combined shear and tension, refer to Section 1.6.3 of the AISC Manual, 6th Edition.

3.9.3.4.2.2 Snubbers

Piping systems designed to resist seismic forces have been restrained by steel supports capable of withstanding these seismic forces. Snubbers are used at locations where restraints are necessary based on piping stress analysis, but thermal movement of the pipe must not be constrained. Performance selection is based on manufacturer's load capacity data and the requirement that the allowable travel of the snubber exceed the calculated pipe thermal travel. The hot and cold settings on the snubber are established such that the pipe's calculated thermal travel will not exceed the snubbers travel range. In systems where it was necessary to use hydraulic or mechanical snubbers to resist seismic forces, the mechanical action associated with the snubber makes it possible to consider them as restraints against pipe whipping (see Section 3.6).

Duke Power Company specifies a margin of zero between design requirements and purchase requirements because design loads are determined by detailed computerized piping analysis or other conservative analysis techniques. In most cases, a margin does exist between the design load and the maximum allowable design load of the suppresser supplied since:

1. Suppressers are manufactured for a relatively small number of load ranges; therefore, each suppresser size covers many possible loadings.
2. Suppressers supplied for the Oconee Nuclear Station clearly envelope the design load required for the particular restraint application.

Prior to at their installation at the Oconee Nuclear Station, all snubbers are functional tested on a specifically designed test stand to insure they meet design criteria. Hydraulic snubbers are tested for activation velocity and bleed rate. Mechanical snubbers are tested for drag and acceleration rate.

Visual inspections are performed on all hydraulic and mechanical snubbers on regular intervals to identify those that are damaged, degraded, or inoperable as caused by physical means, leakage, corrosion, or environmental exposure. The inspection interval is based upon the previous inspection interval and the number of unacceptable snubbers found during that interval. The interval between inspections will not be greater than 48 months.

To verify that a snubber can operate within specific performance limits, Oconee Nuclear Station performs functional testing that involves removing the snubber and testing it on a specifically-designed test stand. As on installation, hydraulic snubbers are tested for activation velocity and bleed rate, and mechanical snubbers are tested for drag and acceleration rate. Ten percent of the total snubber population are tested during each refueling outage. Oconee Nuclear Station separates the snubber population into hydraulic and mechanical and pulls a minimum 10% sample from each group. For each snubber that does not meet the functional test acceptance criteria, an additional minimum 10% sample of that snubber type will be tested until none are found inoperable or all the snubbers of that type have been functionally tested. Functional testing in this manner provides a 95% confidence level that 90% to 100% of the snubbers operate within the specified acceptance limits.

3.9.3.4.2.2.1 Hydraulic Snubbers

When a seismic event acts on a system that uses a hydraulic snubber to resist the seismic forces, it causes the piston rod of the snubber to move faster than the activation threshold velocity of that snubber. When this happens, a differential pressure is generated on the valve that allows fluid to flow from one end of the snubber cylinder to the other and the valve closes. With this by-pass valve closed, the snubber acts as a near rigid structural member, thus limiting any further movement of the pipe at the point of attachment. A by-pass or bleed orifice between the two ends of the cylinder prevents the snubber from exceeding its' rated capacity and allows a gradual pressure drop even under sustaining load against the closed by-pass valve. A hydraulic snubber resists seismic forces by limiting velocity.

The design data for the hydraulic shock and sway suppressers used on Class I piping systems at the Oconee Nuclear Station are summarized in the charts below.

Grinnell Hydraulic Snubbers

Size Bore	(In.) Stroke	Acceleration	Activation Threshold Velocity In./Min	Activation Threshold Normal[(1)] Load(lbs)	One Time Load(lbs)[(1)]
1½	5	Not Applicable	8	3,000	4,000
1 ½	10		8	1,100	1,500
2 ½	5 and 10		8	12,500	25,700
3 ¼	5 and 10	Insensitive To Acceleration	8	21,000	43,500
4	5 and 10		8	32,000	66,000
5	5 and 10		8	50,000	103,000
6	5 and 10		5	72,000	148,000
8	5		3	128,000	264,000

Note:

1. Actual Allowable load may be less than specified depending on length of overall assembly.

LISEGA HYDRAULIC SNUBBERS

SNUBBER TYPE [(1)]	STROKE [(2)]	NORMAL LOAD [(2)]	REACTION VELOCITY	BYPASS VELOCITY
30185x	4 inches	675 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30385x	4 inches	1800 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30395x	8 inches	1800 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30425x	5-7/8 inches	4000 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30435x	11-3/4 inches	4000 lbs	4.7 - 14.2 ipm	.47 - 4.7 ipm
30525x	5-7/8 inches	10350 lbs	4.7 - 14.2 ipm	.47 - 4.7 ipm
30535x	11-3/4 inches	10350 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30625x	5-7/8 inches	22450 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30635x	11-3/4 inches	22450 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30725x	5-7/8 inches	44900 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30735x	11-3/4 inches	44900 lbs.	4.7.- 14.2 ipm	.47 - 4.7 ipm
30825x	5-7/8 inches	78600 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30835x	11-3/4 inches	78600 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30925x	5-7/8 inches	123500 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm
30935x	11-3/4 inches	123500 lbs.	4.7 - 14.2 ipm	.47 - 4.7 ipm

SNUBBER TYPE (1)	STROKE (2)	NORMAL LOAD (2)	REACTION VELOCITY	BYPASS VELOCITY

Notes:

1. These are the model numbers for the stock Lisega snubbers. The model numbers used at the Oconee Nuclear Station are usually followed by a suffix showing that it is a replacement for a particular brand of snubber. (i.e. 303856RF1 is a type 3038 snubber, nuclear specification (5), design year 1986, that replaces a PSA-1 mechanical snubber with a flanged end.)
2. Snubber stroke and end attachments can be modified by the manufacturer, at the request of the purchaser, and this may effect the normal load of the snubber.
3. The 'x' on the end of the snubber type is an abbreviation of the design year (i.e. 6 = 1986)

Lisega has been audited by ASME to certify them to supply Component Standard Supports manufactured without welding in accordance with ASME Section III, Subsection NF.

3.9.3.4.2.2.2 Mechanical Snubbers

When seismic forces in a system are resisted using mechanical snubbers, the mechanical snubber translates linear movement between the system and the support structure into rotational motion within the snubber. The snubber's telescoping cylinder is attached to the fixed support cylinder by a screw and nut assembly. Relative motion between the two causes the screw shaft to turn which causes an inertia mass to turn. The torque required to start the rotary motion of the snubber internals limits the rate of acceleration of the attached pipe. A mechanical snubber resists forces by limiting acceleration.

The design data for mechanical snubbers used on Class I piping systems at the Oconee Nuclear Station is summarized in the chart below.

Pacific Scientific Mechanical Snubbers

Allowable Loads @ 300°F

	SIZE	STROKE (IN>)	ACCELERA-TION LIMIT	NORMAL[1] LOAD (LBS)	ONE TIME[1] LOAD(LBS.)
	1/4	4	0.64ft/sec^2	350	590
	1/2	2.5	0.64ft/sec^2	650	1,040
STD.	1	4	0.64ft/sec^2	1,500	2,300
STROKE	3	5	0.64ft/sec^2	6,000	11,520
	10	6	0.64ft/sec^2	15,000	23,600
	35	6	0.64ft/sec^2	50,000	91,000
	100	6	0.64ft/sec^2	120,000	180,000
EXT. STROKE	1	8	0.64ft/sec^2	1,487	2,200
	3	10	0.64ft/sec^2	6,000	11,520
	10	12	0.64ft/sec^2	14,400	22,032

	SIZE	STROKE (IN>)	ACCELERA-TION LIMIT	NORMAL[1] LOAD (LBS)	ONE TIME[1] LOAD(LBS.)

Note:

1. Actual allowable load may be less than specified depending on angular displacement of load path with end bracket.

3.9.4 Control Rod Drive Systems

The Control Rod Drive Mechanism is described in Section 4.5.3.

3.9.5 Reactor Pressure Vessel Internals

Reactor pressure vessel internals are described in Section 4.5.

3.9.6 References

1. Porse, L., "Reactor Vessel Design Considering Radiation Effects," *ASME Paper No. 63-WA-100*.
2. Pellini, W. S. and Puzak, P. P., "Fracture Analysis Diagram Procedures for the Fracture-Safe Engineering Design of Steel Structures," *Welding Research Council Bulletin 88, May 1963*.
3. Robertson, T. S., "Propagation of Brittle Fracture in Steel," *Journal of Iron and Steel Institute, Volume 175*, December 1953.
4. Kihara, H. and Masubichi, K., "Effects of Residual Stress on Brittle Fracture," *Welding Journal, Volume 38*, April 1959.
5. Hjarne, L., and Leimdorfer, M., "A Method for Predicting the Penetration and Slowing Down of Neutrons in Reactor Shields," *Nuclear Science and Engineering 24*, pp 165-174, 1966.
6. Cadwell, *et al*., "The PDQ-5 and PDQ-6 Programs for the Solution of the Two-Dimensional Neutron Diffusion-Depletion Problem," *WAPD-TM-477*, January 1965.
7. Aalto, *et al*., "Measured and Predicted Variations in Fast Neutron Spectrum in Massive Shields of Water and Concrete," *Nuclear Structural Engineering 2*, pp 233-242, August 1965.
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19. BAW-2292, Revision 0, Mark-B Fuel Assembly Spacer Grid Deformation in B&W Designed 177 Fuel Assembly Plants, Aug. 1997.
20. Letter, R. J. Schomaker, B&W Owners Group to Document Control Desk relating to the Interim Report of Potential Safety Concern on Mark-B Grid Deformation, Framatome Technologies PSC-21-96-5, May 24,1996.
21. NRC Safety Evaluation of B&W Owners Group Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops, dated December 12, 1985.
22. B&W Topical Report BAW-1847, Revision 1, "Leak-Before-Break Evaluation of Margin Against Full Break for RCS Primary Piping of B&W Designed NSS," September 1985.
23. B&W Topical Report BAW-1889P, "Piping Material Properties for Leak-Before-Break Analysis," October 1985.
24. B&W Topical Report BAW-1621, "B&W 177-FA Owners Group - Effects of Asymmetric LOCA Loadings - Phase 11 Analysis", July 1980.
25. B&W Topical Report BAW-10133P, Revision 1, "Mark C Fuel Assembly LOCA-Seismic Analyses," S. J. Shah and R. E. Lide, Revision 1, June 1986.
26. Standard Review Plan, Section 4.2, NUREG-0800, Rev. 2 U. S. Nuclear Regulatory Commission, July, 1981.
27. NRC Safety Evaluation Relating To Elimination of Dynamic Effects of Postulated Primary Loop Pipe Ruptures from Design Basis in Regard to TMI-1, dated November 5, 1987.
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30. Babcock & Wilcox Canada Report No.: BWC-006K-SR-02, Revision 1, “Replacement Steam Generators Transient Analysis Report,” August 2003 (Proprietary) (OSC-8319).
31. Calculation OSC-1862, Functional Specification (Transient Description) for Reactor Coolant System.
32. Calculation OSC-7835, Steam Generator Replacement Project: ONS Unit 1 Reactor Coolant Structural Analysis for ROTSG’s.
33. Calculation OSC-7836, Steam Generator Replacement Project: ONS Units 2 and 3 Reactor Coolant Loop Structural Analysis for ROTSG’s.
34. Nuclear Regulator Commission, Letter to All Holders of Operating Licenses or Construction Permits for Nuclear Power Reactors, from David B. Matthews, May 5, 1988, NRC Bulletin No. 88-04, "Potential Safety-Related Pump Loss."
35. Duke Power Company, Letter from H.B. Tucker to NRC, January 15, 1990, re: Response to NRC Bulletin No. 88-04, "Potential Safety-Related Pump Loss," Action 4 Final Report.

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37. Duke Power Company, Letter from M. S. Tuckman to NRC, February 13, 1996, "McGuire, Catawba, Oconee Response to Generic Letter 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves."
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39. Duke Power Company, Letter from W. R. McCollum to NRC, August 21, 1997, "Oconee Nuclear Site, Docket Nos. 50-269, 50-270, 50-287, "Supplemental Response to Generic Letter 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves."
40. Duke Power Company, Letter from W. R. McCollum to NRC, October 9, 1997, "Oconee Nuclear Site, Docket Nos. 50-269, 50-270, 50-287, "Supplemental Response to Generic Letter 95-07, Pressure Locking and Thermal Binding of Safety-Related Power Operated Gate Valves."
41. NRC, Letter to D. E. LaBarge to W. R. McCollum, November 6, 1997, "Evaluation of Generic Letter 95-07, Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves, Response for Oconee Nuclear Station, Units 1, 2, and 3."
42. B&W Report BAW-2127, Final Submittal for Nuclear Regulatory Commission Bulletin 88-11, Pressurizer Surge Line Thermal Stratification, December 1990.
43. B&W Report BAW-2127 Supplement 2, “Pressurizer Surge Line Thermal Stratification for the B&W 177-FA Nuclear Plants, Summary Report, Fatigue Stress Analysis of the Surge Line Elbows,” May 1992.

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3.10 Seismic Qualification of Instrumentation and Electrical Equipment

This section describes the seismic considerations applied to instrumentation and electrical equipment during the original design of the Oconee Nuclear Station as well as in modifications to the station after issuance of the operating license.

3.10.1 Seismic Qualification Criteria

The seismic design basis for instrumentation and electrical equipment is that the electrical devices considered essential in performing Reactor Protection and Engineered Safeguards functions and in providing emergency power shall be designed to assure that they will not lose their capability to perform intended safety functions during and following the design basis event (MHE). This basic criteria has remained unchanged since the issuance of the operating license; however, the seismic qualification techniques and documentation requirements for various plant modifications have in many instances followed the advances in the state of the art.

The specific equipment included in the scope identified above including the associated seismic qualification documentation reference is provided in Table 3-68.

The seismic adequacy of all electrical cable tray supports is established by the methods and criteria established for cable tray supports in the Generic Implementation Procedure (GIP-3A) for Seismic Verification of Nuclear Plant Equipment, Rev 3A, developed by the Seismic Qualification Utility Group (SQUG).

3.10.2 Methods and Procedures for Qualifying Instrumentation and Electrical Equipment

In order to meet the seismic design objectives defined in Section 3.10.1, the following seismic evaluation methods were employed consistent with the applicable licensing commitment.

Testing

Devices may be qualified by either shaker or impact tests. A certification of the test results or a copy of the test results are required. Additionally, a manufacturer's certification that a certain type of equipment would withstand the seismic conditions is acceptable based on previous testing/experience with similar equipment.

Analysis

Devices may also be qualified by analytical methods. For example, one evaluation method involves calculating/determining the natural frequency of the device, entering the appropriate response spectra damping curves, and determining the corresponding amplification factor. The device is then evaluated using this "G" loading value. Alternatively, the devices may be evaluated without calculating/determining its natural frequency by using the peak amplification factor from the appropriate response spectra damping curve to determine the "G" loading.

An alternate method of seismic qualification for electrical equipment (within the applicable equipment classes) would be an experienced based approach. Seismic adequacy can be established using methods described in the Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment, Revision 3A, developed by the Seismic Qualification Utility Group (SQUG). This method is also commonly known as SQUG.

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3.11 Environmental Design of Mechanical and Electrical Equipment

3.11.1 Equipment Identification and Environmental Conditions

Duke has a program in place for environmental qualification of safety-related electrical equipment inclusive of equipment required to achieve a safe shutdown. The program is described in Duke Energy Procedure AD-EG-ALL-1612. Environmental effects resulting from the postulated design basis accidents documented in Chapter 15 have been considered in the qualification of electrical equipment which is covered by this program. This program has been reviewed and approved by NRC (Reference 2).

3.11.1.1 Equipment Identification

Safety-related electrical equipment that is required to perform a safety function(s) in a postulated harsh environment is identified in Oconee Nuclear Station Environmental Qualification (EQ) Master List (EQML).

Safety-related mechanical equipment including design information is identified in Section 3.2.2.

3.11.1.2 Environmental Conditions

The postulated harsh environmental conditions resulting from a LOCA or High Energy Line Break (HELB) inside the Reactor Building and a HELB outside the Reactor Building are identified and discussed in the Oconee Nuclear Station Environmental Qualification Criteria Manual.

The environmental parameters that compose the overall worst-case containment environment are as follows:

Containment Temperature: Time history as shown in Figure 6-37 for the Design Basis Accident (DBA), a 8.55 ft^2 cold leg break.

Containment Pressure: Time history as shown in Figure 6-36 for a 8.55 ft^2 cold leg break.

Relative Humidity: 100%

Radiation: Total integrated radiation dose for the equipment location includes the 60 year normal operating dose plus the appropriate accident dose based on equipment operability requirements. The bases for determining the containment radiation environment are discussed in Chapter 12.

Chemical Spray: Boric acid spray resulting from mixing in the containment sump with borated water from the borated water storage tank. Refer to Section 6.2.2 for additional information on chemical spray.

3.11.2 Qualification Test and Analysis

Safety-related equipment identified in Section 3.11.1.1 is qualified by test and/or analysis. The test report, which describes the method of qualification for this Class 1E equipment is identified in the Oconee Nuclear Station Environmental Qualification Maintenance Manual, EQMM-1393.01.

3.11.3 Qualification Test Results

The results of the qualification tests and/or analyses for the electrical equipment identified in Section 3.11.1.1 are presented in the qualification documentation references identified in the Oconee Nuclear Station Environmental Qualification Maintenance Manual, EQMM-1393.01.

3.11.4 Evaluation for License Renewal

Some qualification analyses for safety-related equipment identified in Section 3.11.1.1 were found to be a time-limited aging analyses for license renewal. Evaluations were performed for applicable electrical equipment with the results submitted in Reference 5.

3.11.5 Loss of Ventilation

The control area (control room, cable room and electrical equipment room) air conditioning and ventilation systems (Section 9.4.1) are conservatively designed to provide a suitable environment for the control and electrical equipment.

Deleted paragraph(s) per 2005 update.

Control area temperatures related to station blackout are addresssed by SLC 16.8.1.

3.11.6 Estimated Chemical and Radiation Environment

The estimated chemical and radiation environments at Oconee are discussed in Duke Power Company's response to NRC IE Bulletin 79.01B (Reference 1). Additional information regarding chemical and radiation conditions is presented in Section 6.5 and in Chapter 12, respectively.

3.11.7 References

1. Oconee Nuclear Station Response to IE Bulletin 79-OIB, as revised, including Response to NRC Equipment Qualification Safety Evaluation Report.
2. Letter from J. F. Stolz (NRC) to H. B. Tucker (Duke) dated March 20, 1985.

   Subject: Safety Evaluation Report on Environmental Qualification of Electrical Equipment Important to Safety.
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5. Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.
6. NUREG-1723, Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.

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3.12 Cranes and Control of Heavy Loads

The load cycle limit of the Oconee Polar Cranes has been identified as a time-limited aging analysis by reviewing correspondence on the Oconee dockets associated with the control of heavy loads. In 1981, NRC issued Generic Letter 81-07 and NUREG-0612 [Reference 1]. NRC issued a letter [Reference 2] requesting additional information which Duke responded to by letter [Reference 3]. One of the concerns expressed in NUREG-0612 was the potential for fatigue of the crane due to frequent loadings at or near design conditions. Cranes at Oconee are not generally subjected to frequent loads at or near design conditions. The topic of lift cycles of cranes at or near rated load is considered to be a time-limited aging analysis for Oconee because the analysis meet all of the criteria contained in Section 54.3 [Reference 4].

From the license renewal review, the existing analyses addressing heavy load lifts of both the polar cranes and the spent fuel pool cranes were determined to be valid for the period of extended operation [Reference 5].

3.12.1 References

1. Generic Letter 81-07, *NUREG-0612, Control of Heavy Loads,* NRC, February 3, 1981.
2. J. F. Stolz (NRC) to W. O. Parker (Duke) letter dated February 18, 1982, Oconee Nuclear Station, Docket Numbers 50-269, 50-270, and 50-287.
3. W. O. Parker (Duke) letter to Document Control Desk (NRC) dated October 8, 1982, Oconee Nuclear Station, Docket Numbers 50-269, 50-270, and 50-287.
4. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.
5. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3,* Docket Nos. 50-269,, 50-270, and 50-287.

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3.13 Oconee Nuclear Station Response to Beyond-Design-Basis External Event Fukushima Related Required Action (FLEX)

3.13.1 Introduction

On March 11, 2011, an earthquake-induced tsunami caused Beyond-Design-Basis (BDB) flooding at the Fukushima Dai-ichi Nuclear Power Station in Japan. The flooding caused by the tsunami rendered the emergency power supplies and electrical distribution systems inoperable resulting in an extended loss of alternating current (AC) power (ELAP) in five of the six units on the site. The ELAP led to the loss of core cooling as well as spent fuel pool cooling capabilities and a significant challenge to containment. All direct current (DC) power was lost early in the event on Units 1 & 2 and after some period of time at the other units. Units 1, 2, and 3 were affected to such an extent that core damage occurred and radioactive material was released to the surrounding environment.

The US Nuclear Regulatory Commission (NRC) assembled a special task force, the Near-Term Task Force (NTTF) in order to advise the Commission on actions the US Nuclear Industry should undertake in order to preclude a release of radioactive material in response to a natural disaster such as that seen at Fukushima Dai-ichi. NTTF members created NRC Report "Recommendations for Enhancing Reactor Safety in the 21st Century: The Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident," referred to as the "90-day Report," which contained a large number of recommendations for improving safety at US nuclear power sites.

Subsequently, the NRC issued Order EA-12-049, "Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events" (Agencywide Documents Access Management System (ADAMS) Package Accession No. ML12054A736) (Reference 1) and Order EA-12-051, "Order to Modify Licenses with Regard to Reliable Spent Fuel Pool Instrumentation" (ADAMS Package Accession No. ML12056A044) (Reference 2) to implement strategies for Beyond-Design-Basis External Events (BDBEE), and reliable spent fuel pool, respectively.

3.13.2 Order EA-12-049

NRC Order EA-12-049 was effective immediately and directed Oconee Nuclear Station to develop, implement, and maintain guidance and strategies to maintain or restore core cooling, containment, and spent fuel pool cooling in the event of a beyond-design-basis external event.

The Nuclear Energy Institute (NEI), working with the nuclear industry, developed guidelines for nuclear stations to implement the strategies specified in NRC Order EA-12-049. These guidelines were published in the NEI 12-06 document entitled "Diverse and Flexible Coping Strategies (FLEX) Implementation Guide" (Reference 3). This guideline was endorsed by the NRC in final interim staff guidance (ISG) document JLD-ISG-2012-01, Compliance with Order EA-12-049, Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design- Basis External Events, Revision 0, dated August 29, 2012 (ML12229A174) (Reference 4).

The NEI 12-06 FLEX implementation guide adopts a three-phase approach for coping with a BDB event.

- Phase 1 – the initial phase requires the use of installed equipment and resources to maintain or restore core cooling, containment, and SFP cooling capabilities.

- Phase 2 – The transition phase requires providing sufficient portable onsite equipment to maintain or restore these functions until resources can be brought from off site.
- Phase 3 – The final phase requires obtaining sufficient offsite resources to sustain these functions indefinitely.

This three-phase approach was utilized to develop the FLEX strategies for Oconee Nuclear Station.

3.13.3 Order EA-12-051

NRC Order EA-12-051 (Reference 2) states that procedures shall be established and maintained for the testing calibration and use of the primary and backup SFP instrument channels.

Duke developed procedures using guidelines and vendor instructions to address the maintenance, operation, and abnormal response issues associated with the SFP level instrumentation at ONS.

3.13.4 BDB Program

Strategies, details, and programmatic controls for mitigating beyond-design-basis external events are contained in a Duke program document (General Reference per NEI 98-03, Revision 1). Program changes are controlled in accordance with NEI 12-06, Section 11.8, as endorsed by the NRC.

A Duke program document (General Reference per NEI 98-03, Revision 1) also describes items such as a list of FLEX equipment, the BDB Storage Building, initial and periodic testing, FLEX equipment maintenance, and actions to be taken in the event of equipment unavailability.

A Duke program document (General Reference per NEI 98-03, Revision 1) also describes Spent Fuel Pool Instrumentation program requirements including procedures, testing and calibration, and quality assurance.

3.13.5 References

1. Order EA-12-049, "Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events" dated March 12, 2012 (ML12054A736).
2. Order EA-12-051, “Order to Modify Licenses with Regard to Reliable Spent Fuel Pool Instrumentation” dated March 12, 2012 (ML12056A044).
3. NEI 12-06, Diverse and Flexible Coping Strategies (FLEX) Implementation Guide, Revision 0, dated August 2012 (ML12242A378).
4. NRC Interim Staff Guidance JLD-ISG-2012-01, Compliance with Order EA-12-049, Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events, Revision 0, dated August 29, 2012 (ML12229A174).
5. CSD-EG-ONS-1619.1000, “Diverse and Flexible Coping Strategies (FLEX) Program Document - Oconee Nuclear Station

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Appendix 3A. Tables

Table 3-1. System Piping Classification

Piping Class	Design Criteria	Designed For Seismic Loading
A	Class I, USAS B31.7(2)	Yes
B	Class II, USAS B31.7	Yes
C	Class III, USAS B31.7	Yes
D	USAS B31.1.0	Yes
E	USAS B31.1.0(1)	No
F	USAS B31.1.0	Yes
G	USAS B31.1.0	No
H	Good Industry Practice	No

Note:

1. Portions are considered a Class III system in accordance with FSAR Section 3.2.2.1.
2. Class I RCS piping was re-analyzed to the 1983 ASME Code (No Addenda) during the replacement steam generator analysis.

Table 3-2. System Component Classification

	Design Code	Designed For Seismic Loading (D=Dynamic Analysis) (S=Static Analysis)
Reactor Coolant System		
Reactor Vessel	ASME III, Class A	Yes – D
Reactor Vessel Head	ASME III, Class I, 1989 Edition, No Addenda	Yes – D
Pressurizer	ASME III, Class A	Yes - D
Reactor Coolant Pump Casing	ASME III, Class A (not code stamped)	Yes - D
Steam Generator	ASME III, Class A	Yes - D
High Pressure Injection System		
HP Injection Pump	See Table 6-3	Yes - Note 1
Letdown Cooler	ASME III-C & VIII	Yes - D
Seal Return Cooler	ASME III-C & VIII	Yes - Note 2
Letdown Storage Tank	ASME III-C	Yes - Note 2
Purification Demineralizer	ASME III-C	Yes - Note 2
Letdown Filter	ASME III-C	Yes - Note 2
RC Pump Seal Filter	USAS B31.7, Paragraph 2-724, Class II	Yes - Note 3
Chemical Addition and Sampling System		
Boric Acid Mix Tank	USAS B96.1	No
Lithium Hydroxide Mix Tank	-	No
Caustic Mix Tank	-	No
TSP Baskets	AISC	Yes -D
Boric Acid Pump	-	No
Lithium Hydroxide Pump	-	No
Hydrazine Pump	-	No
Caustic Pump	-	No
Pressurizer Sample Cooler	ASME III-C & VIII	No
Steam Generator Sample Cooler	ASME VIII	No
Component Cooling System		

	Design Code	Designed For Seismic Loading (D=Dynamic Analysis) (S=Static Analysis)
Component Cooling Pump	-	Yes - Note 1
Component Cooler	ASME VIII	Yes - Note 2
Component Cooling Surge Tank	AWWA D-100	Yes - S
CRD Cooling Coil Filter	ASME VIII	Yes - S
Reactor Fuel Cooling System		
Spent Fuel Cooler	ASME III-C & VIII	Yes - Note 2
Spent Fuel Pump	-	Yes - Note 1
Spent Fuel Filter	ASME III-C	Yes - S
Borated Water Recirculation Pump	-	Yes - Note 1
Spent Fuel Demineralizer	ASME III-C	Yes - Note 2
Fuel Transfer Tube	ASME III-B	Yes - D
Incore Instrument Handling Tank	AWWA D-100	Yes - D
Low Pressure Injection System		
LP Injection Pump	See Table 6-3	Yes - Note 1
LP Injection Cooler	ASME III-C & VIII	Yes - Note 2
Borated Water Storage Tank	AWWA D-100	Yes - S
Core Flooding Tank	ASME III-C	Yes - D
Reactor Building Spray System		
Reactor Building Spray Pump	See Table 6-3	Yes - Note 1
Reactor Building Penetration Room Ventilation System		
Penetration Room Filter	See Section 6.5.1	Yes - S
Penetration Room Fan	See Section 6.5.1	Yes - Note 4
LP Service Water System		
LP Service Water Pump	-	Yes - Note 1
SSF Systems and Components	See Section 9.6.4.5	Note 9
Reactor Building Cooling System		
Reactor Building Coolers	See Section 6.2.2	Yes - D
Recirculated Cooling Water System		

	Design Code	Designed For Seismic Loading (D=Dynamic Analysis) (S=Static Analysis)
RCW Pump	-	No
RCW Heat Exchanger U1/U2	ASME VIII	Yes - Note 8
RCW Heat Exchanger U3	-	No
RCW Surge Tank	ASME VIII (not code stamped)	No
Coolant Storage System		
Quench Tank	ASME III-C	Yes - Note 2
Quench Tank Cooler	ASME III-C & VIII	Yes - Note 2
Component Drain Pump	-	Yes - Note 1
Coolant Bleed Holdup Tank	ASME VIII (not code stamped)	Yes - S
Bleed Transfer Pump	-	Yes - Note 1
Deborating Demineralizer	ASME III-C	Yes - Note 2
Concentrated Boric Acid Storage Tank	USAS B96.1	Yes - S
Concentrated Boric Acid Storage Tank Pump	-	No
Coolant Treatment System		
Coolant Bleed Evaporator Demineralizer	ASME III-C	Yes - Note 2
Coolant Bleed Evaporator Feed Tank	AWWA D-100	Yes - S
Coolant Bleed Evaporator	ASME VIII (lethal)	Yes - S
Recirculating Pump	-	Yes - S
Concentrate Cooler	ASME VIII (lethal)	Yes - S
Separator	ASME VIII (lethal)	Yes - S
Vapor Condenser	ASME VIII (lethal)	Yes - S
Distillate Pump	-	Yes - S
Distillate Cooler	ASME VIII (lethal)	Yes - S
Condensate Test Tank	USAS B96.1	Yes - S
Condensate Test Tank Pump	-	Yes - Note 1
Condensate Demineralizer	ASME III-C	Yes - S
Coolant Bleed Evaporator Feed Pump	-	Yes - S

	Design Code	Designed For Seismic Loading (D=Dynamic Analysis) (S=Static Analysis)
Steam & Power Conversion System (Pertinent Components Only)		
Condenser	-	Yes - S
Upper Surge Tank	ASME VIII	Yes - S
Emergency Feedwater Pump	-	Yes - Note 1
Emergency Feedwater Pump Turbine	-	Yes - Note 1
Liquid Waste Disposal System		
High Activity Waste Tank	Note 7	Yes - Note 5
High Activity Waste Tank Pump	-	No
Low Activity Waste Tank	Note 7	Yes - Note 5
Low Activity Waste Tank Pump	-	No
Waste Holdup Tank	AWWA D-100	Yes - S
Waste Holdup Transfer Pump	-	Yes - Note 1
Spent Resin Storage Tank	AWWA D-100	Yes - S
Spent Resin Transfer Pump	-	Yes - Note 1
Spent Resin Sluicing Pump	-	Yes - Note 1
Waste Evaporator Feed Tank	AWWA D-100	Yes - S
Waste Evaporator	ASME VIII (lethal)	Yes – S
Recirculating Pump	-	Yes – S
Concentrate Cooler	ASME VIII (lethal)	Yes – S
Separator	ASME VIII (lethal)	Yes – S
Vapor Condenser	ASME VIII (lethal)	Yes – S
Distillate Pump	-	Yes – S
Distillate Cooler	ASME VIII (lethal)	Yes - S
Reactor Building Sump Pump	-	Yes - Note 1
Waste Evaporator Feed Pump	-	Yes - S
Gaseous Waste Disposal System		

	Design Code	Designed For Seismic Loading (D=Dynamic Analysis) (S=Static Analysis)
Waste Gas Compressor	-	Yes - S
Waste Gas Separator	ASME VIII	Yes - S
Seal Water Cooler	-	Yes - S
Waste Gas Tank	ASME VIII-C	Yes - S
Waste Gas Filter	-	Yes - S
Waste Gas Exhauster	-	No
Condenser Cooling Water System		
Intake Structure	-	Yes - S
CCW Pumps	-	Yes - S
CCW Intake Pipe	-	Yes - S
CCW Discharge Pipe	-	Yes - S
ECCW Piping (Structural Portion)	-	Yes - S
Condenser	-	Yes - S
Essential Siphon Vacuum (ESV) System		
ESV Pumps	-	Yes - Note 6
ESV Tanks	ASME Secton VIII	Yes - S

	Design Code	Designed For Seismic Loading (D=Dynamic Analysis) (S=Static Analysis)

Notes:

1. Vendor certification that component will meet seismic loading requirement.
2. Static and Dynamic Analyses performed.
3. Shock tested in lieu of analysis.
4. Vendor certification that component will meet seismic loading requirement will be furnished.
5. Tank meets loading requirement by its location in Auxiliary Building basement floor.
6. Seismic Adequacy evaluated using experience based criteria and procedures.
7. Stainless Steel Lining for Concrete Sump
8. Dynamic analysis performed. Static and/or dynamic analyses can be performed for future changes that affect the U 1/2 RCW Heat Exchanger. Seismic loads are applied to this U 1/2 Heat Exchanger since the attached CCW piping is Class D-seismic.
9. The SSF systems and components needed for safe shutdown are designed to withstand the safe shutdown Earthquake. See Sections 9.6.4.1 and 9.6.4.3
10. A separate PSW structure is provided for major electrical equipment. The PSW structure is designed to withstand the Maximum Hypothetical Earthquake (MHE) and tornado missiles, wind and differential pressure in accordance with Regulatory Guide 1.76 (Revision 1). Other components that receive backup power from the PSW System retain their existing seismic and quality classifications. See Section 9.7.

Table 3-3. Summary of Missile Equations

Missile Category	Principle	Symbolic Form of Equation	Solution
I	Stored strain energy equals kinetic energy	$\frac{\sigma\varepsilon v}{2} = \frac{mV_o^2}{2}$ $\frac{\sigma^2 v}{2E} = \frac{mV_o^2}{2}$	$V_o = \sigma\phi\sqrt{\frac{g}{E\rho}}$ **Note:** The above equation was revised in 2004 update.
II	Work done is Converted to kinetic energy	$F\ell = \frac{m V_o^2}{2}$ $= PA_o\ell$	$V_o = \sqrt{\frac{2PA_o\ell}{m}}$ **Note:** The above equation was revised in 2004 update.
III	Newton's second law	$F = ma$ $a = \dot{V} = \ddot{X} = \frac{F}{m}$ $\dot{V} = \left[\frac{\rho_f A_o V_f}{M}\right]\frac{A_m}{A_j}\left(V_f - V\right)$ **Note:** The above equation was revised in 1999 update.	$(1 - \frac{V}{V_f}) - 1n(1 - \frac{V}{V_f}) = K_1 - \frac{K_2}{r_o + X\tan\beta}$ **Note:** The above equation was revised in 1995 update. $K_1 = (1 - \frac{V_o}{V_f}) - 1n(1 - \frac{V_o}{V_f}) + \frac{K_2}{r_o}$ **Note:** The above equation was revised in 1999 update.
			$K_2 = \frac{\rho_f A_o A_m}{m\pi\tan\beta}$

Note:

1. Either graphical techniques or numerical methods must be used to obtain the solution to category III.

Table 3-4. List of Symbols

σ	=	ultimate tensile stress, (lb/ft^2)
ρ	=	density of missile, ($\#/ft^3$)
ε	=	strain = σ/E, (in./in.)
E	=	modulus of elasticity, (lb/ft^2)
v	=	volume of missile, (ft^3)
m	=	mass of the missile, ($lb\text{-}sec^2/ft$)
V	=	velocity of missile, (ft/sec)
g	=	gravity constant, (ft/sec^2)
F	=	force on the missile, (lb)
ℓ	=	stroke length, (ft)
P	=	system pressure, (lb/ft^2)
A_o	=	missile area under pressure, throat area, (ft^2)
ρ_f	=	density of fluid, ($\#/ft^3$)
V_f	=	jet velocity, (ft/sec)
A_m	=	projected area of missile, (ft^2)
A_j	=	jet area, (ft^2)
β	=	angle of jet expansion, (°from normal)
X	=	distance missile travels, (ft)
V_o	=	initial velocity of missile, (ft/sec)
r_o	=	radius of throat (ft)
K_2	=	constant

Table 3-5. Properties of Missiles - Reactor Vessel & Control Rod Drive

Missile Class	Description	Weight (lbs.)	Impact Area (in^2)	Velocity (ft/sec)	Kinetic Energy (Ft-lbs)
I	1. Closure head nut [Note 1]	80	38	97	11,680
	2. Closure stud w/nut [Note 1]	660	71	97	96,400
	3. 1" Valve bonnet stud	0.5	0.6	73.5	42
	4. C. R. nozzle flange bolt & nut	3.0	3.1	97	438
II	1. CRD closure cap	8.0	7.0	215	5,742
III	1. C. R. drive assembly	1000	64.0	90	125,777
Deleted row(s) per 2004 update					

Note:

1. These values are from the NSSS and Bechtel vendor calculations. HydraNuts have been established as acceptable alternate closure head nuts. Each HydraNut weighs approximately 108 lbs. This increase in weight and associated parameters in the table due to the use of the HydraNuts remains bounded by those of the control rod drive described in Section 3.5.1.1.

Table 3-6. Properties of Missiles - Steam Generator

Missile Class	Description	Weight (lbs.)	Impact Area (in^2)	Velocity (ft/sec)	Kinetic Energy (Ft-lbs)
	Original Steam Generator				
I	1. 1½" Vent valve bonnet stud	2.0	.8	73.5	167
	2. Feedwater inlet flange bolt	0.3	.6	67.5	21
	3. 16" I.D. manway stud, tube side	8.0	2.1	67.5	566
	4. 5" Inspection opening cover stud	1.5	1.2	73.5	125
	5. 1" Valve bonnet stud	0.5	.6	73.5	42
II	1. 1½" Vent valve stem & wheel	5.0	.45	44.5	154
	2. Sample line 1" valve stem & wheel	4.0	.3	35.8	80
	3. Sample line 1" EMO valve stem and wheel	4.0	.3	35.8	80
III	1. 16" I.D. manway cover, tube side	955	615	515	1,950,000
	2. 16" I.D. manway cover, shell side	478	615	777	2,230,000
	3. 5" I.D. inspection cover, tube side	80	150	515	160,000
	4. 5" I.D. inspection cover, shell side	40	150	852	220,000
	5. 1½" Vent valve bonnet and assembly	24	38	371	51,180
	6. Sample line 1" valve bonnet & assy.	30	27	243	27,460
	7. Sample line 1" EMO bonnet & assy.	115	27	138	34,250

Missile Class	Description	Weight (lbs.)	Impact Area (in^2)	Velocity (ft/sec)	Kinetic Energy (Ft-lbs)
	Replacement Steam Generator				
I	1. 1½" Vent valve bonnet stud	2.0	.8	73.5	167
	2. Feedwater inlet flange bolt	0.3	.6	67.5	21
	3. 16" I.D. manway stud, tube side	8.0	2.1	67.5	566
	4. 6" Handhole opening cover stud	1.5	1.2	73.5	125
	5. 1" Valve bonnet stud	0.5	.6	73.5	42
II	1. 1½" Vent valve stem & wheel	5.0	.45	44.5	154
	2. Sample line 1" valve stem & wheel	4.0	.3	35.8	80
	3. Sample line 1" EMO valve stem and wheel	4.0	.3	35.8	80
III	1. 16" I.D. manway cover, tube side	955	615	515	1,950,000
	2. 16" I.D. manway cover, shell side	478	615	777	2,230,000
	3. 6" Handhole opening cover, tube side	80	150	515	160,000
	4. 6" Handhole opening cover, shell side	40	150	852	220,000
	5. 1½" Vent valve bonnet and assembly	24	38	371	51,180
	6. Sample line 1" valve bonnet & assy.	30	27	243	27,460
	7. Sample line 1" EMO bonnet & assy.	115	27	138	34,250

Table 3-7. Properties of Missiles - Pressurizer

Missile Class	Description	Weight (lbs.)	Impact Area (in^2)	Velocity (ft/sec)	Kinetic Energy (Ft-lbs)
I	1. 4" Valve bonnet stud	3.0	1.8	73.5	250
	2. 5" Valve bonnet stud	3.0	2.4	73.5	250
	3. 16" Manway cover stud	7.5	3.1	67.5	530
	4. Heater bundle stud	25.0	7.0	73.5	2100
	5. 3/4" Valve stem stud	0.8	.45	73.5	67
II	1. Spray line 4" EMO valve stem	9	1.0	135.0	2560
	2. Sample line 3/4" valve stem	4	.3	72.7	330
	3. Sample line 3/4" EMO valve stem	4	.3	72.7	330
III	1. 16" I.D. manway cover	250	615	375	546,000
	2. Heater bundle assembly	2500	850	375	5,400,000
	3. Spray line 4" EMO valve bonnet and assembly	325	150	521	1,370,000
	4. 2½" x 6 Relief valve bonnet and assembly	175	65	232	146,000
	5. Sample line 3/4" valve bonnet and assembly	20	21	364	41,150
	6. Sample line 3/4" EMO valve bonnet and assembly	115	21	258	118,400

Table 3-8. Properties of Missiles - Quench Tank and Instruments

Missile Class	Description	Weight (lbs.)	Impact Area (in^2)	Velocity (ft/sec)	Kinetic Energy (Ft-lbs)
	QUENCH TANKS				
I	1. 1½" Drain valve bonnet stud	0.6	.2	73.5	50
	2. 4" Valve bonnet stud	2.0	.3	73.5	167
II	1. 1½" EMO drain valve stem	5.0	.45	11.0	9
	2. 4" EMO valve stem	9.0	1.0	21.5	65
III	1. 1½" EMO drain valve & op.assy.	220	20	73.5	18,450
	2. 1½" Drain valve bonnet & assy.	20	20	73.5	1,670
	3. 4" EMO valve bonnet & op. assy.	355	65	73.5	29,780
	INSTRUMENTS				
III	1. RTE	1.0	.2	208	670
	2. RTE & Plug	2.0	4.0	448	6230

Table 3-9. Properties of Missiles - System Piping

Missile Class	Description	Weight (lbs.)	Impact Area (in^2)	Velocity (ft/sec)	Kinetic Energy (Ft-lbs)
Core Flooding Line					
I	14" C.V. bonnet stud	2.0	1.7	73.5	167
I	14" Valve bonnet stud	3.5	4.0	67.5	248
II	14" C.V. check pivot stud	10.0	1.75	249	9650
II	14" P.O. valve stem	98.0	5.0	143	31,100
III	14" C.V. bonnet & assembly	525.0	125	448	1,640,000
III	14" P.O. valve bonnet and assembly	1900.0	650	558	9,180,000
L.P. Injection Line					
I	12" C.V. bonnet stud	2.0	1.7	73.5	167
II	12" C.V. check pivot stud	10	1.75	249	9,650
III	12" C.V. bonnet and assy.	450	95	558	2,170,000
R.V. Outlet Line to L.P. System					
I	10" Valve bonnet stud	2.5	1.7	73.5	177
I	Relief valve bonnet stud	0.5	.3	73.5	42
I	Relief valve stem assy.	40	12.5	35.3	768
II	10" EMO valve stem	50	3.1	130	13,200
III	10" EMO valve bonnet & assy.	1270	415	558	6,140,000
R.V. Inlet Line from H.P. System					
I	4" C.V. bonnet stud	1.0	.8	73.5	83.5
II	4" C.V. check pivot stud	3.0	.8	158	1170
III	4" C.V. bonnet and assy.	30	19	558	145,000
S.G. Outlet Line to Pump Inlet					
I	1" Drain valve bonnet stud	0.8	.6	73.5	67
II	1" Drain valve stem assy.	4.0	.3	84	438
III	1" Drain valve & bonnet assy.	30.0	27	448	84,380
Pressurizer to C.A. System Line					
I	3/4" Valve bonnet stud	1.0	.45	73.5	83
II	3/4" Valve stem	4	.3	73	330
II	3/4" EMO valve stem	4	.3	73	330
III	3/4" Valve bonnet and assy.	20	21	425	56,250

Missile Class	Description	Weight (lbs.)	Impact Area (in^2)	Velocity (ft/sec)	Kinetic Energy (Ft-lbs)
III	3/4" EMO valve bonnet and assy.	115	21	280	140,000
Primary Pump Seal Water Return to H.P. System Line					
I	3" EMO valve bonnet stud	1.0	1.0	73.5	83.5
II	3" EMO valve stem	25.0	.3	125.7	6150
III	3" EMO valve bonnet and assy.	285.0	85	507	1,137,000
Letdown Cooler Inlet & Outlet Lines					
I	1½" EMO valve bonnet stud	2.0	.8	73.5	167
II	1½" EMO valve stem	1.0	1.0	153.2	1830
III	1½" EMO valve bonnet and assy.	250.0	38	320	397,000
Primary Pump Seal Water Inlet and Outlet Lines					
I	3" Inlet C.V. bonnet stud	1.0	.8	73.5	83.5
I	3" Outlet valve bonnet stud	2.0	1.0	73.5	167
II	3" C.V. check pivot stud	3.0	.8	158.4	1170
II	3" Outlet valve stem	25.0	2.4	125.7	6150
III	3" Inlet C.V. bonnet and assy.	25.0	85	558	120,800
III	3" Outlet valve bonnet and assy.	65.0	85	523	276,000
Primary Pump Vent & Drain Lines					
I	1½" Vent & drain valve bonnet stud	2.0	.8	73.5	167
II	1½" Vent & drain valve stem	5.0	1.0	153.2	1830
III	1½" Vent & drain valve bonnet and assy.	55.0	38	435.0	161,600

Table 3-10. Missile Characteristics

Weight	Impact Area
5944 lbs	Side On - 8.368 sq ft End On - 3.657 sq ft
Velocity	**Kinetic Energy Ft-Lbs**
Initial - 710 fps Impact Cylinder - 502 fps Dome - 431 fps	Initial - 46.5 x 10^6 Impact Cylinder - 23.25 x 10^6 Dome - 18.0 x 10^6

Table 3-11. Depth of Penetration of Concrete

Case I		Case II		Case III	
Cylinder	Dome	Cylinder	Dome	Cylinder	Dome
6"	5½"	12 3/4"	12¼"	35½"	25"

Table 3-12. Containment Coatings

Surface	Coating Systems		Dry Film Thickness	Manufacturer	Remarks
1. Carbon Steel 0°F - 200°F	Original System				Note 1
	Prime Coat	Carbo Zinc 11	3.0 mils DFT	Carboline	
	Finish Coat	Phenoline 305 Finish	4.0 mils DFT	Carboline	
			7.0 mils DFT		
	Maintenance System				Note 2
	over Original System	DP-SP28 Power Tool Cleaning			
	Maintenance Coat	DP#78-1 Carboline 890	2.0 to 7.0 mils DFT	Carboline	
	New System	DP-SP5 White Metal Blast Cleaning	2.0 mils DFT	Carboline	Note 2
	Prime Coat	DP#12-1 Carbo Zinc 11 SG	5.0 mils DFT	Carboline	
	Finish Coat	DP#78-1 Carboline 890	7.0 mils DFT		
2. Carbon Steel 0°F - 200°F	Original System				Note 1
	Prime Coat	Carboline 191 Primer	2.0 mils DFT	Carboline	
	Finish Coat	Phenoline 305 Finish	5.0 mils DFT	Carboline	
			7.0 mils DFT		
	Maintenance System				Note 2
	over Original System	DP-SP28 Power Tool Cleaning			
	Maintenance Coat	DP#78-1 Carboline 890	2.0 to 7.0 mils DFT	Carboline	
	New System	DP-SP5 White Metal Blast Cleaning			Note 2
	Prime Coat	DP#78-1 Carboline 890	2.0 mils DFT	Carboline	
	Finish Coat	DP#78-1 Carboline 890	5.0 mils DFT	Carboline	
			7.0 mils DFT		

Surface	Coating Systems		Dry Film Thickness	Manufacturer	Remarks
3. Carbon Steel 0°F - 750°F	Original System Prime Coat	Carbo Zinc 11	3.0 mils DFT	Carboline	Note 1
	New system Prime Coat	DP-SP5 White Metal Blast Cleaning DP#12-1 Carbo Zinc 11 SG	3.0-5.0 mils DFT	Carboline	Note 2
4. Carbon Steel 0°F-250°F Tank Lining	New System	DP-SP5 White Metal Blast Cleaning			Note 2
	Prime Coat	DP#71-1 7155HHB Plasite Phenolic	4.0 mils DFT	Wisconsin	
	Intermediate Coat	DP#71-1 7155HHB Plasite Phenolic	4.0 mils DFT	Wisconsin	
	Finish Coat	DP#71-1 7155HHB Plasite Phenolic	4.0 mils DFT	Wisconsin	
			12.0 mils DFT		
5. Concrete Floors	Original System				Note 1
	Prime Coat	195Epoxy Surfacer	8.0 mils DFT	Carboline	
	Finish Coat	Phenoline 305 Finish	4.0-8.0 mils DFT	Carboline	
			12.0-16.0 mils DFT		
	Maintenance System			Note 2	
	over Original System	DP-SP25			
	Maintenance Coat	DP#78-1 Carboline 890	Carboline		
	New System				Note 2
	Prime Coat	DP-SP25			
	Finish Coat	DP#36-1 Starglaze 2011S	Seal Concrete	Carboline	
		DP#78-1 Carboline 890	8.0 mils DFT	Carboline	
			8.0 mils DFT		

Surface	Coating Systems		Dry Film Thickness	Manufacturer	Remarks
6. Concrete Walls	Original System	DP-SP17			Note 1
	Prime Coat	DP#36-1 46-X-29-00 Epoxy Surfacer	8.0 mils DFT	Carboline	
	Finish Coat	DP#69-1 76 Series-00 High Build Epoxy	4.0-8.0 mils DFT	Carboline	
			12.0-16.0 mils DFT		
	Maintenance System over Original System	DP-SP17			Note 2
	Maintenance Coat	DP#78-1 Carboline 890	2.0 to 5.0 mils DFT	Carboline	
	New System	DP-SP17	Seal Concrete	Carboline	Note 2
	Prime Coat	DP#36-1 Starglaze 2011S	5.0 mils DFT	Carboline	
	Finish Coat	DP#78-1 Carboline 890	8.0 mils DFT		

Notes:

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

1. *Original coating systems have satisfactorily withstood the following autoclave tests designed to simulate LOCA conditions with no loss of adherence or erosion of material from surface:*

Carbon Steel

a. Test specimens: Coating system applied to sandblasted carbon steel coupons.

b. Water chemistry: 3000 ppm boron as boric acid in water; also 3% boric acid

Surface	Coating Systems	Dry Film Thickness	Manufacturer	Remarks
c.	*Temperature:*			
	<u>For 3000 ppm boron</u>			
	3 hours at 285°F-290°F			
	2 days at 200° F			
	6 days at 150°F			
	4 days at 130°F			
	<u>For 3% Boric Acid</u>			
	3 hours at 75°F-300°F			
	3 hours at 300°F			
	3 hours at 300°F-180° F			
	15 hours cooling to ambient			
	Total 24 hour cycle repeated ten times			

Concrete

a. *Test specimens: Prepared concrete coupons.*

b. *Water Chemistry: 3000 ppm boron as boric acid in water; also 3% boric acid .*

c. *Temperature:*

2 hours at 75°F - 300° F

14 hours at 300°F

2 hours at 75° F

4 hours cooling to ambient

- *We understand testing performed by ANS Subcommittee for Protective Coatings for Reactor Containment Facilities and by Dr. C D Watson at Oak Ridge did not disclose any significant difference between results of static autoclave exposure and autoclave exposure using a spray of solution on panels. On this basis either static or dynamic exposure to spray solution is considered to be acceptable as basis for testing.*
- *We do not have available test results on jet impingement effects; however, it is felt that there is no coating system available which would*

withstand a high temperature, high velocity steam jet. We believe that the assumption of large scale, rapid LOCA by means of a double-ended pipe failure or otherwise, negates the possibility of concentrated local jet impinging on a coated steel area of substantial size. Therefore, we believe the autoclave tests in which specimens were subjected to steam and water at elevated temperatures more nearly approximate overall building environment under LOCA conditions than would a local steam jet application.

- *We understand ANS subcommittee found no system for coating steel or concrete for resisting steam jet impingement and therefore has established no standards for this condition of exposure .*
- *Decontamination factor for Phenoline 305 is 325. Test methods described in Oak Ridge National Laboratory Reports ORNL-3589, 3916 and others.*
- *Carbo Zinc 11 withstands in excess of 3 x* 10^9 *Roentgens when irradiated in water. There is no serious damage to Phenoline 305 at 6 x* 10^9 *Roentgens when irradiated in air. Phenoline 305 withstands in excess of 2 x* 10^9 *Roentgens irradiated in water .*

2. Maintenance coating over Original Coating Systems and New Coating Systems have satisfactorily withstood radiation and autoclave tests with no loss of adherence or erosion of material from surface.
    - Coating Systems are qualified by Engineering in accordance with ANSI N101.2 and ANSI N101.4 for (A) LOCA Conditions and (B) Radiation Tolerance.
    - Coating specifications for shop and field application include the following: Scope, Coating System, Approved Materials, Application Procedures, Touchup Procedures, Workmanship Guide, Inspection Requirements, Record Requirements, and Product Data Sheets.
    - A Materials Certification of each batch of coating material procured is in accordance with ANSI N101.4 and is provided by the Manufacturer.
    - Distribution of Containment Coating Specifications and Coating Schedules are transmitted by Document Control.

Table 3-13. Service Load Combinations for Reactor Building

1. $D + F + L + T_o$		
2. $D + F + L + P + T_A + E(\text{or } W)$		
3. $D + F + L + P'$		
Where:		
D	=	Dead Load
L	=	Appropriate Live Load
F	=	Appropriate Prestressing Load
P	=	Pressure Load (Varies with time from design pressure to zero pressure)
T_o	=	Thermal Loads Due to Operating Temperature
T_A	=	Thermal Loads Based on a Temperature Corresponding to a Pressure P
E	=	Design Earthquake
P'	=	Test Pressure = 1.15 P
W	=	Wind Load

Table 3-14. Accident, Wind, and Seismic Load Combinations and Factors for Class 1 Concrete Structures

Y = 1/∅1.0D + 1.0P + 1.0T + E')
Y = 1/∅ (1.05D + 1.25P + 1.0T + 1.25E or W)
Y = 1/∅ (1.05D + 1.5P + 1.0T)
Y = 1/∅1.0D + 1.0W_t + 1.0P_i) for Tornado Forces.

(Use 0.95 where dead load subtracts from critical stress.) (Wind, W, to replace earthquake, E, in the above formula where wind stresses control)

Where	Y	=	required yield strength of the structure as defined above.
	D	=	dead loads of structure and equipment plus any other permanent loadings contributing stress, such as hydrostatic or soils. In addition, a portion of "live load" should be added when it includes piping, cable trays, etc. suspended from floors and an allowance should be made for future additional permanent loads.
	P	=	design accident pressure.
	T	=	thermal loads based on a temperature corresponding to the factored design accident pressure.
	E	=	seismic load based on design earthquake.
	E'	=	seismic load based on maximum hypothetical earthquake.
	W	=	wind load.
	W_t	=	stress induced by tornado wind velocity (drag, lift and torsion).
	P_i	=	stress due to differential pressure.
	∅	=	Concrete capacity reduction factor.
	∅	=	0.90 for concrete flexure.
	∅	=	0.85 for tension, shear, bond and anchorage in concrete.
	∅	=	0.75 for spirally reinforced concrete compression members.
	∅	=	0.70 for tied compression members.
	∅	=	0.90 for fabricated structural steel embedments.
	∅	=	0.90 for mild reinforcing steel (not prestressed) in direct tension excluding splices.
	∅	=	0.85 for mild reinforcing steel with mechanical splices (for lap splices, ∅= 0.85 as above for bond and anchorage).
	∅	=	0.95 for prestressed tendons in direct tension.

Additional Notes:

The Class 1 structures are proportioned to maintain elastic behavior when subjected to various combinations of dead loads, accident loads, thermal loads and wind or seismic loads. The upper limit of elastic behavior is considered to be the yield strength of the effective load-carrying structural materials.

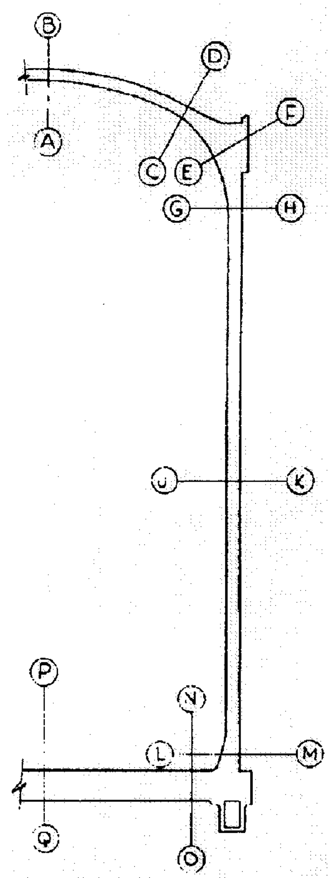
The yield strength for steel (including reinforcing steel) is considered to be the minimum given in the appropriate ASTM specification. Concrete structures are designed for ductile behavior wherever possible; that is, with steel stress controlling the design. The values for concrete, as given in the ultimate strength design portion of the ACI 318-63 Code, will be used in determining "Y", the required yield strength of the structure.

The design loads applied to the structures are increased by load factors based on the probability and conservatism of the predicted normal design loads.

Table 3-15. Inward Displacement of Liner Plate

Case	Nominal Plate Thickness (In.)	Initial Inward Displacement (In.)	Anchor Spacing L_1 (In.)	Anchor Spacing L_2 (In.)	Factor of Safety Against Failure
I	0.25	0.125	15	15	37.0
II	0.25	0.125	15	15	19.4
III	0.25	0.125	15	15	9.9
IV	0.25	0.125	15	15	6.28
V	0.25	0.25	30	15	4.25

Table 3-16. Stress Analysis Results



KEY ELEVATION

(SHOWING LOCATION OF REFERENCE SECTIONS)

Sheet 1 of 6

STRUCTURAL DATA

LOCATION	CONCRETE		REINFORCING STEEL		
	f'_c-psi	t-in	TYPE	p_m -%	p_h -%
A	5000	39	A615GR40	0.05	0.05
B	5000	39	A615GR40	0.23	0.23
C	5000	55	A615GR60	0.16	0.16
D	5000	55	A615GR60	0.30	0.30
E	5000	138	A615GR60	0.06	0.06
F	5000	138	A615GR60	0.18	0.18
G	5000	45	A615GR60	...	...
H	5000	45	A615GR60	0.53	0.53
J	5000	45	A615GR40	...	...
K	5000	45	A615GR40	0.25	0.25
L	5000	63	A615GR60	0.83	0.51
M	5000	83	A615GR60	0.74	0.72
N	5000	102	A615GR60	0.49	0.13
O	5000	102	A615GR60	0.87	0.31
P	5000	102	A615GR60	0.19	0.19
Q	5000	102	A615GR60	0.34	0.34

NOTES

1. LOADING CASES I, II, & III ARE WORKING STRESS ANALYSIS WHEREAS LOADING CASES IV, V, VI ARE YIELD STRESS ANALYSIS.
2. FOR NOTATION AND ALLOWABLE STRESSES SEE SHEET 2
3. ALL CONCRETE EXTREME FIBER STRESS (σ_e) ARE SHOWN FOR THE INSIDE SURFACE. OUTSIDE SURFACE STRESSES ARE INDICATED BY ( ). THE STRESSES LISTED ARE THE CONTROLLING STRESSES FOR THAT SECTION.
4. COMPUTED VS. ALLOWABLE RATIOS FOR CASES IV, V AND VI INCLUDE APPROPRIATE ϕ FACTORS, e.g. $\frac{f_a}{\phi f_a}$
5. ALLOWABLE SHEAR STRESSES INCLUDE STIRRUPS WHEREVER APPLICABLE
6. THE STRESSES SHOWN FOR THE LOAD CASES INCLUDING T_A ARE BASED ON CRACKED SECTION ANALYSIS UNLESS NOTED BY *.
7. DEVIATIONS IN ALLOWABLE STRESSES ARE IN ACCORDANCE WITH PSAR APPENDIX 5-C

Note: For stresses in the area of the construction opening installed and repaired during the steam generator replacement project see calculation OSC-8163.

Table 3-17. Stress Analysis Results

Sheet 2 of 6

NOTATION

D	DEAD LOAD
F	PRESTRESS
P	INTERNAL PRESSURE
E	EARTHQUAKE (DESIGN)
E'	EARTHQUAKE (HYPOTHETICAL)
T_A	ACCIDENT TEMPERATURE
fc	ULTIMATE CONCRETE STRESS
fy	STEEL RE-BAR YIELD STRESS
fa	ALLOWABLE CONCRETE AXIAL STRESS
fce	ALLOWABLE CONCRETE AXIAL & FLEXURE STRESS
v	ALLOWABLE CONCRETE SHEAR STRESS INCLUDING STIRRUPS IF APPLICABLE
fs	ALLOWABLE STEEL STRESS
σ_a	NOMINAL MEMBRANE STRESS
σ_e	COMBINED AXIAL & FLEXURE NOMINAL STRESS
τ	ACTUAL SHEAR STRESS
h	SUBSCRIPT INDICATING HOOP DIRECTION
m	SUBSCRIPT INDICATING MERIDIONAL DIRECTION
p_h	HOOP STEEL PERCENTAGE
p_m	MERIDIONAL STEEL PERCENTAGE
+	TENSILE STRESSES
−	COMPRESSIVE STRESSES
*	UNCRACKED SECTION ANALYSIS

ALLOWABLE STRESSES

	WORKING STRESS DESIGN	YIELD STRESS DESIGN
SHELL CONCRETE:	fa = 1500 psi	fa = ϕa (fc) = (0.85) (5000) = 4,250 psi
	fce = 3000 psi	fce = ϕce (fc) = (0.90) (5000) = 4,500 psi
BASE CONCRETE:	f_{ce} = 2250 psi	fa = ϕa (fc) = (0.85) (5000) = 4,250 psi
		fce = ϕce (fc) = (0.90) (5000) = 4,500 psi
STEEL: A615GR40	fs = 20,000 psi	fs = ϕ (fy) = (0.90) (40,000) = 36,000 psi
A615GR60	fs = 30,000 psi	fs = ϕ (fy) = (0.90) (60,000) = 54,000 psi

Table 3-18. Stress **Analysis Results**

Sheet 3 of 6

"D + F INITIAL" (Stresses in psi) Case I*

	SECTION	MERIDIONAL			HOOP			SHEAR		
		σ OUTSIDE	σ INSIDE	σ AXIAL	σ OUTSIDE	σ INSIDE	σ AXIAL	τ	Vci	Vcw
SHELL	A - B	-1,340	-1,140	-1,250	-1,283	-1,096	-1,178	-14	111	605
	C - D	-218	-1,280	-668	-312	-460	-362	74	100+33	473+33
	E - F	-471	-581	-441	-353	-428	-386	47	185+145	411+145
	G - H	-667	-515	-584	-860	-872	-864	34	666	451
	J - K	-729	-673	-708	-1,205	-1,272	-1,251	-4	—	484
	L - M	-319	-881	-566	-211	-349	-273	-7	101+81	446+81
BASE	N - O	141	-84	23	10	-60	-36	-16	105+257	235+257
	P - Q	-27	-24	-26	-26	-20	-26	7	—	260

ALLOWABLE CONCRETE STRESSES:

Shell: fa = 1500 psi
fcp = 3000 psi

Note: For stresses in the area of the construction opening installed and repaired during the steam generator replacement project see calculation OSC-8163.

Table 3-19. Stress Analysis Results

Sheet 4 of 6

REACTOR BUILDING — SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES

SECTION	LOAD CASE	CONCRETE								REINFORCING STEEL			
		COMPUTED					COMPUTED VS. ALLOWABLE			COMPUTED		COMPUTED VS. ALLOWABLE	
		σem	σeh	σam	σah	τ	$\frac{\sigma e}{f'ce}$	$\frac{\sigma a}{fa}$	$\frac{\tau}{V}$	σm	σh	$\frac{\sigma m}{fs}$	$\frac{\sigma h}{fs}$
A-B	II - D+F+1.15P	(-313)*	(-303)*	-282*	-271*	-5*	0.104*	0.188*	0.038*	—	—	—	—
	III - D+F+P+T_A+E	-1,632	-1,422	-412	-368	-22	.544	.275	0.089	11,608	12,408	.580	.620
	IV - 0.95D+F+1.5P+T_A	-328	-223	+16	+58	0	0.073	0	0.000	26,723	22,326	.742	.620
	V 0.95D+F+1.25P+1.25E+T_A	-1029	-823	-198	-154	-23	0.229	.047	0.920	17,462	17,513	.485	.486
	VI - 0.95D+F+P+E'+T_A	-1,632	-1422	-412	-368	-26	0.363	.097	0.105	11,608	12,408	.322	.345
C-D	II - D+F+1.15P	-310*	-329*	-259*	-278*	83*	0.110*	0.185*	0.216*	—	—	—	—
	III - D+F+P+T_A+E	-2040	-1638	-312	-296	103	0.680	.208	0.896	26,361	21,360	.879	.712
	IV - 0.95D+F+1.5P+T_A	-502	-1493	-131	-240	79	0.329	.056	0.642	15,587	26,135	.288	.484
	V - 0.95D+F+1.25P+1.25E+T_A	-920	-1482	-216	-268	109	0.329	.063	0.380	15,283	21,552	.283	.400
	VI - 0.95D+F+P+E'+T_A	-2232	-1683	-312	-296	109	0.496	.073	0.752	28,762	21,360	.533	.396
E-F	II D+F+1.15P	(-551)*	(-374)*	-328*	-363*	49*	0.183*	0.242*	0.245*	—	—	—	—
	III D+F+P+T_A+E	-298	-1520	-274	-358	83	0.507	0.239	0.170	—	12,800	—	.427
	IV - 0.95D+F+1.5P+T_A	-(305)	-1450	-233	-343	52	0.322	0.081	0.107	2,532	12,213	0.047	.226
	V - 0.95D+F+1.25P+1.25E+T_A	-170	-2367	-230	-350	91	0.526	0.082	0.153	—	36,328	—	.673
	VI - 0.95D+F+P+E+T_A	-295	-1520	-271	-358	91	0.338	0.084	0.151	—	12,800	—	.237

Note: For stresses in the area of the construction opening installed and repaired during the steam generator replacement project see calculation OSC-8163.

Table 3-20. Stress Analysis Results

Sheet 5 of 6

REACTOR BUILDING — SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES

SECTION	LOAD CASE	CONCRETE: COMPUTED σem	σeh	σam	σah	τ	CONCRETE: COMPUTED VS. ALLOWABLE $\frac{\sigma e}{fce}$	$\frac{\sigma a}{fa}$	$\frac{\tau}{v}$	REINFORCING STEEL: COMPUTED σm	σh	REINFORCING STEEL: COMPUTED VS. ALLOWABLE $\frac{\sigma m}{fs}$	$\frac{\sigma h}{fs}$
G H	II D+F+1.15P	(-147)*	(-299)*	-111*	-298*	-10*	0.10C*	0.199*	0.089*	—	—	—	—
	III D+F+P+T_A+E	-744	-1594	-143	-386	42	0.531	.257	0.500	21,517	12,890	.717	.430
	IV 0.95D+F+1.5P+T_A	-50	-616	+50	-124	-17	0.137	.029	0.233	27,548	20,924	.5101	.388
	V 0.95D+F+1.25P+1.25E+T_A	-319	-1108	-25	-255	-57	0.246	.060	0.626	25,157	16,924	.466	.313
	VI 0.95D+F+P+E'+T_A	-724	-1594	-137	-386	52	0.354	.091	0.584	21,696	12,890	.402	.239
J K	II D+F+1.15P	(-255)*	-250*	-228*	-254*	-4*	0.085*	0.169*	0.082*	—	—	—	—
	III D+F+P+T_A+E	-944	-2606	-229	-474	-61	0.869	.316	0.735	16,118	9,344	.806	.467
	IV 0.95D+F+1.5P+T_A	-21	-719	+111	+46	-11	0.160	0	0.847	29,315	19,273	.814	.535
	V 0.95D+F+1.25P+1.25E+T_A	-478	-1319	-98	-186	-73	0.293	.044	0.948	19,986	15,116	.555	.420
	VI 0.95D+F+P+E+T_A	-918	-2606	-222	-474	-73	0.579	.111	0.737	16,334	9344	.454	.260
L M	II D+F+1.15P	(-567)*	(-289)*	-335*	-267*	78*	0.189*	0.223*	0.294*	1.900*	—	0.063*	—
	III D+F+P+T_A+E	-727	-595	-237	-166	199	0.242	.158	0.503	7760	12,825	.259	.411
	IV 0.95D+F+1.5P+T_A	—	-850	-154	-249	140	0.190	.059	0.356	(16,440)	8,997	.304	.167
	V 0.95D+F+1.25P+1.25E+T_A	-449	-340	-141	-144	198	0.100	.034	0.504	10,068	12,367	.186	.229
	VI 0.95D+F+P+E'+T_A	-630	-528	-203	-145	173	0.140	.048	0.456	8,595	12,881	.159	.238

Note: For stresses in the area of the construction opening installed and repaired during the steam generator replacement project see calculation OSC-8163.

Table 3-21. Stress Analysis Results

Sheet 6 of 6

REACTOR BUILDING — SUMMARY OF CONCRETE AND REINFORCING STEEL STRESSES

SECTION	LOAD CASE	CONCRETE								REINFORCING STEEL			
		COMPUTED					COMPUTED VS. ALLOWABLE			COMPUTED		COMPUTED VS. ALLOWABLE	
		σem	σeh	σam	σah	τ	$\frac{\sigma e}{fce}$	$\frac{\sigma a}{fa}$	$\frac{\tau}{v}$	σm	σh	$\frac{\sigma m}{fs}$	$\frac{\sigma h}{fs}$
N-0	II · D+F+1.15P	-215*	-183*	223*	-35*	-182*	0.095*	$f_a = .3f'_c$ NOT APPLICABLE TO SLAB	0.361*	7,755*	7,236*	0.259*	0.241*
	III · D+F+P+T_A+E	-24	—	+151	+73	284	0.011		0.563	23,130	27,666	.838	.922
	IV · 0.95D+F+1.5P+T_A	-50	-627	+188	+15	323	0.139		0.455	27,386	24,980	.507	.463
	V · 0.95D+F+1.25P+1.25E+T_A	—	—	+188	+98	330	—		0.482	30,034	36,326	.556	.673
	VI · 0.95D+F+P+E'+ T_A	-28	—	+157	+90	293	—		0.442	26,379	32,501	.490	.602
P-0	II · D+F+1.15P	-13*	(-14)*	-14*	-15*	9*	0.006*	$f_a = .3f'_c$ NOT APPLICABLE TO SLAB	0.035*	—	—	—	—
	III · D+F+P+T_A+E	-1000	-960	-16	-15	29	0.444		0.492	31,000	29,475	1.03	.9825
	IV · 0.95D+F+1.5P+T_A	-811	-501	-11	-10	6	0.360		0.130	32,600	34,097	.604	.631
	V 0.95D+F+1.25P+1.25E+ T_A	-944	-581	-13	-13	36	0.420		0.563	36,502	36,162	.676	.670
	VI · 0.95D+F+P+E'+ T_A	-1026	-632	-16	-15	35	0.456		0.556	38,844	37,315	.719	.691

Note: For stresses in the area of the construction opening installed and repaired during the steam generator replacement project see calculation OSC-8163.

Table 3-22. Bent Wire Test Results

Sample		**STRESS (psi)**					
Group No.		1	2	3	4	5	6
Bend Angle (Degrees)		-	30	60	90	30	60
Bend Radius (inch)		-	1.25	1.25	1.25	0	0
	1	251,500	257,650	257,650	259,650	251,550	230,150
	2	254,600	259,650	257,650	257,650	251,550	237,250
	3	256,600	257,650	259,650	256,600	252,550	240,300
SERIES I Heat #A67386	4	258,650	258,650	258,650	256,600	247,450	235,250
	5	259,650	261,700	259,650	258,650	248,450	237,250
	6	258,650	259,650	260,700	258,650		
	7	260,700	254,600	261,700	258,650		
	8	259,650	258,650	260,700	258,650		
	9	260,700	258,650	260,700	257,650		
	10	260,700	258,650	255,600	260,700		
Average		258,850	258,550	259,250	258,350	250,300	236,050
	11	252,550	249,500	249,500		243,400	229,100
	12	252,550	249,500	251,550		243,400	227,100
	13	249,500	249,500	248,450		243,400	229,100
SERIES II Heat #A72005	14	248,450	249,500	250,500		242,350	227,100
	15	247,450	250,500	248,450		241,350	228,100
	16	250,500	249,500	248,450			
	17	254,600	253,550	252,550			
	18	251,550	251,550	251,550			
	19	252,550	251,550	249,500			
	20	249,500	254,600	249,500			
Average		250,900	250,900	250,000		242,750	228,100

Table 3-23. Auxiliary Building Loads and Conditions

AREA	CONDITIONS	
Control Room	A,B,C,D,E	
Cable Room	A,B,C,D,E	
Electrical Equipment Room	A,B,C,D,E	
Spent Fuel Pool	A,B,C,D,E	Blow out panels designed to relieve 3 psi differential pressure
Spent Fuel Storage Racks	A,D	Inherently resistant to wind loads
Spent Fuel Handling Crane	A,D,E	Inherently resistant to wind loads. Hold down device provided
Penetration Room Frames	A,B,D	Physical separation provided for missile protection
Cable Shaft	A,B,C,D,E	
Elevator Steel Shaft	A,D	
Main Steam Pipe Supports	A,B,D	
Hot Machine Shop	A,D	
Balance of Auxiliary Building	A,B,D	Frame designed for B, but not external walls above grade. Areas below grade are inherently protected against missiles in C and E.

A = All normal dead, equipment, live, and wind loads due to 95 mph wind or design basis earthquake.

B = Normal dead and equipment loads plus tornado wind load due to 300 mph wind.

C = Tornado missiles of (1) 8 in. diameter x 12 ft. long piece of wood, 200 pounds, 250 mph, and (2) 2,000 pound automobile, 100 mph, 20 sq. ft. impact area, for 25 ft. above grade.

D = Normal dead and equipment loads plus maximum hypothetical earthquake loads.

E = Turbine-generator missile, 5,944 pounds, 502 fps, kinetic energy of 23.25×10^6 ft.-lbs., side on impact area of 8.368 sq. ft. and end on impact area of 3.657 sq. ft.

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Table 3-24. Mark-BZ Fuel Assembly Seismic and Loca Results at 600°F

Loading Case	Allowable Impact Load (lbs)	Grid Deformation	Allowable Grid Deformation (in.)
SSE	2824 (1)	None	0.0
LOCA Core Flood Line Guillotine	2824	None	0.0
LOCA Decay Heat Line Guillotine	2824	None	0.0
SSE and LOCA	2824	None	0.0

Note:

1. That the allowable load is actually higher than the elastic load limit given, since the criteria of SSE is to ensure control rod insertion. Therefore, the value given is conservative.

Table 3-25. Deleted per 1996 Update

Table 3-26. Stress Limits for Seismic, Pipe Rupture and Combined Loads

Case	Loading Combination	Stress Limits
I	Design loads + operating basis earthquake loads	$P_m \leq 1.0S_m$ $(P_L + P_b) \leq 1.5S_m$
II	Design loads + safe shutdown earthquake loads	$P_m \leq 1.2S_m$ $(P_L + P_b) \leq 1.2(1.5S_m)$
III	Design Loads + pipe rupture loads	$P_m \leq 1.2S_m$ $(P_L + P_b) \leq 1.2(1.5S_m)$
IV	Design loads + safe shutdown earthquake loads + pipe rupture loads	$P_m \leq 2/3S_u$ $(P_L + P_b) \leq 2/3S_u$
[1] where	P_L	= Primary local membrane stress intensity
	P_m	= Primary general membrane stress intensity
	P_b	= Primary bending stress intensity
	S_m	= Allowable membrane stress intensity
	S_u	= Ultimate stress for unirradiated material at operating temperature

Note:

1. All symbols have the same definition or connotation as those in ASME B&PV Code Section III, Nuclear Vessels.
2. All components will be designed to insure against structural instabilities regardless of stress levels.

Table 3-27. Deleted Per 1999 Update

Table 3-28. Deleted Per 2004 Update

Table 3-29. Deleted Per 2004 Update

Table 3-30. Deleted Per 2004 Update

Table 3-31. Deleted Per 2004 Update

Table 3-32. Deleted Per 2004 Update

Table 3-33. Deleted Per 2004 Update

Table 3-34. Deleted Per 2004 Update

Table 3-35. Deleted Per 2004 Update

Table 3-36. Deleted Per 2004 Update

Table 3-37. Deleted Per 2004 Update

Table 3-38. Deleted Per 2004 Update

Table 3-39. Deleted Per 2004 Update

Table 3-40. Deleted Per 2004 Update

Table 3-41. Deleted Per 2004 Update

Table 3-42. Deleted Per 2004 Update

Table 3-43. Deleted Per 2004 Update

Table 3-44. Deleted Per 2004 Update

Table 3-45. Deleted Per 2004 Update

Table 3-46. Deleted Per 2004 Update

Table 3-47. Deleted Per 2004 Update

Table 3-48. Deleted Per 2004 Update

Table 3-49. Deleted Per 2004 Update

Table 3-50. Deleted Per 2004 Update

Table 3-51. Deleted Per 2004 Update

Table 3-52. Deleted Per 2004 Update

Table 3-53. Deleted Per 2004 Update

Table 3-54. Deleted Per 2004 Update

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Table 3-57. Deleted Per 2004 Update

Table 3-58. Deleted Per 2004 Update

Table 3-59. Deleted Per 2004 Update

Table 3-60. Deleted Per 2004 Update

Table 3-61. Deleted Per 2004 Update

Table 3-62. Deleted Per 2004 Update

Table 3-63. Deleted Per 2004 Update

Table 3-64. Deleted Per 2004 Update

Table 3-65. Deleted Per 2004 Update

Table 3-66. Deleted Per 2004 Update

Table 3-67. Deleted Per 2004 Update

Table3-68. Electrical Equipment Seismic Qualification

	Equipment Identification	Seismic Qualification Documentation Reference
1.	Reactor Protective System Cabinets/Components	Deleted Per 2013 Update. Reactor Protective System Engineered Safeguards Protective System Replacement Equipment Qualification Report AREVA NP 66-5065212 (OM 201.N-0021.001); TXS Supplemental Equipment Qualification Summary Test Report AREVA NP 66-5015893 (OM 201.N-0021.017); Seismic Anchorage Calculation OSC-8743; Seismic Qualification of ES and RPS Cabinets AREVA NP 51-9002920; Seismic and Isolation Qualification Test Report of Phoenix Contact Relays AREVA NP 38-9057729; Test Report for Seismic Qualification of Additional Hardware for use within Teleperm XS System Areva NP 58-5066097 Deleted Per 2013 Update.
2.	Engineered Safeguards Protective Cabinets/Components	Deleted Per 2013 Update. Reactor Protective System and Engineered Safeguards Protective System Replacement Equipment Qualification Report AREVA NP 66-5065212 (OM 201.N-0021.001); TXS Supplemental Equipment Qualification Summary Test Report AREVA NP 66-5015893 (OM 201.N-0021.017); Seismic Anchorage Calculation OSC-8743; Seismic Qualification of ES and RPS Cabinets AREVA NP 51-9002920; Seismic and Isolation Qualification Test Report of Phoenix Contact Relays AREVA NP 38-9057729; Test Report for Seismic Qualification of Additional Hardware for use within Teleperm XS System Areva NP 58-5066097 Deleted Per 2013 Update.

	Equipment Identification	Seismic Qualification Documentation Reference
3.	Reactor Protective System Sensors 1. RC Pressure Transmitters (NR) 2. RC Temperature RTD's 3. RC Flow Transmitters 4. RB Pressure Switches 5. RCP Power Monitors	Rosemount Report 2758&127516 &D8400102 also B & W 58-0261-00 Rosemount Report 1177117A, and B & W 58-0082-00 B & W 58-0081-00 and Rosemount Report D8400102 Herron Lab Report F-7040, and B & W 58-0080-00 (OM 360-0010) Duke/Exide Test Report PH58644 WEED Instrument Report D6-8680-003(OM-357.-0008-0001) Deleted Per 2013 Update. Wyle Test Report No. 52511-1, Seismic Test Report; NTS Environmental and Seismic Testing of Ancillary Equipment for Oconee ES/RPS Replacement AREVA NP 38-9004984; Seismic Qualification Report Lampbox and Switches AREVA NP 38-9005550
4.	Engineered Safeguards Protective System Sensors 1. RC Pressure Transmitters (WR) 2. RB Pressure Transmitters 3. RB Pressure Switches	Rosemount Test Report D830040(OM-0267.A-0114) &D8400102 (OM-0267-0969) ITT-Barton Test Report R3-764-9 (OM-0267.A-0041) ASCO Test Report AQR-101083 (OM-0267.A-0050)
5.	4160 VAC Station Auxiliary Switchgear (1TC, 1TD, 1TE; 2, 3)	ITE Report No. R-8793, and Gould Report No. 33-53719-SS (OM 302-0617)
6.	600 VAC Load Centers (1X8, 1X9, 1X10; 2, 3)	Gould Report No. 33-53729-SSA (OM 301-0079)
7.	Motor Control Centers (1XS1, 1XS2, 1XS3; 2; 3) 1. A.O. Smith Type "CY" Starters 2. Joslyn Clark Type "TM" Starters a. Oconee (1XS1, 1XS2, 1XS3j2;3) b. Keowee (1XA, 1XS, 2XA, 2XS)	Oconee Nuclear Station, Units 1-2-3 Motor Control Centers, DC Distribution Centers, DC Panelboards, Original QA Documentation Files Seismic Qualification of size 1-4 Joslyn Clark Motor Starters DPC-1393.00-00-0041
8.	DC Distribution Centers (1DCA, 1DCB; 2; 3)	Oconee Nuclear Station, Units 1-2-3 Motor Control Centers, DC Distribution Centers, DC Panelboards, Original QA Documentation Files

	Equipment Identification	Seismic Qualification Documentation Reference
9.	AC Panelboards (1KVIA, 1KVIB, 1KVIC, 1KVID; 2; 3)	Wyle Lab Report 42729-1 (OM-304.0002)
	1SKJ, 1SKK, 1SKL; 2,3	Square-D Report No. 8998-10.09-L31 (OM-0137)
10.	DC Panelboard (1DIA, 1DIB, 1DIC, 1DID; 2; 3)	Wyle Lab Report 42729-1 (OM-304.0002)
11.	Control Batteries/Racks (1CA, 1CB; 2; 3)	C & D Technologies, Environment and Seismic Qualification Report of 125 Volt Vital Instrumentation and Control Batteries, Model LCR-33 and RD02242-06N4 Two Tier Two Row Battery Racks (OM-1320-0103.002)
12.	Battery Chargers (1CA, 1CB, 1CS; 2; 3)	Wyle Lab Report 43185-2 (OM 346-0105-1)
13.	Inverters (1DIA, 1DIB, 1DIC, 1DID; 2; 3)	Wyle Lab Report 43185-2 (OM 346-0105-1)
14.	Isolating Diode Assemblies (1ADA, 1ADB, 1ADC, 1ADD; 2; 3)	Exide Power Systems Div. "Seismic Test of Diode Monitors"
15.	Oconee Main Control Boards	Wyle Lab Report WR 73-1 (OM 1393-0008), OSC-1525 (1), OSC-3942(1), OSC-2509(1)
16.	Engineered Safeguards Terminal Cabinets	Wyle Lab Report WR 73-1 (OM 1393-0008)
17.	Emergency Power Switching Logic Cabinets	Wyle Lab Report WR 73-1 (OM 1393-0008)
18.	Oconee Unit Boards	Wyle Lab Report WR 73-1 (OM 1393-0008), OSC-1525(1), OSC-3942(1), OSC-2509(1)
19.	Oconee Vertical Boards	Wyle Lab Report WR 73-1 (OM 1393-0008), OSC-1525(1), OSC-3942(1), OSC-2509(1)
20.	Oconee Auxiliary Boards	Wyle Lab Report WR 73-1 (OM 1393-0008), OSC-1525(1), OSC-3942(1), OSC-2509(1)
21.	Keowee Emergency Start Cabinets	Wyle Lab Report WR 73-1 (OM 1393-0008)
22.	Keowee Control Boards	Wyle Lab Report WR 73-1 (OM 1393-0008), Loose Parts, NLI-Nuclear Logistics INC. QR-29412516-4 (KM 303. --0045.001)
23.	Keowee Miscellaneous Terminal Cabinets	Wyle Lab Report WR 73-1 (OM 1393-0008)

	Equipment Identification	Seismic Qualification Documentation Reference
24.	Keowee Main Turbine - Generators	ONS Emergency Power Source Seismic Evaluation Technical Position Paper
25.	Keowee – Oconee Underground Power Circuit	ONS Emergency Power Source Seismic Evaluation Technical Position Paper
26.	Keowee Logic Cabinets	Wyle Lab Report WR 73-1 (OM 1393-0008)
27.	Keowee 125 VDC Battery Chargers	OM 320-0167
28.	Keowee 125 VDC Battery/Racks	Keowee Battery Environmental Qualification Report (KM 320-16)
29.	Keowee 125 VDC Distribution Centers	Oconee Nuclear Station, Units 1-2-3 Motor Control Centers, DC Distribution Centers, DC Panelboards, Original QA Documentation Files
30.	230 KV Swyd Battery Chargers	OM 320-0167
31.	230 KV Swyd Control Batteries	C & D Charter Power Systems Report Number QR-27189-01 (OM-320-163)
32.	230 KV Swyd Distribution Centers	Oconee Nuclear Station, Units 1-2-3 Motor Control Centers, DC Distribution Centers, DC Panelboards, Original QA Documentation Files
33.	230 KV Swyd Panelboards	Wyle Lab Report 42729-1, (OM 304.0002)
34.	Oconee/Keowee Overhead Power Path Equipment	
	a. Keowee Main Stepup Transformer – ABB Serial Number STM0032001 (Note 2)	For Seismic Qualification Documentation, reference Purchase Order number 3046710.
	b. Oconee Startup Transformers	G. E. letter to R. S. Thompson, 09-06-76, and G. E. letter to J. E. Stoner, 04-03-77 (OS-83-B)
	c. 230 KV Disconnect Switches	ITE letter & Attachment to R. S. Thompson, 08-26-76, (OS-96-C) and OSC-926
	d. 230 KV Power Circuit Breakers	MEPPI Breakers (OM 323.0335.001), OSC-7895

	Equipment Identification	Seismic Qualification Documentation Reference
	e. 230 KV Swyd. Coupling Capacitor	G. E. letter & Attachments to J. C. Papaspyrou, 08-18-76, (OS-96-D), OSC-926, OM-330-0033-001, and OSC-7895
	f. 230 KV Swyd. Lightning Arrestors	G. E. letter & Attachments to J. C. Papaspyrou, 08-06-76, (OS-96-E), and OSC-926
	h. 230 KV Swyd. DC Panelboards	ITE letter & Attachments to J. E. Stoner, 08-16-76, (OS-89)
	i. 230 KV Swyd. Control Batteries/Racks	C & D letter to C. J. Wylie, 09-02-76 (OS-93)
	k. 230 KV Swyd. Relay House Lighting System (Anchoring Only)	J. P. Bultman letter to J. E. Stoner, 09-23-76, (OS-89)
	l. 230 KV Swyd. Relay Panels/Equipment	Wyle Lab Report WR 76-17 (OM 393-0006)
35.	AC Control Rod Drive Breaker Cabinet	FANP Qualfication Test Report QR 02-10 – Cutler Hammer DSII Series Low Voltage AC Trip Circuit Breakers and Switchgear– Rev 03, dated 12-19-03. (OM 2201.M-0377.001)
36.	Standby Shutdown Facility	
	a. Control Console	Wyle Lab Report 45676-1 (OM 1393-0013), OSC-279[(1)]
	b. Miscellaneous Equipment and Interconnecting Cabinets	Wyle Lab Report 45676-1 (OM 1393-0013), OSC-279[(1)]
	c. Diesel Generator	Flight Dynamics Inc. Report No. A-11-80 (OM 351-0206)
	d. 4160 VAC Switchgear	Gould Report No. 33-53566-SS(OM-302-0615)
	e. 600 VAC Motor Control Centers	GTE Seismic Report (OM 308-0361-001, -002, and 003)
	f. 208 VAC Motor Control Centers	GTE Seismic Report (OM 308-0361-001, -002, and -003)
	g. 120 VAC/125 VDC Panelboards	GTE Seismic Report (OM 308-0361-001, 002, and 003)
	h. 600 VAC Load Centers	Gould Report No. 33-53729-SSA (OM301-80)
	i. Inverters	SCI Seismic Evaluation (OM 320-0214-001)

	Equipment Identification	Seismic Qualification Documentation Reference
	j. Battery Chargers	OM-320-0202.001 (Environmental and Seismic Qualification Report 125 VDC/500 AMP SSF Chargers CSF & CSFS)
	k. Voltage Regulators	Wyle Lab Report 44741-1 (OM 352-0012)
	l. Control Batteries/Racks	OM-320-0202.002 (Environmental and Seismic Qualification Report, 125 Volt SSf Batteries DCSf & DCSf-S Model LCR-21 on Two-Step and Single-Row Battery Racks)
	m. SSF Transmitters	Rosemount Test Reports D8400102, Rev. B (OM-267-0969) D8300040 (OM-267.A-0114)
37.	TMI Action Item Additions	
	a. Reactor Building High Range Radiation Monitors	Victoreen Report No. 950-301 (OM 360-35)
	b. Anticipatory Reactor Trip Pressure Switches and RPS Logic Equipment	B & W Report No. BWNP-20210-1 (OM-304-0001, OM-2304-0001) or Static-O-Ring Report Nos. 9058-102 (OM-267A-0124) and 9058-104 (OM-267-1284)
	c. Hydrogen Analyzer Control Panel (Duke Portion)	Wyle Lab Report No. 45477-1 (OM 1393-0009)
	d. Post-Accident Monitoring Recorders	Wyle Lab Report WR-80-48, Rev. 1 (OM 1393-0012)
	e. Post-Accident Monitoring Indicators	Wyle Lab Report WR-80-48, Rev. 1 (OM 1393-0012)
	f. Emergency Feedwater Initiation Pressures Switches	Custom Component Switches, Inc. Report No. QTR 604-01 (CG 3008.02-01, CG 3008.02-06) or Static-O-Ring Report Nos. 9058-102 (OM-267A-0124) and 9058-104 (OM-267-1284)
	g. Normal and Emergency Sump Level Transmitters	FCI Test Report No. 708143 (OM 267-0762)
	h. RB Pressure Transmitters	RMT Report No. D8400102 Rev. B (OM-267-0969)
	i. Post Accident Sampling Solenoid Valves (Air)	Valcor Test Report QR-70900-65 (CNM-1210.04-0394) Valcor Test Report QR-52600-5940-2 (OM 360-34)
	j. Post Accident Sampling Solenoid Valves (Liquid)	Target Rock Report No. 2375 (OM 360-32)
	k. High Point Vent System Solenoid Valves	Target Rock Report No. 2375 (OM-360-32)

	Equipment Identification	Seismic Qualification Documentation Reference
	l. RVLIS (Reactor Vessel Level Cabinets Instrumentation System)	Westinghouse Reports WCAP-8687 EQTR-E53A (OM-311.B-24), EQDP-ESE-4 (OM-311.B-25), WCAP8687 EQTR-E04A (OM-311.B-26), WCAP8687 EQAR-E61B (OM-311.B-32), WCAP8687 EQTR-E02A (OM-311.B-35) and E04A-ADD1 (OM-311.B-40).
	m. OTSG Level Control System Cabinets	Wyle Lab Report No. 44662-1 (OM 393-0001).
38.	Reactor Coolant Pump Monitor Cabinet	Rochester Instrument Systems SN 909335 (OM 393-0007)
39.	OSW Upgrade	
	1. Electrical Equipment in the ESV Bldg.	
	a. 600/240/120 VAC, Single-phase 7.5 kVA Transformer (1, 2, and 3SKMT, 3SKNT)	Technical Document No CGD-3014.04-01-0002
	b. 600/240/120 VAC, Single-phase 2 kVA Transformer (1, 2, 3SKPT)	Technical Document No CGD-3014.04-01-0002
	c. 240/120 VAC, Single-phase panelboards (1, 2, and 3SKM, N, P)	Technical Document No CGD-3014.01-24-0002
	d. ESV Local Control Panels (1, 2, 3ESVLCP)	Calc 7330 - Seismic Qualification of Service Water Equipment using NARE Guidelines
	2. Electrical Equipment in the Plant Control Complex.	
	a. ESV Relay Panel (1, 2 ESV1 and 3ESV1, 2, 3)	Calc 7330 - Seismic Qualification of Service Water Equipment using NARE Guidelines
	b. Joslyn/Clark, size #2 "TM" Starter (1 ea. in MCCs 1, 2, 3XS1, 2, 3)	Seismic Qualification Test of a Joslyn/Clark Motor Starter DPC 1393.00-00-0032.
40.	Motor Control Centers (1, 2 and 3XS4, 3XS5, 3XS6)	Qualification of Cutler Hammer MCCs. (OM 308.-0443.001)
41.	600VAC Load Centers (1, 2 and 3X10)	Qualification of ABB Load Centers (OM 303.-0167.001)
42.	Automatic Feedwater Isolation System (AFIS)	Qualification Report of Modified Star Components (OM-1311.D.0020)

	Equipment Identification	Seismic Qualification Documentation Reference
43.	Keowee 13.8 kV Switchgear (KPF1, KPF2)	NLI-Nuclear Logistics Inc. QR-29412516-1 (KM 303. --0037.001)
44.	Keowee Relay Panelboard (EB20)	NLI-Nuclear Logistics Inc. QR-29412516-3 (KM 303. --0042.001)
45.	Generator Bus Transition Junction Box (GEN1, GEN2)	NLI-Nuclear Logistics Inc. QR-29412516-2 (KM 303. --0039.001)
46.	PSW 125 VDC Panelboard (1A, 2A)	Kinectrics K-115099-FR-0001 (KM 303. --0049.002)

Note:

1. Where past and current documentation is shown within the table, these calculations and reports represent the current qualification documents for the equipment.
2. The GE unit formerly in service as the Keowee Main Step-up transformer (which is now the spare) was replaced with a new ABB transformer by EC 95361.

Appendix 3B. Figures

Figure 3-1. Frequency and Mode Shapes - Auxiliary Building - North South Direction (Sheet 1 of 2)

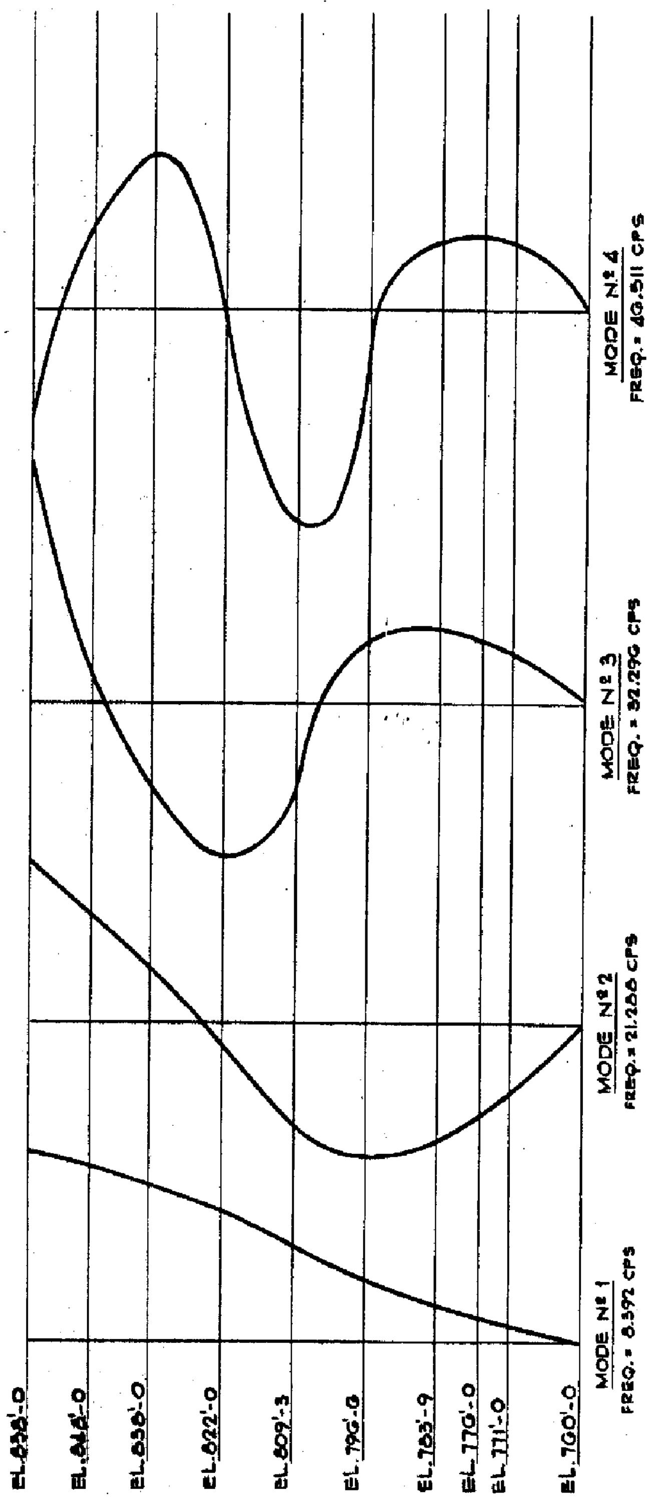


Figure 3-2. Frequency and Mode Shapes - Auxiliary Building - East West Direction (Sheet 2 of 2)

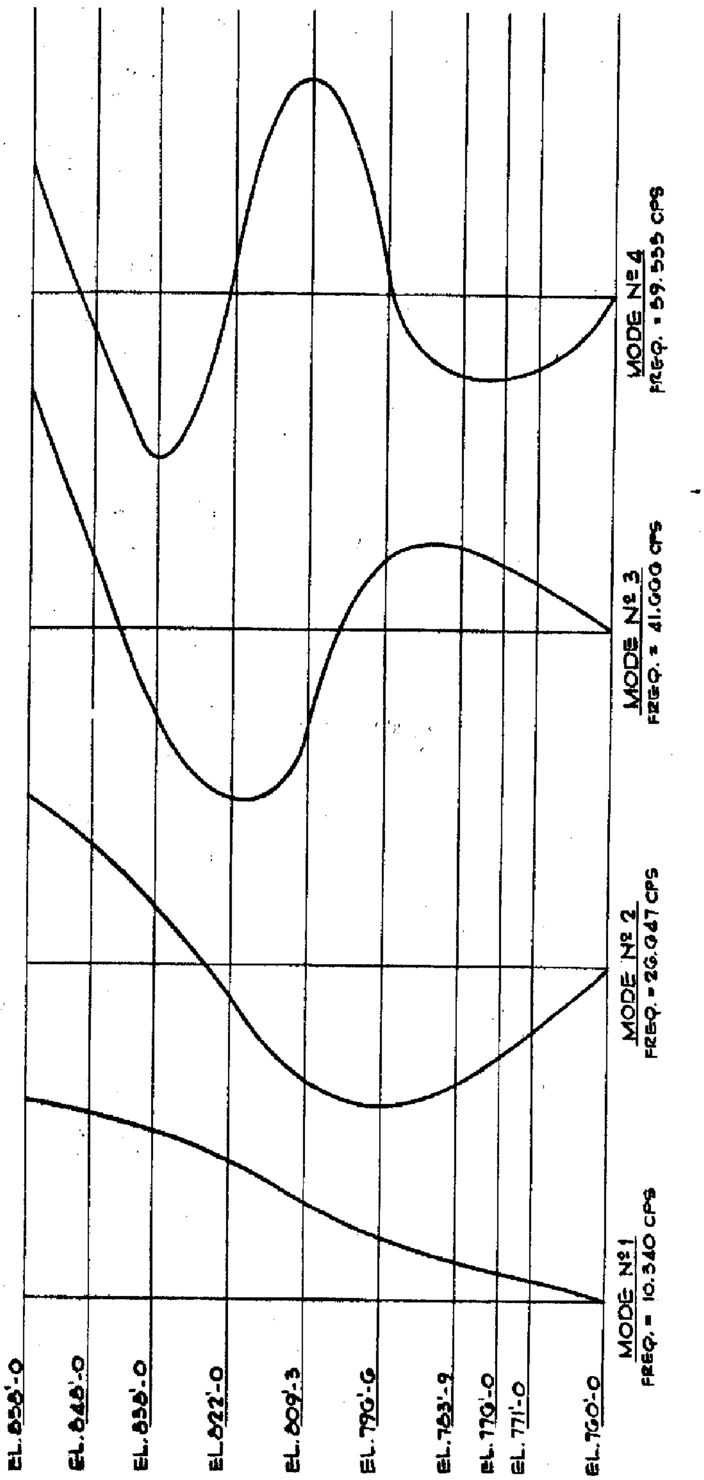


Figure 3-3. Auxiliary Building Mass Model

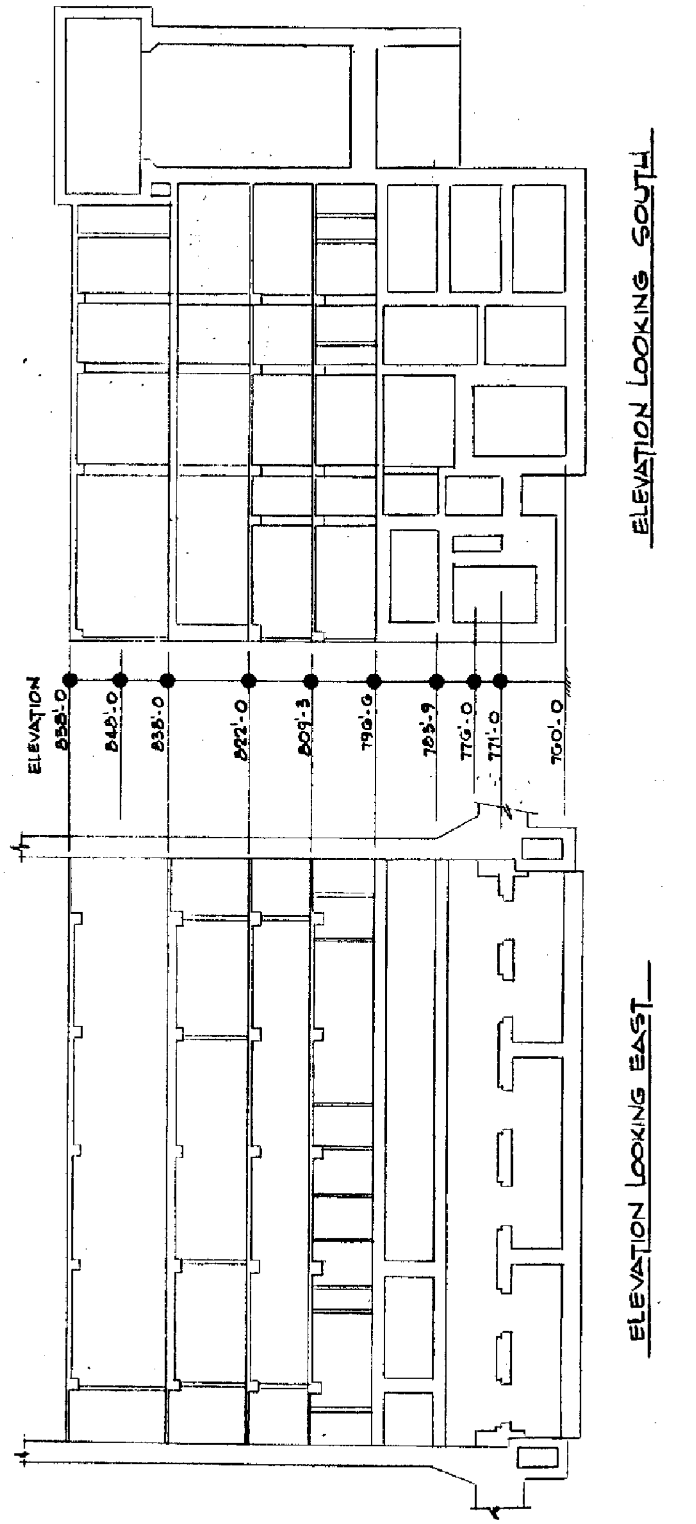


Figure 3-4. Auxiliary Building - East West Direction - Seismic Model Results (Sheet 1 of 2)

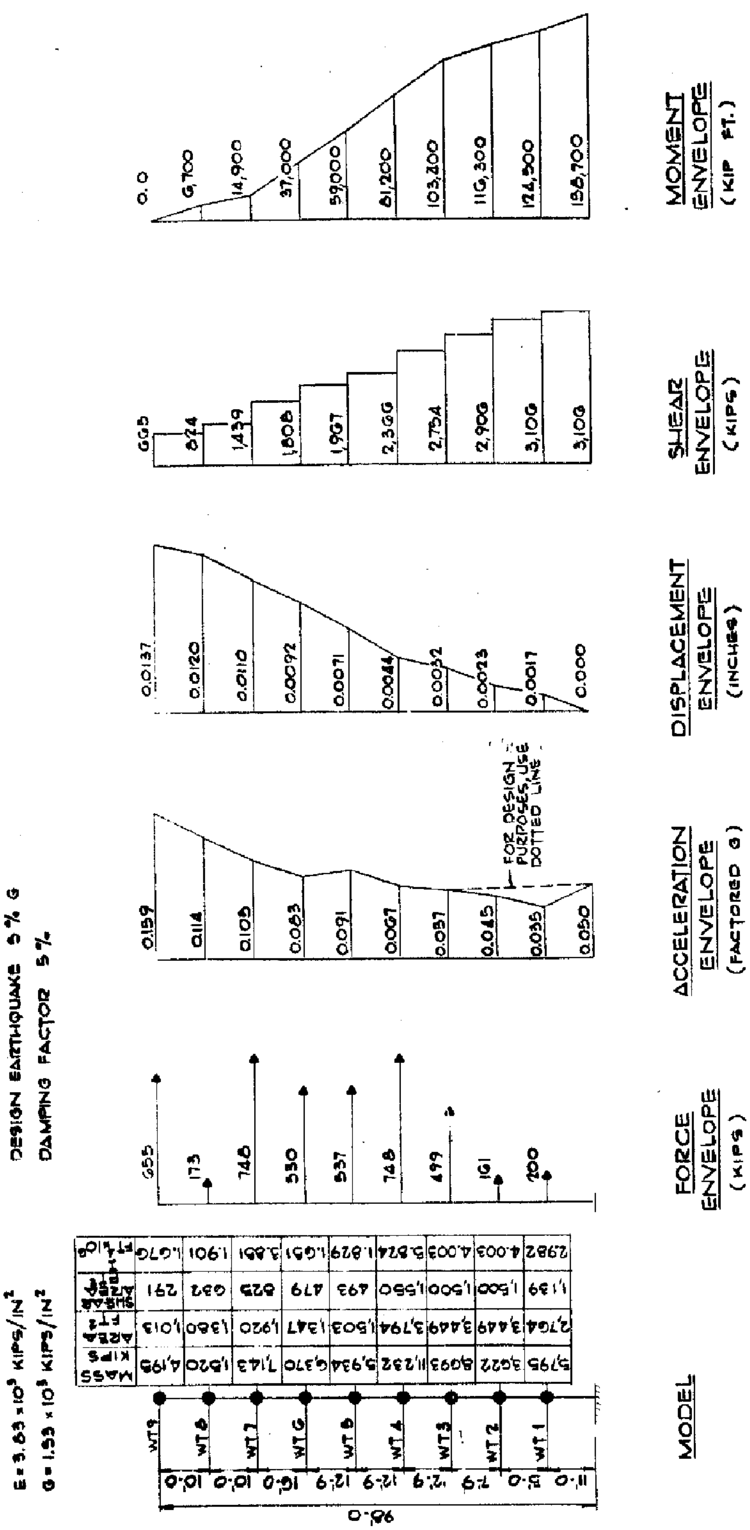


Figure 3-5. Auxiliary Building - North South Direction - Seismic Model Results (Sheet 2 of 2)

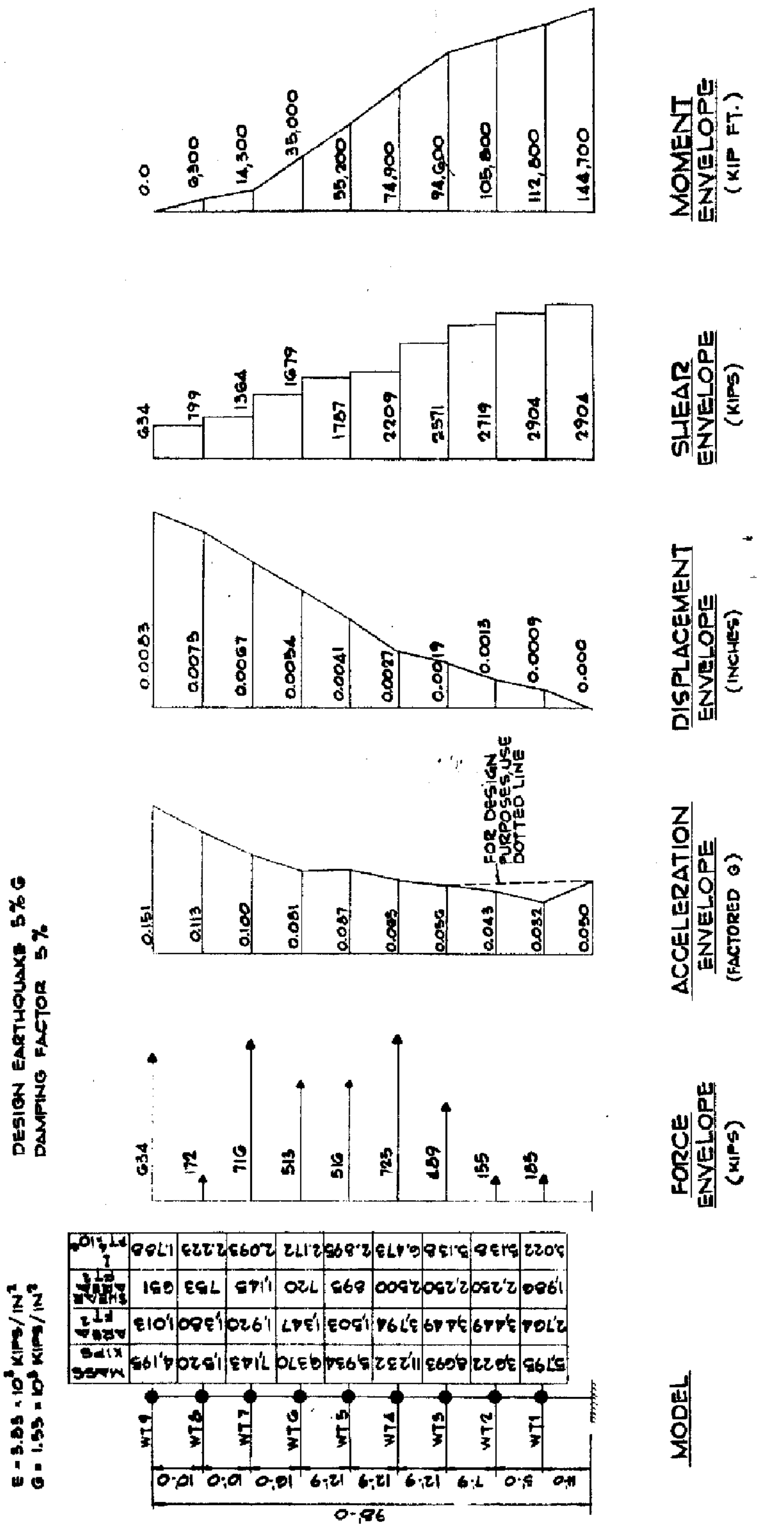


Figure 3-6. Example Spectrum Curves

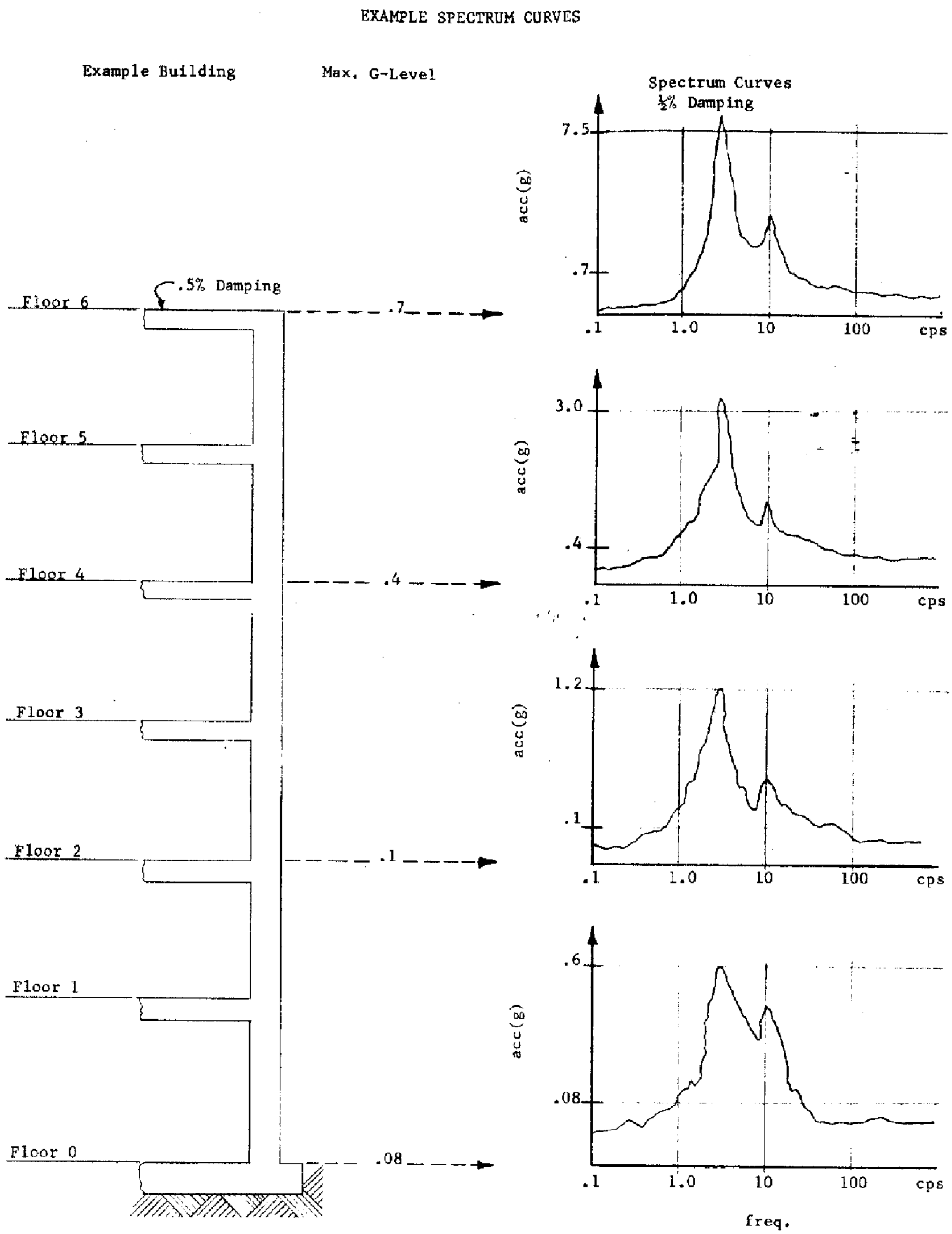


Figure 3-7. Reactor Building - Seismic Model Results (Sheet 1 of 2)

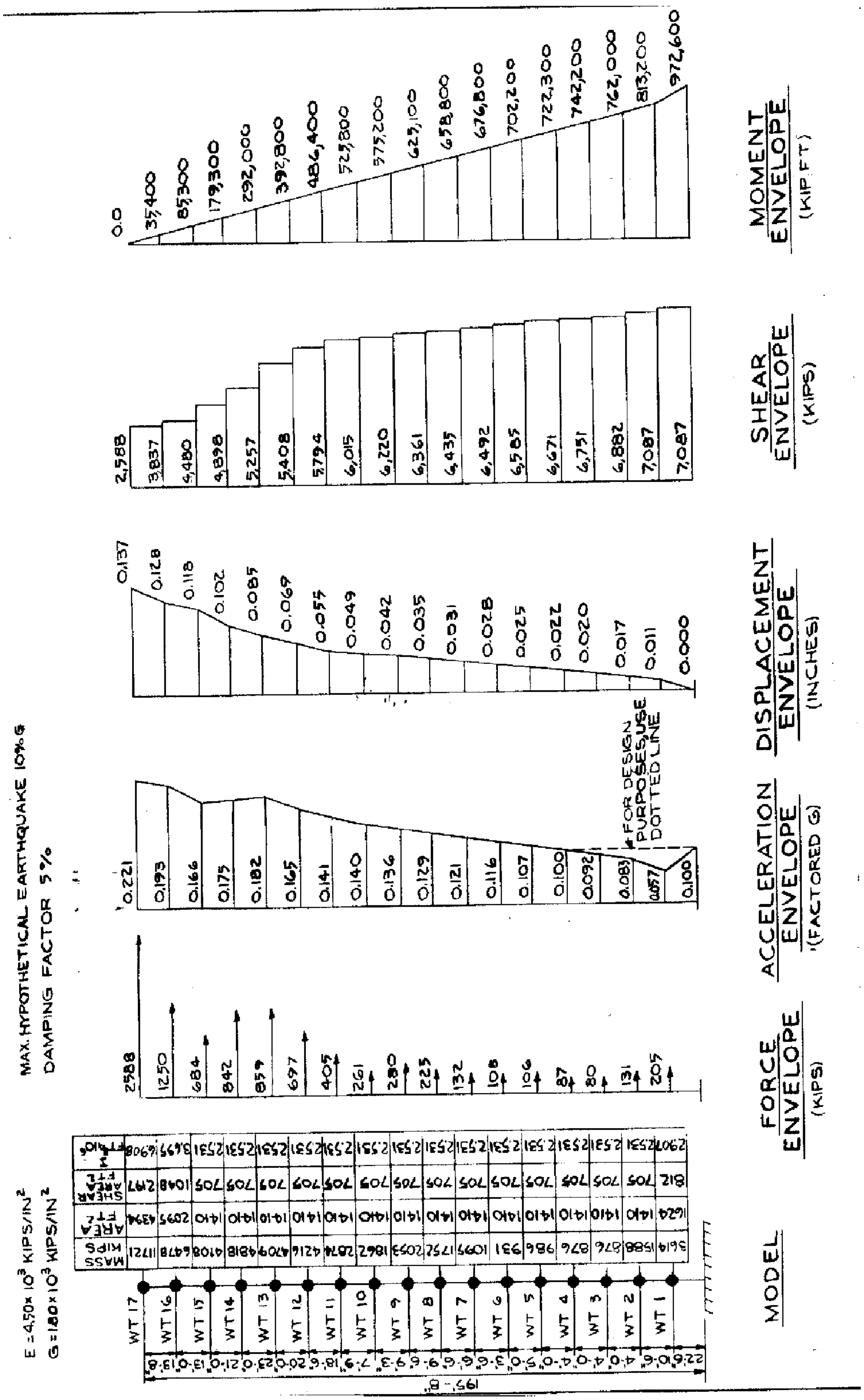


Figure 3-8. Reactor Building - Seismic Model Results (Sheet 2 of 2)

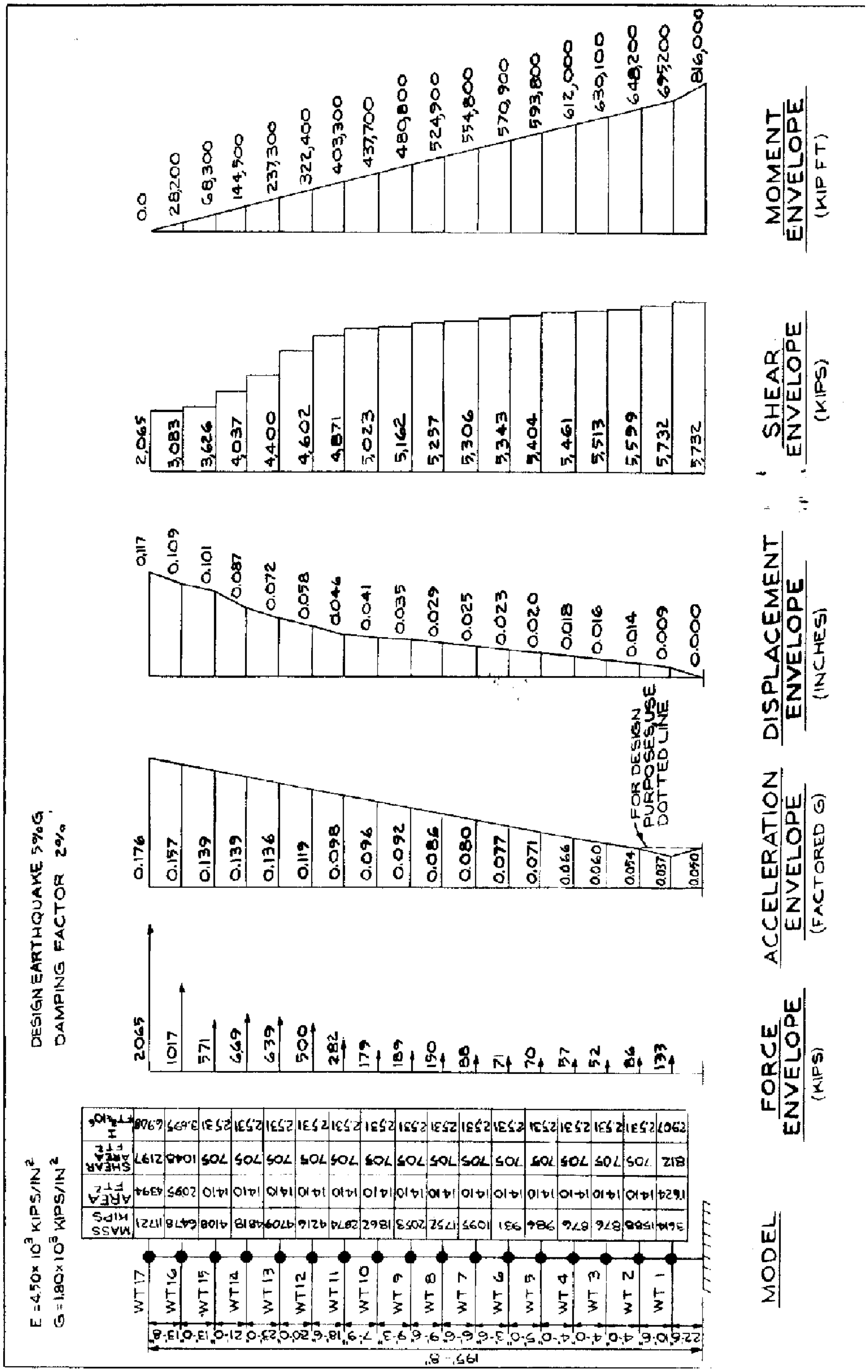


Figure 3-9. Main Steam System West Generator Problem Number 1-01-08. Calculation OSC 1296-06 "HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

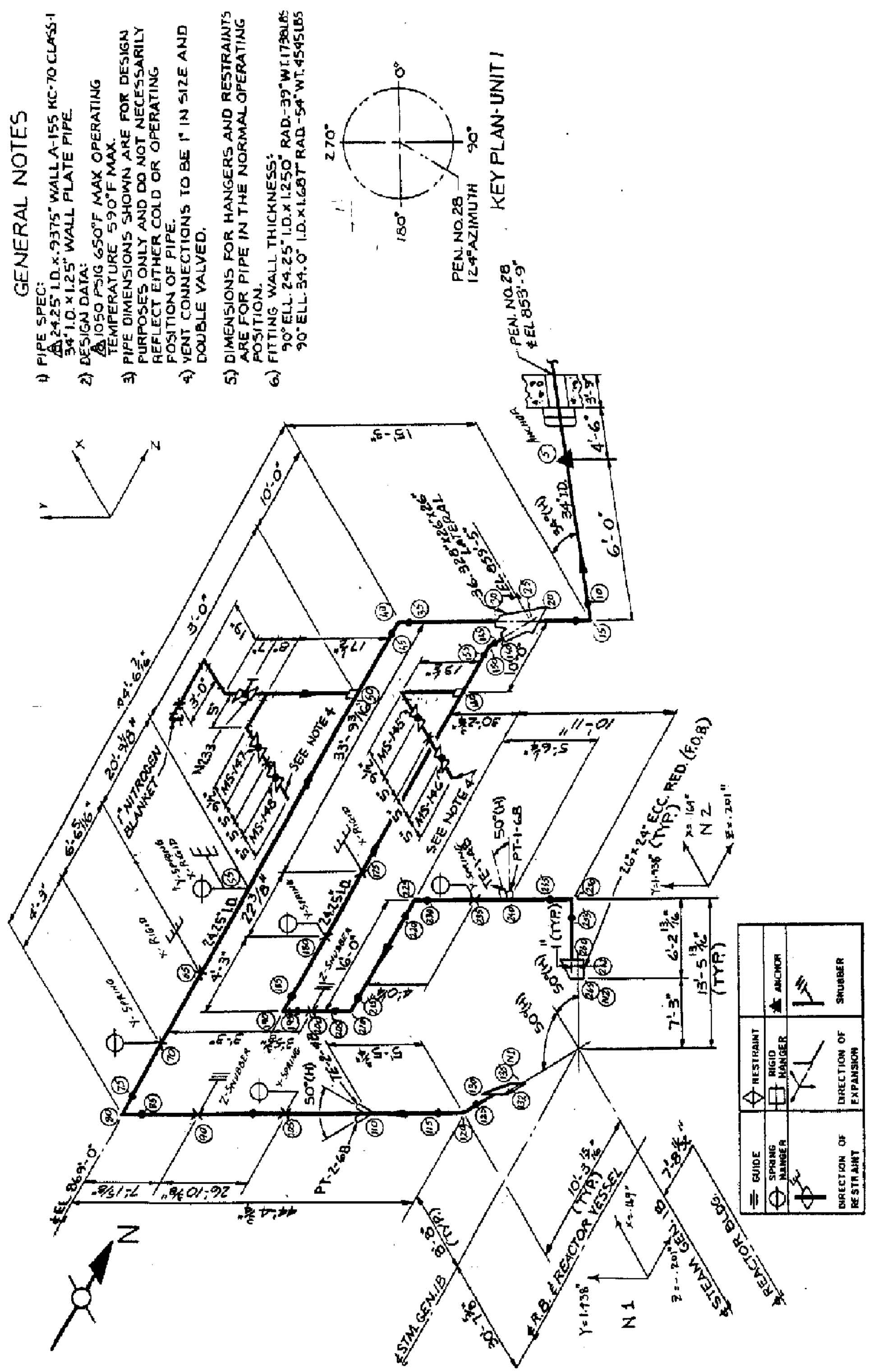


Figure 3-10. Core Flooding Tank 1A Problem Number 1-53-9. Calculation OSC 1300-06 "HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

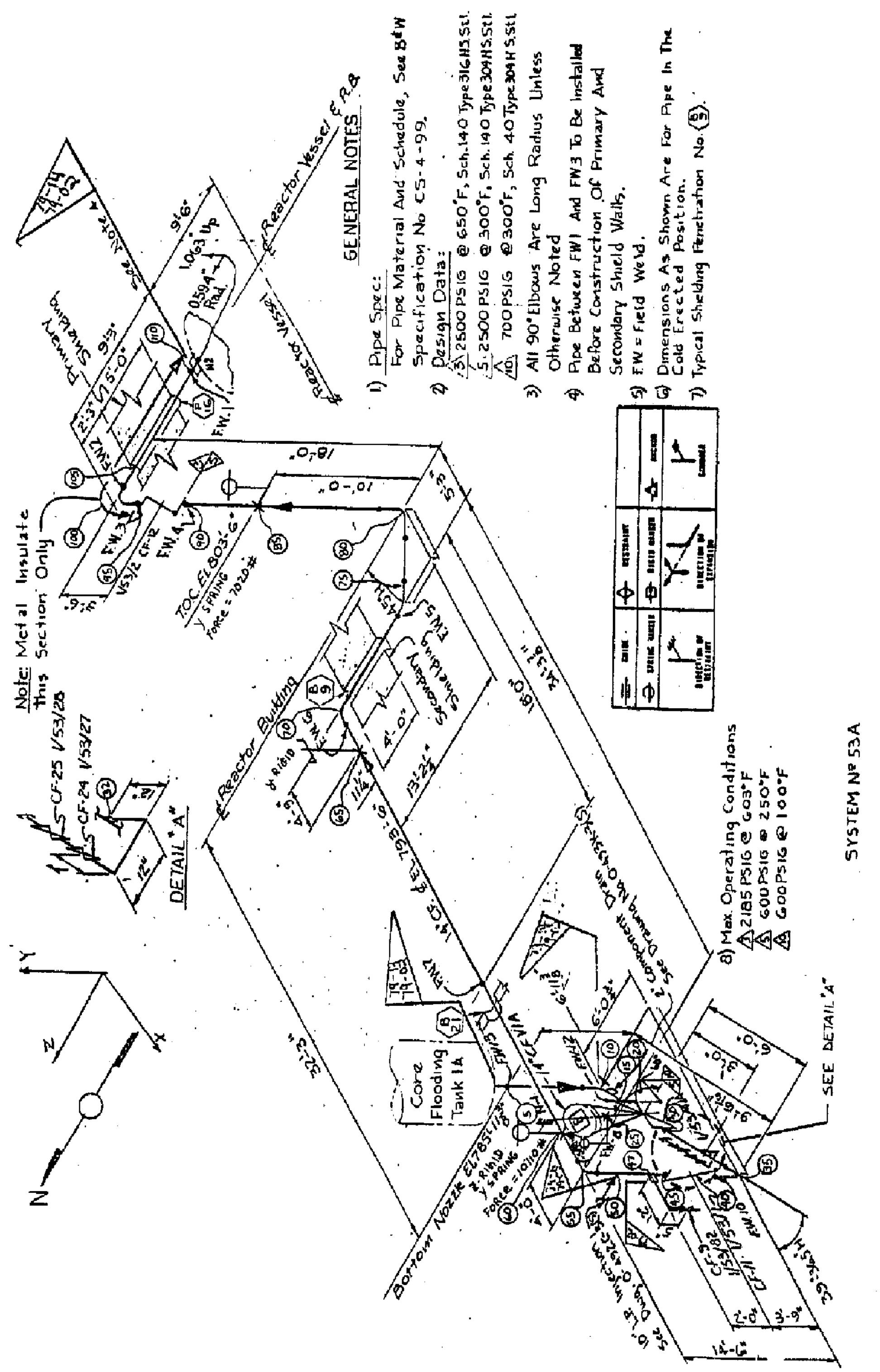


Figure 3-11. Low Pressure Injection System West Generator Problem Number 1-53-9. Calculation OSC 1300-06

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

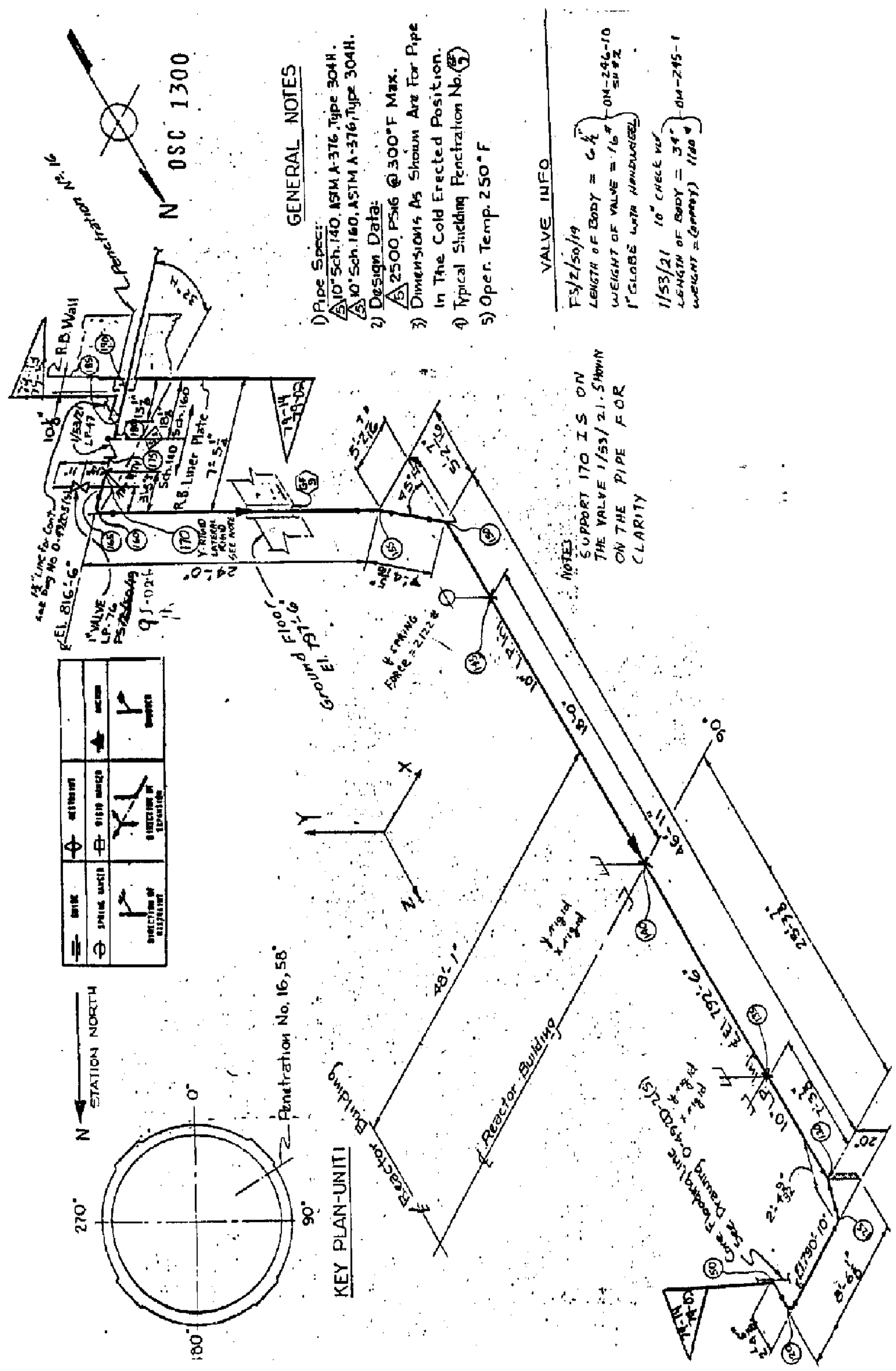


Figure 3-12. RCP Piping to HPI Letdown Coolers Problem Number 1-55-03. Calculation OSC 1660-11 "HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

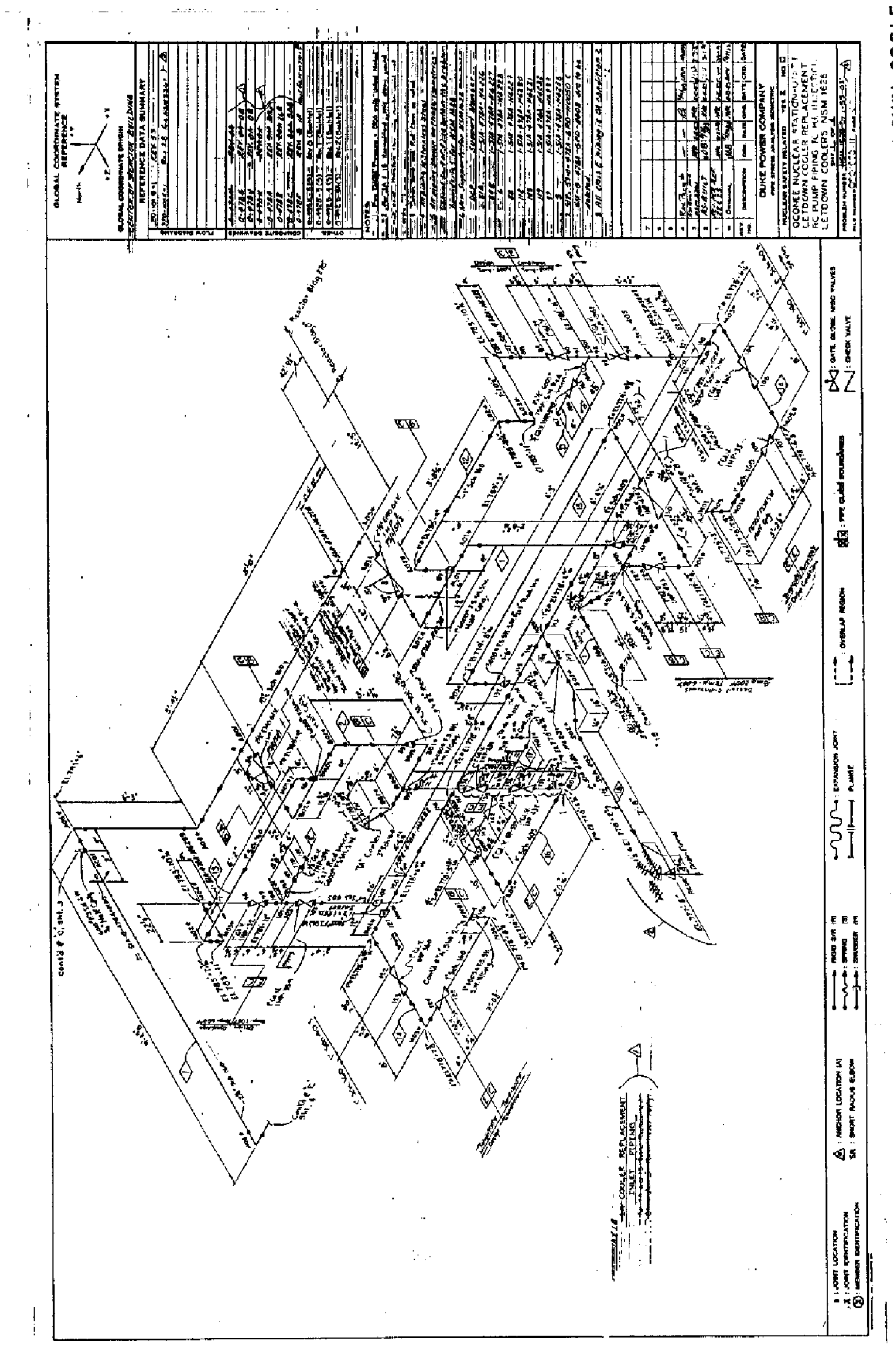


Figure 3-13. RCP Piping to HPI Letdown Coolers Problem Number 1-55-03. Calculation OSC 1660-11 "HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

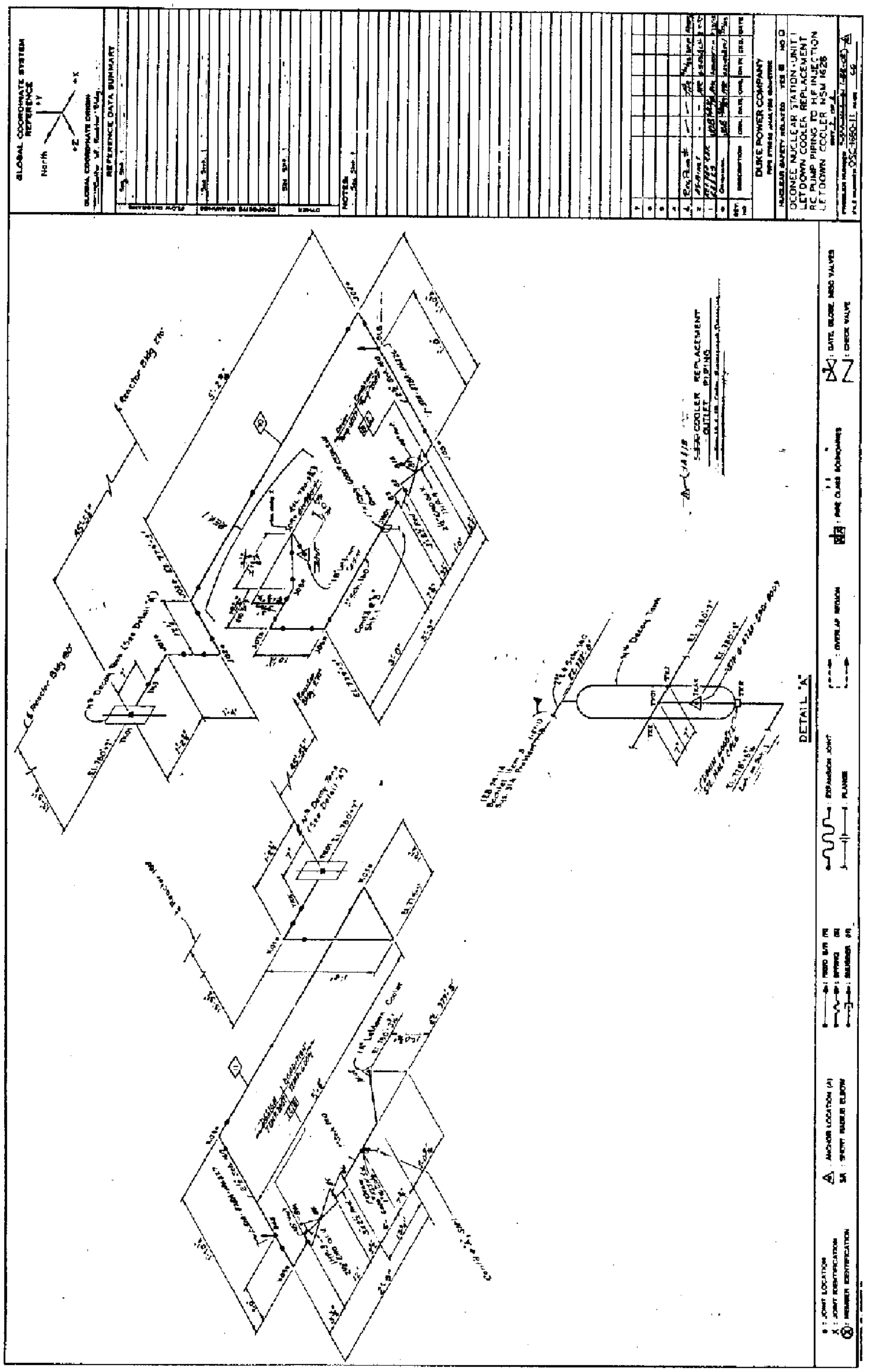


Figure 3-14. RCP Piping to HPI Letdown Coolers Problem Number 1-55-03. Calculation OSC 1660-11

"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

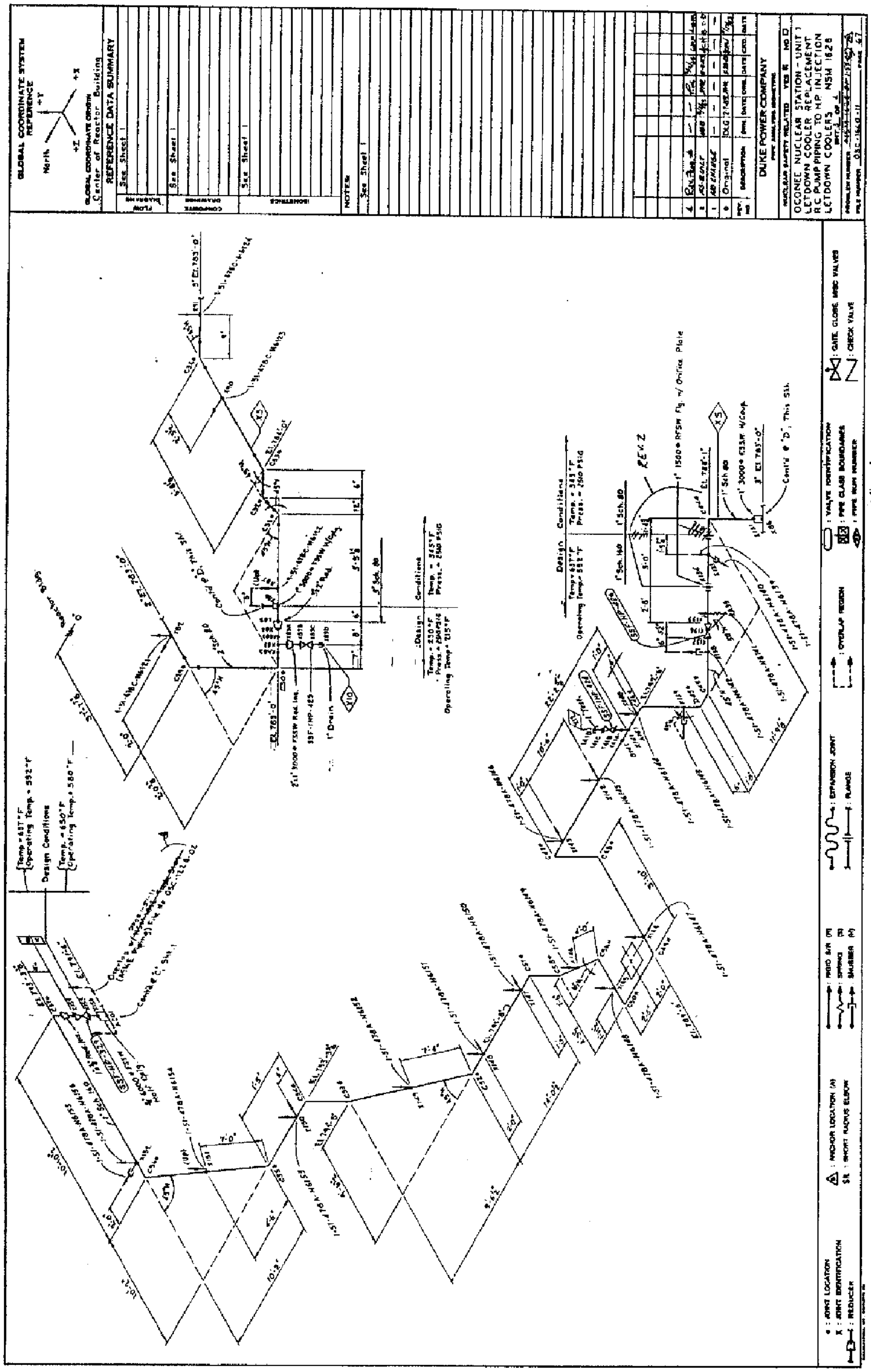


Figure 3-15. RCP Piping to HPI Letdown Coolers Problem Number 1-55-03. Calculation OSC 1660-11 "HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"

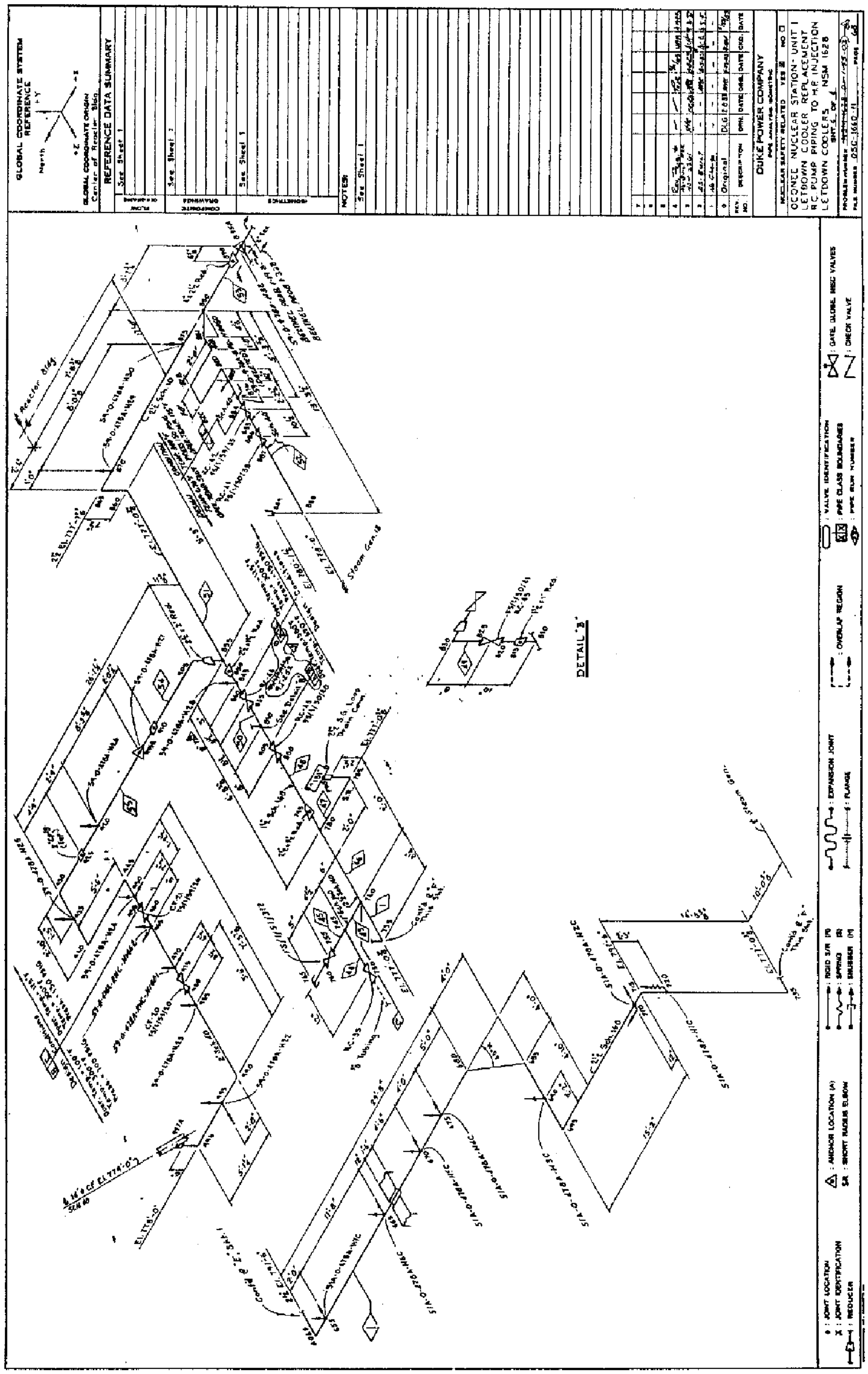
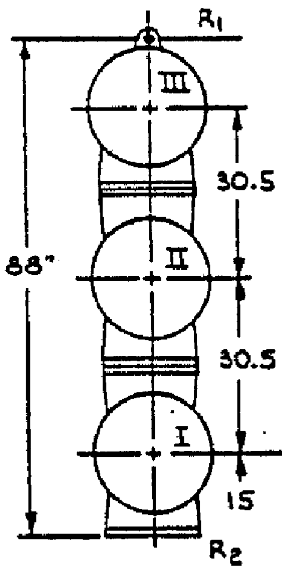
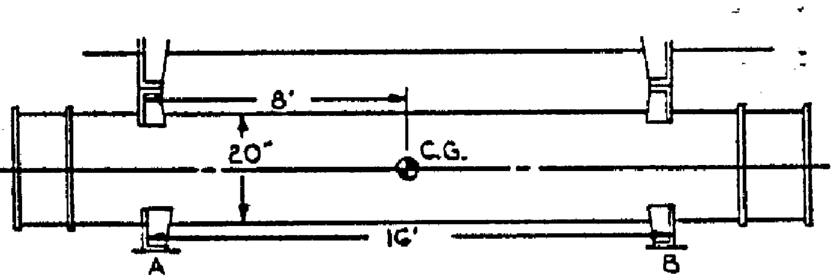


Figure 3-16. Seismic Analysis of Component Coolers

SEISMIC ANALYSIS OF
COMPONENT COOLERS



WEIGHT FULL OF WATER 9000 LBS EACH UNIT
VERTICAL SEISMIC LOAD 1.15 X 9000 = 10.300 LBS/IN
HORIZONAL SEISMIC LOAD .15 X 9000 = 1350 LBS/IN



FOUNDATION LOADS

VERTICAL (DOWNWARDS): 10300 X 3/2 = 15,450 LBS AT EACH SUPPORT
LONGITUDINAL: 1350 X 3 = 4050 LBS AT SUPPORT "A"
0 LBS AT SUPPORT "B" (SLOTTED HOLES)

LATERAL
R_1 = 2 X 675/2 X 88^3 X (15^2 [73 + 2 X 88] + 45.5^2 [42.5 + 2 X 88] + 76^2 [12 + 2 X 88]) = 1660 LBS = TOTAL LOAD ON SEISMIC LUG

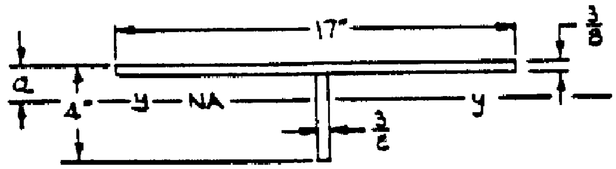
R_2 = 3 X 1350/2 - 1660/2 = 1195 LBS EACH SUPPORT ON FOUNDATION

LATERAL MOVEMENT
675/2 X 88^2 ([73 + 88] + [42.5 + 88] + [12 + 88] = 16.7 IN/LBS
(NEGLIGIBLE)

LOADS ON SUPPORTS OF UNIT I

VERTICAL (COMPRESSIVE)	15450 LBS
LATERAL (SHEAR)	1195 LBS
LONGITUDINAL (SHEAR)	4050 LBS
LONGITUDINAL MOMENT	4050 (15-10) = 20250 IN/LBS
LATERAL MOMENT	NEGLIGIBLE

Figure 3-17. Seismic Analysis of Component Coolers



AREA

$17 \times \frac{3}{8} + 3.625 \times \frac{3}{8}$

$= 6.4 + 1.34 = 7.74 \text{ IN.}^2$

$6.4 \times .186 = 1.19$

$1.34 \times 2.188 = \underline{2.93}$

4.12

$a = 4.12/7.74 = .534 \text{ IN.}$

$$I_{y-y} = 6.4(.534-.186)^2 + 17 \times .375^3/12 + 1.34 \times (2.188-.534)^2 + .375 \times 3.625^3/12$$

$$= .775 + .075 + 3.66 + 1.49 = 6.00 \text{ IN}^4 \quad S.M._{y-y} = \frac{6}{4-.534} = 1.73 \text{ IN}^3$$

STRESSES IN SUPPORTS

COMPRESSIVE	$15450/7.74$	= 2000 PSI
MAX SHEAR	$\sqrt{1195^2 + 4050^2}/7.74$	= 545 PSI
BENDING STRESS	$20250/.173$	= 11700 PSI

MAX STRESS FROM SIMULTANEOUS HORIZONTAL AND VERTICAL ACCEL

$2000 + 11700 = 13700$ PSI

LOADS ON SHELL AT LOWER SUPPORTS

DIRECT SUPPORT LOAD	15450 LBS
LONGITUDINAL MOVEMENT	$4050 \times 6 = 24300$ IN/LBS
INTERNAL PRESSURE	100 PSI

EVALUATION OF LOCALIZED STRESSES IN SHELL AT LOWER SUPPORT USING O ROURKE FORMULAS FOR STRESS AND STRAIN - EDITION 1954 - PAGE 282

$K = .02 - .00012(150-90) = .0128$

EQUIVALENT DIRECT LOAD ON SHELL

$15450 + 24300/\frac{2}{3} \times 10 = 19090$ LBS

DURING SIMULTANEOUS HORIZONTAL AND VERTICAL ACCELERATION

$.0128 \times \frac{19090}{.25^2} \; L_y \frac{20}{.25} = 17100$ PSI

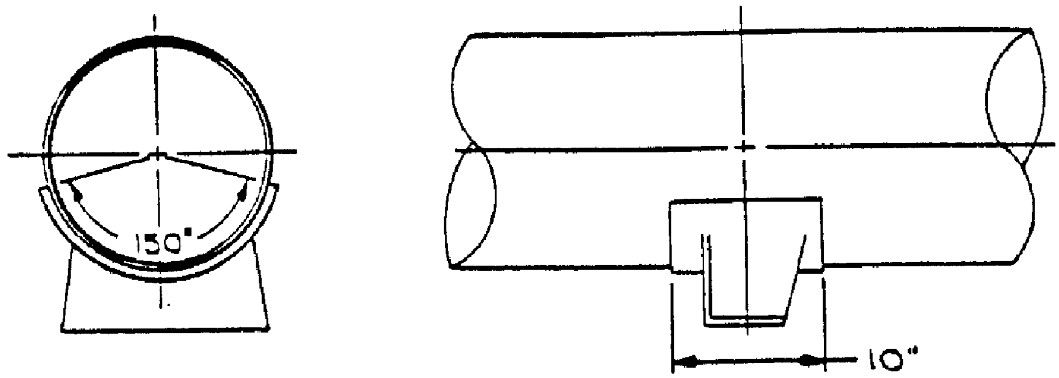
STRESS IN SHELL FROM PRESSURE

$\frac{100 \times 9.75}{.25} + .6 \times 100 = 3960$ PSI

THE SHELL WILL NOT COLLAPSE

Figure 3-18. Seismic Analysis of Component Coolers

TYPICAL SUPPORT SADDLE



SEISMIC LUG

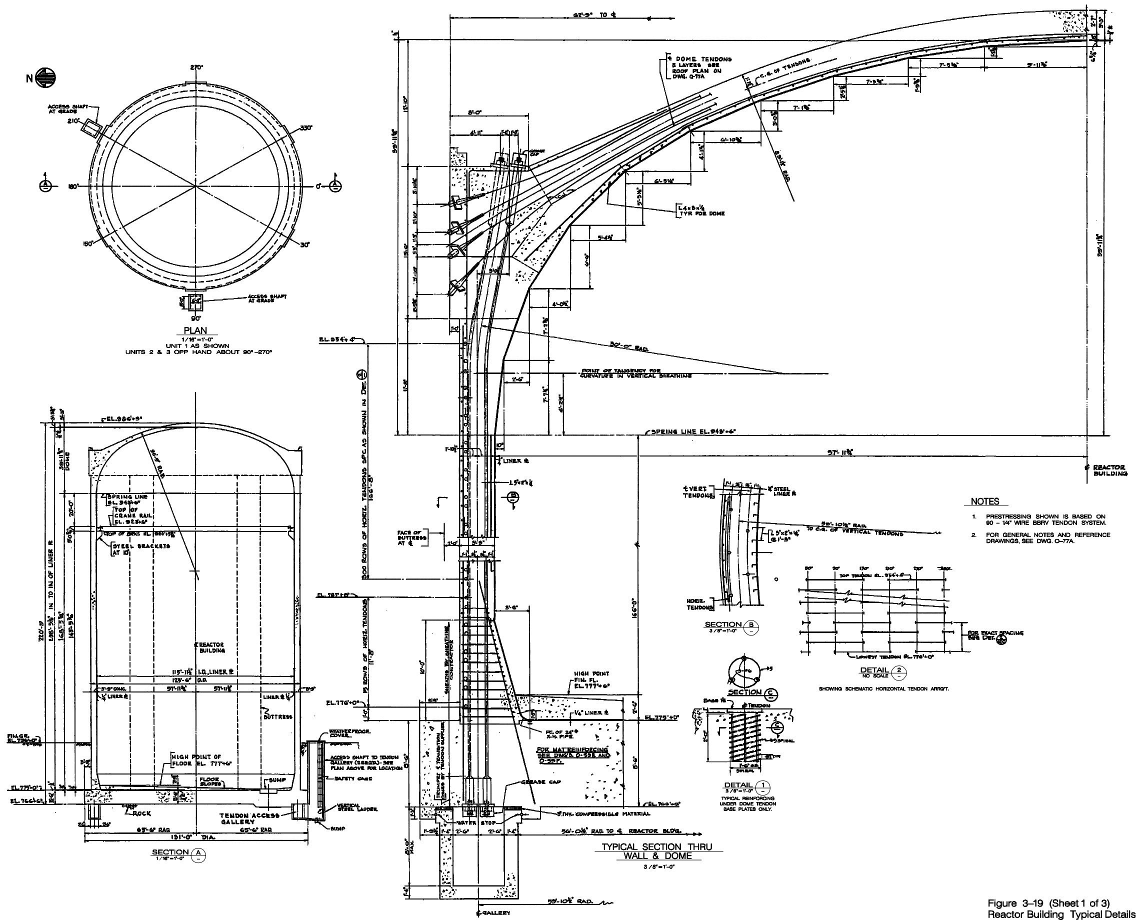
MOMENT $2 \times 1660 = 3320$ IN LBS
SM OF LUG $\frac{3}{4} \times 3^2/6 = 1.13$ IN^2
STRESS IN LUG $3320/1.13 = 2930$ PSI

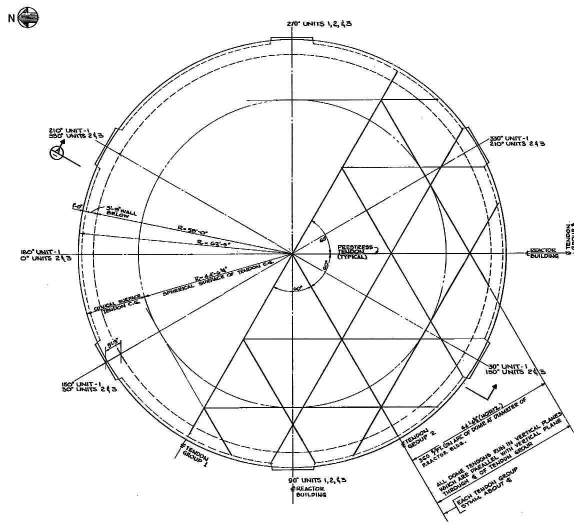
EQUIVALENT DIRECT LOAD ON SHELL
$2 \times 3320/\frac{2}{3} \times 3 = 3320$ LBS

MAX. LOCAL STRESS IN SHELL
$.03 \times \frac{3320}{.25^2}$ $L_y \frac{20}{.25} = 7160$ PSI

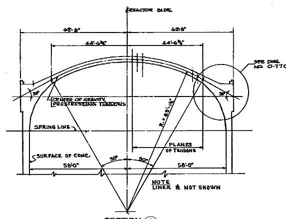
STRESS IN SHELL FROM PRESSURE 3960 PSI
NO PAD REQUIRED

Figure 3-19. Reactor Building Typical Details





ROOF PLAN
1/8" = 1'-0"
SHOWING PRESTRESSING TENDON ARRG'T.



SECTION A
1/8" = 1'-0"

GENERAL NOTES

1. UNLESS NOTED OTHERWISE ON THE DRAWINGS OR IN THE SPEC. NO. OS-161, ALL WORK SHALL BE IN ACCORDANCE WITH A.C.I. CODE 318-63.
2. CONCRETE STRENGTH SHALL BE AS FOLLOWS:
   WALL & DOME = 5000 PSI @ 28 DAYS
   FOUNDATION SLAB = 5000 PSI @ 28 DAYS
3. ASSUMED MODULUS OF ELASTICITY OF CONCRETE IS 3×10^6.
4. NON PRESTRESSED REINFORCING IS BY OWNER.
5. PRESTRESS LOSSES SHALL BE BASED ON THE FOLLOWING:
   DUE TO CREEP IN CONC. – 420×10^{-6} PSI
   DUE TO SHRINKAGE IN CONC. – 50×10^{-6} PSI
6. ALL PRESTRESSING FORCES ARE MINIMUM REQUIRED EFFECTIVE PRESTRESS VALUES AFTER LOSSES HAVE OCCURRED.
7. HORIZONTAL PRESTRESSING FORCES ARE SHOWN IN EACH BAY AND ARE CONSTANT BETWEEN THE BUTTRESSES.
8. THE TYPICAL DETAILS OF PRESTRESSING AROUND OPENINGS AND PENETRATIONS INDICATE THE GENERAL ARRANGEMENT ONLY. ACTUAL DESIGN DETAILS, INCLUDING THE SIZE, SPACING AND LAYOUT SHALL BE DEVELOPED BASED ON GENERAL ARRANGEMENT SHOWN.
9. THE PRESTRESSING ARRANGEMENT SHOWN ON THE DRAWING IS BASED ON THE BBRV, 1/4" 90 WIRE SYSTEM AND IS FOR INFORMATION AND GUIDANCE ONLY.
10. TENDON RELAXATION LOSS SHALL BE BASED ON A DESIGN LIFE OF 40 YEARS AND AN AVERAGE SERVICE TEMPERATURE OF 70°F.
11. BEARING PLATE THREADED HOLEDS TO BE PLUGGED WITH BOLTS PRIOR TO APPLYING COATING SYSTEM.

ITEM #90 (Furn. by Prescon Corp.)
COVERS THE FURN OF PRESTRESS SYSTEM FOR UNITS 1 & 2.

ITEM #90-1 (Furn. by Prescon Corp.)
COVERS THE FURN. OF PRESTRESS SYSTEM FOR UNIT 3.

ITEM #90-3 (Furn. in field)
COVERS THE FURN. OF BOLTS TO PLUG BEARING PLATE HOLES.

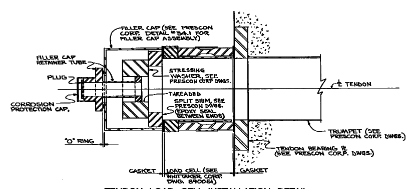
ITEM #93-1 (Furn. by Viscosity Oil)
COVERS THE FURN. OF TENDON SHEATH FILLER MATERIAL.

REFERENCE DRAWINGS

PRESTRESSING REQUIREMENTS, ROOF & MISC. DET.	O-77A
PRESTRESSING REQUIREMENTS, WALL DETAILS	O-77B
PRESTRESSING REQUIREMENTS, TYP. DETAILS	O-77C
PRESTRESSING REQUIREMENTS, HATCHES	O-77D
POST TENSIONING STRESSING COMPONENTS DETAILS	O-77E

REFERENCE SPECIFICATIONS

POST TENSIONING SYSTEM	OS-161
PRESTRESSING TENDON SHEATHS	OS-161-1
TENDON SHEATH FILLER MATERIAL	OS-161-3



TENDON LOAD CELL INSTALLATION DETAIL
(FOR LOCATION OF LOAD CELLS, SEE O-78A)

Figure 3-19 (Sheet 2 of 3)
Reactor Building Typical Details

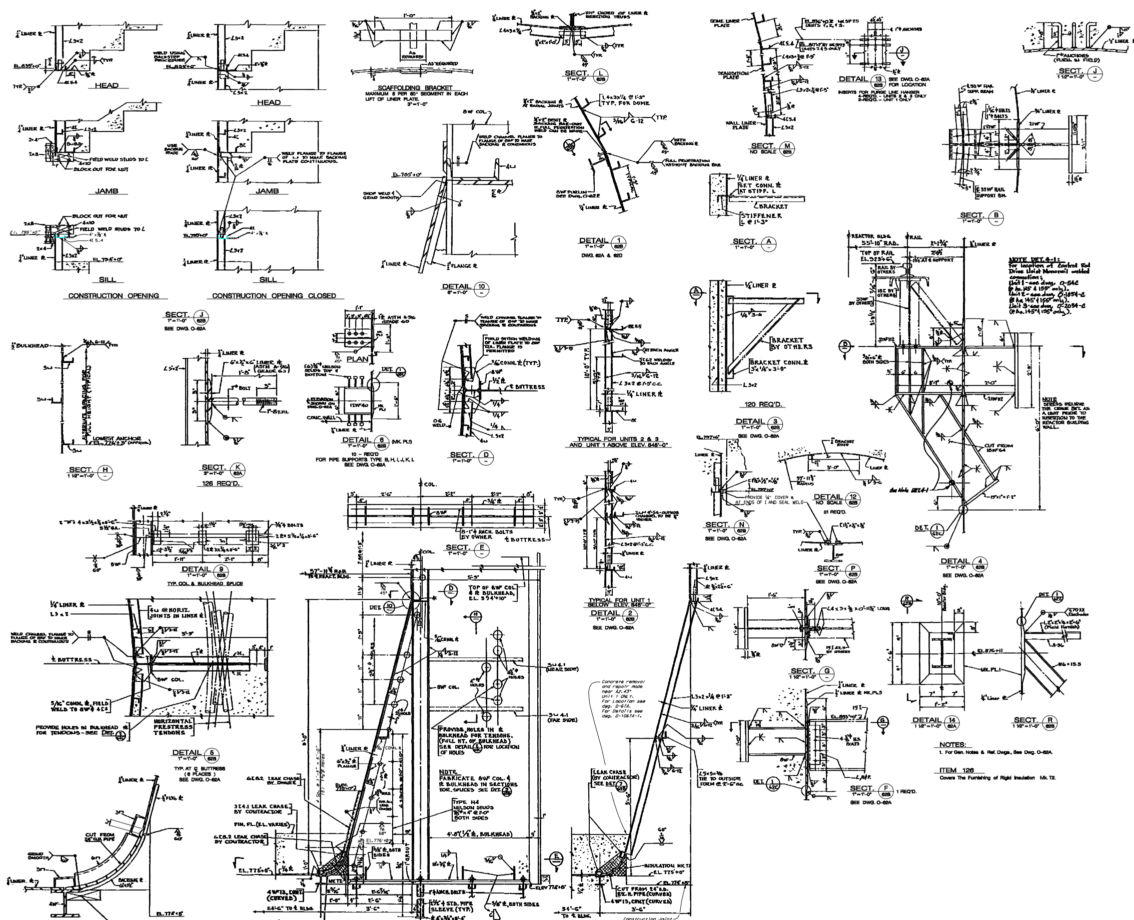


Figure 3-19 (Sheet 3 of 3)
Reactor Building Typical Details

Figure 3-20. Typical Electrical and Piping Penetrations

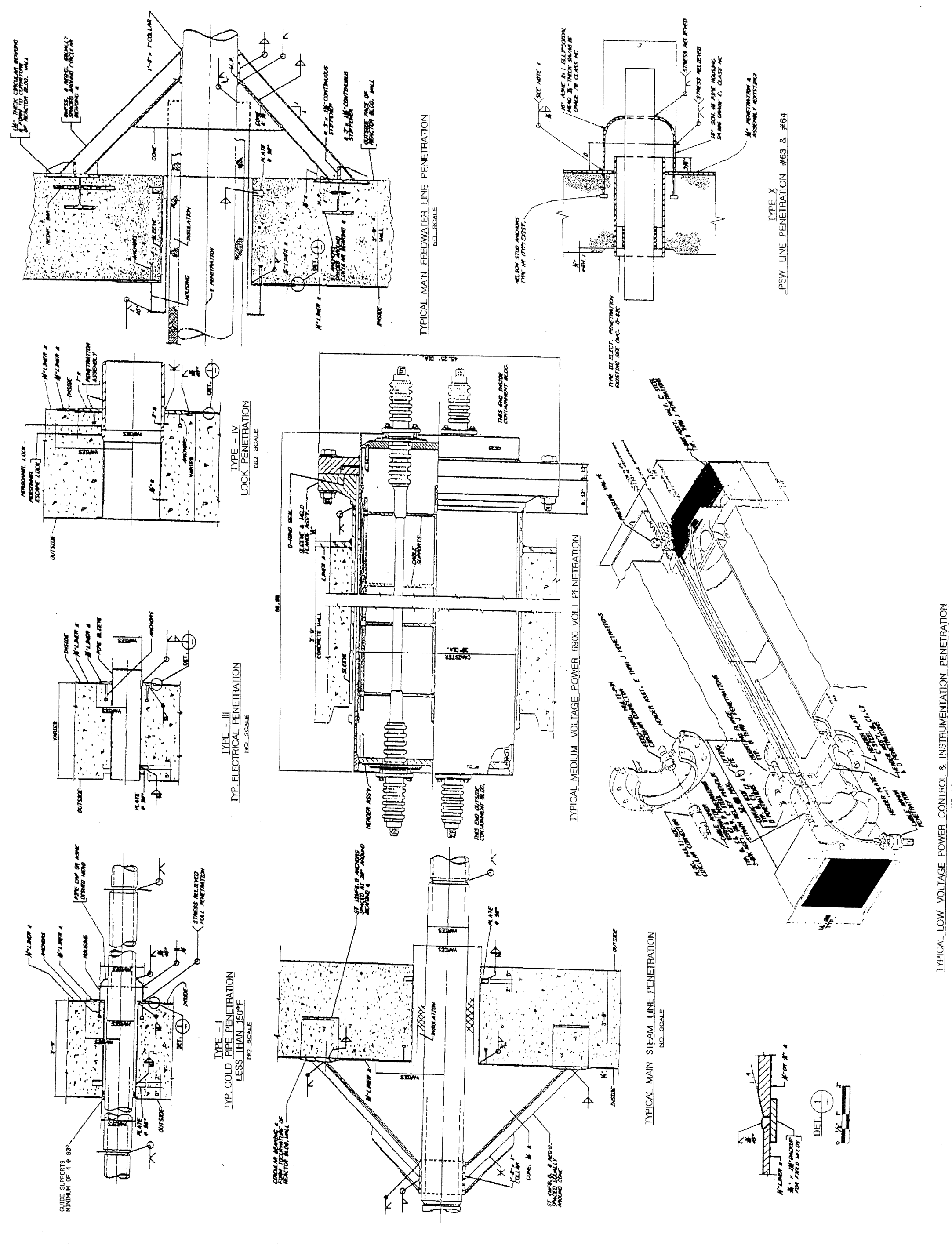


Figure 3-21. Details of Equipment Hatch and Personnel Hatch

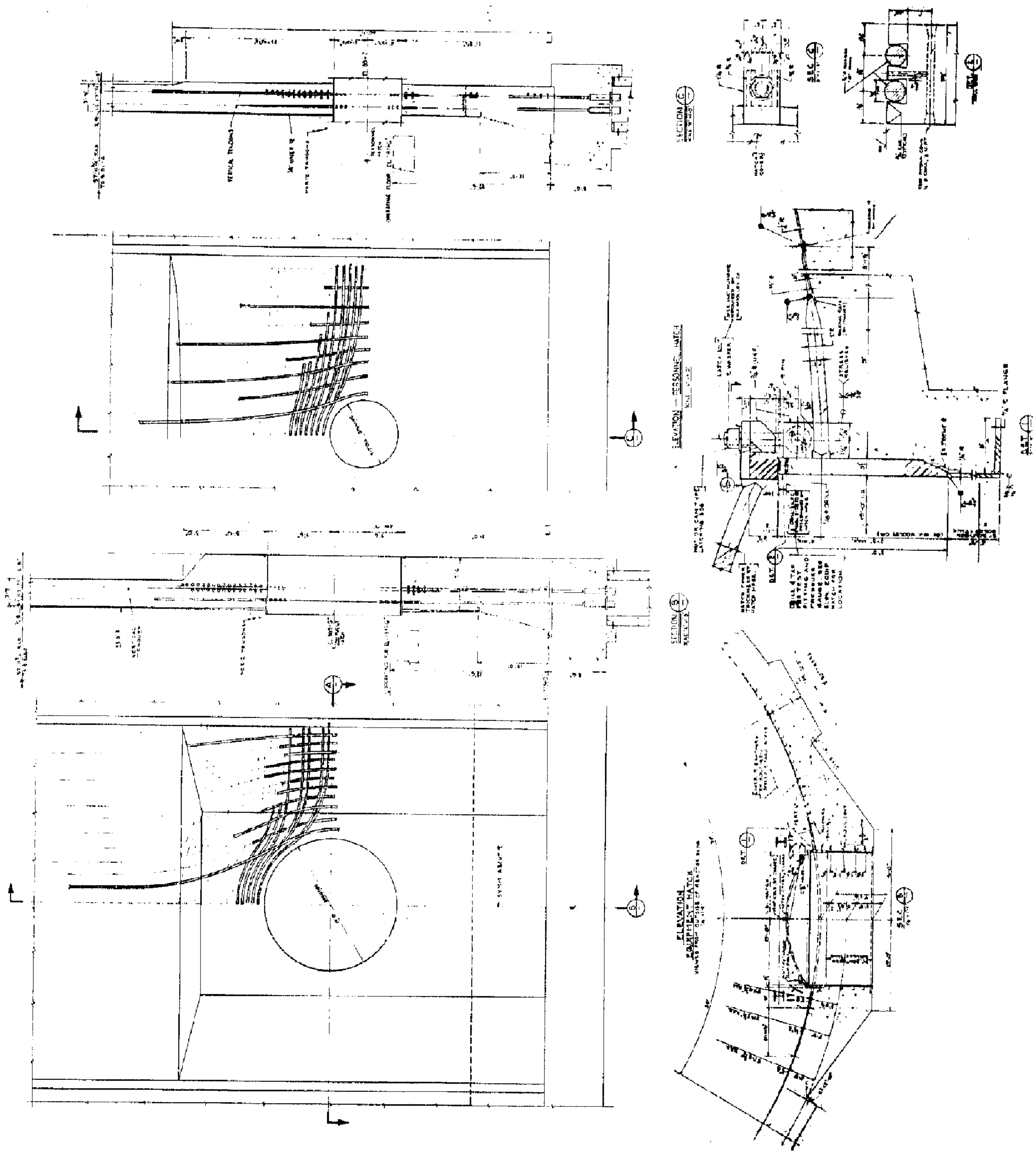


Figure 3-22. Reactor Building Finite Element Mesh

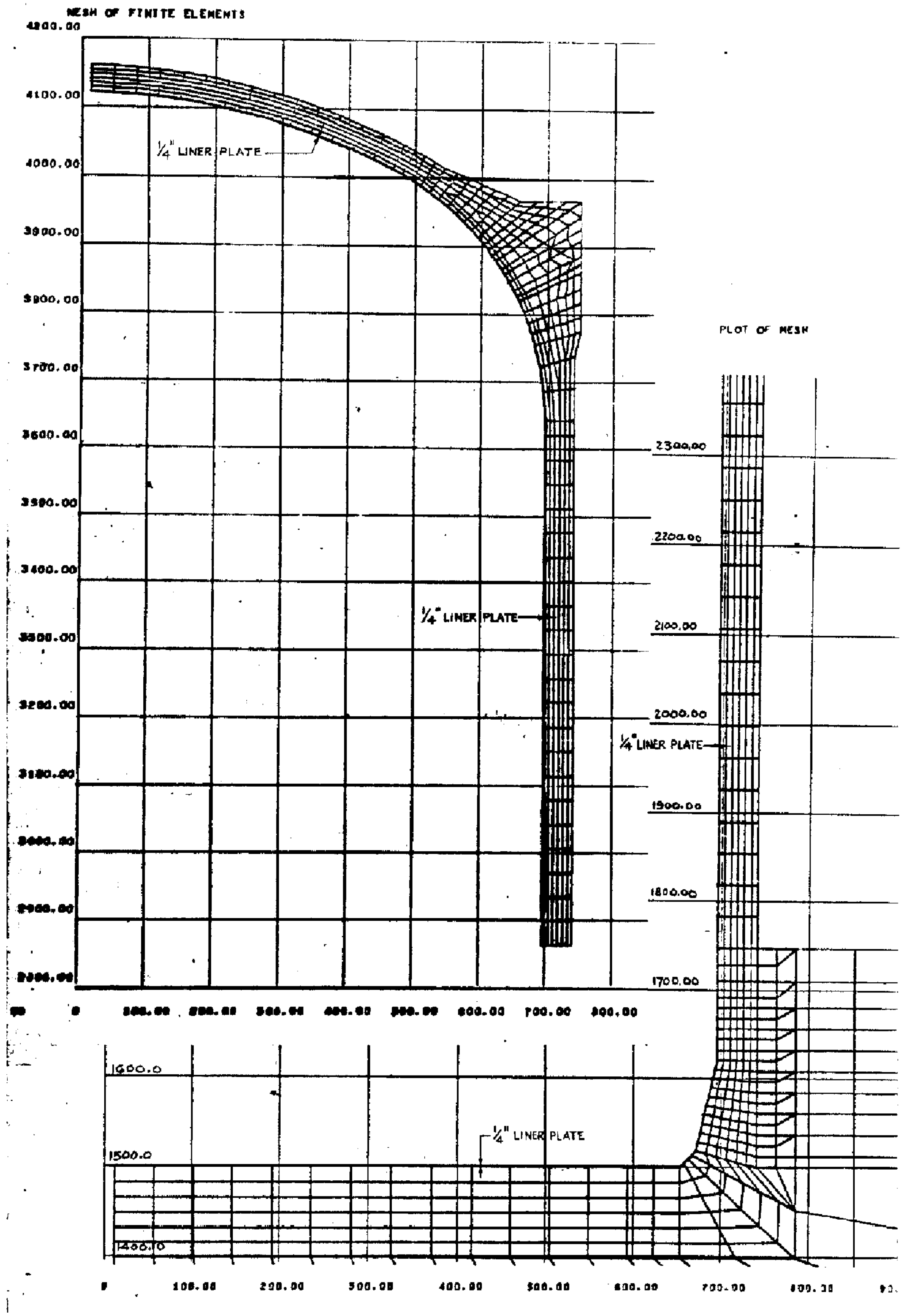


Figure 3-23. Reactor Building Finite Element Mesh

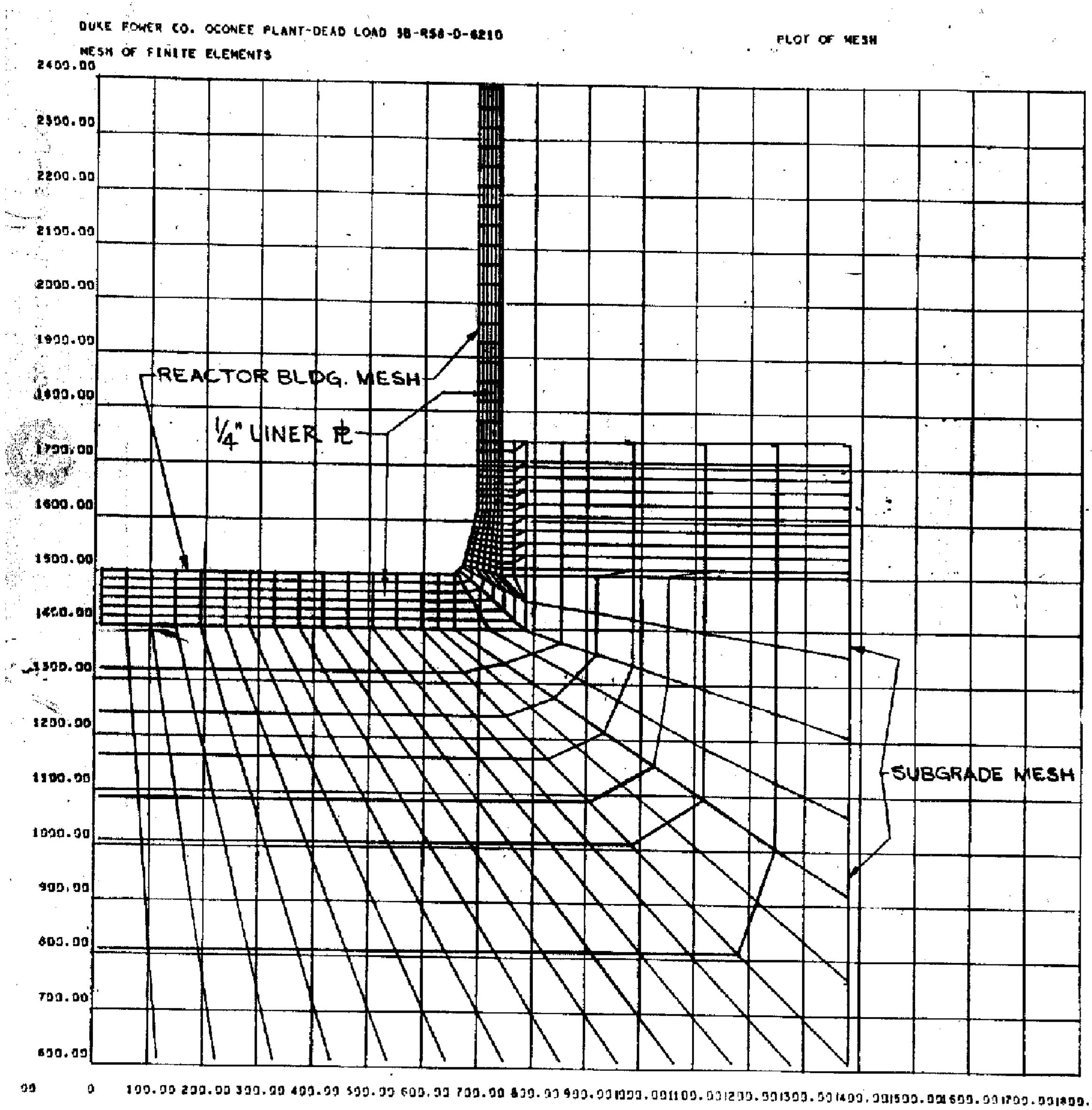


Figure 3-24. Reactor Building Thermal Gradient

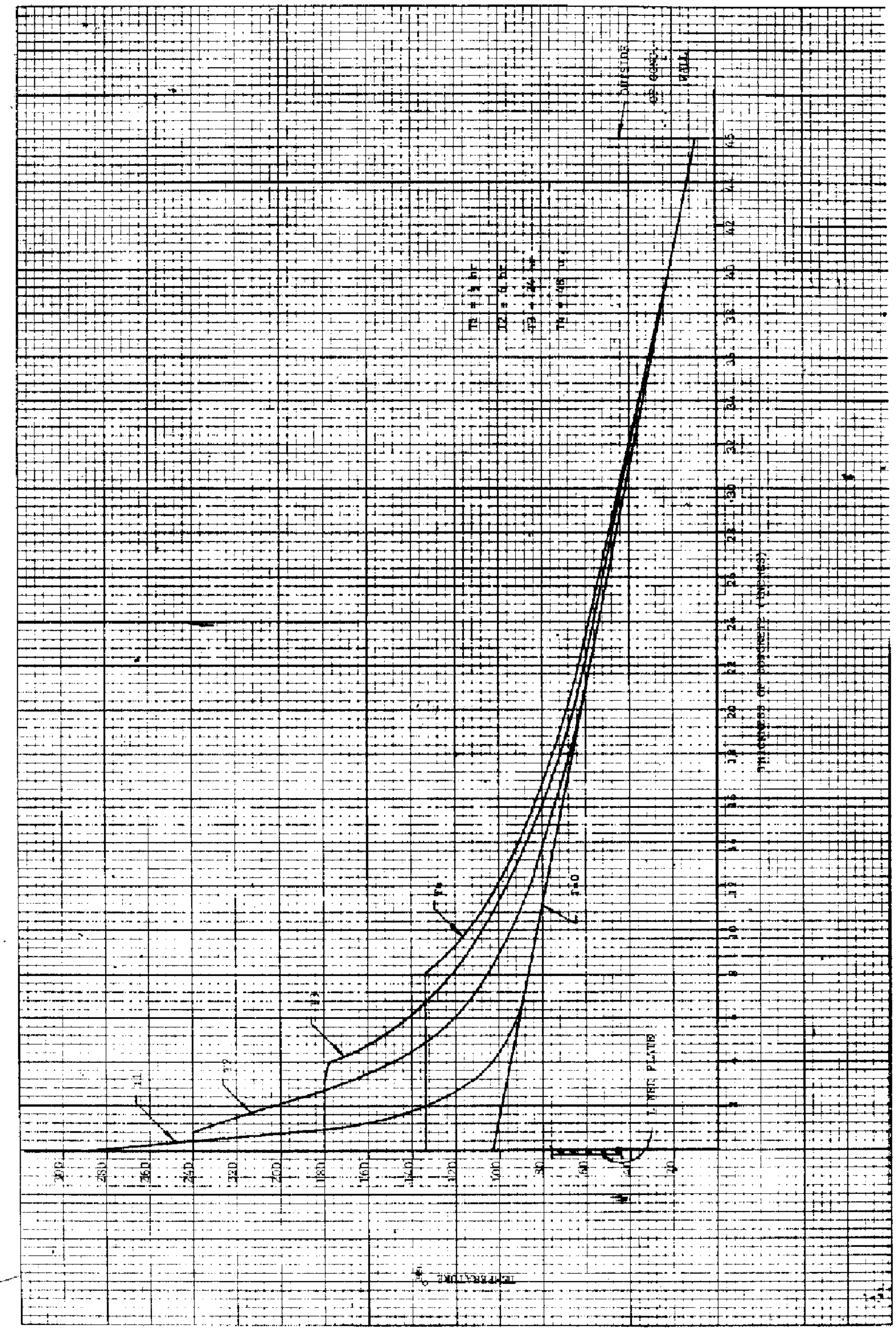
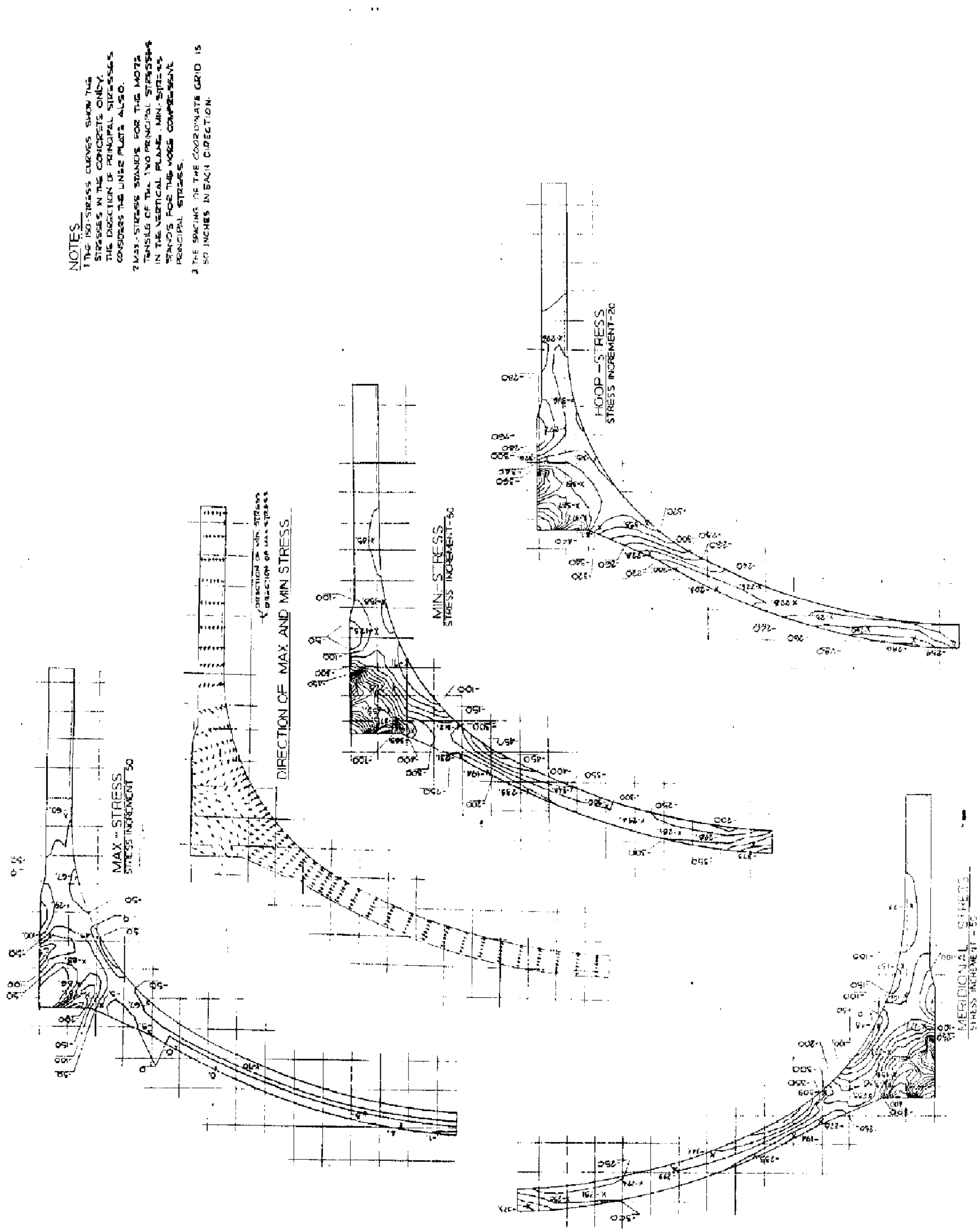
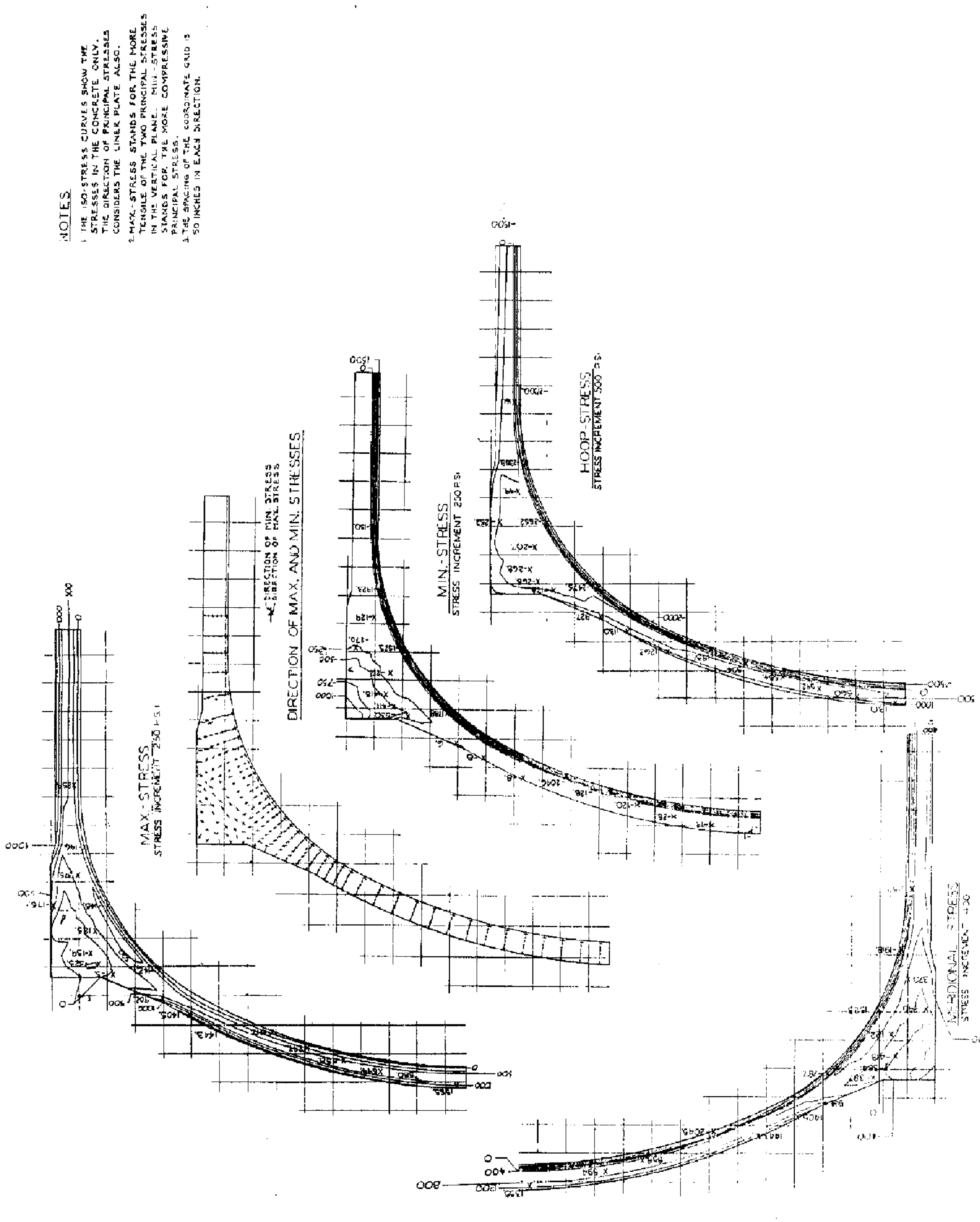
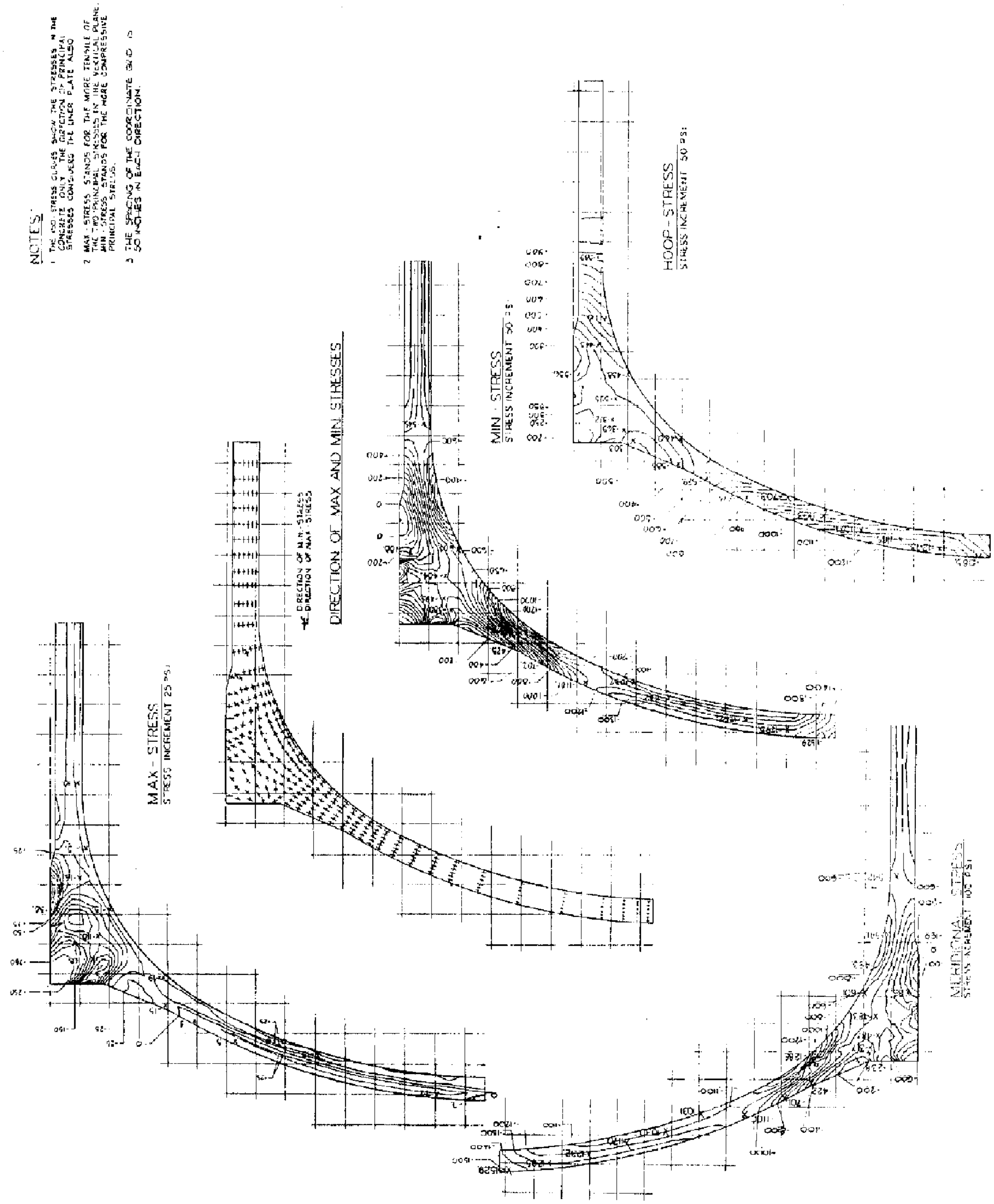


Figure 3-25. Reactor Building Isostress Plot Wall and Dome




NOTES
1. THE ISO-STRESS CURVES SHOW THE STRESSES IN THE CONCRETE ONLY. THE DIRECTION OF PRINCIPAL STRESSES CONSIDERS THE LINER PLATE ALSO.
2. MAX.-STRESS STANDS FOR THE MORE TENSILE OF THE TWO PRINCIPAL STRESSES IN THE VERTICAL PLANE. MIN.-STRESS STANDS FOR THE MORE COMPRESSIVE PRINCIPAL STRESS.
3. THE SPACING OF THE COORDINATE GRID IS 50 INCHES IN EACH DIRECTION.
MAX.-STRESS
STRESS INCREMENT 250 P.S.I.
DIRECTION OF MIN. STRESS
DIRECTION OF MAX. STRESS
DIRECTION OF MAX. AND MIN. STRESSES
MIN.-STRESS
STRESS INCREMENT 250 P.S.I.
HOOP-STRESS
STRESS INCREMENT 500 P.S.I.
MERIDIONAL STRESS
STRESS INCREMENT 400


NOTES:
MAX - STRESS
STRESS INCREMENT 25 PSI
DIRECTION OF MAX AND MIN STRESSES
MIN - STRESS
STRESS INCREMENT 50 PSI
HOOP - STRESS
STRESS INCREMENT 50 PSI
MERIDIONAL STRESS
STRESS INCREMENT 100 PSI

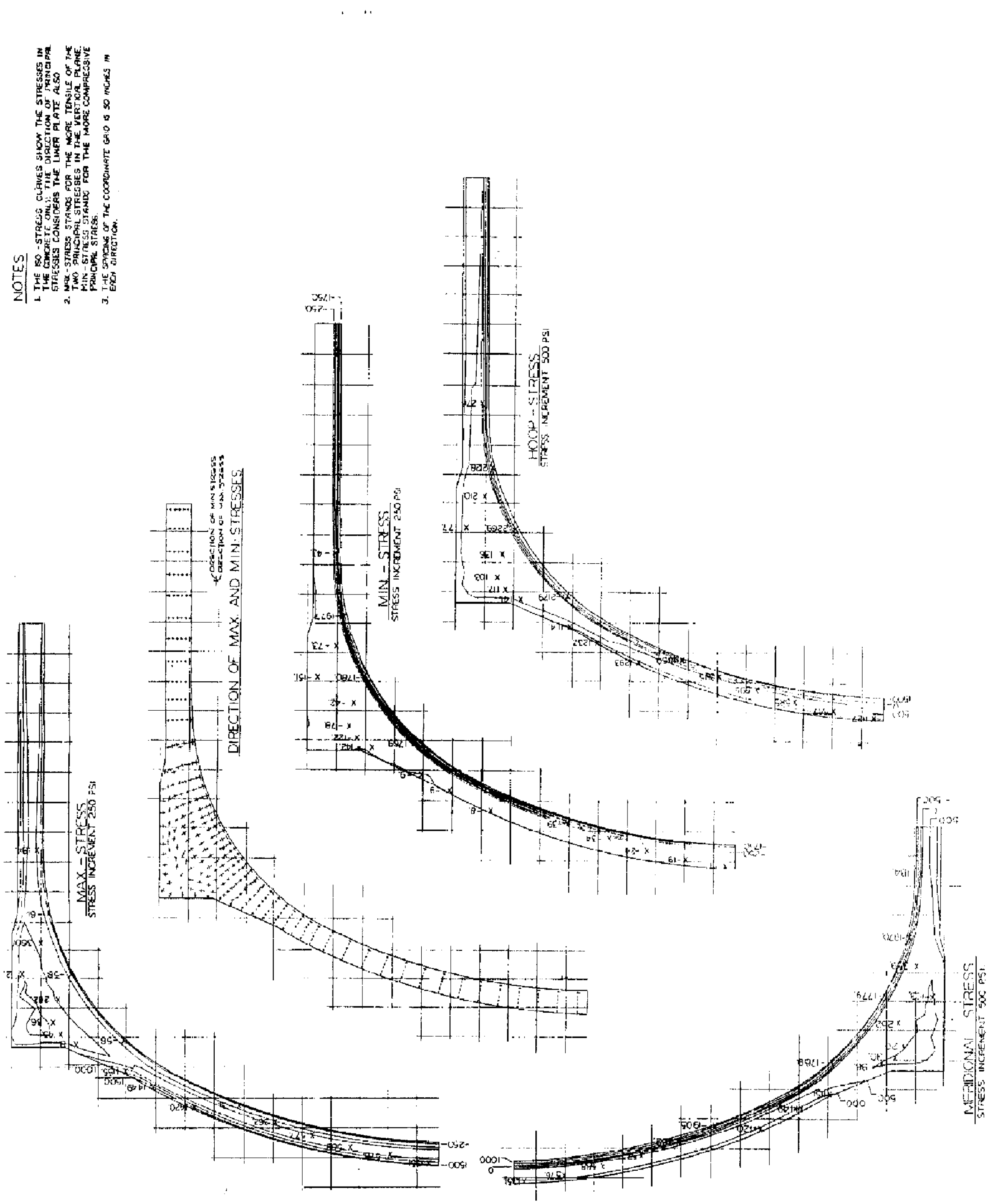
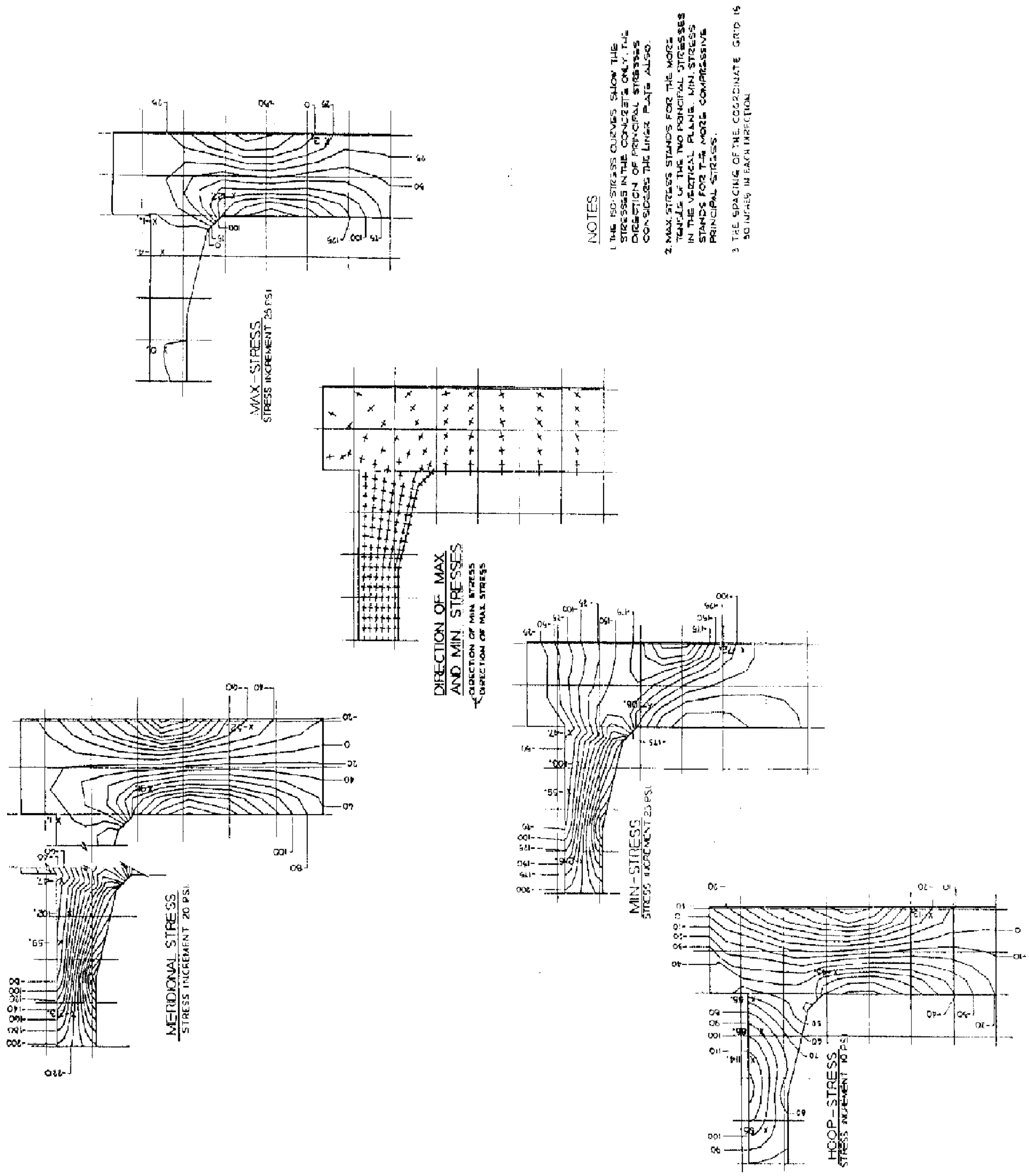
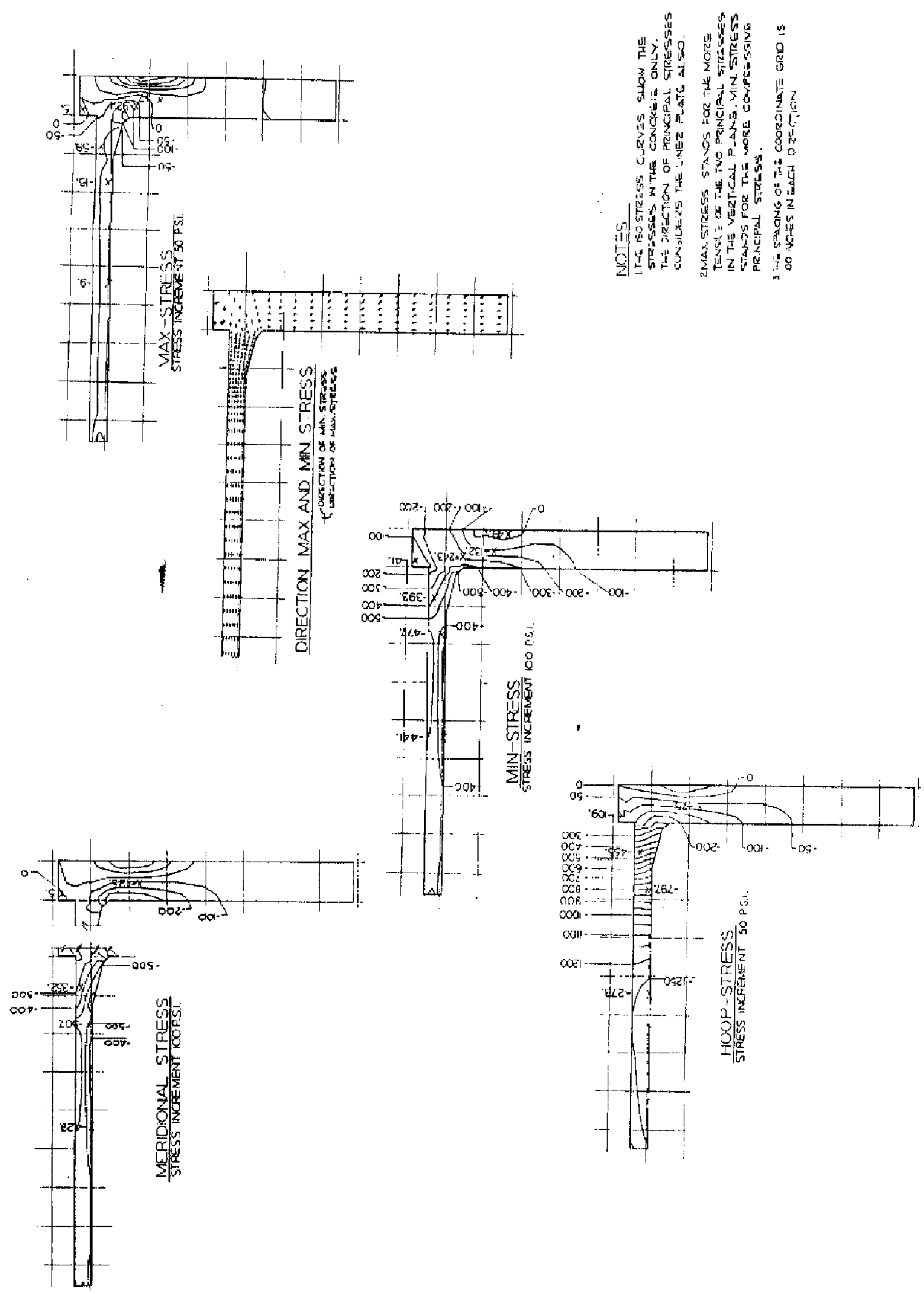
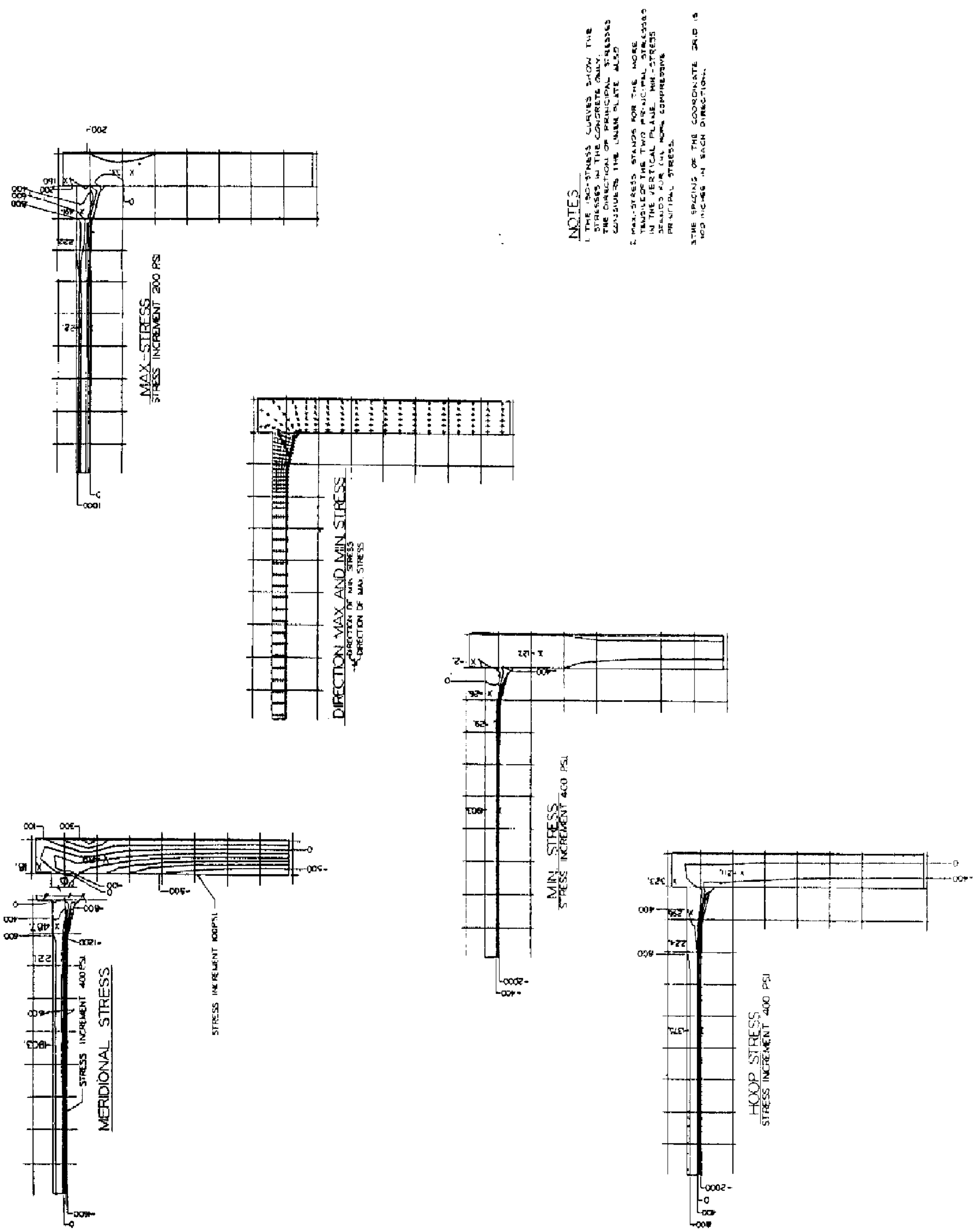
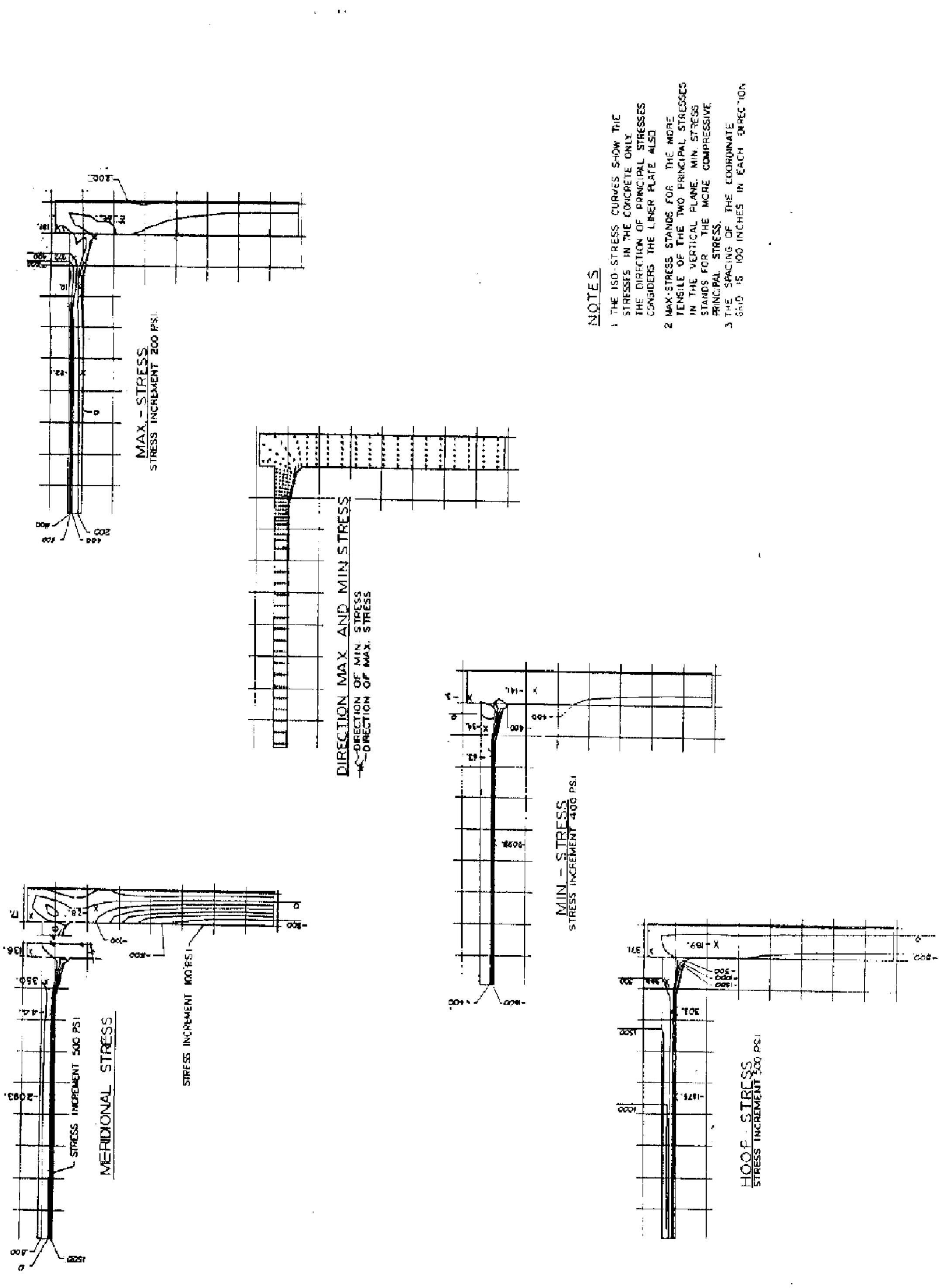

NOTES
1. THE ISO-STRESS CURVES SHOW THE STRESSES IN THE CONCRETE ONLY. THE DIRECTION OF PRINCIPAL STRESSES CONSIDERS THE LINER PLATE ALSO
2. MAX-STRESS STANDS FOR THE MORE TENSILE OF THE TWO PRINCIPAL STRESSES IN THE VERTICAL PLANE. MIN-STRESS STANDS FOR THE MORE COMPRESSIVE PRINCIPAL STRESS.
3. THE SPACING OF THE COORDINATE GRID IS 50 INCHES IN EACH DIRECTION.
MAX.-STRESS
STRESS INCREMENT 250 PSI
DIRECTION OF MAX. AND MIN. STRESSES
MIN.-STRESS
STRESS INCREMENT 250 PSI
HOOP-STRESS
STRESS INCREMENT 500 PSI
MERIDIONAL STRESS
STRESS INCREMENT 500 PSI

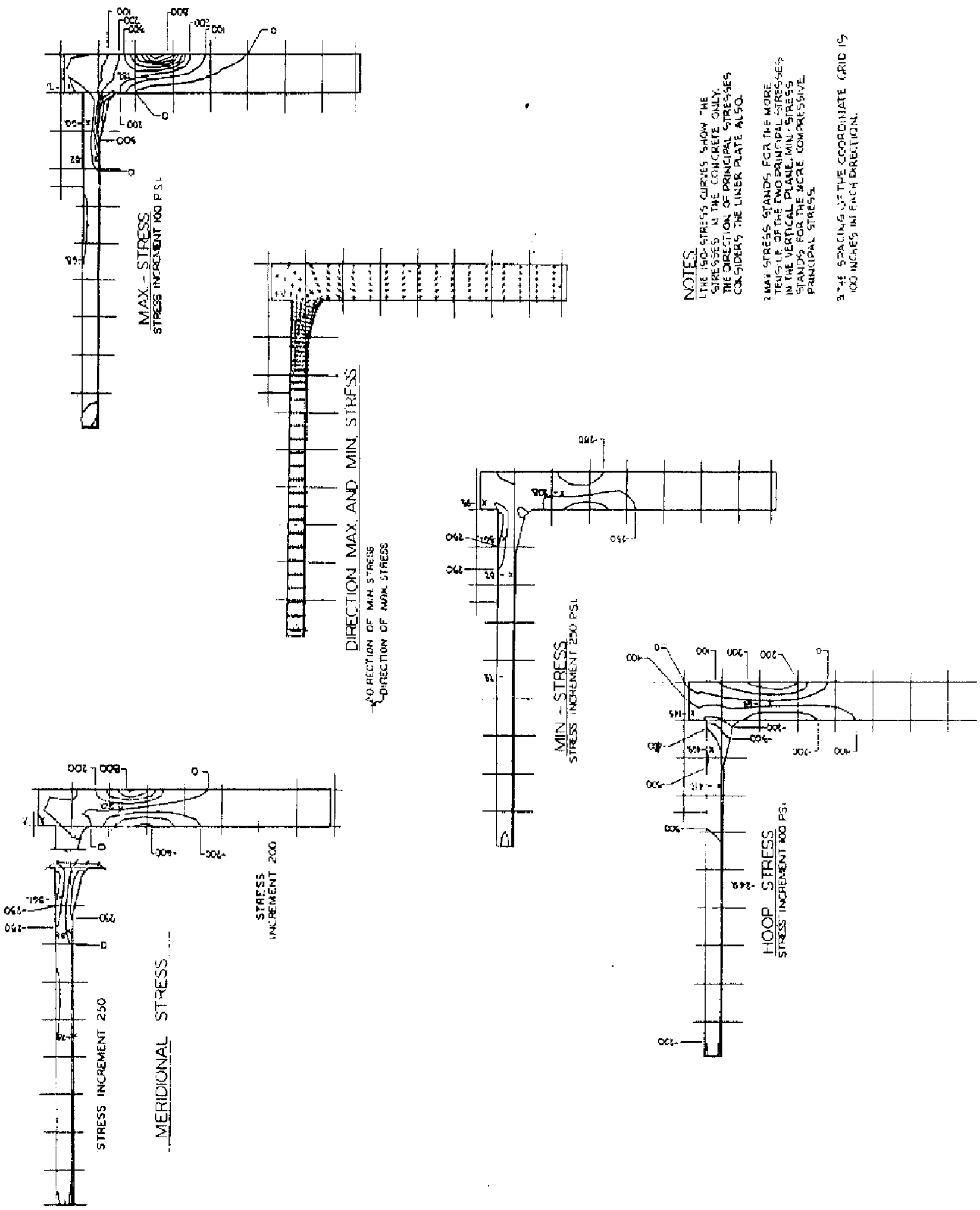
Figure 3-26. Reactor Building Isostress Plot Wall and Base




MAX-STRESS
STRESS INCREMENT 50 PSI
DIRECTION MAX AND MIN STRESS
MIN-STRESS
STRESS INCREMENT 100 PSI
HOOP-STRESS
STRESS INCREMENT 50 PSI
MERIDIONAL STRESS
STRESS INCREMENT 100 PSI
NOTES


NOTES
MAX-STRESS
STRESS INCREMENT 200 PSI
DIRECTION MAX AND MIN STRESS
DIRECTION OF MIN STRESS
DIRECTION OF MAX STRESS
MIN STRESS
STRESS INCREMENT 400 PSI
MERIDIONAL STRESS
STRESS INCREMENT 400 PSI
STRESS INCREMENT 100 PSI
HOOP STRESS
STRESS INCREMENT 400 PSI


NOTES
1 THE ISO-STRESS CURVES SHOW THE STRESSES IN THE CONCRETE ONLY. THE DIRECTION OF PRINCIPAL STRESSES CONSIDERS THE LINER PLATE ALSO
2 MAX-STRESS STANDS FOR THE MORE TENSILE OF THE TWO PRINCIPAL STRESSES IN THE VERTICAL PLANE. MIN STRESS STANDS FOR THE MORE COMPRESSIVE PRINCIPAL STRESS.
3 THE SPACING OF THE COORDINATE GRID IS 100 INCHES IN EACH DIRECTION
MAX.-STRESS
STRESS INCREMENT 200 PSI
DIRECTION MAX AND MIN STRESS
DIRECTION OF MIN. STRESS
DIRECTION OF MAX. STRESS
MIN.-STRESS
STRESS INCREMENT 400 PSI
MERIDIONAL STRESS
STRESS INCREMENT 500 PSI
STRESS INCREMENT 100 PSI
HOOP-STRESS
STRESS INCREMENT 300 PSI


MAX - STRESS
STRESS INCREMENT 100 PSI
DIRECTION MAX. AND MIN. STRESS
DIRECTION OF MIN. STRESS
DIRECTION OF MAX. STRESS
MIN - STRESS
STRESS INCREMENT 250 PSI
HOOP STRESS
STRESS INCREMENT 100 PSI
MERIDIONAL STRESS
STRESS INCREMENT 250
STRESS INCREMENT 200
NOTES
1. THE ISO-STRESS CURVES SHOW THE STRESSES IN THE CONCRETE ONLY. THE DIRECTION OF PRINCIPAL STRESSES CONSIDERS THE LINER PLATE ALSO.
2. MAX STRESS STANDS FOR THE MORE TENSILE OF THE TWO PRINCIPAL STRESSES IN THE VERTICAL PLANE. MIN. STRESS STANDS FOR THE MORE COMPRESSIVE PRINCIPAL STRESS.
3. THE SPACING OF THE COORDINATE GRID IS 100 INCHES IN EACH DIRECTION.

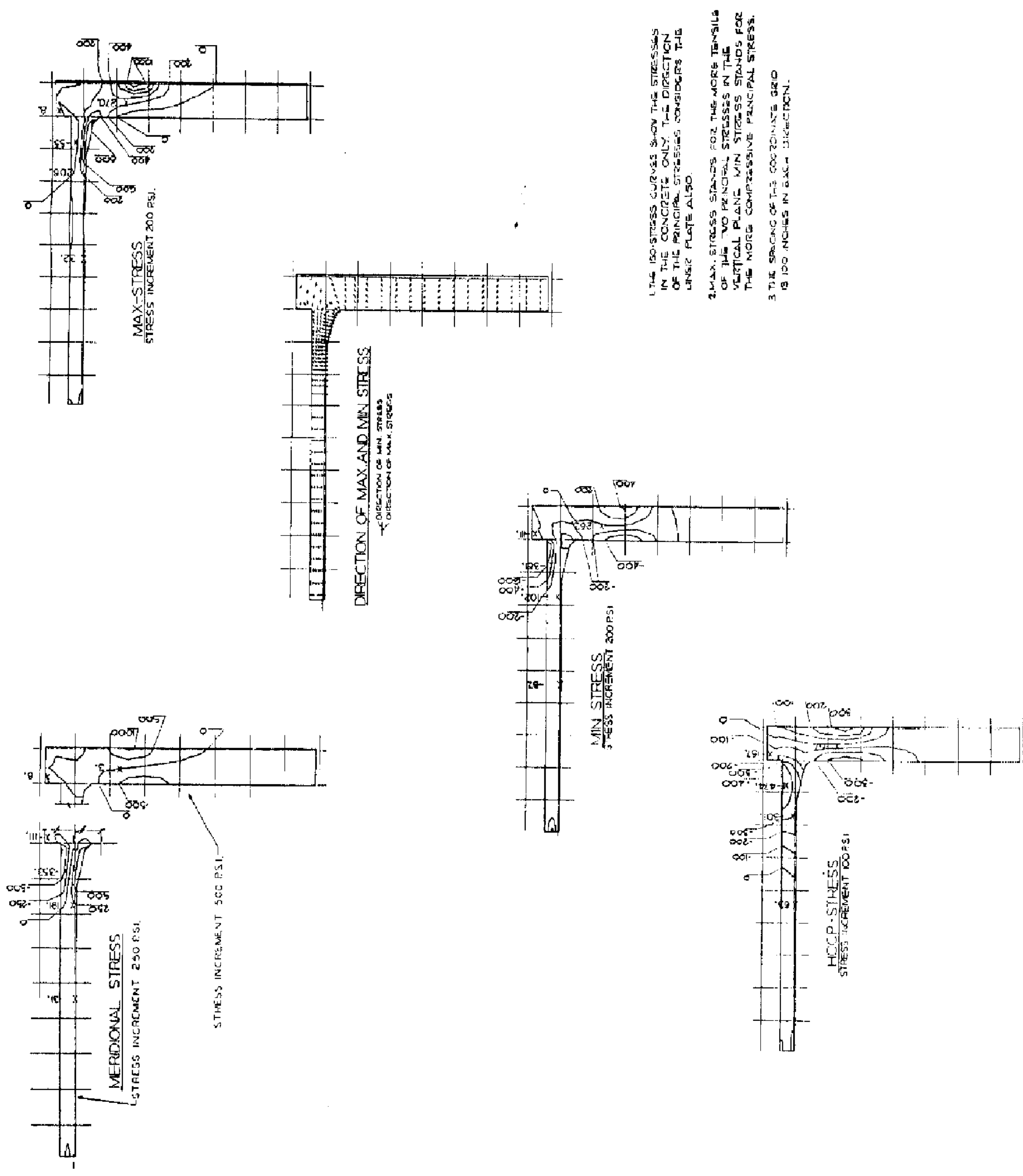
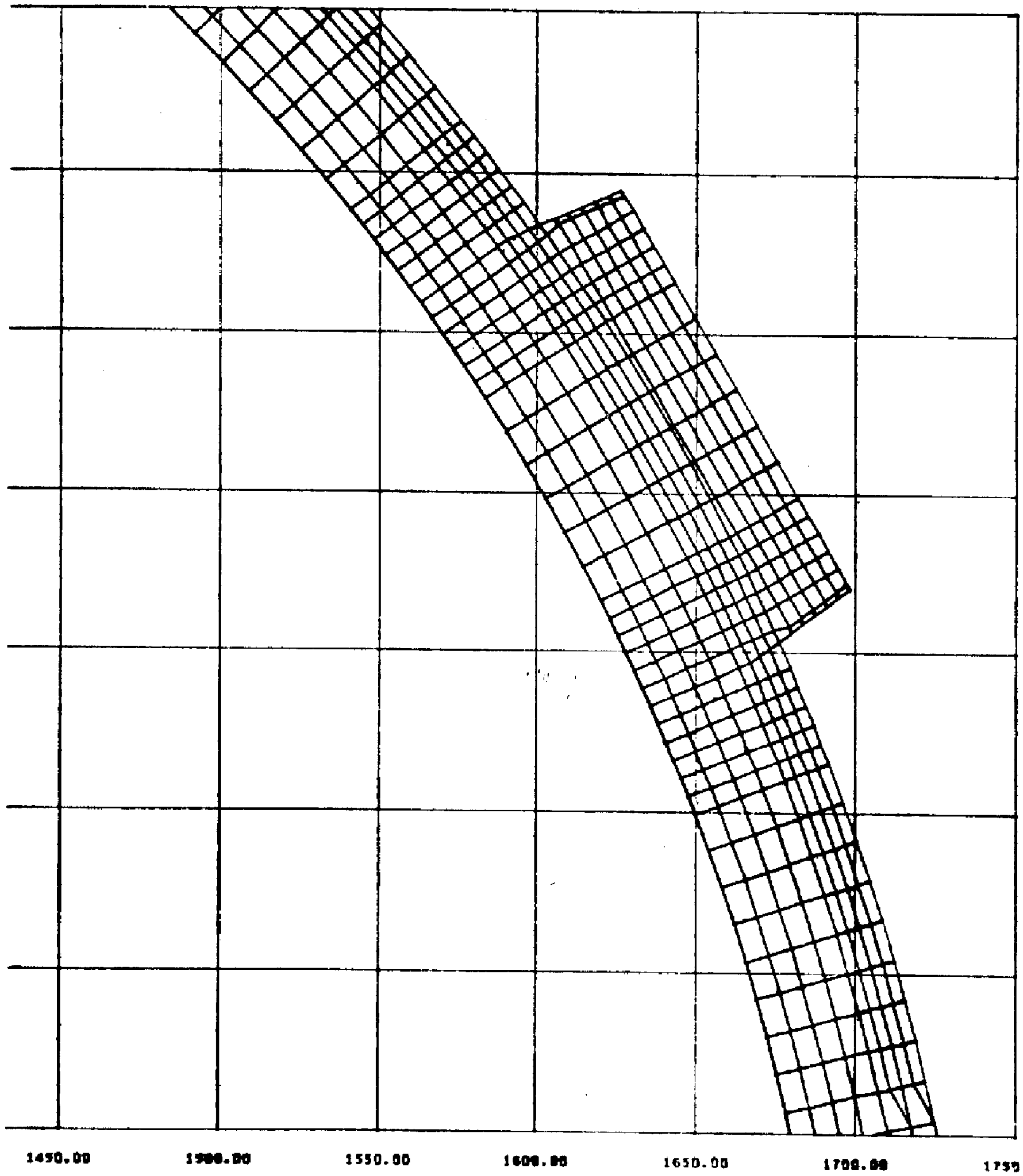
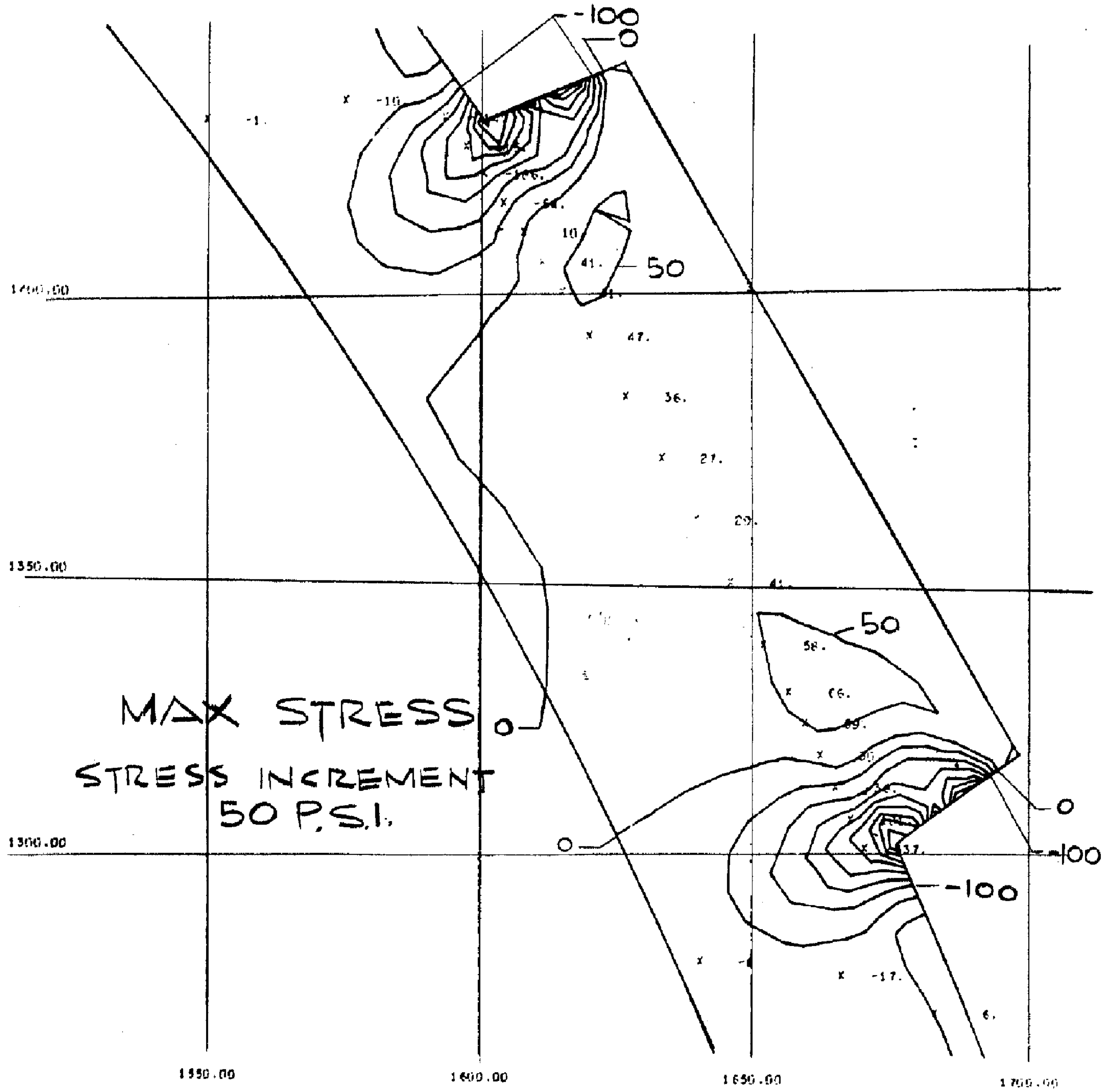

MERIDIONAL STRESS
STRESS INCREMENT 250 PSI.
STRESS INCREMENT 500 PSI.
MAX-STRESS
STRESS INCREMENT 200 PSI.
DIRECTION OF MAX.AND MIN STRESS
DIRECTION OF MIN. STRESS
DIRECTION OF MAX. STRESS
MIN STRESS
STRESS INCREMENT 200 PSI
HOOP-STRESS
STRESS INCREMENT 100 PSI
1. THE ISO-STRESS CURVES SHOW THE STRESSES IN THE CONCRETE ONLY. THE DIRECTION OF THE PRINCIPAL STRESSES CONSIDERS THE LINER PLATE ALSO.
2. MAX. STRESS STANDS FOR THE MORE TENSILE OF THE TWO PRINCIPAL STRESSES IN THE VERTICAL PLANE. MIN STRESS STANDS FOR THE MORE COMPRESSIVE PRINCIPAL STRESS.
3. THE SPACING OF THE COORDINATE GRID IS 100 INCHES IN EACH DIRECTION.

Figure 3-27. Reactor Building Finite Element Mesh Wall Buttresses



REACTOR BUILDING FINITE ELEMENT
MESH WALL BUTTRESSES

Figure 3-28. Reactor Building Isostress Plot for Buttresses



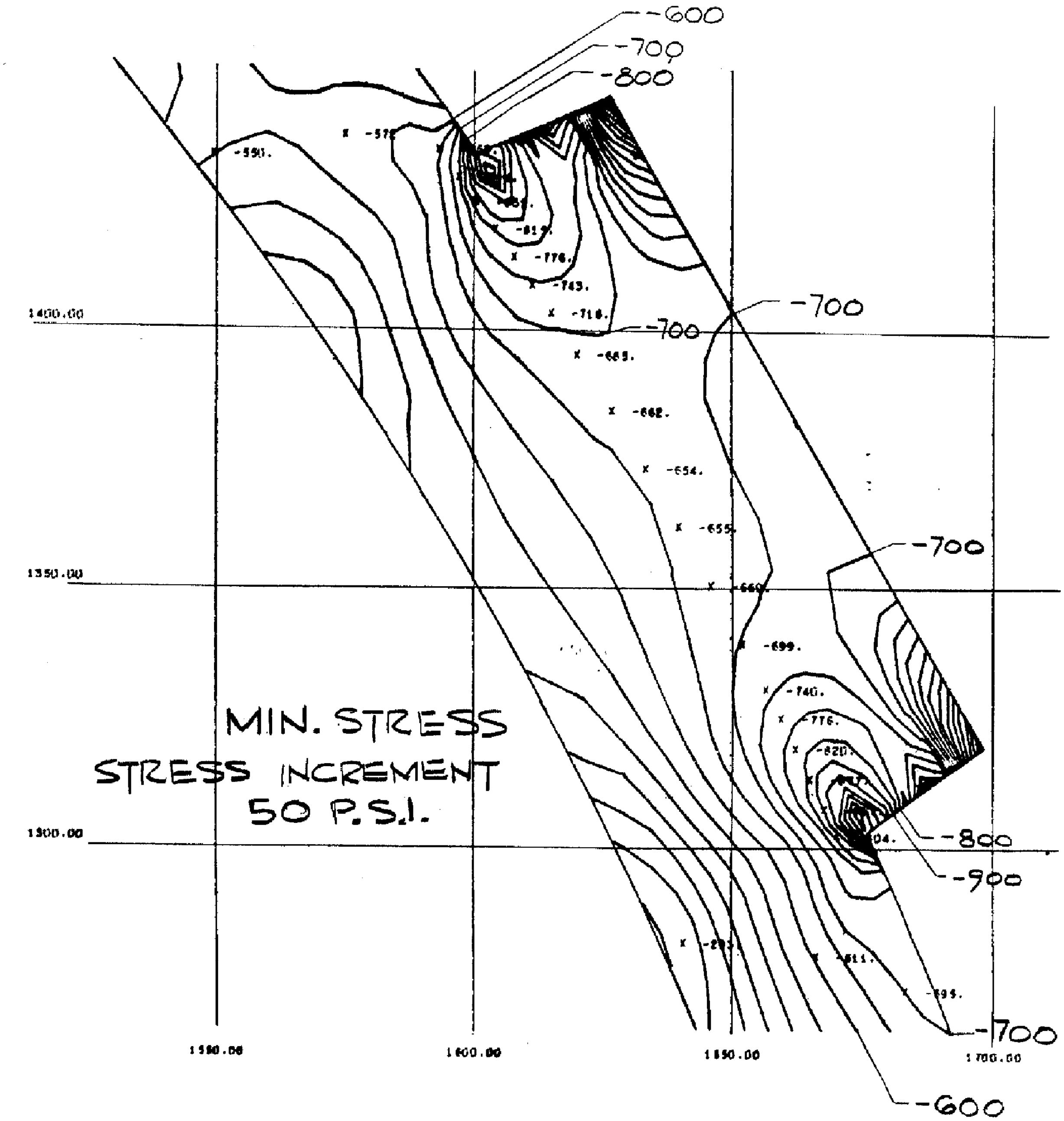

-600
-700
-800
-700
-700
-700
-800
-900
-700
-600
MIN. STRESS
STRESS INCREMENT
50 P.S.I.
1400.00
1350.00
1300.00
1550.00
1600.00
1650.00
1700.00
-550.
-819.
-776.
-743.
-718.
-665.
-662.
-654.
-655.
-699.
-740.
-776.

Figure 3-29. Temperature Gradient at Buttress

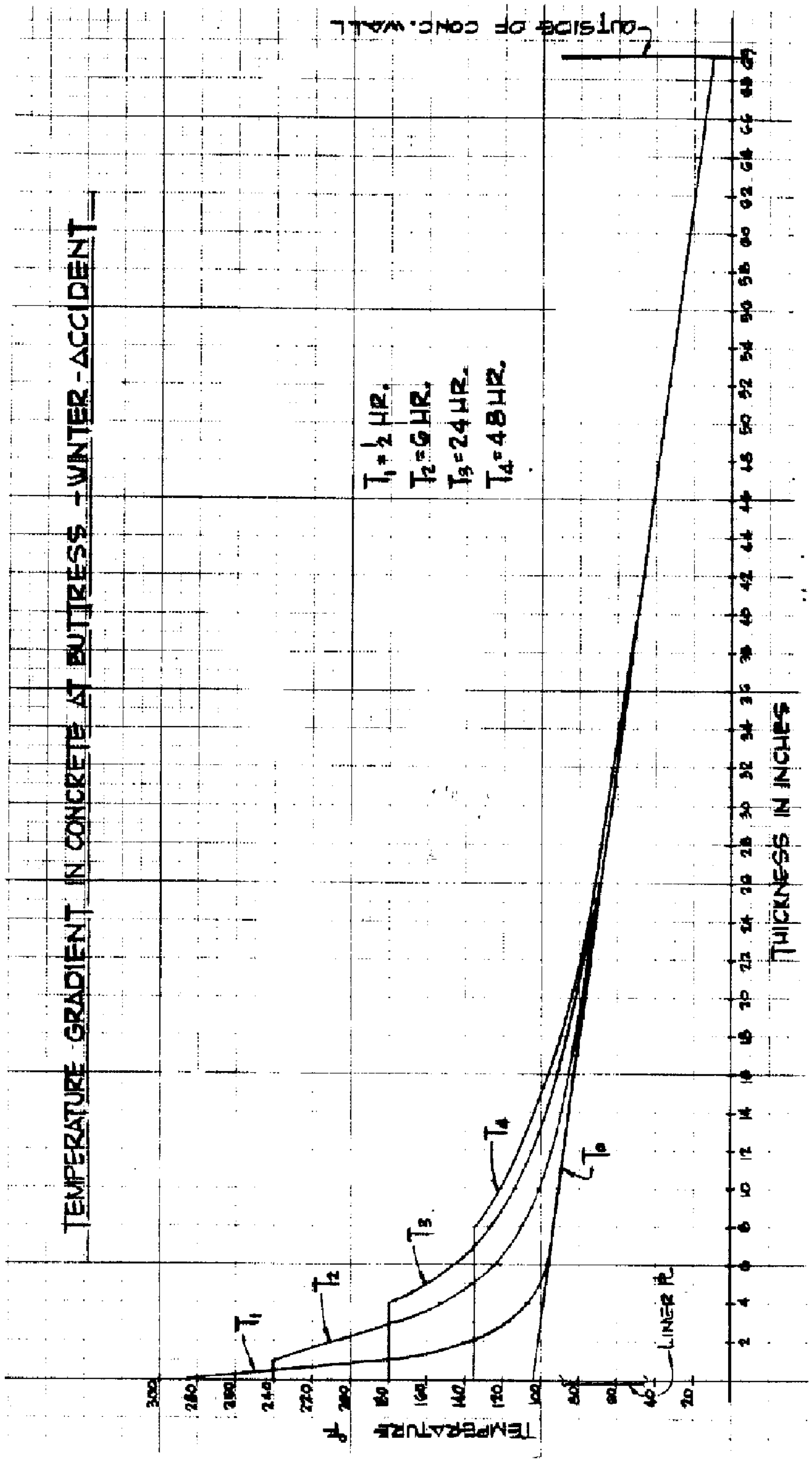


Figure 3-30. Buttress Reinforcing Details

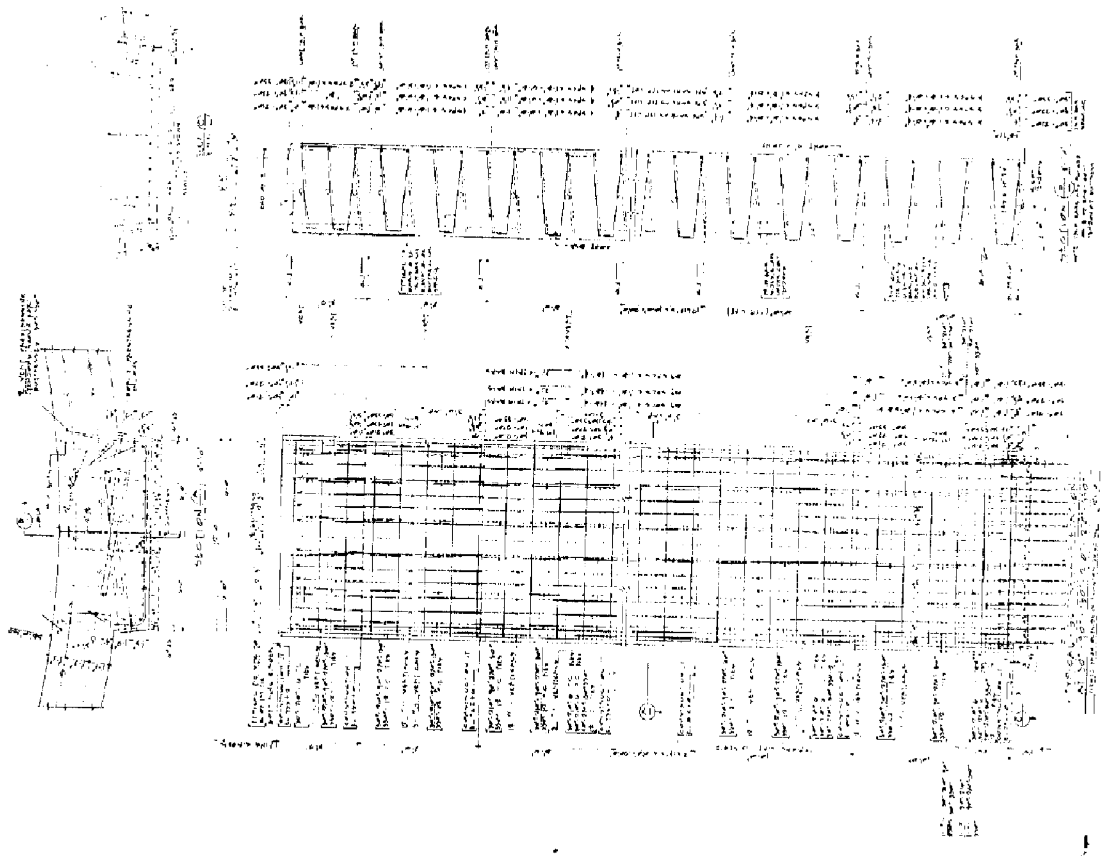


Figure 3-31. Reactor Building Equipment Hatch Mesh

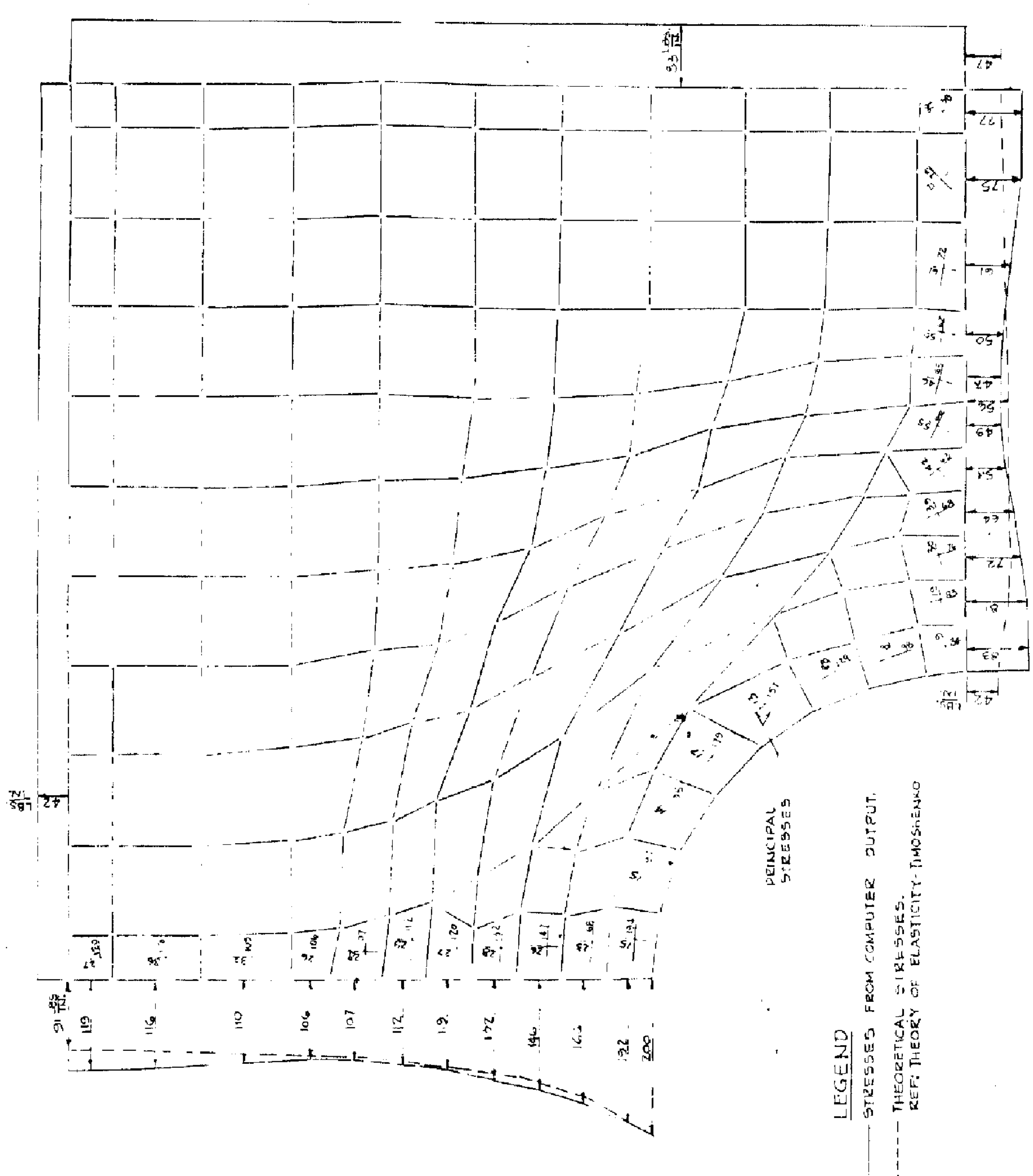


Figure 3-32. Reactor Building Penetration Loads

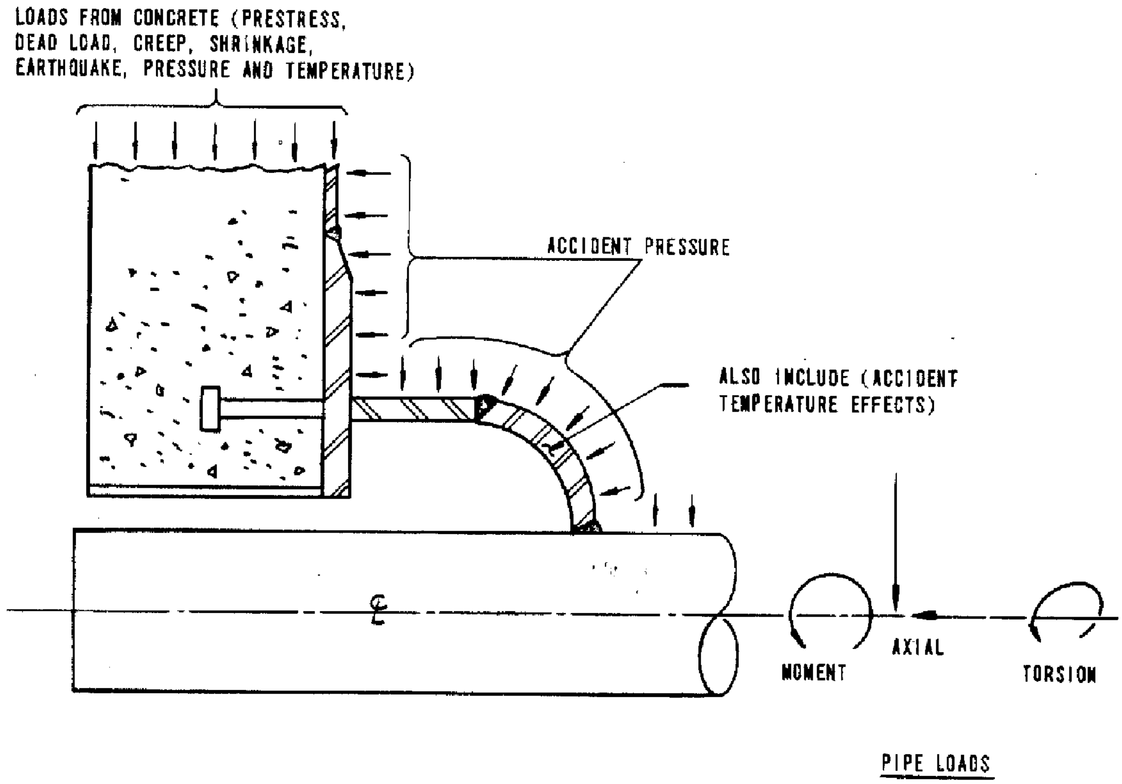
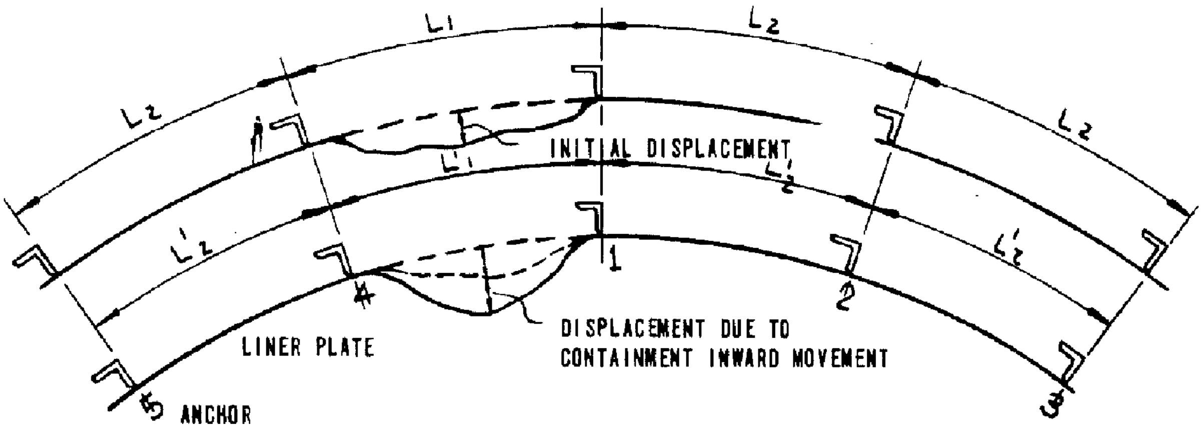


Figure 3-33. Reactor Building Model for Liner Plate Analysis for Radial Displacement



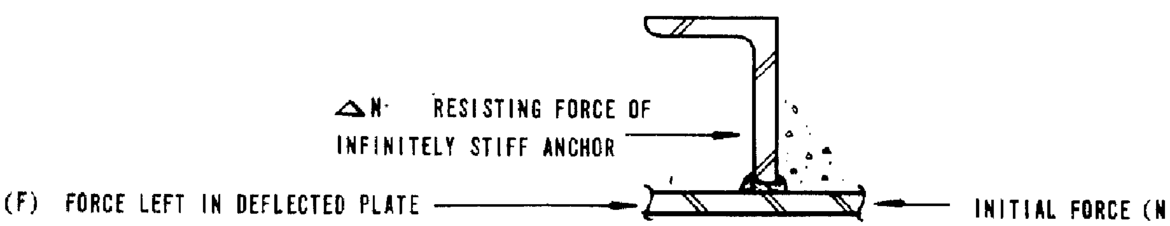
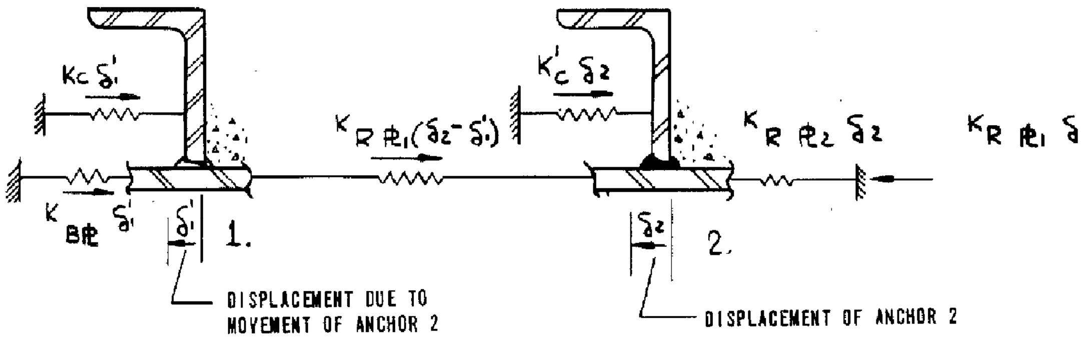


Figure 3-34. Reactor Building Model for Liner Analysis for Anchor Displacement



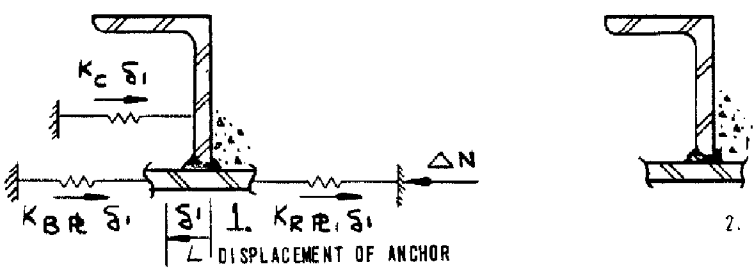
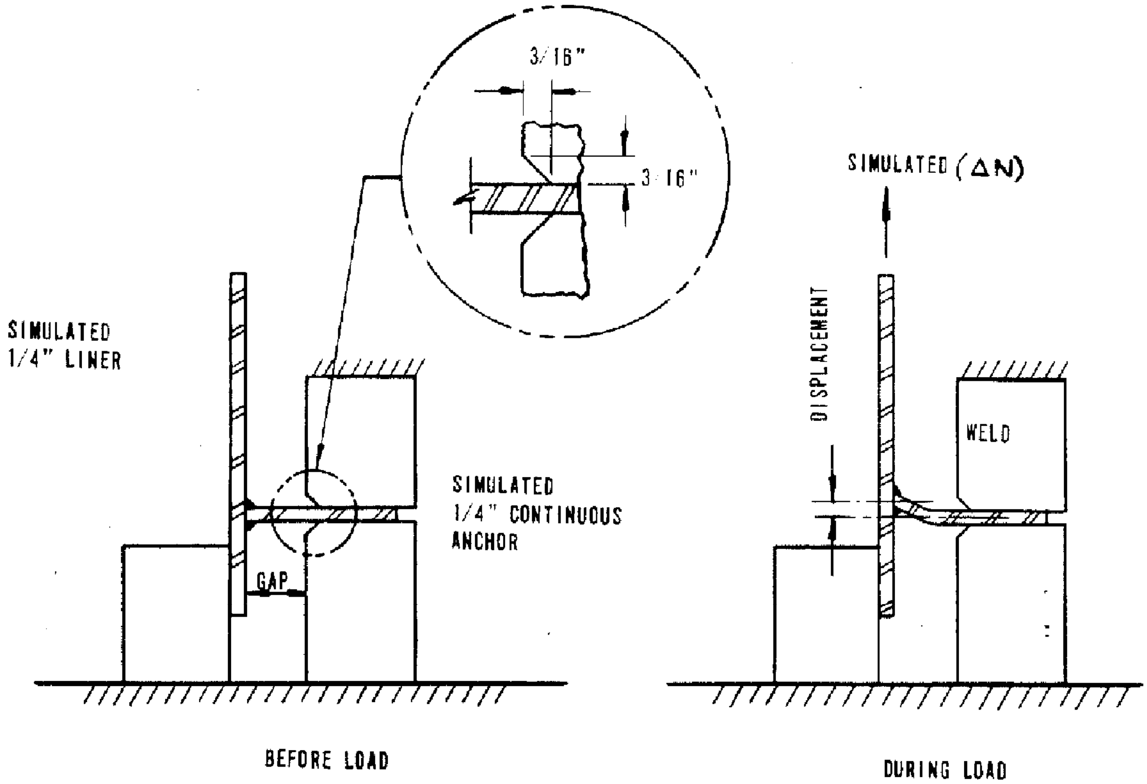


Figure 3-35. Reactor Building - Results from Tests on Liner Plate Anchors



WELD CONFIGURATION	GAP (IN)	ULTIMATE LOAD (K/IN)	ULTIMATE DISPLACEMENT (IN)	LOCATION OF FAILURE
3/16	0	14.95	.14	LINER PLATE
3/16	5/8	5.56	.68	ANCHOR WELD
3/16 6-12	0	7.65	.18	ANCHOR WELD
3/16 6-12	5/8	2.93	.60	ANCHOR WELD
3/16 4-12	0	6.67	.18	ANCHOR WELD
3/16 4-12	5/8	2.46	.30	ANCHOR WELD

Figure 3-36. Location of Plugged Sheaths

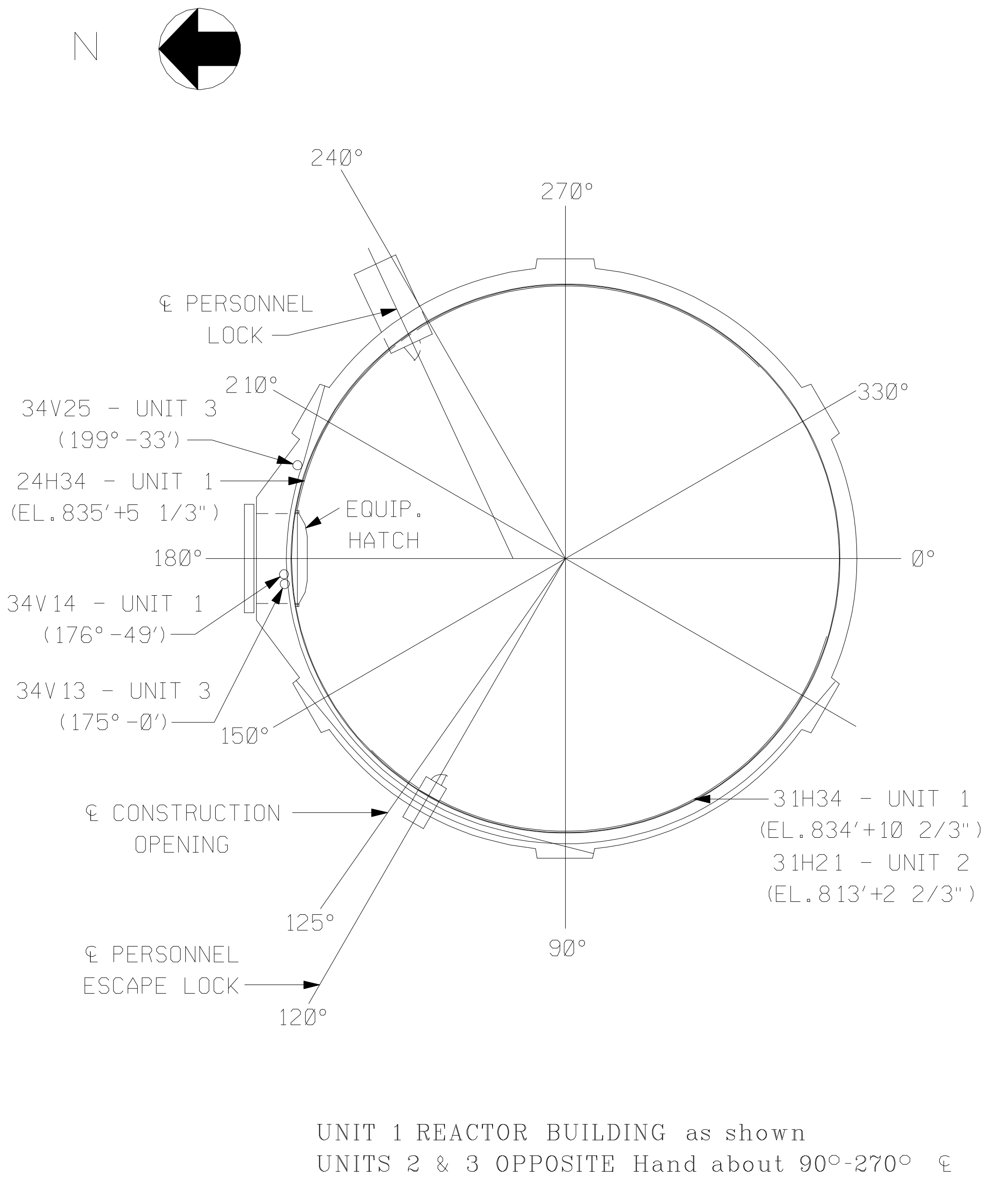
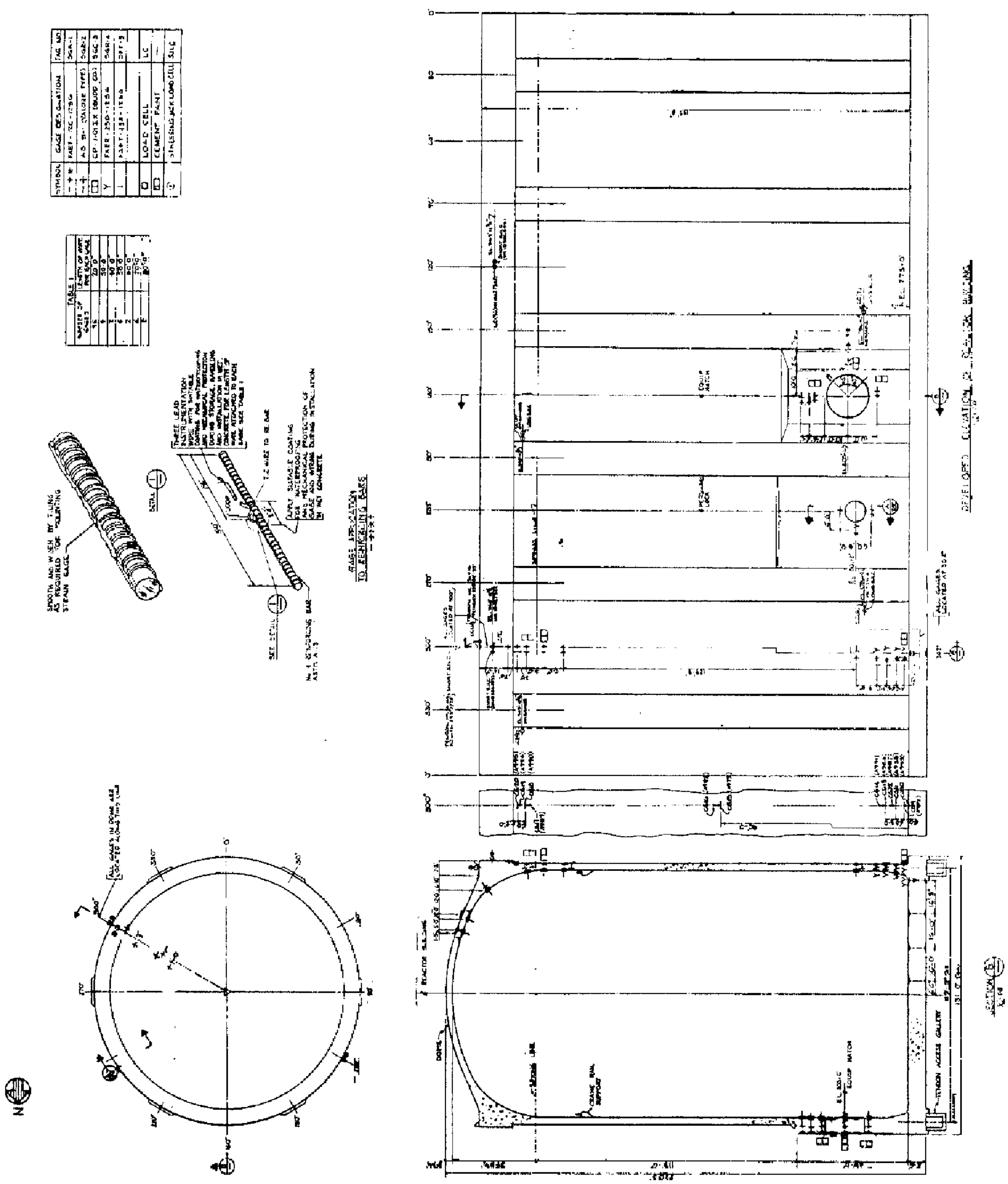
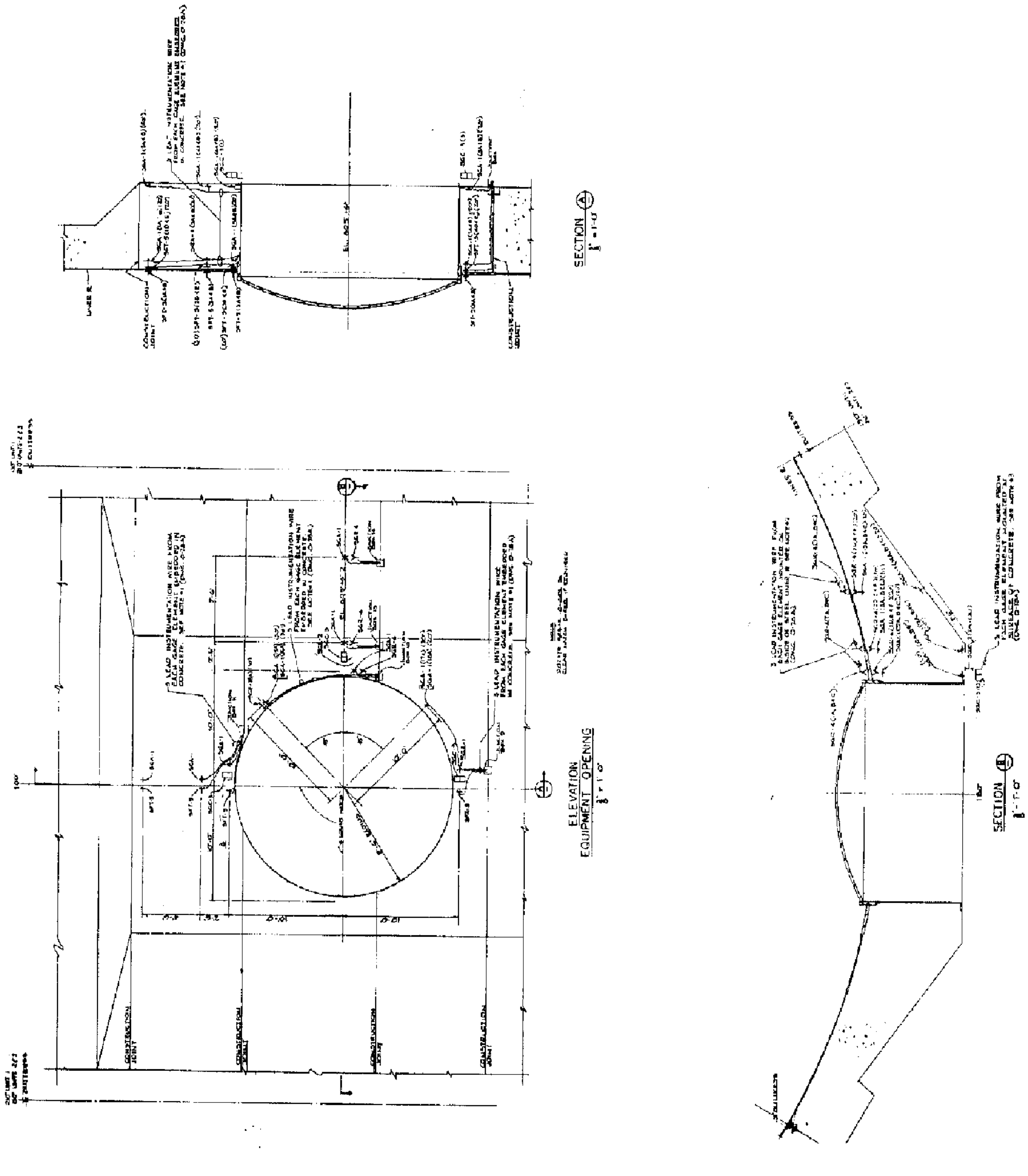
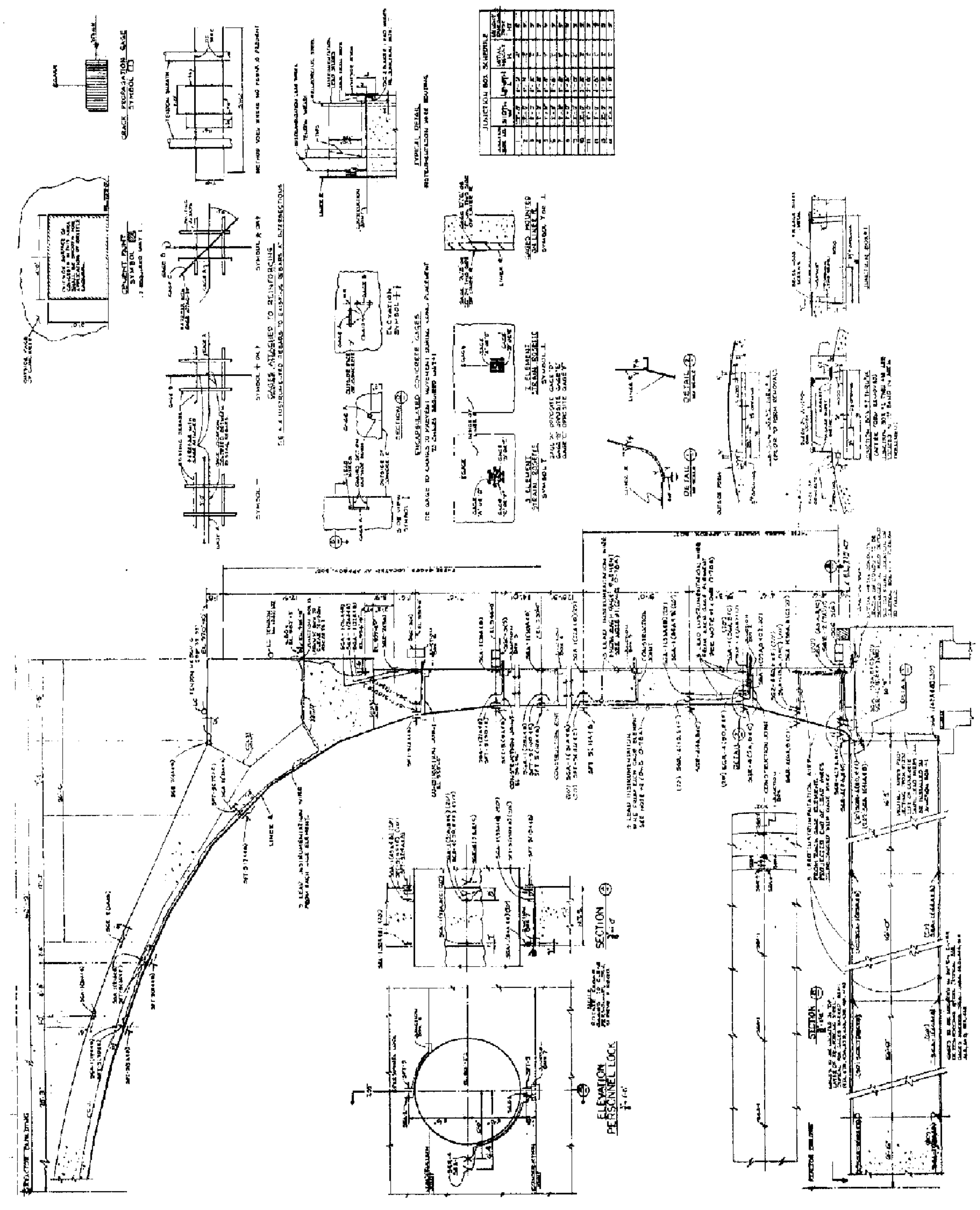


Figure 3-37. Reactor Building Instrumentation for Unit 1




SECTION A
ELEVATION
EQUIPMENT OPENING
SECTION B


SECTION AT 300° & 302°
ELEVATION
PERSONNEL LOCK
JUNCTION BOX SCHEDULE

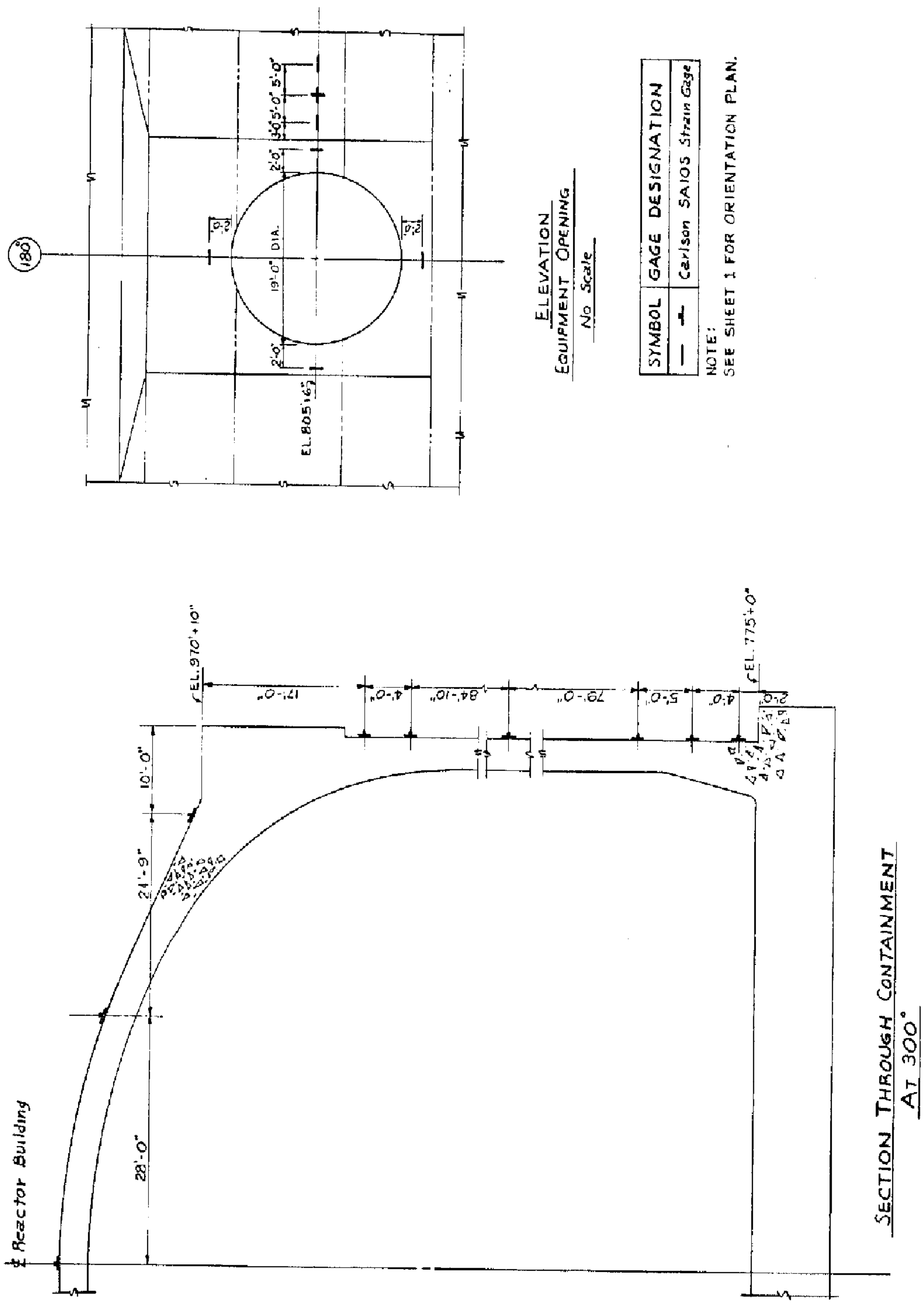

180°
19'-0" DIA.
EL. 805'-1 6/7"
ELEVATION
EQUIPMENT OPENING
No Scale
SYMBOL
GAGE DESIGNATION
Carlson SA10S Strain Gage
NOTE:
SEE SHEET 1 FOR ORIENTATION PLAN.
EL. 970'+10"
EL. 775'+0"
10'-0"
21'-9"
28'-0"
Reactor Building
SECTION THROUGH CONTAINMENT
AT 300°

Figure 3-38. Turbine Building Cross-Section at Line 21

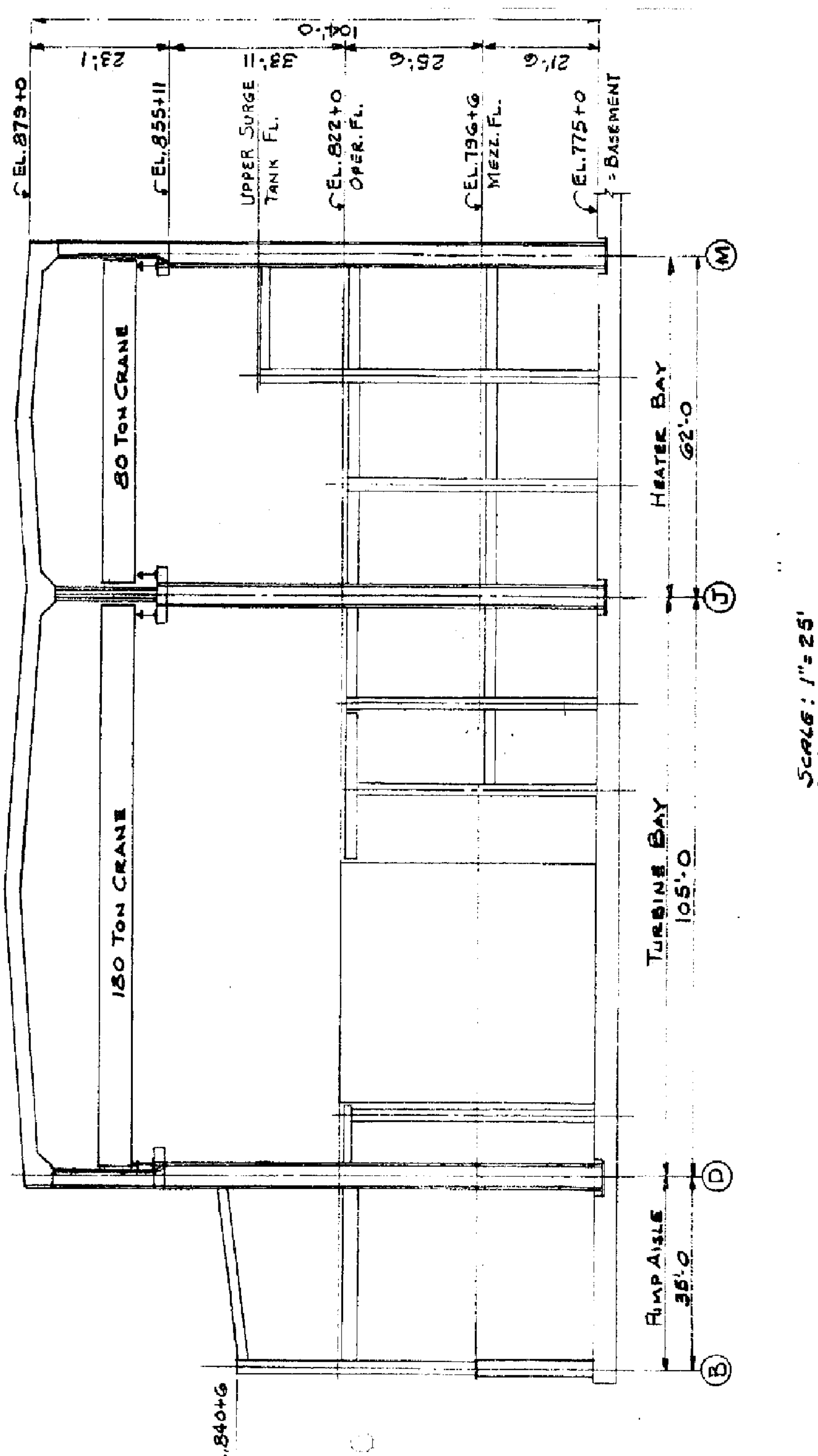


Figure 3-39. Deleted Per 1996 Update

Figure 3-40. Deleted Per 1996 Update

Figure 3-41. Deleted Per 1996 Update

Figure 3-42. Deleted Per 1996 Update

Figure 3-43. Deleted Per 1996 Update

Figure 3-44. Deleted Per 1996 Update

Figure 3-45. Deleted Per 1996 Update

Figure 3-46. Deleted Per 1996 Update

Figure 3-47. Deleted Per 1996 Update

Figure 3-48. Deleted Per 1996 Update

Figure 3-49. Deleted Per 2004 Update

Figure 3-50. Deleted Per 2004 Update

Figure 3-51. Deleted Per 2004 Update

Figure 3-52. Seismic, Thermal, and Dead Load Analytical Model for the Pressurizer Surge Line Piping (Units 2 and 3)

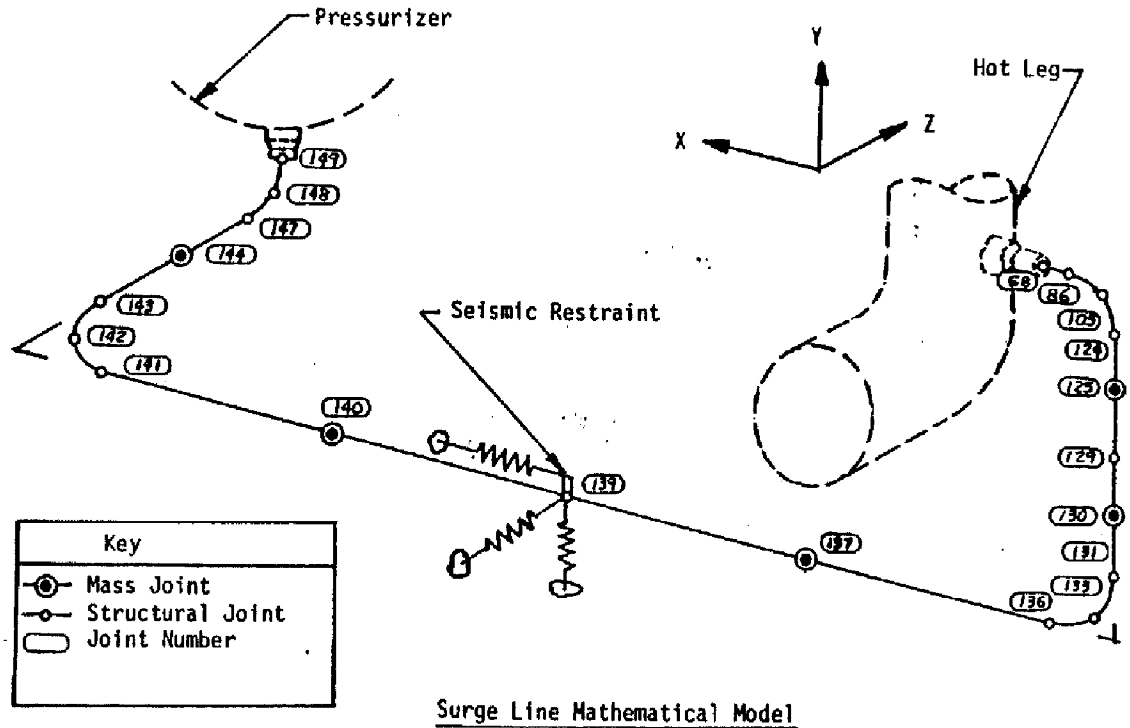


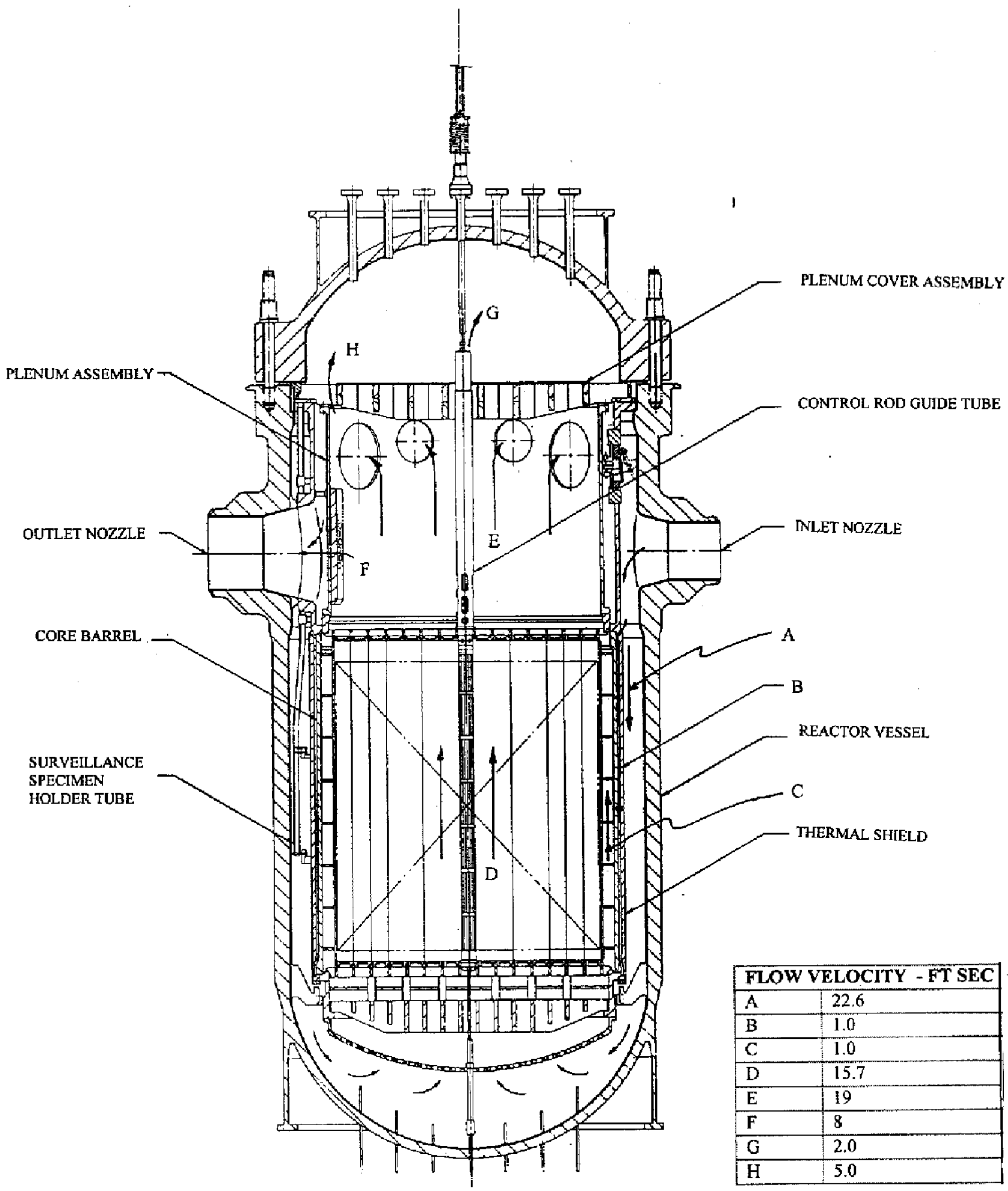
Figure 3-53. Deleted Per 2003 Update

Figure 3-54. Deleted Per 2003 Update

Figure 3-55. Deleted Per 2004 Update

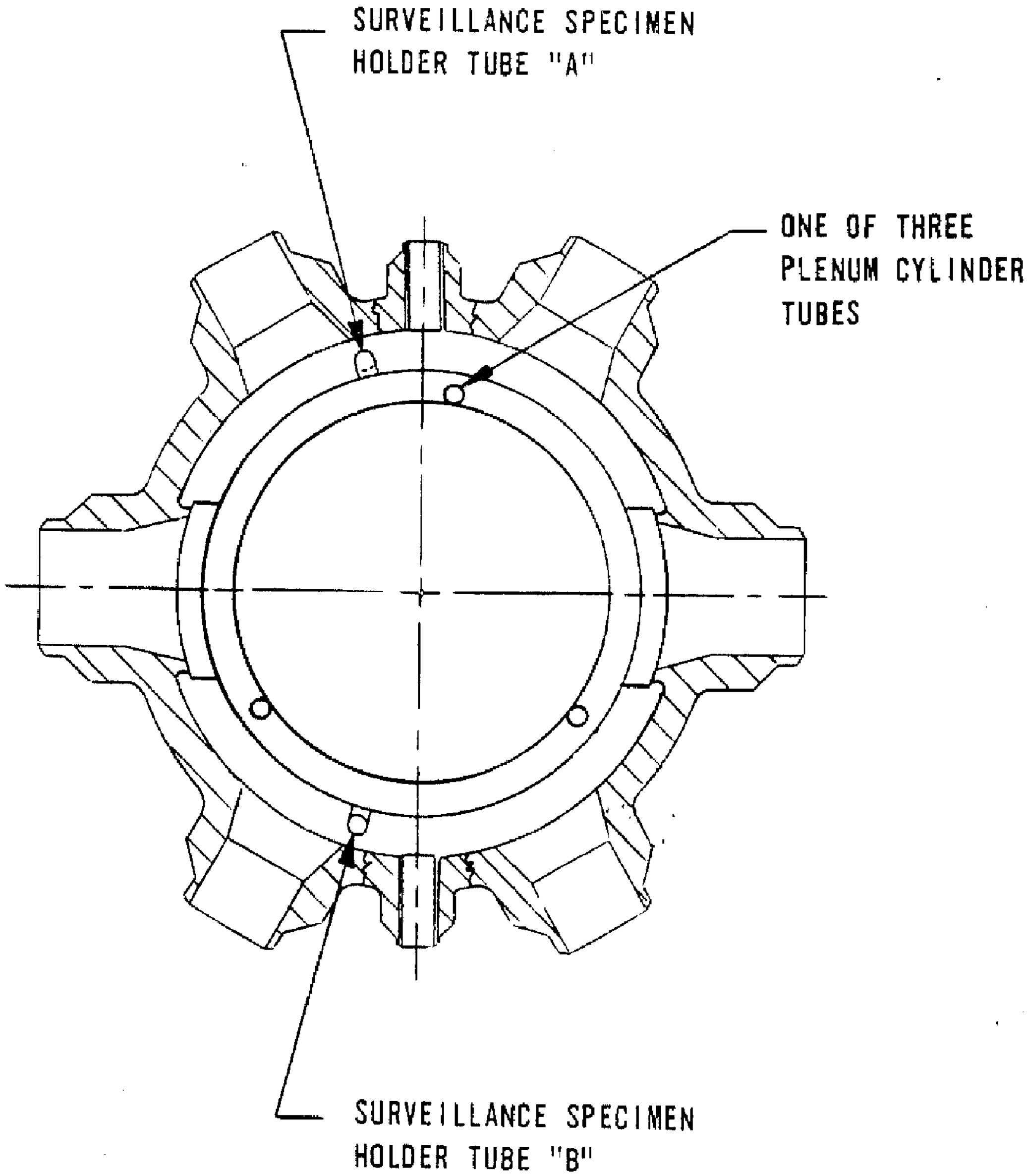
Figure 3-56. Deleted Per 2004 Update

Figure 3-57. Directions and Velocities of the Coolant Flow in the Reactor



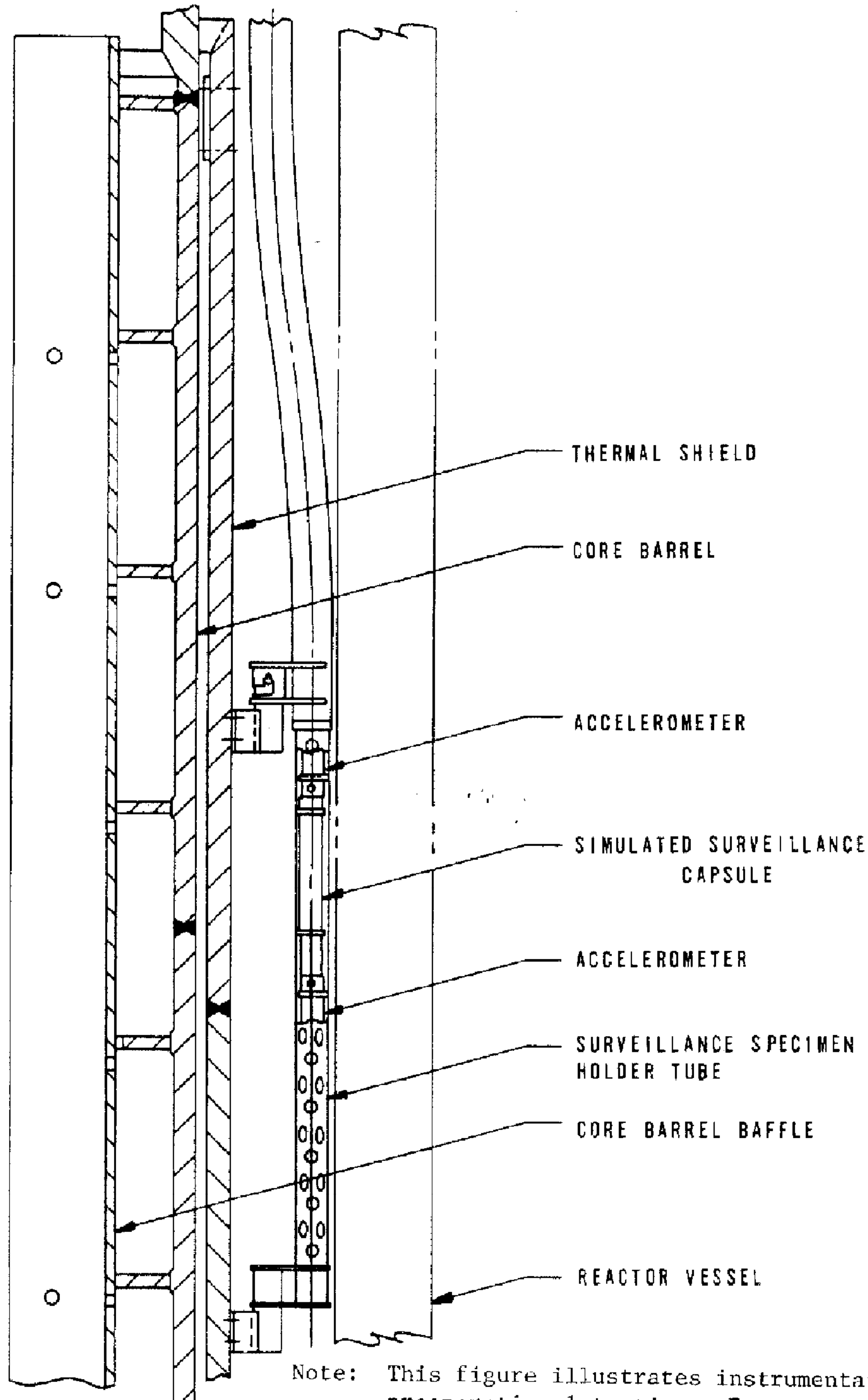
FLOW VELOCITY - FT SEC	
A	22.6
B	1.0
C	1.0
D	15.7
E	19
F	8
G	2.0
H	5.0

Figure 3-58. Location of Instrumentation Surveillance Specimen Holder Tubes and the Plenum Cylinder Tubes



Note: This figure illustrates location of instrumentation for preoperational testing. Present Oconee units do not use Specimen Holder Tubes. Instead, material samples are irradiated in a host reactor.

Figure 3-59. Location of the Instrumentation in the Specimen Holder Tube



Note: This figure illustrates instrumentation for preoperational testing. Present Oconee units do not use Specimen Holder Tubes. Instead, material samples are irradiated in a host reactor.

Figure 3-60. Location of the Accelerometer in Plenum Cylinder Tube

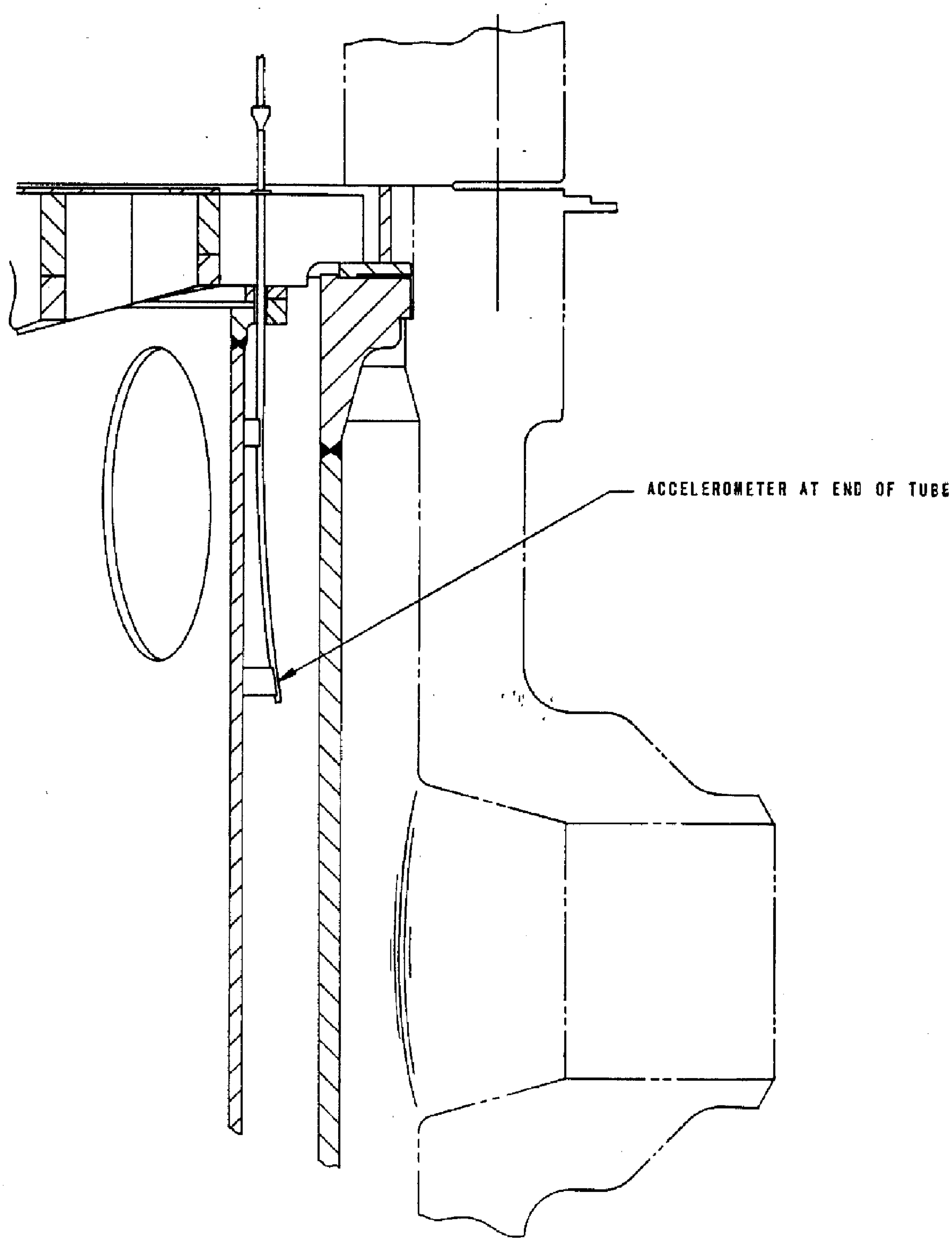


Table of Contents

List of Tables

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List of Figures

4.0 Reactor

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4.1 Summary Description

The reactor is a pressurized water reactor and is functionally comprised of the reactor internals, fuel system, and control rod drives. The fuel system consists of the fuel assemblies and control components.

The major functions of the reactor internals are to support the core, maintain fuel assembly alignment, and direct the flow of reactor coolant.

The fuel system is designed to operate at 2,568 MWt with sufficient design margins to accommodate transient operation and instrument error without damage to the core and without exceeding limits for the Reactor Coolant System (RCS). The fuel system is designed to meet the performance objectives within the limits of design and operation specified in Section 4.2, Section 4.3, and Section 4.4.

The fuel assembly is designed for structural adequacy and reliable performance during core operation. This includes steady-state and transient conditions under the combined effects of pressure, temperature, hydraulic forces, and irradiation. The fuel assembly is mechanically compatible with the reactor internals control rod assemblies and burnable poison rod assemblies. There are 2 axial power shaping rod (APSR) coupling designs. See Table 4-22 for information on compatibility of the fuel assembly designs with the APSR coupling designs. In addition to incore operation, the fuel assembly must be designed for handling, shipping, and storage to assure that the fuel assembly maintains its dimensional and structural integrity. Section III of the ASME Boiler and Pressure Vessel Code serves as a guide for fuel assembly and reactivity control component analysis.

The fuel assembly thermal-hydraulic operating characteristics have been determined and found to be compatible with design limits. Power peaks are controlled during transients so that no fuel melting occurs. The minimum core DNB ratio at the design overpower is maintained above the design limit. Although net steam generation occurs in the hottest core channels at the design overpower, hydraulic stability analyses have shown that no flow oscillations will occur.

The control components (control rod assemblies, axial power shaping rod assemblies, and burnable poison rod assemblies) are designed to perform their functions in controlling the reactor.

Core reactivity is controlled by control rod assemblies (CRAs), axial power shaping rod assemblies (APSRAs), burnable poison rod assemblies (BPRAs) and soluble boron in the coolant. Sufficient CRA worth is available to shut the reactor down with at least 1% $\Delta k/k$ subcritical margin in the hot condition at any time during the life cycle with the most reactive CRA stuck in the fully withdrawn position. Equipment is provided to add soluble boron to the reactor coolant to ensure a similar shutdown capability when the reactor is cooled to ambient temperatures.

The reactivity worth of a CRA and the rate at which reactivity can be added are limited to ensure that credible reactivity accidents cannot cause a transient capable of damaging the RCS or causing significant fuel failure.

The control rod guide path is designed to ensure that the control assemblies will not disengage from the fuel assembly guide tubes during operation. Guidance is provided by close-tolerance indexing of the fuel assembly upper end fitting with the upper grid rib section.

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4.2 Fuel System Design

The fuel system consists of fuel assemblies and control components which are designed to the bases described in Section 4.2.1 and Section 4.2.2.

4.2.1 Design Bases - Fuel System Design

The fuel is designed to meet the performance objectives specified in Section 4.2.1.1 without exceeding the limits of design and operation specified in Section 4.2.1.2.

4.2.1.1 Fuel System Performance Objectives

The core is designed to operate at 2568 MWt (rated power) with sufficient design margins to accommodate transient operation and instrument error without fuel damage.

The fuel rod cladding is designed to maintain its integrity for the anticipated operating transients throughout the fuel assembly lifetime. The effects of gas release, fuel dimensional changes, and corrosion- or irradiation-induced changes in the mechanical properties of cladding are considered in the design of fuel assemblies.

4.2.1.2 Limits

4.2.1.2.1 Nuclear Limits

The core has been designed to the following nuclear limits and capabilities, all of which are intended to preserve the integrity of the fuel assemblies:

1. The core will have sufficient reactivity to produce the design power level and lifetime without exceeding the control capacity or shutdown margin.
2. Fuel assemblies have been designed for the maximum burnups shown in Table 4-2.
3. Power histories must be bounded by those assumed within generic mechanical and thermal hydraulic (fuel assembly) analyses. If they are not bounded, acceptable reanalyses shall be performed.
4. The maximum feed fuel enrichment is constrained by the maximum allowed in the Technical Specifications (Spent Fuel Pool storage requirements).
5. Values of important core safety parameters predicted for the cycle have been verified to be conservative with respect to their values assumed in the Chapter 15 safety/accident (and any other pertinent) analyses. If they are not conservative, acceptable reanalyses shall be performed.

   Controlled reactivity insertion rates due to a single CRA group withdrawal shall be limited to a maximum value assumed within the Section 15.3 Rod Withdrawal Accident at Rated Power, and within the Section 15.2 Startup Accident. Controlled reactivity insertion rates due to soluble boron removal shall be limited to a maximum value assumed within the Section 15.4 Moderator Dilution Accident.

   The overall power coefficient is negative in the power operating range. However, as described within Chapter 15, the control system is capable of compensating for reactivity changes resulting from either positive or negative nuclear coefficients.
6. Reasonable and permissive reactor control and maneuvering procedures during nominal operation and during transients will not produce unacceptable peak-to-average power

distributions. This, along with criteria 7 and 8, below, preserves the LOCA linear heat rate, linear heat rate to melt (LHRTM), and DNBR limits.

7. Part length axial power shaping rods (APSRs) may be utilized to allow the shaping of power axially in the core, thereby thwarting any tendency towards axial instability resulting from a redistribution of xenon.

   To preclude the possiblity of azimuthal instability resulting from a redistribution of xenon, the highest moderator temperature coefficient assumed within Chapter 15 safety/accident analyses must be bounded by the threshold listed within Table 4-7.

8. Technical Specification limits of specified operating parameters (quadrant power tilt, power imbalance, and control rod insertion), and on reactor protective system trip setpoints (power imbalance) after allowance for appropriate measurement tolerances should have adequate margin from design limits of these parameters during operational conditions throughout the cycle such that sufficient operating flexibility is retained for the fuel cycle.

4.2.1.2.2 Reactivity Control Limits

The control system and operational procedures will provide adequate control of the core reactivity and power distribution. The following control limits and capabilities shall be:

1. A control system consisting of part length axial power shaping rods (APSRs) shall be provided to control the core axial power distribution.

2. A shutdown margin of at least 1.0% $\Delta\rho$ shall be maintained throughout core life with the most reactive CRA stuck in the fully withdrawn position. However, for shutdown margin calculations with all control rods verified fully inserted by two independent means, it is not necessary to account for a stuck rod in the shutdown margin calculation. (Reference 24)

3. CRA withdrawal rate (as listed within Chapters 7 and 15) shall limit the maximum reactivity insertion rate to that assumed within the Section 15.3 Rod Withdrawal Accident at Rated Power, and within the Section 15.2 Startup Accident.

4. Boron dilution rate (as listed within Chapter 15) shall limit the maximum reactivity insertion rate to that assumed within the Section 15.4 Moderator Dilution Accident.

5. A control rod shall not be misaligned from the group average by the value listed within the Technical Specifications, and constrained within Chapters 7 and 15 (Control Rod Misalignment Accident). Except during the startup physics test program, operating rod overlap shall be within the bounds listed within the Technical Specifications, and constrained within Chapters 7 and 15 (Startup Accident).

6. Maximum boron (hot full power, or otherwise) will be constrained by those assumed within Chapter 15 or Technical Specifications. Sufficient soluble boron shall be available within the control system equipment (BWST, CBAST, and CFT) to ensure a 1.0% $\Delta\rho$ shutdown capability with the most reactive CRA stuck in the fully withdrawn position when the reactor is cooled to ambient temperatures.

7. There are no design constraints on BPRA poison enrichment or number of BPRA assemblies, except for those inferred by the peak-to-average power distributions constraints listed within Table 4-1, by Chapter 15 constraints, by Technical Specifications constraints (such as moderator temperature coefficient), or by the limiting core bypass flow assumed within thermal hydraulic analyses.

8. During Refueling (Mode 6), shutdown margin is assured by administrative means in various procedures. This is consistent with Duke's response to NRC Bulletin 89-03, "Potential Loss of Required Shutdown Margin During Refueling Operations" (References 22, 23).

For more detail, refer to Section 4.3.

4.2.1.2.3 Thermal and Hydraulic Limits

The reactor core is designed to meet the following thermal and hydraulic limits:

1. The fuel pin must be designed so that the maximum fuel temperature does not exceed the fuel melting limit at any time during core life. The TACO3 or COPERNIC computer programs are used to verify heat rate capacity (Reference 2 or 25).
2. The minimum allowable DNBR during steady-state operation and anticipated transients is: (a) 1.18 with the BWC correlation (Reference 6), (b) 1.19 with the BWU-Z correlation with FB11 multiplication factor (Reference 19), or (c) a proprietary value with the BHTP correlation (Reference 19).
3. Although generation of net steam is allowed in the hottest core channels, flow stability is required during all steady-state and operational transient conditions.

By preventing a departure from nucleate boiling (DNB), neither the cladding nor the fuel is subjected to excessively high temperatures.

For more detail refer to Section 4.4.

4.2.1.2.4 Mechanical Limits

Fuel assemblies are designed for structural adequacy and reliable performance during core operation, handling, and shipping. Design criteria for core operation include steady state and transient conditions under combined effects of flow induced vibration, temperature gradients, and seismic disturbances.

Spacer grids, located along the length of the fuel assembly, position fuel rods in a square array, and are designed to maintain fuel rod spacing during core operation, handling, and shipping. Spacer-grid to fuel-rod contact loads are established to minimize fretting, but also allow axial relative motion resulting from fuel rod irradiation growth and differential thermal expansion.

The fuel assembly upper end fitting is indexed to the plenum assembly by the upper grid rib section immediately above the fuel assemblies to assure proper alignment of the fuel assembly guide tubes to the control rod guide tube. The guidance of the control rod assembly and axial power shaping rod assembly is designed such that these assemblies will never be disengaged from the fuel assembly guide tubes during operation. The fuel rods are designed to meet the following mechanical limits:

1. Section III of the ASME Boiler and Pressure Vessel Code is used as a guide in classifying the stresses into various categories and combining these stresses to determine stress intensities. Refer to Section 4.2.3.1.1 for the Duke clad stress and strain methodology.
2. Cyclic Strain limits for this stress condition are established based on low cycle fatigue techniques, not to exceed 90 percent of the material fatigue life. Evaluation of cyclic loading is based on conservative estimates of the number of cycles to be expected. An example of this type of stress is the thermal stress resulting from thermal gradients across the cladding thickness.
3. Cladding uniform strain is limited to a maximum of 1.0 percent.

4. Cladding Collapse

   The digital computer code CROV (References 1 and 11) is used to demonstrate that the effective full power hours (or equivalent burnup) to complete cladding collapse is greater than the incore residence time. Refer to Section 4.2.3.1.2 for Duke's creep collapse methodology.

5. Fuel Thermal Analysis

   The digital computer code TACO3 or COPERNIC (Reference 2 or 25) is used to ensure that fuel performance is satisfactory. Specifically the centerline temperature is maintained below fuel melt limits and end of life pin pressure is maintained below the value which would cause clad lift off. Refer to Section 4.2.3.1.3 for design evaluations of the fuel thermal analyses.

6. The cladding oxide thickness for the highest burnup rod in each sub-batch is limited to 100 μm as calculated on a best estimate basis.

4.2.2 Description - Fuel System Design

The complete core has 177 fuel assemblies which are arranged in the approximate shape of a cylinder. All fuel assemblies are similar in mechanical construction, and are mechanically interchangeable in any core location. The reactivity of the core is controlled by 61 control rod assemblies (CRAs) and 8 axial power shaping rod assemblies (APSRAs), a variable number of burnable poison rod assemblies (BPRAs), and soluble boron in the coolant. APSRAs are similar in physical configuration to the CRAs but have absorber material only in the lower portion of the rods. Burnable poison rod assemblies (Figure 4-1) are installed in selected fuel assemblies not containing an APSRA or a CRA. The burnable poison rod assemblies (BPRAs) assure that the net effect of the power Doppler and moderator temperature coefficients at power will be negative through core lifetime. The mechanical and geometric configuration of the CRAs and BPRAs permit full interchangeability in any fuel assembly.

Deleted paragraph(s) per 2005 update.

Important core design, thermal, and hydraulic characteristics are tabulated in Table 4-1, and fuel assembly component materials are presented in Table 4-2.

4.2.2.1 Fuel Assemblies

4.2.2.1.1 General

Fuel assembly designs (References 17, 18, and 21) are limited to those that have been analyzed with the applicable NRC approved codes and methods. A limited number of lead test assemblies (LTAs) that have not completed representative testing may be placed in non-limiting core locations.

The fuel assembly design shown in Figure 4-37 is typical of the designs used in Oconee 1, 2 and 3.

Cladding, fuel pellets, end caps, and fuel support components form a “fuel rod”. Two hundred and eight fuel rods, sixteen control rod guide tubes, one instrumentation tube assembly, eight spacer grids, and two end fittings make up the basic “Fuel Assembly” (Figure 4-37). Some fuel assembly designs prior to MK-B-HTP had seven segmented spacer sleeves. The guide tubes, spacer grids, and end fittings form a structural cage to arrange the rods and tubes in a 15 x 15 array. The center position in the assembly is reserved for instrumentation. Control rod guide tubes are located in 16 locations of the array. Use of similar material in the guide tubes and fuel rods results in minimum differential thermal expansion. Fuel assembly components, materials, and dimensions are tabulated in Table 4-2. Fuel assembly design descriptions are depicted in Table 4-23.

4.2.2.1.2 Fuel Rod

The fuel rod consists of fuel pellets, cladding, fuel support components, and end caps. All fuel rods are internally pressurized with helium.

The pellets are manufactured by cold pressing enriched uranium dioxide powder into cylinders with edge chamfers and dish at each end and then sintering to obtain the desired density and microstructure. After sintering, the pellets are centerless ground to the required diametrical dimensions.

There are spring spacers located both above and below the pellet stack in the MK-B10D and MK-B10E fuel assembly designs. Both springs are designed to accommodate maximum thermal expansion of the fuel column without being deflected beyond solid height. The lower spring is much stiffer by design, so the fuel column preload, thermal expansion and irradiation expansion principally compresses the upper spring. The MK B-10F and higher fuel assembly designs do not contain a bottom plenum spring.

The fuel rods within an assembly may have differing enrichments radially. Axially, the fuel rods may be of a constant enrichment, or they may be blanketed, which means that a portion of the top and bottom of the fuel stack has a lower enrichment. The function, behavior, and analysis of fuel rods containing axial blankets or radial zoning is the same as uniformly enriched fuel rods.

Fission gas generated in the fuel is released into pellet voids, the radial gap between the pellets and the cladding, and into the plenum spring space. Fuel rod data are given in Table 4-2, and a typical fuel rod is shown in Figure 4-4.

4.2.2.1.3 Spacer Grids

Spacer grids are constructed from strips which are slotted and fitted together in “egg crate” fashion. Each grid has 32 strips, 16 perpendicular to 16, which form the 15 x 15 lattice. The square walls formed by the interlaced strips provide support for the fuel rods in two perpendicular directions. Contact points on the walls of each square opening are integrally punched in the strips.

4.2.2.1.4 Lower End Fittings

The lower end fitting positions the assembly in the lower grid rib section. During fabrication, the lower ends of the fuel rods are seated on the grillage of the lower end fitting. Penetrations in the lower end fitting are provided for attaching the control rod guide tubes and for access to the instrumentation tube assembly. The lower end fittings are of an anti-straddle design which will prevent the fuel assembly from being improperly seated on the lower grid assembly.

4.2.2.1.5 Upper End Fitting

The upper end fitting positions the upper end of the fuel assembly in the upper grid rib section and provides means for coupling the handling equipment. An identifying number on each upper end fitting provides positive identification.

Attached to the upper end fitting is a holddown spring. This spring provides a positive holddown margin to oppose hydraulic forces resulting from the flow of the primary coolant.

Penetrations in the upper end fitting grid are provided for the guide tubes.

The upper end fitting can be removed to perform fuel assembly reconstitution.

4.2.2.1.6 Guide Tubes

The Zircaloy and M5 guide tubes provide continuous guidance for the control rod assemblies when inserted in the fuel assembly and provide the structural continuity for the fuel assembly. On the MK-B10D to MK-B10F through MK-B-11A designs, the upper guide tube nut is held secure by a crimped locking cup. On the MK B-10G, each guide tube is designed to engage with a locking device on the upper end fitting. MK-B-HTP fuel has a recon crimp top hat nut to secure the upper end fitting to the guide tube. Transverse location of the guide tubes is provided by the spacer grids. The guide tube hole size is optimized so that more coolant flows alongside the fuel rods.

4.2.2.1.7 Instrumentation Tube Assembly

This assembly serves as a channel to guide, position, and contain the in-core instrumentation within the fuel assembly. The instrumentation probe is guided up through the lower end fitting to the desired core elevation. It is retained axially at the lower end fitting by a retainer sleeve.

4.2.2.1.8 Spacer Sleeves

The spacer sleeve fits around the instrument tube between spacer grids and prevents axial movement of the spacer grids during primary coolant flow through the fuel assembly. MK-B-HTP fuel no longer utilizes spacer sleeves.

4.2.2.2 Lead Test Assembly Programs

The effort to continually improve fuel performance often necessitates use of lead test assemblies (LTA). Per Technical Specifications, Duke is allowed to operate cores with a limited number of LTAs that have not completed representative testing as long as they are located in non-limiting core regions (locations). The use of LTAs allows demonstration of the acceptability of different or improved fuel designs. Demonstration programs provide the fundamental engineering data used to develop computer codes and analytical methods. Demonstration programs also provide representative testing to ensure that a fuel design complies with all fuel safety design bases.

4.2.2.2.1 Current Demonstration Programs

Westinghouse-177 (WH-177)

Beginning with Oconee 3 Cycle 22, Duke installed four WH-177 LTAs in the reactor core. The WH-177's were designed by Westinghouse Corporation and are similar to LTAs previously used at TMI-1 except that they have an improved mid-grid design and three added intermediate support grids. These FAs have a 15 X 15 fuel rod array and are fully compatible with the other Mk-B design FAs in the core.

With regard to interaction with the plant fuel handling equipment, the WH-177 LTAs do require use of a special handling tool in order to receive them into each SFP.

Since the primary purpose of this LTA program is to demonstrate the mechanical and thermal hydraulic compatibility of the WH-177 LTAs at Oconee, these assemblies are subject to a detailed post irradiation examination (PIE) program to verify acceptable performance and validation of the design.

For details on differences between the Westinghouse and AREVA designs, see Table 4-24 and Figure 4-38.

4.2.3 Design Evaluation - Fuel System Design

This subsection contains a description of the fuel system design evaluation and is primarily a mechanical evaluation.

Nuclear design evaluation is contained within Section 4.3.3. Thermal hydraulic design evaluation is presented in Section 4.4.3.

4.2.3.1 Fuel Rod

The basis for the design of the fuel rod is discussed in Section 4.2.1.2. Materials testing and actual operation in reactor service with Zircaloy cladding have demonstrated that Zircaloy-4 and M5 material have sufficient corrosion resistance and mechanical properties to maintain the integrity and serviceability required for design burnup.

If radiochemistry data indicates that there are fuel rods in the core with breached cladding, a campaign may be scheduled for the next refueling outage to perform ultra-sonic testing of suspect fuel assemblies.

Fuel assemblies found with damaged or leaking fuel rods, can be reconstituted in order to replace damaged rods. One replacement option is a fuel rod that contains pellets of naturally enriched uranium dioxide (UO_2). Aside from enrichment, this rod is similar in design and behavior to a standard fuel rod and is analyzed using standard approved methods. Another replacement option is a solid filler rod made of stainless steel, Zircaloy or M5. Solid filler rods are useful when grid damage exists. A maximum of 10 such filler rods can be substituted into a single fuel assembly. Fuel assemblies with severe structural damage or with failed pins that can not be completely removed may be recaged or discharged. A recage operation entails transferring all of the sound fuel rods from the damaged cage to a new fuel assembly cage. This new fuel assembly will function the same as the assembly which it replaces. A safety evaluation (generic or core specific) is performed for repaired fuel assemblies to ensure acceptable nuclear, mechanical, and thermal-hydraulic performance. While the focus of this section has been on the replacement of damaged or leaking rods, a sound rod can be replaced. For example, a sound rod may be sent to a hot cell for detailed examination.

The NRC has approved Duke's reconstitution topical report (Reference 7). This report details the methodology and guidelines Duke Power Company will use to support fuel assembly reconstitution with filler rods. This methodology ensures acceptable nuclear, mechanical, and thermal-hydraulic performance of reconstituted fuel assemblies.

4.2.3.1.1 Clad Stress and Strain

The following descriptions summarize the analyses of fuel rod cladding stress and strain for reload fuel cycle designs, as performed by Duke. References 13, 14, 15 and 16 define the stress analysis methodology. The strain methodology is defined in Reference 2 or 25.

1. Cladding Stress Analysis

   The cladding stress analysis uses Section III of the ASME Boiler and Pressure Vessel Code as a guide in classifying the stresses into various categories, assigning appropriate limits to these categories, and combining these stresses to determine stress intensity. Each new fuel cycle design is assessed to determine if reanalysis is required. The stress analysis is very conservative, and reanalysis should not be required for most reload fuel cycle designs.

The static stress analysis uses design stress intensity limits on mechanical properties based on the requirements of ASME code Article III-2000. The design stress intensity value, SM, for Zircaloy-4 and M5 is 2/3 of the minimum non-irradiated yield strength at operating temperature as specified in Reference 2 for Zircaloy-4 and Reference 20 for M5.

In performing the stress analysis, all the loads are selected to represent the worst case loads and are then combined. This represents a conservative approach since they cannot occur simultaneously. This insures that the worst conditions for condition I and II events are satisfied. In addition, these input parameters were chosen so that they conservatively envelope all Mk-B design conditions. The effects of corrosion are accounted for in the stress analysis.

The primary membrane stresses result from pressure loading. Stresses resulting from creep ovalization are addressed in the creep collapse analysis.

The internal pressure of the peak fuel rod in the reactor will be limited to a proprietary value below that which would cause (1) the fuel-clad gap to increase due to outward cladding creep during steady-state operation and (2) extensive DNB propagation to occur. (Section 4.2.3.1.3)

The minimum internal fuel rod pressure at HZP conditions is combined with the maximum design system pressure during a transient to simulate the maximum compressive pressure differential across the cladding. The worst case compressive pressure loads are combined with the other worst case loads. These are described below:

a. The maximum grid loads will occur at BOL. During operation, the contact force will relax with time due to fuel rod creep-down and ovalization as well as grid spring relaxation.

b. Conservative cladding dimensions with regard to stress.

c. The maximum radial thermal stress will occur at the maximum rated power (power level corresponding to centerline fuel melt). This stress cannot physically occur at the same time the maximum pressure loading occurs, but is assumed to do so for conservatism. (Maximum cladding temperature gradient is combined with minimum pin pressure.)

d. Ovality bending stresses are calculated at BOL conditions. A linear stress distribution is assumed.

e. Flow induced vibration and differential fuel rod growth stresses are also addressed.

The resulting stresses meet the above criteria for both primary membrane and primary plus secondary stress intensities.

2. Cladding Strain Analysis

The limit on transient cladding strain is that uniform total strain of the cladding should not exceed 1.0%.

Duke performs a generic strain analysis using TACO3 or COPERNIC to ensure that the strain criterion is not exceeded. For each reload cycle, the generic strain power history is compared to the predicted power history in the final fuel cycle design. If the generic power history is violated, cladding strain is re-analyzed using a new generic power history.

Maximum tensile elastic and plastic strain occurs at the clad inside diameter. Clad strain is calculated as:

$$CladStrain\,\% = \frac{Clad\ D_{transient} - Clad\ D_{transient\ beginning}}{Clad\ D_{\mathrm{transient\ beginning}}}\ x\ 100$$

where Clad D is a code specific diameter prior to and after a power ramp (transient), which is calculated by TACO3 or COPERNIC using the methodology explained in Reference 2 or 25.

4.2.3.1.2 Cladding Collapse

Cladding creepdown under the influence of external (system) pressure is a phenomenon that must be evaluated during each reload fuel cycle design to ensure that the most limiting fuel rod does not exceed the cladding collapse exposure limit. Cladding creep is a function of neutron flux, cladding temperature, applied stress, cladding thickness, and initial ovality. Acceptability of a fuel cycle design is demonstrated by comparing the power histories of all the fuel assemblies against the generic assembly power history used in existing design analyses. Changes in pellet or cladding design are also evaluated against previously analyzed fuel rod geometries and a reanalysis is performed if necessary.

The CROV (References 1 and 11) computer code calculates ovality changes in the fuel rod cladding due to thermal and irradiation creep and is used to perform the fuel rod creep collapse analysis when required. CROV predicts the conditions necessary for collapse and the resultant time to collapse. Conservative inputs to the CROV cladding collapse analysis include the use of minimum cladding wall thickness and maximum initial ovality (conservatively assumed to be a uniform oval tube), as allowed by manufacturing specifications or batch specific as-built tolerance limits. Other conservatisms included are minimum backfill pressure (with TACO3) and zero fission gas release. Internal pin pressure and cladding temperatures, input to CROV (Reference 1), are calculated by TACO3 or COPERNIC using a (conservative) generic radial power history, and a typical axial flux shape.

The conservative fuel rod geometry and conservative power history are used to predict the number of EFPH (or equivalent burnup) required for complete cladding collapse. To demonstrate acceptability, the maximum cumulative residence time for the fuel is compared against the EFPH (or equivalent burnup) required for complete collapse. All operating cores must meet this criterion.

4.2.3.1.3 Fuel Thermal Analysis

Duke Power Company is performing its own reload design analyses per the approved methods in Reference 2 or 25. Duke currently uses the TACO3 or COPERNIC fuel pin performance codes. The following paragraphs summarize the methods that are used by Duke in performing its Oconee reload fuel temperatures, end of life pin pressure, and ECCS analysis interface criteria analyses.

1. Fuel Pin Pressure Analysis

   The pin pressure limit is intended to preserve the fuel-clad heat transfer characteristics by preventing clad liftoff. This limit provides reasonable assurance that: (1) excessive fuel temperatures, (2) excessive internal gas pressures due to fission gas release, and (3) excessive cladding stresses and strains are prevented.

   The maximum allowable pin burnup is based on whichever of the following conditions occurs first:

   a. Maximum Internal Pin Pressure: The fuel rod internal pressure is limited to a proprietary value above the nominal system pressure.

b. Clad Liftoff Limit: Clad liftoff occurs when the clad's outward creep rate exceeds the pellet's swelling rate. Clad liftoff is based on the ratio of cladding diametral strain rate divided by the fuel diametral strain rate at each axial elevation. Fuel-clad liftoff occurs when this ratio is ≥ 1.0 at any axial elevation where the local LHR is ≥ 3.0 kw/ft.

Duke performs a generic pin pressure analysis using the methodology described in Reference 2 or 25. For each reload cycle, the generic power history is compared to the predicted power history in the final fuel cycle design. If the generic power history is violated, the EOL pin pressure is re-calculated using a new generic power history.

2. Linear Heat Rate Capability

The fuel cannot exceed the temperature which would cause it to melt. Linear Heat Rate to Melt (LHRTM) limits are used to determine core protection limits which ensure that fuel melting will not occur. Duke performs a generic LHRTM analysis using the methodology described in Reference 2 or 25.

TACO3 and COPERNIC reduce the best estimate fuel temperature by a proprietary value which is based on comparison with measured data that inherently includes the effects of manufacturing variations, code predictions, transient fission gas release, and cladding oxide formation.

For each reload cycle, the generic power history is compared to the predicted power history in the final fuel cycle design. If the generic power history is violated, LHRTM is re-analyzed using a new generic power history.

3. ECCS Analysis Interface Criteria

Duke reviews each batch of fuel and the fuel cycle design for compatibility with the vendor's fuel rod thermal analysis inputs to the ECCS analysis. Review criteria have been developed by Duke and have been reviewed and approved by the vendor.

Should the fuel rod thermal analysis inputs for a specific cycle lie outside the vendor's generic analysis, Duke will reperform the fuel rod thermal analysis to ensure that the results remain bounded by the results of the vendor's generic analysis. In the unlikely event that the cycle specific thermal analysis results (fuel temperature and pin pressure) are more limiting than the vendor's generic analysis, either the fuel cycle design must be modified or the vendor must resolve the concern within the vendor's ECCS analysis. Responsibility for identification of incompatibility and resolution lies with Duke.

4.2.3.1.4 Cladding Corrosion

The cladding oxide thickness, for the highest burnup rod in each sub-batch, is limited to 100 μm on a best estimate basis. References 12, 14, 21 and 25 define the corrosion analysis methodology. If an assembly contains a rod whose predicted oxide thickness is over 100 μm, it can be designated a lead corrosion assembly and continue to operate. Corrosion measurements will be taken on these assemblies after they have been discharged from the core. The total number of lead corrosion assemblies is limited to 8 per cycle. The total number of lead corrosion and other demonstration assemblies is limited to 12 per cycle.

4.2.4 Fuel Assembly, Control Rod Assembly, and Control Rod Drive Mechanical Tests and Inspection

To demonstrate the mechanical adequacy and safety of the fuel assembly, control rod assembly (CRA), and control rod drive, a number of functional tests have been performed.

4.2.4.1 Prototype Testing

A full-scale prototype fuel assembly, CRA, and control rod drive have been tested in the Control Rod Drive Line (CRDL) Facility located at the B&W Research Center, Alliance, Ohio (Reference 3). This full-sized loop is capable of simulating reactor environmental conditions of pressure, temperature, and coolant flow. To verify the mechanical design, operating compatibility, and characteristics of the entire control rod drive fuel assembly system, the drive was stroked and tripped to duplicate the expected 20-year operational life.

A portion of the testing was performed with maximum misalignment conditions. Equipment was available to record and verify data such as fuel assembly pressure drop, vibration characteristics, and hydraulic forces and to demonstrate control rod drive operation and verify scram times. All prototype components were examined periodically for signs of material fretting, wear, and vibration/ fatigue to insure that the mechanical design of the equipment met reactor operating requirements.

The Type C prototype drive mechanism used originally on Oconee 3 was tested at Diamond Power Specialty Corporation, Lancaster, Ohio (Reference 3). This consisted of component testing, a 100 percent misalignment life test (equivalent to 20 year operation), and motor performance tests. Throughout these tests the drive components were examined for material fretting, wear and vibrational fatigue.

4.2.4.2 Model Testing

Many functional improvements have been incorporated in the design of the fuel assembly as a result of model tests. For example, the spacer grid to fuel rod contact area was fabricated to ten times reactor size and tested in a loop simulating the coolant flow Reynolds number of interest. Thus, visually, the shape of the fuel rod support areas was optimized with respect to minimizing the severity of flow vortices and pressure drop. A 9-rod (3 x 3) assembly using stainless steel spacer grid material has been tested at reactor conditions (640°F, 2,200 psi, 13 fps coolant flow) for 210 days. Two full sized canned fuel assemblies with stainless steel spacer grids have been tested at reactor conditions, one for 40 days and the other for 22 days. A prototype canless fuel assembly using Inconel 718 spacer grids has been tested for approximately 90 days, approximately half of that time at reactor conditions. The principal objectives of these tests were to evaluate fuel assembly and fuel rod vibration and/or fretting wear resulting from flow-induced vibration. Vibratory amplitudes have been found to be very small, and, with the exception of a few isolated instances which are attributed to pretest spacer grid damage, no unacceptable wear has been observed.

4.2.4.3 Component and/or Material Testing

4.2.4.3.1 Fuel Rod Cladding

Refer to Reference 1 for a detailed report of externally pressurized fuel rod creep collapse tests.

4.2.4.3.2 Fuel Assembly Structural Components

The structural characteristics of the fuel assemblies which are pertinent to loadings resulting from normal operation, handling, earthquake, and accident conditions are investigated experimentally in test facilities such as the CRDL Facility. Structural characteristics such as natural frequency and damping are determined at the relatively high (up to approximately 0.300 in.) amplitude of interest in the seismic and LOCA analyses. Natural frequencies and amplitudes resulting from flow-induced vibration are measured at various temperatures and flow velocities, up to reactor operating conditions.

4.2.4.3.3 Areva Fuel Surveillance Program

Areva` conducts various test programs aimed at obtaining fundamental engineering data on fuel and control components for design, manufacturing, and licensing support. The extensive previous operating history and detailed fuel surveillance confirms the basic soundness of the Areva fuel design. The operation of all Areva fuel will continue to be closely monitored using activities such as manufacturing reviews, coolant chemistry monitoring, post irradiation examinations, etc. to ensure continued safe and reliable fuel performance. Post irradiation examinations typically perform tests such as visual inspections, fuel assembly growth measurements, spacer grid position determination, fuel assembly bow measurements, shoulder gap measurement, water channel measurements, spring preload, verification of the quick disconnect upper end fitting operation, and other non-destructive testing.

Fuel with suspected defective fuel rods are typically examined and tested for leakage. Leakage verification may utilize an ultrasonic test rig, a vacuum can sipping system, or an in-mast sipping system. The ultrasonic technique looks for water inside the fuel rod. The vacuum and in-mast sipping techniques pull a liquid or gas sample from above the assembly and pipe the sample to a shielded detector in order to look for elevated gaseous fission products emanating from the leaking fuel rod. If these methods indicate that a fuel pin is defective, then the fuel assembly will either be repaired or evaluated for acceptability for use in future cycle designs.

4.2.4.4 Control Rod Drive Tests and Inspection

4.2.4.4.1 Control Rod Drive Developmental Tests

The testing and development program for the roller nut drive has been completed. The prototype drive was tested at the B&W Research Center at Alliance, Ohio. Wear characteristics of critical components have indicated that material compatibility and structural design of these components would be adequate for the design life of the mechanism. The trip time for the mechanism as determined under test conditions of reactor temperature, pressure, and flow was well within the specification requirements.

Deleted paragraph(s) per 2005 update .

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4.3 Nuclear Design

The reactor core is designed to operate at 2568 MWt with sufficient nuclear design margins to accommodate transient operation without damage to the core. The core design characteristics are given in Table 4-1.

Core reactivity is controlled by control rod assemblies (CRA), soluble boron in the coolant, and burnable poison rod assemblies (BPRA). Sufficient CRA worth is available to shut down the reactor with at least a 1% $\Delta k/k$ subcritical margin in the hot condition at any time during the cycle with the most reactive CRA stuck in the fully withdrawn position. Equipment is provided to add soluble boron to the reactor coolant to ensure a similar shutdown capability when the reactor is cooled to ambient temperatures.

The reactivity worth of a CRA and the rate at which reactivity can be added are limited to ensure that credible reactivity accidents cannot cause a transient capable of damaging the RCS or causing significant fuel failure.

4.3.1 Design Bases - Nuclear Design

The core has been designed to the following nuclear limits and capabilities, all of which are intended to preserve the integrity of the fuel assemblies:

1. The core will have sufficient reactivity to produce the design power level and lifetime without exceeding the control capacity or shutdown margin.
2. Fuel assemblies have been designed for the maximum burnups shown in Table 4-2.
3. Power histories must be bounded by those assumed within generic mechanical and thermal hydraulic (fuel assembly) analyses. If they are not bounded, acceptable reanalyses shall be performed.
4. The maximum feed fuel enrichment is constrained by the maximum allowed in the Technical Specifications (Spent Fuel Pool storage requirements).
5. Values of important core safety parameters predicted for the cycle have been verified to be conservative with respect to their values assumed in the Chapter 15 safety/accident (and any other pertinent) analyses. If they are not conservative, acceptable reanalyses shall be performed.

   Controlled reactivity insertion rates due to a single CRA group withdrawal shall be limited to a maximum value assumed within the Chapter 15 Rod Withdrawal Accident at Rated Power, and within the Chapter 15 Startup Accident. Controlled reactivity insertion rates due to soluble boron removal shall be limited to a maximum value assumed within the Chapter 15 Moderator Dilution Accident.

   The overall power coefficient is negative in the power operating range. However, as described within Chapter 15, the control system is capable of compensating for reactivity changes resulting from either positive or negative nuclear coefficients.
6. Reasonable and permissive reactor control and maneuvering procedures during nominal operation and during transients will not produce unacceptable peak-to-average power distributions. This, along with criteria 7 and 8, below, preserves the LOCA linear heat rate, linear heat rate to melt (LHRTM), and DNBR limits.

7. Part length axial power shaping rods (APSRs) may be utilized to allow the shaping of power axially in the core, thereby thwarting any tendency towards axial instability resulting from a redistribution of xenon.

   To preclude the possiblity of azimuthal instability resulting from a redistribution of xenon, the highest moderator temperature coefficient assumed within the Chapter 15 safety/accident analyses must be bounded by the threshold listed within Table 4-7.

8. Technical Specification limits of specified operating parameters (quadrant power tilt, power imbalance, and control rod insertion), and on reactor protective system trip setpoints (power imbalance) after allowance for appropriate measurement tolerances should have adequate margin from design limits of these parameters during operational conditions throughout the cycle such that sufficient operating flexibility is retained for the fuel cycle.

4.3.2 Description - Nuclear Design

A summary of the nuclear characteristics of the core is given in Table 4-3.

4.3.2.1 Excess Reactivity

The Oconee reactor cores are designed with sufficient excess reactivity to yield the desired cycle length. This excess reactivity is controlled by soluble boron, burnable poison rod assemblies (BPRA), and control rod assemblies (CRA).

Generally, the nuclear designer makes an engineering trade-off between soluble boron and burnable poison rods to assure that the BOC moderator coefficient for power levels above 95 percent Hot Full Power (HFP) is nonpositive. Table 4-4 shows a typical fuel cycle's excess reactivity at various conditions.

Table 4-5 shows the k-effective calculated for a single fuel assembly. The minimum critical mass, with and without xenon and samarium poisoning, may be specified as a single assembly or as multiple assemblies in various geometric arrays. The unit fuel assembly has been investigated for comparative purposes. A single cold, clean assembly containing an enrichment of 3.5 weight percent is subcritical. Two assemblies side-by-side are supercritical under these conditions.

4.3.2.2 Reactivity Control

The excess reactivity is controlled by a combination of soluble boron, lumped burnable poison, and control rods. Long term decreases in reactivity caused by fuel burnup are offset by decreases in soluble boron concentration and decreases in burnable poison worth. Short term reactivity effects are controlled by changes in control rod position.

Soluble Boron

Figure 4-5 illustrates a typical variation of soluble boron versus cycle length of a fuel cycle. The change in boron concentration accounts for depletion of the fuel and is also a function of the BPRA loading and burnout.

Burnable Poison Rod Assemblies (BPRAs)

Figure 4-6 shows a typical burnable poison loading and enrichment scheme for a fuel cycle. The BPRAs burnout as the fuel depletes and at end of cycle have a small residual reactivity effect caused by structural materials and water displacement effects.

The BPRA loadings and placement are chosen to shape radial power peaks and to decrease initial soluble boron concentration to a level where the BOC moderator temperature coefficient is non-positive above 95% full power. Since the BPRA assemblies are located in the control rod guide tubes, they cannot be placed in rodded locations. In addition, they will usually be in fresh fuel assemblies. See Section 4.5.2.4 for a physical description of the BPRAs. See the appropriate reload design change report for actual BPRA loadings for any particular cycle.

Control Rod Assemblies

Oconee has 61 full length control rods assigned to seven control rod groups (1 to 7). Groups 1 to 4 are designated safety banks and are maintained out of the core above HZP. Groups 5 to 7 are designated control banks and may be inserted to pre-established limits shown in the Core Operating Limits Report between HZP and HFP.

A typical control rod pattern is shown in Figure 4-7. The groupings of control rods into the various rod groups can vary with reload cycle and reference to the appropriate reload design change report should be made for the particular pattern being used for a particular cycle. In addition to being able to shut the reactor down, full length control rods are used to control reactivity changes caused by power level changes, transient xenon, and small periodic boron dilution changes.

Oconee has 8 Axial Power Shaping Rods (APSRs) which are always assigned to Group 8. These rods do not insert upon reactor trip and are used for axial power shaping and can be used to damp axial xenon oscillations.

Reactivity Control During Refueling

Core subcriticality during refueling operations (Mode 6) is maintained through plant fuel handling procedures that ensure adequate shutdown margin is maintained. (References 20, 21 responses to NRC Bulletin 89-03, “Potential Loss of Required Shutdown Margin During Refueling Operations”).

4.3.2.3 Reactivity Shutdown Analysis

The ability to shut down the core from any operating condition by 1% $\Delta\rho$ is a Technical Specification requirement. This is accomplished by analytical calculations during the reload design and rod index limits are set such that at least a 1% $\Delta\rho$ shutdown margin is available for a trip from any allowable operating condition.

Table 4-6 illustrates a shutdown margin calculation for a sample Oconee fuel cycle. Conservatisms include a worth reduction penalty for control rod burnup and a 10 percent rod worth uncertainty. The flux redistribution effect is included if the power deficit was calculated with a two-dimensional code. This item does not need to be shown in a shutdown margin table if a three-dimensional calculation of power deficit was performed.

A detailed discussion of the calculation of the remaining parameters in Table 4-6 can be found in Reference 1 and Reference 2.

For the shutdown margin calculation for a particular reload cycle refer to the bases behind the appropriate reload design change report.

4.3.2.4 Reactivity Coefficients

Reactivity coefficients form the basis for studies involving normal and abnormal reactor operating conditions. These coefficients have been investigated as part of the analysis of this core and are described below as to function and overall range of values.

4.3.2.4.1 Doppler Coefficient

The Doppler coefficient reflects the change in reactivity as a function of fuel temperature. The Doppler coefficient of reactivity is due primarily to Doppler broadening of the U-238 resonances with increasing fuel temperature. A rise in fuel temperature results in an increase in the effective absorption cross section of the fuel and a corresponding reduction in neutron production. A typical range for the Doppler coefficient under operating conditions would be -1.1×10^{-5} to -1.7×10^{-5} $(\Delta\rho)$/deg F.

4.3.2.4.2 Moderator Void Coefficient

The moderator void coefficient relates the change in neutron multiplication to the presence of voids in the moderator. The expected range for the void coefficient is shown in Figure 4-8.

4.3.2.4.3 Moderator Pressure Coefficient

The moderator pressure coefficient relates the change in moderator density, resulting from a reactor coolant pressure change, to the corresponding effect on neutron production. This coefficient is opposite in sign and considerably smaller when compared to the moderator temperature coefficient. A typical range of pressure coefficients over a life cycle would be -1.4×10^{-7} to $+4 \times 10^{-6}$ $(\Delta\rho)$/psi.

4.3.2.4.4 Moderator Temperature Coefficient

The moderator temperature coefficient relates a change in neutron multiplication to the change in reactor coolant temperature. Reactors using soluble boron as a reactivity control have a less negative moderator temperature coefficient than do cores controlled solely by movable or fixed CRA. The major temperature effect on the coolant is a change in density. An increasing coolant temperature produces a decrease in water density and an equal percentage reduction in boron concentration. The boron concentration change results in a positive reactivity component by reducing the absorption in the coolant. The magnitude of this component is proportional to the total reactivity held by soluble boron. Distributed poisons (burnable poison rods or inserted control rods) have a negative effect on the moderator coefficient for a specified boron concentration. That is, the moderator coefficient for a system with 1200 ppm boron in the coolant and 1% rod worth inserted will be more negative than for a system with 1200 ppm boron and no rods inserted. Depending on the core size, core loading, and power density, a plant may or may not require additional distributed poisons to yield the appropriate moderator temperature coefficient as determined by the safety analysis and the stability analysis of the core. An example of this, as pertaining to the first cycle, is illustrated in Table 4-7.

Items 4d and 6 in Table 4-7 above reflect three dimensional calculations using thermal feedback. These coefficients are more negative than the two-dimensional isothermal values previously calculated and shown. It is seen from comparison (Table 4-7, Table 4-8, Table 4-9) that three-dimensional spatially distributed effects are important in the determination of reactivity coefficients.

The three-dimensional PDQ07 calculation with thermal feedback was also used to calculate for Oconee 1, Cycle 1 the change in spatially dependent moderator coefficient for changes in inlet, outlet, and core average moderator temperature ($°F_m$), as shown in Table 4-8.

The Oconee reactors operate above approximately 15% of rated power on a constant core average moderator temperature with both inlet and outlet temperature changing with power level. The core average moderator temperature as seen by the control system is defined to be

$$T_m = \frac{T_{in} + T_{out}}{2}$$

The BOL distributed temperature moderator coefficients for different reactor power levels are presented in Table 4-9 for Oconee 1, Cycle 1, and for a typical reload cycle with three dimensional codes PDQ07 and SIMULATE-3, respectively, and both with thermal feedback. These coefficients were found by changing both inlet and outlet temperatures. Criticality in each case was attained by appropriate control rod insertion for Oconee 1, Cycle 1, and by boron for the typical reload cycle.

The moderator temperature coefficient was also calculated for the equilibrium xenon condition at the beginning of the fuel cycle. The calculation assumed 2.1% $\Delta\rho$ in control rods for Oconee 1, Cycle 1; boron search was used for a typical reload cycle. The 100% power moderator coefficient varied in the manner shown in Table 4-10.

The EOL coefficient was calculated for a change in both the inlet and outlet temperatures with a boron concentration of 17 ppm. The coefficient for 100% power was found to be:

$$\alpha_m = -2.8 \times 10^{-4} \frac{\Delta\rho}{°F_m}$$

This, then, is the "rods out" moderator coefficient at the end of the first fuel cycle for Oconee 1, Cycle 1.

The coefficients reported in Table 4-8 and Table 4-9 (Oconee 1, Cycle 1) are for a core containing 2.1 percent $\Delta\rho$ in control rods. A "rods out" calculation for the beginning of life moderator conditions in Item 2, Table 4-8 was performed as a basis for comparison and the result was

$$\alpha_m = +0.52 \ \times \ 10^{-4} \Delta\rho / °F_m$$

An examination of the data in Table 4-7 shows that the limiting factor on a moderator coefficient is the value used during Oconee 1, Cycle 1 safety analysis, i.e., $+0.9 \times 10^{-4}$ $\Delta\rho/°F_m$. The margin between this value and the nominal calculated value of $+0.27 \times 10^{-4}$ $\Delta\rho/°F_m$ is considered adequate to cover uncertainties.

4.3.2.4.5 Power Coefficient

The power coefficient, αp, is the fractional change in neutron multiplication per unit change in core power level. A number of factors contribute to αp, but only the moderator temperature coefficient and the Doppler coefficient contributions are significant. The power coefficient can be written as:

$$\alpha_p = \alpha_m \frac{\partial^T m}{\partial P} + \alpha_f \frac{\partial^T f}{\partial P}$$

where:

α_m = moderator temperature coefficient

α_f = fuel Doppler coefficient

$\frac{\partial^T m}{\partial P}, \frac{\partial^T f}{\partial P}$ = change in moderator and fuel temperature per unit change in core power.

Power coefficients were calculated for Oconee 1, Cycle I and for a typical reload cycle at BOL (time zero) at various power levels. For Oconee 1, Cycle 1, a boron concentration of 1200 ppm was used for all power levels, and criticality was achieved with control rods. For a typical reload cycle, boron search was used for all power levels, and criticality was achieved by boron. The three-dimensional codes PDQ07 and SIMULATE-3, both with thermal feedback, were used to include the effects of spatially distributed fuel and moderator temperatures.

The results are presented in Table 4-11.

4.3.2.4.6 pH Coefficient

Currently, there is no definite correlation which will permit prediction of pH reactivity effects. Some of the parameters needing correlation are the effects relating pH reactivity change for various operating reactors, pH effects versus reactor operating time at power, and changes in effects with varying clad, temperature, and water chemistry. Yankee, Saxton, and Indian Power Station 1 have experienced reactivity changes at the time of pH changes, but there is no clear-cut evidence that pH is the direct reactivity influencing variable without considering other items such as clad materials, fuel assembly crud deposition, system average temperature, and prior system water chemistry.

The pH characteristic of this design is shown below in Table 4-12 where the cold values are measured and the hot values are calculated.

Saxton experiments (Reference 3) have indicated a pH reactivity effect of 0.0016 $\Delta\rho/\Delta$pH unit change with and without local boiling in the core. Considering system makeup rate of 35,000 lb/h and the core in the hot condition with 1,200 ppm boron in the coolant, the corresponding changes in pH are 0.02 pH units per hour for boron dilution and 0.05 pH units per hour for ^{7}Li dilution (starting with 0.5 ppm ^{7}Li). Applying the pH worth value quoted above from Saxton, the total reactivity insertion rate for the hot condition is 3.1 x 10^{-8} $\Delta\rho$/sec. This insertion rate or reactivity can be easily compensated by the operator or the Integrated Control System.

4.3.2.5 Reactivity Insertion Rates

Figure 4-10 displays a typical integrated rod worth of three overlapping rod banks as a function of distance withdrawn. The indicated groups are those used in the core during power operation. Using an assumed nominal of 1.5% $\Delta\rho$ CRA groups and an assumed 30 in./min CRA drive speed in conjunction with the reactivity response given in Figure 4-10 yields a maximum reactivity insertion rate of 1.09 x 10^{-4} ($\Delta\rho$)/sec. The maximum reactivity insertion rate for soluble boron removal, using an assumed boron dilution rate of 500 GPM, is 0.16 x 10^{-4} ($\Delta\rho$)/sec.

4.3.2.6 Power Decay Curves

Figure 4-11 displays the beginning-of-life power decay curves for the CRA worths corresponding to the 1 percent hot shutdown margin with and without a stuck rod. The power decay is initiated by the trip of the CRA with a 300 msec delay from initiation to start of CRA motion. The time required for insertion of a CRA 2/3 of the distance into the core is 1.4 sec.

4.3.3 Nuclear Evaluation

The nuclear evaluation for a fuel cycle design is composed of the preliminary fuel cycle design, the final fuel cycle design, safety analysis physics parameters, maneuvering analysis, core operating limits (Technical Specifications and Core Operating Limits Report) calculation, final core loading map calculation, and core monitoring parameters calculation.

The preliminary fuel cycle design determines the number and enrichment of the fresh fuel to be inserted for a given cycle.

The final fuel cycle design uses the models discussed in Section 4.3.3.1 to optimize the placement of fresh and burned fuel assemblies, control rod groupings, and BPRA (if any) to result in an acceptable fuel design. It must meet the following current design criteria with appropriate reductions to account for calculational uncertainties:

1. Operate to the scheduled end-of-cycle (EOC) plus a long window for operational uncertainty, potentially using reduction in average coolant temperature and/or coast down in power for reactivity addition and reduction in initial enrichment requirements.
2. The U235 fuel enrichment must be bounded by that listed within the Technical Specifications (Spent Fuel Pool storage requirements).
3. Maximum pin burnup must be bounded by the appropriate limit for a fuel type.
4. Maximum assembly average burnup must be bounded by the appropriate limit for a fuel type.
5. The power histories must be bounded by those used in generic analyses, or provide acceptable results when specifically analyzed.
6. For the current bypass flow assumptions, the typical number of 44 BPRAs gives sufficient margin.

During the safety analysis physics parameters, a number of physics parameters are calculated and are verified as conservative with respect to those assumed within the Chapter 15 safety/accident analyses. These include, but are not limited to, the following:

1. Moderator temperature coefficient
2. Doppler coefficient
3. Ejected rod worth
4. Dropped rod worth
5. Total/maximum CRA group worth
6. Kinetics parameters
7. Shutdown margin
8. Maximum reactivity insertion rates (due to controlled rod withdrawal and boron dilution)
9. Differential boron worth
10. Boron concentrations

The purpose of a maneuvering analysis is to generate three dimensional power distributions, rod positions, and imbalances for a variety of reasonable and permissive rod positions, xenon distributions, and power levels. The maneuvering analysis can be described as four discrete phases. The first is the nominal fuel cycle depletion performed at a nominal rod index (typically, rod index = 292 and APSRs at 35% withdrawn) to establish a fuel depletion history. The second is the power maneuver performed at BOC (4 EPFD), at EOC (with appropriate adjustments to ensure critical conditions), and at least one other point in between; APSRs are positioned as necessary to maintain xenon control and to maintain predetermined imbalance limits. The third is to perform control rod and APSR scans at the most severe times of the power maneuver. The fourth step is to perform selected control rod and APSR scans at various nominal depletion steps. Each of these phases involves running multiple three dimensional cases and generation of three dimensional power distributions, rod positions, and imbalances for each case. The data is processed by utility codes to calculate margins to LHRTM, DNBR, and LOCA limiting criteria, and to produce 'fly-speck' plots. Application of appropriate calculational conservatisms are described within References 2, 4, 18, and 22. Note that the derivations of the LHRTM, DNBR, and LOCA limiting criteria have been bounded by limiting power distribution listed within Table 4-1.

In addition, the initial rod positions assumed within the following safety parameters must be bounded by the rod insertion limits determined during the maneuvering analysis:

1. Shutdown margin at HZP, BOC to EOC ≥ 1.0% $\Delta\rho$ (with the most reactive CRA stuck in the fully withdrawn position).
2. Maximum ejected rod worth at HZP, NoXe, BOC and EOC, as bounded by that assumed within the Chapter 15 Rod Ejection Accident.
3. Maximum ejected rod worth at HFP, EqXe, BOC and EOC, as bounded by that assumed within the Chapter 15 Rod Ejection Accident.
4. Maximum dropped rod worth at HFP, NoXe, EOC, as bounded by that assumed within the Chapter 15 Control Rod Misalignment Accident.
5. Maximum dropped rod worth HFP, EqXe, EOC, as bounded by that assumed within the Chapter 15 Control Rod Misalignment Accident.

During core operating limits calculation, data from 'fly-speck' plots generated during the maneuvering analysis are used to set limits on operational alarm setpoints (quadrant power tilt, control rod insertion, power-imbalance), and reactor protective system trip setpoints (power-imbalance). In addition, limits on control rod insertion based on the shutdown margin and required boron concentrations within the control system equipment are developed (or retrieved from appropriate sources). These limits are chosen such that sufficient operating flexibility is retained for the fuel cycle, while maintaining sufficient margin to design and safety criteria. These limits are set according to the allowances for appropriate measurement tolerances and uncertainties, which include, but are not limited to the following:

1. In-core detector system (observability and variability) and in-core monitoring software uncertainties
2. Out-of-core to In-core calibration/correlation uncertainty
3. Control rod position uncertainties
4. Flux-flow ratio adjustment
5. Reactor protective system hardware uncertainties
6. Boron concentration and volume uncertainties

The following Technical Specification limit is presumed as being met by the startup physics test program criteria for moderator temperature coefficient (which must be less than $+0.5 \times 10^{-4}$ $\Delta\rho$/deg F):

1. Moderator temperature coefficient $\leq$ 0.0 at > 95% hot full power.

Table 4-9 for a typical reload design, generated with SIMULATE-3, shows that this presumption is valid. The moderator temperature coefficient (MTC), when changing conditions from BOC, HZP, NoXe, and ARO to BOC, 95%fp, NoXe, and ARO, becomes negative; note that the 95% no xenon condition is conservative. Given the change, and startup physics test program criteria of +0.5 x 10^{-4} $\Delta\rho$/deg F, the MTC at 95%fp is negative (approximately -0.7 x 10^{-4} $\Delta\rho$/deg F).

During final core loading map calculation, placement of fuel assemblies and related core components in a reload core are determined. Special considerations such as even distributions of fresh fuel loadings and BPRA poison loadings are taken into account to minimize the possibility of an asymmetric or tilted core which would perturb the assumptions and predictions made during the fuel cycle design process.

During core monitoring parameters calculation, certain physics parameters are calculated to enable an orderly and safe startup of the cycle, to perform the startup physics test program, and to perform corefollow calculations. Other physics parameters are used to update the in-core monitoring software residing within the plant process computer. The in-core monitoring software monitors the quadrant tilt, power imbalance, and rod positions, and actuates alarms if these parameters violate the operational limits. Periodic calculations are also done to verify the existence of the 1.0% $\Delta\rho$ shutdown margin, and to check predictions versus measured data. As such, monitoring of core performance during cycle operation confirms the validity of predictions and ensures that design and safety criteria are satisfied.

The analytical models and their applications are discussed in this section as well as core instabilities associated with xenon oscillations.

4.3.3.1 Analytical Models

Reactor design calculations are made using a large number of computer codes. The following section describes the major analytical models employed by DUKE in the design of Oconee reload cores. Table 4-13 specifies the cycle of each unit when these methodologies were first applied. The methodology used in a particular reload design is stated in the bases behind appropriate reload design change report.

4.3.3.1.1 CASMO-3 or CASMO-4/SIMULATE-3-Based Methodology

The CASMO-3/SIMULATE-3-based calculational methods for nuclear design have been reviewed and approved by the NRC in Reference 18. This methodology was first applied during the reload design analysis of Unit 1 Cycle 16. The CASMO-4/SIMULATE-3 based calculation methods for nuclear design have been reviewed and approved by the NRC in Reference 22. This methodology was first applied for the reload design analysis of Unit 2 Cycle 26.

Verification to Measured Data

The verification of the CASMO-3 and CASMO-4/SIMULATE-3-based methods for nuclear design are documented in Reference 18 and Reference 22, respectively.

4.3.3.1.2 Control of Power Distributions

The reactors are designed to permit power maneuvering on control rods. Various calculations are performed during the maneuvering analysis to develop operational power-imbalance, RPS power imbalance, and rod insertion limits. These three-dimensional calculations account for effects of rod insertion, xenon distribution, and power level on the power distribution. A more detailed discussion of these calculations can be found in Reference 2.

During startup testing an out-of-core detector correlation test is performed to calibrate the imbalance as measured by the out-of-core detectors (NI-5, -6, -7, and -8) to that measured by in-core detectors. Uncertainties in the measurement of imbalance and power level are accounted for to assure that the reactor trips before any DNBR or fuel melt limit is reached.

The out-of-core neutron flux detectors each consist functionally of two nominally 70 inch sections of uncompensated ion chambers placed opposite the top and bottom halves of the core. Comparison of the signals from the two detectors gives an indication of the core axial offset or imbalance. This imbalance signal (top core power minus bottom core power) is monitored in the control room. When an imbalance is indicated, the operator may move the APSR's in the direction of the imbalance to reduce the axial offset, i.e.,

positive offset - move APSR's toward top;

negative offset - move APSR's toward bottom.

The integrated control system will automatically compensate for reactivity changes and consequent power swings caused by the part length control rod movement.

4.3.3.1.3 Nuclear Design Uncertainty (Reliability) Factors

In various calculations additional conservatism is applied to the calculated parameters. The factors sometimes are analysis dependent and are tabulated in References 18 and 22.

4.3.3.1.4 Power Maldistributions

Misaligned Control Rods

The reactor has a control function to protect against a rod out of step with its group. The position of each rod is compared to the average of the group. If an assymetric fault is detected at power levels greater than 60% of rated power, a rod withdrawal inhibit is activated and the Integrated Control System (ICS) runs the plant back to 55% of rated power. If a rod is dropped, the Integrated Control System (ICS) cannot maintain core power to match demand by withdrawal of other rods, and the plant is run back to less than 60 percent of rated power. Several cases were also analyzed for BOL for Oconee 1, Cycle 1, with single dropped rods. The calculations were performed with half-core X-Y geometry in PDQ07 at rated power without thermal feedback. The results are given in Figure 4-13.

The maximum radial-local power peak is 1.92. The original FSAR design limit is a 2.1 radial-local at rated power with a 1.5 cosine yielding a 1.3 DNBR based on the W-3 correlation. At a 114 percent overpower condition the design limit can also be expressed as a 1.9 radial-local with a 1.5 cosine yielding a 1.3 DNBR. The dropped rods illustrated in Figure 4-13 do not represent violations of the thermal limits of the design.

Several dropped rod cases run with SIMULATE-3 and current core design models indicate less severe radial-local power peaks; primarily because the current cores operate in a feed and bleed mode and the Oconee 1, Cycle 1 core was a rodded core. It should also be noted that dropped rod accidents are analyzed within Chapter 15 (Control Rod Misalignment Accident), and that this analysis showed that the consequence of a dropped rod is minimal such that the core and RCS pressure boundary are preserved, even when the worst assumed safety parameters are used and no credit is taken for ICS action.

Radial power tilts can be detected with the out-of-core and in-core instrumentation, and the operator has the flexibility to monitor the upper or the lower out-of-core detectors to determine the X-Y power symmetry condition at any time.

For the assumed case where one CRA is left out of the core while the remainder of the group is fully inserted, this condition would not occur except with regard to rod “swaps”. Since rod swaps are performed at reduced power, and since the operator can monitor the out-of-core detectors, an X-Y tilt resulting from such a condition could be detected and appropriate action taken before the approach to thermal limits could be realized.

The APSR drives are also equipped with the position monitors and the alarm function for a rod out of step with the group average. These drives, however, do not permit rod drops. With the power removed from the rod drive windings of the APSR, the roller nut will not disengage and the rod remains in its position. Since the APSR's are made of low-absorbing (gray) material, it is not likely that thermal limits will be exceeded if one of the rods were stuck and the rest of the group were moved.

Azimuthal Xenon Oscillations

The Oconee reactors are predicted to have a substantial margin to threshold for azimuthal xenon oscillations. Therefore, this mode is not considered to be likely to produce a power peaking problem.

Fuel Misloading

Assurance of the proper loading of fuel rods into assemblies is provided through fuel vendor loading controls and procedures. Fuel rods are mechanically identified so that traceability and accountability of each rod exists. The manufacturing process relies on administrative procedures and quality control independent verification to assure that fuel rods are placed in the proper assembly location.

Gross fuel assembly misplacement in the core is prevented by administrative core loading procedures and the prominent display of fuel assembly identification markings on the upper end fitting of each assembly. After the core is loaded, an independent check is performed to verify the core loading.

During startup physics testing, misloaded fuel may be discovered by unexpected quadrant power tilt or differences between predicted and measured power distributions.

4.3.3.2 Xenon Stability Analysis and Control

Modal and digital analysis of the Oconee 1, Cycle 1 core indicated that a tendency toward xenon instability in the axial mode would exist for a given combination of events (BOL, rodded core). Therefore, eight part-length Axial Power Shaping Rod Assemblies (APSRA) have been included in the design. They will be positioned during operation to maintain an acceptable distribution of power for any particular operating condition in the core, thereby reducing the tendency for axial oscillations. Similar analysis which was performed on the Oconee 2, Cycle 1 core indicated that it would be stable with regard to axial oscillations. Oconee 3, Cycle 1 was assumed to have characteristics similar to those of Oconee 1.

The azimuthal stability of the cores are dependent upon core loadings, power densities, and moderator temperature coefficients. In any event, the cores will not be susceptible to diverging azimuthal oscillations. If the loadings and power densities are low enough, the core will be inherently stable (Oconee 1, Cycle 1). If not, then burnable poison is added in the amount necessary to provide a moderator temperature coefficient that will result in azimuthal stability (Oconee 2&3, Cycle 1). A detailed description of the xenon analyses performed on Unit 1 and 2 cores may be found in Reference 5.

The first two parts of Reference 5, which considered modal and one-dimensional digital analyses, pointed out the need for multi-dimensional calculations regarding xenon stability. The reactor core designs for Oconee Units 1 and 2, Cycle 1, have been analyzed in three dimensions with thermal feedback. For the Unit 1 operating core at beginning of life, the predicted azimuthal stability index is -0.07 hr^{-1}. Using modal analysis with the three-dimensional results shows that the shape factor must be approximately 50 percent flat for the power coefficient of -5.05 x 10^{-6} as calculated by previously described methods. Since the curves in Part 1 of Reference 5 were generated for a power coefficient of -3.92 x 10^{-6} $\Delta\rho$/MWt, it was necessary to generate two new curves for azimuthal stability. These curves are shown in Figure 4-14 and Figure 4-15. From Figure 4-14 the threshold (i.e., stability index = 0) moderator coefficient for the nominal case is approximately +3 x 10^{-4} $\Delta\rho/°F_m$. Including compounded errors from Figure 4-15, the threshold moderator coefficient is approximately +1 x 10^{-4} $\Delta\rho$/°F. Using the least favorable predictions of the Doppler and moderator coefficients, a stability index of -0.067 hr^{-1} is obtained. This corresponds to a power coefficient of -4.73 x 10^{-6} $\Delta\rho$/MWt. For the Unit 2 operating core at beginning of life (96 FPH), the predicted azimuthal stability index is -.085 hr^{-1}. Again, using modal analysis combined with three-dimensional results shows the shape factor to be approximately 40 percent flat for the calculated power coefficient of -4.67 x 10^{-6} $\Delta\rho$/MWt. Azimuthal stability curves for the nominal and compounded error cases are shown in Figure 4-16 and Figure 4-17 respectively. From Figure 4-16 the nominal threshold moderator coefficient extrapolates to approximately +5 x 10^{-4} $\Delta\rho/°F_m$. When compounded errors are considered as in Figure 4-17 the threshold moderator coefficient is approximately +2.5 x 10^{-4} $\Delta\rho/°F_m$.

This analysis is considered to be valid and bounding for the current core designs for the following reasons:

1. The minimum moderator temperature coefficient (MTC) threshold value, as listed within Table 4-7, is +1.0 x 10^{-4} $\Delta\rho$/degF. The most positive moderator temperature coefficient assumed within Chapter 15 safety/accident analysis is less than the threshold value.
2. There is considerable margin for a BPRA core (i.e., Oconee 2, Cycle 1 within Reference 5) between the Table 4-7 threshold MTC and the calculated threshold MTC, even when compounded errors are taken into account.
3. Current nuclear design bases require that the overall power coefficient be negative in the power operating range. As such, any azimuthal oscillations within current cores are self-damping by virtue of reactivity feedback effects.

Operating procedures are in effect which allow the reactor operator to damp out any axial xenon oscillation if it should occur.

4.3.4 Nuclear tests and inspections

Nuclear Testing and Inspection can be divided into two areas:

1. Initial Core
2. Startup Testing for Reload Cores.

4.3.4.1 Initial Core Testing

The startup testing performed on Oconee 1, 2, and 3 initial cores was an extensive program to verify both calculational methods and proper behavior of the core. The results of this testing was reported in References 6, 7, and 8.

4.3.4.2 Zero Power, Power Escalation, and Power Testing For Reload Cores

The Startup Physics Test Program for Oconee Nuclear Station, or OSPTP, is structured to provide assurance that the installed reactor core following each reload conforms to the design core. This program provides the minimum tests which will be conducted on each Oconee unit. Additional tests may be performed during a specific startup test program as conditions warrant. However, in all cases, the following tests will be performed:

1. Pre-critical Test Phase
   a. Control Rod Drop Time
2. Zero Power Physics Test Phase
   a. Critical Boron Concentration
   b. Moderator Temperature Coefficient
   c. Control Rod Worth
3. Power Escalation Test Phase
   a. Low Power Testing (5-30% FP)
   b. Intermediate Power Testing (40-75% FP)
   c. Full Power Testing (90-100% FP)

In addition to the above tests, which comprise the basic Startup Physics Test Program, a separate test, the Reactivity Anomaly at Full Power is performed during steady-state operation pursuant to Technical Specification SR 3.1.2.1, "Reactivity Balance". This procedure is used to verify that the measured “all-rods-out” (ARO) hot full power (FP) critical boron concentration is in agreement with the predicted value. The test conditions, procedure descriptions, acceptance criteria, and review requirements for each of the above are described in the sections that follow.

For all these tests, specific acceptance criteria are provided (see OSPTP Summary). Upon completion of each test, the results are reviewed by a designated individual. If the results meet the specific acceptance criteria, then the test is considered to be satisfactorily completed. However, if the results exceed the specific acceptance criteria, an extensive review is performed by cognizant engineers from within Duke Energy or from outside organizations, as appropriate, to identify and correct the cause of the discrepancy. Continuation of the test program, including any power escalations, will be dependent upon satisfactory resolution of any unacceptable test result. Representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering will approve actions under the conditions stated for each test.

The current Startup Physics Test Program for Oconee Nuclear Reactor was submitted by References 9 and 13, approved by Reference 14, and subsequently modified by References 10 and 16, and approved by References 15 and 17.

4.3.5 Pre-Critical Test Phase

4.3.5.1 Control Rod Drop Time

4.3.5.1.1 Plant Conditions

Full reactor coolant system (RCS) flow (4 pumps).

4.3.5.1.2 Procedure

The control rod drop time for each full-length control rod assembly (CRA) to fall from the fully withdrawn position to the 25% withdrawn position is measured. The sequence of events recorder is normally used to record the time interval between initiation and termination of the event. The test may be performed by dropping all full length CRAs simultaneously, any combination for full length groups simultaneously, or each individual full length group, from the fully withdrawn position. In all cases, the sequence of events recorder records the drop time of each CRA individually.

The results are reviewed by the Test Coordinator and compared with the acceptance criterion, 1.66 seconds. The accuracy of the measurement of control rod drop time as performed by the sequence of events recorder is approximately ± 0.005 seconds.

The use of Type C Control rod drive mechanisms requires the use of a slightly higher trip delay time. This difference is accounted for in the affected safety analysis.

4.3.5.1.3 Follow-Up Actions

If any measured control rod drop time is greater than 1.40 seconds but less than 1.66 seconds, then the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed prior to 100% FP.

If any control rod drop time exceeds 1.66 sec., then the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. Also, the actions specified by Technical Specifications 3.1.4, "Control Rod Group Alignment Limits", will be taken.

4.3.6 Zero Power Physics Test Phase

4.3.6.1 Critical Boron Concentration

4.3.6.1.1 Plant Conditions

Hot Zero Power, ~532°F, ~2155 psig, steady RCS flow (3 or 4 pumps).

4.3.6.1.2 Procedure

The ARO critical boron concentration is measured by establishing an equilibrium RCS boron concentration near the predicted ARO critical boron concentration. Control Rod Groups 1 through 6 are fully withdrawn. Control Rod Group 8 is maintained at the nominal designed position. A sample of the equilibrium boron concentration is taken and analyzed to determine the critical boron concentration. Since it may not be practical to establish critical equilibrium conditions with Group 7 either fully withdrawn (ARO) or with Group 7 at an “Essentially” ARO (EARO) position defined as inserted no more than 20% of the predicted worth of Group 7 (not to exceed 0.2% $\Delta k/k$), the small amount of inserted worth of Group 7 or worth of Group 8 (from its nominal designed position) is measured by a reactivity calculation or Reactimeter. This reactivity (and Group 7 predicted worth if at EARO) is then used to adjust the boron concentration to obtain the measured ARO boron concentration.

The results are reviewed by the Test Coordinator and compared with the predicted boron concentration. If the difference between the measured and predicted values does not exceed 50 ppm Boron (45 ppm Boron for EARO), the results are acceptable.

4.3.6.1.3 Follow-Up Actions

If measuring EARO and the acceptance criterion (± 45ppmB) is not met, the RCS will be borated such that ARO can be measured, and the test measurement will be repeated.

If the acceptance criterion (± 50 ppmb) between measured and predicted ARO critical boron concentration is not met, the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed with the results and recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to 100% FP.

If the difference between measured and predicted ARO critical boron concentration is greater than 100 ppm Boron, the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed with the results and recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to exceeding 15% FP.

4.3.6.2 Moderator Temperature Coefficient

4.3.6.2.1 Plant Conditions

Hot Zero Power, ~532°F, ~2155 psig, steady RCS flow (3 or 4 pumps).

4.3.6.2.2 Procedure

The moderator temperature coefficient (MTC) test begins with the reactor at critical equilibrium conditions. This test is performed by executing a change in RCS average temperature of approximately
±3°F while data are taken. Stability in RCS temperature is necessary at this first plateau. The hold time at each RCS temperature plateau during the test is approximately five minutes. After data are taken at the first RCS temperature plateau, the RCS average temperature is changed approximately 3°F in the opposite direction and allowed to stabilize. Changes in reactivity associated with the induced RCS temperature transient are measured by a reactivity calculation or Reactimeter. This overall temperature coefficient is corrected for the contribution of the isothermal doppler coefficient of reactivity to give the moderator coefficient of reactivity. The measurement is also corrected to an average temperature of 532°F.

The results are reviewed by the Test Coordinator and compared with the predicted MTC. If the difference between the measured and predicted values does not exceed 0.3×10^{-4} $\Delta k/k/°F$ and the maximum positive MTC is less than 0.5×10^{-4} $\Delta k/k/°F$ then the results are acceptable.

4.3.6.2.3 Follow-Up Actions

If the measured maximum positive MTC exceeds 0.5×10^{-4} $\Delta k/k/°F$, the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed with the results and recommended actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to exceeding 15% FP.

If the 0.3×10^{-4} $\Delta k/k/°F$ acceptance criterion is exceeded and the maxium positive MTC is less than 0.5×10^{-4} $\Delta k/k/°F$, the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed with the results and recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to 100% FP.

4.3.6.3 Control Rod Worth

4.3.6.3.1 Plant Conditions

Hot Zero Power, ~532°F, ~2155 psig, steady RCS flow (3 or 4 pumps).

4.3.6.3.2 Procedure

The measurement of regulating rod group worths begin from a critical steady state condition with all regulating rod groups withdrawn as far as possible (i.e., within ~ 0.10% Δk/k of EARO or higher). From this point a boron concentration necessary to deborate control rod Groups 7 and 6 to fully inserted is calculated, Group 5 is also measured if it contains new control rods. (See Reference 19). The resulting reactivity change during deboration is compensated for by discrete insertion of control rods with both signals being recorded by a reactivity calculation or Reactimeter. Integral rod worths are calculated by summing the differential rod worths for each control rod group.

The results are reviewed by the Test Coordinator and compared with the predicted control rod group worths. If the difference between the measured and predicted individual rod group worths does not exceed 15%, and the difference between the measured and predicted total worth of control rod Groups 6 and 7 (and Group 5 if required) does not exceed 10%, then the results are acceptable.

4.3.6.3.3 Follow-Up Actions

If the difference between the measured and predicted total worth of control rod Groups 6 and 7 (and Group 5 if required) exceeds 10%, then, following calculation of the minimum control rod position for which the worth of the control rods withdrawn would equal 1% Δk/k, additional control rod group worths will be measured. The worths of additional control rod groups will be measured in sequence from Group 5 to Group 2, until either the difference between the measured and predicted total worth of all control rod groups measured does not exceed 10%, or the calculated minimum control rod position is reached. In the latter case, control rod worth testing will halt. The results will be reviewed by cognizant engineers to determine the appropriate additional corrective actions required to resolve the discrepancy. This review will be completed with the results and the recommended actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to exceeding 15% FP.

If the difference between the measured and predicted control rod worths of any of the individual control rod groups exceeds 15%, the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed prior to reaching 100% FP.

4.3.7 Power Escalation Test Phase

4.3.7.1 Low Power Testing

4.3.7.1.1 Plant Conditions

5 to 30% FP, ~579°F, ~2155 psig, full RCS flow (4 pumps).

4.3.7.1.2 Procedure

Once the unit is between 5 and 30% FP, the output of the plant OAC reactor calculations program is analyzed. This program processes the signals from fixed incore detectors and provides a relative core power distribution as output. The incore detector outputs are checked in order to identify malfunctioning detectors. After these have been eliminated, the results for corrected assembly power in functioning instrumented symmetric core locations are compared.

The results are reviewed by the Test Coordinator. If the reactor calculations outputs appear normal, and the deviation between the highest and lowest corrected assembly power for symmetric core locations is less than ±10%, then the results are acceptable.

4.3.7.1.3 Follow-Up Actions

If the reactor calculations outputs appear abnormal, the raw detector signals are evaluated to determine if a significant core asymmetry exists. If no significant asymmetry exists, power escalation is continued. If an asymmetry exists, the Site Reactor Engineering Supervisor is contacted to initiate a program of testing and evaluation before further power increase. The problem with the reactor calculations program is investigated and corrected, but this is not a prerequisite for power increase if no significant asymmetry exists.

If the reactor calculations outputs appear normal and the deviation between corrected assembly powers for symmetric core locations is greater than ±10%, the cause of the indicated deviation is investigated. If the deviation is due to identifiable reactor calculations program problems, it is corrected per normal procedures and power escalation testing may continue. If the cause of the deviation cannot be identified, the Site Reactor Engineering Supervisor is contacted to initiate a program of testing and evaluation.

The results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the deviation. This review will be completed with the results and the recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to any further escalation of power.

4.3.7.2 Intermediate Power Testing

4.3.7.2.1 Plant Conditions

40 to 75% FP, ~579°F, ~2155 psig, full RCS flow (4 pumps).

4.3.7.2.2 Procedure

Once the unit is between 40 and 75% FP, the output of the plant OAC reactor calculations program is analyzed. This program processes the signals from fixed incore detectors and provides a relative core power distribution as output. The incore detector outputs are checked, in order to identify malfunctioning detectors. After these have been eliminated, the radial and total peaking factors obtained from the plant OAC are compared with the values calculated using the computer codes utilized during the reload design process on an eighth-core basis.

The results are reviewed by the Test Coordinator. If, for each assembly location with normalized measure power greater than 1.0, the measured radial peaking factor does not exceed the predicted radial peaking factor by more than 12.0% of the predicted radial peaking factor, and if, for each assembly location with normalized measured power greater than 1.0, the measured total peaking factor does not exceed the predicted total peaking factor by more than 15.0% of the predicted total peaking factor, and if the RMS difference between predicted and measured radial peaking factors is less than 0.075, then the results are acceptable.

4.3.7.2.3 Follow-Up Actions

If any observed parameter exceeds its specified values in the Technical Specifications, actions will be taken as required by the Technical Specifications.

Also, the observed parameter will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed with the results and recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to any further escalation of power.

If any acceptance criteria are exceeded, the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed with the results and recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to escalation to 100% FP.

4.3.7.3 Full Power Testing

4.3.7.3.1 Plant conditions

90 to 100% FP, ~579°F, ~2155 psig, full RCS flow (4 pumps).

4.3.7.3.2 Procedure

Once the unit is between 90 and 100% FP with Xenon equilibrium, the output of the plant OAC reactor calculations program is analyzed. This program processes the signals from fixed incore detectors and provides a relative core power distribution as output. The incore detector outputs are checked, in order to identify malfunctioning detectors. After these have been eliminated, the radial and total peaking factors obtained from the OAC are compared with the values calculated as part of the reload design process on an eighth-core basis. The results are reviewed by the Test Coordinator. If, for each assembly location with normalized measure power greater than 1.0, the measured radial peaking factor does not exceed the predicted radial peaking factor by more than 12.0% of the predicted radial peaking factor, and if, for each assembly location with normalized measured power greater than 1.0, the measured total peaking factor does not exceed the predicted total peaking factor by more than 15.0% of the predicted total peaking factor, and if the RMS difference between predicted and measured radial peaking factors is less than 0.075, then the results are acceptable.

4.3.7.3.3 Follow-Up Actions

If any observed parameter exceeds its specified values in the Technical Specifications, actions will be taken as required by the Technical Specifications.

Also, the observed parameter will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed with the results and the recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to any escalation of power.

If any acceptance criteria are exceeded, the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy. This review will be completed with the results and recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering prior to any escalation of power.

4.3.7.4 Reactivity Anomaly

4.3.7.4.1 Plant Conditions

Hot Full Power, ~579°F, ~2155 psig, full RCS flow.

4.3.7.4.2 Procedure

As a part of the periodic testing program and separate from the startup testing program, the ARO critical boron concentration at power is checked against normalized predicted values approximately each 31 EFPD of steady-state operation. With the reactor at steady-state conditions, as near as practical to full power ARO conditions, a sample of the RCS is taken and analyzed for boron concentration. This value of boron concentration is then adjusted to account for the reactivity worth of regulating control rod assemblies in the core at the time of the measurement, and any other minor variations from designed conditions.

The results are reviewed by the Site Reactor Engineering Supervisor and are compared with the normalized predicted ARO boron concentration for the time in the cycle at which the measurement was taken.

The ARO boron concentration procedure is also used to ensure that the curve to maintain boron concentration for SSF operability is conservative. This is done by ensuring that the Measured ARO Boron minus Predicted ARO Boron is ≥ -25 ppmB. 25 ppmB is used because shutdown boron concentrations for SSF operability supplied by Nuclear Design contain a 25 ppmB analytical uncertainty. If the difference between measured and predicted ARO boron concentration values does not exceed 50 ppm or < -25 ppm boron for SSF subcriticality (see Section 9.6.1), then the results are acceptable.

4.3.7.4.3 Follow-Up Actions

If the acceptance criterion (±50 ppmb) is not met and the difference between measured and predicted ARO boron concentration is less than 100 ppm Boron, the results will be reviewed by cognizant engineers to determine the appropriate corrective action required to resolve the discrepancy. This review will be completed with the results and recommended corrective actions approved by representatives from Oconee Nuclear Station Reactor Engineering and Regulatory Compliance, and General Office Nuclear Engineering within 14 days.

If the acceptance criterion (±50 ppmb) is not met and the difference between measured and predicted ARO boron concentration is greater than 100 ppm Boron, then the results will be reviewed by cognizant engineers to determine the appropriate corrective actions required to resolve the discrepancy pursuant to Technical Specification 3.1.2. "Reactivity Balance".

If the acceptance criteria for SSF subcriticality (≥ -25 ppmb) is not met the results will be reviewed by cognizant engineers to determine the appropriate corrective action required to resolve the discrepancy and ensure the SSF subcriticality function (Section 9.6.1) is met.

Oconee Startup Physics Test Program (OSPTP) Summary

TEST	PLANT CONDITIONS	ACCEPTANCE CRITERIA
1. Control Rod Trip Time Test	RCS Full Flow	1.66 seconds
2. All Rods Out Critical Boron	HZP	± 50 ppmB (ARO) ± 45 ppmB (EARO)
3. Moderator Temperature Coefficient	HZP	± $0.3x10^{-4}$ $\Delta\rho$/°F max. pos. MTC <$0.5x10^{-4}$ $\Delta\rho$/°F
4. Control Rod Worth	HZP	Individual Groups ± 15% Sum of Groups ± 10%
5. Low Power Testing	5 - 30 %FP	Relative Core Power Distribution ± 10%
6. Intermediate Power Testing	40 - 75%FP	Total/Radial Peaking (assembly location > 1.0 normalized measured power) ±15.0%/±12.0.0% RMS (Radial) < 0.075%
7. Full Power Testing	90 - 100 %FP	Total/Radial Peaking (assembly location > 1.0 normalized measured power) ±15.0%/±12.0.0% RMS (Radial) < 0.075%
8. Reactivity Anomaly	HFP	All Rods Out Critical Boron ± 50 ppmB

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4.4 Thermal and Hydraulic Design

4.4.1 Design Bases

The bases for the thermal and hydraulic design have been established to enable the reactor to operate at 2,568 MWt rated power with sufficient design margins to accommodate both steady-state and transient operation without damage to the core and without exceeding the design pressure limits for the reactor coolant system. The thermal-hydraulic design bases also help to ensure that the fuel rod cladding will maintain its integrity during steady-state operation, design overpower, and anticipated operational transients occurring throughout core life.

Fuel cladding integrity is ensured by limiting the core to the following thermal-hydraulic boundaries during steady-state operation at power levels up to and including the design overpower, and during anticipated transient operation.

1. The fuel pin cladding, fuel pellets, and fuel pin internals must be designed so that the fuel-to-clad gap characteristics ensure that the maximum fuel temperature does not exceed the fuel melting limit at the 112 percent design overpower at any time during core life. See Section 4.2.3.1.3 for a discussion of fuel melting temperature.

2. The minimum allowable DNBR during steady-state operation and anticipated transients for Mark-BZ, Mark-B11, Mark-B11A, and Mark-B-HTP fuel are:

   a. Mark-BZ fuel is established as 1.18 with the BWC correlation (Reference 1) for non-SCD analyses and 1.43 for SCD analyses (Reference 13).

   b. MK-B11 and Mark-B11A fuel is established as 1.19 with the BWU-Z correlation with the FB11 multiplicative factor for non-SCD analyses and 1.33 for SCD analyses (Reference 13).

   c. MK-B-HTP fuel is established with BHTP correlation as a proprietary value for NON-SCD analysis and 1.34 for SCD analysis (Reference 13).

   These limits on MDNBR ensure a 95 percent confidence level that there is a 95 percent probability DNB will not occur.

3. Although generation of net steam is allowed in the hottest core channels, flow stability is required during all steady-state and operational transient conditions.

By preventing a departure from nucleate boiling (DNB), neither the cladding nor the fuel is subjected to excessively high temperatures.

The core flow distribution and coolant velocities have been set to provide adequate cooling capability to the hottest core channels and to maintain minimum DNB ratios greater than the design limit. Fuel assembly design and cladding integrity criteria are discussed in Section 4.2.1.2.4.

4.4.2 Description of Thermal and Hydraulic Design of the Reactor Core

Table 4-1 and Table 4-2 depicts typical thermal-hydraulic design conditions.

4.4.2.1 Core Design Analysis Description

The methodology of the analysis used with the design bases criterion is fully described in DPC-NE-2003P-A (Reference 2) and DPC-NE-2005P-A (Reference 13).

The input information and analytical tools for the thermal hydraulic design and for the evaluation of individual hot channels is as follows:

1. Heat transfer, critical heat flux equations, and data correlations.
2. Nuclear peaking factors.
3. Engineering hot channel factors.
4. Core flow distribution hot channel factors.
5. Design reactor power.
6. Thermal hydraulic analysis computer codes.

These inputs have been derived from test data, physical measurements and calculations.

Critical heat flux (CHF) calculations are performed with the Areva BWC or BWU-Z with FB11 multiplication factor, or BHTP correlations. Items 1 through 5 on the above list are explained in Chapters 5 and/or 6 of DPC-NE-2003P-A (Reference 2). VIPRE-01 (Reference 3) is the computer code used in these analyses (Item 6).

The design overpower is the highest credible reactor operating power permitted by the Reactor Protective System including maximum instrumentation errors. Normally, trip on overpower will occur at a significantly lower power than the design overpower.

The Statistical Core Design, or SCD, methodology described in Reference 13 allows for the statistical combination of the variables that directly affect the DNB performance of the fuel. The key DNB parameters include: reactor power, core inlet temperature, core flow rate, core exit pressure, and three dimensional power distribution. This statistical combination takes into account the probability of each key DNB parameter being within a specified uncertainty distribution at any given point in time. The result is the ability to input nominal values of these parameters into any analysis and still maintain the 95% probability with 95% confidence that DNB will not occur.

4.4.3 Thermal and Hydraulic Evaluation

4.4.3.1 Introduction

A summary of the characteristics of the reactor core design is given in Section 4.1. The methodology of the thermal and hydraulic design analysis is presented in DPC-NE-2003P-A (Reference 2), and DPC-NE-2005P-A (Reference 13).

4.4.3.2 Deleted Per 1990 Update

4.4.3.3 Evaluation of the Thermal and Hydraulic Design

4.4.3.3.1 Hot Channel Coolant Conditions

The NRC approved VIPRE-01 code is used to calculate the reactor coolant enthalpy, mass flow, vapor void, and DNBR distributions within the core for all expected operating conditions. The VIPRE-01 code is described in detail in (Reference 3), and the models and empirical correlations that are used are discussed in (References 2 and 13).

Steady-state analyses yield the MDNBR and quality in the hot channel at nominal and maximum design overpower conditions. Table 4-1 contains a typical hot channel MDNBR value at nominal reactor conditions.

4.4.3.3.2 Coolant Channel Hydraulic Stability

Flow regime maps of mass flow rate and quality were constructed in order to evaluate channel hydraulic stability. The confidence in the design is based on a review of both analytical evaluations (References 4 through 8) and experimental results obtained in multiple rod bundle burnout tests. Bubble-to-annular and bubble-to-slug flow limits proposed by Baker (Reference 4) are consistent with the FCF experimental data in the range of interest. The analytical limits and experimental data points have been plotted to obtain the maps for the four different types of cells in the reactor core. These are shown in Figure 4-21, Figure 4-22, Figure 4-23, and Figure 4-24. The experimental data points represent the exit conditions in the various types of channels just previous to the burnout for a representative sample of the data points obtained at design operating conditions in the nine rod burnout test assemblies. In all of the bundle tests, the pressure drop, flow rate, and rod temperature traces were repeatable and steady, and did not exhibit any of the characteristics associated with flow instability.

Values of hot channel mass velocity and quality at 114 percent and 130 percent power for both nominal and design conditions are shown on the maps. The potential operating points are within the bounds suggested by Baker. Experimental data points for the reactor geometry with much higher qualities than the operating conditions have not exhibited unstable characteristics (Reference 9).

4.4.3.3.3 Reactor Coolant Flow System

Another significant variable to be considered in evaluating the design is the total reactor coolant system (RCS) flow. Conservative values for system and reactor pressure drop have been determined to insure that the required system flow is obtained in the as-built plant. Measured RCS flow is above the design flow used in the core reload thermal hydraulic analyses.

The difference between the RCS flow and the reactor core flow is the core bypass flow. The core bypass flow is defined as that part of the flow that does not contact the active heat transfer surface area. The bypass flow paths are (1) core shroud, (2) core barrel annulus, (3) the control rod guide tubes and instrument tubes, and (4) all interfaces separating the inlet and outlet regions of the reactor vessel. The core bypass flow is generally less than 9%; however, the bypass flow rate is dependent on the number of assemblies not containing control rods, burnable poison rods, or source rods in each cycle as explained in Reference 2.

4.4.3.3.4 Deleted Per 1990 Update

4.4.3.3.5 Core Flow Distribution

Inlet plenum effects have been determined from a 1/6 scale model flow test. The isothermal flow test data has shown that the hot bundle receives average or better flow. It is conservatively assumed in all DNB analysis (assuming 4 operating RC pumps) that the inlet flow in the hot bundle is 5 percent less than the average bundle flow (Reference 2). A more restrictive inlet flow maldistribution factor is assumed for 3 pump operation analyses.

Flow redistribution accounts for the reduction in flow in the hot channel resulting from the high flow resistance due to the local or bulk boiling in the hot channel. The effect on flow of the non-uniform design power distribution is inherently considered in the VIPRE-01 code for all of the conditions analyzed.

4.4.3.3.6 Mixing Coefficient

The flow distribution within the hot assembly is calculated using the VIPRE-01 code which allows for the interchange of momentum and heat between channels. The turbulent mixing model incorporated in the VIPRE-01 code and used for all core thermal-hydraulic analyses is discussed in Reference 2. A conservative mixing coefficient of 0.01, based on predictions of mixing tests, is used for DNB analyses for Mark-BZ fuel assembly design. A conservative mixing coefficient of 0.038, per Reference 13, is used for DNB analyses for Mark-B11 fuel assembly design due to the presence of mixing vane grids. For Mark-B-HTP fuel DNB analyses, proprietary turbulent mixing factors, per Reference 13, are used for spans containing HTP or HMP spacer grids.

4.4.3.3.7 Deleted Per 1990 Update.

4.4.3.3.8 Hot Channel Factors

Hot channel factors are included in the calculation of the statistical core design DNBR limit (Reference 13) to account for possible deviations of several parameters from their design values. The power hot channel factor, F_q, accounts for variations in average pin power caused by differences in the absolute number of grams of U_{235} per rod. F_q is applied to the heat generation rate of the hot pin of the hot subchannel. The value of F_q used is given in Reference 13. References 14 and 15 have shown that small local heat flux spikes (which result from power spikes due to flux depressions at the spacer grids and local variations in pellet enrichment/weight) have no effect on the critical heat flux. The hot channel flow area is also reduced when calculating the SCD limit to account for manufacturing tolerances.

4.4.3.3.9 Rod Bow Effects and Penalty

The mechanisms and resulting effects of fuel rod bow are discussed in Areva topical report BAW-10147P-A (Reference 10) and BAW-10186P-A (Reference 17). The topical report concludes that the DNB penalty due to rod bow is insignificant and unnecessary because the power production capability of the fuel decreases with irradiation. The rod bow correlation developed in Reference 10 also conservatively predicts the rod bow behavior of Mark-BZ fuel, Mark-B11 fuel and MK-B-HTP fuel.

4.4.4 Thermal and Hydraulic Tests and Inspection

4.4.4.1 Reactor Vessel Flow Distribution and Pressure Drop Test

A 1/6-scale model of the reactor vessel and internals has been tested to evaluate:

1. The flow distribution to each fuel assembly of the reactor core and to develop any necessary modifications to produce the desired flow distribution.
2. Fluid mixing between the vessel inlet nozzle and the core inlet, and between the inlet and outlet of the core.
3. The overall pressure drop between the vessel inlet and outlet nozzles, and the pressure drop between various points in the reactor vessel flow circuit.
4. The internals vent valves for closing behavior and for the effect on core flow with valves in the open position.

The reactor vessel, flow baffle, and core barrel were made of clear plastic to allow use of visual flow study techniques. All parts of the model except the core are geometrically similar to those in the production reactor. The simulated core was designed to maintain dynamic similarity between the model and production reactor.

Each of the 177 simulated fuel assemblies contained a calibrated flow nozzle. The test loop is capable of supplying cold water (75°F) to three inlet nozzles and hot water (140°F) to the fourth. Temperature was measured in the inlet and outlet nozzles of the reactor model and at the inlet and outlet of each of the fuel assemblies. Static pressure taps were located at suitable points along the flow path through the vessel. This instrumentation provided the data necessary to accomplish the objectives set forth for the tests. The tests are summarized in BAW-10037 (Reference 9).

4.4.4.2 Fuel Assembly Heat Transfer and Fluid Flow Tests

Although the original design of the reactor is based on the W-3 heat transfer correlation, FCF has conducted a continuous research and development program for fuel assembly heat transfer and fluid flow applicable to the design of the reactor. Single-channel tubular and annular test sections and multiple rod assemblies have been tested at the Alliance Research Center. Also, 5x5 rod bundle sections have been tested at the Columbia University Heat Transfer Laboratory. This test work substantiates the thermal design of the reactor core. The multiple rod CHF tests are briefly discussed below.

4.4.4.2.1 Deleted Per 1990 Update

4.4.4.2.2 Multiple-Rod Fuel Assembly Heat Transfer Tests

The following sections discuss the fuel assembly heat transfer tests for the BWC, BWU-Z with FB11 multiplicative factor, and BHTP CHF correlations.

<u>BWC CHF Correlation</u>

As a part of the development of the 15 x 15 Zircaloy grid Mark-BZ fuel assembly design, a series of CHF tests were run at Areva's Alliance Research Center heat transfer facility. The tests were performed for 15 x 15 geometry with Zircaloy grids and full length non-uniform axial flux shapes. A total of 211 data points were obtained covering the following conditions:

Note: The following conditions were revised in 1998 update.

Pressure	1,600 < P < 2,600 psia
Local Mass Velocity	0.43 < G < 3.8 -Mlbm/hr-ft^2
Local Quality	-0.20 < X_{loc} < 0.26

The BWC correlation was developed from 17 x 17 Mark-C CHF data. The BWC correlation was shown to conservatively represent the Mark-BZ CHF data with a 95/95 DNBR limit of I.18 (Reference 1).

The BWC correlation was developed by Areva's using the LYNX2 computer code (Reference 12). To verify use of the BWC correlation with the VIPRE-01 code, the Mark-BZ CHF data was predicted and compared with Areva's LYNX2 results. As discussed in Reference 2, the VIPRE-01 BWC results show that a DNBR limit of 1.18 will provide 95% probability of precluding DNB at a 95% confidence level.

<u>BWU-Z CHF Correlation, With FB11 Multiplicative Factor</u>

As part of the development of a 15x15 mixing vane grid design, critical heat flux tests have been performed at Columbia University Heat Transfer Research Facility (HTRF) for Mark-B11 fuel. The tests were performed for a 15x15 geometry with Zircaloy mixing vane grids and full length non-uniform axial flux shape. The BWU-Z CHF correlation with the FB11 multiplier, Reference 16, was developed based on Mark-B11 15x15 mixing vane CHF data. The FB11 multiplier of 0.98 on the BWU-Z CHF correlation is based on a total of 216 data points. The BWU-Z CHF correlation was developed by Areva from a data base of 530 data points on fuel with Zircaloy mixing vane spacer grid designated Mark BW17. The Mark-B11 spacer grid design is a 15x15 version of Areva 17x17 Mark-BW17 design. The BWU-Z CHF correlation with the FB11 multiplier is applicable to the following range of variables:

Pressure	$400 \le P \le 2465$ psia
Local Mass Velocity	$0.36 \le G_{loc} \le 3.55$ Mlbm/ft^2-hr
Local Quality	$X_{loc} \le 0.74$

The BWU-Z correlation with the Mark-B11 multiplier of 0.98 was shown to conservatively represent the Mark-B11 CHF data with a 95/95 DNBR limit of 1.19 (Reference 16).

BHTP CHF Correlation

The BHTP correlation was developed by Areva using the LYNXT computer code (Reference 20). To verify use of the BHTP correlation with the VIPRE-01 code, the BHTP CHF data was predicted and compared with Areva's LYNXT results. As discussed in Reference 13, VIPRE-01 BHTP results show that the proprietary DNBR limit in Reference 13 will provide 95% probability of precluding DNB at a 95% confidence level. This CHF correlation is applicable to the following range of variables:

Pressure	$1,385 \le P \le 2,425$ psia
Local Mass Velocity	$0.492 \le G \le 3.549$ Mlbm/hr-ft^2
Local Quality	$X_{loc} \le 0.512$

The BWU-Z correlation with Mark-B11 multiplier was developed by FCF using the LYNX2 computer code (Reference 12). To verify use of the BWU-Z correlation with the Mark-B11 multiplier with the VIPRE-01 code, the Mark-B11 CHF data was predicted and compared with FCF's LYNX2 results. As discussed in Reference 13, the VIPRE-01 BWU-Z with Mark-B11 multiplier results show that a DNBR limit of 1.19 will provide 95% probability of precluding DNB at a 95% confidence level.

4.4.4.2.3 Fuel Assembly Flow Distribution, Mixing and Pressure Drop Tests

Flow visualization and pressure drop data have been obtained from a ten-times-full-scale (10X) model of a single rod in a square flow channel. These data have been used to refine the spacer grid designs with respect to mixing turbulence and pressure drop. Additional pressure drop testing has been conducted using 4-rod (5X), 4-rod (1X), 1-rod (1X), and 9-rod (1X) models.

Testing to determine the extent of interchannel mixing and flow distribution has also been conducted. Flow distribution in a square 4-rod test assembly has been measured. A salt solution injection technique was used to determine the average flow rates in the simulated reactor assembly corner cells, wall cells, and unit cells. Interchannel mixing data were obtained for the same assembly. These data have been used to confirm the flow distribution and mixing relationships employed in the core thermal and hydraulic design. Flow tests on a mockup of two adjacent fuel assemblies have been conducted. Additional mixing, flow distribution, and pressure drop data will be obtained to improve future core power capability. The following fuel assembly geometries have been tested to provide additional data:

1. A 9-rod (3 x 3 array) mixing test assembly, to determine flow pressure drop, flow distribution, and degree of mixing.
2. A 64-rod assembly simulating larger regions and various mechanical arrangements within a 15 x 15 fuel assembly and between adjacent fuel assemblies to determine flow distribution in the assembly and between adjacent assemblies.

Mark-B11 Fuel Assembly Flow Tests

The flow-induced vibration (FIV) tests, pressure drop tests, Laser Doppler Velocimeter (LDV) tests, and critical heat flux (CHF) tests were conducted on the Mark-B11 fuel assembly design per Reference 18. The FIV tests were performed to examine the vibrational response of the Mark-B11 fuel assembly and to verify that there were no flow related phenomena that would adversely affect fuel integrity. The pressure drop tests were conducted to determine form loss coefficients for the Mark-B11 components. The LDV tests were conducted to characterize the subchannel flow distribution within the Mark-B11 fuel assembly design. The CHF tests were conducted to develop a CHF correlation that would accurately represent the CHF performance of the Mark-B11 mixing vane grid.

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4.5 Reactor Materials

4.5.1 Reactor Vessel Internals

4.5.1.1 Reactor Internal Materials

Reactor internals are fabricated primarily from SA-240 (Type 304) material and designed within the allowable stress levels permitted by the ASME Code, Section III, for normal reactor operation and transients. Structural integrity of all core support assembly circumferential welds is assured by compliance with ASME Code Sections III and IX, radiographic inspection acceptance standards, and welding qualification.

4.5.1.2 Design Bases

The reactor internal components are designed to withstand the stresses resulting from startup; steady state operation with one or more reactor coolant pumps running; and shutdown conditions. No damage to the reactor internals will occur as a result of loss of pumping power.

The core support structure is designed as a Class I structure, as defined in Section 3.2 to resist the effects of seismic disturbances. The basic design guide for the seismic analysis is AEC publication TID-7024, "Nuclear Reactors and Earthquakes."

Lateral deflection and torsional rotation of the lower end of the core support assembly is limited in order to prevent excessive deformation resulting from seismic disturbance thereby assuring insertion of control rod assemblies (CRAs). Core drop in the event of failure of the normal supports is limited by guide lugs so that CRAs do not disengage from the fuel assembly guide tubes (Section 4.5.1.3).

The structural internals are designed to maintain their functional integrity in the event of any major loss-of-coolant accident. The dynamic loading resulting from the pressure oscillations because of a loss-of-coolant accident will not prevent CRA insertion.

Internals vent valves are provided to relieve pressure resulting from steam generation in the core following a postulated reactor coolant inlet pipe rupture, so that the core will be rapidly re-covered by coolant.

Allowable Stresses

Section 3.9.2.4 describes the stress analysis for fuel assemblies under faulted conditions. Section 3.9.3.1 describes the analysis of the reactor internals. Additional criteria for stresses due to flow-induced vibratory loads are given in B&W Topical Report "Design of Reactor Internals and Incore Instrument Nozzles for Flow Induced Vibrations," (Reference 1).

Methods of Load Analysis to be Employed for Reactor Internals and Fuel Assembly.

Section 3.9.2.4 describes the methods used to analyze fuel assemblies under faulted conditions. Section 3.9.3.1 describes the analysis of the reactor internals.

Duke actively participated in a B&W Owners Group effort that developed a series of technical reports whose purpose was to demonstrate that the aging effects for reactor coolant system components are adequately managed for the period of extended operation for license renewal. One of the B&W Owners Group topical reports that was submitted is BAW-2248A [Reference 6] which addresses the reactor vessel internals. Time-limited aging analyses applicable to the Oconee reactor vessel internals are addressed within BAW-2248A. This report was incorporated by reference onto the Oconee dockets [Reference 7].

Time-limited aging analyses applicable to the Oconee reactor vessel internals, along with the results of their review for license renewal, are as follows: (1) flow-induced vibration endurance limit assumptions - A review of the existing analysis showed conservatism in the original design, and no further action is needed in the period of extended operation to assure validity of the design; (2) transient cycle count assumptions for the replacement bolting - The ongoing programmatic actions under the Thermal Fatigue Management Program (See Section 5.2.1.4) will assure the validity of the design assumptions in the period of extended operation; and (3) reduction in fracture toughness - The actions developed as a part of the Reactor Vessel Internals Inspection (See Section 18.3.20) will assure the validity of the design assumptions in the period of extended operation. [Reference 8]

4.5.1.3 Description - Reactor Internals

Reactor internal components include the plenum assembly and the core support assembly. The core support assembly consists of the core support shield, vent valves, core barrel, lower grid, flow distributor, incore instrument guide tubes, and thermal shield. The plenum assembly consists of the upper grid plate, the control rod guide assemblies, and a plenum cylinder. Figure 4-26 shows the reactor vessel, reactor vessel internals arrangement, and the reactor coolant flow path. Figure 4-27 shows a cross section through the reactor vessel, and Figure 4-28 shows the core flooding arrangement.

Reactor internal components do not include fuel assemblies, control rod assemblies (CRAs), or incore instrumentation. Fuel assemblies and control rod assemblies are described in Section 4.2.2, control rod drives in Section 4.5.3, and core instrumentation in Section 7.6.2.

The reactor internals are designed to support the core, maintain fuel assembly alignment, limit fuel assembly movement, and maintain CRA guide tube alignment between fuel assemblies and control rod drives. They also direct the flow of reactor coolant, provide gamma and neutron shielding, provide guides for in core instrumentation between the reactor vessel lower head and the fuel assemblies, and support the internals vent valves. The vent valves are designed to vent the stream generated within the core, thereby permitting the rapid re-covering of the core by coolant following a reactor coolant inlet pipe rupture. All reactor internal components can be removed from the reactor vessel to allow inspection of the reactor internals and the reactor vessel internal surface.

A shop fitup and checkout of the internal components for Oconee 1 in an as-built reactor vessel mockup insured proper alignment of mating parts before shipment. Dummy fuel assemblies and control rod assemblies were used to check fuel assembly clearances and CRA free movement.

To minimize lateral deflection of the lower end of the core support assembly as a result of horizontal seismic loading, integral weld-attached, deflection-limiting guide lugs are welded on the reactor vessel inside wall. These blocks also limit the rotation of the lower end of the core support assembly which could result from flow-induced torsional loadings. The lugs allow free vertical movement of the lower end of the internals for thermal expansion throughout all ranges of reactor operating conditions. In the unlikely event that a flange, circumferential weld, or bolted joint might fail, the lugs limit the possible core drop to 1/2 in. or less. The elevation plane of these lugs was established near the elevation of the vessel support skirt attachment to minimize dynamic loading effects on the vessel shell or bottom head. A 1/2 in. core drop does not allow the lower end of the CRA rods to disengage from their respective fuel assembly guide tubes, even if the CRAs are in the full-out position. In this rod position, approximately 6-1/2 in. of rod length remains in the fuel assembly guide tubes. A core drop of 1/2 in. does not result in a significant reactivity change. The core cannot rotate and bind the drive lines, because rotation of the core support assembly is prevented by the guide lugs.

The core internals are designed to meet the stress requirements of the ASME Code, Section III, during normal operation and transients. Additional criteria and analysis are given in Reference 1. A detailed stress analysis of the internals under accident conditions has been completed and is reported in B&W Topical Report No. 10008, Part 1 (Reference 2). This report analyzes the internals in the event of a major loss-of-coolant accident (LOCA) and for the combination of LOCA and seismic loadings. It is shown that although there is some internals deflection, failure of the internals does not occur because the stresses are within established limits. These deflections would not prevent CRA insertion because the control rods are guided throughout their travel, and the guide-to-fuel assembly alignment cannot change because positive alignment features are provided between them and the deflections do not exceed allowable values. All core support circumferential weld joints in the internals shells are inspected to the requirements of the ASME Code, Section III.

4.5.1.3.1 Plenum Assembly

The plenum assembly is located directly above the reactor core and is removed as a single component before refueling. It consists of a plenum cover, upper grid, CRA guide tube assemblies, and a flanged plenum cylinder with openings for reactor coolant outlet flow. The plenum cover is constructed of a series of parallel flat plates intersecting to form square lattices and has a perforated top plate and an integral flange at its periphery. The cover assembly is attached to the plenum cylinder top flange. The perforated top plate has matching holes to position the upper end of the CRA guide tubes. The plenum cover is attached to the top flange of the plenum cylinder by a flange. Lifting lugs are provided for remote handling of the plenum assembly. These lifting lugs are welded to the cover grid. The CRA guide tubes are welded to the plenum cover top plate and bolted to the upper grid. CRA guide assemblies provide CRA guidance, protect the CRA from the effects of coolant cross-flow, and provide structural attachment of the grid assembly to the plenum cover.

Each CRA guide assembly consists of an outer tube housing, a mounting flange, 12 perforated slotted tubes and four sets of tube segments which are oriented and attached to a series of castings so as to provide continuous guidance for the CRA full stroke travel. The outer tube housing is welded to a mounting flange, which is bolted to the upper grid. Design clearances in the guide tube accommodate misalignment between the CRA guide tubes and the fuel assemblies. Final design clearances are established by tolerance studies and Control Rod Drive Line Facility (CRDL) prototype test results. The test results are described in Section 4.2.4.4.

The plenum cylinder consists of a large cylindrical section with flanges on both ends to connect the cylinder to the plenum cover and the upper grid. Holes in the plenum cylinder provide a flow path for the coolant water. The upper grid consists of a perforated plate which locates the lower end of the individual CRA guide tube assembly relative to the upper end of a corresponding fuel assembly. The grid is bolted to the plenum cylinder lower flange. Locating keyways in the plenum assembly cover flange engage the reactor vessel flange locating keys to align the plenum assembly with the reactor vessel, the reactor closure head control rod drive penetrations, and the core support assembly. The bottom of the plenum assembly is guided by the inside surface of the lower flange of the core support shield.

4.5.1.3.2 Core Support Assembly

The core support assembly consists of the core support shield, core barrel, lower grid assembly, flow distributor, thermal shield, incore instrument guide tubes, and internals vent valves. Static loads from the assembled components and fuel assemblies, and dynamic loads from CRA trip, hydraulic flow, thermal expansion, seismic disturbances, and loss-of-coolant accident loads are all carried by the core support assembly.

The core support assembly components are described as follows:

1. Core Support Shield

   The core support shield is a flanged cylinder which mates with the reactor vessel opening. The forged top flange rests on a circumferential ledge in the reactor vessel closure flange. The core support shield lower flange is bolted to the core barrel. The inside surface of the lower flange guides and aligns the plenum assembly relative to the core support shield. The cylinder wall has two nozzle openings for coolant flow. These openings are formed by two forged rings, which seal to the reactor vessel outlet nozzles by the differential thermal expansion between the stainless steel core support shield and the carbon steel reactor vessel. The nozzle seal surfaces are finished and fitted to a predetermined cold gap providing clearance for core support assembly installation and removal. At reactor operating temperature, the mating metal surfaces are in contact to make a seal without exceeding allowable stresses in either the reactor vessel or internals. Eight vent valve mounting rings are welded in the cylinder wall for internals vent valves.

2. Core Barrel

   The core barrel supports the fuel assemblies, lower grid, flow distributor, and incore instrument guide tubes. The core barrel consists of a flanged cylinder, a series of internal horizontal former plates bolted to the cylinder, and a series of vertical baffle plates bolted to the inner surfaces of the horizontal formers to produce an inner wall enclosing the fuel assemblies. The core barrel cylinder is flanged on both ends. The upper flange of the core barrel cylinder is bolted to the mating lower flange of the core support shield assembly and the lower flange is bolted to the lower grid assembly. All bolts are lock welded after final assembly. Coolant flow is downward along the outside of the core barrel cylinder and upward through the fuel assemblies contained in the core barrel. A small portion of the coolant flows upward through the space between the core barrel outer cylinder and the inner baffle plate wall. Coolant pressure in this space is maintained lower than the core coolant pressure to avoid tension loads on the bolts attaching the plates to the horizontal formers.

3. Lower Grid Assembly

   The lower grid assembly provides alignment and support for the fuel assemblies, supports the thermal shield and flow distributor, and aligns the incore instrument guide tubes with the fuel assembly instrument tubes. The lower grid consists of two lattice type grid structures, separated by short tubular columns, and surrounded by a forged flanged cylinder. The upper structure is a perforated plate, while the lower structure consists of intersecting plates welded to form a grid. The top flange of the forged cylinder is bolted to the lower flange of the core barrel.

   A perforated flat plate located midway between the two lattice structures aids in distributing coolant flow prior to entrance into the core. Alignment between fuel assemblies and incore instruments is provided by pads bolted to the upper perforated plate.

4. Flow Distributor

The flow distributor is a perforated dished head with an external flange which is bolted to the bottom flange of the lower grid. The flow distributor supports the incore instrument guide tubes and distributes the inlet coolant entering the bottom of the core.

5. Thermal Shield

   A cylindrical stainless steel thermal shield is installed in the annulus between the core barrel cylinder and reactor vessel inner wall. The thermal shield reduces the incident gamma absorption internal heat generation in the reactor vessel wall and thereby reduces the resulting thermal stresses. The thermal shield upper end is restrained against inward and outward vibratory motion by restraints bolted to the core barrel cylinder. The lower end of the thermal shield is shrunk fit on the lower grid flange and secured by 96 high strength bolts.

6. Incore Instrument Guide Tube Assembly

   The incore instrument guide tube assemblies guide the incore instrument assemblies from the instrument penetrations in the reactor vessel bottom head to the instrument tubes in the fuel assemblies. Horizontal clearances are provided between the reactor vessel instrument penetrations and the instrument guide tubes in the flow distributor to accommodate misalignment. Fifty-two incore instrument guide tubes are provided and are designed so they will not be affected by the core drop described in Section 4.5.1.3.

7. Internals Vent Valves

   Internals vent valves are installed in the core support shield to prevent a pressure imbalance which might interfere with core cooling following a postulated inlet pipe rupture. Under all normal operating conditions, the vent valve will be closed. In the event of the pipe rupture in the cold leg of the reactor loop, the valve will open to permit steam generated in the core to flow directly to the leak, and will permit the core to be rapidly recovered and adequately cooled after emergency core coolant has been supplied to the reactor vessel. The design of the internals vent valve is shown in Figure 4-29 and Figure 4-30.

   Each valve assembly consists of a hinged disc, valve body with sealing surfaces, split-retaining ring, and fasteners. Each valve assembly is installed into a machined mounting ring integrally welded in the core support shield wall. The mounting ring contains the necessary features to retain and seal the perimeter of the valve assembly. Also, the mounting ring includes an alignment device to maintain the correct orientation of the valve assembly for hinged-disc operation. Each valve assembly will be remotely handled as a unit for removal or installation. Valve component parts, including the disc, are of captured design to minimize the possibility of loss of parts to the coolant system, and all operating fasteners include a positive locking device. The hinged-disc includes a device for remote inspection of disc function. Vent valve materials are listed in Table 4-16.

   The vent valve materials were selected on the basis of their corrosion resistance, surface hardness, antigalling characteristics, and compatibility with mating materials in the reactor coolant environment.

   The arrangement consists of eight 14-in. inside diameter vent valve assemblies installed in the cylindrical wall of the internals core support shield (refer to Figure 4-26). The valve centers are coplanar and are 42 in. above the plane of the reactor vessel coolant nozzle centers. In cross section, the valves are spaced around the circumference of the core support shield wall.

   The hinge assembly provides eight loose rotational clearances to minimize any possibility of impairment of disc-free motion in service. In the event that one rotational clearance should bind in service, seven loose rotational clearances would remain to allow unhampered disc free motion. In the worst case, at least four clearances must bind or seize solidly to adversely affect the valve disc free motion.

In addition, the valve disc hinge loose clearances permit disc self-alignment so that the external differential pressure adjusts the disc seal face to the valve body seal face. This feature minimizes the possibility of increased leakage and pressure-induced deflection loadings on the hinge parts in service.

The external side of the disc is contoured to absorb the impact load of the disc on the reactor vessel inside wall without transmitting excessive impact loads to the hinge parts as a result of a loss-of-coolant accident.

4.5.1.4 Evaluation of Internals Vent Valve

A vapor lock problem could arise if water is trapped in the steam generator blocking the flow of steam from the top of the reactor vessel to a cold leg leak. Under this condition, the steam pressure at the top of the reactor would rise and force the steam bubbles through the water leg in the bottom of the steam generator. This same differential pressure that develops a water leg in the steam generator will develop a water leg in the reactor vessel which could lead to uncovering of the core.

The most direct solution to this problem is to equalize the pressure across the core support shield, thus eliminating the depression of the water level in the core. This was accomplished by installing vent valves in the core support shield to provide direct communication between the top of the core and the coolant inlet annulus. These vent valves open on a very low-pressure differential to allow steam generated in the core to flow directly to the leak from the reactor vessel. Although the flow path in the steam generator is blocked, this is of no consequence since there is an adequate flow path to remove the steam being generated in the core.

During the vent valve conceptual design phase, criteria were established for valves for this service. The design criteria were (1) functional integrity, (2) structural integrity, (3) remote handling capability, (4) individual part capture capability, (5) functional reliability, (6) structural reliability, and (7) leak integrity throughout the design life. The design criteria resulted in the selection of the hinged-disc (swing-disc) check valve, which was considered suitable for further development.

Because of the unique purpose and application of this valve, B&W recognized the need for a complete detailed design and development program to determine valve performance under nuclear service conditions. This program included both analytical and experimental methods of developing data. It was performed primarily by B&W and the selected valve vendor or his subcontractors.

Vent valve preliminary design drawings were prepared and analyzed both by B&W and the vendor/subcontractor. Specifications and drawings were prepared, and orders were placed with the vendor for the design, development, fabrication, and test of a full-size prototype vent valve. The prototype valve was completed and subjected to the tests described in Section 4.5.4. All testing was successfully completed and minor problems encountered during valve assembly handling or use were corrected to arrive at the final design for the production valve (Reference 4).

The only significant problem encountered during test was seizing of one jack screw. This was attributable to an excessive thickness of “Electrolyze” which spalled off the screw threads. This problem was corrected by reducing the specified “Electrolyze” thickness from 0.0015 in. to 0.0004 in. max. and no further galling was encountered. To further enhance resistance to galling, the final design jackscrew has a 1-1/8 in.-8 Acme thread form instead of a 1 in.-12 UNF and the material is an age hardened corrosion resistant alloy instead of 410 SS.

No further jackscrew problems have occurred or are anticipated on the basis that the surfaces are separated by the low friction "Electrolyze", different materials of different hardnesses are used, loose fits are employed, and thread contact stresses are low (3775 psi).

The final design of this valve is shown in Figure 4-29. The valve disc hangs closed in its natural position to seal against a flat, stainless steel seat inclined 5 degrees from vertical to prevent flow from the inlet coolant annulus to the plenum assembly above the core. In the event of LOCA, the reverse pressure differential will open the valve. At all times during normal reactor operation, the pressure in the coolant annulus on the outside of the core support shield is greater than the pressure in the plenum assembly on the inside of the core support shield. Accordingly, the vent valve will be held closed during normal operation. With four reactor coolant pumps operating, the pressure differential is 42 psi resulting in a several-thousand pound closing force on the vent valve.

Under accident conditions, the valve will begin to open when a pressure differential of less than 0.15 psi develops in a direction opposite to the normal pressure differential. At this point, the opening force on the valve counteracts the natural closing force of the valve. With an opening pressure differential of no greater than 0.3 psi, the valve would be fully open. With this pressure differential, the water level in the core would be above the top of the core. In order for the core to be half uncovered, assuming solid water in the bottom half of the core, a pressure differential of 3.7 psi would have to be developed. This would provide an opening force of about 10 times that required to open the valve completely. This is a conservative limit since it assumes equal density in the core and the annulus surrounding the core. The hot, steam-water mixture in the core will have a density much less than that of the cold water in the annulus, and somewhat greater pressure differentials could be tolerated before the core is more than half uncovered.

An analog computer simulation was developed to evaluate the performance of the vent valves in the core support shield. This analysis demonstrated that adequate steam relief exists so that core cooling will be accomplished.

The behavior of the valve disc during LOCA conditions was investigated and the rather complex dynamic behavior of the disc during LOCA was analyzed as a series of simpler models which provide conservative predictions of peak stresses and deflections.

The valve disc remains closed initially for the LOCA hot leg (36 in. pipe) case and the disc opening on subsequent differential pulses is less than one-half of the initial disc to vessel wall impact velocity for the LOCA cold leg (28 in. pipe) case. Therefore, the disc motion and initial impact with the vessel inside wall was chosen as the worst case and the only one requiring consideration. The cold-leg LOCA pressure time history acting on the disc was approximated by a piecewise linear time function. The momemt due to pressure was equated to the rotary inertia of the disc to determine the velocity of impact with the vessel inside wall.

The model chosen for the initial impact consisted of three effective springs and two masses to represent the disc with its lug, the compliance of the disc, and the vessel inside wall.

Loads generated on impact were based on the conservation of energy. The stresses obtained for these loads indicated that the elastic model assuming conservation of energy was not valid and that the impact must assume plastic deformation. The locations and modes of plastic deformation are illustrated in BAW-10005 (Reference 4).

The plastic analysis provided the following information:

1. Crush deformation of lug after disc corner contacts the vessel wall is predicted to be 0.165 inches.
2. The total deformation of lug from contact with the vessel wall until disc assembly motion is arrested is predicted to be 0.483 inches.
3. The total angular deformation at the plastic hinge is predicted to be 0.016 radians.
4. An analysis was performed on the reactor vessel wall for disc assembly impact and the results indicate that while the stainless steel cladding is deformed locally, the reactor maintains its structural and pressure boundary integrity.

Because of conservative assumptions used in the plastic analysis, actual deformations will be considerably less than the above predicted values. Although plastic deformation may occur as predicted above on impact, the disc will retain its structural integrity. Plastic deformation of the disc dissipates the stored kinetic energy stored in the disc effectively; thus the energy available for rebound is less than 1 percent of the initial impact energy and is too low to overcome the pressure differential and cause impact on the valve body. Disc and body hinge components were analyzed for worst case disc impact loadings and the resulting stresses were found to be less than the allowable limits; therefore, the valve disc free-motion (venting) function will be unaffected.

From the above, it is concluded that vent valve performance will not be impaired during the course of an accident because disc free-motion part stresses remain within allowable limits, disc structural integrity is maintained, vessel pressure boundary integrity is maintained, and plastic deformation of the disc seating surface improves the venting function.

With reference to Figure 4-30, each jackscrew assembly consists of a jackscrew, internally splined mating nut ring, nut ring spring, capture cover and cover attachment fasteners (socket head cap screws). In the figure, the splined nut ring and its spring are hidden from view by the capture cover. The potential for loss of jackscrew assembly parts during the plant lifetime is considered remote on the basis that the jackscrews and capture parts are accessible for visual inspection during scheduled refueling outages. A jackscrew loss is considered remote because a failure in service is highly improbable with the low compressive load (1000 psi) involved and the jack screw is retained in the valve body by a central shoulder and the ends are threaded into the retaining rings. An in-service failure of the splined nut ring and its spring is remote because these parts are subjected to little or no load and even if they did fail all parts would be retained within the capture cover. Capture cover failure and loss is highly improbable on the same basis that is it not loaded in service. The capture cover is attached to the upper retaining ring by socket head cap screws which are lock welded to the cover at installation. By design, these screws are retention rather structural devices and are not loaded in service. These screws do not require a pre-load to hold the formed cover in place; therefore, a loss of pre-load by lock welding would not jeopardize the cover or screw installation or structural integrity. Two fillet welds 180° apart are used to lock weld each screw head to the capture cover and in the absence of loads on both the cover and screws, the likelihood of lock weld failure and loss of screw heads is considered remote. With the capability to inventory these cap screw heads visually at scheduled refuelings, any problem related to the loss of these screws would be apparent early in the plant life and the valve assemblies could be removed for corrective action.

The internals vent valves are described, including materials and hinge part loose clearances in Table 4-17.

The internals vent valves have been tested for ability to withstand the effects of vibratory excitations and for other functional characteristics as described in Section 4.5.4.

4.5.2 Core Components

This section addresses core components that are not an integral part of the fuel assembly itself. Specifically addressed are the following: control rod assembly, axial power shaping rod assembly, and burnable poison rod assembly.

4.5.2.1 Fuel Assemblies

The fuel system (fuel assembly and its components) is addressed in Section 4.2.

4.5.2.2 Control Rod Assembly (CRA)

Each control rod assembly (Figure 4-31) has 16 control rods, a stainless steel spider, and a female coupling. The 16 control rods are attached to the spider by means of a nut threaded to the upper shank of each rod. After assembly, all nuts are lock welded. The control rod drive is coupled to the CRA by a bayonet type connection. Full length guidance for the CRA is provided by the control rod guide tube of the upper plenum assembly and by the fuel assembly guide tubes. The CRAs and guide tubes are designed with adequate flexibility and clearances to permit freedom of motion within the fuel assembly guide tubes throughout the stroke.

Oconee 3, Cycle 8 introduced a new long life control rod assembly design. Future replacement CRAs for all units will be of this type. The extended life control rod assembly (CRA) is nearly identical to B&W's standard design. The present designed spider/coupling arrangement is retained as are all other envelope dimensions. Reference to Table 4-18, demonstrates the differences between the standard and the plant-life CRA design. The major differences are found in the slight reduction in the absorber OD and the use of Inconel 625 clad (as compared to the standard SS 304 material). Inconel 625 CRA cladding was selected because of its added creep and corrosion resistance. In addition, the rodlets are prepressurized with helium, and the cladding is slightly thicker to retard creepdown and ovalization.

Each control rod has a section of neutron absorber material. The absorber material is an alloy of silver-indium-cadmium. End pieces are welded to the tubing to form a water-tight and pressure-tight container for the absorber material.

Both the inconel and the stainless steel tubing provide the structural strength of the control rods and prevents corrosion of the absorber material. A tube spacer similar to the type used in fuel assemblies is used to prevent absorber motion within the cladding during shipping and handling, and to permit differential expansion in service.

These control rods are designed to withstand all operating loads including those resulting from hydraulic force, thermal gradients, and reactor trip deceleration. The ability of the control rod clad to resist collapse has been established in a test program on cold-worked stainless steel tubing. Because the Ag-In-Cd alloy poison does not yield a gaseous product under irradiation, internal pressure and swelling of the absorber material does not cause excessive stressing or stretching of the clad.

Because of their length and the possible lack of straightness over the entire length of the rod, some interference between control rods and the fuel assembly guide tubes is expected. However, the parts involved, especially the control rods, are flexible and only small friction drag loads result. Similarly, thermal distortions of the control rods are small because of the low heat generation and adequate cooling. Consequently, control rod assemblies do not encounter significant frictional resistance to their motion in the guide tubes.

4.5.2.3 Axial Power Shaping Rod Assembly (APSRA)

Gray APSR's are provided for additional control of axial power distribution. Each axial power shaping rod assembly (Figure 4-32) has 16 axial power shaping rods, a stainless steel spider, and a female coupling. The 16 rods are attached to the spider by means of a nut threaded to the upper shank of each rod. After assembly all nuts are lock welded. The axial power shaping rod drive is coupled to the APSRA by a bayonet connection. The female couplings of the APSRA and CRA have slight dimensional differences to ensure that each type of rod can only be coupled to the correct type of drive mechanism.

There are 2 APSR coupling designs which are not fully interchangeable between fuel assembly designs, because of the difference in hold down spring designs and APSR drive mechanisms. Table 4-22 depicts the APSR coupling, APSR drive mechanism, and fuel assembly compatibility for each unit.

When the APSRA is inserted into the fuel assembly it is guided by the guide tubes of the fuel assembly. Full length guidance of the APSRA is provided by the control rod guide tube of the upper plenum assembly. At the full out position of the control rod drive stroke, the lower end of the APSRA remains within the fuel assembly guide tube to maintain the continuity of guidance throughout the rod travel length. The APSRAs are designed to permit maximum conformity with the fuel assembly guide tube throughout travel.

Each axial power shaping rod has a section of neutron absorber material. For these gray APSRs, this absorber material is Inconel 600, and the clad is coldworked, Type 304 or 304L stainless steel tubing. The tubing provides the structural strength of the axial power shaping rods and prevents corrosion of the absorber material.

Gray APSRs are designed with improved creep life. Cladding thickness and rod ovality control, which are the primary factors controlling the creep life of a stainless steel material, have been improved to extend the creep life of the gray APSR. Minimum design cladding thickness is 25 mils.

The gray APSRs are prepressurized to extend their lifespan.

Pertinent data on gray APSRs is shown in Table 4-19.

These axial power shaping rods are designed to withstand all operating loads including those resulting from hydraulic forces and thermal gradients. The ability of the axial power shaping rod clad to resist collapse due to the system pressure has been established in a test program on cold worked stainless steel tubing. The absorber material does not yield gaseous products under irradiation, therefore, internal pressure is not generated within the clad. Swelling of the absorber material is negligible, and does not cause unacceptable clad strain.

Because of their great length and unavoidable lack of straightness, some slight mechanical interference between axial power shaping rods and the fuel assembly guide tubes must be expected. However, the parts involved are flexible and result in very small friction drag loads. Similarly, thermal distortions of the rods are small because of the low generation and adequate cooling. Consequently, the APSRAs do not encounter significant frictional resistance to their motion in the guide tubes.

4.5.2.4 Burnable Poison Rod Assembly (BPRA)

Each BPRA (Figure 4-1) has 16 burnable poison rods, a stainless steel spider, and a coupling mechanism. The coupling mechanism and the 16 rods are attached to the spider. The BPRA is inserted into the fuel assembly guide tubes through the upper end fitting. Retention is provided by the feet on the BPRA spider, which rest upon the fuel assembly holddown spring retainer ring. Thus the BPRA is pinned between this retainer ring and the reactor's upper grid pads. All Oconee fuel which is of the Mk B5 (or later) design, uses this BPRA design.

The burnable poison rod is clad in cold-worked Zircaloy-4 tubing and Zircaloy-4 upper and lower end pieces. The end pieces are welded to the tubing to form a water and pressure-tight container for the absorber material. The Zircaloy-4 tubing provides the structural strength of the burnable poison rods.

In addition to their nuclear function, the BPRA also serve to minimize guide tube bypass coolant flow. Pertinent data on the BPRA is shown in Table 4-20.

The burnable poison rods are designed to withstand all operating loads including those resulting from hydraulic forces and thermal gradients. The ability of the burnable poison rod clad to resist collapse due to the system pressure and internal pressure has been demonstrated by an extensive test program on cold-worked Zircaloy-4 tubing (Section 4.2.4.3.1).

A spacer spring is used at the top of the poison stack to control the poison pellet motion with the cladding during shipping and handling and to allow for thermal expansion and swelling during cycle operation.

4.5.3 Control Rod Drives

Oconee Units 1, 2 and 3 uses the Type C control rod drive mechanism. The control rod drive mechanisms are sealed, reluctance motor-driven screw units.

4.5.3.1 Type C Mechanisms

The control rod drive mechanism (CRDM) positions the control rod within the reactor core, provides for controlled withdrawal or insertion of the control rod assemblies, is capable of rapid insertion or trip, and indicates the location of the control rod with respect to the reactor core. The speed at which the control rod is inserted or withdrawn from the core is consistent with the reactivity change requirements during reactor operation. For conditions that require a rapid shutdown of the reactor, the shim safety drive mechanism releases the CRA and supporting CRDM components permitting the CRA to move by gravity into the core. The reactivity is reduced during such a rod insertion at a rate sufficient to control the core under any operating transient or accident condition. The control rod is decelerated at the end of the rod trip insertion by a snubber assembly which is attached to the lower end of the torque tube. The CRDM data is listed in Table 4-21, and criteria applicable to drive mechanisms for both control shim rod assemblies and axial power shaping rod assemblies are given below. Additional requirements for the mechanisms which actuate only control shim rod assemblies are also given below.

4.5.3.1.1 General Design Criteria

1. Single Failure

   No single failure shall inhibit the protective action of the control rod drive system. The effect of a single failure shall be limited to one CRDM.

2. Uncontrolled Withdrawal

   No single failure or sequence of dependent failures shall cause uncontrolled withdrawal of any control rod assembly (CRA).

3. Equipment Removal

The disconnection of plug-in connectors, modules, and subassemblies from the protective circuits shall be annunciated or shall cause a reactor trip.

4. Position Indication

   Continuous position indication, as well as an upper and lower position limit indication, shall be provided for each CRDM. The accuracy of the position indicators shall be consistent with the tolerance set by reactor safety analysis.

5. Drive Speed

   The control rod drive control system shall provide two uniform mechanism speeds. The drive controls, or mechanism and motor combination, shall have an inherent speed limiting feature. The speed of the mechanism shall be 30 in./min for both insertion and withdrawal in the “Run” mode of control. The withdrawal speed shall be limited to not exceed 25 percent overspeed in the event of speed control fault. The speed of the mechanism shall be 3 in./min for both insertion and withdrawal in the “Jog” mode of control.

6. Mechanical Stops

   Each CRDM shall have positive mechanical stops at both ends of the stroke or travel. The stops shall be capable of receiving the full operating force of the mechanisms without failure.

7. Control Rod Positioning

   The control rod drives shall provide for controlled withdrawal or insertion of the control rods out of, or into, the reactor core to establish and hold the power level required.

4.5.3.1.2 Additional Design Criteria

The following criterion is applicable only to the mechanisms which actuate control rod assemblies: The shim safety drives are capable of rapid insertion or trip for emergency reactor conditions.

4.5.3.1.3 Shim Safety Drive Mechanism

The Type C shim safety drive mechanism consists of a motor tube which houses a lead screw and its rotor assembly, and a snubber assembly. The top end of the motor tube is closed by a closure and vent assembly. An external motor stator surrounds the motor tube (a pressure housing) and position indication switches are arranged outside the motor tube extension.

The control rod drive output element is a non-rotating translating lead screw coupled to the control rod. The screw is driven by separating anti-friction roller nut assemblies which are rotated magnetically by a motor stator located outside the pressure boundary. Current impressed on the stator causes the separating roller nut assembly halves to close and engage the lead screw. Mechanical springs disengage the roller nut halves from the screw in the absence of a current. For rapid insertion, the nut halves separate to release the screw and control rod, which move into the core by gravity. A snubber assembly within the torque tube decelerates the moving CRA to a low speed a short distance above the CRA full-in position. The final CRA deceleration energy is absorbed by the belleville spring assembly. The CRDM is a totally sealed unit with the roller nut assemblies magnetically driven by the stator coil through the motor tube pressure housing wall. The lead screw assembly is connected to the control rod by a bayonet type coupling. An anti-rotation device (torque taker) prevents rotation of the lead screw while the drive is in service. A closure and vent assembly is provided at the top of the motor tube housing to permit access to couple and release the lead screw assembly from the control rod. The top end of the lead screw assembly is guided by the torque taker assembly.

Two of the six phase stator housing windings are energized to maintain the control rod position when the drive is in the holding mode.

4.5.3.1.4 CRDM Subassemblies

The CRDM is shown in Figure 4-34. Subassemblies of the CRDM are described as follows:

1. Motor Tube

   The motor tube is a three-piece welded assembly designed and manufactured in accordance with the requirements of the ASME Code, Section III, for Class A nuclear pressure vessel. Materials conform to ASTM or ASME, Section II, Material Specifications. All welding shall be performed by personnel qualified under ASME Code, Section IX, Welding Qualifications. The motor tube wall between the rotor assembly and the stator is constructed of martensitic stainless steel to present a small air gap to the motor. The upper end of the motor tube functions only as a pressurized enclosure for the withdrawn lead screw and is made of stainless steel transition welded to the upper end of the low alloy steel motor section. The lower end of the low alloy steel tube section is welded to a stainless steel machined forging which is flanged at the face which contacts the vessel control rod nozzle. Double gaskets, which are separated by a ported test annulus, seal the flanged connection between the motor tube and the reactor vessel.

2. Motor

   The motor is a synchronous reluctance unit with a slip-on stator. The rotor assembly is described in 6 below. The stator is a 48-slot four-pole arrangement with water cooling coils wound on the outside of its casing. The stator is varnish impregnated after winding to establish a sealed unit. It is six phase star-connected for operation in a pulse-stepping mode and advances 15 mechanical degrees per step. The stator assembly is mounted over the motor tube housing as shown in Figure 4-34.

3. Plug and Vent Valve

   The upper end of the motor tube is closed by a closure insert assembly containing a vapor bleed port and vent valve. The vent valve and insert closure have double seals. The insert closure is retained by a closure nut which is threaded to the inside of the motor tube. The sealing for the closure is applied by hydraulically tensioning the closure insert and is retained by the closure nut.

   Deleted paragraph(s) per 2005 update

4. Actuator

   The actuator consists of the translating lead screw, its rotating nut assembly, and the torque taker assembly on the screw. The actuator lead screw travel is 139 inches.

5. Lead Screw

   The lead screw has a lead of 0.750 in. The thread is double lead with a single pitch spacing of 0.375 in. Thread lead error is held to close tolerances for uniform loading with the roller nut assemblies. The thread form is a modified ACME with a blank angle that allows the roller nut disengage without lifting the screw.

6. Rotor Assembly

   The rotor assembly consists of a ball bearing supported rotor tube carrying and limiting the travel of a pair of scissors arms. Each of the two arms carry a pair of ball bearing supported roller (nut) assemblies which are skewed at the lead screw helix angle for engagement with the lead screw. The current in the motor stator (two of a six winding stator) causes the arms that are pivoted in the rotor tube to move radially toward the motor tube wall to the limit provided thereby engaging the four roller nuts with the centrally located lead screw. Also, four separating springs mounted in the scissor arms keep the rollers disengaged when the power is removed from the stator coils. A second radial bearing mounted to the upper end of the rotor tube has its outer race pinned to both scissor arms thereby synchronizing their motion during engagement and disengagement. When a three phase rotating magnetic field is applied to the motor stator, the resulting force produces rotor assembly rotation.

7. Torque Extension Tube and Torque Taker

The torque tube is a separate tubular assembly containing a key that extends the full length of the leadscrew travel. The tube assembly is secured in elevation and against rotation at the lower end of the closure assembly by a retaining ring, keys and the insert closure. The lower end of the torque tube houses the snubber assembly and is the down stop. The leadscrew contacts the insert closure assembly for the upper mechanical stop.

The torque taker assembly consists of the position indicator permanent magnet, the snubber piston and a positioning keyway. The torque taker assembly is attached to the top of the leadscrew and has a keyway that mates with the key in the torque tube to provide both radial and tangential positioning of the leadscrew.

8. Snubber Assembly

The total snubber assembly is composed of a piston that is the lower end of the torque taker assembly and a snubber cylinder and belleville spring assembly which is attached to the lower end of the torque tube. The snubber cylinder is closed at the bottom by the snubber bushing and leadscrew. The snubber cylinder has a twelve-inch active length in which the free-fall tripped leadscrew and control rod assembly is decelerated without applying greater than ten times gravitational force on the control rod. The damping characteristics of the snubber is determined by the size and position of a number of holes in the snubber cylinder wall and the leakage at the snubber piston and bushing. Leakage reduction at the snubber piston and bushing can only be reduced to a minimum amount caused by practical operating clearances. Therefore, at the end of the snubbing stroke, there is kinetic energy from a five foot per second impact velocity that is absorbed by the belleville spring assembly by a slight instantaneous overtravel past the normal down stop.

9. Lead Screw Guide

The lead screw guide bushing acts as a primary thermal barrier and as a guide for the screw shaft. As a primary thermal barrier, the bushing allows only a small path for free convection of water between the mechanism and the closure head nozzle. Fluid temperature in the mechanism is largely governed by the flow of water up and down through this bushing. The diametrical clearance between screw shaft and bushing is large enough to preclude jamming the screw shaft and small enough to hold the free convection to an acceptable value. In order to obtain trip travel times of acceptably small values, it is necessary to provide an auxiliary flow path around the guide bushing. The larger area path is necessary to reduce the pressure differential required to drive water into the mechanism to equal the screw displacement. The auxiliary flow paths are closed for small pressure differentials (several inches of water) by ball check valves which prevent the convection flow but, open fully during trip.

10. Position Indications

Two methods of position indication are provided: an absolute position indicator and a relative position indicator. The absolute position transducer consists of a series of magnetically operated reed switches mounted in a tube parallel to the motor tube extension. Each switch is hermetically sealed. Switch contacts close when a permanent magnet mounted on the upper end of the lead screw extension comes in close proximity. As the lead screw (and the control rod assembly) moves, switches operate sequentially producing an analog voltage proportional to position. Additional reed switches are included in the same tube with the absolute position transducer to provide full withdrawal and insertion signals. The relative position indicator consists of a programmable logic controller that generates a signal proportional to the position demand for the rod, as derived from counting the number and sequence of power pulses sent to the rod drive moter stator windings.

11. Motor Tube Design Criteria

The motor tube design complies with Section III of the ASME Boiler and Pressure Vessel Code for a Class A vessel. The operating transient cycles, which are considered for the stress analysis of the reactor pressure vessel, are also considered in the motor tube design.

Quality standards relative to material selection, fabrication, and inspection are specified to insure safety function of the housings essential to accident prevention. Materials conform to ASTM or ASME, Section II, Material Specifications. All welding shall be performed by personnel qualified under ASME Code, Section IX, Welding Qualifications. These design and fabrication procedures establish quality assurance of the assemblies to contain the reactor coolant safely at operating temperature and pressure.

In the highly unlikely event that a pressure barrier component or the control rod drive assembly does fail catastrophically, i.e., ruptured completely, the following results would ensue:

a. Control Rod Drive Nozzle

The assembly would be ejected upward as a missile until it was stopped by the missile shield over the reactor. This upward motion would have no adverse effect on adjacent assemblies.

b. Motor Tube

The failure of this component anywhere above the lower flange would result in a missile-like ejection into the missile shielding over the reactor. This upward motion would have no adverse effect on adjacent mechanisms.

12. Axial Power Shaping Rod Drive

For actuating the partial length control rods which maintain their set position during a reactor-trip of the shim safety drive, the CRDM is modified so that the roller nut assembly will not disengage from the lead screw on a loss of power to the stator. Except for this modification, the shim drives and the axial power shaping rod drives are identical.

4.5.3.2 Deleted Per 2002 Update

4.5.3.2.1 Deleted Per 2002 Update

4.5.3.2.2 Deleted Per 2002 Update

4.5.4 Internals Tests and Inspections

4.5.4.1 Reactor Internals

The hydraulic design of the upper and lower plena of the internals is evaluated and guided by the results from the 1/6 scale model flow test which is described in Section 4.4.4. These test results have guided the design to obtain minimum flow maldistribution, and the test data allowed verification of vessel flow and pressure drop.

The effects of internals misalignment was evaluated on the basis of the test results from the CRDL tests described in Section 4.2.4. These test results, correlated with the internals guide tube design, insure that the CRA can be inserted at specified rates under conditions of maximum misalignment.

Internals shop fabrication quality control tests, inspection, procedures, and methods are similar to those for the pressure vessel described in Section 5.2.3.11. The internals surveillance specimen holder tubes and the material irradiation program are described in Section 5.2.3.13.

A listing is included herewith for all internals nondestructive examinations and inspections with applicable codes or standards applicable to all core structural support material of various forms. In addition, one or more of these examinations are performed on materials or processes which are used for functions other than structural support (i.e. alignment dowels, etc.) so that virtually 100 percent of the completed internals materials and parts are included in the listing. Internals raw materials are purchased to ASME Code Section II or ASTM material specifications. Certified material test reports are obtained and retained to substantiate the material chemical and physical properties. All internals materials are purchased and obtained to a low cobalt limitation. The ASME Code Section III, as applicable for Class A vessels, is generally specified as the requirement for reference level nondestructive examination and acceptance. In isolated instances when ASME III cannot be applied, the appropriate ASTM Specifications for non-destructive testing are imposed. All welders performing weld operations on internals are qualified in accordance with ASME Code Section IX applicable Edition and Addenda. The primary purpose of the following list of non-destructive tests is to locate, define, and determine the size of material defects to allow an evaluation of defect, acceptance, rejection, or repair. Repaired defects are similarly inspected as required by applicable codes.

4.5.4.1.1 Ultrasonic Examination

1. Wrought or forged raw material forms are 100 percent inspected throughout the entire material volume to ASME III, Class A.
2. Personnel conducting these examinations are trained and qualified.

4.5.4.1.2 Radiographic Examination (includes X-ray or radioactive sources)

1. Cast raw material forms are 100 percent inspected to ASME III Class A or ASTM.
2. All circumferential full penetration structural weld joints which support the core are 100 percent inspected to ASME III Class A.
3. All radiographs are reviewed by qualified personnel who are trained in their interpretation.

4.5.4.1.3 Liquid Penetrant Examination

1. Cast form raw material surfaces are 100 percent inspected to ASME III Class A or ASTM.
2. Full penetration non-radiographic or partial penetration structural welds are inspected by examination of root, and cover passes to ASME III Class A.
3. All circumferential full penetration structural weld joints which support the core have cover passes inspected to ASME III Class A.
4. Personnel conducting these examinations are trained and qualified.

4.5.4.1.4 Visual (5X Magnification) Examination

This examination is performed in accordance with and results accepted on the basis of a B&W Quality Control Specification which complies with NAV-SHIPS 250-1500-1. Each entire weld pass and adjacent base metal are inspected prior to the next pass from the root to and including the cover passes.

1. Partial penetration non-radiographically or non-ultrasonically feasible structural weld joints are 100 percent inspected to the above specification.
2. Partial or full penetration attachment weld joints for nonstructural materials or parts are 100 percent inspected to the above specification.
3. Partial or full penetration weld joints for attachment of mechanical devices which lock and retain structural fasteners.
4. Personnel conducting these examinations are trained and qualified.

After completion of shop fabrication, the internals components are shopfitted and assembled to final design requirements. The assembled internals components undergo a final shop fitting and alignment of the internals with the "as built" dimensions of the reactor vessel. Dummy fuel and CRAs are used to insure that ample clearances exist between the fuel and internals structures guide tubes to allow free movement of the CRA throughout its full stroke length in various core locations. Fuel assembly mating fit is checked at all core locations. The dummy fuel and CRAs are identical to the production components except that they are manufactured to the most adverse tolerance space envelope, and they contain no fissionable or absorber materials.

All internal components can be removed from the reactor vessel to allow inspection of all vessel interior surfaces. Internals components surfaces can be inspected when the internals are removed to the canal underwater storage location.

4.5.4.2 Internals Vent Valves Tests and Inspection

The internals vent valves are designed to relieve the pressure generated by steaming in the core following a LOCA so that the core will remain sufficiently cooled. The valves were designed to withstand the forces resulting from rupture of either a reactor coolant inlet or outlet pipe. To verify the structural adequacy of the valves to withstand the pressure forces and perform the venting function, the following tests were performed:

4.5.4.2.1 Hydrostatic Testing

A full-size prototype valve assembly (valve disc retaining mechanism and valve body) was hydrostatically tested to the maximum pressure expected to result during the blowdown.

4.5.4.2.2 Frictional Load Tests

Sufficient tests were conducted at zero pressure to determine the frictional loads in the hinge assembly, the inertia of the valve disc, and the disc rebound resulting from impact of the disc on the seat so that the valve response to cyclic blowdown forces may be determined analytically.

4.5.4.2.3 Pressure Testing

A prototype valve was pressurized to determine the pressure differential required to cause the valve disc to begin to open. A determination of the pressure differential required to open the valve disc to its maximum open position was simulated by mechanical means.

4.5.4.2.4 Handling Test

A prototype valve assembly was successfully installed and removed remotely in a test stand to confirm the adequacy of the vent valve handling tool.

4.5.4.2.5 Closing Force Test

A 1/6 scale model valve disc closing force (excluding gravity) test is described in Section 4.4.4.

4.5.4.2.6 Vibration Testing

The full-size prototype valve's response to vibration was determined experimentally to verify prior analytical results which indicated that the valve disc would not move relative to the body seal face as a result of vibration caused by transmission of core support shield vibrations. The prototype valve was mounted in a test fixture which duplicated the method of valve mounting in the core support shield. The test fixture with valve installed was attached to a vibration test machine and excited sinusoidally through a range of frequencies which encompassed those which may reasonably be anticipated for the core support shield during reactor operation. The relative motion between the valve disc and seat was monitored and recorded during test. The test results indicated that there was no relative motion of the valve to its seat for conditions simulating operating conditions. After no relative motion was observed or recorded during test, the valve disc was manually forced open during test to observe its response. The disc closed with impact on its seat, rebounded open and reseated without any adverse affects to valve seal surfaces, characteristics, or performance. From this oscillograph record, the natural frequency of the valve disc was conservatively calculated as approximately 1500 cps; whereas, the range of frequencies for the Oconee system (including internals components) has been established as 15 to 160 cps.

These frequencies are separated by an ample margin to conclude that no relative motion between the valve disc and its seal will occur during normal reactor operation.

4.5.4.2.7 Production Valve Testing

Each production valve will be subjected to tests described in Sections 4.5.4.2.2 and 4.5.4.2.3 except that no additional analysis will be performed in conjunction with the test described in Section 4.5.4.2.2.

The valve disc, hinge shaft, shaft journals (bushings), disc journal receptacles, and valve body journal receptacles are designed to withstand without failure the internal and external differential pressure loadings resulting from a loss-of-coolant accident. These valve materials will be nondestructively tested and accepted in accordance with the ASME Code III requirements for Class A vessels as a reference quality level.

4.5.4.2.8 Subsequent Operations

During scheduled refueling outages after the reactor vessel head and the internals plenum assembly have been removed, the vent valves are accessible for visual and mechanical inspection. A hook tool is provided to engage with the valve disc exercise lug described in Item 7 of Section 4.5.1.3.2. With the aid of this tool, the valve disc will be manually exercised to evaluate the disc freedom. The hinge design incorporates special features, as described in Item 7 of Section 4.5.1.3.2 to minimize the possibility of valve disc motion impairment during its service life. With the aid of the hook tool, the valve disc can be raised and a remote visual inspection of the valve body and disc sealing faces can be performed for evaluation of observed surface irregularities.

Remote installation and removal of the vent valve assemblies if required is performed with the aid of the vent valve handling tool which includes unlocking and operating features for the retaining ring jackscrews.

An inspection of hinge parts is not planned until such time as a valve assembly is removed because its free-disc motion has been impaired. In the unlikely event that a hinge part should fail during normal operation, the most significant indication of such a failure would be a change in the free-disc motion as a result of altered rotational clearances.

4.5.5 References

1. E. O. Hooker, H. J. Fortune, "Design of Reactor Internals and Incore Instrument Nozzles for Flow Induced Vibrations", B&W, *BAW-10051*, Lynchburg, VA., September 1972.
2. BAW-10008, Part 1, Rev. 1, Reactor Internals Stress and Deflection due to Loss-of-Coolant Accident and Maximum Hypothetical Earthquake, June 1970.
3. Deleted Per 1997 Update
4. "Internals Vent Valve Evaluation", B&W, BAW-10005, Revision 1, Lynchburg, VA., June 1970.
5. James T. Williams, R. E. Harris, John Ficor, "Control Rod Drive Mechanism", B&W, *BAW-10029A*, *Revision 3*, Lynchburg, VA., August 1976.
6. *Demonstration of the Management of Aging Effects for the Reactor Vessel Internals*, BAW-2248A, The B&W Owners Group Generic License Renewal Program, March 2000.
7. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3*, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, 50-270, and 50-287.
8. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

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Appendix 4A. Tables

Table 4-1. Core Design, Thermal, and Hydraulic Data

Reactor	
Rated Heat Output, MWt	2,568
Vessel Coolant Inlet Temperature, 100% power, F	557.8
Vessel Coolant Outlet Temperature, 100% power, F	602.4
Core Outlet Temperature, 100% power	606.2
Core Operating Pressure, psia	2200
Reactor Coolant flow, % design flow	108.5
Note: The following parameters specified below are based on the fuel assembly nomenclature.	
Core and Fuel Assemblies [1]	
Total Number of Fuel Assemblies in Core	177
Number of Fuel Rods per Fuel Assembly	208
Number of Control Rod Guide Tubes per Assembly	16
Number of In-Core Instrumentation Positions per Fuel Assembly	1
Fuel Rod Outside Diameter, in.	
Mk-B10	0.430
Mk-B11, Mk-B11A	0.416
Mk-B-HTP	0.430
Clad Thickness, in.	
Mk-B10 to B10E	0.0265
Mk B-10F, Mk B-10G, and Mk B-10L	0.0250
Mk-B11, Mk-B11A	0.0240
Mk-B-HTP	0.0250
Fuel Rod Pitch, in.	0.568
Fuel Assembly Pitch Spacing, in.	8.587
Fuel Assembly Overall Length (Typical), in.	
Mk-B2 to B10L, Mk-B11 and Mk-B11A	165.695
Mk-B-HTP	165.895
Unit Cell Metal/Water Ratio (Volume Basis)	0.82
Fuel	
Material	UO_2

Form	Dished-End, Cylindrical Pellets
Pellet Diameter, in.	
MK B-10 to B-10E	0.3700
MK B-10F, MK B-10G, and MK B-10L	0.3735
Mk-B11, Mk-B11A	0.3615
Mk-B-HTP	0.3735
Active Length, in.	
MK B10 to B-10E	140.5 - 140.7
MK B-10F, MK B-10G, and MK B-10L	142.3
Mk-B11, Mk-B11A	143.05
Mk-B-HTP	143.0
Density, % of Theoretical	
Mk B-10 to B-10E	95.0
Mk B-10F, Mk B-10G, and Mk B-10L	96.0
Mk-B11, Mk-B11A	96.0
Mk-B-HTP	96.0
Heat Transfer and Fluid Flow at Rated Power [2]	
Total Heat Transfer Surface in Core, ft^2	
Mk-B10 to B-10E	48,525
Mk-B10F, Mk-B10G and Mk-B10L	49,147
Mk-B11, Mk-B11A	47,797
Mk-B-HTP	49,389
Average Heat Flux, Btu/hr-ft^2	
Mk-B10 to B-10E	175.7×10^3
Mk-B10F, Mk-B10G and Mk-B10L	173.5×10^3
Mk-B11, Mk-B11A	178.4×10^3
Mk-B-HTP	177.5×10^3
Maximum Heat Flux, Btu/hr-ft^2	
Mk-B10 to B-10E	452×10^3
Mk-B10F, Mk-B10G and Mk-B10L	446×10^3
Mk-B11, Mk-B11A	458×10^3
MK-B-HTP	456×10^3

Average Power Density in Core, kW/ℓ	
Mk-B10 to B-10E	85.46
Mk-B10F, Mk-B10G and Mk-B10L	84.38
Mk-B11, Mk-B11A	83.94
Mk-B-HTP	83.97
Average Thermal Output, kW/ft of Fuel Rod	
Mk-B10, Mk-B10D, and Mk-B10E	5.8
Mk-B10F, Mk-B10G, Mk-B10L, Mk-B11 and Mk-B11A	5.7
Mk-B-HTP	5.7
Maximum Thermal Output, kW/ft of Fuel Rod	
Mk-B10, Mk-B10D and Mk-B10E	14.9
Mk-B10F, Mk-B10G and Mk-B10L	14.7
Mk-B11, Mk-B11A	14.6
Mk-B-HTP	14.6
Average Core Fuel Temperature, F	
Mk-B10,Mk-B10D and Mk-B10E	1215
Mk-B10F, Mk-B10G and Mk-B10L	1162
Mk-B11, Mk-B11A	1175
Mk-B-HTP	1162
Total Reactor Coolant Flow, lb/hr (108.5% Design Flow)	142.3×10^6
Core Flow Area (Effective for Heat Transfer), ft^2	
Mk-B10 though Mk-B10L	49.645
Mk-B11, Mk-B11A	52.032
Mk-B-HTP	49.620
Core Coolant Average Velocity, fps (108.5% Design Flow)	
Mk-B10 through Mk-B10L (7.00% Bypass Flow)	15.94
Mk-B11, Mk-B11A (7.50% Bypass Flow)	15.13
Mk-B-HTP (6.49% Bypass Flow)	16.04
Power Distribution	
Maximum/Average Power Ratio, Radial x Local ($F_{\Delta h}$ Nuclear)	1.714
Maximum/Average Power Ratio, Axial (F_z Nuclear)	1.5 cos
Overall Power Ratio (F_q Nuclear)	2.57
Power Generated in Fuel and Cladding, %	97.3

Hot Channel Factors	
Power Peaking Factor (F_Q)	
Mk-B10, Mk-B10D and Mk-B10E	1.0107
Mk-B10F, Mk-B10G and Mk-B10L	1.0132
Mk-B11, Mk-B11A	1.0133
Mk-B-HTP	1.0132
Hot Spot Maximum/Average Heat Flux Ratio	
(F_q nuc and mech)	
Mk-B10, Mk-B10D and Mk-B10E	2.71
Mk-B10F to B10L ,Mk-B11 and Mk-B11A	2.72
Mk-B-HTP	2.64
Flow Area Reduction Factor(F_A) for MK-B10 through Mk-B10L, Mk-B11, Mk-B11A, and MK-B-HTP	
Unit/CRGT Bundle Cells	0.98
IGT Bundle Cells	0.97
DNB Data	
Design Overpower (% Rated Power)	112
CHF Correlation	
Mk-B10 through Mk-B10L	BWC
Mk-B11, Mk-B11A	BWU-Z with FB11 Multiplier
Mk-B-HTP	BHTP
DNB Limit - Non SCD	
Mk-B10 through Mk-B10L	1.18
Mk-B11, Mk-B11A	1.19
Mk-B-HTP	Proprietary
DNB Limit – SCD	
Mk-B10 through Mk-B10L	1.43
Mk-B11, Mk-B11A	1.33
Mk-B-HTP	1.34
Typical minimum DNBR	
Mk-B10 through Mk-B10L	2.47
Mk-B11, Mk-B11A	2.76
Mk-B-HTP	2.58

Note:

1. Parameters are based on cold dimensions for each of the respective fuel assembly designs, as applicable.
2. Based on reference peaking and active fuel length for each fuel rod type specified at BOL conditions.

Table 4-2. Fuel Assembly Components

Item	Material	Dimensions (In)
Fuel Clad (in.)		
Mk B-10 through B10E	Zircaloy-4	0.430 OD x 0.377 ID
Mk B-10F through Mk B-10L	Zircaloy-4	0.430 OD x 0.380 ID
Mk-B11, Mk-B11A	M5	0.416 OD x 0.368 ID
Mk-B-HTP	M5	0.430 OD x 0.380 ID
Fuel Rod Length (Typical), in.		
Mk-B10 to B10L		154.16
Mk-B11, Mk-B11A		155.30
Mk-B-HTP		155.00
Fuel Assembly:		
Overall Length B10, B11 and B11A (Typical), in.		165.695
Overall Length B-HTP (Typical), in.		165.895
Control Rod Guide Tube (in.)		
Mk-B10 to Mk-B10L	Zircaloy-4	0.530 OD x 0.016 wall
Mk-B11	Zircaloy-4	0.530 OD x 0.016 wall
Mk-B11A	M5	0.530 OD x 0.016 wall
Mk-B-HTP	M5	0.530 OD x 0.016 wall
Instrumentation Tube (in.)		
Mk-B10 to B10L	Zircaloy-4	0.493 OD x 0.441 ID
Mk-B11, Mk-B11A	Zircaloy-4	0.493 OD x 0.441 ID
Mk-B-HTP	M5	0.493 OD x 0.400 ID
End Fittings		
Mk-B10 to B10L	Stainless Steel (Castings)	
Mk-B11, Mk-B11A	Stainless Steel	
Mk-B-HTP	Stainless Steel	
End Spacer Grid		
Mk B-10 to Mk B-10L	Inconel-718	0.020 thick exteriors 0.018 thick interiors

Item	Material	Dimensions (In)
Mk-B11, Mk-B11A	Inconel-718	0.020 thick exteriors 0.018 thick interiors
Mk-B-HTP	Inconel-718	
Intermediate Spacer Grid		0.025 thick exteriors 0.013 thick exteriors
MK-B10 to MK-B10L	Zircaloy-4	0.021 thick exteriors 0.018 thick interiors
Mk-B11, Mk-B11A	Zircaloy-4	0.021 thick exteriors 0.018 thick interiors
Mk-B-HTP	M5	0.026 thick exteriors 0.014 thick interiors
Spacer Sleeve		
Mk-B10 to B10L	Zircaloy-4	0.554 OD x 0.502 ID
Mk-B11, Mk-B11A	Zircaloy-4	0.554 OD x 0.502 ID
Mk-B-HTP	M5	0.554 OD x 0.502 ID
Fuel Assembly Design:		Fuel Assembly Burnup
Mk B-10 through Mk B-10L, Mk-B11, Mk-B11A, and Mk-B-HTP		Consistent with a Maximum rod burnup of 62,000 MWD/MTU (Reference 15) of Section 4.2.5

Note:

1. Typical geometry. Batch specific is reported in individual reload reports.
2. Mk-B9 fuel rods are used in Mk-B10 and Mk-B10D/E fuel assembly designs. Mk-B10 design fuel rods are used in Mk-B10F/G/L fuel assembly designs (See Table 4-23).

Table 4-3. Nuclear Design Data

	Oconee I	**Oconee II**	**Oconee III**
Fuel Assembly Volume Fractions			
(Mk-B11, Mk-B11A)			
Fuel	0.291	0.291	0.291
Moderator	0.607	0.607	0.607
Zircaloy (includes M5 cladding)	0.091	0.091	0.091
Void	0.011 1.000	0.011 1.000	0.011 1.000
(Mk-B-HTP)			
Fuel	0.310	0.310	0.310
Moderator	0.582	0.582	0.582
Zircaloy (includes M5 cladding)	0.097	0.097	0.097
Void	0.011 1.000	0.011 1.000	0.011 1.000
Total UO_2 (Metric Tons)			
First Cycle	94.1	93.1	93.1
Deleted Row per 2008 Update			
Equilibrium (Mk-B11, Mk-B11A)	92.2	92.2	92.2
Equilibrium (Mk-B-HTP)[1]	98.2 / 97.8	98.2 / 97.8	98.2 / 97.8
Core Dimensions, in.			
Equivalent Diameter	128.9	128.9	128.9
Deleted Row per 2008 Update			
Nominal Active Height (Mk-B11, B11A)	143.1	143.1	143.1
Nominal Active Height (Mk-B-HTP)	143.0	143.0	143.0
Unit Cell H_2O to U Atomic Ratio (Fuel Assembly)			
Cold	2.85	2.88	2.88
Hot	2.04	2.06	2.06
Full-Power Lifetime, Days			
First Cycle	309	440	479
Equilibrium Cycle[2]	480 / 700	480 / 700	480 / 700
Fuel Irradiation, MWD/MTU			
First Cycle Average	9,582	14,396	14,978

	Oconee I	**Oconee II**	**Oconee III**
Deleted Row per 2008 Update			
Equilibrium Cycle Average (Mk-B11 & B11A)	15,172	15,172	15,172
Equilibrium Cycle Average (Mk-B-HTP)[3]	14,241 / 20,854	14,241 / 20,854	14,241 / 20,854
Fuel Loading, wt% U-235			
Core Average First Cycle	2.10	2.62	2.56
First Reload Average	3.15	2.64	2.54
Typical Core Average Equilibrium Cycle			
Nominal Loading[3]	4.00 / 4.74	4.00 / 4.74	4.00 / 4.74
Radial-Zoned Loading[3]	3.70 / N/A	3.70 / N/A	3.70 / N/A
Axial Blanket Loading	2.00-2.50	2.00-2.50	2.00-2.50
Control Data			
Control Rod Material	Ag-In-Cd	Ag-In-Cd	Ag-In-Cd
Number of Full Length CRA's	61	61	61
Control Rod Cladding Material	INC-625	INC-625	INC-625
APSR Material	INC-600	INC-600	INC-600
Number of APSR's	8	8	8
APSR Cladding Material	SS 304 or 304L	SS 304 or 304L	SS 304 or 304L

Note:

1. The first value is for LEU HTP fuel. The second value is for Gadolinia-bearing HTP fuel.
2. 480 EFPD is the equilibrium 18 month cycle length; 700 EFPD is the equilibrium 24 month cycle length.
3. The first value is typical of 18 month cycles and the second value is typical of 24 month cycles.

Table 4-4. Typical Fuel Cycle Excess Reactivity, HFP Samarium

Cycle Time (EFPD)	18 Month Cycle Excess Reactivity (%Δk/k) at Specified Condition[1]			
	70°F, No Xe	300°F, No Xe	HZP, No Xe	HFP, No Xe
0	18.58	17.33	15.10	13.11
50	17.88	16.65	14.35	12.43
100	17.18	15.96	13.59	11.48
200	15.39	14.19	11.64	9.24
300	13.61	12.43	9.69	6.99
450	10.66	9.44	6.57	3.38
480	9.92	8.68	5.72	2.59
Cycle Time (EFPD)	**24 Month Cycle Excess Reactivity (%Δk/k) at Specified Condition[2]**			
	60°F, No Xe	**300°F, No Xe**	**HZP, No Xe**	**HFP, No Xe**
0	16.77	15.57	13.06	11.07
50	16.16	15.00	12.54	10.55
100	15.55	14.42	12.02	10.03
200	14.93	13.87	11.44	9.37
300	14.31	13.32	10.86	8.70
400	13.36	12.35	9.74	7.44
500	12.05	11.01	8.31	5.83
693	8.92	7.86	4.99	2.50

Note:

1. 18 Month Data from 0 to 300 EFPD were derived with CRG-8 at 30% WD, and data from 450 to 480 EFPD were derived with CRG-8 at 100% WD.
2. 24 Month Data from 0 to 500 EFPD were derived with CRG-8 at 35%WD, and data at 693 EFPD were derived with CRG-8 at 100% WD.

Table 4-5. Effective Multiplication Factor k_{eff} Single Fuel Assembly[1]

	Hot	0.77
	Cold[2]	0.87

Note:

1. Based on an enrichment of 3.5 weight percent.
2. A center-to-center assembly pitch of 21 in. is required for this k_{eff} in cold, unborated water with no xenon or samarium.

Table 4-6. Shutdown Margin Calculation for Typical Oconee Fuel Cycle

18 Month Cycle	**BOC, %Δk/k**	**EOC, %Δk/k**
Available Rod Worth		
Total rod worth, HZP	7.76	8.65
Worth reduction due to burnup of poison material	-0.40	-0.40
Maximum stuck rod, HZP	-1.17	-1.55
Net worth	6.19	6.70
Less 10% uncertainty	0.62	0.67
Total available worth	5.57	6.03
Required Rod Worth		
Power deficit, HFP to HZP	1.34	3.01
Max allowable inserted rod worth	0.40	0.53
Total required worth	1.74	3.54
Shutdown margin (total available worth minus total required worth)	3.83	2.49
24 Month Cycle	**BOC, %Δk/k**	**EOC, %Δk/k**
Available Rod Worth		
Total rod worth, HZP	8.11	8.65
Worth reduction due to burnup of poison material	-0.40	-0.40
Maximum stuck rod, HZP	-1.39	-1.50
Net worth	6.31	6.75
Less 10% uncertainty	0.63	0.67
Total available worth	5.68	6.07
Required Rod Worth		
Power deficit, HFP to HZP	1.55	3.02
Max allowable inserted rod worth	0.36	0.48
Total required worth	1.91	3.50
Shutdown margin (total available worth minus total required worth)	3.77	2.57

Note:

1. Required shutdown margin is 1.00% Δk/k.
2. The power deficit calculation was done with a three-dimensional code.

Table 4-7. Moderator Temperature Coefficient (For the First Cycle)

Conditions	Oconee I	Oconee II	Oconee III
1. Core size, no. fuel assemblies	177	177	177
2. Core average enrichment w/o U-235	2.10	2.62	2.56
3. Avg Power density, MWt/assembly	14.508	14.508	14.508
4. Initial critical conditions (hot full power, clean)			
a. Boron concentration, ppm	1200	1341	1291
b. CRA inserted worth, % $\Delta k/k$ [a]	2.1	1.0	1.0
c. Burnable poison worth, % $\Delta k/k$	0.0	4.0	4.0
d. Moderator temperature coefficient, $[10^{-4}\ (\Delta k/k)/F]$ [b]	+0.27	+0.03	-0.01
5. Threshold value of moderator temperature coefficient, $[10^{-4}\ (\Delta k/k)/F]$ [c]	+1	>+1	>+1
6. Moderator temperature coefficient at hot full power, equilibrium xenon, BOL, $[10^{-4}\ (\Delta k/k)/F]$ [b]	-0.30	-0.50	-0.54
7. Most positive value of moderator temperature coefficient used in safety analysis, $[10^{-4}\ (\Delta k/k)/F]$ [c]	+0.9	+0.9	+0.9
8. Most negative value of moderator temperature coefficient used in safety analyses $[10^{-4}\ (\Delta k/k)/F]$ [c]	-3.5	-3.5	-3.5

Note:

a. Inserted rod worth shown for Oconee 1 results from 3-D calculations and reflects transient group worth, APSR's, and partial Doppler insertion.

b. See Section 4.3.2.4.4.

c. Value is applicable to current safety analyses.

Table 4-8. BOL Distributed-Temperature Moderator Coefficients, 100% Power, 1200 ppm Boron (O1C01)

Type of Temperature Change	T_{in} (°F)	T_{out} (°F)	$\alpha_m \left(x10^{-4} \frac{\Delta\rho}{°F}_m\right)$
1. T_{in}constant, T_{out} change	554.03 554.03	606.90 609.33	+0.14
2. T_{in} and T_{out} change	554.03 555.00	606.90 607.73	+0.27
3. T_{in} change T_{out} constant	554.03 551.20	606.90 606.79	+0.36

Table 4-9. BOL Distributed-Temperature Moderator Coefficients, vs Power, No Xenon

% Power (% Full Power)	$\alpha_m (x\,10^{-4} \frac{\Delta\rho}{°F_m})$ Oconee 1, Cycle 1 (1200 ppm)	Typical 18 Month Reload Cycle (Boron Search)
0	-	+0.44 (2010 ppm)
15	+0.42	+0.13 (1991 ppm)
60	+0.30	-0.08 (1905 ppm)
95	-	-0.23 (1845 ppm)
100	+0.27	-0.25 (1837 ppm)
% Power (% Full Power)	**Oconee 1, Cycle 1 (1200 ppm)**	**Typical 24 Month Reload Cycle (Boron Search)**
0	--	+0.08 (1975 ppm)
15	+0.42	--
20	--	-0.36 (1915 ppm)
60	+0.30	--
80	--	-0.64 (1808 ppm)
100	+0.27	-0.73 (1771 ppm)

Table 4-10. BOL Distributed-Temperature Moderator Coefficient, 100% Full Power

	$\alpha_m (\times 10^{-4} \frac{\Delta\rho}{°F\,m})$	
	0 Days (NoXe)	4 Days (EqXe)
Oconee 1, Cycle 1	+0.27 (1200 ppm)	-0.30 (920 ppm)
Typical 18 Month Reload Cycle	-0.25 (1837 ppm)	-0.59 (1481 ppm)
Typical 24 Month Reload Cycle	-0.73 (1771 ppm)	-1.07 (1374 ppm)

Table 4-11. Power Coefficients of Reactivity

	$\alpha_p (x\,10^{-4} \frac{\Delta\rho}{\%\Delta P})$	
Power (% Full Power)	**Oconee 1, Cycle 1 (1200 ppm)**	**Typical 18 Month Reload Cycle (Boron search)**
15	-2.04	-1.24 (1991 ppm)
60	-1.56	-1.10 (1905 ppm)
100	-1.11	-1.07 (1837 ppm)
Power (% Full Power)	**Oconee 1, Cycle 1 (1200 ppm)**	**Typical 24 Month Reload Cycle (Boron search)**
15	-2.04	-1.43 (1930 ppm)
60	-1.56	-1.35 (1842 ppm)
100	-1.11	-1.32 (1774 ppm)

Table 4-12. pH Characteristics

^{7}Li, ppm	T_{mod}, °F	Boron Concen., ppm	pH Units
0.5	70	1,800	5.0
2.0	70	1,800	5.6
0.5	580	1,200	7.0
2.0	580	1,200	7.5
0.5	580	17	7.2
2.0	580	17	7.8
0.5	70	17	7.9
2.0	70	17	8.5

Table 4-13. Design Methods

Unit	Initial Cycle	Design Methods
1	16	Section 4.3.3.1.1
2	15	Section 4.3.3.1.1
3	16	Section 4.3.3.1.1

Table 4-14. Deleted per 1999 Update

Table 4-15. Deleted per 1997 Update

Table 4-16. Internals Vent Valve Materials

Valve Part Name	Material and Form	Material Specification No.
Valve Body	304 S.S. Casting [1]	ASTM A351-CF8
Valve Disc	304 S.S. Casting [1]	ASTM A351-CF8
Disc Shaft	431 S.S. Bar [2]	ASTM A276 Type 431 Cond. T
Shaft Bushings	Stellite No. 6	
Retaining Rings (Top and Bottom)	15-5 pH (H1100) S.S. forgings	AMS 5658
Ring Jack Screws	"A-286 Superalloy" S.S. [3]	AMS 5737 C
Jackscrew Bushings	431 S.S. Bar	ASTM A276 Type 431 Cond. A
Misc. Fasteners, covers, locking devices, etc.	304 S.S. plate bar, etc.	ASTM A240 ASTM A276

Note:

1. Carbide solution annealed, C_{max} 0.08%, Co_{max} 0.2%
2. Heat treated and tempered to Brinnel Hardness Number (BHN) range of 290-320.
3. Heat treated to produce a BHN of 248 min.

The hinge assembly consists of a shaft, two valve body journal receptacles, two halve disc journal receptacles, and four flanged shaft journals (bushings). Loose clearances are used between the shaft and journal inside diameters, and between the journal outside diameters and their receptacles. The hinge assembly is shown and the clearance gaps are identified in Figure 4-30. The bushing clearances are listed in Table 4-17.

The valve disc hinge journal contains integral exercise lugs for remote operation of the disc with the valve installed in the core support shield.

Table 4-17. Vent Valve Shaft & Bushing Clearances Clearance Gaps are illustrated in Figure 4-30

A.	Cold Clearance Dimensions @ 70°F			
Bushing I.D. Shaft O.D.	1.500 1.490 .010	to to to	1.505 1.485 .020	clearance (Gaps 1, 2, 7 & 8)
Body I.D. Bushing O.D.	2.000 1.997 .003	to to to	2.003 1.995 .008	clearance (Gaps 3, 4, 5 & 6)
Bushing End Clearance Gaps 9 + 10				
Body Lugs Disc Hub	5.752 4.746 1.006 .996 0.10	to to to to to	5,75 6 4,74 2 1.01 4 .992 0.22	End Clearance (Gaps 9 + 10)
Bushing Flange	.249 .248	x 4 = x 4 =	.996 .992	

B.	Hot Clearance Differential Change from 70 to 580°F		
Shaft:	A286	9.8×10^{-6} in/in/F	
Bushing:	Stellite #6	8.1×10^{-6}	
Bodies:	CF8 Stainless	9.82×10^{-6}	
	$\Delta T = 580 - 70 = 510$		

Shaft Bushing I.D.	$\Delta D = D\alpha\Delta T = 1.5\ (9.8 \times 10^{-6})\ 510 =$ $= 1.5\ (8.1 \times 10^{-6})\ 510 =$	.0075 .0062 –.0013 decrease
Bushing O.D. Body I.D.	$= 2\ (8.1 \times 10^{-6})\ 510 =$ $= 2\ (9.82 \times 10^{-6})\ 510 =$	.0083 .010 +.0017 increase
Bushing Endplay Hot		

CF8 Body Stellite # 6 Bushing Flange	$\Delta L = 1\ (9.82 \times 10^{-6})\ 510 =$ $= 1\ (8.1 \times 10^{-6})\ 510 =$	.0050 <u>.0041</u> .0009 increase

Table 4-18. Control Rod Assembly Data

Item		Data
	Number of CRA	61
A.	Standard CRA Design	
	Number of Control Rods per Assembly	16
	Outside Diameter of Control Rod, in.	0.440
	Cladding Thickness, in.	0.021
	Cladding Material	Type 304 SS, Cold-Worked
	End Plug Material	Type 304 SS, Annealed
	Spider Material	SS Grade CF3M
	Poison Material	80% Ag, 15% In, 5% Cd
	Female Coupling Material	Type 304 SS, Annealed
	Length of Poison Section, in.	134
	Stroke of Control Rod, in.	139
B.	Plant-Life CRA Design[1]	
	Number of Control Rods per Assembly	16
	Outside Diameter of Control Rod, in.	0.441
	Cladding Thickness, in.	0.023
	Cladding Material	Inconel 625
	End Plug Material	Inconel 625
	Spider Material	SS Grade CF3M
	Poison Material	80% Ag, 15% In, 5% Cd
	Female Coupling Material	Type 304 SS, Annealed
	Length of Poison Section, in.	139
	Stroke of Control Rod, in.	139

Note:

1. The plant-life CRA is prepressurized with Helium.

Table 4-19. Axial Power Shaping Rod Assembly Data

Item	Data
Gray APSR Design	
Number of Axial Power Shaping Rod Assemblies	8
Number of Axial Power Shaping Rods per Assembly	16
Outside Diameter of Axial Power Shaping Rod, in.	0.440
Cladding Thickness, in.	0.027
Cladding Material	Type 304 or 304L SS, Stainless Steel Cold-Worked
Plug Material	Type 304, 304L, or 308 SS
Poison Material	Inconel - 600
Spider Material	SS Grade CF3M
Female Coupling Material	Type 304 or 304L SS
Length of Poison Section, in.	63
Stroke of Control Rod, in.	139

Table 4-20. Burnable Poison Rod Assembly Data

Item	Data
Number of Burnable Poison Rods per Assembly	16
Outside Diameter of Burnable Poison Rod, in.	0.430
Cladding Thickness, in.	0.035
Cladding Material	Zircaloy-4, Cold Worked
End Cap Material	Zircaloy-4, Annealed
Poison Material	B_4C in. Al_2O_3
Length of Poison Section, in. [1]	126 / 123.2
Spider Material	SS Grade CF3M
Coupling Mechanism Material	Type 304 SS, Annealed

Note:

1. The poison length was 126” in the feed fuel up through cycle O1C27. The length changed to 123.2” beginning with the feed fuel in O2C26 to align with the gadolinia-bearing fuel which was introduced in O2C26.

Table 4-21. Control Rod Drive Mechanism Design Data

	Shim Safety	**Axial Power Shaping**
Type	Roller Nut Drive	Roller Nut Drive
Quantity	61	8
Location	Top-mounted	Top-mounted
Direction of Trip	Down	Does not trip
Velocity of Normal (Run) Withdrawal and Insertion, in./min.	30	30
Velocity of Jog Withdrawal and Insertion in./min.	3	3
Maximum Travel Time for Trip		
2/3 Insertion, sec	1.40[1]	Drive has no trip function
3/4 Insertion, sec	1.52[1]	Drive has no trip function
Length of Stroke, in.	139	139
Design Pressure, psig	2,500	2,500
Design Temperature, °F	650	650
Weight of Mechanism (App.)	940 lb	940 lb

Note:

1. These time values include rod motion only. The Technical Specification surveillance requirement for maximum control rod drop time includes, in addition, 0.14 seconds from the time the control rod drive breakers receive the signal to trip to the beginning of rod motion. This is appropriate since the elapsed time measured in the test begins with that signal to trip the CRD Breaker.

Table 4-22. Fuel Assembly / APSR Compatibility

Plant and Unit	Drive Type	Type of APSR Coupling- Spider Assembly Required for Mk-B10, Mk-B11, Mk-B11A and MK-B-HTP Fuel Designs
Deleted row(s) per 2002 Update.		
Oconee Unit 1&2	Type C APSR Drive[2]	Mk-B Standard OR Extended Coupling
Oconee Unit 3	Type C APSR Drive	Mk-B Standard OR Extended Coupling

Note:

1. The length of the Mk-B Standard and Extended Coupling APSR Hubs is 7.0 in. (nom.) and 7.57 in. (nom.), respectively. The length equals the sum of the female coupling, spider, and lower hub B, which is the distance from the bottom seating surface to the top of the female coupling.
2. Type C APSR Drive has R4C position indicators and hydraulic tension closures.

Table 4-23. Fuel Assembly Design Descriptions

Assembly Designation	Cage Design	Rod Design	Clad Material	Axial Blanket	Zoned Enrichment	HDS [2] Design	UEF [3] Attachment	Debris Filter
Mk-B10	B10	B9	Zirc-4	No	No	Cruciform	Lock Nut	Plug/Grid
Mk-B10D	B10	B9	Zirc-4 [1]	No	No	Cruciform	Lock Nut	Plug/Grid
Mk-B10E	B10	B9	Zirc-4	Yes	No	Cruciform	Lock Nut	Plug/Grid
Mk-B10F	B10	B10	Zirc-4	Yes	No	Cruciform	Lock Nut	Plug/Grid
Mk-B10G	B10	B10	Zirc-4	Yes	No	Cruciform	Quick Disconnect	Plug/Grid
Mk-B10L	B10	B10	Zirc-4	Yes	Yes	Cruciform	Quick Disconnect	Plug/Grid
Mk-B11	B11	B11	M5	Yes	Yes	Cruciform	Quick Disconnect	Plug/Grid
Mk-B11A	B11	B11	M5	Yes	Yes	Cruciform	Quick Disconnect	Plug/Grid
Mk B-HTP	HTP	HTP	M5	Yes	Yes	Cruciform	Recon Crimp Top Hat Nut	Fuel Guard

Note:

1. Consumer's or Smud Cladding
2. HDS = Hold Down Spring
3. UEF = Upper End Fitting

Table 4-24. Design Information for Current Demonstration Programs vs Typical FAs

Parameter	WH-177 LTA	Mk-B11A	MK-B-HTP
Hold-down Spring	3-leaf	Cruciform	Cruciform
Rod Array	15 X 15	15 X 15	15 X 15
Rods per Assembly	208	208	208
Rod Pitch, in.	0.568	0.568	0.568
Fuel Weight (as UO_2), lbs.	1149	1012	1080
Fuel Assembly weight (wet), lbs	1323	1304	1378
Number of Grids per Assembly	11	8	8
Composition of end grids	Inconel 718	Inconel 718	Inconel 718
Intermediate Support Grids	Yes	No	No
Number of Guide Thimbles per Assembly	16	16	16
Composition of Guide Thimbles	ZIRLO™	M5	M5
Fuel Rod Outside Diameter, in.	0.422	0.416	0.430
Clad Material	ZIRLO™	M5	M5
Fuel Pellet Material	UO_2	UO_2	UO_2/UO_2-Gd
Fuel Enrichments, wt%	<5	<5	<5
Overall FA Length, in	166.1	165.7	165.8

Appendix 4B. Figures

Figure 4-1. Burnable Poison Rod Assembly

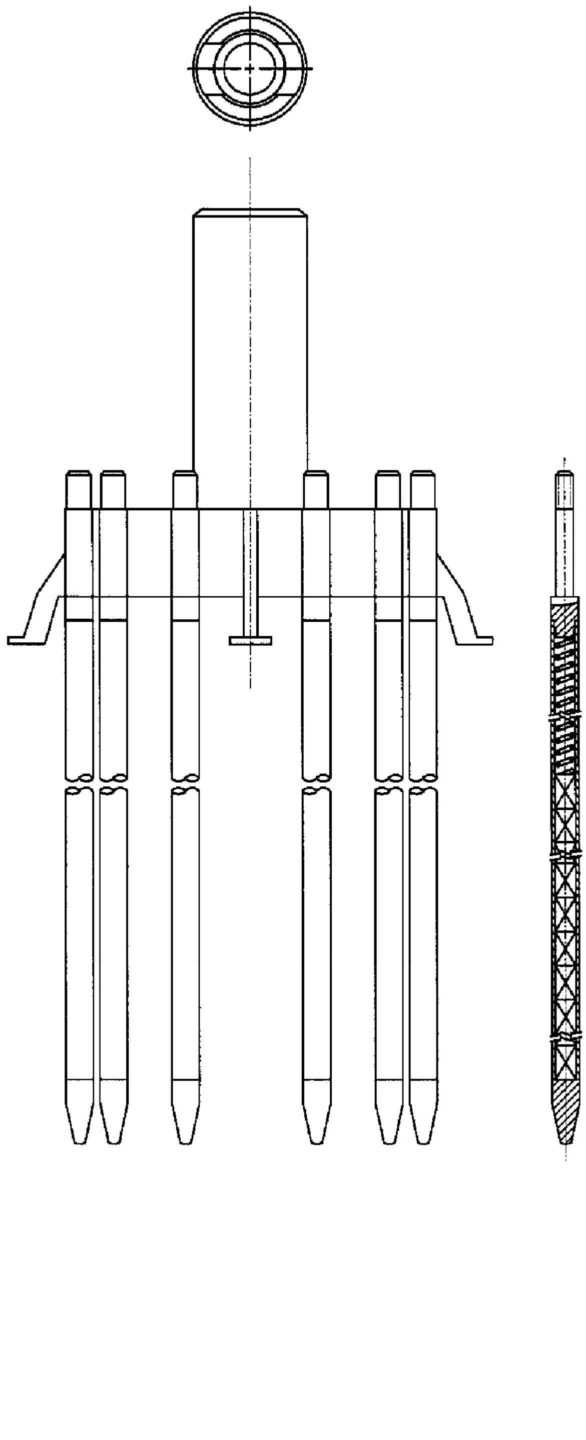


Figure 4-2. Deleted Per 1999 Update

Figure 4-3. Deleted Per 1999 Update

Figure 4-4. Typical Pressurized Fuel Rod

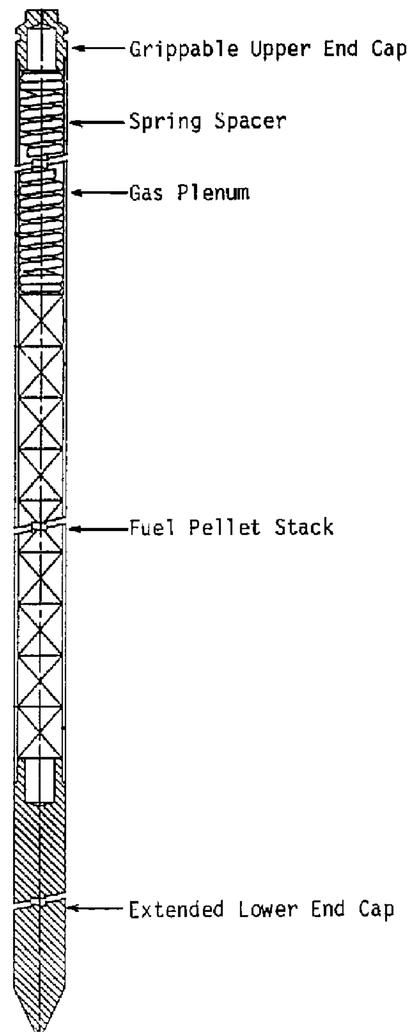
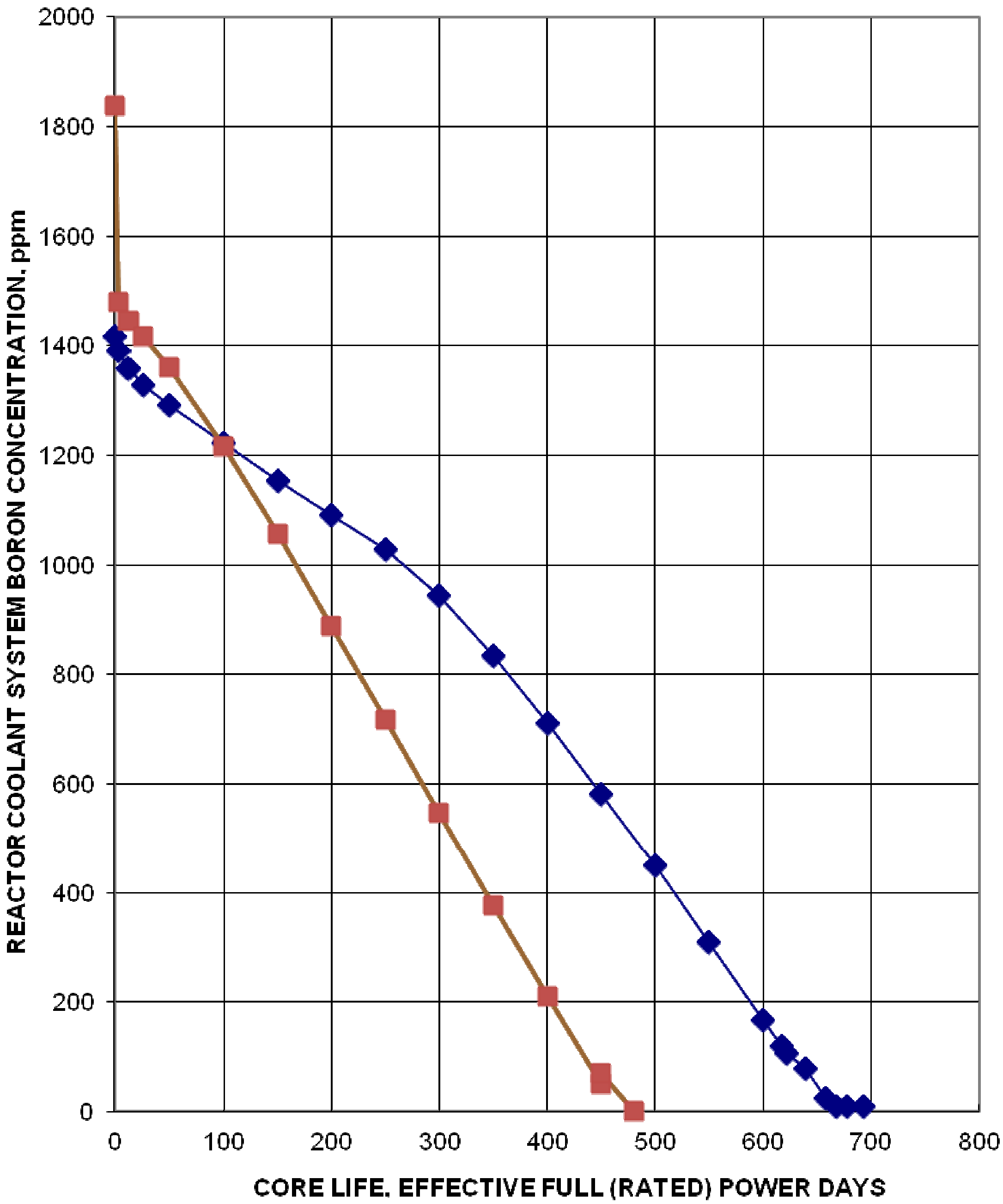


Figure 4-5. Typical Boron Concentration Versus Core Life



Note: Square data points represent 18 month cycles and diamonds represent 24 month cycles

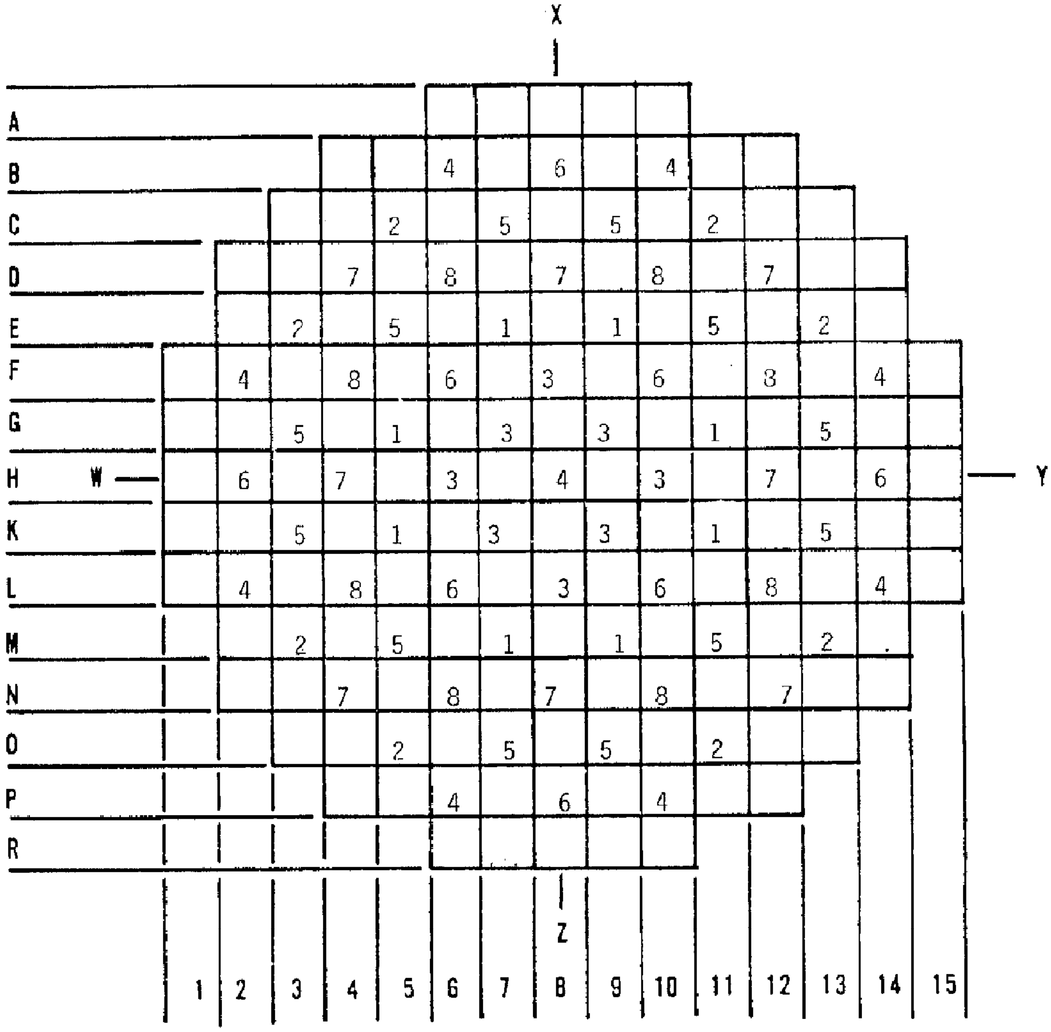
Figure 4-6. Typical BPRA Concentration and Distribution

[HISTORICAL INFORMATION BELOW NOT REQUIRED TO BE REVISED.]

	8	9	10	11	12	13	14	15
H		0.80		1.10		0.80		
K	0.80				1.10		None	
L				1.10		0.00		
M	1.10		1.10		0.50			
N		1.10		0.50		None		
O	0.80		0.00		None			
P		None						
R								

X.XX — BPRA CONCENTRATION, WT % B_4C IN Al_2O_3

Figure 4-7. Typical Control Rod Locations and Groupings



X GROUP NUMBER

GROUP	NO. OF RODS	FUNCTION
1	8	SAFETY
2	8	SAFETY
3	8	SAFETY
4	9	SAFETY
5	12	CONTROL
6	8	CONTROL
7	8	CONTROL
8	8	APSRs
TOTAL	69	

Figure 4-8. Typical Uniform Void Coefficient

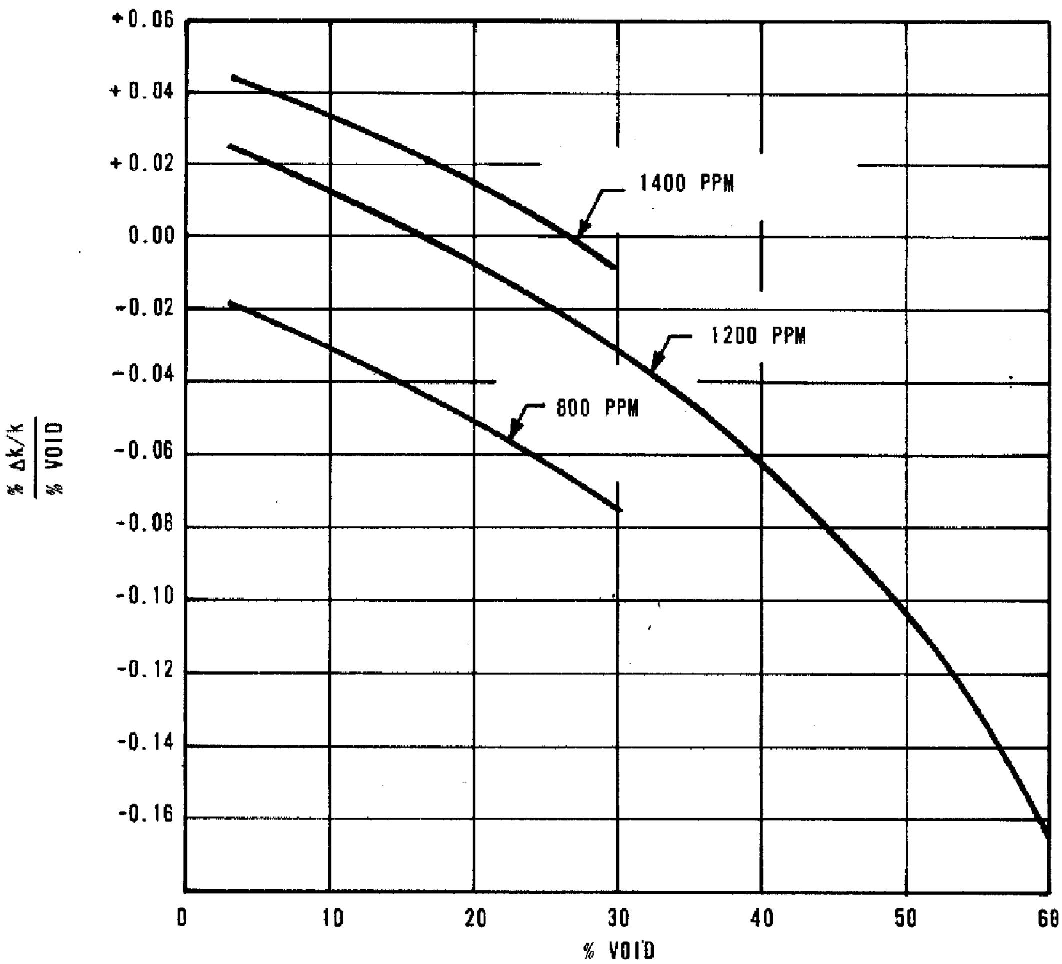


Figure 4-9. Deleted per 1995 Update

Figure 4-10. Typical Rod Worth Versus Distance Withdrawn

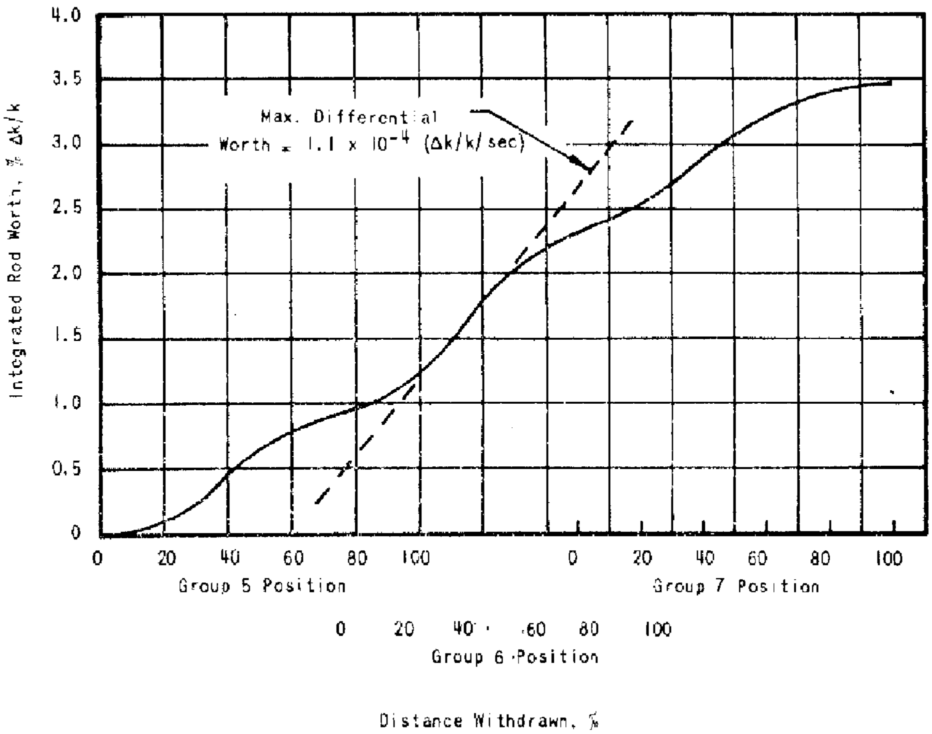
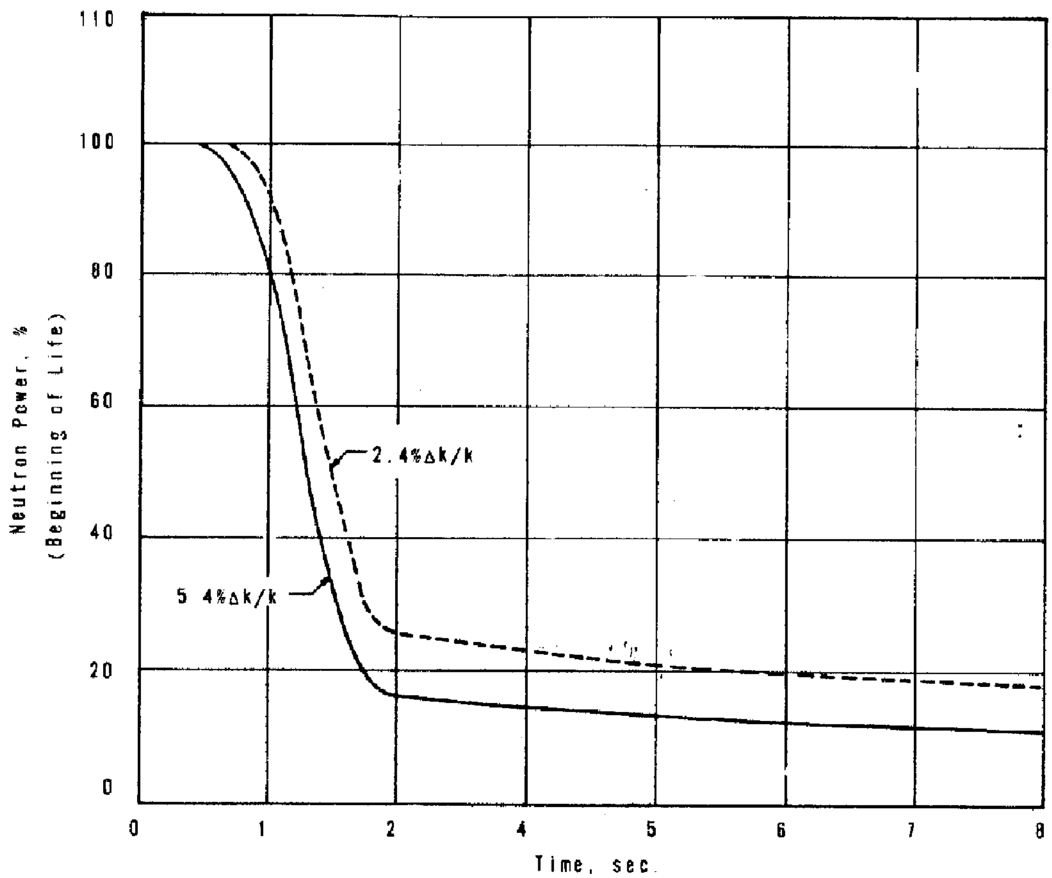


Figure 4-11. Percent Neutron Power Versus Time Following Trip



PER CENT NEUTRON POWER
VERSUS TIME FOLLOWING TRIP

Figure 4-12. Power Spike Factor Due to Fuel Densification

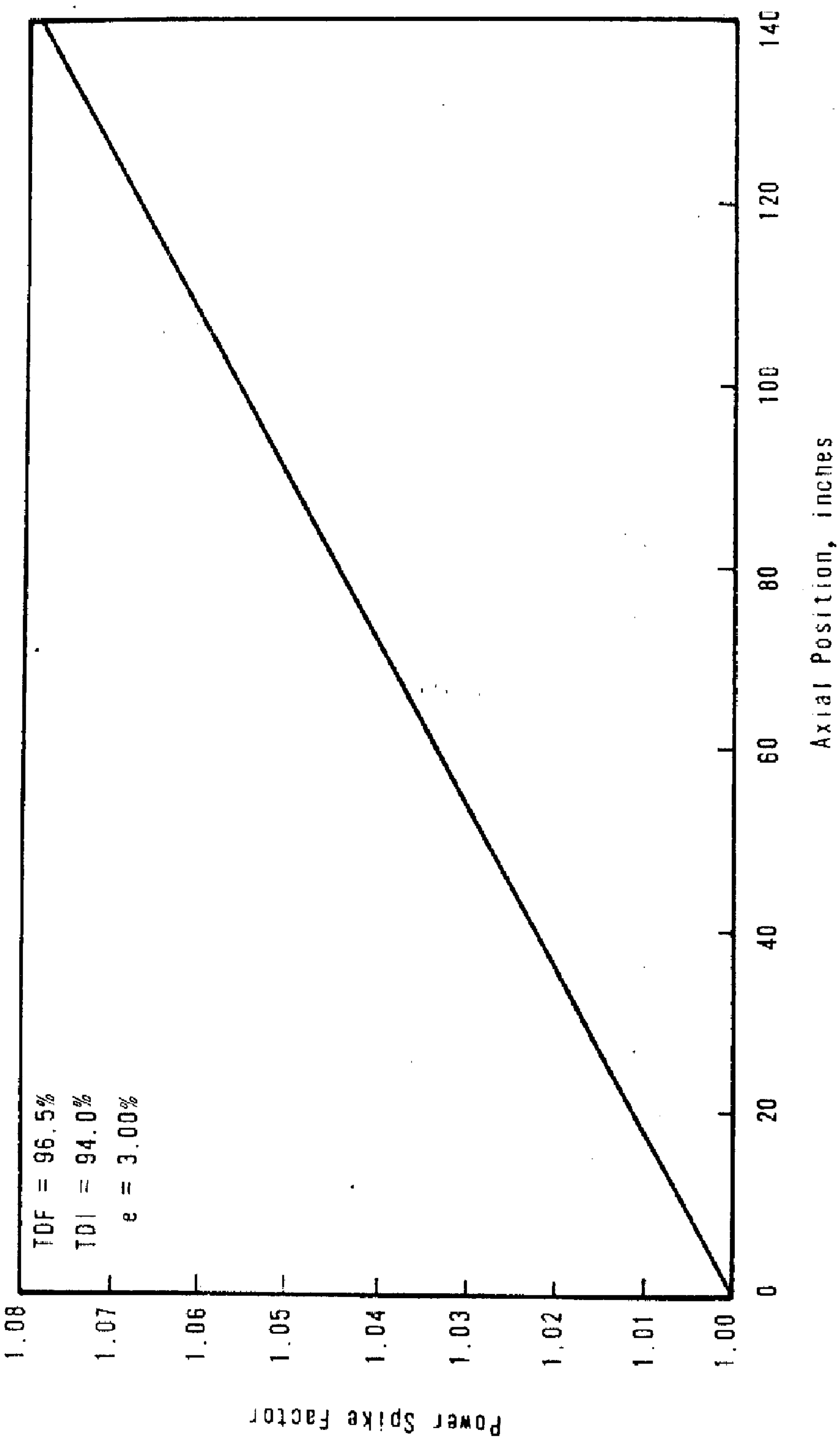


Figure 4-13. Power Peaking Caused by Dropped Rod (Oconee Unit 1, Cycle 1)

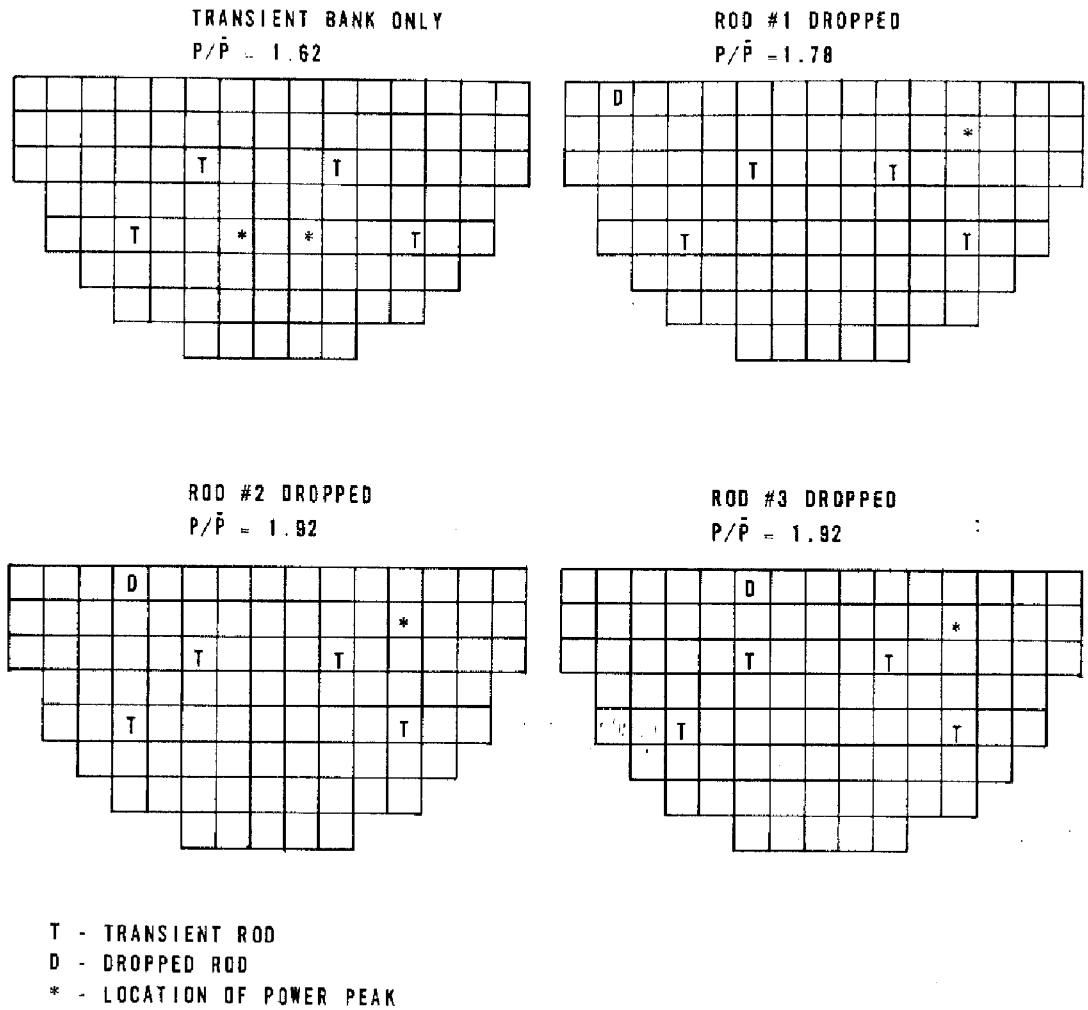


Figure 4-14. Azimuthal Stability Index Versus Moderator Coefficient From Three Dimensional Case (Oconee Unit 1, Cycle 1)

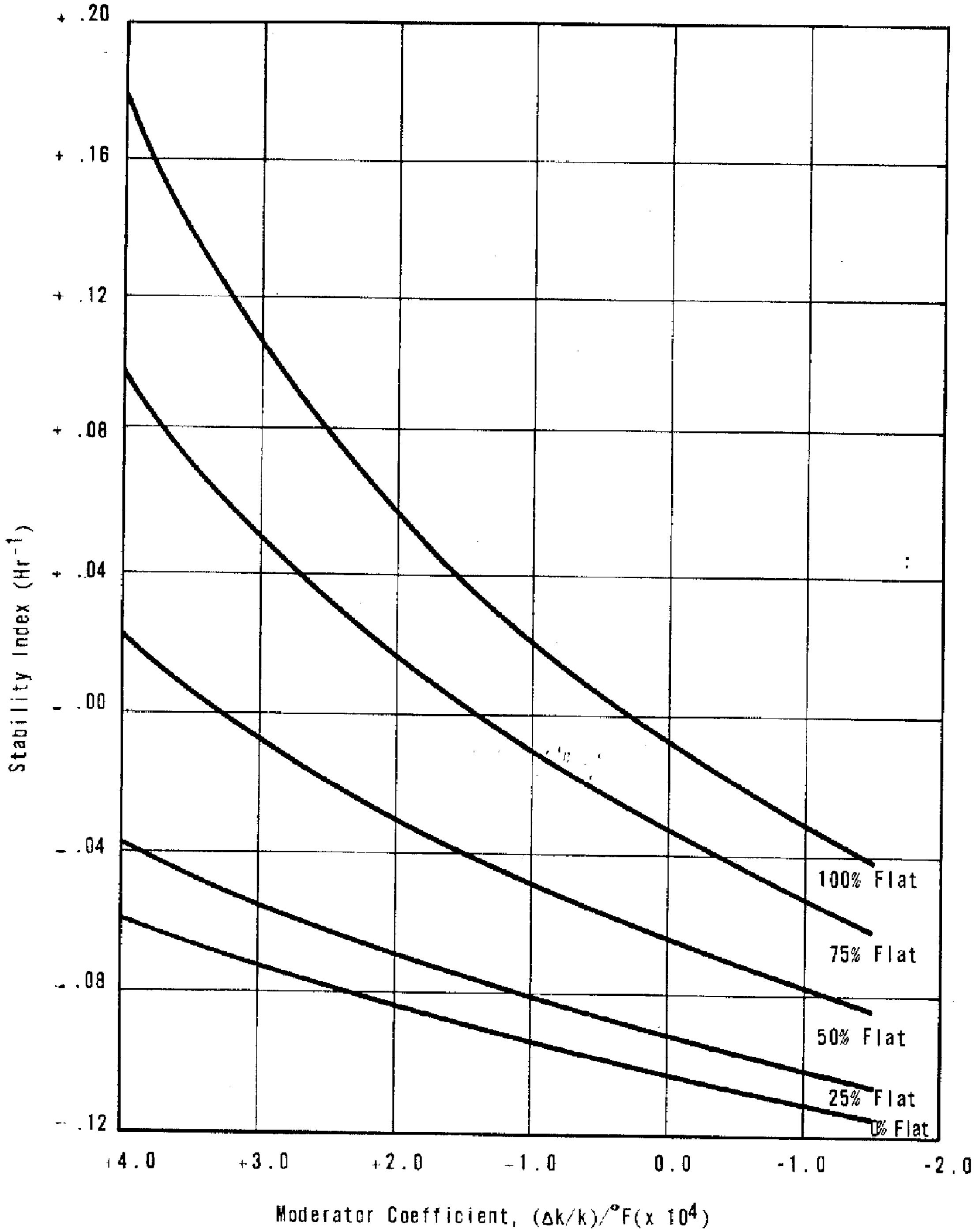


Figure 4-15. Azimuthal Stability Index with Compounded Error Versus Moderator Coefficient Calculated From Three Dimensional Case (Oconee Unit 1, Cycle 1)

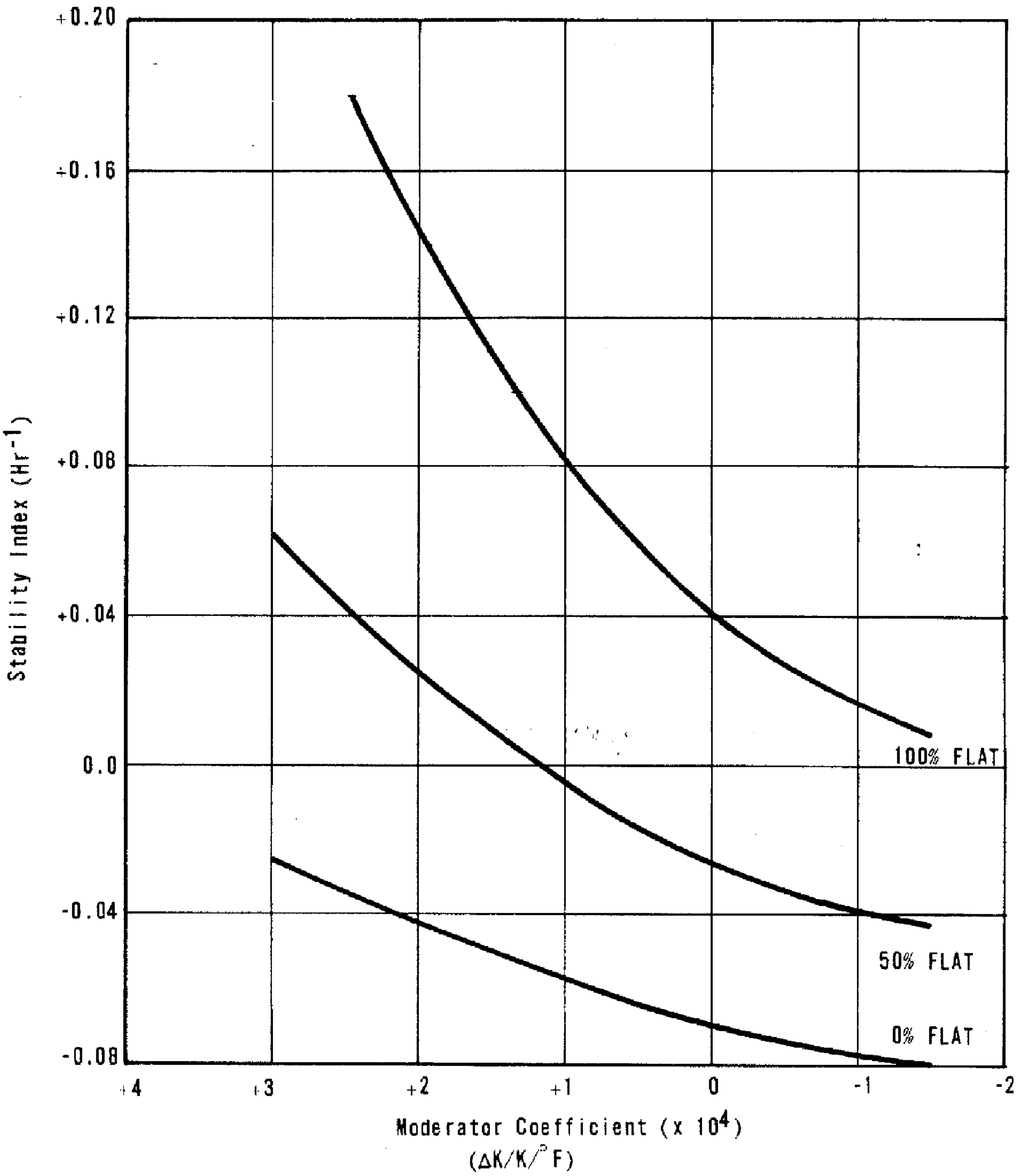


Figure 4-16. Azimuthal Stability Index Versus Moderator Coefficient From Three Dimension Case (Oconee Unit 2, Cycle 1)

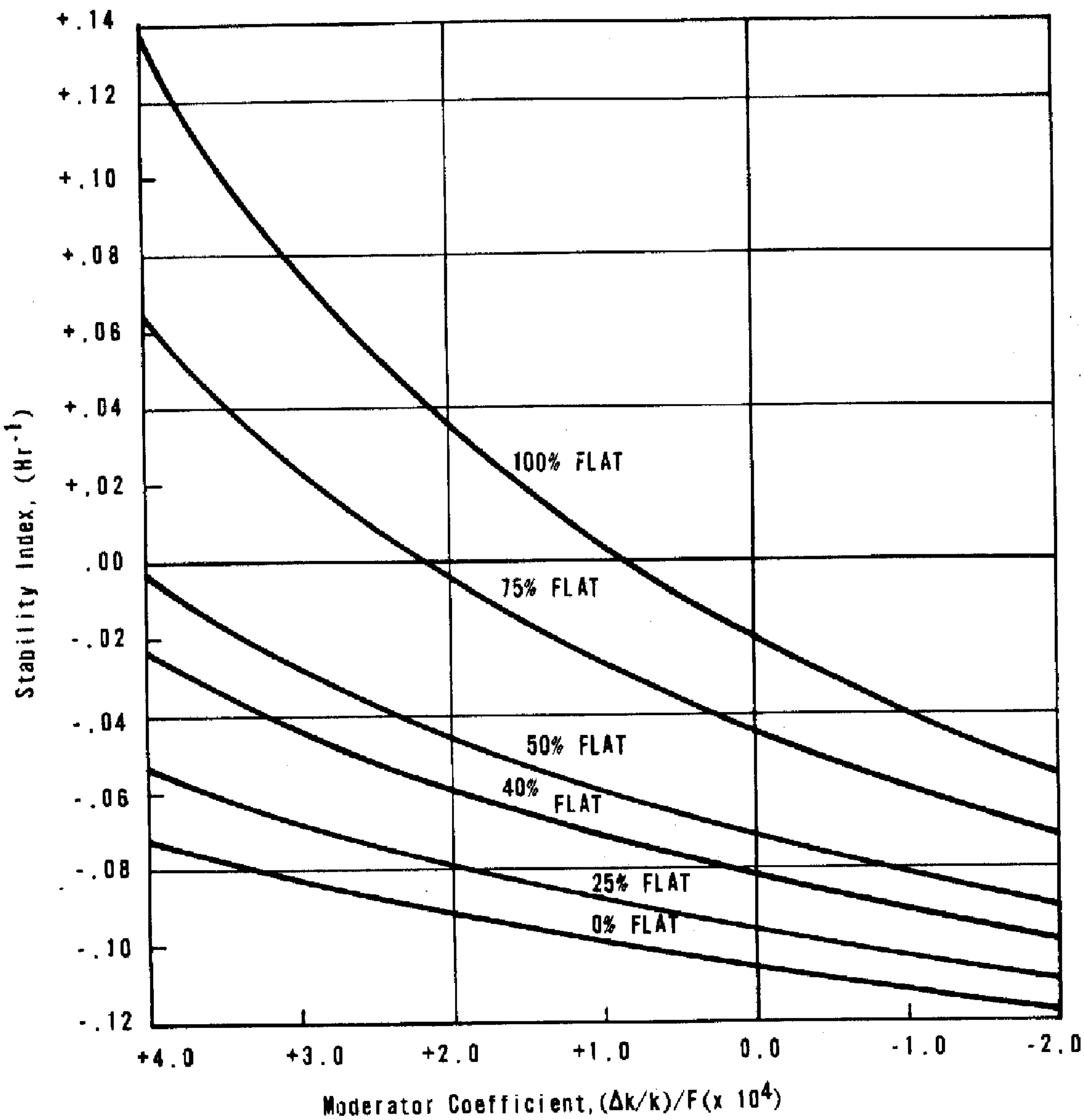


Figure 4-17. Azimuthal Stability Index with Compounded Error Versus Moderator Coefficient From Three Dimensional Case (Oconee Unit 2, Cycle 1)

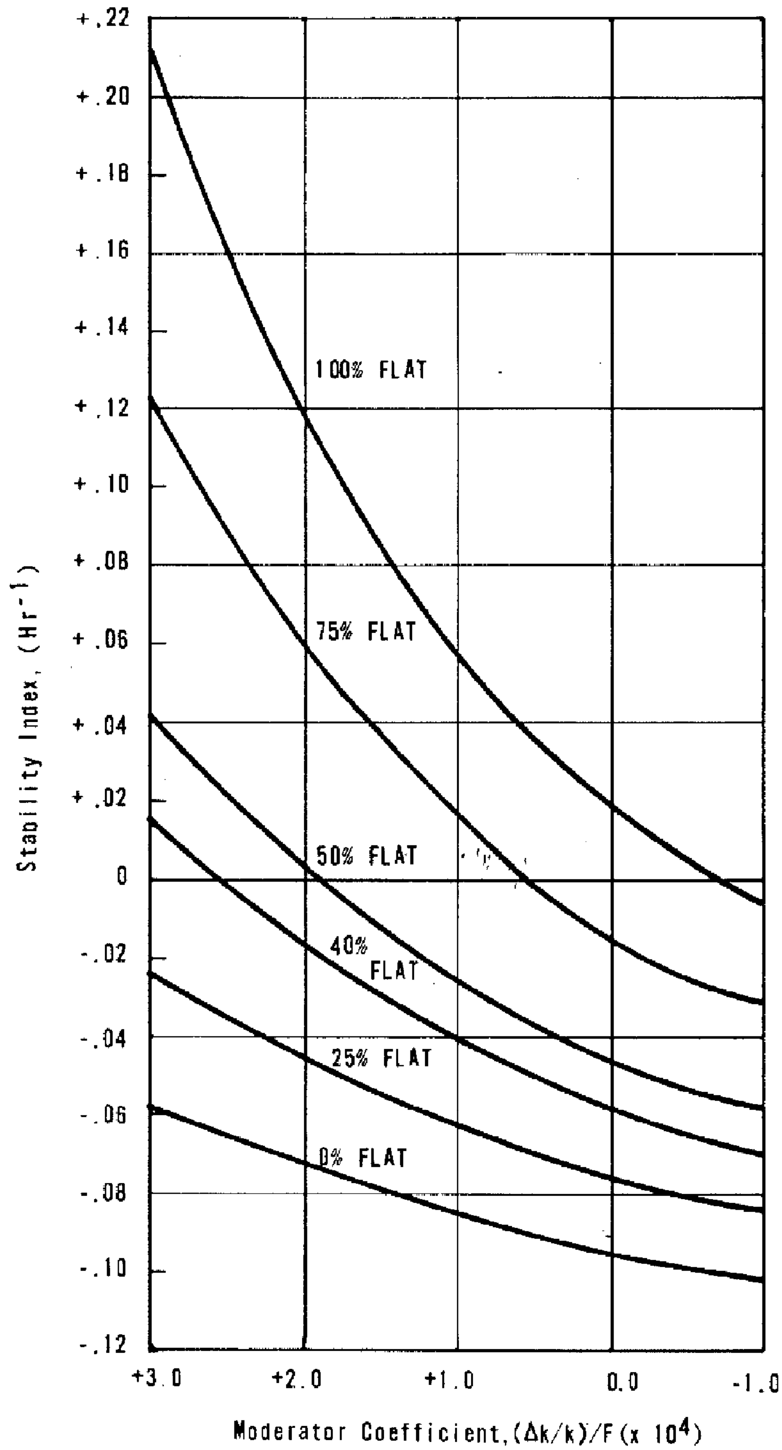


Figure 4-18. Deleted per 1997 Update

Figure 4-19. Deleted Per 1995 Update

Figure 4-20. Deleted Per 1995 Update

Figure 4-21. Flow Regime Map for the Hot Unit Cell

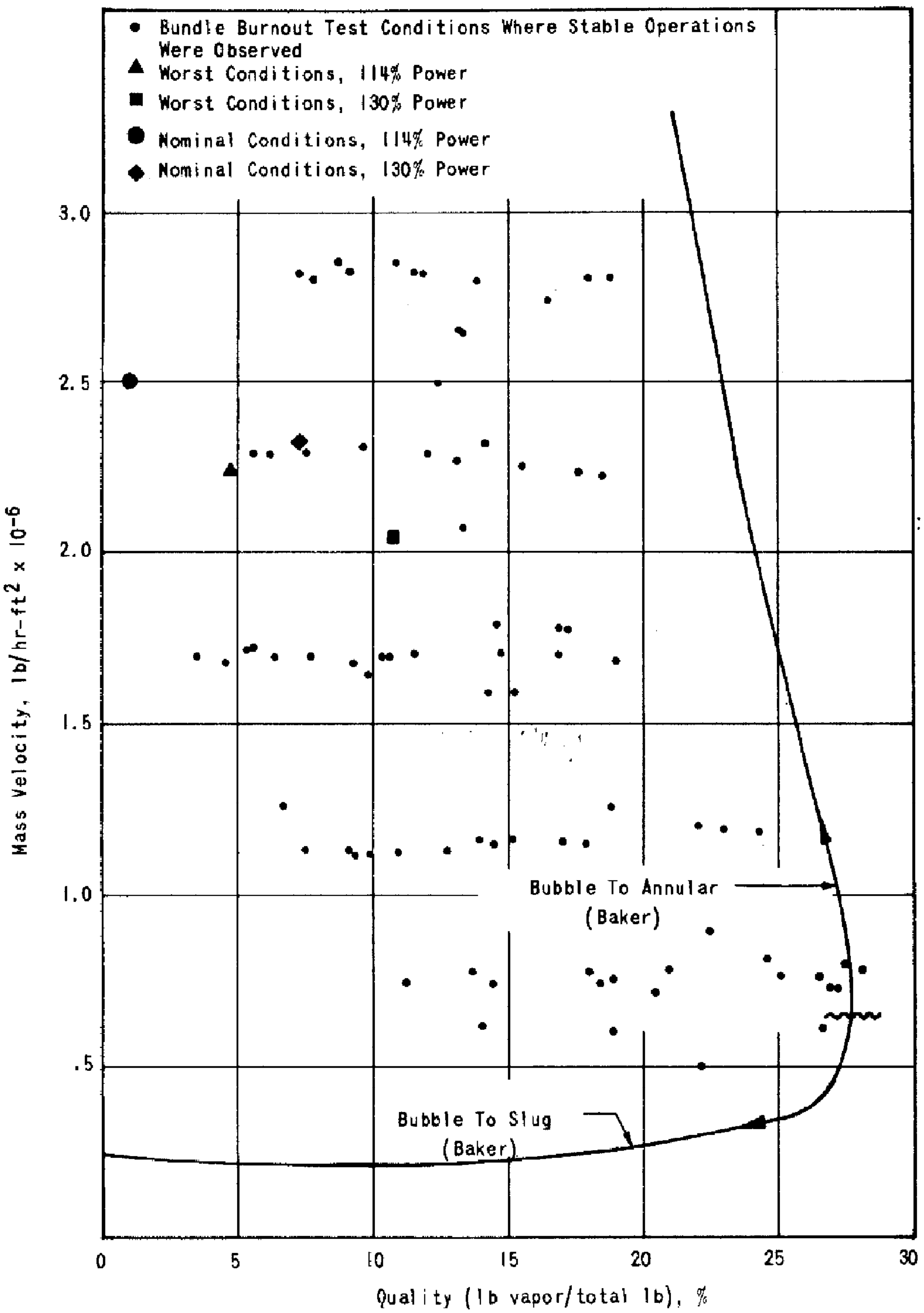


Figure 4-22. Flow Regime Map for the Hot Control Rod Cell

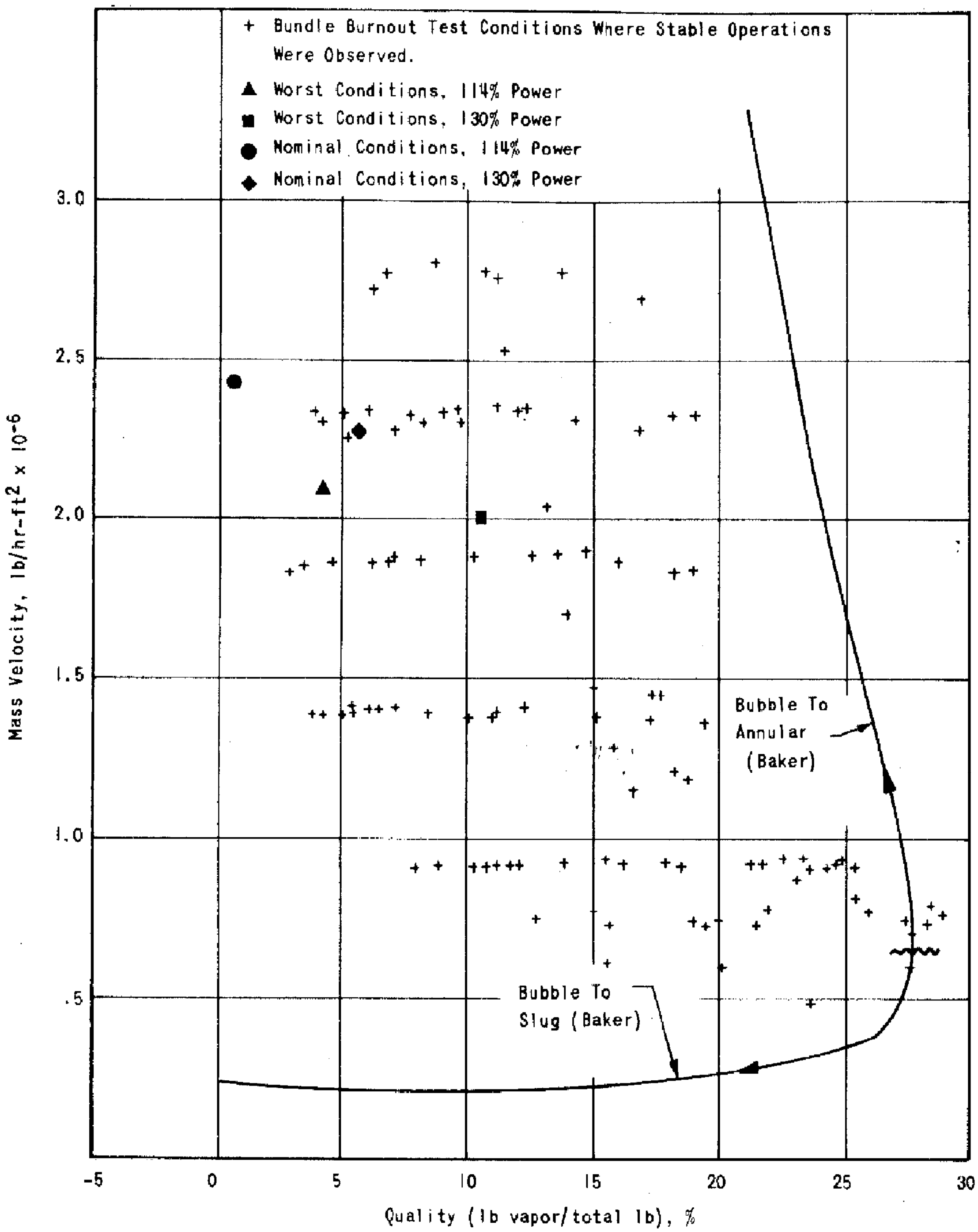


Figure 4-23. Flow Regime Map for the Hot Wall Cell

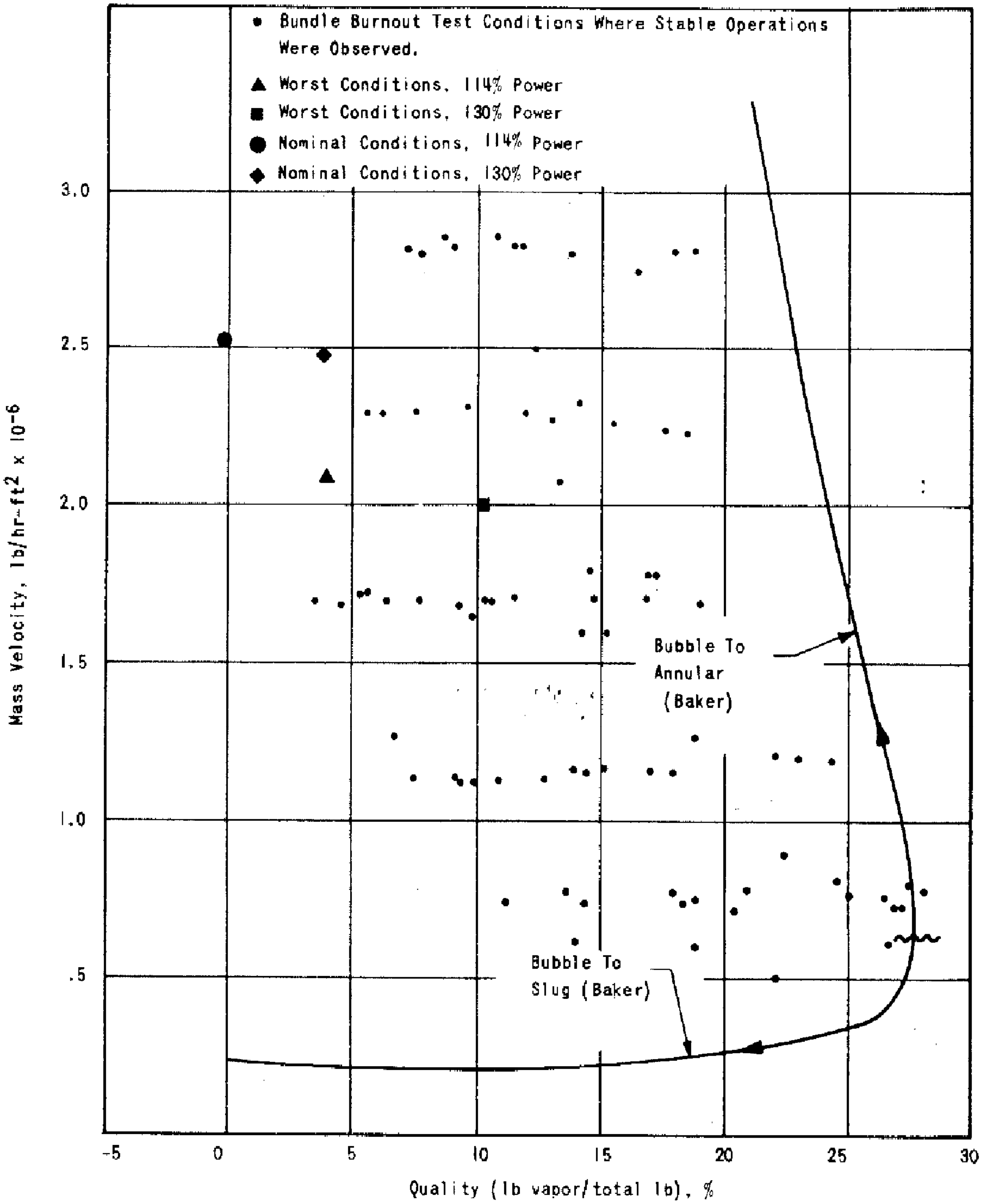


Figure 4-24. Flow Regime Map for the Hot Corner Cell

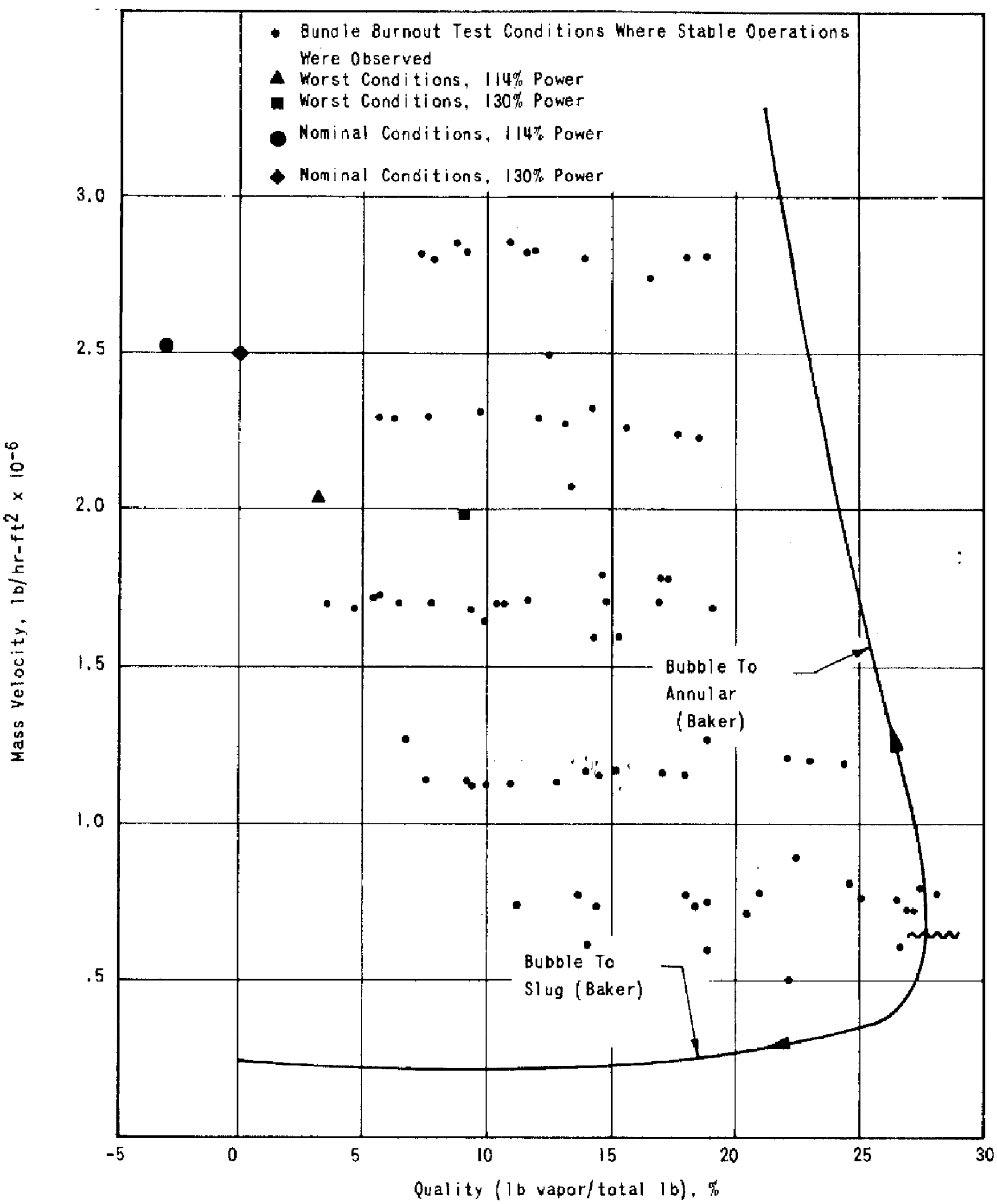


Figure 4-25. Deleted Per 1996 Update

Figure 4-26. Reactor Vessel and Internals General Arrangement

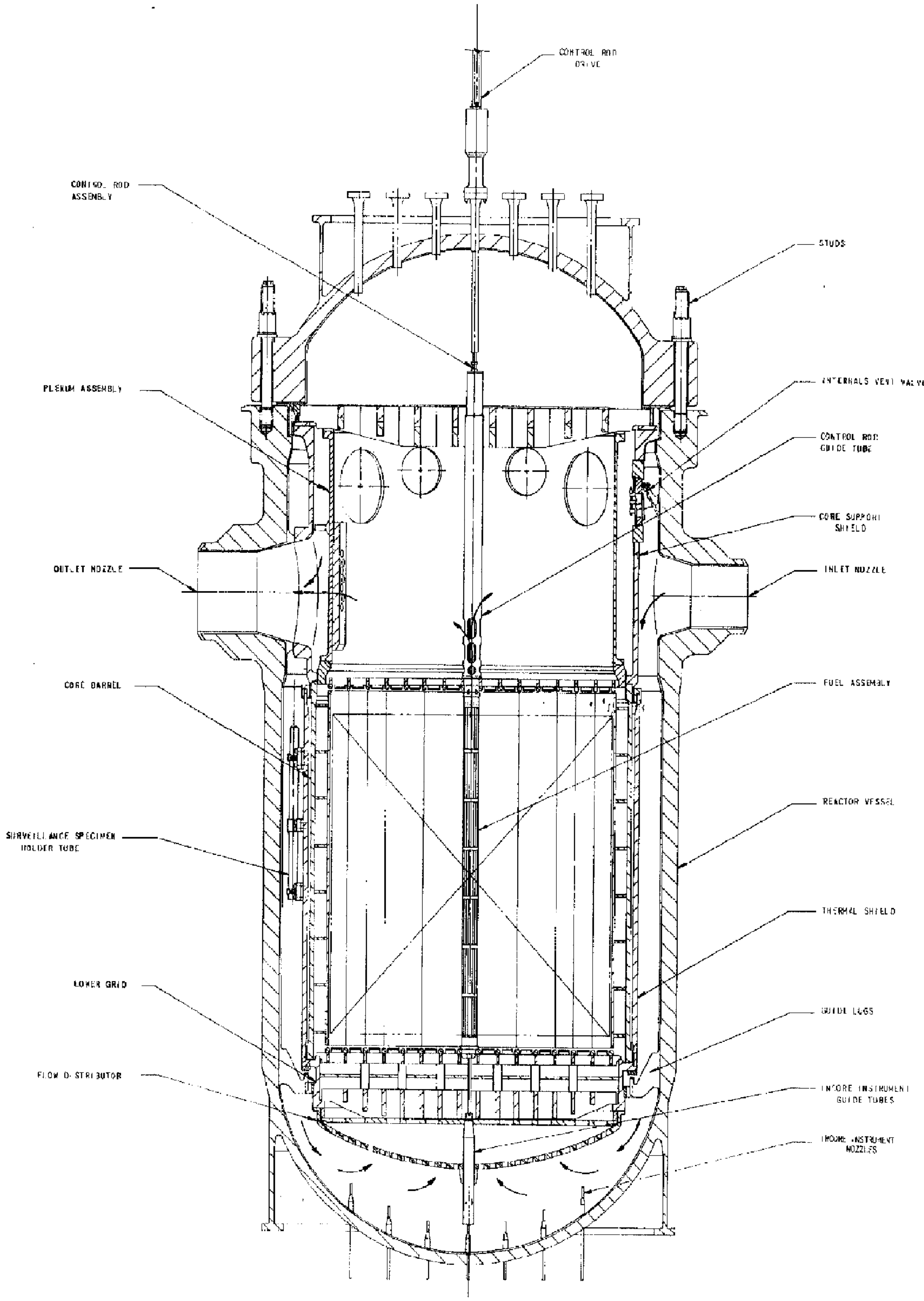


Figure 4-27. Reactor Vessel and Internals Cross Section

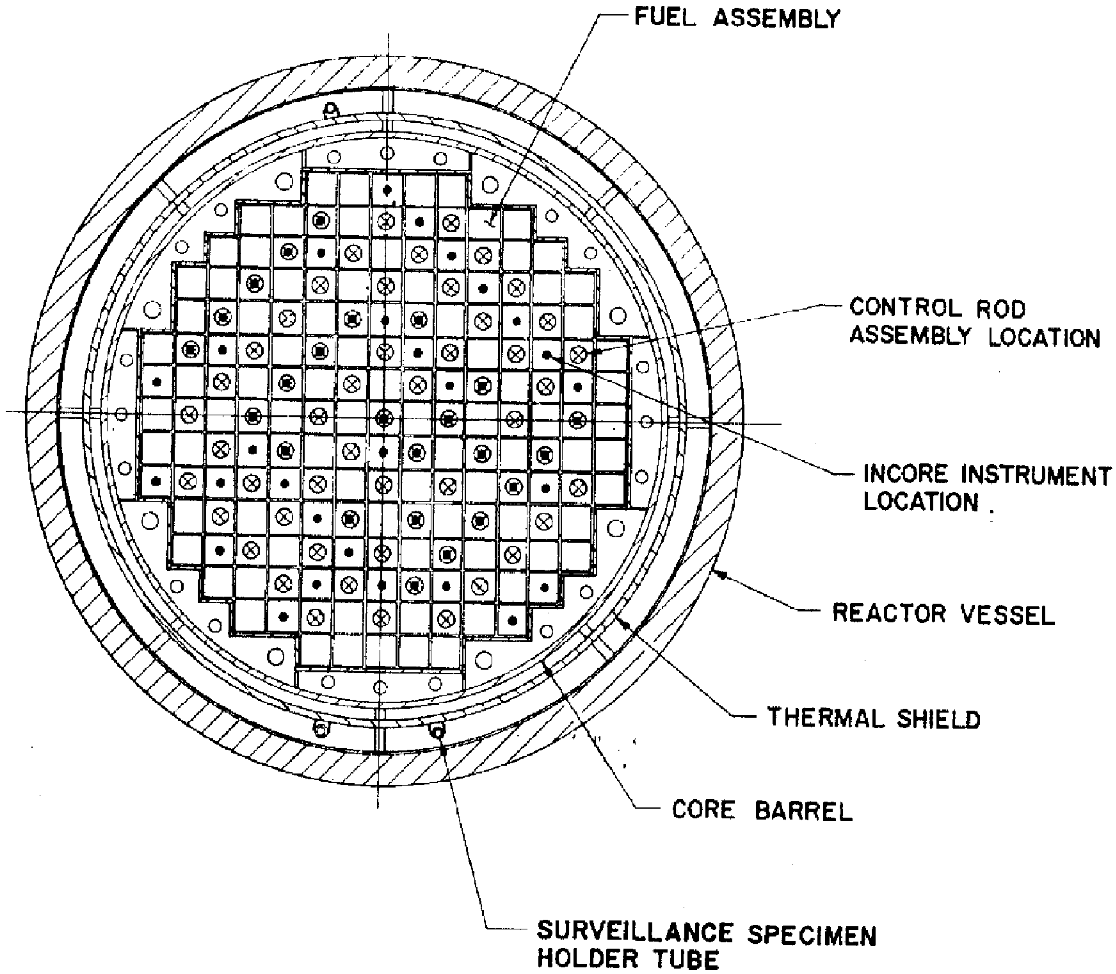


Figure 4-28. Core Flooding Arrangement

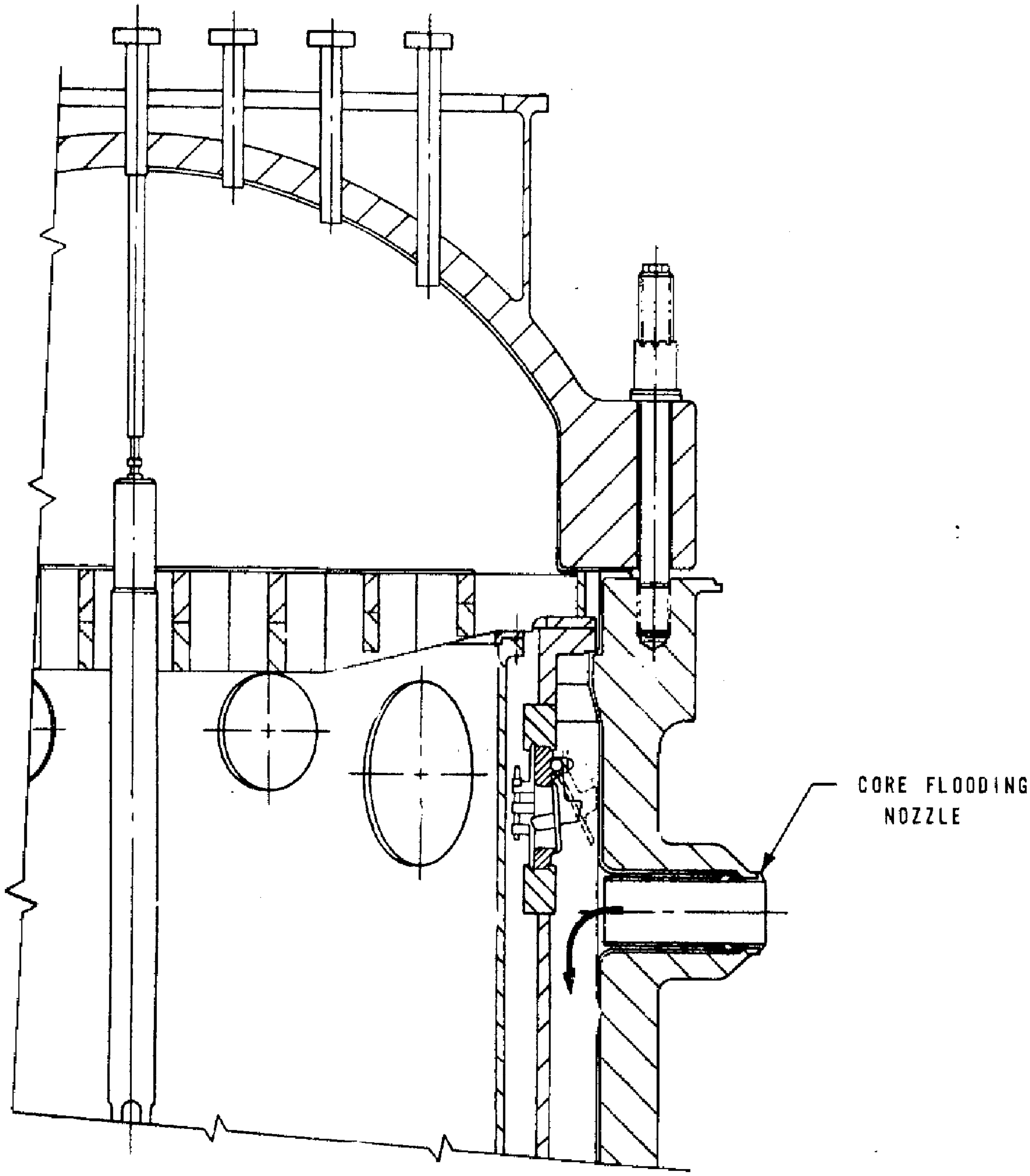


Figure 4-29. Internals Vent Valve Clearance Gaps

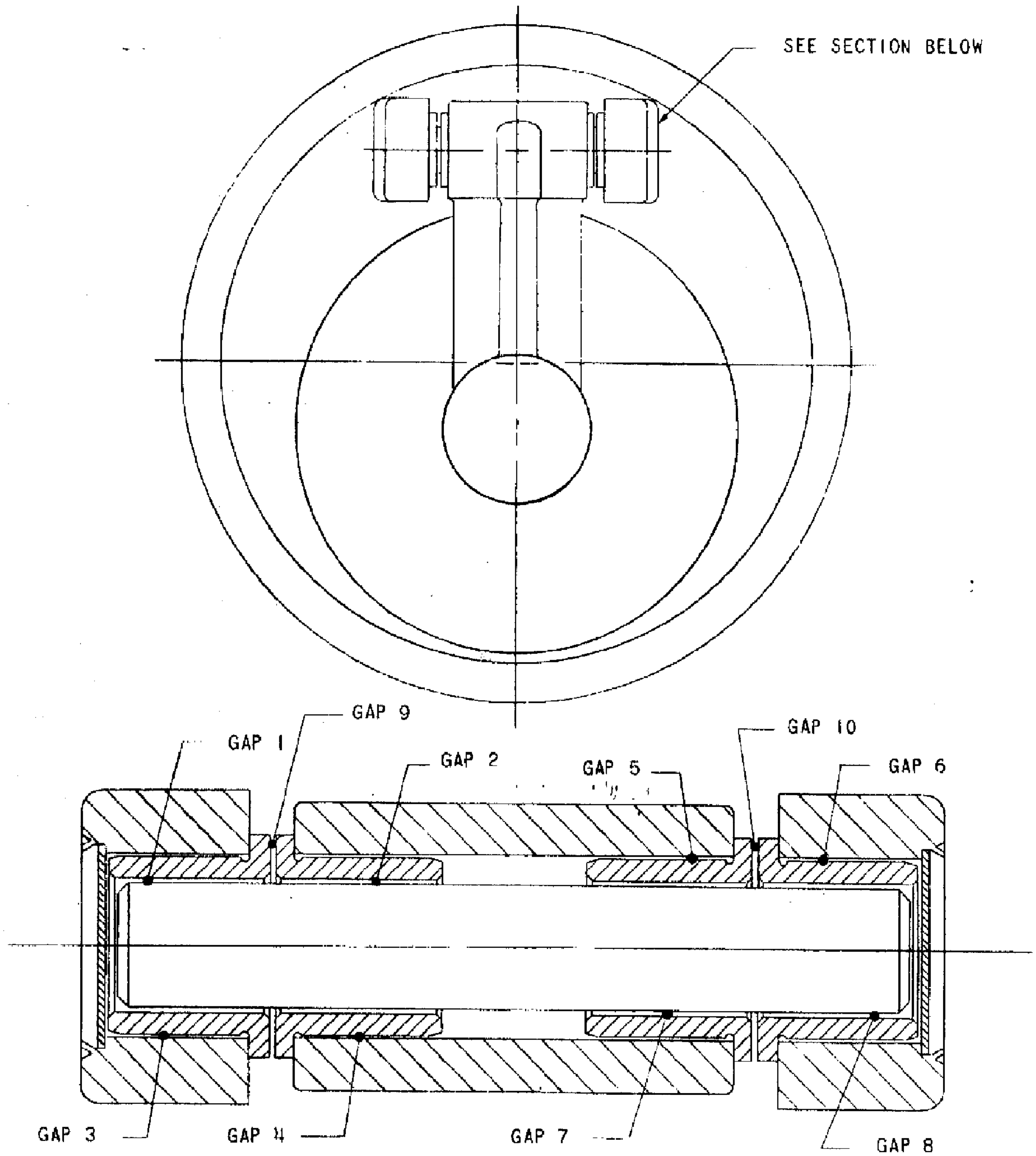


Figure 4-30. Internals Vent Valve

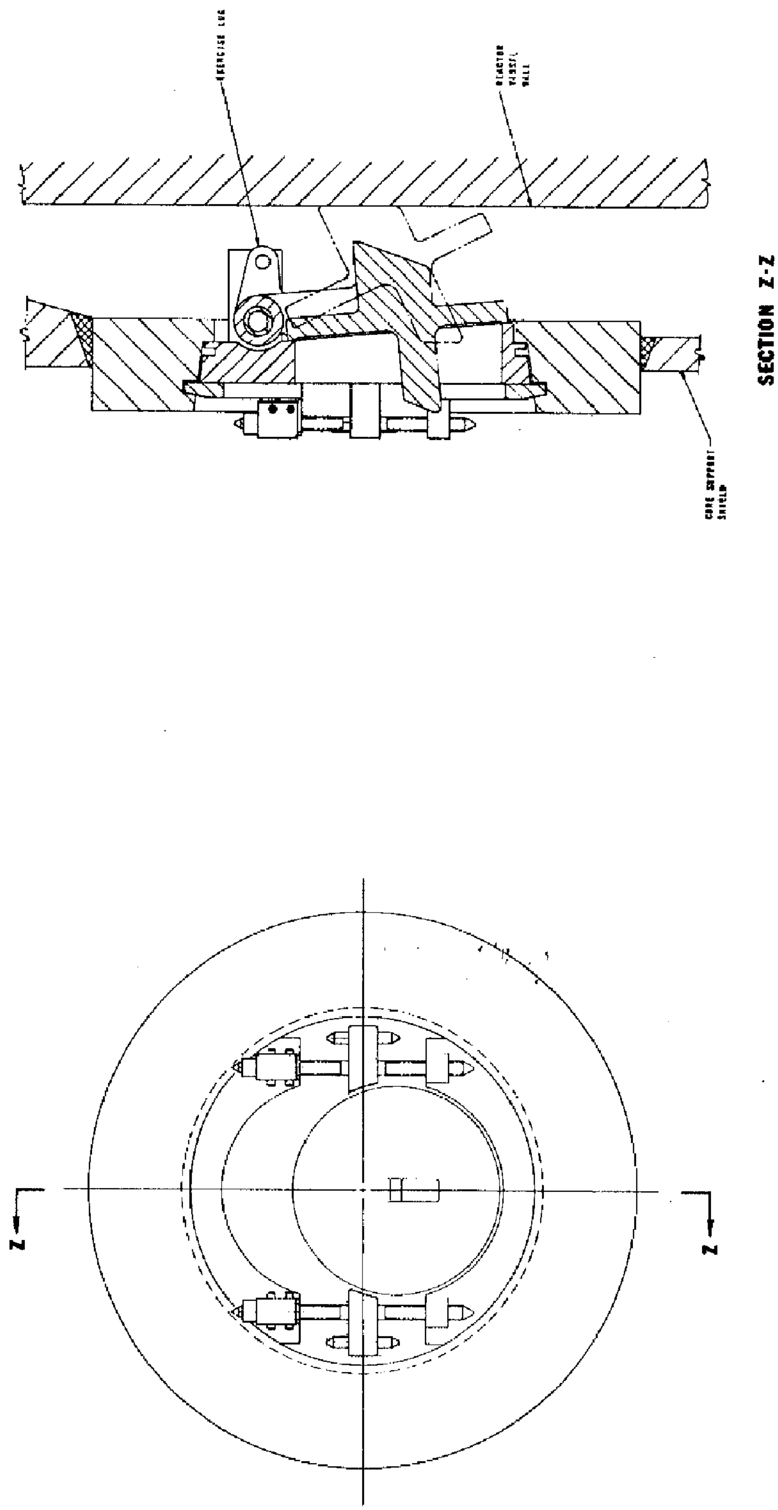


Figure 4-31. Control Rod Assembly

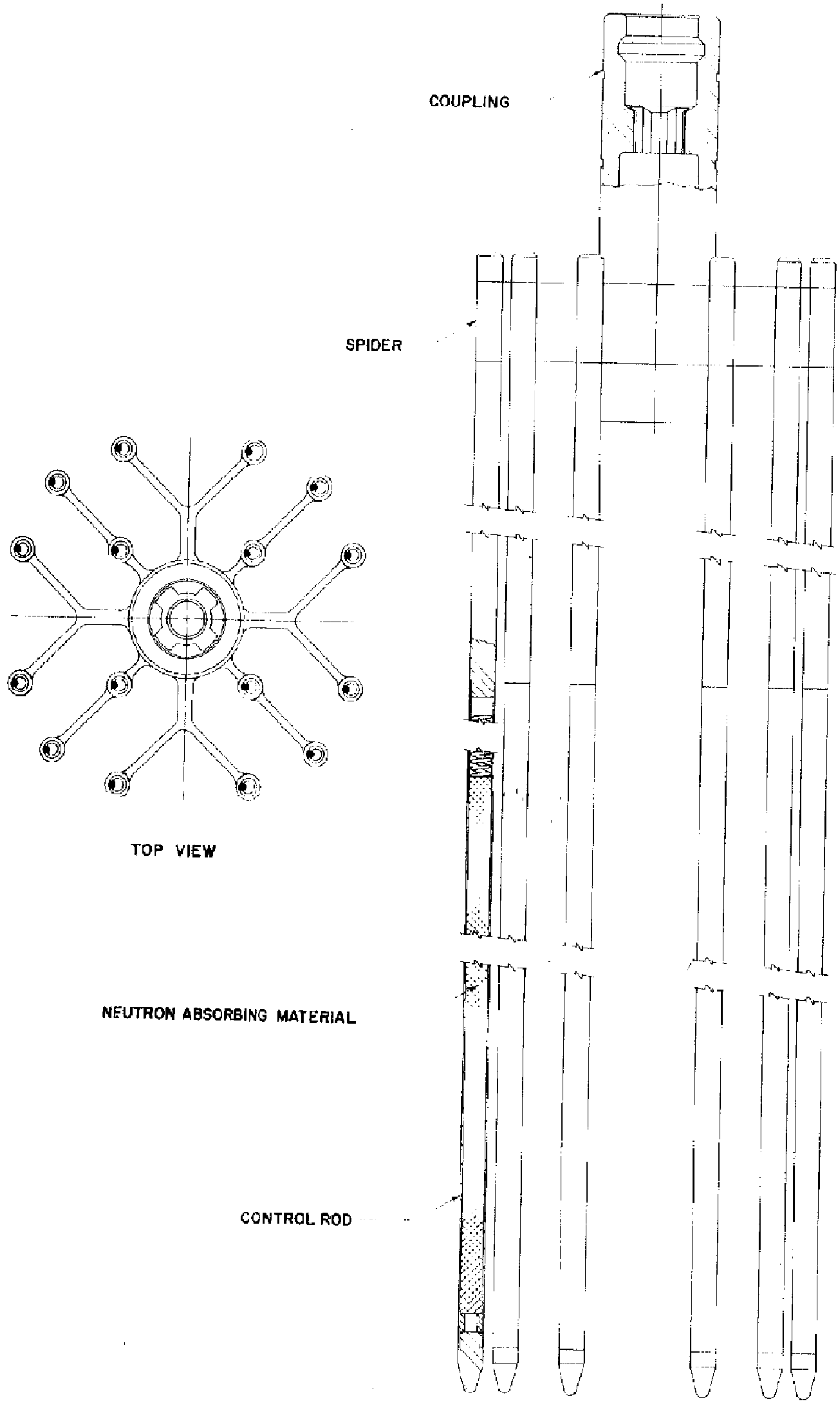


Figure 4-32. Axial Power Shaping Rod Assembly

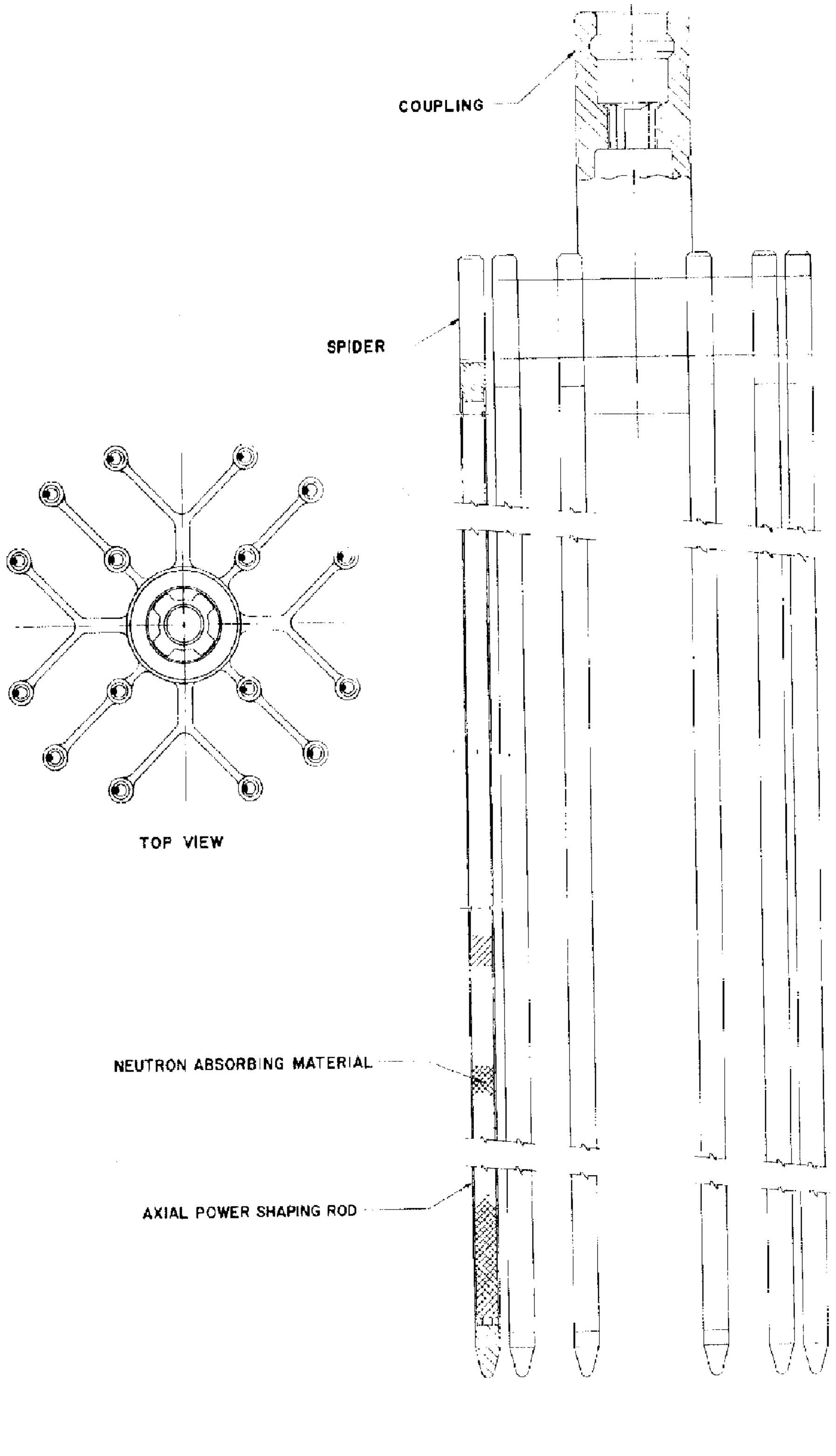


Figure 4-33. Deleted Per 1999 Update

Figure 4-34. Control Rod Drive - General Arrangement

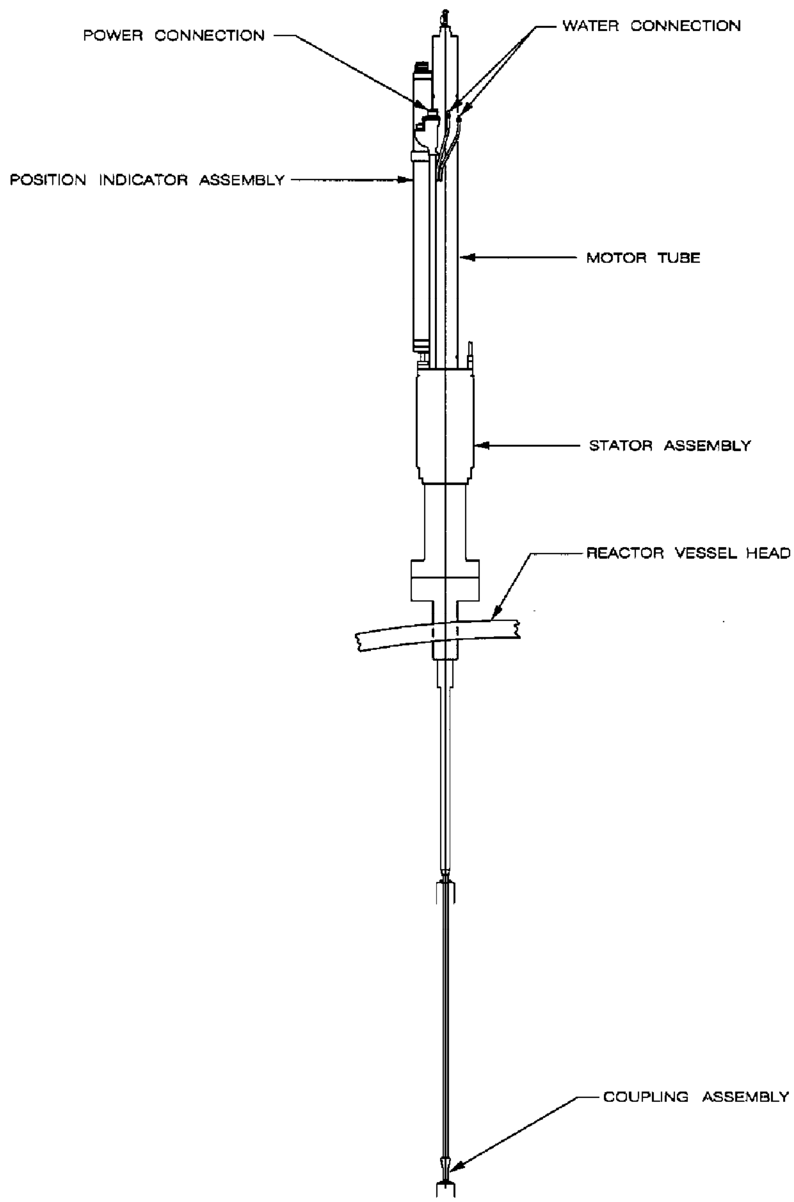


Figure 4-35. Deleted Per 1999 Update

Figure 4-36. Deleted Per 1999 Update

Figure 4-37. Typical Fuel Assembly

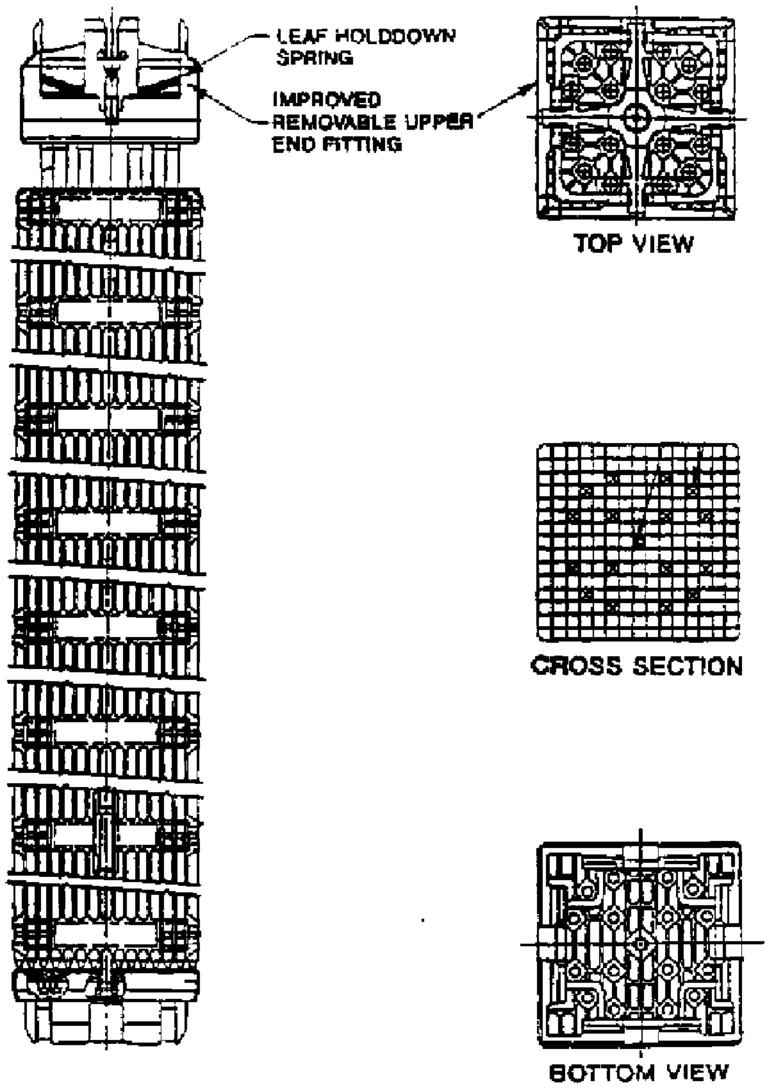


Figure 4-38. Westinghouse 177 Fuel Assembly

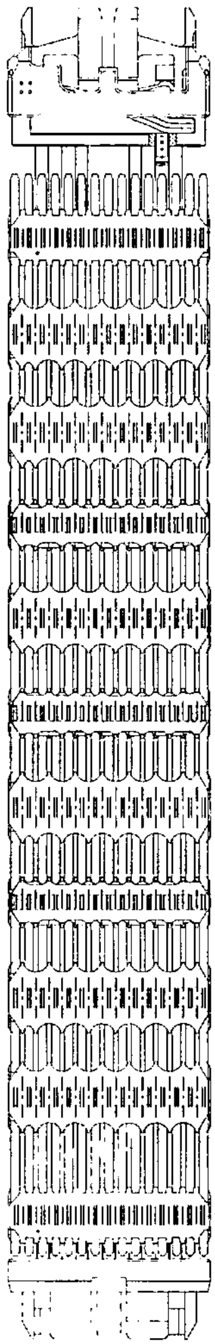


Table of Contents

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List of Tables

List of Figures

5.0 Reactor Coolant System and Connected Systems

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5.1 Summary Description

5.1.1 General

5.1.1.1 System

The Reactor Coolant System consists of the reactor vessel, two vertical once-through steam generators, four shaft-sealed reactor coolant pumps, an electrically heated pressurizer and interconnecting piping. The system is arranged in two heat transport loops, each with two reactor coolant pumps and one steam generator. The reactor coolant is transported through piping connecting the reactor vessel to the steam generators and flows downward through the steam generator tubes transferring heat to the steam and water on the shell side of the steam generator. In each loop, the reactor coolant is returned to the reactor through two lines, each containing a reactor coolant pump, to the reactor vessel. In addition to serving as a heat transport medium, the coolant also serves as a neutron moderator and reflector, and a solvent for the soluble poison (boron in the form of boric acid). The system pressure settings are listed in Table 5-1; the integrity of the reactor coolant pressure boundary is described in Section 5.2; the reactor vessel design is described in Section 5.3; and other major components and subsystems in the reactor coolant pressure boundary (RCPB) are described in Section 5.4. The maximum reactor coolant system volume is 12,085 ft^3 for Unit 3 original steam generators, 12,005 ft^3 for Units 2 and 3 replacement steam generators and 11,848 ft^3 for Unit 1 replacement steam generators. (RCS volumes listed assume 0% tube plugging and MK-B11 fuel.)

The Reactor Coolant System piping diagrams are Figure 5-1 (Oconee 1) and Figure 5-2 (Oconee 2 & 3).

In 1970, the Oconee 1 reactor coolant pumps were replaced with Westinghouse Model 93A pumps. The reactor coolant piping was modified slightly to accommodate the replacement pumps. Both the original pumps and the replacement pumps were bottom suction and side discharge allowing installation of the replacement pumps on the same centerlines as the original pumps. The original motors were utilized with the replacement pumps.

Figure 5-3 and Figure 5-4 show the revised arrangement of the reactor coolant piping for Oconee 1.

5.1.1.2 System Protection

Engineered safety features and associated systems are protected from missiles which might result from a loss of coolant accident. Protection is provided by concrete shielding and/or segregation of redundant components.

The reactor vessel is surrounded by a concrete primary shield wall and the heat transport loops are surrounded by a concrete secondary shield wall. These shielding walls provide missile protection for the Reactor Building liner plate and equipment located outside the secondary shielding.

Removable concrete slabs over the reactor vessel area and the concrete deck over the area outside of the secondary shield wall also provide shielding and missile protection.

The Reactor Coolant System is analyzed for maximum hypothetical earthquake to determine that resultant stresses do not jeopardize the safe shutdown of the Reactor Coolant System and removal of decay heat.

5.1.1.3 System Arrangement

The system arrangement in relation to shielding walls, the Reactor Building and other equipment in the building are described in Chapter 1. Plan and elevation drawings showing principal dimensions of the Reactor Coolant System in relation to the supporting or surrounding concrete structures are provided in Figure 5-3, Figure 5-4 (Oconee 1), Figure 5-5, Figure 5-6 (Oconee 2) and Figure 5-7, Figure 5-8 (Oconee 3).

In 2003, the Unit 1 steam generators were replaced with steam generators manufactured by Babcock and Wilcox Canada. In 2004, the steam generators in Unit 2 and Unit 3 were also replaced with steam generators manufactured by Babcock and Wilcox Canada.

5.1.1.4 System Parameters

5.1.1.4.1 Flow

The Reactor Coolant System is designed on the basis of 176,000 gpm flow rate in each heat transport loop.

5.1.1.4.2 Temperatures

Reactor Coolant System temperatures as a function of power are shown in Figure 5-9. The system is controlled to a constant average temperature throughout the power range from 15 percent to 100 percent full power. The average system temperature is decreased between 15 percent and 0 percent of full power to the saturation temperature at 900 psia.

5.1.1.4.3 Heatup

All Reactor Coolant System components are designed for a continuous heatup rate of 100°F/hr.

5.1.1.4.4 Cooldown

All Reactor Coolant System components are structurally designed for a continuous cooldown rate of 100°F/hr. System cooldown to 250°F is accomplished by use of the steam generators and by bypassing steam to the condenser with the Turbine Bypass System. The Low Pressure Injection System provides the heat removal for system cooldown below 250°F.

5.1.1.4.5 Volume Control

The only coolant removed from the Reactor Coolant System is that which is letdown to the High Pressure Injection System. The letdown flow rate is set at the desired rate by the operator positioning the letdown control valve and/or opening the stop valve for the letdown orifice.

To maintain a constant pressurizer water level, total makeup to the Reactor Coolant System must equal that which is letdown from the system. Total makeup consists of the seal injection water through the reactor coolant pump shaft seals and makeup returned to the system through the reactor coolant volume control valve (High Pressure Injection System). The pressurizer level controller provides automatic control of the valve to maintain the desired pressurizer water level. Reactor coolant volume changes during plant load changes exceed the capability of the reactor coolant volume control valve, and thus result in variations in pressurizer level. The level is returned to normal as the system returns to steady state conditions.

5.1.1.4.6 Chemical Control

Control of the Reactor Coolant Chemistry is a function of the Chemical Addition and Sampling System. Sampling lines from various points off the RCS and Auxiliary Systems provide samples of the reactor coolant for chemical analysis. During normal reactor operation, all chemical addition is made from the Chemical Addition and Sampling System to the High Pressure Injection System. Chemical additions may also be made directly to the RCS via the Pressurizer or the Low Pressure Injection System when the Unit is not at power. See Chapter 9 for detailed information concerning the Chemical Addition and Sampling System and for the High Pressure Injection System.

5.1.1.4.7 Boron

Boron in the form of boric acid is used as a soluble poison in the reactor coolant. Concentrated boric acid is stored in the Chemical Addition and Sampling System and is transported to the Reactor Coolant System in the same manner as described above for chemical addition. The concentrated boric acid may be stored in the concentrated boric acid storage tank (CBAST) or directly in the boric acid mix tank. The CBAST receives concentrated boric acid from the boric acid mix tank. The CBAST is required to contain a specified concentration of boric acid based on the volume in the tank in order to supply a source of concentrated soluble boric acid to the Reactor Coolant System in addition to the borated water storage tank. The concentrated boric acid is pumped to the High Pressure Injection System which transports it to the Reactor Coolant System. Boron concentrations are reduced by running letdown flow through the deborating demineralizers and/or diluting the reactor coolant with demineralized water. All bleed and feed operations for changing the boric acid concentrations of the reactor coolant are made between the High Pressure Injection System and the Coolant Storage System.

5.1.1.4.8 pH

The pH of the reactor coolant is controlled to minimize corrosion of the Reactor Coolant System surfaces which minimizes coolant activity and radiation levels of the components.

5.1.1.4.9 Water Quality

The reactor coolant water chemistry specifications have been selected to provide the necessary boron content for reactivity control and to minimize corrosion of Reactor Coolant System surfaces. The solids content of the reactor coolant is maintained below the design level by minimizing corrosion through chemistry control and by continuous purification by the demineralizer of the High Pressure Injection System. Excess hydrogen is maintained in the reactor coolant to chemically combine with the oxygen produced by radiolysis of the water.

5.1.1.4.10 Vents and Drains

Vent and drain lines are located at the high and low points of the system and provide the means for draining, filling, and venting the heat transport loops and pressurizer. The reactor vessel cannot be drained below the top of the reactor outlet nozzle using these drain lines. Each vent and drain line contains two manual valves in series. Vent lines are routed to a header connected to the quench tank gas space and drain lines are routed to a header connected to the suction of the component drain pump.

5.1.2 Performance Objectives

5.1.2.1 Steam Output

The Reactor Coolant System is designed to operate at a core power level of 2,568 MWt and transfer a total of 2,584 MWt (including 16 MWt input from reactor coolant pumps) to the steam generators. The system will produce a total steam flow of 10.8 million lbm/hr (replacement steam generators).

5.1.2.2 Transient Performance

The Reactor Coolant System will follow step or ramp load changes under automatic control without relief valve or turbine bypass valve action as follows:

5.1.2.2.1 Step Load Changes

Increasing or decreasing load steps of 10 percent of full power in the range between 20 percent and 90 percent full power.

5.1.2.2.2 Ramp Load Changes

Increasing load ramps of 1 percent per minute between 2 percent and 15 percent, 5 percent per minute between 15 percent and 20 percent, 9.9 percent between 20 percent and 95 percent and 5 percent per minute between 95 percent and 100 percent full power are acceptable. Decreasing load ramps of 9.9 percent between 100 percent and 20 percent, 5 percent per minute between 20 percent and 15 percent and 1 percent per minute between 15 percent and 2 percent full power are acceptable.

The combined actions of the Control System and the Turbine Bypass System permit a 40 percent load rejection or a turbine trip from 40 percent full power without safety valve action. The combined actions of the Control System, the turbine bypass valves, and the main steam safety valves are designed to accept separation of the generator from the Transmission System without reactor trip.

5.1.2.3 Partial Loop Operation

The Reactor Coolant System will permit operation with less than four reactor coolant pumps in operation. The nominal steady-state operating power levels for combinations of reactor coolant pumps operating are as follows:

Reactor Coolant Pumps Operating	Rated Power, %
4	100
3	75

5.1.2.4 Natural Circulation

Natural circulation provides an acceptable method of energy removal from the core with transfer of energy to the Secondary System through the steam generators. The controlling parameters which determine the magnitude of the natural circulation flow rates, i.e., steam generator liquid level and source of feedwater (emergency or main), produce more than adequate circulation rates under steady conditions. The margins to the limits for acceptable operation are more than adequate for steady-state and expected transients.

Natural circulation cooldown mode of operation is not expected to be undertaken at Oconee Nuclear Station except for SBLOCA events which do not allow continued operation of or restart of reactor coolant pumps. Most procedures recommend that MODE 3 with average Reactor Coolant temperature ≥525°F be maintained until those systems required for forced circulation are put back into service. However, there are exceptions to this strategy such as the most limiting fire scenarios where forced cooling is not restored.

In response to Generic Letter 81-21, Duke has developed a procedure to continuously vent the reactor vessel head to containment during a natural circulation cooldown to Decay Heat Removal System conditions. Venting the upper head area will maintain a cooling water flow through the upper head area and prevent the formation of a steam void in this area. This procedure results in a single steam void in the RCS, i.e, in the pressurizer, and simplifies pressure control during cooldown. NRC Safety Evaluation Report (Reference 1) concurs with Duke that natural circulation cooldown is not a safety concern due to operator training and procedures.

For Units where the revised tornado mitigation strategies as described in Section 3.2.2 have been implemented, the effects of a tornado may drive a unit to an average reactor coolant temperature less than 525°F. The subsequent minor reduction in RCS temperature required to compensate for the increase in RCS inventory by the SSF RCMU pump during plant stabilization does not constitute a natural circulation cooldown requiring use of the reactor vessel head vent. Refer to Reference 3 for additional information.

For units with the HELB Mitigation Strategy (Reference 4) implemented, the effects of a HELB may drive a unit to an average reactor coolant temperature less than 525°F. The subsequent minor reduction in RCS temperature required to compensate for the increase in RCS inventory by the SSF RCMU pump during plant stabilization does not constitute a natural circulation cooldown requiring use of the reactor vessel head vent. Refer to Reference 4 for additional information.

5.1.3 References

1. Letter from J. F. Stolz (NRC) to H. B. Tucker (Duke) dated June 5, 1985. Subject: NRC Safety Evaluation Report on Duke Response to Generic Letter 81-21 Natural Circulation Cooldown.
2. Issuance of Amendments Regarding Transition to Risk-Informed, Performance-Based Fire Protection Program with 10 CFR 50.48(c)
3. License Amendments Nos. 415, 417, and 416 (date of issuance – October 31, 2019); Tornado Mitigation.
4. License Amendment No. 421, 423, and 422 (date of issuance – March 15, 2021); HELB Mitigation.

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5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.1 Design Conditions

5.2.1.1 Pressure

The Reactor Coolant System components are designed structurally for an internal pressure of 2,500 psig.

5.2.1.2 Temperature

With the exception of the components associated with the pressurizer, the Reactor Coolant System pressure boundary components are designed for a temperature of 650°F. The pressurizer and associated code safety valves, power operated relief valve and piping, surge line, sample and drain lines and associated valves, and a portion of the spray line piping are designed for 670°F.

5.2.1.3 Reactor Loads

Reactor Coolant System components are supported and interconnected so that stresses resulting from combined mechanical and thermal forces are within established code limits. Equipment supports are designed to transmit piping rupture reaction loads to the foundation structures.

The Reactor Coolant System supports are on an eight foot six inch thick, heavily reinforced concrete slab which rests on a solid rock subgrade. The minimum ultimate crushing strength of rock cores tested was 720 kips per square foot and the maximum applied dynamic gross load is 30 kips per square foot. Based on the subgrade, the ratio of applied load to bearing capacity of the subgrade, and the monolithic nature of the base slab, differential settlement of the foundation is not anticipated.

5.2.1.4 Cyclic Loads

All Reactor Coolant System components are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. Design transient cycles are shown in Table 5-2 and Table 5-23.

Flow-induced vibration analyses have been performed for the fuel assembly, including fuel rods, and for the reactor internals components. The analyses and design criteria for the thermal shield, flow distributor assembly, surveillance holder tubes and shroud tubes, and the "U" baffles are given in B&W Topical Report BAW-10051, Reference 1.

Components subjected to cross flow are checked for response during design, so that the fundamental frequencies associated with cross flow are above the vortex shedding frequencies. It has also been conservatively determined that the flow induced pressure fluctuations acting on the disc of the vent valve are such that for normal operation there is always a positive net closing force acting on the disc. Emergency operational modes are covered in B&W Topical Report BAW-10008, Part I, Reference 2.

Oconee Technical Specification 5.5.6 establishes the requirement to provide controls to track the number of UFSAR Section 5.2.1.4 cyclic and transient occurrences to assure that components are maintained within design limits. This requirement is managed by the Oconee Thermal Fatigue Management Program.

For license renewal, continuation of the Oconee Thermal Fatigue Management Program into the period of extended operation will provide reasonable assurance that the thermal fatigue analyses, including applicable flaw growth calculations, will remain valid or that appropriate action is taken in a timely manner to assure continued validity of the design.

References for this Section: Application [Reference 38] and Final SER [Reference 39]

5.2.1.5 Seismic Loads and Loss-of-Coolant Loads

Reactor Coolant System components are designated as Class I equipment and are designed to maintain their functional integrity during an earthquake. Design is in accordance with the seismic design bases shown below. The loading combinations and corresponding design stress criteria for internals and pressure boundaries of vessels and piping are given in the section. A discussion of each of the cases of loading combinations follows:

Protection criteria against dynamic effects associated with pipe breaks is covered in Section 3.6. Large reactor coolant loop pipe ruptures (double-ended guillotine breaks) were eliminated for steam generator replacement by the application of leak-before-break-criteria to the reactor coolant loop piping. This was permitted by the NRC as described in Reference 62.

5.2.1.5.1 Seismic Loads

Case I - Design Loads Plus Operating Basis Earthquake (OBE) Loads - For this combination, the reactor must be capable of continued operation; therefore, all components excluding piping are designed to Section III of the ASME Code for Reactor Vessels. The primary piping was originally designed according to the requirements of USAS B31.1 and B31.7. The S_m values for all components, excluding bolting, are those specified in Table N-421 of the ASME code. The S_m value for bolts are those specified in Table N-422 of the ASME Code. The Class I RCS piping was redesigned to the 1983 ASME (No Addenda) Code during the steam generator replacement project.

CASE II - Design Loads Plus Safe Shutdown Earthquake (SSE) - In establishing stress levels for this case, a “no-loss-of-function” criterion applies, and higher stress values than in Case I can be allowed. The multiplying factor of 1.2 has been selected in order to increase the code-based stress limits and still insure that for the primary structural materials, i.e., 304 SST, 316 SST, SA302B, SA212B, and SA106C, an acceptable margin of safety will always exist. A more detailed discussion of the adequacy of these margins of safety is given in BAW-10008, Part 1, “Reactor Internals Stress & Deflection Due to LOCA and Maximum Hypothetical Earthquake (MHE)”. Note that the MHE is equivalent to the SSE. The S_m value for all components are those specified in Table N-421 of the ASME Code.

5.2.1.5.2 Loss-of-Coolant Loads

A loss-of-coolant accident coincident with a seismic disturbance has been analyzed to assure that no loss of function occurs. In this case, primary attention is focused on the ability to initiate and maintain reactor shutdown and emergency core cooling. Two additional cases are considered as follows:

Case III - Design Loads Plus Pipe Rupture Loads - For this combination of loads, the stress limits for Case II are imposed for those components, systems, and equipment necessary for reactor shutdown and emergency core cooling.

Case IV - Design loads plus Safe Shutdown Earthquake (SSE) Loads Plus Pipe Rupture Loads - Two thirds of the ultimate strength has been selected as the stress limit for the simultaneous occurrence of MHE and reactor coolant pipe rupture. As in Case III, the primary concern is to maintain the ability to shut the reactor down and to cool the reactor core. This limit assures that a materials strength margin of safety of 50 percent will always exist.

The design allowable stress of Case IV loads is given in BAW-10008 for 304 stainless steel. This curve is used for all reactor vessel internals including bolts. It is based on adjusting the ultimate strength curves published by U.S. Steel to minimum ultimate strength values by using the ratio of ultimate strength given by Table N-421 of Section III of the ASME code at room temperature to the room temperature strength given by U.S. Steel.

In Cases II, III, and IV, secondary stresses were neglected, since they are self-limiting. Design stress limits in most cases are in the plastic region, and local yielding would occur. Thus, the conditions that caused the stresses are assumed to have been satisfied. BAW-10008, Part 1, contains a more extensive discussion of the margin of safety, the effects of using elastic equations, and the use of limit design curves for reactor internals. Table 5-3 provides the stress limits for seismic, pipe rupture, and combined loads.

5.2.1.6 Service Lifetime

A specific service lifetime is not established for the major reactor coolant system components. Rather, through the license renewal process, a detailed aging management review has assured that programs are in place to manage the impact of aging on these components. The number of cyclic system temperature and pressure changes (Table 5-2 and Table 5-23), is also managed and corrective actions taken when appropriate.

5.2.1.7 Water Chemistry

The water chemistry is selected to provide the necessary boron content for reactivity control and to minimize corrosion of the Reactor Coolant System surfaces. To ensure the best protection is provided, reactor coolant water quality specifications are based upon the most current revision of the EPRI PWR Primary Water Chemistry Guidelines and vendor recommendations. These are addressed in site specific or fleet documents.

5.2.1.8 Vessel Radiation Exposure

The reactor vessel is the only Reactor Coolant System component exposed to a significant level of neutron irradiation and is therefore the only component subject to material radiation damage. The maximum predicted exposure from fast neutrons (E > 1.0 MeV) at the inside vessel surface over a 40 and 60-year life with an 82.5 and 80-percent load factor, respectively, has been computed to be as follows (per References 27, 28, 29, 56, 57, and 58):

	33 EFPY	48 EFPY
Oconee Unit 1	9.56×10^{18} neutrons/cm^2	1.31×10^{19} neutrons/cm^2
Oconee Unit 2	9.25×10^{18} neutrons/cm^2	1.28×10^{18} neutrons/cm^2
Oconee Unit 3	9.13×10^{18} neutrons/cm^2	1.26×10^{18} neutrons/cm^2

5.2.1.9 Leak Before Break

Leak-before-break is used at Oconee in three applications. The first application is to establish Mark - B fuel assembly spacer grid impact loads and displacement time histories. It is also used to eliminate the dynamic effects of large bore breaks, thereby allowing the removal of the RCS piping whip restraints. Leak-before-break was also used to justify deletion of all or portions of the RCS LOCA restraints during steam generator replacement as discussed in Section 5.4.8.6. See Section 3.9.2.4. The second application supports the flaw growth analysis performed for the cast austenitic steel reactor coolant pump inlet and exit nozzles. The third application (discussed below) is used to eliminate the need to analyze for specific pipe ruptures in the CF/LPI Systems for Units 1, 2 and 3. The second and third applications are discussed in the following paragraphs.

The successful application of Leak-Before-Break (LBB) to the Oconee Reactor Coolant System main coolant piping is described in B&WOG topical report entitled, "The B&W Owners Group Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSSS," BAW-1847, Revision 1, September 1985. This report provides the technical basis for evaluating postulated flaw growth in the main Reactor Coolant System piping under normal plus faulted loading conditions and was approved by the NRC (Reference 62) for the current term of operation. The time-limited aging analyses in BAW-1847, Revision 1, include fatigue flaw growth and the qualitative assessment of thermal aging of cast austenitic stainless steel reactor coolant pump inlet and exit nozzles.

Subsequent analyses by Babcock and Wilcox Canada (Reference 59) demonstrated the acceptability of the weld and piping materials added to the Reactor Coolant System during replacement of the steam generators. This report also increased the acceptable heat up and cool down cycles from 240 to 360 for the LBB evaluation.

Fatigue flaw growth evaluations are based on transient definitions defined by the Reactor Coolant System design specification and described in Table 5-2 and Table 5-23. The transient cycles that make up the thermal fatigue design basis are being monitored by the Oconee Thermal Fatigue Management Program. If a transient cycle count approaches or exceeds the allowable design limit, corrective actions are taken. The cast austenitic stainless steel reactor coolant pump inlet and outlet nozzles are susceptible to thermal aging. Thermal aging of cast austenitic stainless steel causes a reduction of fracture toughness. Reduction of fracture toughness of the reactor coolant pump nozzles has been determined to be acceptable for the period of extended operation through a flaw stability analysis.

The successful application of Leak-Before-Break (LBB) to the Oconee Core Flood Piping System is described in the FANP report entitled, “Leak-Before-Break analysis of the Core Flood and Low Pressure Injection/Decay Heat Removal Piping Systems of Oconee Units 1, 2 and 3 (Reference 67). This report provides the technical basis for evaluating postulated flaw growth in the Core Flood system piping under normal plus faulted loading conditions and was approved by the NRC [Reference 71].

The LBB evaluation concluded that LBB technology is applicable to the Core Flood system piping inside containment for Oconee Units 1, 2 and 3. This includes both CF/LPI piping trains between the two valves (LP-176 and LP-177), the two Core Flood Tank nozzles and up to but not including the two RV Core Flood Nozzles. The margin of 10 on leakage detection, the margin of 2 on postulated crack size and the margin of 1.0 on loads combined by the absolute sum method required by Standard Review Plan 3.6.3 were demonstrated. Therefore, the use of LBB technology to eliminate the dynamic effects of postulated pipe breaks in these systems is justified.

The Core Flood LBB evaluation [Reference 67] eliminates the need to analyze for the dynamic effects associated with pipe ruptures in the identified piping.

References for this Section: [Reference 40], [Reference 41] and [References 67, 68, 69, 70, 71].

5.2.2 Codes and Classifications

The codes listed in this section and Table 5-4 include the code addenda and case interpretations issued through Summer 1967 unless noted otherwise. Quality control and quality assurance programs relating to the fabrication and erection of system components are summarized in Section 5.2.3.11.

The applicable ASME Boiler and Pressure Vessel Code, Section XI Edition and Addenda used for Inservice Inspection shall comply with 10CFR50.55a.

5.2.2.1 Vessels

The design, fabrication, inspection and testing of the reactor vessel and closure head, steam generator (both reactor coolant side and secondary side), pressurizer and attachment nozzles on the vessels is in accordance with the ASME Boiler and Pressure Vessel Code, Section III, for Class A vessels.

5.2.2.2 Piping

The design, fabrication, inspection and testing of the reactor coolant piping excluding the pressurizer surge line and the spray line is in accordance with USAS B31.7, Code for Pressure Piping, Nuclear Power Piping, dated February, 1968, and as corrected for Errata under date of June, 1968. The pressurizer surge and spray lines were fabricated and initially inspected in accordance with USAS B31.7, February 1968 with June, 1968, Errata. However, the surge line, which was analyzed in accordance with the ASME Code, 1977 edition, Summer 1979 Addenda, has been reanalyzed to the 1986 ASME Code in response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Straitifcation” concerns. The spray line has been reanalyzed to the 1983 Edition of the ASME Code. The following Reactor Coolant Branch lines were analyzed, up to the first isolation valve from the Reactor Coolant Loop, to Class 1 rules of the 1983 Edition, no addenda, of the ASME code:

1. High Pressure Injection (Emergency Injection)
2. High Pressure Injection (Normal Injection)
3. High Pressure Injection (Letdown)
4. Low Pressure Injection (Decay Heat Removal Drop-line)
5. Low Pressure Injection (Core Flood)
6. Reactor Coolant Drains
7. Pressurizer Relief Valve Nozzles

Deleted paragraph(s) per 2004 update

The main feedwater header and the auxiliary feedwater header for the replacement steam generator are designed, fabricated, inspected and tested in accordance with the requirements of the ASME Code for Class I piping components. These piping components meet the ASME stress and fatigue limits as stipulated in NB-3600. The analysis is documented in the Base Design Condition Report (BWC-006K-SR-01) (Reference 60) and the Transient Analysis Stress Report (BWC-006K-SR-01) (Reference 61).

For the analysis of the reactor coolant loop for the replacement of the steam generators, the design code for the RCS piping was changed from the 1968 Edition of the USA Standard B31.7 to subsection NB of Section III of the 1983 Edition of the ASME Boiler and Pressure Vessel Code (no addenda). The basic material allowable stresses used were the lower of those in the 1968 B31.7 or those in the 1983 ASME Boiler and Pressure Vessel Code. Stress allowable factors were taken from the 1983 ASME Boiler and Pressure Vessel Code.

5.2.2.3 Reactor Coolant Pumps

The reactor coolant pump casings are designed, fabricated, inspected and tested to meet the intent of the ASME Boiler and Pressure Vessel Code, Section III, for Class A vessels, but are not code stamped.

5.2.2.4 Relief Valves

The pressurizer code safety valves and the electromatic relief valve comply with Article 9, Section III, of the ASME Boiler and the Pressure Vessel Code.

5.2.2.5 Welding

Welding qualifications are in accordance with the ASME Boiler and Pressure Vessel Code, Section III and Section IX and Section XI, as applicable.

5.2.3 System Design Evaluation

5.2.3.1 Design Margin

The Reactor Coolant System is designed structurally for 2,500 psig and 650°F. The system will normally operate at 2,155 psig and 604°F.

In the event of a complete loss of power to all reactor coolant pumps, reactor coolant flow, coastdown, and subsequent natural circulation flow is more than adequate for core cooling and decay heat removal as shown by the analysis in Chapter 15.

The number of transient cycles specified in Table 5-2 and Table 5-23 for the fatigue analysis is conservative.

5.2.3.2 Material Selection

For Reactor Coolant System major components, materials of construction are listed in Table 5-5. Each of the materials used in the Reactor Coolant System has been selected for the expected environment and service conditions. Materials were chosen for specific uses at various locations within the system because of their compatibility with the reactor coolant. There are no novel material applications in the Reactor Coolant System. Reactor Coolant System materials normally exposed to the coolant are corrosion-resistant materials consisting of 304 or 316 stainless steel, Inconel, Alloy 600, Alloy 690, 17-4PH (H1100), Zircaloy or weld deposits with corrosion resistant properties equivalent to or better than those of 304 SS.

In some specific locations of the Reactor Coolant System, small areas of Low Alloy Steel (LAS) or Carbon Steel (CS) may be exposed to the reactor coolant as a result of RCS component modifications. In each case, a corrosion evaluation was performed demonstrating the component meets the appropriate design Code design requirements for the duration of its service life. Two examples are the mitigation of the Alloy 600 Pressurizer thermowell and the Alloy 600 Pressurizer 1 inch vent nozzle components. Small areas of CS were exposed in the annulus region between the replacement Stainlees Steel vent nozzle and the Pressurizer head (less than 22 sq. in.), as well as the replacement Alloy 690 thermowell and the Pressurizer shell (less than 30 sq. in.). For each design, a corrosion evaluation was performed as documented in a calculation (Reference 72) and ONS License Amendment Request (References 73 & 74). This was approved by the NRC in their Safety Evaluation Report (Reference 75).

To assure long steam generator tube lifetime, feedwater quality entering the steam generator is maintained as high as practical. The current revision of the SGOG EPRI PWR Secondary

Chemistry Guidelines and vendor recommendations are used to prepare operating specifications which are addressed in the Chemistry Section Manual.

The selection of materials and the manufacturing sequence for the Reactor Coolant System components, is arranged to insure that no pressure boundary material is furnace-sensitized stainless steel. Safe ends are provided on those carbon steel nozzles of the system vessels which connect to stainless steel piping. All dissimilar metal welds, with the exception of Inconel to Stainless Steel pipe welds, will be made in the manufacturer's shops.

Piping systems designed to resist seismic forces have been restrained by steel supports capable of withstanding these seismic forces. The restraints also act as pipe stops restraining the lines against whipping. In systems, where it was necessary to use hydraulic or mechanical snubbers to resist seismic forces, the mechanical action associated with the snubbers makes it possible to consider them as restraints against pipe whipping. A more detailed discussion of the types of snubbers in use at Oconee is provided in Section 3.9.3.4.2.2.

The basic design criteria for pipe whip protection is as follows:

1. All penetrations are designed to maintain containment integrity for any loss of coolant accident combination of containment pressures and temperatures.
2. All penetrations are designed to withstand line rupture forces and moments generated by their own rupture as based on their respective design pressures and temperatures.
3. All primary penetrations, and all secondary penetrations that would be damaged by a primary break, are designed to maintain containment integrity.
4. All secondary lines whose break could damage a primary line and also breach containment are designed to maintain containment integrity.

The pressure boundary of the RCS is fabricated primarily from ferritic materials, while that of the attached systems is fabricated primarily from austenitic material.

Consequently, the RCS components are the only ones that require special protection against nonductile failure and that must comply with the fracture toughness requirements of Appendix G to 10 CFR 50. This protection is ensured by establishing pressure-temperature limitations on the RCS. The margin of safety is controlled by not exceeding the calculated allowable pressure at any given temperature. The following loading conditions require pressure-temperature limits:

1. Normal operations including bolt preloading, heatup, and cooldown.
2. Preservice system hydrostatic test.
3. Inservice system leak and hydrostatic tests.
4. Reactor core operation.

For a better understanding of the required protection against non-ductile failure, typical operational parameters of the RCS are described in the following sections for each of the loading conditions.

5.2.3.2.1 Normal Operation

During bolt preload, the reactor vessel closure studs are tensioned to the specified load. Bolt preloading is not allowed until the reactor coolant temperature or the volumetric average temperature of the closure head region (including the studs) is higher than the specified minimum preload temperature. After the studs are tensioned, system pressure can be increased by the pressurizer until it is above the net positive suction head (NPSH) required for reactor coolant pump (RCP) operation. The heatup transient begins when the RCP is started.

During heatup, the RCS is brought from MODE 5 to MODE 3 with average Reactor Coolant temperature ≥525°F. The heat sources used to increase the temperature of the system are the RCP and any residual (decay) heat from the core. Normally, when the pumps are started, the temperature of the water in the pressurizer is about 400°F; this corresponds to the pressure in the RCS, which is about 300 psig. The coolant temperature is at or above the minimum specified bolt preload temperature.

Initially, the reactor coolant temperature may be as low as room temperature for initial core loading or as high as 130°F for subsequent refueling. The system pressure is maintained below the maximum allowable pressure of approximately 625 psig (20 percent of preoperational system hydrostatic test pressure) until the reactor coolant temperature is approximately 270°F.

At any given time throughout the heatup transient, the temperature of the reactor coolant is essentially the same throughout the system except, of course, in the pressurizer. The system pressure, as controlled by the pressurizer heaters, is maintained between the minimum required for RCP NPSH and the maximum established to meet the fracture toughness requirements. The heatup rate is maintained below the maximum rate used to establish the maximum allowable pressure-temperature limit curve.

RCS cooldown brings the system from MODE 3 to MODE 5. The cooldown is normally accomplished in two phases: The first phase reduces the fluid temperature from approximately 550°F to below the design temperature of the decay heat removal system (approximately 300°F). This temperature reduction is accomplished using the steam generators but bypassing the turbine and dumping the steam directly to the condenser. Once below its design temperature (and pressure), the Decay Heat Removal System (DHRS) is activated in the second phase to further reduce the reactor coolant temperature to that desired.

Before cooldown, the RCS temperature is maintained constant by balancing the heat removal rate from the steam dump with the heat contributed by the RCP and core decay heat. The system pressure is maintained by the pressurizer. The cooldown is normally initiated by stopping two RCPs in one loop. The two remaining pumps provide coolant circulation through both steam generators, and the turbine steam bypass flow controls the cooldown rate. The primary pressure during cooldown is controlled with the pressurizer heaters and spray. After cooling down below the DHRS design temperature and pressure, the cooling mode is changed from the steam generators to the DHRS. Before the switch, the RCS pressure is below 625 psig (20 percent of preoperational system hydrostatic test pressure) and below the DHRS pressure but above the pressure required for the RCP to operate.

To minimize the thermal shock on the RCPB, the two RCP remain in operation as the water flow of the DHRS is initiated. The DHRS flow rapidly mixes with the reactor coolant; but during this period, the indicated RCS temperature may fluctuate until mixing is complete. After the switch is completed, the RCP are stopped. During this phase, the cooldown rate is controlled by the temperature and flow of the DHRS.

5.2.3.2.2 Preservice System Hydrostatic Test

Prior to initial operation, the RCS is hydrostatically tested in accordance with ASME Code requirements. During this test, the system is brought up to an internal pressure not less than 1.25 times the system design pressure. This minimum test pressure is in accordance with Article NB-6000 of ASME Section III. Since the system design pressure is 2500 psig, the preservice system hydrostatic test pressure is 3125 psig. Initially, the RCS is heated to a temperature above the calculated minimum test temperature required for adequate fracture toughness. This heatup is accomplished by running the RCP. The pressurizer heaters are used to heat the pressurizer to the required temperature. Before the test temperature is reached, the pressure is maintained above NPSH required for the RCP but below the maximum allowable pressure for adequate fracture toughness. When the test temperature is reached, the RCP are stopped and RCS makeup water is added to fill the pressurizer. The test pressure is then reached using either the pressurizer heaters or the hydrostatic pumps connected to the RCS. The test pressure is held for the minimum specified time, and the examination for leakage follows in accordance with the ASME Code.

5.2.3.2.3 Inservice System Pressure Testing

Class 1, 2, and 3 system pressure testing complies with Section XI, Articles IWA-5000, IWB-5000, IWC-5000, and IWD-5000.

5.2.3.2.4 Reactor Core Operation

The reactor core is not allowed to become critical until the RCS fluid temperature is above 525°F except for brief periods of low-power physics testing. This temperature is much higher than the minimum permissible temperature for the inservice system hydrostatic pressure test, and it is also at least 40°F above the calculated minimum temperature required at normal pressure for operation throughout the service life of the plant.

5.2.3.3 Reactor Vessel

The ability of the reactor pressure vessel to resist fracture is the primary factor in ensuring the safety of the primary system in light water cooled reactors. The beltline region of the reactor vessel is the most critical region of the vessel because it is exposed to neutron irradiation. The general effects of fast neutron irradiation on the mechanical properties of such low-alloy ferritic steels as SA302B, Code Case 1339, used in the fabrication of the Oconee 1 reactor vessel, and SA508, Class 2, used in the fabrication of Oconee 2 and 3 reactor vessels, are well characterized and documented in the literature. The low-alloy ferritic steels used in the beltline region of reactor vessels exhibit an increase in ultimate and yield strength properties with a corresponding decrease in ductility after irradiation. In reactor pressure vessel steels, the most serious mechanical property change is the increase in temperature for the transition from brittle to ductile fracture accompanied by a reduction in the Charpy upper-shelf impact strength.

10 CFR 50, Appendix G, “Fracture Toughness Requirements,” specifies minimum fracture toughness requirements for the ferritic materials of the pressure-retaining components of the reactor coolant pressure boundary (RCPB) of water-cooled power reactors and provides specific guidelines for determining the pressure-temperature limitations on operation of the RCPB. The toughness and operational requirements are specified to provide adequate safety margins during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the pressure boundary may be subjected over its service lifetime. Although the requirements of 10 CFR 50, Appendix G, became effective on August 13, 1973, the requirements are applicable to all boiling and pressurized water-cooled nuclear power reactors, including those under construction or in operation on the effective date.

10 CFR 50, Appendix H, “Reactor Vessel Materials Surveillance Program Requirements”, defines the material surveillance program required to monitor changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region of water-cooled reactors resulting from exposure to neutron irradiation and the thermal environment. Fracture toughness test data are obtained from material specimens withdrawn periodically from the reactor vessel.

These data will permit determination of the condition under which the vessel can be operated with adequate safety margins against fracture throughout its service life.

A method for guarding against brittle fracture in reactor pressure vessels is described in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G. This method utilizes fracture mechanics concepts and the reference nil-ductility temperature, RT_{NDT}, which is defined in ASME Section III, Paragraph NB 2331. The RT_{NDT} of a given material is used to index that material to a reference stress intensity factor curve (K_{IR} curve), which appears in Appendix G of ASME Section III. The K_{IR} curve is a lower bound of dynamic, static, and crack arrest fracture toughness results obtained from several heats of pressure vessel steel. When a given material is indexed to the K_{IR} curve, allowable stress intensity factors can be obtained for the material as a function of temperature. Allowable operating limits can then be determined using the allowable stress intensity factors.

The RT_{NDT} and, in turn the operating limits of a nuclear power plant, can be adjusted to account for the effects of radiation on the properties of the reactor vessel materials. The radiation embrittlement and the resultant changes in mechanical properties of a given pressure vessel steel can be monitored by a surveillance program in which a surveillance capsule containing prepared specimens of the reactor vessel materials is periodically removed from the operating nuclear reactor and the specimens tested. The increase in the Charpy V-notch 30-ft-lb temperature, is added to the original RT_{NDT} along with a margin value to adjust the RT_{NDT} for radiation embrittlement. This adjusted RT_{NDT} is used to index the material to the K_{IR} curve, which, in turn is used to set operating limits for the nuclear power plant. These new limits take into account the effects of irradiation on the reactor vessel materials.

5.2.3.3.1 Stress Analysis

Original Analysis

A stress evaluation of the reactor vessel was initially performed in accordance with Section III of the ASME Code. The evaluation showed that stress levels are within the Code limits.

Table 5-6 lists the reactor vessel steady-state stresses from the initial stress evaluation at various load points. The results of the initial transient analysis and the determination of the initial fatigue usage factor at the same load points are listed in Table 5-7. Calculation OSC-1815 provides the current stress values and fatigue usage factors for the reactor vessel. As specified in the ASME Code, Section III, Paragraph 415.2(d)(6), the cumulative fatigue usage factor is less than 1.0 for the design cycles listed in Table 5-2. Figure 5-10 illustrates the points of stress analysis for the stresses listed in Table 5-6 and the fatigue usage factors listed in Table 5-7.

The initial stress summaries provided in UFSAR Table 5-6 and Table 5-7 demonstrated that all of the requirements for stress limits and fatigue required by ASME Section III for all of the operational requirements imposed by the design specifications were met (the current stress analysis is presented in calculation OSC-1815). The values tabulated in these summaries were the maximum value obtained in each region. The imposed transients are based on description of the realistic behavior that might be expected for this plant. Transients such as loss of flow and load that cause temperature and pressure variations are included in the reactor vessel specification and Table 5-2. Their effect on accumulated usage factor were included in the initial stress analysis as summarized in Table 5-7. These transients were not the major contributors to the largest usage factor of 0.38 for the stud bolts from the initial fatigue evaluation as given in Table 5-7. The current reactor vessel fatigue evaluation provided in OSC-1815 shows that the largest usage factor for the stud bolts remains less than 1.0."

Replacement Steam Generator Analysis

A load comparison and stress analysis was performed for the reactor vessel nozzles and support skirt. All of the locations are acceptable with the replacement steam generators in service. The comparison showed that stress levels are still within the ASME Code limits. The evaluation of the reactor vessel during the replacement steam generator analysis increases the usage factor of the inlet and outlet nozzles, but does not change the acceptance to Section III of the ASME Code.

Calculation OSC-1815 provides the current stress values and fatigue usage factors for the reactor vessel. As specified in the ASME Code, Section III, Paragraph 415.2(d)(6), the cumulative fatigue usage factor is less than 1.0 for the design cycles listed in Table 5-2.

The imposed transients are based on description of the realistic behavior that might be experienced for this plant. Transients such as loss of flow and load that cause temperature and pressure variations are included in the reactor vessel specification and Table 5-2. Their affect on accumulated usage for the reactor vessel were updated during the replacement steam generator analysis (see the current stress analysis presented in calculation OSC-1815). These transients are the major contributing factor to the largest usage factor of 0.61 for the inlet and outlet nozzles. Calculation OSC-1815 shows that all of the usage factors for the reactor vessel components remain below 1.0 after the replacement steam generator analysis.

5.2.3.3.2 Reference Nil-Ductility Temperature (RT_{NDT})

Throughout the lifetime of a reactor vessel, the impact and tensile properties of the ferritic beltline region materials will change because of neutron irradiation. These changes require periodic adjustment of pressure-temperature relationships for heatup and cooldown during normal, upset, and testing conditions.

To determine the pressure-temperature operating limitations for the RCPB the reference nil-ductility temperature (RT_{NDT}) of the ferritic materials must be established. The RT_{NDT} is needed to calculate the critical stress intensity factor (K_{IR}). In ASME Section III, Appendix G, K_{IR} is related to temperature, T, and to RT_{NDT} by the following equation:

$$K_{IR} = 26.777 + 1.223 \quad \exp[0.0145(T - RT_{NDT} + 160)]\text{ksi}\sqrt{\text{in}}.$$

This relationship is applicable only to ferritic materials that have a specified minimum yield strength of 50,000 psi or less at room temperature.

Since the impact properties of the beltline region materials of a reactor vessel will change throughout its lifetime, periodic adjustments are required on the pressure-temperature limit curves of the RCPB. The magnitude of these adjustments is proportional to the shift in RT_{NDT} caused by neutron fluence. Therefore, it is essential to determine the radiation-induced ΔRT_{NDT} of the beltline region materials.

The RT_{NDT} of the ferritic materials, which were specified and tested in accordance with the fracture toughness requirements of the ASME Section III Summer 1972 Addenda (to 1971 Edition) or subsequent addenda, are determined as required by that Code. When enough material is available, the RT_{NDT} of those beltline region materials, which were specified and tested in accordance with an edition or addenda of ASME Section III prior to the Summer 1972 Addenda, are obtained by testing specimens oriented normal to the principal working direction. The test procedure is in accordance with ASME Section III, paragraph NB 2300 (Summer 1972 Addenda).

The Oconee pressure boundaries were designed and constructed in accordance with the requirements of an edition or addenda of ASME Section III issued before the Summer 1972 Addenda. Except for the beltline region materials for which sufficient test material is available, the RT_{NDT} of the ferritic materials must be estimated. This is necessary because the test data required for the exact determination of RT_{NDT} were not required by the applicable ASME Code.

Generally, drop weight tests were not performed, and the Charpy V-notch tests were limited to “fixed” energy level requirements for specimens oriented in the longitudinal (principal working) direction at a temperature of 40°F or lower.

To obtain an RT_{NDT} estimate that is appropriately conservative, B&W has collected and evaluated the data from tests conducted on pressure-retaining ferritic materials to which the new fracture toughness requirements were applied. Based on these evaluations, techniques were developed to estimate RT_{NDT}. These techniques as well as the results are described in B&W Topical Report BAW-10046P, Reference 4.

10 CFR 50, Appendix G, requires complete characterization of the unirradiated impact properties of all the beltline region materials of the reactor vessel. The complete characterization includes the determination of RT_{NDT} and Charpy (C_v) test curves for the directions normal to and parallel to the principal working direction (other than the thickness direction). Appendix G also requires a minimum C_v USE of 75 ft-lb for all beltline region materials unless it is demonstrated that lower values of upper-shelf fracture energy provide an adequate margin for deterioration from irradiation.

For the beltline region materials of reactor vessels that were specified in accordance with the requirements of an edition or addenda of ASME Section III issued before the Summer 1972 Addenda, the complete C_v test curves, including C_v USE, is determined when the material forms part of the reactor vessel surveillance program. For the beltline region materials that do not form part of the surveillance program, and when enough material is available, the C_v test curve and USE are determined only in the direction normal to the principal working direction. No minimum Charpy V-notch USE are required, other than the 50 ft-lbs/35 mils of lateral expansion for the beltline region materials of these reactor vessels. When the unirradiated USE of these materials is below 75 ft-lb/, the procedures described in BAW-10046P are applied to predict the end-of-service USE.

The C_v USE must be estimated for reactor vessel beltline region materials that were specified in accordance with the requirements of an edition or addenda of ASME Section III issued before the Summer 1972 Addenda and for which insufficient material is available for testing. All available data from tests conducted on reactor vessel beltline region materials were collected and evaluated in order to obtain an appropriately conservative estimate. Not all the data were obtained in accordance with the methods specified in ASME Section III, Appendix G, since in some cases the absorbed energy was obtained only at one temperature. Based on these evaluations, estimates of C_v USE were developed. The techniques and results are described in BAW-10046P.

5.2.3.3.3 Neutron Flux at Reactor Vessel Wall

The design value for the fast neutron flux greater than 1.0 MeV at the inner surface of the reactor vessel is 3.0×10^{10} n/cm^2-sec at a rated power of 2,568 MWt. The most recent corresponding calculated maximum fast neutron flux at the vessel wall is approximately a factor of 3 lower. For 40 years at 80 percent load this corresponds to a fluence of approximately 1×10^{19} n/cm^2 for the vessel wall.

A semiempirical method is used to calculate the surveillance capsule and reactor vessel flux. The method employs explicit modeling of the surveillance capsule, reactor vessel, and internals and uses a time-weighted average pin-by-pin core power distribution in the two-dimensional DOT IV, version 4.3, computer code. DOT IV is a two-dimensional code which is used to calculate the energy- and space-dependent neutron flux at all points of interest in the specific reactor system configuration. DOT IV employs the discrete ordinates method of solution of the Boltzmann transport equation and has multigroup and asymmetric scattering capability.

The calculational model is an R-theta geometric representation of a plan view through the reactor core midplane using one-eighth core symmetry. The model includes the core with a time-averaged radial power distribution core liner, coolant regions, core barrel, thermal shield, pressure vessel, and concrete. The DOT calculation is carried out with an S_8 order of angular quadrature, a P_3 expansion of the scattering matrix, and the CASK23E cross-section set. The P_3 order of scattering indicates a third order LeGendre polynomial scattering approximation which adequately describes the predominately forward scattering of neutrons observed in the deep penetration of steel and water media. This calculation provides the neutron flux as a function of energy at the detector position and, in addition to the flux, the DOT IV code calculates the saturated specific activity of the various neutron dosimeters located in the surveillance capsule using the ENDF/B5 dosimeter reaction cross-sections. The saturated activity of each dosimeter is then adjusted by a factor which corrects for fraction of saturation attained during the dosimeter's actual detailed irradiation history. Additional corrections are normally made to account for the effects of the following:

1. photon-induced fissions in the U and Np dosimeters,
2. short half-life of isotopes produced in Fe and Ni dosimeters, and
3. Pu-239 generated in the U-238 dosimeter.

These calculated activities are used for comparison with the measured dosimeter activity values. The basic equation for the calculated activity $(\mu Ci/g)$ is

$$D_i = \frac{N}{A_n 3.7x10^4} f_i \sum_E \sigma_n(E)\phi(E) \sum_{j=1} F_j(1 - e^{-\lambda_1 t_j})e^{-\lambda_i(T-\tau_j)}$$

where:

N	=	Avagadro's number,
A_n	=	atomic weight of target material n,
f_i	=	either weight fraction of target isotope in nth material or fission yield of desired isotope,
$\sigma_n(E)$	=	group-averaged cross sections for material n
$\phi(E)$	=	group-averaged fluxes calculated by DOT analysis,
F_j	=	fraction of full power during jth time interval t_j ,
λ_i	=	decay constant of ith material,
t_j	=	length of the jth time period,

T	=	sum of total irradiation time, i.e., residual time in reactor and wait time between reactor shutdown and counting,
τ_j	=	Cumulative time from reactor startup to end of jth time period, i.e.,

$$\tau_j = \sum_{k=1}^{j} t_k .$$

The flux normalization factor C_i is then obtained by the following equation:

$$C_i = \frac{D_i\,(\text{measured})}{D_i\,(\text{measured})}$$

With C specified, the neutron fluence greater than 1 MeV can be calculated from

$$\phi t(E > 1.0\text{MeV}) = C \sum_{E=1}^{E=15\text{MeV}} \phi(E) \sum_{j=1}^{j=M} F_j t_j$$

where M is the number of irradiation time intervals; the other values are defined above.

The specific results of these calculations are included in the specific capsule evaluation reports prepared as part of the Reactor Vessel Materials Surveillance Program (FSAR Section 5.2.3.13).

5.2.3.3.4 Radiation Effects

The adjusted reference temperatures are calculated by adding the predicted radiation-induced ΔRT_{NDT}, the unirradiated RT_{NDT}, and a margin value. The predicted ΔRT_{NDT} is calculated using the respective neutron fluence and copper and nickel contents. The design curves of Regulatory Guide 1.99 were used to predict the radiation-induced ΔRT_{NDT} values as a function of the material's copper and phosphorous content and neutron fluence. With the issuance of Rev. 2 of Regulatory Guide 1.99 in May, 1988, ΔRT_{NDT} values are obtained on the basis of copper and nickel contents.

The effects of radiation on the Charpy USE level of the beltline region material is estimated using the curves shown in Regulatory Guide 1.99, Rev. 2, Figure 2.

Several operating plant reactor vessels were manufactured with “high-copper MnMoNi/Linde 80” submerged-arc weld metal. This class of weld metal is susceptible to relatively large changes in impact properties when exposed to fast neutron irradiation. The Charpy V-notch upper-shelf energy (C_vUSE) of some of these welds may drop below the 50 ft-lb threshold required by federal regulatory requirements (10 CFR 50, Appendix G) during the 40-year reactor design life. Should the C_vUSE drop below 50 ft-lb, certain corrective actions would be required that could severely impact plant availability.

One of the major goals of the B&W Owners Group Program has been to determine the period of time each 177-fuel assembly (FA) reactor vessel can operate without violating the 50 ft-lb C_vUSE threshold. The work that has been completed in this program includes reports entitled “Prediction of Charpy Upper Shelf Energy Drop in Irradiated Weld Metals,” “Pressure Vessel Fluence Analysis for 177-FA Reactors”, “Chemistry of B&W 177-FA Owners Group Reactor Vessel Beltline Welds”.

BAW-1803, Rev. 1, Reference 6, describes the implementation of predictive methodology developed in this program to determine the service life to reach the 50 ft-lb C_vUSE threshold for each of the Owners Group reactor vessels. It was also necessary to establish a means of predicting the pre-service C_vUSE of each of the beltline region reactor vessel welds. The available C_vUSE data obtained from B&W manufactured, early vintage welds (high-Cu MnMoNi/Linde 80 submerged-arc) were analyzed collectively for this purpose.

Based on the developed methods, the limiting Oconee reactor welds are predicted to exhibit a C_vUSE of more than 50 ft-lb for >32 EFPY plant operation for the 40-year design life (BAW-2192PA, Reference 30 and BAW-2178PA, Reference 31). Charpy Upper-Shelf Energy Analsysis for 60-year design life are detailed in Section 5.2.3.3.10 and reported in Table 5-27, Table 5-28, and Table 5-29.

5.2.3.3.5 Fracture Mode Evaluation

An analysis has been made to demonstrate that the reactor vessel can accommodate without failure the rapid temperature change associated with the postulated operation of the Emergency Core Cooling System (ECCS) at end of vessel design life. A summary of the evaluation follows:

The state of stress in the reactor vessel during the loss-of-coolant accident was evaluated for an initial vessel temperature of 603°F. The inside of the vessel wall is rapidly subjected to 90°F injection water of the maximum flow rate obtainable. The results of this analysis show that the integrity of the vessel is not violated.

The assumed modes of failure are ductile yielding and brittle fracture, which includes the nil-ductility approach and the fracture mechanics approach. The modes of failure are considered separately in the following paragraphs.

Ductile Yielding

The criterion for this mode of failure is that there shall be no gross yielding across the vessel wall using the minimum specified yield strength in the ASME Code, Section III. The analysis considered the maximum combined thermal and pressure stresses through the vessel wall thickness as a function of time during the safety injection. Comparison of calculated stresses to the material yield stress indicated that local yielding may occur in the inner 8.0 percent of the vessel wall thickness.

Brittle Fracture

Because the reactor vessel wall in the core region is subjected to neutron flux resulting in embrittlement of the steel, this area was analyzed from both a nil-ductility approach and a fracture mechanics approach. The results of the two methods of analysis compare favorably and show that pressure vessel integrity is maintained.

The criterion used in the nil-ductility approach is that a crack cannot propagate beyond any point where the applied stress is below the threshold stress for crack initiation (5-8 ksi), or when the stress is compressive. This approach involves making the very conservative assumption that all of the vessel material could propagate a crack by a low-energy absorption or cleavage mode. End-of-life vessel conditions were assumed. The crack arrest temperature through the thickness of the wall was developed on a stress-temperature coordinate system. The actual quench-induced, stress-temperature condition through the thickness of the wall at several times during the quench was developed and plotted. The maximum depth at which the material in the vessel wall would be in tension or at which the stress in the material would be in excess of the threshold stress for crack initiation (5-8 ksi) was determined by comparison of the plots. The comparison showed that a crack could propagate only through the inner 35 percent of the wall thickness if a crack initiation threshold of 5-8 ksi is applicable.

The foregoing method of analysis is essentially a stress analysis approach which assumes the worst conceivable material properties and a flaw size large enough to initiate a crack. Actually, the outer 83 percent of the vessel wall is at a temperature above the Ductility Transition Temperature (DTT) (NDTT + 60°F) when credit is taken for the neutron shielding, and for the original DTT profile through the wall thickness. The analysis is conservative in that it does not deny that cracks can be initiated, and in that it assumed a crack from 1 to 2 ft long to exist in the vessel wall at the time of the accident. Therefore, it can be concluded that, if a crack were present in the worst location and orientation (such as a circumferentially oriented crack on the inside of the vessel wall), it could not propagate through the vessel wall.

A fracture mechanics analysis was conducted which assumed a continuous surface flaw to exist on the inside surface of the vessel wall. The criterion used for the analysis is that a crack cannot propagate when the stress intensity at the tip of the crack is below the critical crack stress intensity factor (K_{IC}). Topical Report BAW-10018, Reference 7, provides the details of the analysis. This report includes an evaluation considering the Irwin fracture mechanics method and performs a sensitivity analysis of the effect of varying the conservatism of several major parameters on the result.

5.2.3.3.6 Pressurized Thermal Shock

In response to the TMI Action Plan (Item II.K.2.13 “Thermal-Mechanical Report”) the effect of cold high pressure injection water entering the reactor vessel during a small break loss of coolant accident or an overcooling transient was considered. The concern was that the cold injection water could rapidly cool the reactor vessel welds and that the resulting thermal stresses, coupled with the relatively high pressure stress on the vessel, would lead to a loss of vessel integrity. This type of event is a particular concern later in life as the vessel neutron fluence increases and the metal becomes more brittle. Various vendor, utility, and EPRI research performed in response to this action item showed that good mixing of the injection water with the warmer Reactor Coolant System fluid would occur, even under near zero loop flow conditions. In particular, the vent valves in the Oconee plant would provide a source of heated water flowing directly from the vessel upper plenum to the downcomer, thus mitigating the cooling effect of the injection flow. The NRC Staff concluded that there is reasonable assurance that vessel integrity would be maintained during a II.K.2.13 event (Reference 12).

The NRC amended its regulations for light water nuclear power plants, effective July 23, 1985, to establish a screening criterion related to the fracture resistance of PWR vessels during PTS events. Only those plants that exceed the screening criterion are required to perform further analysis using Regulatory Guide 1.154. All Oconee units passed the screening criterion (References 32, 35, and 36) and, therefore, met the regulations regarding the PTS concern. This rule was further amended on June 14, 1989, to make the definition of RT_{PTS} equal to RT_{NDT} in Regulatory Guide 1.99, Rev. 2. Assessment in accordance with the amended rule is complete (BAW-2143, Reference 23). All Oconee units satisfy this revised screening criterion.

Section 50.61(b)(1) provides rules for protection against pressurized thermal shock events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of reference temperature whenever there is a significant change in projected values of RT_{PTS}, or upon request for a change in the expiration date for the operation of the facility. For license renewal, RT_{PTS} values are calculated for 48 EFPY for Oconee Units 1, 2, and 3.

Section 50.61(c) provides two methods for determining RT_{PTS}: (Position 1) for material that does not have credible surveillance data available, and (Position 2) for material that does have credible surveillance data. Availability of surveillance data is not the only measure of whether Position 2[1] may be used; the data must also meet tests of sufficiency and credibility.

RT_{PTS} is the sum of the initial reference temperature (IRT_{NDT}), the shift in reference temperature caused by neutron irradiation (ΔRT_{NDT}), and a margin term (M) to account for uncertainties.

IRT_{NDT} is determined using the method of Section III of the ASME Boiler & Pressure Vessel Code. That is, IRT_{NDT} is the greater of the drop weight nil-ductility transition temperature or the temperature that is 60°F below that at which the material exhibits Charpy test values of 50 ft-lbs and 35 mils lateral expansion. For a material for which test data is unavailable, generic values may be used if there are sufficient test results for that class of material. For Linde 80 weld material with the exception of WF-70, the IRT_{NDT} is taken to be the currently NRC accepted values of -7°F or -5°F. For WF-70, the IRT_{NDT} is similarly taken to be a measured value, -26.5°F, in accordance with the discussion and results presented in BAW-2202[2] [Reference 42]. For forgings and plate material, measured values are used where appropriate data is available. Where not available, the generic value of +3°F is used for forgings and +1°F is used for plate material [Reference 43].

For Position 1 material (surveillance data not available), **ΔRT_{NDT}** is defined as the product of the chemistry factor (**CF**) and the fluence factor (**ff**). **CF** is a function of the material's copper and nickel content expressed as weight percent. "Best estimate" copper and nickel contents are used which is the mean of measured values for the material. For Oconee, best estimate values were obtained from the following FTI reports: BAW-1820, BAW-2121P, BAW-2166, and BAW-2222[3] [References 44, 45, 46, and 47]. The value of **CF** is directly obtained from tables in Section 50.61. **ff** is a calculated value[4] using end-of-license (EOL) peak fluence at the inner surface at the material's location. Fluence values were obtained by extrapolation to 48 EFPY of the current 32 EFPY values for each Oconee unit.

For beltline welds and plate materials for which surveillance data is available, evaluations were performed in accordance with Regulatory Guide 1.99, Revision 2, Position 2. The applicable chemistry factors, margin, and RT_{PTS} at 48 EFPY are summarized in Table 5-24, Table 5-25, and Table 5-26.

For Position 2 material (surveillance data available), the discussion above for Position 1 applies except for determination of **CF**, which in this instance is a material-specific value calculated as follows:

1. Multiply each ΔRT_{NDT} value by its corresponding **ff**.
2. Sum these products.

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[1] The term "Position" is taken from Regulatory Guide 1.99, the methodology of which was incorporated into 10 CFR 50.61.

[2] BAW-2202 is an FTI topical report submitted to the NRC for their acceptance on September 29, 1993. The NRC's acceptance for use at the Zion plants was published in the Federal Register, Vol. 59, No. 40 Page 9782 – 9785, March 1, 1994.

[3] BAW-1820 and BAW-2121P were provided to the NRC for their information. BAW-2166 and BAW-2222 were provided to the NRC as part of the Generic Letter 92-01 program.

[4] $ff = f^{(0.28-0.1*\log f)}$, where $f = fluence*10^{-19}$ (n/cm^2, E>1MeV).

3. Divide this sum by the sum of the squares of the **ff**s.

The margin term (M) is generally determined as follows:

$$M = 2(\sigma_I^{\ 2} + \sigma_\Delta^{\ 2})^{0.5}$$

where σ_I is the standard deviation for IRT_{NDT}

and σ_Δ is the standard deviation for ΔRT_{NDT}.

For Position 1, $\sigma_I = 0$ if measured values are used. If generic values are used, σ_I is the standard deviation of the set of values used to obtain the mean value. For ΔRT_{NDT}, σ_Δ = 28°F for welds and 17°F for base metal (plate and forgings), except that σ_Δ need not exceed one-half of the mean value of ΔRT_{NDT}. For Position 2, the same method for determining the σ values are used except that the σ_Δ values are halved (14°F for welds and 8.5°F for base metal).

Section 50.61(b)(2) establishes screening criteria for RT_{PTS} 270°F for plates, forgings, and axial welds and 300°F for circumferential welds. The values for RT_{PTS} at 48 EFPY are provided in Table 5-24, Table 5-25, and Table 5-26 for Units 1, 2, and 3, respectively. The RT_{PTS} values reported herein are based on updated 48 EFPY fluence projections using the evaluation based methodology described in BAW-2251 [Reference 48, Appendix D] and BAW-2241P [Reference 49]. The chemistry and surveillance data for the beltline materials are reported in BAW-2325 [Reference 50].

The projected RT_{PTS} values for Units 1, 2 and 3 are within the established screening criteria for 48 EFPY. For Unit 1, the limiting weld is SA-1073 with a projected value of RT_{PTS} at 48 EFPY of 230.3°F (screening limit of 270°F). For Unit 2, the limiting weld is WF-25, with a projected value of RT_{PTS} at 48 EFPY of 296.8°F (screening limit of 300°F). For Unit 3, the limiting weld is WF-67 with a projected value of RT_{PTS} at 48 EFPY of 253.5°F (screening limit of 300°F). [Reference 51]

Reference for this section: Final SER [Reference 39].

5.2.3.3.7 Closure (Reactor Vessel)

The reactor closure head flange is bolted to the reactor vessel flange as shown in Figure 5-14. Two hollow metallic O-rings seal the reactor vessel when the reactor closure head is bolted in place. A line taps into the annulus between the two O-rings to afford a means to test the vessel closure seal after refueling and to monitor for leakage during operation.

After refueling, the vessel closure is tested to verify that it is properly sealed by pressurizing the annulus between the O-rings with demineralized water and monitoring for pressure decay, which indicates leakage. The line that taps into the annulus between the O-rings is configured to serve as both the demineralized water test line and as the drain line.

During steady-state operation and virtually all transient operating conditions, reactor closure head leakage past the metallic O-rings will be negligible. Only in the event of a rapid transient operation, such as an emergency cooldown, would there be some leakage past the inner-most O-ring seal. A stress analysis on a similar vessel design indicates this leak rate would be approximately 10 cc/min and no leakage would occur past the outer O-ring seal. Leakage past the inner O-ring is monitored by detecting flow through the line that taps into the annulus between the O-rings (or leak-off line). A temperature sensor on the leak-off line is provided with control room indication to monitor for a temperature increase, which indicates leakage flowing through the leak-off line.

The reactor closure head flange is attached to the reactor vessel flange with sixty 6-1/2 in. diameter studs. To insure uniform loading of the closure seal, the studs are hydraulically tensioned. The studs have a minimum yield strength of 130,000 psi. The studs, when tightened for operating conditions, will have a tensile stress of approximately 30,000 psi. An evaluation of stud failures shows that:

1. 10 adjacent studs can fail before leak occurs.
2. 25 adjacent studs can fail before the remaining studs reach yield strength.
3. 26 adjacent studs can fail before the remaining studs reach the ultimate tensile strength.
4. 43 symmetrically located studs can fail before the remaining studs reach yield strength.

The fatigue evaluation results of the studs is included in Table 5-7.

5.2.3.3.8 Control Rod Drive Service Structure

The control rod drive service structure is designed to support the control rod drives to assure no loss of function in the event of a combined loss of coolant accident and maximum hypothetical earthquake. Requirements for rigidity, imposed on the structure to avoid adversely affecting the natural frequency of vibration of the vessel and internals, as well as space requirements for service routing, result in stress levels considerably lower than design limits. The structure is more than adequate to perform its required function.

5.2.3.3.9 Control Rod Drive Mechanism

Appendix G to 10 CFR 50 requires that the adequacy of the fracture toughness properties of ferritic materials such as type 403 modified stainless steel be demonstrated to the Commission on a case-by-case basis. The type 403 modified steel is used as an RCPB material in the motor tube of the control rod drive mechanism. This section demonstrates that, for this application, the material has adequate fracture toughness for protection against non-ductile failure.

The nominal wall thickness of the motor tube section of interest is more than 1/2 inch and less than 5/8 inch. In the early editions of ASME Section III up to the Winter 1971 Addenda to the 1971 Edition, materials with a nominal section thickness of 1/2 inch or less did not require impact testing. Starting with the Summer 1972 Addenda, the nominal section thickness increased to 5/8 inch or less. Thus, in the early editions of ASME Section III, the Type 403 modified steel required impact testing, but in the new editions it does not. However, since this material was selected for use, B&W has ordered it to meet the impact toughness requirements for ASME Section III, Summer 1972 and later Addenda, the imposed acceptance standard for nominal wall thicknesses from 5/8 to 3/4 inch, inclusive is presented in paragraph NB-2332. The material has also been specified to meet the requirements of SA 182 grade F6 (forgings) or ASTM A276 (bars) as modified by ASME Code Case 1337.

When ordered according to the early revisions of Code Case 1337 (including Revision 6) and to the early editions of ASME Section III, the type 403 modified forgings or bars were required to be impact-tested at 20°F. The minimum average energy of a set of three Charpy V-notch specimens was 35 ft-lb, with one specimen allowed to be less than 35 but not less than 30 ft-lb. For both forgings and bars, the Charpy specimens were oriented in the axial (longitudinal) direction.

In the Summer 1972 Addenda to the 1971 Edition of ASME Section III, the fracture toughness requirements of all pressure boundary ferritic materials changed; however, no acceptance criterion was given for the martensitic high-alloy chromium steels, such as type 403 modified steel. A year later, the Summer 1973 Addenda re-established the acceptance criteria for the type 4XX steels. Beginning with this addenda, the fracture toughness requirements and acceptance criteria for the type 4XX steels are described in paragraph NB-2332 of ASME Section III. This paragraph requires that three Charpy V-notch specimens be tested at temperatures lower than or equal to the lowest service temperature. The lateral expansion of each specimen must be equal to or greater than 20 mils. The test temperature has been specified as equal to or less than 40°F. The orientations of the specimens are transverse (normal to principal working direction) for the forgings and axial for the steel bars.

The fracture toughness requirements of Code Case 1337, starting with Revision 7, are the same as those of ASME Section III, Summer 1973 Addenda to the 1971 Edition.

It is considered that the fracture toughness requirements of the new edition of ASME Section III provide adequate protection against nonductile failure. The proof of adequate toughness is based on demonstrating that the type 403 modified steels used in the construction of components designed to an edition or addenda of ASME Section III prior to the Summer 1973 Addenda meet or exceed the toughness requirements of that addenda.

Based on actual test data, the lowest service temperature of the control rod drive mechanism can be as low as 40°F; however, for additional protection against non-ductile failure, B&W has defined the component's lowest service temperature at 100°F. This specified lowest service temperature is 60°F above the temperature at which the fracture toughness requirements are specified and met. The additional 60°F provides margins of safety beyond that required by the ASME code and by Appendix G to 10 CFR 50.

5.2.3.3.10 Charpy Upper-Shelf Energy

Appendix G of 10 CFR 50 requires that reactor vessel beltline materials "have Charpy upper-shelf energy ... of no less than 75 ft-lb initially and must maintain Charpy upper-shelf energy throughout the life of the vessel of no less than 50 ft-lb ... ." The B&WOG positions on upper shelf energy for 32 EFPY are documented in the responses to Generic Letter 92-01, as reported in BAW-2166 and BAW-2222 and, the low upper shelf toughness analyses documented in BAW-2275 [Reference 52], which is included in BAW-2251 as Appendix B.

Regulatory Guide 1.99, Revision 2 provides two methods for determining Charpy upper-shelf energy (C_VUSE): Position 1 for material that does not have credible surveillance data available and Position 2 for material that does have credible surveillance data. For Position 1, the percent drop in C_VUSE, for a stated copper content and neutron fluence, is determined by reference to Figure 2 of Regulatory Guide 1.99, Revision 2. This percentage drop is applied to the initial C_VUSE to obtain the adjusted C_VUSE. For Position 2, the percent drop in C_VUSE is determined by plotting the available data on Figure 2 and fitting the data with a line drawn parallel to the existing lines that upper bounds all the plotted points.

The 48 EFPY C_VUSE values were determined for the reactor vessel beltline materials for each Oconee Unit and are reported in Table 5-27, Table 5-28, and Table 5-29. The T/4 fluence values reported in these tables were calculated in accordance with the ratio of inner surface to T/4 values (i.e. neutron fluence lead factors at T/4) determined in the latest Reactor Vessel Surveillance Program report. As shown in these tables, the C_VUSE is maintained above 50 ft-lb for base metal (plates and forgings), however, for Oconee the C_VUSE for weld metal drops below the required 50 ft-lb level at 48 EFPY. Appendix G of 10 CFR 50 provides for this by allowing operation with lower values of C_VUSE if "it is demonstrated ... that the lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code."

This equivalent margin analysis was performed for 48 EFPY and is reported in BAW-2275 for service levels A, B, C, and D. The analysis used very conservative material models and load combinations, i. e., treating thermal gradient stress as a primary stress. For service levels A and B, the analytical results demonstrate that there is sufficient margin beyond that required by the acceptance criteria of Appendix K of the ASME Code (1995 Edition). For service levels C and D, the most limiting transient was evaluated, and again the analytical results demonstrate that there is sufficient margin beyond that required by the acceptance criteria of Appendix K of the ASME Code. The evaluations for all service levels conclusively demonstrate the adequacy of margin of safety against fracture for the reactor vessels within the scope of this report for 48 EFPY. NRC approval of the analysis in BAW-2275 is included in NUREG-1723 (Reference 39).

5.2.3.3.11 Intergranular Separation in HAZ of Low Alloy Steel under Austenitic SS Weld Cladding

Intergranular separations in low alloy steel heat-affected zones under austenitic stainless steel weld claddings were detected in SA-508, Class 2 reactor vessel forgings manufactured to a coarse grain practice, and clad by high-heat-input submerged arc processes. BAW-10013 contains a fracture mechanics analysis that demonstrates the critical crack size required to initiate fast fracture is several orders of magnitude greater than the assumed maximum flaw size plus predicted flaw growth due to design fatigue cycles. The flaw growth analysis was performed for a 40-year cyclic loading, and an end-of-life assessment of radiation embrittlement (i.e., fluence at 32 EFPY) was used to determine fracture toughness properties. The report concluded that the intergranular separations found in B&W vessels would not lead to vessel failure. This conclusion was accepted by the Atomic Energy Commission[5]. To cover the period of extended operation, an analysis was performed using current ASME Code requirements; this analysis is fully described in BAW-2274 [Reference 53] which is contained in BAW-2251 as Appendix C.

In May 1973, the Atomic Energy Commission issued Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components," [Reference 54]. The guide states that underclad cracking "has been reported only in forgings and plate material of SA-508 Class 2 composition made to coarse grain practice when clad using high-deposition-rate welding processes identified as 'high-heat-input' processes such as the submerged-arc wide-strip and the submerged-arc 6-wire processes. Cracking was not observed in clad SA-508 Class 2 materials clad by 'low-heat-input' processes controlled to minimize heating of the base metal. Further, cracking was not observed in clad SA-533 Grade B Class 1 plate material, which is produced to fine grain practice. Characteristically, the cracking occurs only in the grain-coarsened region of the base-metal heat-affected zone at the weld bead overlap." The guide also notes that the maximum observed dimensions of these subsurface cracks is 0.165-inch deep by 0.5-inch long.

The BAW-10013 fracture mechanics analysis is a flaw evaluation performed before the ASME Code requirements for flaw evaluation, the K_{Ia} curve for ferritic steels as indexed against RT_{NDT}, and the ASME Code fatigue crack growth curves for carbon and low alloy ferritic steels were available. The revised analysis uses current fracture toughness information, applied stress intensity factor solutions, and fatigue crack growth correlations for SA-508 Class 2 material. The objective of the analysis is to determine the acceptability of the postulated flaws for 48 EFPY using ASME Code, Section XI, (1995 Edition), IWB-3612 acceptance criteria.

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[5] R. C. DeYoung (USAEC) to J. F. Mallay (B&W), letter transmitting topical report evaluation, October 11, 1972.

The revised analysis was applied to three relevant regions of the reactor vessel: the beltline, the nozzle belt, and the closure head/head flange. The analysis conservatively considered 360 cycles of 100°F/hr normal heatup and cooldown transients. For the power maneuvering transients, the range in applied stress intensity factors for the closure head region were assumed to be the same as that determined for the beltline region. This assumption is considered conservative since the closure head region is subject to a low flow condition while the beltline region is subject to a forced flow condition.

An initial flaw size of 0.353-inch deep by 2.12-inch long (6:1 aspect ratio) was conservatively assumed for each of the three regions. The flaw was further assumed to be an axially oriented, semi-elliptical surface flaw in contrast to the observed flaws which are subsurface with a maximum size of 0.165-inch deep by 0.5-inch long.

The maximum crack growth and applied stress intensity factor for the normal and upset conditions were found to occur in the nozzle belt region. The maximum crack growth, considering all the normal and upset condition transients for 48 EFPY, was determined to be 0.180-inch, which results in a final flaw depth of 0.533-inch. The maximum applied stress intensity factor for the normal and upset condition results in a fracture toughness margin of 3.6 which is greater than the IWB-3612 acceptance criterion of 3.16.

The maximum applied stress intensity factor for the emergency and faulted conditions occurs in the closure head to head flange region and the fracture toughness margin was determined to be 2.24, which is greater than the IWB-3612 acceptance criterion of 1.41. It is therefore concluded that the postulated intergranular separations in the Oconee Unit 1, 2, and 3 reactor vessel 508 Class 2 forgings are acceptable for continued safe operation through the period of extended operation.

5.2.3.4 Steam Generators

Deleted paragraph(s) per 2004 update

Design of Replacement Steam Generators

The replacement steam generators (ROTSGs) for Oconee were manufactured by Babcock and Wilcox Canada. They incorporate the basic Once Through Steam Generator (OTSG) features of the original Oconee steam generators with a number of changes made to improve operation, maintenance, reliability and accident response. The basic operating characteristics in terms of heat transfer, transient response, primary volume, primary pressure loss, secondary inventory, and emergency feedwater performance were not changed significantly from the OTSG. The ROTSGs have the following design features that are considered the major improvements to the OTSG design.

1. Thermally treated Alloy 690 tubes
2. Stainless Steel (410S) broached plate tube supports
3. Elimination of the tube free lane
4. Addition of steam nozzle flow restrictors
5. All welded, erosion-corrosion resistant main and auxiliary feedwater headers
6. Conical support stool to improve access for inspection and ISI

For the replacement steam generators, stress analysis has been completed as documented in detail in the Base Design Condition Report (BWC-006K-SR-01), the Transient Analysis Stress Report (BWC-006K-SR-02) and the "ASME Design Report" (BWC-006K-SR-08). The results, as compared to data for the original steam generator research and development reported above, are as follows:

During normal heat-up operation of the steam generator, the tube mean temperature should not be more than 80°F higher than the shell mean temperature. The maximum calculated mean tube to shell ΔT at normal operating conditions poses no problems to the structural integrity of the reactor coolant boundary. The effect of loss of reactor coolant would impose tensile stresses on the tubes and cause slight yielding across the tubes. Such a condition would introduce a small permanent deformation in the tubes but would in no way violate the boundary integrity. The rupture of a main steam line would result in an overcooling transient in which the steam generator tubes cool down faster than the steam generator shell. The tubes are then subjected to a tensile load that may cause tube deformation. An analysis of the MSLB accident is performed to determine the input for the steam generator tube stress analysis. The MSLB accident is analyzed with the RETRAN-3D code (Reference 55). A spectrum of break sizes is analyzed from a full power initial condition. The limiting break size is a double-ended guillotine rupture since it maximizes the cooldown rate and the resulting stresses on the steam generator tubes. Main feedwater is isolated to the affected steam generator on low steam line pressure by the Automatic Feedwater Isolation System (AFIS) instrumentation. This circuit also inhibits the auto-start of or auto-stops the turbine-driven emergency feedwater (EFW) pump. The motor-driven EFW pump to the affected steam generator is tripped by the AFIS circuitry when the rate of depressurization setpoint is exceeded coincident with low steam line pressure. For smaller break sizes that do not exceed the rate of depressurization setpoint, operator action is credited at 10 minutes to isolate motor-driven EFW flow to the affected steam generator. The results of the RETRAN analysis, including the primary and secondary system pressures and the tube-to-shell temperature difference were used as input for the steam generator structural analysis. This analysis determined a tube axial load of 2240 lbf for the MSLB. The applicable tube stress acceptance criteria are based on the ASME Code and industry practice. Specifically, the steam generator tubes shall retain a margin of safety against burst of gross failure of three times normal operating differential pressure, or 1.43 times the limiting accident differential pressure. In addition, ASME Section III has established a limit of the lesser of 2.4 x Sm, or 0.7 x Su for design loads. The steam generator tubes have been evaluated for loads greater than the 2240 lbf MSLB accident load and have been shown to meet these acceptance criteria. The tube stresses have also been evaluated for an MSLB without AFIS actuation, but with operator action within 10 minutes to isolate feedwater to the affected steam generator, and found to be acceptable. The tube stresses for a LBLOCA bound those for MSLB.

For the Units without the revised tornado mitigation strategy as described in UFSAR Section 3.2.2 implemented: Feedwater line breaks, the tornado event, and other overheating events impose compressive loads on the steam generator tubes as the RCS heats up and/or the steam generator shell cools down. The tornado protection analysis credits a maximum compressive tube-to-shell ΔT of +105 °F while the feedwater line break analysis crediting HPI forced cooling results in a lower compressive tube-to-shell ΔT. Analyses have demonstrated that steam generator tube integrity is maintained for these loads for the replacement steam generators.

For the Units with the revised tornado mitigation strategy as described in UFSAR Section 3.2.2 implemented: Feedwater line breaks and other overheating events impose compressive loads on the steam generator tubes as the RCS heats up and/or the steam generator shell cools down. Analyses have demonstrated that steam generator tube integrity is maintained for these loads for the replacement steam generators.

Calculations confirm that the steam generator tube sheet will withstand the loading resulting from a loss-of-coolant accident. The basis for this analysis is a hypothetical rupture of a reactor coolant pipe resulting in a maximum design pressure differential from the secondary side of

1050 psi. Under these conditions there is no rupture of the primary to secondary boundary (tubes and tube sheet).

The maximum primary membrane plus primary bending stress in the tube sheet under these conditions is 15,600 psi across the center ligaments which is well below the ASME Section III allowable limit of 45,000 psi at 650°F. Under the condition postulated, the stresses in the primary head show only the effect of its role as a structural restraint on the tube sheet. The stress intensity at the juncture of the spherical head with the tube sheet is 16,100 psi which is well below the allowable stress limit. It can therefore be concluded that no damage will occur to the tube sheet or the primary head as a result of this postulated accident.

In regard to tube integrity under loss of reactor coolant, the analytical procedure per ASME Code NM-3133.3 is completed to show that for the 5/8 in. o.d./0.034 inch wall Alloy 690 tubing, the allowable Design condition external pressure is 1022 psig. The hypothetical rupture pressure differential of 1050 psi is therefore acceptable considering higher allowable for ASME Level D faulted condition.

The rupture of a secondary pipe has been assumed to impose a maximum design pressure differential of 2,500 psi across the tubes and tube sheet from the primary side. The criterion for this accident permits no violation of the reactor coolant boundary (primary head, tube sheet, and tubes).

To meet this criterion, the stress limits delineated in the ASME Pressure Vessel Code, Section III for Design condition. An examination of stresses under these condition show that for the case of a 2,500 psi design pressure differential, the stresses in the tube, primary head and tube sheet are within acceptable limits. These stresses together with the corresponding stress limits are given in Table 5-8.

The ratio of allowable stresses (based on the ASME Code Design condition allowable membrane stress of Sm and allowable membrane plus bending stress 1.5 Sm) to the computed stresses for a design pressure differential of 2,500 psi are summarized in Table 5-9.

5.2.3.5 Reliance on Interconnected Systems

The principal heat removal system interconnected with the Reactor Coolant System is the Steam and Power Conversion System. This system provides capability to remove reactor decay heat for the hypothetical case where all station power is lost. Under these conditions decay heat removal from the reactor core is provided by the natural circulation characteristics of the Reactor Coolant System. The turbine driven emergency feedwater pump supplies feedwater to the steam generators. Cooling water flow to the condenser is provided by the emergency discharge line which discharges to the tailrace of the Keowee Dam. Should the condenser not be available to receive the steam generated by decay heat, which is unlikely in view of emergency discharge line flow, the water stored in the feedwater system can be pumped to the steam generators and the resultant steam vented to atmosphere to provide required cooling. The analysis of the plant component functions credited for coping with the unlikely condition of total loss of station power is presented in Section 8.3.2.2.4.

5.2.3.6 System Integrity

The Reactor Protective System (Chapter 7) monitors parameters related to safe operation and trips the reactor to protect against Reactor Coolant System damage caused by high system pressure. The pressurizer code safety valves prevent Reactor Coolant System overpressure after a reactor trip as a result of reactor decay heat and/or any power mismatch between the Reactor Coolant System and the Secondary System.

As a pump-motor shaft is designed to have a natural frequency at least 20 percent above the critical speed, the shaft is too stiff to respond to any of the lower seismic frequencies. The pump and motor bearings are designed to be capable of meeting the seismic design criteria.

The design specification for the control rod drives requires that the drives be capable of withstanding the seismic loadings within the stress limits for Class I equipment.

The purchase specifications for the Emergency Core Cooling System (ECCS) pumps and valves require that the units be capable of operating under the seismic loads predicted to exist at the building elevations where the units will be located. The equipment supplier has certified that the units, based on tests which exceeded the specification requirements on similar units, do adequately meet the purchase specification requirements for operation under seismic loads. The instrumentation transmitters are tested to demonstrate their suitability for the specified seismic conditions.

The center of gravity for this type of equipment is low and both the pump and the driver are rigidly connected to a structural baseplate which in turn is bolted to the building. This type of equipment is structurally quite rigid and in most instances will accommodate very high “g” loadings.

5.2.3.7 Overpressure Protection

The Reactor Coolant System is protected against overpressure by the pressurizer code safety valves mounted on top of the pressurizer. The capacity of these valves is determined from considerations of: (1) the Reactor Protective System; (2) pressure drop (static and dynamic) between the points of highest pressure in the Reactor Coolant System and the pressurizer; and (3) accident or transient overpressure conditions.

The combined capacity of the pressurizer code safety valves is based on the hypothetical case of withdrawal of a regulating control rod assembly bank from a relatively low initial power. The accident is terminated by high pressure reactor trip with resulting turbine trip. This accident condition produces a power mismatch between the Reactor Coolant System and Secondary System larger than that caused by a turbine trip without immediate reactor trip, or by a partial load rejection from full load.

The Low Temperature Overpressure Protection (LTOP) System protects the reactor vessel from excessive pressures at low temperature conditions. As a result of Generic Letter 88-11 and a review of operating practices at Oconee, the supporting analyses for the LTOP System have been revised.

The following low temperature overpressure events have been evaluated:

1. Erroneous actuation of the High Pressure Injection System.
2. Erroneous opening of the core flood tank discharge valve.
3. Erroneous addition of nitrogen to the pressurizer.
4. Makeup control valve (makeup to the RCS) fails full open.
5. All pressurizer heaters erroneously energized.
6. Temporary loss of the Decay Heat Removal System's capability to remove decay heat from the RCS.
7. Thermal expansion of the RCS after starting a reactor coolant pump, as a result of the stored energy in the steam generators.

The reactor vessel is protected from damage during these events by the LTOP System. The LTOP System consists of two diverse trains. One train consists of the pressurizer power operated relief valve (PORV) with a lift setpoint based on the low temperature pressure limits. The pressure limits for low temperature operation are 100% of the steady-state Appendix G curve. The second train consists of operator action, assisted by administrative controls, alarms, and an operating philosophy that maintains a steam or gas bubble in the pressurizer during all modes of operation (except for inservice hydrostatic testing).

The pressurizer PORV has a dual setpoint. During normal operation, the lift setpoint is 2450 psig. A lower PORV lift setpoint is used during startup and shutdown conditions. The lower setpoint is enabled by actuation of a switch in the control room whenever the RCS temperature is below 325°F. In order to prevent the LTOP pressure limits from being exceeded, a low pressure setpoint is specified within Technical Specifications.

The second LTOP train relies on operator action to mitigate a low temperature overpressure event. In order to assure that adequate time is available for operator action, administrative controls exist for:

1. RCS pressure;
2. Pressurizer level;
3. Nitrogen addition system;
4. Number of operating reactor coolant pumps;
5. Deactivation of the A and B injection trains of the HPI System;
6. Deactivation of both core flood tanks.
7. A dedicated operator provided with approved procedures monitors RCS pressure and pressurizer level during operations at RCS temperatures below 325°F. The sole duty of the operator is to detect and mitigate LTOP transients before the RCS pressure exceeds the low temperature pressure limits.
8. In addition, alarms are provided to alert the operator that an overpressure event is occurring. The LTOP analysis credits either a RCS pressure or pressurizer level alarm to alert the operator. These alarms ensure that a time is available for the operator to mitigate an overpressure event prior to exceeding the low temperature pressure limits.
9. Deactivation of one bank of pressurizer heaters

The low temperature overpressure scenarios have been analyzed using conservative assumptions (Reference 37). Assuming a single failure of either of the two diverse methods of overpressure protection, the analyses demonstrate that the reactor vessel is protected from damage during events which cause increasing pressure.

The two trains (active and passive) of the LTOP System taken together are single failure proof. The individual trains are not single failure proof.

LTOP System seismic, loss of air, loss of offsite power, and IEEE-279 design requirements are as follows:

1. The active (PORV) and passive (Operator action) LTOP mitigation trains do not have to be seismically designed,
2. A loss of instrumentation air event does not affect the LTOP mitigation trains' ability to mitigate an LTOP event,

3. A loss of offsite power event does not affect the LTOP mitigation trains' ability to mitigate an LTOP event,
4. The LTOP System does not meet IEEE-279 design requirements,

   Because:

1. A pressurizer nitrogen or steam bubble is maintained in the RCS at all times (except for hydrostatic testing).
2. It can be shown that a seismic event, a loss of air event, and a loss of offsite power do not cause an LTOP event.
3. Sufficient administrative controls are in place, per Technical Specifications, to further minimize the probability of an LTOP event.

The above criteria are based on the premise that neither a seismic event nor loss of instrumentation air event nor a loss of offsite power event randomly occur at the same time as an LTOP event at Oconee Nuclear Station.

5.2.3.8 System Incident Potential

Potential accidents and their effects and consequences as a result of component or control failures are analyzed and discussed in Chapter 15.

The pressurizer spray line contains an electric motor-operated backup valve which can be closed should the pressurizer spray valve malfunction and fail to close; this would prevent depressurization of the system to the saturation pressure of the reactor coolant. An electric motor-operated valve located between the pressurizer and the pressurizer electromatic relief valve can be closed to prevent pressurizer steam blowdown in the unlikely event the electromatic relief valve fails to reclose after being actuated. Because of the other protective features in the plant, it is unlikely that the code valves will ever lift during operation. In addition, it is extremely unlikely these valves would stick open, since there is adequate experience to indicate the reliability of code safety valves. The analyses in Chapter 15 bound an opening in the system equal to one pressurizer code safety valve in the open position.

The consequences of crud filling one of the two instrument lines from the flow annulus to the flow transmitters has been evaluated.

No mechanism can be postulated which would completely block one of these lines. The Reactor Coolant System is a very clean system and is continuously filtered to assure that no significant particulate matter is circulated. The boric acid in the coolant is in concentrations about a factor of two below its solubility limit at 70°F and no precipitation would occur. The entire flow monitoring system is essentially stagnant because it is a pressure-sensitive device. There is no flow in the sensing lines to induce material into these lines. Any matter of sufficient size to block the instrument lines would have to penetrate the annulus which is of a smaller size than the instrument lines. Blockage of less than four entry ports to the annulus does not significantly impare the flow reading.

If the assumption is made that the line did become blocked, however, two possible situations would arise. The blockage of the high-pressure line would cause the average flow to appear high as flow decreases. Similarly, if the low pressure line is blocked, the average flow will appear higher than normal as flow is decreased. In both cases, the loss of one pump will not cause trip based on flux-flow if the power is constant at rated power. The results of a single pump coastdown from rated power was analyzed without trip or power runback. The minimum

Departure from Nucleate Boiling Ratio (DNBR) reached when the flow has settled to the three-pump steady state values is 1.34.

If power runback from the Integrated Control System (ICS) is assumed, the reactivity added by control rod insertion is sufficient to reduce the power to 89 percent by the time the flow has reached its new value. Therefore, the hypothetical blocking of the instrument line would not cause the core thermal design limit to be exceeded as a result of the loss of one pump from rated power. These analyses of crud filling one of the two instrument lines from the flow annulus to the flow transmitters are not reflective of the current methods described in Section 15.6. These analyses are being retained for historical purposes only.

5.2.3.9 Redundancy

Each heat transport loop of the Reactor Coolant System contains one steam generator and two reactor coolant pumps. Operation at reduced reactor power is possible with one or more pumps out of service. For added reliability, power to each pump is normally supplied by one of two electrically separated buses. Each of the two pumps per loop is fed from separate buses.

Two core flooding nozzles are located on opposite sides of the reactor vessel to ensure core reflooding water in the event of a single nozzle failure. Reflooding water is available from either the core flooding tanks or the low pressure injection pumps. The high pressure injection lines are connected to the Reactor Coolant System on each of the four reactor coolant inlet pipes.

5.2.3.10 Safety Limits and Conditions

5.2.3.10.1 Maximum Pressure

The Reactor Coolant System serves as a barrier which prevents release of radionuclides contained in the reactor coolant to the Reactor Building atmosphere. In the event of a fuel cladding failure, the Reactor Coolant System is the primary barrier against the release of fission products to the Reactor Building. The safety limit of 2,750 psig (110 percent of design pressure) has been established. This represents the maximum transient pressure allowable in the Reactor Coolant System under the ASME Code, Section III.

5.2.3.10.2 Maximum Reactor Coolant Activity

Release of activity into the reactor coolant in itself does not constitute a hazard. Activity in the reactor coolant constitutes a hazard only if the amount of activity is excessive and it is released to the environment. The plant systems are designed for operation with activity in the Reactor Coolant Systems resulting from 1 percent defective fuel. Activity would be released to the environment if the reactor coolant containing gaseous activity were to leak to the steam side of the steam generator. Gaseous activity could then be released to the environment by the steam jet air ejector on the main condenser. In 10 CFR 20, maximum effluent concentrations (EC) for continuous exposure to gaseous activity have been established. These ECs will be used as the basis for maximum release of activity to the environment which has unrestricted access.

5.2.3.10.3 Leakage

Reactor Coolant System leakage rate is determined by comparing instrument indications of reactor coolant average temperature, pressurizer water level and letdown storage tank water level over a time interval. All of these indications are recorded. The letdown storage tank capacity is 31 gallons per inch of height, and each graduation on the level recorded represents two inches of tank height.

Reactor Coolant System leak detection is also provided by monitoring the Reactor Building normal sump level and the letdown storage tank level. The Reactor Building normal sump capacity is 15 gallons per inch of height, excluding embedded piping. Since the pressurizer level controller maintains a constant pressurizer level, any Reactor Coolant System volume change due to a leakage would manifest itself as a Reactor Building normal sump level change and/or a corresponding letdown storage tank level change. Alarm indication in the control room for the Reactor Building normal sump is provided at a low level of 1 inch of water and a high level of 8 inches of water. For the Letdown Storage Tank, alarm (statalarm) indication is provided at a low level of 60 inches of water and a high level of 90 inches of water. Considering the most adverse initial conditions of a low level in the Reactor Building sump and a high level in the letdown storage tank, a 1 gpm leak from the Reactor Coolant System would initiate a Reactor Building sump high level alarm indication in the control room within 3 hours and a letdown storage tank low level alarm indication in the control room within 17 hours. A three gpm leak would be detected in 1/3 the time given above for detection of a one gpm leak. Normally, with the Reactor Building sump level and the letdown storage tank level between their high alarm and the low alarm respectively, these detection times would be reduced.

If the leak allows primary coolant into the containment atmosphere, additional leak detection is provided by the Reactor Building Process Monitoring System and the Reactor Building Area Monitoring System. The sensitivity and time for detection of a Reactor Coolant System leak by any of the radioactivity monitoring systems depends upon reactor coolant activity and the location of the leak. Alarm indication for each sample point in these systems is in the control room.

If the leak is in a steam generator, the leak can be detected by a decrease in the level of the letdown storage tank as described above, Secondary Tritium Analysis, Xenon Analysis, and also by main steam line and condenser air ejector off gas radiation monitors. The sensitivity of the radiation monitors for leak detection depends upon the activity of the Reactor Coolant System.

Class I fluid systems other than the Reactor Coolant System pressure boundary will be monitored for leakage by monitoring the various storage and/or surge tanks for the applicable systems. The Radiation Monitoring System for the station will aid in leak detection of systems containing radioactive fluids. In addition to the above, routine Operator and/or Health Physics radiation surveillance will detect leakage in both radioactive and non-radioactive systems.

RCS leakage limits are based on the ability of the SSF RC makeup system to prevent RC pump seal failure (Reference resolution to GSI-23) and provide makeup flow for other normal RCS leakage. RCS leakage limits are also based on providing adequate decay heat removal from the RCS using the SSF ASW System.

5.2.3.10.4 System Minimum Operational Components

One pressurizer code safety valve is capable of preventing overpressurization when the reactor is not critical since its relieving capacity is greater than that required by the sum of the available heat sources, i.e., pump energy, pressurizer heaters, and reactor decay heat. Both pressurizer code safety valves are required to be in service prior to criticality to conform to the system design relief capabilities. One steam generator is required to be operable prior to criticality as the steam generator is the means for normal decay heat removal at temperatures above 250°F.

A reactor coolant pump or low pressure injection pump is required to be in operation prior to reducing boron concentration by dilution with make-up water. Either pump will provide mixing which will prevent sudden positive reactivity changes caused by dilute coolant reaching the reactor.

5.2.3.10.5 Leak Detection

The entire Reactor Coolant System is located within the secondary shielding and is inaccessible during reactor operation. Any leakage drains to the Reactor Building normal sump. Any coolant leakage to the atmosphere will be in the form of fluid and vapor. The fluid will drain to the sump and the vapor will be condensed in the Reactor Building coolers and also reach the sump via a drain line from the cooler.

For the reactor coolant pump, the leakage past the middle seal is routed to the Letdown Storage Tank; leakage past the outermost seal is routed to the quench tank or reactor building normal sump.

Locating the actual point of Reactor Coolant System leakage can most readily be accomplished when the reactor is shutdown, thereby allowing personnel access inside the secondary shielding. Location of leaks can then be accomplished by visual observation of escaping steam or water, or of the presence of boric acid crystals which would be deposited near the leak by evaporation of the leaking coolant.

Leakage of reactor coolant into the Reactor Building during reactor operation will be detected by sump level, tank levels, radioactivity, or any combination of these.

All leakage, both reactor coolant and cooling water is collected in the Reactor Building normal sump. The sump water level is indicated and annunciated at high level in the control room. Changes in sump water level are an indication of total leakage. Pursuant to the NUREG 0737, Item II.F.1.5 safety grade redundant level transmitter to the normal and emergency containment sumps have been installed. Both sump levels are indicated and recorded in the control room. Measurement of the letdown storage tank coolant level provides a direct indication of reactor coolant leakage. Since the pressurizer level is maintained constant by the pressurizer level controller, any coolant leakage is replaced by coolant from the letdown storage tank resulting in a decrease in tank level. Both the pressurizer and letdown storage tank coolant levels are recorded in the control room. A comparison of these two recordings over a time period yields the total reactor coolant leakage rate.

Changes in the reactor coolant leakage rate in the Reactor Building may cause changes in the control room indication of the Reactor Building atmosphere particulate and gas radioactivities. The gaseous or the particulate containment atmosphere radioactivity monitors can be used to detect RCS leakage. Radioactivity detection systems are included for monitoring both particulate and gaseous activiities because of their sensitivities and rapid responses to RCS leakage, but have recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contaimination or cladding defects. If there are few fuel elements cladding defects and low levels of activation products, the gaseous or particulate containment atmosphere radioactivity monitors are limited to detech leakage; however, the requirements can be met at the design bases criteria for the detectors. TS 3.4.15 addresses RCS leakage detection instrumentation requirements (Reference 78).

5.2.3.11 Quality Assurance

Assurance that the Reactor Coolant System will meet its design bases insofar as the integrity of the pressure boundary is concerned, is obtained by analysis, inspection, and testing.

5.2.3.11.1 Stress Analyses

Detailed stress analyses of the individual Reactor Coolant System components including the vessel, piping, pumps, steam generators, and pressurizer have been performed for the Design Bases.

For the replacement steam generator analysis the complete reactor coolant system was treated as one entity for the analysis of the effect of the Operating Basis Earthquake (OBE) and the Maximum Hypothetical Earthquake (MHE, also called the SSE) on the piping and nozzle stresses.

Independent thermal and dynamic analyses have been performed to insure that piping connecting to the Reactor Coolant System is of the proper schedule and that it does not impose forces on the nozzles greater than allowable. Small nozzles are conservatively designed and utilize ASA schedule 160. The reactor coolant pump casing has been completely analyzed including a dynamic analysis separately from the loop to insure that the stresses throughout the casing are below the allowable for all design conditions.

Stress analysis reports required by codes for the several components have been prepared by the manufacturer and reviewed for adequacy by a separate organization.

5.2.3.11.2 Shop Inspection

Inspection and non-destructive testing of materials prior to and during manufacturing in accordance with applicable codes and additional requirements imposed by the manufacturer have been carried out for all of the Reactor Coolant System components and piping. The extent of these inspections and testing is listed in Table 5-10 for each of the components in the system. Shop testing culminates with a hydrostatic test of each component followed by magnetic particle inspection of the component external surface. Piping will be hydrostatically tested in the field and will undergo a final field inspection.

Preoperational mapping of the reactor vessel by ultrasonic examination was accomplished to establish acceptability of the vessel for service. To meet the requirements of IS-232 of Section XI of the ASME Code, the acceptance standards contained in N625.4 of the 1965 edition of Section III of the ASME Code with Addenda through Summer 1967 were used.

Components were cleaned, packaged to prevent contamination, and shipped over a pre-selected route to the site. For materials purchased or manufactured outside of B&W, the results of the material inspection and testing program have been observed or audited by B&W, and audited by the applicant. In addition there was an independent audit by B&W's Nuclear Power Generation Department Quality Assurance Section.

5.2.3.11.3 Field Inspection

Field welding of reactor coolant piping and piping connecting to nozzles is performed using procedures which will result in weld quality equal to that obtained in shop welding. Non-destructive testing of the welds is identical to that performed on similar welds in the shop and is shown in Table 5-10. Accessible shop and field welds and weld repairs in the reactor coolant piping are inspected by magnetic particle or liquid penetrant tests following the system hydrostatic test.

5.2.3.11.4 Testing

The Reactor Coolant System including the reactor coolant pump internals, reactor closure head, control rod drives, and associated piping out to the first stop valve undergoes a hydrostatic test following completion of assembly. The hydrostatic test is conducted at a temperature 60°F greater than the highest nil-ductility temperature. During the hydrostatic test, a careful examination is made of all pressure boundary surfaces including gasketed joints.

5.2.3.12 Tests and Inspections

This section discusses tests and inspections performed during and after the assembly of the individual components into a completed Reactor Coolant System. These tests and inspections are performed to demonstrate the functional capabilities of the components after assembly into a completed system, to inspect the quality of the system closure weldments, and to monitor system integrity during service.

5.2.3.12.1 Construction Inspection

The coolant piping for each loop is shipped to the field in six subassemblies. The loops are then assembled in the field. In order to accommodate the small fabricating and field installation tolerances, a number of the subassemblies are fabricated with excess length. Thus, the final fitting of the coolant piping is accomplished in the field. The ends with excess length are field machined. All carbon steel-to-carbon steel field welds are back-clad with stainless steel following removal of the backing rings. Consumable inserts are used in stainless-to-stainless welds, such as surge line and some coolant pump welds. All welding is inspected in accordance with requirements of the applicable codes or better.

Welding of the auxiliary piping to Reactor Coolant System nozzles is done to the same standards as the main coolant piping. Consumable inserts are used in all cases.

Cleaning of reactor coolant piping and equipment is accomplished both before and after erection of various equipment. Piping and equipment nozzles will require cleaning in the area of the connecting weldments. Most of the piping and equipment are large enough for personnel entry and are cleaned by locally applying solvents and demineralized water and by wire brush to remove trapped foreign particles. Where surfaces and equipment cannot be reached by personnel entry and have been cleaned in vendor shops to the required cleanliness for operation and appropriately protected to maintain cleanliness during handling, shipping, storage, and installation, further cleaning will not be performed. Appropriate checks to verify maintenance of required cleanliness will be performed prior to operation.

5.2.3.12.2 Installation Testing

The Reactor Coolant System will be hydrostatically tested in accordance with USAS B31.7, Nuclear Power Piping Code. The test pressure will affect all parts of the Reactor Coolant System up to and including means of isolation from auxiliary systems, such as valves and blank flanges. The hydrostatic test will be performed at temperature above Design Transition Temperature.

The Reactor Coolant System relief valves will be inspected and shop-tested in accordance with Section III of the ASME code for Nuclear Vessels. The relief pressure setting will be made during the shop test.

5.2.3.12.3 Functional Testing

Prior to initial fuel loading, the functional capabilities of the Reactor Coolant System components will be demonstrated at operating pressures and temperatures. Measurement of pressures, flows, and temperatures will be recorded for various system conditions. Operation of reactor coolant pumps, pressurizer heaters, Pressurizer Spray System, control rod drive mechanism, and other Reactor Coolant System equipment will be demonstrated. For descriptions of the various functional tests performed, refer to Chapter 14.

5.2.3.12.4 Inservice Inspection

Inservice examination of ASME Code Class I, 2 and 3 components are performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR 50, Section 50.55a(g)(4), to the extent practical within the limitations of design, geometry and materials of construction of the components, except where specific written relief has been granted by the Commission.

Vessels, heat exchangers, pumps, valves, and piping, are classified in accordance with 1OCFR50.55a and NRC Regulatory Guide 1.26. For each ASME code class, systems have been identified which will be examined. Appropriate Duke drawings and documents provide the exact boundaries for each system to be examined.

The examination categories to be used are those listed in Tables IWB, IWC, IWD, and IWF-2500-1 of ASME Section XI. Specific examinations will be identified by an Item Number specified in the Oconee Inservice Inspection Plan.

The examination techniques to be used for inservice inspection include radiographic, ultrasonic, magnetic particle, liquid penetrant, eddy current and visual examination methods.

Repair procedures are prepared as necessary by Duke Power Company Nuclear Generation Department. These procedures are reviewed for compliance with Section XI. Reexamination to Section XI is included in the repair process.

5.2.3.13 Reactor Vessel Material Surveillance Program

The original Oconee design included three reactor vessel surveillance specimen holder tubes (SSHT) located near the reactor inside vessel wall. Each of these SSHT housed two capsules containing reactor vessel surveillance specimens. When failures of the SSHT occurred at other Babcock & Wilcox (B&W) designed plants, the three Oconee units were shut down in succession, starting in March 1976 to inspect the SSHT. The inspection revealed that all of the SSHTs had suffered some damage. To prevent further damage all surveillance capsules and all parts of the SSHT that had failed or were deemed likely to fail during the remainder of that operating cycle were removed from the vessels.

Since the discovery of the damage to the SSHT, B&W has undertaken the design, manufacture and testing of an improved SSHT. SSHT of this improved design were installed in Davis-Besse 1, Crystal River 3 and Three Mile Island 2. (Three Mile Island 2 no longer operating but capsules were salvaged for irradiations at other host plants.) All of these plants have the same basic B&W 177 fuel assembly reactor design as Oconee 1, 2, and 3. The acceptability of the redesigned SSHT has been demonstrated by a test program reviewed and approved by the NRC staff and conducted in conjunction with the hot functional test performed at Davis-Besse 1.

Installation of the redesigned SSHT in the Davis Besse I, Crystal River 3 and Three Mile Island 2 reactor vessels did not present any unusual radiological difficulties because installation was prior to neutron activation of the reactor internals. Studies of methods of installing the redesigned SSHT in the irradiated B&W reactors indicate that substantial installation difficulties will be experienced primarily because precision machining, alignment and inspection must be performed remotely and under water. Although such problems do not in themselves justify relief from a requirement to reinstall the SSHT in Oconee 1, 2, and 3, they would be likely to cause significant radiation to personnel. Based on its experience in removing the SSHT at Three Mile Island 1 and Rancho Seco 1, B&W estimated that installing SSHT in irradiated reactors could result in personnel exposures totaling about 100 man-rem per reactor. In the interest of maintaining the radiation exposure of plant personnel as low as reasonably achievable, the licensee, in cooperation with B&W and the owners of other B&W 177 fuel assembly plants, has proposed an alternative program that does not require reinstalling the SSHT in Oconee 1, 2, and 3 and the other irradiated B&W plants.

The capsules removed from the Oconee vessels which had damaged SSHT were placed in a host reactor, Crystal River 3, as part of the integrated surveillance program discussed herein. These capsules contain samples of plate or forging material and heat-affected zone material from the vessel beltline as well as weld metal. The weld metal is expected to be controlling because it is more radiation sensitive.

This program includes provisions to provide additional information, if required under 10 CFR 50, Appendix G, Paragraph IV.A.1.b, in addition to the normal requirements of Appendix H.

The plan involves integrating the interrupted surveillance program at Oconee and other plants with the programs for new plants in a manner generally similar to that covered in 10 CFR 50, Appendix H, Paragraph III.B, except that the plants are at different sites. There are three distinct features of this plan.

1. The original surveillance materials from one or more reactors that have been in service will now be irradiated in a new host reactor, that can be fitted with the newly-designed capsule holders on the thermal shield in less time and without significant radiation exposure of the workmen, and
2. There will be more weld metal specimens and some larger fracture mechanics (compact tension or CT) specimens placed in the capsules, and
3. A data-sharing feature in which all available irradiation data for the beltline welds of a given reactor some of which will come from other surveillance programs, will be considered in predicting its adjusted reference temperature and in making any fracture analyses for that reactor. Typically, several of the welds in any one vessel were made with the same weld wire and flux as those used on some other reactors. The data sharing feature is required because the welds in these reactors have high radiation sensitivity due to high copper content and low initial upper shelf energy.

The specific program for Oconee 1, 2, and 3 involved installing the Oconee surveillance capsules in extra locations provided in the Crystal River 3 vessel. This plan accomplished the original purpose of obtaining information on the effect of radiation on material that is representative of the material in the Oconee reactor vessels on a schedule that provides an appropriate lead time over the vessel irradiation rate. The overall integrated program also provides information relevant to Oconee 1, 2, and 3 from surveillance programs in Crystal River 3, and Davis Besse 1 on material considered to be essentially identical to the actual welds in the Oconee vessels. Details are provided below.

5.2.3.13.1 Oconee 1

The limiting weld materials for the Oconee 1 vessel are Procedure Qualification (P.Q.) numbers SA-1426, SA-1430, SA-1229, and SA-1585, except for pressurized thermal shock (PTS) for which the limiting material is SA-1073 (Reference 32)[6] (BAW-2192, BAW-2178, References 30

[6] Weld materials are specifically identified by the ASME Code by the procedure Qualification Test number. A procedure qualification test is required on each combination of heat of weld wire and batch of flux.

and 31). The first two are longitudinal welds in the lower shell course, the second two are beltline circumferential welds, and the last material is a longitudinal weld in the intermediate shell. The end of life (EOL) fluences for these welds are estimated to be 7.67 x 10^{18}, 7.67 x 10^{18}, 8.44 x 10^{18}, 8.99 x 10^{l8}, and 6.55 x 10^{18} (Reference 27) nvt, (E > 1 MeV) at the inner surface, respectively.

The original surveillance material, WF-112, was made using the same heat of filler wire but a different batch of flux as WF-154, one of the radiation sensitive welds in Oconee 2. Metallurgical considerations suggests that the radiation behavior is affected more by the wire than the flux, thus WF-112 is expected to respond to radiation much like WF-154. This data will be a useful part of the data base for B&W vessels.

BAW-1543 (NP), Revision 4, Supplement 6-A, Reference 14 documents where samples of the pertinent weld materials have been or are being irradiated in the integrated program, what kinds of specimens will be used, and when information will be available. The irradiation schedule and withdrawal dates will be modified to optimize the information obtained as indicated to be appropriate as test results are obtained and evaluated. Reference 14 is updated periodically to reflect the most recent capsule reports.

ANP-2650 “Updated Results for Additional Information Regarding Reactor Pressure Vessel Integrity” (Reference 76) dated July 2007 includes the data from capsules tested between January 1999 and May 2007 and provides the following:

1. Credibility and surveillance capsule data chemistry factor assessments for each Linde 80 heat including new capsules since BAW-2325, Revision 1 (Reference 50).
2. Pressurized Thermal Shock (PTS) values for each of the plants participating in the Babcock and Wilcox Master Integrated Surveillance Program (Oconee 1, 2 and 3 included) are updated for the plant’s current licensing period (60 calendar years for plants with license renewal) considering the surveillance data obtained from the new capsules. The PTS values are consistent with the plants current licensing basis (May 2007).
3. Adjusted Reference Temperature (ART) values for each of the participating plant’s current effective P/T curves considering surveillance data obtained from the new capsules (May 2007).

Information from capsules tested prior to January 1999 can be found in BAW-2325 Revision 1 (Reference 50).

5.2.3.13.2 Oconee 2

The limiting weld material for the Oconee 2 vessel is P.Q. number WF-25 which is used in the center circumferential weld. (BAW-2192 and BAW-2178, References 30 and 31). The end of life (EOL) fluence for this weld is estimated to be 8.70 x 10^{18} nvt (E > 1 MeV) (Reference 28) at the inner surface.

The original surveillance material, WF-209-1, while not identical to any of the beltline welds in B&W reactors, is of the same weld wire heat as WF-70 (but different flux lot) and is predicted to be radiation sensitive, based on its copper and nickel contents. Data from WF-209-1 will be a useful addition to the data base for these reactors.

BAW-1543 (NP), Revision 4, Supplement 6-A, Reference 14 documents where samples of the pertinent weld materials have been or are being irradiated in the integrated program, what kinds of specimens will be used, and when information will be available. Reference 14 is updated periodically to reflect the most recent capsule reports.

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2. Pressurized Thermal Shock (PTS) values for each of the plants participating in the Babcock and Wilcox Master Integrated Surveillance Program (Oconee 1, 2 and 3 included) are updated for the plant's current licensing period (60 calendar years for plants with license renewal) considering the surveillance data obtained from the new capsules. The PTS values are consistent with the plants current licensing basis (May 2007).
3. Adjusted Reference Temperature (ART) values for each of the participating plant's current effective P/T curves considering surveillance data obtained from the new capsules (May 2007).

Information from capsules tested prior to January 1999 can be found in BAW-2325 Revision 1 (Reference 50).

5.2.3.13.3 Oconee 3

The limiting weld material for the Oconee 3 vessel is P.Q. Number WF-67 (BAW-2192 and BAW-2178, References 30 and 31). WF-67 is used for the center circumferential weld (inner 75%). The end of life (EOL) fluence for WF-67 is estimated to be 8.59 x 10^{18} nvt, (E > 1 MeV) (Reference 29) at the inner surface.

The original surveillance material, WF 209-1, is the same as that used in Oconee 2. This discussion of WF-209-1 in 5.2.3.13.2 applies here.

BAW-1543 (NP), Revision 4, Supplement 6-A, Reference 14 documents where samples of the pertinent weld materials have been or are being irradiated in the integrated program, what kinds of specimens will be used, and when information will be available. Reference 14 is updated periodically to reflect the most recent capsule reports.

ANP-2650 "Updated Results for Additional Information Regarding Reactor Pressure Vessel Integrity" (Reference 76) dated July 2007 includes the data from capsules tested between January 1999 and May 2007 and provides the following:

1. Credibility and surveillance capsule data chemistry factor assessments for each Linde 80 heat including new capsules since BAW-2325, Revision 1 (Reference 50).
2. Pressurized Thermal Shock (PTS) values for each of the plants participating in the Babcock and Wilcox Master Integrated Surveillance Program (Oconee 1, 2 and 3 included) are updated for the plant's current licensing period (60 calendar years for plants with license renewal) considering the surveillance data obtained from the new capsules. The PTS values are consistent with the plants current licensing basis (May 2007).
3. Adjusted Reference Temperature (ART) values for each of the participating plant's current effective P/T curves considering surveillance data obtained from the new capsules (May 2007).

Information from capsules tested prior to January 1999 can be found in BAW-2325 Revision 1 (Reference 50).

5.2.3.13.4 Integrated Surveillance Program

BAW-1543 (NP), Revision 4, Supplement 6-A, Reference 14, Supplement to the Master Integrated Reactor Vessel Material Surveillance Program, June 2007, specifies the Oconee specimen capsules that were irradiated in Crystal River 3. These capsules include the weld material and other materials such as plate or forging material samples and weld heat affected zone material samples from the Oconee vessels.

For those welds where no surveillance specimens exist, guidance for predictions is based on 10CFR50.61 and Regulatory Guide 1.99 Rev. 2.

BAW-1543, Rev. 4, February 1993 (Reference 77), presents a "Master Integrated Reactor Vessel Surveillance Program" that provides for additional surveillance capsules which contain tension test, Charpy V-notch, and larger-sized compact fracture specimens of 8 different "Linde 80" weld wire heats (14 different wire/flux combinations). These specimens will provide direct data for those materials represented and will provide a statistical base for those other materials for which archive material is not available. For Oconee-1, the weld wire heat used in SA-1229 was irradiated in 2 supplemental capsules. For Oconee-1 and Oconee-2, WF-25 was irradiated in 7 supplementary capsules. For Oconee-3, WF-67 was irradiated in 6 supplementary capsules.

All Oconee RVSP capsules, except for standby capsules, have been tested, essentially completing the requirement for reactor vessel surveillance irradiations. In addition, the supplementary capsules have provided additional irradiation shift and fracture toughness data.

Research programs being funded by the NRC have provided information on the effect of radiation on these specific weld materials and on several additional Linde 80 weld materials expected to respond to radiation in a similar manner. These programs, Heavy Section Steel Technology (HSST), consist of many tension test, C_v and CT specimens irradiated in a test reactor.

The information developed from the “Master Integrated Reactor Vessel Surveillance Program” and the HSST programs help provide assurance of safety margins against vessel failure per 10 CFR 50, Appendix G.

There are uncertainties involved in applying radiation effects information obtained in other reactors to the Oconee vessels. The major uncertainties involved include:

1. Accuracy of neutron fluence calculations,
2. Magnitude and effect of variation in neutron spectra between reactors,
3. Magnitude and effect of variations in irradiation temperature between reactors,
4. Magnitude and effect of variations in rate of irradiation on material properties.

The effects of these variables have been studied for many years and are discussed below.

1. Neutron flux calculations for the reactor vessel wall and irradiation capsule locations have been developed over many years. The dosimetry used in irradiation capsules has furnished information that was used to check out and refine the calculational methods. It is generally believed that the fast neutron flux and fluence in these locations can be calculated to an accuracy of ±20 percent, particularly if some dosimetry checks are available. Dosimeters from the original Oconee surveillance program were removed and tested for verification of vessel fluence calculations.

It should be emphasized that the effect of neutron radiation on reactor vessel steel varies as the square root of the fluence, so uncertainties of 20 to 50 percent influence are not highly significant.

The design of the Oconee vessels, internals and cores is almost identical to that of the other reactors that are used to obtain radiation effects information.

These considerations are the basis for the conclusion that uncertainties in the calculation of neutron fluence are small, and the effect of such uncertainties on the assessment of the radiation effects on the vessel material will also be small.

2. Although differences in neutron energy spectra can cause uncertainties in the effects of radiation on material when evaluated without considering spectrum effects, only very large differences in spectra are significant. The variations from one B&W 177 fuel assembly reactor to another are relatively minor, because they have almost identical geometry.

   The possible differences in neutron spectra that could occur between the B&W power reactors to be involved in the integrated program has been considered. Such effects can be dealt with, if necessary, through the use of neutron damage functions that are being developed for that purpose. However, the worst expected differences are judged inconsequential based on present knowledge of irradiation effects.

3. The effect of the temperature of irradiation has also been the subject of considerable research. It is well known that radiation damage is less severe at 600°F than at 500°F (the temperature range of concern). The differences in effect on the steel appear to be noticeable and should be taken into account if the irradiation temperature difference is over about 25°F. Enough information is known to permit conservative evaluations of the effect of temperature differences of at least 50°F, and probably even 100°F or more. The differences in the temperature of the surveillance capsules and vessel walls between the B&W power reactors involved in the proposed integrated program are estimated to be less than 25°F, and can be conservatively evaluated.

4. The effect of irradiation has also been evaluated by research programs at NRL and other laboratories. The general consensus of experts on this subject is that there will be no major differences in material property changes by irradiation rates varying over 2 to 3 orders of magnitude. However, the differences in the rates of irradiation of specimens in the integrated program and the limiting material in the walls of the affected vessels are less than one order of magnitude, therefore, it is concluded that there will be no significant uncertainties in this program associated with differences in rate of irradiation.

The “Master Integrated Reactor Vessel Surveillance Program” provides the information for Oconee 1, 2, and 3 to comply with 10 CFR 50, Appendix G. It also provides assurance that the uncertainties involved in using data obtained from appropriate surveillance specimens irradiated in other B&W power reactors to establish Oconee 1, 2, and 3 vessel operating limitations are small and can be accounted for by imposition of appropriate margins.

Additionally, the “Master Integrated Reactor Vessel Surveillance Program” provides more useful information than could have been extracted from the original surveillance program. The program also gives results of the kind required to meet 10 CFR 50, Appendix G, Paragraph IV.A.1.b.

An extension of the exemption for Oconee Units I, 2 and 3 from the requirements for an in-vessel material surveillance program as set forth in 10 CFR 50, Appendix H, was requested by the Duke Power Company in January 1982 (Reference 10). In its submittal to the NRC, Duke Power Company stated that at present there were no plans to modify the Surveillance

Specimen Holder Tubes (SSHT's) or the Core Support Assembly on any Operating B&W plant which would change the geometrical similarity of the reactors or preclude the continued irradiation of the surveillance capsules in the host plants. Thus, adequate surveillance information will continue to be obtained for the Oconee units. An evaluation of the Surveillance Capsules removed from operating B&W plants and an evaluation of the reactor vessel fluence were included in the Duke Submittal to demonstrate the adequacy of the Surveillance Program. Duke Power Company submittal concluded that:

1. Based on the Surveillance capsule data obtained on all the B&W-177FA plants to date, it has been demonstrated that the prediction techniques used in establishing the vessel operation limits (i.e., Reg. Guide 1.99, Rev. 2) are conservative.
2. A high degree of accuracy has been demonstrated by B&W in estimation of the reactor vessel fluence using the power histories of the reactors and the dosimetry measurements from the host plants with SSHT's.
3. The Specimen Capsules being irradiated at Crystal River-3 have received neutron fluence greater than the fluence received by the Oconee Reactor Vessels by 7 to 10 EFPYs. The Specimen Capsules are expected to continue to lead the respective reactor vessels accumulated peak fluence for the life of the plant.

NRC granted an extension to the exemption for the Oconee Nuclear Station, Units l, 2 and 3 from the requirement for an in-vessel Material Surveillance program as set forth in 10 CFR 50, Appendix H, for a period of five years in June 1982 (Reference 11). The Commission stated in its safety evaluation that the information derived from the surveillance specimens in the host vessel, relevant to Oconee Nuclear Station Units l, 2 and 3 reactor vessels would be sufficient to provide assurance of safety margins and comply with 10 CFR 50, Appendix G. In addition, the NRC concurred with the Duke position that the dosimetry results have shown that the fluences can be estimated from the power histories with reasonable accuracy and accepted the methodology contained in BAW 1485, June 1978. In June, 2007, the NRC accepted BAW-1543, Rev. 4, Supplement 6-A, and found the program capable of monitoring the effect of neutron irradiation and the thermal environment on the fracture toughness of ferritic reactor vessel beltline materials in the plants that are participating in the material surveillance program. This includes Oconee 1, 2 and 3.

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5.3 Reactor Vessel

5.3.1 Description

The reactor vessel consists of a cylindrical shell, a spherically dished bottom head, and a ring flange to which a removable reactor closure head is bolted. The reactor vessel is supported by a cylindrical support skirt.

The original reactor vessel heads were replaced in 2003-2004 because of cracking discovered in a number of penetration nozzles. The replacement reactor vessel closure head is a one piece low alloy steel forging clad with stainless steel. All internal surfaces of the vessel and closure head are clad with stainless steel or nickel-chromium-iron (Ni-Cr-Fe) weld deposit. Cracking in the penetration nozzles was determined to be caused by Primary Water Stress Corrosion Cracking (PWSCC) and was associated with long service at reactor operating temperatures (References 3,4). The replacement penetration nozzles are made from Alloy 690 which is more resistant to PWSCC than the original Alloy 600 nozzles. Ongoing inspection programs are part of the Duke In-Service Inspection Program (See Section 18.3.1.2).

The reactor vessel outlines are shown in Figure 5-14 (Oconee 1), Figure 5-15 (Oconee 2), and Figure 5-16 (Oconee 3). The replacement reactor vessel closure head is shown in Figure 5-33. The general arrangement of the reactor vessel with internals is shown in Figure 4-26 and Figure 4-27. Reactor vessel design data is listed in Table 5-11.

All major reactor vessel nozzles are installed with full penetration welds. All control rod drive and incore instrument nozzles are installed with partial penetration welds. The gasket leakage tap is installed in each reactor vessel flange with a partial penetration weld.

Deleted Paragraph(s) per 2009 Update

The reactor vessels are constructed of a combination of formed plates and forgings. The ring forgings in the reactor vessel shells, other than closure flanges, for Oconee 1, 2, and 3 are identified in Figure 5-14, Figure 5-15, and Figure 5-16. The replacement reactor vessel closure heads are a single piece forging.

The core support assembly is supported by a ledge on the inside of the vessel flanges, and its location is maintained on this elevation by the closure head flange. The core support assembly directs coolant flow through the reactor vessel and core, supports the core, and guides the control rods in the withdrawn position.

The coolant enters the reactor through the inlet nozzles, passes down through the annulus between the thermal shield and vessel inside wall, reverses at the bottom head, passes up through the core, turns around through the plenum assembly, and leaves the reactor vessel through the outlet nozzles.

The vessel has two outlet nozzles through which the reactor coolant is transported to the steam generators and four inlet nozzles through which reactor coolant reenters the reactor vessel. Two smaller nozzles located between the reactor coolant inlet nozzles serve as inlets for decay heat cooling and emergency cooling water injection (core flooding and low-pressure injection engineered safety features functions). The reactor coolant and the control rod drive penetrations are located above the top of the core to maintain a flooded core in the event of a rupture in a reactor coolant pipe or a control rod drive pressure housing. The reactor vessel is vented through the control rod drives.

The bottom head of the vessel is penetrated by instrumentation nozzles. The closure head is penetrated by flanged nozzles which provide for attaching the control rod drive mechanisms and for control rod extension shaft movement.

Guide lugs welded inside the reactor vessel's lower head limit a vertical drop of the reactor internals and core to 1/2 inch or less and prevent rotation about the vertical axis in the unlikely event of a major internals component failure.

The reactor vessel shell material is protected from fast neutron flux and gamma heating effects by a series of water annuli and stainless steel barriers located between the core and the vessel's wall.

5.3.2 Vessel Materials

5.3.2.1 Materials Specifications

The materials used in the reactor vessel are discussed in Section 5.2.3.2 and listed in Table 5-5. The original reactor vessel material properties, as used in licensing Oconee, are presented in Table 5-12 and Table 5-13. Additional material physical properties are presented in Table 5-14. These properties have been updated as new data became available as explained in Section 5.2.3.3.

5.3.2.2 Special Processes for Manufacturing and Fabrication

The reactor vessel and appurtenances are constructed in accordance with the ASME Code, Section III edition and addenda listed in Table 5-4. Processes and materials, including product form used in fabrication of the reactor vessel, are discussed in Section 5.2.3, and were selected to ensure reactor vessel integrity, and to meet regulatory requirements and recommendations. Special or unusual processes not meeting the above requirements were not used in construction of the reactor vessel.

5.3.2.3 Special Methods for Nondestructive Examination

The required nondestructive examinations carried out during fabrication are presented in Table 5-10. These inspections were performed in accordance with procedures meeting the requirements of the edition and addenda of the ASME Code, Section III listed in Table 5-4. Nondestructive examination techniques used were selected to provide adequate sensitivity, reliability, and reproducibility to inspect surfaces and detect internal discontinuities. Acceptance standards were in accordance with the requirements of the ASME Code, Section III for the given product and/or fabrication process.

5.3.3 Design Evaluation

The summary description of the reactor vessel, including major considerations in achieving reactor vessel safety and vessels contributing to the vessel's integrity, is contained in Section 5.2. B&W is the reactor vessel designer and fabricator.

5.3.3.1 Design

The ASME Code, Section III, is the Primary design criteria for the reactor vessel. Chapter 5 describes the reactor vessel design, including construction features and arrangement drawing. Materials of construction are listed in Table 5-5. The design code is given in Table 5-4. Table 5-11 gives the design basis values used in the design.

5.3.3.2 Materials of Construction

The materials of construction for the reactor vessel are listed in Table 5-5. Special requirements, reason for selection, and suitability of the materials used are included in Section 5.2.3. The materials selected have been used extensively in nuclear vessel construction and exhibit well defined properties and serviceability.

5.3.3.3 Fabrication Methods

Fabrication methods used in constructing the reactor vessel are described in Section 5.2.2. The suitability of the fabrication methods is demonstrated by the excellent service history of vessels constructed using these methods.

5.3.3.4 Inspection Requirements

Fabrication inspection requirements imposed on the reactor vessel are summarized in Section 5.2.3.11 and Table 5-10. Preservice and inservice inspection requirements are summarized in Section 5.2.3.12.

5.3.3.5 Shipment and Installation

B&W specified cleanliness requirements during shipment of the reactor vessel to ensure its arrival at the site in satisfactory condition. B&W also provided appropriate instructions and consultation to the owner for onsite cleaning and vessel protection. Temporary protective coatings and/or covers were applied to the vessel during shipment and storage as appropriate for expected environmental conditions. Water chemistry was controlled during initial fill, testing, and operation of the vessel to prevent an environment that may be conducive to material failure.

5.3.3.6 Operating Conditions

The operational limits specified to ensure reactor vessel safety are described in Section 5.2.1. These are compared with normal intended and upset operating conditions in Section 5.2.1. The design transients for the reactor vessel are specified in Section 5.2.1.

5.3.3.7 Inservice Surveillance

A discussion of the reactor vessel material surveillance program is given in Section 5.2.3.13.

5.3.4 Pressure - Temperature Limits

5.3.4.1 Design Bases

B&W Topical Report BAW-10046A, Reference 1, provides the bases for setting operational limits on pressure and temperature. This topical report provides detailed assurance that, throughout the life of the plant, operations will comply to requirements of 10 CFR 50, Appendix G. Regulatory Guide 1.99 is used to predict the effects of neutron irradiation on the beltline region materials. For assurance of compliance with 10 CFR 50, Appendix H, through out the life of the plant, see Section 5.2.3.12.

5.3.4.2 Limit Curves

Topical Report BAW-10046A provides the following information:

1. Procedures and criteria used

2. Safety margins
3. Bases used to determine the limits
4. Procedures that will be used to revise the limits

The limits of pressure and temperature for the following conditions are provided in Technical Specification 3.4.3.

1. Inservice leak and hydrostatic tests
2. Normal operation, including heatup and cooldown
3. Reactor core operation

5.3.5 References

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5.4 Component and Subsystem Design

5.4.1 Reactor Coolant Pumps

The reactor coolant pumps installed on Oconee 1 are Westinghouse Model 93A, while those installed on Oconee 2 and 3 are Bingham. The following briefly describes the significant changes for Oconee 1. Except where noted, the Oconee 1 design is the same as that of Oconee 2 and 3. The reactor coolant flow distribution with less than four pumps operating is presented in Table 5-15.

5.4.1.1 Reactor Coolant Pumps (Oconee 1 Only)

Each reactor coolant loop contains two vertical single stage centrifugal-type pumps which employ a 3 stage mechanical seals assembly. A cutaway view of the pump is shown in Figure 5-17 and the principal design parameters for the pumps are listed in Table 5-16. The estimated reactor coolant pump performance characteristic is shown in Figure 5-18. Connections to the pumps are shown on Figure 5-1.

Reactor coolant is pumped by the impeller attached to the bottom of the rotor shaft. The coolant is drawn up through the bottom of the impeller, discharged through passages in the guide vanes and out through a discharge in the side of the casing. The motor-impeller can be removed from the casing for maintenance or inspection without removing the casing from the piping. All parts of the pumps in contact with the reactor coolant are constructed of austenitic stainless steel or equivalent corrosion resistant materials. Reactor coolant pump materials of construction are listed in Table 5-5.

The Shaft Seal System consists of face-type mechanical Seals operating in tandem. The shaft seal system is made up of three mechanical seals operating in Tandem, wherein about one-third of the system pressure is expanded in each seal. Each seal is capable of operation at full system pressure. The fluid which leaks past the face type mechanical seal passes in to a seal leakage chamber and out to the quench tank. A low pressure mechanical seal prevents the escape of fluid to atmosphere.

A portion of the high pressure water flow from the high pressure injection pumps is injected into the reactor coolant pump between the impeller and the mechanical seal. Part of the flow enters the Reactor Coolant System through a labyrinth seal in the lower pump shaft to serve as a buffer to keep reactor coolant from entering the upper portion of the pump. The remainder of the injection water flows along the drive shaft, through the mechanical seal, and finally out of the pump. A small amount which leaks through the final seal is also collected and removed from the pump.

Component cooling water is supplied to the thermal barrier cooling coil. The pump may be operated with loss of either injection water or cooling water per GSI-23.

5.4.1.2 Reactor Coolant Pumps (Oconee 2 & 3)

The reactor coolant pumps are single suction, single stage, vertical, radially balanced, constant speed centrifugal pumps. This type of pump employs mechanical seals to prevent reactor coolant fluid leakage to the atmosphere. A view of the pump is shown in Figure 5-19 and the principal design parameters are listed in Table 5-17. The estimated reactor coolant pump performance characteristics are shown in Figure 5-20. Connections to the pumps are shown on Figure 5-21 (Oconee 2) and Figure 5-22 (Oconee 3).

The pump casing design utilizes a quad-volute inner case permanently welded to a pressure containing outer case. The configuration of the pressure containing outer case is kept simple so that the casing quality will meet the required radiographic level and the stresses can be analyzed to meet the requirements of the design specification. The quad-volute inner casing consists of four volute passages spaced 90° apart which receive the discharge from the pump impeller and guide it efficiently into the outer casing where it flows to the discharge nozzle through a passage having a constantly increasing cross-sectional area. The pump casing is welded into the piping system and the pump internals can be removed for inspection or maintenance without removing the casing from the piping.

The pump cover and stuffing box is a unit containing a thermal barrier, recirculation impellers, shaft, journal bearing, and mechanical face-type seals. The pump shaft is coupled to the motor with a spacer coupling which will permit removal and replacement of the seals without removing the motor. The pump cover has a cooling jacket to remove the heat which passes through the thermal barrier. This jacket has a capacity large enough to remove all heat which is transmitted to the cover. However, additional cooling capacity is provided, in case injection cooling water is lost. A recirculation impeller on the shaft immediately above the journal bearing circulates water in the bearing chamber to a heat exchanger and returns it to the chamber. The pump may be operated with loss of either injection water or cooling water per GSI-23.

The Shaft Seal System consists of face-type mechanical seals operating in tandem. Injection water, at a pressure above the pump suction pressure, is injected into the pump bearing chamber. A small portion of the injection water flows into the pump through a restriction bushing. The major portion flows through cooling slots in the o.d. of the bearing steel. The shaft seal system is made up of three mechanical seals operating in tandem, wherein about one-third of the system pressure is expanded in each seal. Each seal is capable of operation at the full system pressure. The fluid which leaks past the face-type mechanical seal passes into a seal leakage chamber and then out to the quench tank. A low pressure mechanical seal at the top of the seal leakage chamber prevents the escape of fluid to the atmosphere.

Electroslag welding is used to make the seven-inch thick circumferential butt weld which welds together the upper and lower halves of the pump casing. This weld is performed in accordance with ASME Code Case 1355-2 which permits electroslag welding of Class A pressure vessels. The casings are cast and welded by ESCO, who is the leading supplier of RCP casings for the industry.

Electroslag welding is a welding process wherein coalescence is produced by heat generated in a conductive molten slag which melts the filler metal and the surfaces of the work to be welded. The weld pool is shielded by this slag and moves along the full cross section of the joint as the welding progresses. The conductive slag is maintained molten by its resistance to the flow of electric current passing between the electrode and the work. Water cooled, non-fusing metal shoes are used to contain the molten metal on both sides of the weld. The welding is performed in a vertical position with the start and finished performed on run-out tabs affixed to the casting. These run-out tabs are later cut off and discarded. The only variables contained in the method of welding are the wide range of amperage (480-units 720H) and voltage (44-52V) needed to control the molten pool of metal.

The weld is examined 100 percent using liquid penetrant and radiographic examination methods in accordance with Section III of the ASME Code. Ultrasonic inspection is not performed because the pump casing material, austenitic stainless steel, precludes achieving meaningful inspection results.

The pump casing receives two heat treatment cycles. The first is a solution annealing treatment where the pump casing halves are furnace heated to 1900°F, held for a specified time, and water quenched. The second heat treatment is a stabilizing treatment in which the welded pump casing is heated to 725°F and air cooled.

Three types of analyses are performed on the pump to verify compliance with ASME Section III: thermal, stress and closure. The first two types are performed using mathematical models of the structure which are analyzed with computer techniques, the third using a merging of preceeding- math model results using an assumption of displacement compatibility at contiguous boundaries. The approaches and computer programs are examined in greater length in calculation OSC-1812, Section 3.0 and Section 4.0.

In the analysis, to determine temperatures throughout the pump, the pump is broken into two mathematically modeled sections which are analyzed using the THAN thermal analysis program. The first model is of typical pump casing wall section, transient analysis are performed on this section. The second model is of the cover. A steady state thermal analysis is made of this region for both wet and drained cooling jacket conditions.

The stress calculations utilize the STARDYNE I, Wilson Jones and NAOS computer programs. Stresses are below their nominal allowables stated in the ASME Boiler and Pressure Vessel Code, Section III, 1968 Edition with addenda through summer, 1970.

A summary of the code allowables and maximum stresses is listed in Table 5-18 and shown pictorially on Figure 5-23 and Figure 5-24. The reinforcement area is as defined in paragraph N-454 of the ASME Code Section III. The stress analysis performed on the bowl and the attached nozzles showed that the stresses are within the allowable limits. Note that a factor of two was applied to the nozzle loading due to seismic reactions and when these were combined with the dead weight and thermal expansion reactions, the stress levels were within the realistic allowable stress intensities shown in Table 5-18.

The casing cover analysis indicates that the thermal stresses and pressure stresses on the cover are within the Section III code allowables.

There are no deviations from the applicable ASME Code requirements in the design and fabrication of the pump casings other than code stamping.

5.4.2 Steam Generator

The steam generator general arrangement is shown in Figure 5-25. Principal design data are tabulated in Table 5-20.

The once-through steam generator supplies superheated steam and provides a barrier to prevent fission products and activated corrosion products from entering the Steam System.

The steam generator is a vertical, straight tube, tube and shell heat exchanger which produces superheated steam at constant pressure over the power range. Reactor coolant flows downward through the tubes and transfers heat to generate steam on the shell side. The high pressure (reactor coolant pressure) parts of the unit are the hemispherical heads, the tube sheets and the tubes between the tube sheets. Tube support plates maintain the tubes in a uniform pattern along their length. The replacement steam generators are supported by a pedestal.

The shell, the outside of the tubes, and the tube sheets form the boundaries of the steam producing section of the vessel. Within the shell, the tube bundle is surrounded by a cylindrical baffle. There are openings in the baffle at the feedwater inlet nozzle elevation to provide a path for steam to afford contact feedwater heating. The upper part of the annulus formed by the baffle plate and the shell is the superheat steam outlet, while the lower part is the feedwater inlet heating zone.

Vent, drain, and instrumentation nozzles, and inspection handholes are provided on the shell side of the unit. The reactor coolant side has manway openings in both the top and bottom heads. The replacement steam generators have a flat bottom lower head that eliminated the need for a drain nozzle. Venting of the reactor coolant side of the unit is accomplished by a vent connection on the reactor coolant inlet pipe to each unit.

Feedwater or Emergency Feedwater is supplied to the steam generator through an emergency feedwater ring located at the top of the steam generator to assure natural circulation of the reactor coolant following the unlikely event of the loss of all reactor coolant pumps.

Four heat transfer regions exist in the steam generator as feedwater is converted to superheated steam. Starting with the feedwater inlet these are:

5.4.2.1 Feedwater Heating Region

Feedwater is heated to saturation temperature by direct contact heat exchange. The feedwater entering the unit is sprayed into the downcomer annulus formed by the shell and the cylindrical baffle around the tube bundle. Steam is drawn by aspiration into the downcomer and heats the feedwater to saturation temperature.

The saturated water level in the downcomer provides a static head to balance the static head in the nucleate boiling section, and the required head to overcome pressure drop in the circuit formed by the downcomer, the boiling sections, and the bypass steam flow to the feedwater heating region. The downcomer water level varies with steam flow from 15 - 100 percent load. A constant minimum level is held below 15 percent load.

5.4.2.2 Nucleate Boiling Region

The saturated water enters the tube bundle just above the lower tube sheet and the steam-water mixture flows upward on the outside of the tubes counter current to the reactor coolant flow. The vapor content of the mixture increases almost uniformly until DNB is reached, and then film boiling and super heating occurs.

5.4.2.3 Film Boiling Region

Dry saturated steam is produced in the film boiling region of the tube bundle.

5.4.2.4 Superheated Steam Region

Saturated steam is raised to final temperature in the superheater region. The amount of surface available for superheat varies inversely with load. As load decreases the superheat section gains surface from the nucleate and film boiling regions. Mass inventory in the steam generator increases with load as the length of the heat transfer regions vary. Changes in temperature, pressure, and load conditions cause an adjustment in the length of the individual heat transfer regions and result in a change in the inventory requirements. If the inventory is greater than that required, the pressure increases. Inventory is controlled automatically as a function of load by the feedwater controls in the Integrated Control System.

Steam Generator Feedwater quality is addressed in the Chemistry Section Manual.

5.4.3 Reactor Coolant Piping

The general arrangement of the reactor coolant piping is shown in Figure 5-3, Figure 5-4, Figure 5-5, Figure 5-6, Figure 5-7, and Figure 5-8. Principal design data are tabulated in Table 5-21.

The major piping components in this system are the 28-inch i.d. cold leg piping from the steam generator to the reactor vessel and the 36-inch i.d. hot leg piping from the reactor vessel to the steam generator. Also included in this system are the 10-inch surge line and the 2-1/2-inch spray line to the pressurizer. The system piping also incorporates the auxiliary system connections necessary for operation. In addition to drains, vents, pressure taps, injection, and temperature element connections, there is a flow meter section in each 36-inch line to the steam generators to provide a means of determining the flow in each loop.

The 28-inch and 36-inch piping is carbon steel clad with austenitic stainless steel. Short sections of 28-inch stainless steel transition piping are provided between the pump casing and the 28-inch carbon steel lines.

For Oconee 1 only a 28 in. i.d. x 31 in. i.d. stainless steel transition section is installed between the existing 28 in. i.d. coolant piping and the 31 in. i.d. pump suction.

Also a 28 in. i.d. small angle elbow section between the pump discharge nozzle and the reactor inlet pipe is installed to account for the radial discharge of the replacement pump. The original pump had a tangential discharge nozzle. The elbow section is carbon steel with a section of stainless for welding to the pump casing nozzle.

Stainless steel or Inconel safe-ends are provided for field welding the nozzle connections to smaller piping. The piping safe-ends are designed so that there will not be any furnace sensitized stainless steel in the pressure boundary material. This is accomplished either by installing stainless steel safe-ends after stress relief or using Inconel. Smaller piping, including the pressurizer surge and spray lines, is austenitic stainless steel. All piping connections in the Reactor Coolant System, larger than 2 inch diameter, are butt-welded except for the flanged connections on the pressurizer relief valves.

Thermal sleeves are installed where required to limit the thermal stresses developed because of rapid changes in fluid temperatures. They are provided in the following nozzles: the four high pressure injection nozzles on the reactor inlet pipes; the two core flooding low pressure injection nozzles on the reactor vessel; and the surge line nozzle and spray line nozzle on the pressurizer.

As part of the Steam Generator Replacement Project, the lower cold leg 45^{o} elbow at the OTSG outlet nozzles were cut at a location of 22.5^{o}. The 22.5^{o} section of the elbow that was removed with the OTSG was replaced by an equivalent elbow integrally forged with the ROTSG outlet nozzle. The material for the replacement elbow is SA-508 Cl. 3a.

5.4.4 Reactor Coolant Pump Motors

The reactor coolant pump motors are large, vertical, squirrel cage, induction machines. The motors have flywheels to increase the rotational-inertia, thus prolonging pump coastdown and assuring a more gradual loss of main coolant flow to the core in the event pump power is lost. The flywheel is mounted on the upper end of the rotor, below the upper radial bearing and inside the motor frame. An anti-reverse device is included in the flywheel assembly to eliminate reverse rotation when there is back flow. Prevention of back rotation also reduces motor starting time.

The motors are enclosed with water-to-air heat exchangers so as to provide a closed circuit air flow through the motor. Radial bearings are floating pad type, and the thrust bearing is a double-acting Kingsbury type designed to carry the full thrust of the pump. A High Pressure Oil System with separate pumps is provided with each motor to jack and float the rotating assembly before starting. Once started, the motor provides its own oil circulation.

Instrumentation is provided to monitor motor cooling, bearing temperature, winding temperature, winding differential current, and speed. Instrumentation is also provided for measuring shaft displacement and frame velocity vibration.

In evaluating the design of the reactor coolant pump motor as it relates to the safety of the Reactor Coolant System, many items have been considered, namely: the overspeed of the motor; flywheel and shaft integrity; bearing design and system monitoring; seismic effects; and quality control and documentation.

An analysis of these considerations are given as follows as an indication of the safety and reliability that is integral with the motors:

5.4.4.1 Overspeed Considerations

The reactor coolant pump motors normally receive their electrical power from the nuclear generating unit through the unit's Auxiliary Electric System. On load rejection, the generating unit is designed to separate from the transmission network and remain in a standby operating condition carrying its own auxiliaries.

Figure 5-27 shows the turbine speed response following load rejection with the steam control valves wide open (VWO). On load rejection with VWO, the speed of the turbine-generator will increase under the control of the Normal Speed Governing Control System. The maximum speed attainable under the Normal Speed Governing Control System is less than 106 percent with the unit auxiliaries connected. This governing system is comprised of three independent control activities, namely: the speed control unit, power unbalance relay and the fast acting intercept valves all of which function to limit overspeed to below 106 percent.

As indicated in Figure 5-27 there are additional safety devices backing up the speed governing system, namely:

1. Mechanical overspeed trip which operates at 110 percent turbine-generator speed.
2. Generator overfrequency relay trip which is an electrical trip that operates at 111 percent turbine-generator speed.
3. Electrical back-up overspeed relay trip which operates at 110 percent turbine generator speed.

In addition, each individual reactor coolant pump motor control circuit includes an overfrequency relay which trips the motor at 115 percent motor (or turbine-generator) speed. Therefore, it is evident that the reactor coolant pump motors speed will be limited to less than 115 percent.

5.4.4.2 Flywheel Design Consideration

For conservatism, the design of the flywheel on the reactor coolant pump motor is based on a design speed of 125 percent. The primary stress at the flywheel bore radius, with a speed of 125 percent, is 20,000 psi which is less than 50 percent of the 50,000 psi minimum yield strength of the flywheel material. This, therefore, yields a centrifugal stress design safety margin of 250 percent at 125 percent speed.

The Duke Power Company specification on the motor calls for 500 motor starts in forty years; the flywheels have been designed for 10,000 starts yielding a safety factor of 20. However, calculation based on the material used in the flywheel results in 400,000 cycles required for crack initiation which results in a flywheel fatigue design safety factor of 800.

The reactor coolant pump motors are large, vertical, squirrel cage, induction motors. The motors have flywheels to increase rotational-inertia, thus prolonging pump coastdown and assuring a more gradual loss of main coolant flow to the core in the event that pump power is lost. The flywheel is mounted on the upper end of the rotor, below the upper radial bearing and inside the motor frame. The assumed operation of the reactor coolant pumps was 500 motor starts over forty years. The aging effect of concern is fatigue crack initiation in the flywheel bore key way from stresses due to starting the motor. Therefore, this topic is considered to be a time-limited aging analysis for license renewal.

The flywheels have been designed for 10,000 starts that provide a safety factor of 20 over the original operation assumptions. Reaching 10,000 starts in 60 years would require on average a pump start every 2.1 days. This conservative design is valid for the period of extended operation.

References for this section: Application [Reference 5] and Final SER [Reference 6]

5.4.4.3 Flywheel Material, Fabrication, Test and Inspection

5.4.4.3.1 Material

The flywheel is manufactured from vacuum degassed ASTM 533 steel.

5.4.4.3.2 Fabrication and Test

1. Flywheel blanks are flame cut from a plate with enough surplus material to allow for the removal of the flame affected metal.
2. At least three charpy tests are made on each plate parallel and normal to the rolling direction to determine that the blank meets specifications.
3. A complete 100 percent volumetric ultrasonic test is made on the blank and tension and bend tests are also made prior to shipment of a blank to Westinghouse Electric Company.
4. Following the machining of the flywheel at the Westinghouse plant, a complete 100 percent volumetric ultrasonic test is conducted on the fly wheel and a liquid penetrant test is conducted on the bore.
5. After the flywheel is installed and the motor is completely assembled, a 125 percent overspeed test for one minute is conducted on the assembled unit.
6. Following the overspeed test, a periphery sonic test is conducted on the flywheel through access holes in the motor frame.
7. To assure the original integrity of each flywheel during operation, the following inservice inspections will be performed.

   A qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals.

5.4.4.4 Shaft Design and Integrity

The shear stress on the shaft in the vicinity of the flywheel is 5520 psi with short circuit torque on the motor. The minimum strength of the shaft material is 23,000 psi which results in a safety factor of four under the maximum torque condition. Because of the conservatism used in the design of the shaft, it is concluded that shaft failure is not credible.

5.4.4.5 Bearing Design and Failure Analysis

The motor pump assembly is supported by a Kingsbury type thrust bearing which consists of a runner and upper and lower thrust plates. The history of the Kingsbury type bearing design indicates that the device is highly reliable and has a non-locking failure mode.

Provided on the motor are a number of devices to warn the operator of bearing trouble and these devices are each independent in their operation. The thrust bearing monitoring devices are as follows:

1. Two thermocouples located diametrically opposite to each other in the upper thrust plates.
2. Two thermocouples located diametrically opposite to each other in the lower thrust plates.
3. One thermocouple in the upper oil pot.
4. Oil pot level alarm device.
5. Shaft displacement and frame velocity vibration devices.

These devices are arranged to provide alarm indications to the control room operator. If a thrust bearing fails with the motor operating, the result would be melting of the bearing babbit and, finally automatic tripout of the motor on overload. However, bearing degradation which would lead to this point would be evident to the control room operators in at least one of the indicators discussed above and would be mitigated by manually securing the pump. Therefore, since seizure of the bearing will not result from a bearing failure, it is concluded that missiles will not be produced.

5.4.4.6 Seismic Effects

The pump motor units have been analyzed against the combination effects of mechanical and seismic loads including the gyroscopic effects of the flywheel to verify that the stress limits will not be exceeded and the pump motor unit will operate through the maximum hypothetical earthquake.

5.4.4.7 Documentation and Quality Assurance

The Duke Power Company and the motor supplier, Westinghouse Electric Corp., have a rigid quality assurance program directed at assuring the integrity of the reactor coolant pump motors.

A quality assurance folder was initially developed by Duke Power Company on each motor and included the following:

1. Specifications and addendum
2. Description of the manufacturer's quality control organization and engineering order handling.
3. Copies of all inspection reports relating to the appropriate motor.
4. Samples of quality control drawings.
5. Copies of all test reports including flywheel material vendor test reports; Westinghouse motor test reports; bearing assembly reports; shaft tests; sonic test reports on the machined flywheel prior to assembly on the motor and following the 125 percent speed test; and certification on the motor test report that the overspeed test was conducted on the assembled motor.

6. Copies of the Duke Form QA-2 which is the manufacturer's certification to Duke Power Company Design Engineering that the motors were manufactured per specification and the Duke Power quality assurance program.
7. Copies of Duke Form QA-1 which the indication to the field quality control engineer that the motor described thereon was manufactured to the specification and the Duke quality assurance program.
8. Copies of Duke Form QC-31 which is the field receiving report on the motor.

   A copy of each quality assurance folder was sent to the field quality control engineer and a copy was placed in the Design Engineering Department file. See the applicable controlled Procurement Package for RCP motor QA information.

Babcock & Wilcox has analyzed the reactor coolant pump assembly action resulting from postulated Reactor Coolant System breaks. B&W Topical Report, BAW-10040, Reference 1, describes the homologous pump model used for the speed calculations and presents results for the spectrum of breaks analyzed.

A discussion of the linear elastic fracture analysis to determine the structural failure speed of the reactor coolant pump motor flywheel assembly is also included.

5.4.5 Reactor Coolant Equipment Insulation

The majority of the Reactor Coolant System components are insulated with metal reflective type insulation. This insulation is supported by rings welded to weld pads on the components during field installation of the insulation. The weld pads to which the holding rings are attached are added to the components prior to final stress relief of the component. The replacement OTSGs do not have insulation support rings welded to the OTSGs instead, the support rings are friction supported. The remaining portion of the RCS is insulated with approved removable blanket insulation, secured with velcro fasteners.

The insulation units are removable and are designed for ease of removal and installation in such areas as field welds, nozzles, and bolted closures. The insulation units permit free drainage of any condensate or moisture from within the insulation unit.

5.4.6 Pressurizer

The pressurizer general arrangement is shown in Figure 5-28 and principal design data are tabulated in Table 5-22.

The electrically heated pressurizer establishes and maintains the Reactor Coolant System pressure within prescribed limits, and provides a steam surge chamber and a water reserve to accommodate reactor coolant density changes during operation.

The pressurizer is a vertical cylindrical vessel with a bottom surge line penetration connected to the reactor coolant piping at the reactor outlet. The pressurizer contains removable electric heaters in its lower section and a water spray nozzle in its upper section. Heat is removed or added to maintain Reactor Coolant System pressure within desired limits. The pressurizer vessel is protected from thermal effects by a thermal sleeve in the surge line and by an internal diffuser located above the surge pipe entrance to the vessel.

During outsurges, as Reactor Coolant System pressure decreases, some of the pressurizer water flashes to steam, thus assisting in maintaining the existing pressure. Heaters are then actuated to restore the normal operating pressure. During insurges, as system pressure increases, water from the reactor vessel inlet piping is sprayed into the steam space to condense steam and reduce pressure. Spray flow and heaters are controlled by the pressure controller. The pressurizer water level is controlled by the level controller.

Since all sources of heat in the system, core, pressurizer heaters, and reactor coolant pumps, are interconnected by the reactor coolant piping with no intervening isolation valves, relief protection is provided on the pressurizer. Overpressure protection consists of two code safety valves and one electromatic relief valve.

To eliminate abnormal buildup or dilution of boric acid within the pressurizer, and to minimize cooldown of the coolant in the spray and surge lines, a bypass flow is provided around the pressurizer spray control valve. This continuously circulates a minimum of one gpm of reactor coolant from the heat transport loop. A sampling connection to the liquid volume of the pressurizer is provided for monitoring boric acid concentration. A steam space sampling line provides capability for monitoring of or venting accumulated gases.

During cooldown and after the decay heat system is placed in service, the pressurizer can be depressurized and cooled by circulating through a connection from the High Pressure Injection System to the pressurizer spray line.

Electroslag welding is utilized in the fabrication of the pressurizer, only in the longitudinal seams of the shell courses. A total of three individual electroslag welds are made in the fabrication of each pressurizer. The techniques used in the electroslag welding are identical to those used in the electroslag welding program reported as Appendix F of Dockets No. 50-237 and 50-249 (Dresden Units 2 and 3). The procedures used were appropriately modified to reflect the difference in materials of the components being welded.

Each weld is subjected to radiographic inspection, ultrasonic inspection, and the finished surfaces of the weld are magnafluxed. In addition, each plate is ordered with excess width so that test specimens may be removed after heat treatment. Physical property test specimens including tensile and impact specimens of the base material heat affected zone and weld metal is obtained from this excess material in accordance with Section III of the ASME Code. Radiographic, ultrasonic, and magnetic particle inspection is preformed in accordance with Section III of the ASME Code and as required by Code Case 1355 which permits such welds for Class A vessels.

Physical tests are performed per Section N-511 of Section III of the ASME Code. For example:

1. All weld metal tensile specimens from each heat of weld wire, batch of flux, and for each combination of heat of wire and batch of flux used is obtained and tested after heat treatment.
2. Charpy impact test specimens representing weld metal and heat affected base material for every heat of wire, batch of flux, and combination of heat of wire and batch of flux used is tested.
3. Charpy V-notch impact specimens and tensile specimens are tested for 15 percent of all production welds. Included in this 15 percent are the tests required by 1 and 2 above.

Two men, one on the inside and one on the outside of the vessel, are used to check the progress of the weld, and to insure that the prescribed welding procedure is being followed. The weld is started in a U-shaped starting fixture about six inches deep attached to the bottom of the joint. The weld stabilizes in this starting tab which is later cut off and discarded. The weld once started is not stopped until the total seam is completed.

The weld receives a heat treatment which consists of a water quench for 1625°F, and a temper of 1150°F, followed by an air cool. This post-weld heat treatment refines the grain of the weld and the base material heat affected zone such that it is virtually indistinguishable from the unaffected base material. The microstructure is the same through the weld.

Normal Reactor Coolant System pressure control is by the pressurizer steam cushion in conjunction with the pressurizer spray, electromatic relief valve, and heaters. The system is protected against overpressure by Reactor Protective System circuits such as the high pressure trip and by pressurizer relief valves located on the top head of the pressurizer. The schematic arrangement of the relief valves is shown in Figure 5-1 and Figure 5-2. Reactor Coolant System pressure settings and relief valve capacities are listed in Table 5-1.

Reduction of pressure during Reactor Coolant System cooldown is accomplished by the pressurizer spray provided by the reactor coolant pump. Below a system temperature of approximately 250°F, the Low Pressure Injection System is used for system heat removal and the steam generators and reactor coolant pumps are removed from service. During this period, spray flow is provided by a branch line from one high pressure injection line to the pressurizer spray line for further pressure reduction or complete depressurization of the Reactor Coolant System.

5.4.6.1 Pressurizer Spray

The pressurizer spray line originates at the discharge of a reactor coolant pump in the same heat transport loop that contains the pressurizer. Pressurizer spray flow is controlled by a solenoid valve using an on-off control in response to the opening and closing pressure set points. An electric motor operated valve in series with the spray line is to provide for remote spray line isolation.

5.4.6.2 Pressurizer Heaters

The pressurizer heaters replace heat lost during normal steady state operation, raise the pressure to normal operating pressure during Reactor Coolant System heatup from the cooled down condition, and restore system pressure following transients. The heaters are arranged into four banks, which are then divided into eleven groups. The heaters are controlled by the pressure controller. The first bank utilizes proportional control and will normally operate at partial capacity to replace heat lost, thus maintaining pressure at the set point. On-off control is used for the remaining three banks. A low level interlock prevents the heaters from being energized with the heaters uncovered.

The total pressurizer ambient heat loss is dependent in part on the insulation losses, which can vary due to tightness of fit and condition. Any pressurizer steam space leakage can also remove energy from the pressurizer. Pressurizer heater input may also decrease over the course of an operating cycle due to tripped breakers or burnt elements. A minimum required heater capacity capable of being powered from an emergency power source is necessary to offset these losses and ensure that RCS pressure can be maintained. Unless adequate heater capacity is available, reactor coolant subcooling cannot be maintained indefinitely. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to loss of single phase natural circulation and decreased capability to remove core decay heat.

The pressurizer heaters for each unit are supplied from non-safety-related motor control centers (MCC) with the exception of SSF group B and C pressurizer heaters. The Group B and C heaters are supplied from safety related MCCs. The non-safety related MCCs as well as the SSF group B heaters are in turn powered via load centers from the 4160-volt engineered safeguard buses. These buses are powered from a hydro station which is the emergency generation source (EGS) in the event of loss of offsite power. This emergency source has ample capacity to provide emergency power to all pressurizer heaters and is capable of doing so promptly following an accident. The pressurizer heaters are divided among the three 4160 volt EGS buses such that the loss of one entire 4160 volt bus will not preclude the capability to supply sufficient pressurizer heaters to maintain natural circulation in MODE 3 with average Reactor Coolant temperature ≥525°F.

SSF, Bank 2, Group C heaters for all three Units are powered via SSF Switchgear OTS1 which is normally powered from Unit 2 B2T Compartment 4. Although Unit 2 B2T is a safety related MCC, Compartment 4 is load shed during some scenarios in which the EGS supplies power. During these scenarios, the Group C heaters for all units would be unavailable. The loss of Group C of heater capacity per unit does not reduce overall heater capacity below what is adequate for the pressurizer heaters to perform their design function.

Uncovering energized direct immersion heaters does not immediately harm the heaters. Three original heaters, one for each bundle assembly, were tested in air to provide an accelerated life test as follows:

1. Tested for 100 hours at sheath temperature of 600°F to 1600°F with a watt density of 85 watt/in.^{2}.
2. Cycled 400 times with a cycle time of 15 minutes on and 15 minutes off with a watt density of 65 watt/in.^{2}.

The heaters successfully completed this test, which simulated a total of 200 hours "on" time for the heaters in an uncovered environment while in an energized condition. Moreover, the heater sheath is designed for 2500 psig and 670°F with the heater terminal also designed for these same conditions. Therefore, the heater sheath could fail and the pressurizer vessel integrity would be maintained. This conclusion has been substantiated in tests conducted by the heater vendor for a similar design.

The original heater bundles in Unit 1 were replaced using heaters of a new design. A new heater was selected at random from the production lot and tested in air with tests representative of the original heater tests-in-air. The new design heater successfully passed both tests.

5.4.6.3 Pressurizer Code Safety Valves

Two pressurizer code safety valves are mounted on individual nozzles on the top head of the pressurizer. The valves have a closed bonnet with bellows and supplementary balancing piston. The valve inlet and outlet is flanged to facilitate removal for maintenance or set point testing.

5.4.6.3.1 Safety Valve Testing and Qualification

During the EPRI Safety Valve testing, it was determined that the short inlet Dresser 31739A valve successfully met all the test requirements with the "reference" ring settings. The performance of the valve was determined to be dependent on the ring settings. Duke Power Company evaluated the safety impact of the inadequate safety ring settings and determined that for the limiting RCS overpressure transients the plant safety can be maintained. In October 1982, all the Oconee Nuclear Station safety valves were adjusted to the recommended settings resulting from EPRI tests. Duke Power Company has committed to the optimal ring settings for the Dresser 31739A safety valves, which are described in the corresponding NRC Safety Evaluation Report (Reference 4).

5.4.6.4 Pressurizer Electromatic Relief Valve

The pressurizer electromatic relief valve, also called power operated relief valve (PORV), is mounted on a separate nozzle on the top head of the pressurizer. The main valve operation is controlled by the opening or closing of a pilot valve which causes unbalanced forces to exist on the main valve disc. The pilot valve is opened or closed by a solenoid in response to the pressure set points. Flanged inlet and outlet connections provide ease of removal for maintenance purposes.

The Power Operated Relief Valve (PORV) in each Oconee unit is actuated by a DC solenoid-operated pilot valve that is connected to a Class IE DC system. The block valve for the PORV is an AC motor operated valve and is connected to an AC emergency power supply. The power supplies for the PORV and its associated block valve are therefore independent and diverse.

5.4.6.4.1 PORV and Block Valve Testing and Qualification

Under the EPRI Test Program, for all tests applicable to Oconee, the Dresser PORV was opened and closed on demand. The functionability of the Dresser PORV has been shown for all expected operating and accident conditions applicable to Oconee Nuclear Station and the requirements of NUREG-0737, Item II.D.1.A have been met.

Under the EPRI PORV Block Valve Test Program, a Westinghouse motor-operated gate valve was tested on steam to full differential pressure conditions. Oconee Nuclear Station uses the same Westinghouse valve and LimiTorque operator for PORV block valve application. Based upon the successful EPRI tests for the valve-operator combination, the Oconee PORV block valves meet the intent of NUREG-0737 Item 11.D.1.B. The program test results were submitted to NRC in April 1982 and October 1985 (Reference 2).

With the initiation of NRC Generic Letter 89-10 (GL89-10) the Nuclear Industry and NRC have taken a much more focused, rigorous approach to assuring Active Motor Operated Valves (MOVs) have sufficient operating margin. The EPRI Performance Prediction Methodology (PPM) is a more conservative calculation guideline for determining MOV operating margins. Based on the EPRI PPM and other inputs, the operator for valves 1, 2, 3RC-4, the unit's PORV Block valves, have been upgraded from an SB-00-15 to an SB-0-25 operator.

5.4.6.5 Relief Valve Effluent

Effluent from the pressurizer electromatic-relief and code safety valves discharges into the quench tank which condenses and collects the relief valve effluent. After the quench tank receives relief valve effluent, the tank contents are cooled to normal temperature by the component drain pump and quench tank cooler of the Coolant Storage System. The tank fluid is circulated from the tank through the cooler and returned to the tank by spraying into the tank vapor space. The quench tank is protected against overpressure by a rupture disc sized for the total combined relief capacity of the two pressurizer code safety valves and the pressurizer electromatic relief valve. The quench tank can be remotely vented to the Gaseous Waste Disposal System.

An Acoustical Monitoring System is installed on each unit. It is a reliable, single channel system, powered from a battery backed vital bus. It will provide the operator with positive indication of valve position and an annunciation of an open valve in the control room. The valve position indication components have been seismically and environmentally qualified as appropriate for conditions applicable to their location.

Backup valve position indication is provided by temperature sensors located downstream of the PORV and safety valves and by the quench tank level indicator.

5.4.7 Interconnected Systems

5.4.7.1 Low Pressure Injection

The Low Pressure Injection System provides the capability below about 250°F for cooling the Reactor Coolant System during plant cooldown. During this mode of operation, coolant is drawn from the Reactor Coolant System through a nozzle on the reactor outlet pipe, circulated through the low pressure injection coolers by the low pressure injection pumps and then injected back into the Reactor Coolant System through two nozzles on the reactor vessel into the inlet side of the core. The heat received by this system is rejected to the Low Pressure Service Water System. Components in these two systems are redundant for reliability purposes.

The Low Pressure Injection System also performs an emergency injection function for a loss of coolant accident and provides long term emergency core cooling; this is described in Chapter 6.

5.4.7.2 High Pressure Injection

The High Pressure Injection System controls the Reactor Coolant System coolant inventory, provides the seal water for the reactor coolant pumps, and recirculates Reactor Coolant System letdown for water quality maintenance and reactor coolant boric acid concentration control. Letdown of reactor coolant is through a nozzle on the outlet coolant pipe from one steam generator. The discharge of the high pressure injection pumps connects to a nozzle on each of the reactor inlet pipes downstream of the reactor coolant pumps. The reactor coolant which is letdown is returned to the Reactor Coolant System through the nozzles in a different heat transport loop from the heat transport loop containing the letdown line. Components are redundant for reliability purposes (Section 9.3.2).

The High Pressure Injection System utilizes four injection nozzles in carrying out the high pressure emergency injection function after a loss of coolant accident.

The High Pressure Injection/Makeup (HPI/MU) Nozzle assemblies at Oconee incorporate a thermal sleeve to provide a thermal barrier between the cold HPI/MU Fluid and the HOT HPI Nozzle. In 1982, High Pressure Injection/Makeup Nozzle cracking problems were identified on several operating B&W plants. A task force formed by B&W owners group identified the root cause of the failures and undertook modifications, in consultations with NRC to eliminate such future failures.

Site inspections of Oconee 1, 2 and 3 were conducted. Oconee 2 and Oconee 3 were found to have nozzle cracking and thermal sleeve displacement problems. The radiographic and ultrasonic testing of Oconee 1 indicated that no abnormal conditions were present in any of the nozzles; this is attributable to the unique double thermal sleeve design of the Oconee 1 nozzles.

The B&W Owner's task force studied the safe end nozzle cracking problems on a generic basis and reported its findings to the NRC. The B&W Owner's task force developed a report that included its findings and recommendations to address the nozzle problems. Duke sent a letter to the NRC providing information that Duke supported the findings and recommendations provided in the B&W report (Reference 3). The task force concluded that all cracked safe ends of the HPI/MU nozzles were associated with loose thermal sleeves; the cracked safe ends were associated with the makeup nozzles only, and the cracks were propagated by thermal fatigue. The B&W Owner's task force report provided recommendations regarding the HPI/MU nozzles. These recommendations included that inspections be made to the HPI/MU nozzles and that if the inspections indicated a gap existed or abnormal conditions were present, to perform recommended modifications to the design of the HPI/MU nozzles. The modified design installs a hard rolled thermal sleeve which prevents thermal shock to the nozzle assembly and helps reduce flow induced vibrations more effectively. An in-service inspection program had been developed to provide early detection of the safe-end cracking problems. The Oconee 1 makeup nozzles did not require modifications but are now subject to an augmented ISI program.

Augmented HPI thermal sleeve inspections (bore scope) have continued to identify cracking at the RCS end of the modified thermal sleeves. In an effort to eliminate all HPI thermal sleeve cracking, Oconee embarked on an HPI thermal sleeve redesign effort in 2002. A 2-ply HPI thermal sleeve design was developed and qualified. The new design was used to replace HPI/MU cracked nozzles on ONS 2 and ONS 3 in 2004. This redesign also included the replacement of the Alloy 600 weld between the stainless steel HPI nozzle safe end and the carbon steel RCS HPI nozzle with Alloy 690 weld material. This 2-ply design has an inner and outer thermal sleeve that significantly reduces through wall stress gradients and the potential for crack initiation and growth.

5.4.7.3 Core Flooding System

The Core Flooding System floods the core in the event of a loss of coolant accident. Connection to the reactor vessel is through the two nozzles described above for low pressure injection. The low pressure injection and core flooding lines tie together and connect to the same nozzle on the reactor vessel.

The core flood nozzles have flow restrictors installed to minimize blowdown due to postulated core flood line break.

5.4.7.4 Secondary System

The principal Decay Heat Removal System interconnected with the Reactor Coolant System is the Steam and Power Conversion System. The Reactor Coolant System is dependent upon the Steam and Power Conversion System for decay heat removal at normal operating conditions and for all reactor coolant operating temperatures above 250°F. The system is discussed in detail in Chapter 10.

The Turbine Bypass System routes steam to the condensers when the turbine has tripped or is shutdown and also during large plant load reduction transients when steam generation exceeds the demand. Overpressure protection for the secondary side of the steam generators is provided by the turbine bypass system and by safety valves mounted on the main steam lines outside of the Reactor Building. The Emergency Feedwater System will supply water to the steam generators in the event that the Main Feedwater System is inoperative. The physical layout of the Reactor Coolant System provides natural circulation of the reactor coolant to ensure adequate core cooling following a loss of all reactor coolant pumps.

5.4.7.5 Sampling

A sample line from the pressurizer steam space to the Chemical Addition and Sampling System permits detection of non-condensible gases in the steam space. This sample line also permits a bleeding operation from the vapor space to the letdown line of the High Pressure Injection System to transport accumulated noncondensible gases in the pressurizer to the letdown storage tank.

5.4.7.6 Remote RCS Vent System

The Oconee design has the capability for venting post-accident non-condensible gases that, in sufficient quantities, could accumulate at high points in the RCS and impair natural circulation. Although such an event is highly unlikely, the remote RCS vents on the RCS hot legs and reactor vessels will enable venting of these gases. The reactor vessel head vents are also opened during RCS cooldowns conducted with natural circulation cooling to provide cooling flow through the upper head area and minimize steam void formation in that area. This venting was added to the emergency procedure guidelines in response to Generic Letter 81-21 (Reference 11), in order to simplify RCS pressure control during natural circulation cooldown.

The design of the RCS High Point Vent System consists of two valves installed in series in each of the following existing vent connections: steam generator piping high points, and reactor vessel head high point. The redundant valve in each vent line assures that venting operations can be terminated under postulated single failure. The three pairs of valves each receive electrical power from a different safety related power source. Vent valve position indication is provided by limit switches within each solenoid valve. The valves require power to open and fail close on loss of power. The existing power operated relief valve can be used to vent the pressurizer.

The reactor vessel head vent is attached to an existing Axial Power Shaping Rod motor tube and closure assembly. Two normally deenergized solenoid valves are installed in the vent line and controlled from the control room. The vent ties into a hot leg vent and discharges into the air stream from the Reactor Building Cooling Units when operated.

One independent remotely operated vent is provided at the high point of each 36-inch RCS hot leg line. Each vent makes use of the existing manual vent line. A tee has been added after the first manual valve and a new manual valve has been added after the tee. The first manual valve (1RC-19, 1RC-38, 2RC-19, 2RC-196, 2RC-38, 3RC-19, 3RC-38) is in the open position. The function of the first valve has been transferred to the second valve (1RC-168, 1RC-169, 2RC-168, 2RC-169, 3RC-168, 3RC-169). The new vent runs from the tee through two solenoid valves and discharges into the air stream from the Reactor Building Coolant Units. The solenoid valves are remotely controlled from the Control Room. The function of the manual vent is unaffected.

The reactor coolant vent system is acceptable to the NRC and in conformance with the requirements of 10CFR 50.44 paragraph (c)(3)(iii) and the guidelines of NUREG 0737 Item II.B.1, and NUREG-0800 Section 5.4.12.

5.4.8 Component Foundations and Supports

The supports for all major components listed in this section are analyzed in detail to insure adequate structural integrity for their intended function during normal operating, seismic, and accident conditions. Following calculation of sources of loading, stresses and motions at significant locations are computed and compared to applicable criteria. Details of this analysis are given in Chapter 3.

5.4.8.1 Reactor Vessel

The reactor vessel is bolted to a reinforced concrete foundation designed to support and position the vessel and to withstand the forces imposed on it by a combination of loads including the weight of vessel and internals, thermal expansion of the piping, design basis earthquake (DBE), and dynamic load following reactor trip.

The foundation, in addition, is designed and built to restrain the vessel during the combined forces imposed by the circumferential rupture of a 36-inch reactor outlet line and a simultaneous maximum hypothetical earthquake (MHE). With the implementation of LBB, the foundation is no longer required to withstand the forces associated with the full rupture of a 36-inch reactor outlet line. However, the foundation has not been modified and this capability provides defense in depth.

The vessel foundation further is designed to provide accessibility for the installation and later inspection of incore instrumentation, piping, and nozzles; to contain ductwork and vent space for cooling air to remove heat losses from the vessel insulation; and to provide a sump and drainage line for leak detection.

5.4.8.2 Pressurizer

The pressurizer is supported on a structural steel foundation by eight lugs welded to the side of the vessel.

The foundation and supports are designed to withstand the loads imposed by the weight of the pressurizer including its contents and attached piping, relief valve reaction forces, and forces imposed by the design basis earthquake. In addition, the foundation and supports will restrain the vessel during the combined forces imposed by the circumferential rupture of the 10-inch surge line coupled with the MHE.

The foundation is also designed to permit accessibility to pressurizer surfaces for inspection. Oversized/slotted holes are provided to prevent development of stresses due to thermal expansion of the Pressurizer.

5.4.8.3 Steam Generator

The steam generator foundation is designed to support and position the generator. The foundation is designed to accept the loads imposed by the generators and feedwater piping filled with water, the attached reactor coolant piping also filled with water, and steam lines under the MHE. For the Replacement Steam Generators (RSG), with the implementation of Leak-Before-Break (LBB), the design of the RSG connection to the reactor building foundation no longer considers the rupture of the 28-inch reactor coolant lines. The applicable loading for the RSG foundation consists of deadweight, thermal, seismic, main steam pipe break (MSLB), and main feedwater pipe break (FWLB) load cases.

For the RSG, with the implementation of LBB, the design of the upper lateral support and the Lubrite bearing plates no longer considers the rupture of the 36-inch reactor coolant line. The applicable loading for the RSG upper lateral support and Lubrite bearing plates consists of deadweight, thermal, seismic, main steam pipe break (MSLB), and main feedwater pipe break (FWLB) load cases. Also, the revised seismic analysis for the reactor coolant system piping, with the RSG component, considers the upper lateral support to be an active seismic support.

5.4.8.4 Piping

The reactor coolant piping, inlet and outlet lines, are supported by the reactor vessel and steam generator nozzles. The piping will withstand the forces imposed on it by the MHE.

5.4.8.5 Pump and Motor

The reactor coolant pump casing, internals, and motor weight are supported by the 28 inch coolant lines and constant load hangers attached to the motor. In the cold condition, the coolant piping will support the coolant pump and motor without the hangers. The hangers are designed to withstand the forces imposed on them by the MHE.

5.4.8.6 LOCA Restraints

Each steam generator has a support located opposite the upper tube sheet and transfers forces from the generator into the shield walls in the event of a circumferential rupture of the 36-inch line.

Each 28-inch reactor coolant inlet line and 36-inch reactor coolant outlet line has a restraint located outside of and bolted to the primary shield to limit pipe motion in the event of a circumferential rupture of the piping inside the primary shield.

A detailed study of the primary loop was performed to determine potential pipe break locations which could possibly cause either fluid impingement or pipe impact forces on the Secondary System. The results of this evaluation indicated the most credible break locations which could cause either of these effects are:

1. A guillotine break at the pump discharge in the cold leg piping;
2. A longitudinal split in the vertical pump suction segment of the cold leg piping; or,
3. A longitudinal split in the vertical segment of the hot leg piping.

All of the above breaks could potentially affect the generator because of their proximity to it. The main steam lines, however, are shielded from the effects of pipe breaks by the generator.

The primary piping and steam generator were analyzed for each of the above breaks and supports provided to restrain the pipe from whipping into the generator. In addition, the stresses in the generator shell due to the fluid impingement forces were calculated and found to be within acceptable limits.

The restraints on the primary loop are shown in Figure 5-29 and Figure 5-30. The coolant pump is restrained by steel supports from the primary shield wall. The hot leg piping is restrained by the concrete support at the primary cavity penetration, an intermediate steel support from the primary wall, and another steel support near the generator upper tube sheet. The vertical segment of the cold leg piping is restrained by a steel support midway along its length, which would spread any rupture load over a larger area of the generator shell.

The original design of the Oconee Reactor Coolant System included LOCA restraints on the RCS hot leg and cold leg piping and on the Reactor Coolant Pumps (RCPs). Their original design function was to limit the hot and cold leg RCS piping movement in the event of a guillotine break of the RCS piping.

The B&W Owners Group Topical Report BAW-1847, Revision 1 (September 1985, Reference 7), demonstrated, with a fracture mechanics evaluation of the RCS piping, that such postulated RCS piping breaks had an extremely low probability of occurrence. This fracture mechanics evaluation of the RCS piping is known as Leak-Before-Break (LBB, see Section 5.2.1.9).

The NRC approved the B&W Owners Group Topical Report in a Safety Evaluation Report dated December 12, 1985 (Reference 8). This SER and the subsequent February 18, 1986 letter to Duke (Reference 9) provided the NRC's authorization for the implementation of LBB for the Oconee Reactor Coolant System. With the implementation of LBB, the RCS piping large break LOCA's are no longer required to be postulated for the dynamic effects on the RCS piping and components, thus eliminating the need for the RCS piping and RCP LOCA restraints.

As a result of steam generator replacement for Oconee, some of the RCS piping LOCA restraints were modified or deleted, as shown in Figure 5-29 and Figure 5-30. The LOCA restraint attached to the RCS hot leg elbow located at elevation 809' was partially deleted. The LOCA restraints attached to the RCS cold leg piping located at elevation 794' were completely deleted. The LOCA restraints attached to the RC pumps were completely deleted.

As shown in Figure 5-29 and Figure 5-30, some of the original LOCA restraints were retained after steam generator replacement. Each steam generator has a support located opposite the upper tube sheet and transfers forces from the steam generator into the shield walls in the event of a circumferential rupture of the 36-inch line.

Each 28-inch reactor coolant pump inlet line and 36-inch reactor coolant pump outlet line has a restraint located outside of and bolted to the primary shield to limit pipe motion in the event of a circumferential rupture of the piping inside the primary shield. The hot leg restraints were partially deleted during steam generator replacement.

The original restraints were installed based on a detailed study of the primary loop that was performed to determine potential pipe break locations which could possibly cause either fluid impingement or pipe impact forces on the Secondary System. The results of this evaluation indicated the most credible break locations which could cause either of these effects are:

1. A guillotine break at the coolant pump discharge in the cold leg piping;
2. A longitudinal split in the vertical reactor coolant pump suction segment of the cold leg piping; or,
3. A longitudinal split in the vertical segment of the hot leg piping.

All of the above breaks could potentially affect the steam generator because of their proximity to it. The main steam lines, however, are shielded from the effects of pipe breaks by the steam generator. The primary piping and steam generator were analyzed for each of the above breaks and supports provided to restrain the pipe from whipping into the steam generator. In addition, the stresses in the steam generator shell due to the fluid impingement forces were calculated and found to be within acceptable limits.

The restraints on the primary loop are shown in Figure 5-29 and Figure 5-30. The reactor coolant pump was restrained by steel supports from the primary shield wall. The hot leg piping is restrained by the concrete support at the primary cavity penetration (which was partially deleted during steam generator replacement), an intermediate steel support from the primary wall, and another steel support near the steam generator upper tube sheet. The vertical segment of the cold leg piping was restrained by a steel support midway along its length, which would spread any rupture load over a larger area of the steam generator shell.

To verify the location and size of the piping supports, the piping was analyzed for rupture loads occurring at the worst point along its length. The rupture thrust force was assumed equal to P x A, where P is the coolant pressure and A the flow-sectional area of the pipe. The thrust was applied as an equivalent static force using a dynamic load factor of 2.0. Assuming the force to be a point load acting at the midpoint of the span between supports, the piping stresses were calculated using beam models. The supports were located so as to prevent the formation of plastic hinges in the piping, which would lead to an unstable linkage-type structure and possible impacting against the generator.

To evaluate the effect of fluid jet impingement on the generator, an equivalent static pressure load on the shell was calculated. A break of 14 ft^2 for the hot leg or 8.5 ft^2 for the cold leg was assumed. The maximum initial mass velocity was computed using the methods outlined in the report "Maximum Two-Phase Vessel Blowdown From Pipes, APED-4827," by F. J. Moody. It was assumed that the fluid leaves the break in a direction normal to the pipe and that its velocity undergoes a 90° change in direction upon impinging on the steam generator. The resulting shell pressure loading was calculated to be 1300 psi.

A shell analysis was performed on the steam generator to determine the stress intensity due to the above loading. A B&W proprietary digital computer code, which considers two-dimensional shells with asymmetric loading, was utilized. The loading distribution and stress model are shown in Figure 5-31 and Figure 5-32. The maximum stress intensity was computed to be 38,600 psi. This is less than the allowable stress of 46,670 psi. Based on these results for the 36- inch i.d. pipe break, it was concluded that the steam generator shell could also withstand the reduced loading which would be generated by a 28-inch i.d. break.

5.4.8.6.1 Replacement Steam Generator LOCA Analysis

For the replacement steam generator RCS structural analysis, there are ten high energy line breaks considered.

1. Single Main Steam Line Break
2. Double Main Steam Line Break
3. Single Main Feedwater Line Break
4. Double Main Feedwater Line Break
5. Surge Line Break at the Hot Leg Nozzle
6. Surge Line Break at the Pressurizer Nozzle
7. Surge Line Break at the Intermediate Surge Line Drain, North Direction Thrust
8. Surge Line Break at the intermediate Surge Line, East Direction Thrust
9. Decay Heat Line Break at the Hot Leg Nozzle
10. Core Flood Line Break

For each of the ten breaks the replacement steam generator and primary piping whip restraints are considered inactive because the component displacements are not large enough to cause a contact between the restraint and the component. The restraints on the reactor coolant pumps were not included in the analysis because they are to be removed during the steam generator replacement.

Each of the above high energy line breaks were analyzed using the proprietary Framatome ANP computer program BWSPAN to calculate the loads incurred through out the reactor coolant system due to the effects of jet impingement and asymmetric cavity pressure. All of the reactor coolant system piping, components and supports have been shown to be acceptable for the loading applied by each of the above high energy line breaks.

5.4.9 References

1. BAW-10040, Reactor Coolant Pump Assembly Overspeed Analysis
2. Letter from H. B. Tucker (Duke) to H. R. Denton (NRC) dated October 1, 1985. Subject: Performance Testing of Relief and Safety Valves.
3. Babcock & Wilcox Owners Group Safe End Task Force Report on Generic HPI/MU Nozzle Component Cracking. B&W Document #77-1140611-00, submitted by Duke to the NRC in a letter dated February 15, 1983.
4. Letter from L. A. Weins (NRC) to H. B. Tucker (Duke) dated July 19, 1989. Subject: Safety Evaluation Report for NUREG-0737, Item II.D.1, Performance Testing of Relief and Safety Valves for Oconee Units 1, 2, and 3 (TACS 44600, 44601, and 44602).

5. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3*, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, - 270, and -287.
6. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.
7. B&W Owners Group Topical Report "The B&W Owners Group Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSSS", BAW-1847, Revision 1, September 1985.
8. Letter from Dennis M Crutchfield (NRC) to L. C. Oakes (B&W Owner Group) dated December 12, 1985, Subject: "Safety Evaluation of B&W Owners Group Report with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops"
9. Letter from John F. Stoltz (NRC) to H. B. Tucker (Duke) dated February 18, 1986, Subject: "Safety Evaluation of B&W Owners Group Report with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops"
10. Letter from Leonard A. Wiens (NRC) to J. W. Hampton (Duke) dated March 24, 1995, Subject: "Evaluation of the Oconee, Units 1, 2, and 3 Generic Safety Issues (GSI) Resolution" (GSI-23, GSI-105, and GSI-153)
11. H. B. Tucker (Duke) Letter to H. R. Denton (NRC) dated December 12, 1984, Subject: "DPC Intent Regarding Natural Circulation Cooldown Per Generic Letter 81-21"

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Appendix 5A. Tables

Table 5-1. Reactor Coolant System Pressure Settings

	Pressure, psig	Capacity, lb/hr, total
Design Pressure	2500	
Pressurizer Code Safety Valves	2500	667,000
High Pressure Trip	2355[(1)]	
Pressurizer Electromatic Relief Valve		
Open	2450[(1)]	107,000
Close	2400[(1)]	
High Pressure Alarm	2255[(1)]	
Pressurizer Spray Valve		
Open	2205[(1)]	
Close	2155[(1)]	
Operating Pressure [1]	2155	
Low Pressure Alarm	2055	
Low Low Pressure Alarm	1920[(1)]	
Low Pressure Trip	1800[(1)]	
Hydrotest Pressure	3125	

Note:

1. At sensing nozzle on reactor outlet pipe.

Table 5-2. Transient Cycles for RCS Components Except Pressurizer Surge Line

Transient Number	Transient Description (ASME Category)	Design Cycles	Component Exceptions (See notes)
1A	Heatup from 70°F to 8% Full Power (Normal)		
	Total	360	(1)
1B	First 25% of Plant Life Cooldown from 8% Full Power (Normal)	90	
	Last 75% of Plant Life Cooldown from 8% Full Power (Normal)	270	
	Total	360	(1)
2	Power Change 0 to 15% and 15 to 0% (Normal)	1440	
3	Power Loading 8 to 100% Power (Normal)	18,000	(7)
4	Power Unloading 100 to 8% Power (Normal)	18,000	(7)
5	10% Step Load Increase (Normal)	8,000	
6	10% Step Load Decrease (Normal)	8,000	
7	Step Load Reduction (100 to 8% Power) (Upset)		
	Resulting from turbine trip	160	
	Resulting from electrical load rejection	150	
	Total	310	
8	Reactor Trip (Upset)		
	Type A	40	
	Type B	160	
	Type C	90	
	Trip included in transient numbers 11, 15, 16, 17 and 21	122	
	Total[3]	412	
	Manual Actuation of High Presure Injection System after Reactor Trip	70	(2) (3)
9	Rapid Depressurization (Upset)	40	(2)
10	Change of Reactor Coolant Flow (Upset)	412	
11	Rod Withdrawal Accident (Upset)	40	
12	Hydrotests (Test)		
	All RCS components	10	(7)
13	Steady-state Power Variations (Normal)	∞	
14	Control Rod Drop (Upset)	60	
15	Loss of Station Power (Upset)	40	

Transient Number	Transient Description (ASME Category)	Design Cycles	Component Exceptions (See notes)
16	Steam Line Failure (Faulted)	1	
17A	Loss of Feedwater to One Steam Generator (Upset)	30	
17B	Stuck Open Turbine Bypass Valve (Emergency)	10	
18	Loss of Feedwater Heater (Upset)	620	
19	Feed and Bleed Operations (Normal)	4,000	(3)
20	Miscellaneous (Normal)		
	Miscellaneous A	30,000	(3)
	Miscellaneous B	20,000	
	Miscellaneous C	$4x10^6$	
21	Loss of Coolant (Faulted)	1	(4)
22	Test Transients (Test)		
	High Pressure Injection System	40	(3)
	Core flooding check valve	240	

Component and General Flaw Location	Limiting Transient	Total Allowable Transient Cycles
Deleted row(s) per 2004 update		
Deleted row(s) per 2003 update		

Note:

1. Certain components have flaw tolerance evaluations as allowed by ASME Section XI (Refer to Section 5.2.2 and 5.2.3.12.4) that assume a reduced number of heatup and cooldown cycles. The lowest of the reduced number of cycles is used as the limit for the number of unit heatups and cooldowns. These evaluations will be updated, the flaws will be reexamined, or the flaws will be removed if the reduced number of transient cycles becomes limiting. A tabulation of the evaluations is presented below.
2. Some components are evaluated to less than the design number of cycles and are tracked within the ONS Thermal Fatigue Management Program. The number of actual events are expected to remain below the analyzed number of events throughout the current 60-year plant life.
3. Not applicable to replacement Steam Generators.
4. Deleted Per 2003 Update
5. Deleted Per 2004 Update
6. Deleted Per 2004 Update
7. The Reactor Vessel closure head assemblies are limited to 5000 power loading and unloading cycles and 15 hydrotests as discussed in Supplement B of OSS-0279.00-00-0003.

Table 5-3. Stress Limits for Seismic, Pipe Rupture, and Combined Loads

Case	Loading Combination	Stress Limits
I	Design loads + operating basis earthquake loads	$P_m \leq 1.0\ S_m$ $(P_L + P_b) \leq 1.5\ S_m$
II	Design loads + safe shutdown earthquake loads	$P_m \leq 1.2\ S_m$ $(P_L + P_b) \leq 1.2\ (1.5\ S_m)$
III	Design loads + pipe rupture loads	$P_m \leq 1.2\ S_m$ $(P_L + P_b) \leq 1.2\ (1.5\ S_m)$
IV	Design loads + safe shutdown earthquake loads + pipe rupture loads	$P_m \leq 2/3\ S_u$ $(P_L + P_b) \leq 2/3\ S_u$

Where[1]	P_L	=	Primary local membrane stress intensity
	P_m	=	Primary general membrane stress intensity
	P_b	=	Primary bending stress intensity
	S_m	=	Allowable membrane stress intensity
	S_u	=	Ultimate stress for unirradiated material at operating temperature

Note:

1. All symbols have the same definition or connotation as those in ASME B&PV Code Section III, Nuclear Vessels.
2. All components will be designed to insure against structural instabilities regardless of stress levels.

Table 5-4. Reactor Coolant System Component Codes

Component	Codes	Addendum
Reactor Vessel	ASME III Class A	Summer 1967[1]
Replacement Reactor Vessel Head	ASME III Class 1	1989, No addendum[3,4]
Pressurizer	ASME III Class A	Summer 1967[1]
Reactor Coolant System Piping	USAS B31.7	Errata through June[5] 1968
Feedwater Header	USAS B31.1	1967
R. C. Pump Casings	ASME III Class A (not code stamped)	Summer 1967
Safety and Relief Valves	ASME III Art. 9	Summer 1967
Welding Qualifications	ASME III and IX	Summer 1967
Replacement Steam Generator (primary and secondary sides)	ASME III Class 1	1989 No addendum

Note:

1. Welded joints tested in accordance with requirements of Article 7, Summer 1966 Addenda.
2. This table reflects original design/construction code information. Refer to UFSAR Section 5.2.2 for additional information on Reactor Coolant System Codes and Classifications.
3. Input Document for Replacement RVCHA Licensing and Safety Evaluation, Babcock & Wilcox Canada, BWC Report No. 068S-LR-01 Rev 2; OM 201.R-0141.001.
4. History Docket for Closure Heads, Customer Spec.# OSS-0279.00-00-003, Babcock & Wilcox Canada, BWC-Cont. 068S, 068S-01.
5. Reactor Coolant piping was requalified to the 1983 ASME code during the Steam Generator Replacement project.

Table 5-5. Materials of Construction

Component	Section	Materials
Reactor Vessel	Pressure Plate	SA-533, Grade B, Class 1 [1]
	Pressure Forgings	A-508-64, Class 2 (Code Case 1332-3)
	Cladding	18-8 Stainless Steel or Ni-Cr-Fe
	Studs, Nuts and Washers	A-540, Grade B23 or B24 (Code Case 1335-2)
	Thermal Shield and Internals	SA-240, Type 304
	Guide Lugs	Ni-Cr-Fe, SB-168 (Code Case 1336)
Replacement Reactor Vessel Head	Pressure Forging	SA-508, Class 3 [2,3]
	Cladding	308L/309L [2,3]
	CRDM Flange	SA-182, Grade F316LN [2,3]
	CRDM Guide Tube	SB-167 UNS N06690 (ASME Section III Code Case N474-2) [2,3]
Steam Generator	Deleted per 2004 update	
	Pressure Forgings	SA-508 CL.3A
	Cladding for Heads	308L/309L Stainless Steel
	Cladding for Tube Sheets	UNS N06052 (Code Case 2142)
	Tubes	SB-163 UNS N06690 (Code Case N-20-4)
	Studs - Reactor Coolant Side	SA-193, Grade B7
	Nuts - Reactor Coolant Side	SA-194, Grade 7
	Studs - Secondary Side	SA-193, Grade B7
	Nuts - Secondary Side	SA-194, Grade 7
Pressurizer	Shell, Heads, and External Plate	SA-212, Grade B
	Forgings	A-508-64, Class 1 (Code Case 1332-3)
	Cladding	18-8 Stainless Steel
	Studs and Nuts	SA-320, Grade L43
	Internal Plate	SA-240, Type 304
	Internal Piping	SA-312, Type 304
	Sampling and Level Indication Piping Safe Ends	SA-479, Type 316
Reactor Coolant Piping	28 in. and 36 in.	SA-516, Grade 70 (Elbows) A-106, Grade C (Straights)
	Cladding	18-8 Stainless Steel

Component	Section	Materials
	10 in. Surge Line and 2-1/2 in. Spray Line	A-403, Grade WP 316 (Elbows) A-376, Type 316 (Straights)
	Piping Safe Ends	SA-479, Type 316; A-376, Type 316 and Ni-Cr-Fe, SB-166
Reactor Coolant Pumps		
Oconee 1	Forging	
	Stainless Steel	SA182, 304
	Static Casting	
	Stainless Steel	SA-351, Gr. CF8
	Seal Housing	SA-351, Gr. CF3 or SA-182, F316
	Tubing and Pipe	
	Stainless Steel	SA-213, Type 316 or 304 and SA-376 or 312 (Seamless) Type 304 or 316
	Bolting Material	SA-193, SA-540
	Welding Filler Metals	SA-298 or SA-371
	Plate, Sheet and Strip	SA-240
Oconee 2 & 3	Castings	
	Casing	A-351, Grade CF8M
	Stuffing Box	A-351, Grade CF8M
	Forgings	
	Shaft	A-473, Type 316
	Bolting	
	Casing Studs	A-193, Grade B7
	Casing Nuts	A-194, Type 2H
Valves	Valve Bodies	A-351, Grade CF8M A-182, F316 and F347; SA-479, Type 316

Note:

1. This material is metallurgically identical to SA-302, Grade B, as modified by Code Case 1339.
2. Input Document for Replacement RVCHA Licensing and Safety Evaluation. Babcock & Wilcox Canada, BWC Report No.068S-LR-01 Rev. 2, OM 201.R-0141.001.
3. History Docket for Closure Heads, Customer Spec# OSS-0279.00-00-0003, Babcock & Wilcox Canada, BWC-CONT. 068S, 068S-01 (Vol. 1 of 4).

Table 5-6. Summary of Primary Plus Secondary Stress Intensity for Components of the Reactor Vessel

Area	Stress Intensity psi	Allowable Stress 3 S_m, psi (Operating Temperature)
Control Rod Housing	24,800	69,900
Head Flange	58,000	80,000
Vessel Flange	43,000	80,000
Closure Studs	89,400	107,400
Primary Nozzles -Inlet	24,000	80,000
Outlet	24,000	80,000
Bottom Head to Shell	23,300	80,000
Bottom Instrumentation	10,100	69,900
Nozzle Belt to Shell	32,300	80,000
Core Flooding Nozzle	23,660	80,000
Support Skirt	88,000	93,700

Note:

1. Locations or points of stress analysis are illustrated on Figure 5-10.
2. "The values shown in this table are historical. See calculation OSC-1815 for current values."

Table 5-7. Summary of Cumulative Fatigue Usage Factors for Components of the Reactor Vessel

Item		Usage Factor[1]
Control Rod Housing		0.0
Head Flange		0.10
Vessel Flange		0.05
Stud bolts		0.38
Primary Nozzles –	Inlet	0.06
	Outlet	0.06
Bottom Head to Shell		0.0
Bottom Instrumentation		0.0
Nozzle Belt to Shell		0.0
Core Flooding Nozzle		0.02
Support Skirt		0.14

Note:

1. As defined in Section III of the ASME Boiler and Pressure Vessel Code, Nuclear Vessels.

   "The values shown in this table are historical. See calculation OSC-1815 for current values."

   Points of stress analysis are illustrated on Figure 5-10.

Table 5-8. Stresses Due to a Maximum Design Steam Generator Tube Sheet Pressure Differential of 2,500 psi at 650°F

Stress	Computed Value	Allowable Value
	Original Steam Generator	
Deleted row(s) per 2004 update		
	Replacement Steam Generator	
Primary Membrane	16.5 Ksi	30.0 Ksi (S_m)
Primary Membrane plus Primary Bending	30.1 Ksi	45.0 Ksi (1.5 S_m)

Table 5-9. Ratio of Allowable Stresses to Computed Stresses for a Steam Generator Tube Sheet Pressure Differential of 2,500 psi

Component Part	Stress Ratio
Original Steam Generator	
Deleted row(s) per 2004 update	
Replacement Steam Generator	
Primary Head	2.21
Primary Head Tube Sheet Joint	1.53
Tubes	1.20
Tube Sheet	
Average Membrane SI ratio	1.82
Membrane plus bending SI ratio	1.50

Table 5-10. Fabrication Inspections

Component	RT	UT	PT	MT	ET
1. Reactor Vessel					
1.1 Forgings					
1.1.1 Flanges		X[1]		X	
1.1.2 Studs, Bar		X			
1.1.3 Studs After Final Machining				X	
1.1.4 Skirt Adaptor		X[1]			
1.1.5 Nozzle Shell Forgings		X		X	
1.1.6 Main Nozzle Forgings		X		X	
1.1.7 Dutchman Forging		X[1]		X	
Deleted row(s) per 2004 update					
1.1.10 Replacement RVH CRDM Nozzle Flange		X [7,8]	X [7,8]		
1.1.11 Replacement RVH CRDM Nozzle Guide Tube		X [7,8]	X [7,8]		
1.1.12 Replacement Reactor Vessel Closure Head		X [7,8]	X [7,8]	X [7,8]	
1.2 Plates					
1.2.1 Head and Shell Plate		X[1]		X[6]	
1.2.2 Support Skirt		X[1]		X[6]	
1.3 Instrumentation Tubes		X	X		
1.4 Closure O-Rings		X	X		
1.5 Weldments					
1.5.1 Longitudinal and Circumferential Main Seams	X			X	
1.5.2 CRD Mechanism Adaptor to Shell	X		X		
1.5.3 CRD Mechanism Adaptor to Flange	X		X		
1.5.4 Main Nozzles	X			X	
1.5.5 Instrumentation Nozzle Connection			X		
1.5.6 Nozzle Safe-Ends, Weld Deposit		X	X		

Component	RT	UT	PT	MT	ET
1.5.7 Temporary Attachment After Removal				X	
1.5.8 All Accessible Welds After Hydrotest				X	
1.5.9 O-Ring Closure Weld	X		X		
1.5.10 Cladding, Sealing Surfaces		X[6,2]	X		
1.5.11 Cladding, All Other		X[6,3]	X		
1.5.12 Insulation Support Lugs				X	
1.5.13 Replacement RVH					
CRDM Nozzle Flange to guide Tube Weld	X[7,8]		X[7,8]		
CRDM Nozzle to Replacement RVCH Weld			X[7,8]		
2. Replacement Steam Generator					
2.1 Tube Sheet					
2.1.1 Forging		X		X	
2.1.2 Cladding		X	X		
2.2 Heads					
2.2.1 Forging		X		X	
2.2.2 Cladding		X	X		
2.3 Shell					
2.3.1 Forging		X		X	
2.4 Tubes		X	X		X
2.5 Nozzles (Forgings)		X	X or	X	
2.6 Studs, Bar					
2.7 Studs After Final Machining				X	
2.8 Weldments					
2.8.1 N/A					
2.8.2 N/A					
2.8.3 Shell, Circumferential	X	X		X	
2.8.4 Cladding, Sealing Surfaces		X	X		
2.8.5 Cladding, all other		X	X		

Component	RT	UT	PT	MT	ET
2.8.6 Nozzle to Shell (Steam Noz)	X	X		X	
2.8.7 Level Sensing/Drain Connection		X	X		
2.8.8 Instrument Connection			X		
2.8.9 Conical Support	X		X		
2.8.10 Tube to Tubesheet		X			
2.8.11 Temporary Attachment after Removal		X or	X		
2.8.12 Hydrostatic Test (All Accessible Welds)		X or	X		
2.8.13 Lifting Lugs		X or	X		
2.8.14 N/A					
3. Pressurizer					
3.1 Heads					
3.1.1 Plate		X[1]		X	
3.1.2 Cladding		X[6,3]	X		
3.2 Shell					
3.2.1 Forging		X[1]		X	
3.2.2 Plate		X[1]		X[6]	
3.2.3 Cladding		X[6,3]	X		
3.3 Heater Bundles					
3.3.1 Cover Plate		X		X	
3.3.2 Diaphragm and Spacer Plate		X	X		
3.3.3 Studs, Bar		X			
3.3.4 Studs and Nuts After Final Machining				X	
3.3.5 Heaters					
3.3.5.1 Tubing		X	X[6]		
3.3.5.2 Positioning of Heater Element in Tube	X				
3.4 Nozzle (Forgings)		X		X	
3.5 Weldments					

Component	RT	UT	PT	MT	ET
3.5.1 Shell, Longitudinal as Deposited by Submerged Arc	X			X	
3.5.2 Shell, Longitudinal as Deposited by Electroslag	X	X		X	
3.5.3 Shell, Circumferential	X			X	
3.5.4 Cladding, Sealing Surfaces		X[6,2]	X		
3.5.5 Cladding, All Other		X[6,2]	X		
3.5.6 Nozzle to Shell	X			X	
3.5.7 Nozzle Safe-Ends (If Weld Deposit)		X	X		
3.5.8 Nozzle Safe-End (If Forging or Bar)	X		X		
3.5.9 Instrumentation and Vent Connections			X		
3.5.10 Support Brackets				X	
3.5.11 Heater Guide Tube Pad		X	X		
3.5.12 Temporary Attachment After Removal				X	
3.5.13 All Accessible Welds After Hydrotest				X	
3.5.14 Insulation Support Pads				X	
4. Piping					
4.1 Pipe					
4.1.1 Forgings		X[1]		X	
4.1.2 Cladding		X[6,3]	X		
4.2 Bends					
4.2.1 Plate		X[1]		X[6]	
4.2.2 Cladding		X[6,3]	X		
4.3 Nozzle Forgings		X		X	
4.4 Weldments					
4.4.1 Longitudinal	X			X	
4.4.2 Circumferential	X			X	
4.4.3 Cladding, Elbows		X[6,3]	X		
4.4.4 Cladding, Straight		X[6,3]	X		

Component	RT	UT	PT	MT	ET
4.4.5 Nozzles to Run Pipe	X			X	
4.4.6 Thermowell Connections			X		
4.4.7 Insulation Support Lug Pads				X	
5. Reactor Coolant Pumps					
5.1 Castings	X		X		
5.2 Forgings		X	X		
5.3 Weldments					
5.3.1 Circumferential	X		X		
5.3.2 Piping Connections			X		
6. Valves					
6.1 Castings	X		X		
6.2 Forgings		X	X		

Note:

1. 100% scanning for longitudinal wave technique and 100% shear wave technique.
2. UT of clad defects and bond to base metal.
3. UT of clad bond to base metal (spot check).
4. Also gas leak test--B&W requirement.
5. Over 12-inch length on each end.
6. Additional B&W requirement.

   RT: Radiographic
   UT: Ultrasonic
   PT: Dye Penetrant
   Mt: Magnetic Particle
   ET: Eddy Current

7. Input Document for Replacement RVCHA Licensing and Safety Evaluation. BWC Report No. 068S-LR-01 Rev. 2, OM 201.R-0141.001.
8. History Docket for Closure Heads, Customer Spec. No. OSS-0279.00-00-003, Babcock & Wilcox Canada, BWC-CONT. 068S, 068S-01 (Vol. 1-2 of 4).

Table 5-11. Reactor Vessel Design Data

Design Pressure, psig			2500
Design Temperature, °F			650
Coolant Operating Temperature, Inlet/Outlet, °F			554/604
Hydrotest Pressure, psig			3125
Coolant Volume (Hot, Core and Internals in Place), ft^3			4058
Reactor Coolant Flow, lb/hr			131.32×10^6
Number of Reactor Closure Head Studs			60
Diameter of Reactor Closure Head Studs, in.			6-1/2
Vessel Dimensions			
Overall Height of Vessel and Closure Head, ft-in.[1]			40-8-3/4
Shell i.d., in.			171
Flange i.d., in.			165
Straight Shell Minimum Thickness, in.			8-7/16
Shell Cladding Minimum Thickness, in.			1/8
Shell Cladding Nominal Thickness, in.			3/16
Insulation Thickness, in.			3
Replacement Closure Head Insulation Thickness, in.			3 1/4[6]
Replacement Closure Head Nominal Thickness, in.			7[4,5]
Lower Head Minimum Thickness, in.			5
Vessel Nozzles			
Function	No.	ID, in.	Material
Coolant Inlet	4	28	Carbon Steel - SS Clad
Coolant Outlet	2	36	Carbon Steel - SS Clad
Core Flooding - LP Injection	2	12	Carbon Steel[2] - SS Clad
Control Rod Drive	61	2.76	Inconel[3]
Axial Power Shaping Rod Drive	8	2.76	Inconel[3]
Row(s) Deleted Per 2000 Update			
In-Core Instrumentation	52	3/4 Sch 160	Inconel
Dry Weight, lbs			
Vessel			646,000
Replacement Closure Head			155,200[4,7]
Studs, Nuts, and Washers			39,500

Note:

1. Instrument nozzle to CRD flange.
2. With stainless steel safe end added after stress relief.
3. With stainless steel flanges.
4. Input Document for Replacement RVCHA Licensing and Safety Evaluation. Babcock & Wilcox Canada, BWC Report No. 068S-LR-01 Rev. 2, OM 201.R-0141.001.
5. History Docket for Closure Heads, Customer Spec. #OSS-0279.00-00-003, Babcock & Wilcox Canada, BWC-CONT. 068S, 068S-01 (Vol. 1 of 4).
6. Transco Drawing RT-48783-DR1, RPV Top Head Service Structure Insulation Drip Panels Key Layout and Details (Layout D1), OM 241.R—0005,001.
7. BWC Drawing 068SE001, RPV Closure Head General Arrangement, OM 201.R—0001.001.

Table 5-12. Reactor Vessel -- Physical Properties (Oconee 1)

Item	Heat No.	Ultimate Strength (10^3 psi)	Yield Strength (10^3 psi)	Elong. in 2 in. (%)	Impact Test Temp. (°F)	Impact Values
Deleted row(s) per 2003 update						
Bottom Head	A 0973-2	87.2	65.0	24.5	+10	35-30-47
Intermediate Shell Plate	C 2197-2	91.5	70.0	25.0	+10	39-45-26
Upper Shell Plate (1)	C 3265-1	87.0	66.2	28.1	+10	34-64-27
Upper Shell Plate (2)	C 3278-1	84.5	63.5	28.1	+10	35-29-53
Lower Shell Plate (1)	C 2800-1	85.0	60.5	29.0	+10	36-39-39
Lower Shell Plate (2)	C 2800-2	90.5	69.0	25.0	+20	32-33-49
Core Flooding Nozzle	94894	98.0	74.0	21.5	+10	45-53-40
Core Flooding Nozzle	94894	92.5	71.0	24.0	+10	37-50-45
Inlet Nozzle	123S346VA1	90.0	67.5	25.0	+10	104-94-142
Inlet Nozzle	123S346VA2	92.7	72.5	26.0	+10	104-121-106
Inlet Nozzle	124S502VA1	97.2	76.0	25.0	+10	120-106-101
Inlet Nozzle	124S502VA1	94.0	73.5	23.5	+10	110-85-77
Outlet Nozzle	122S316VA2	90.0	67.0	26.0	+10	131-110-94
Outlet Nozzle	122S316VA1	90.0	68.5	25.0	+10	92-86-82
Upper Shell Flange	4P16373P156 6	82.5	57.4	29.0	+10	49-41-71
Dutchman Forging	122S347VA1	94.5	74.5	24.0	+10	92-70-70
Deleted row(s) per 2003 update						
Upper Nozzle Belt Forging	ZV-2888	82.0	57.0	30.5	+34 avg	30 avg
Lower Nozzle Belt Forging	ZV-2861	85.0	63.5	29.0	+26 avg	30 avg

Item	Heat No.	Ultimate Strength (10^3 psi)	Yield Strength (10^3 psi)	Elong. in 2 in. (%)	Impact Test Temp. (°F)	Impact Values
Replacement RVH Forging	O1W60-1-1	87.7 avg	66.4 avg	29.4 avg		

Note:

1. From History Docket for Closure Heads, Customer Spec. #OSS-0279.00-00-003, Babcock & Wilcox Canada, BWC-CONT. 068S, 068S-01, Vol. 1 of 4.

Table 5-13. Reactor Vessel - Chemical Properties (Oconee 1). (References 34, 60)

	Element											
Heat Number	**C**	**Mn**	**P**	**S**	**Si**	**Ni**	**Mo**	**Co**	**V**	**Cr**	**Cu**	**A1**
Deleted row(s) per 2003 update												
A 0973-2	.21	1.34	.011	.016	.18	.46	.47	.010	--	--	--	--
C 2197-2	.21	1.28	.008	.010	.17	.50	.46	.021	--	--	--	--
C 3265-1	.21	1.42	.015	.015	.23	.50	.49	.016	--	--	--	--
C 3278-1	.19	1.26	.010	.016	.23	.60	.47	.016	--	--	--	--
C 2800-1	.20	1.40	.012	.017	.20	.63	.50	.014	--	--	--	--
C 2800-2	.20	1.40	.012	.017	.20	.63	.50	.014	--	--	--	--
94894	.22	0.62	.006	.009	.23	.87	.60	.016	--	0.33	--	--
123S346VA1	.22	.61	.010	.010	.20	.69	.56	.01	0.01	.27	--	--
123S346VA2	.21	.62	.010	.008	.20	.69	.57	.01	.01	.28	--	--
124S502VA1	.22	.65	.010	.010	.22	.75	.59	.02	.01	.35	--	--
124S502VA2	.23	.68	.010	.014	.22	.78	.60	.02	.01	.31	--	--
122S316VA2	.20	.62	.010	.009	.28	.73	.57	.013	.01	.33	--	--
122S316VA1	.18	.58	.010	.014	.28	.68	.61	.015	.01	.32	--	--
4P16373P1566	.20	.72	.010	.012	.28	.74	.55	.011	.03	.34	--	--
122S347VA1	.20	.62	.010	.008	.25	.66	.55	.021	.02	.32	--	--
Deleted row(s) per 2003 update												
ZV-2888	.22	.70	.010	.008	.32	.62	.59	.007	.02	.36	--	--
ZV-2861	.18	0.64	0.006	0.010	0.29	0.65	0.57	0.01	0.01	0.31	--	--
O1W60-1-1	.18	1.46	.005	<0.0001	.17	.89	.51	--	<0.003	.15	0.05	0.021

Note:

1. From History Docket for Closure Heads, Customer Spec. #055-0279.00-00-003, Babcock & Wilcox Canada, BWC-CONT. 068S, 068S-01, Vol. 1 of 4

Table 5-14. Reactor Vessel - Mechanical Properties (Oconee 2 & 3). (Reference 33)

	Specimen Description	Drop Weight NDT (F)	Cv Energy at +10°F (ft - lb)	Approximate Upper Shelf Cv Energy (ft-lb)
Oconee 2				
Top Shell Forging	C.1/5 T[1]	+20	86, 46, 79	127
	C.1/4 T	+10	100, 89, 72	140
	C.1/2 T	+20	62, 77, 40	141
Bottom Shell Forging	C.1/5 T[1]	+20	116, 93, 104	140
	C.1/4 T	+20	82, 83, 90	139
	C.1/2 T	+20	101, 89, 92	149
Top Weld Deposit (WF 154)	1/4T	Not Available	41, 37, 43	Not Available
Center Weld Deposit (WF 25)	1/4T	Not Available	38, 28, 49	Not Available
Bottom Weld Deposit (WF 112)	1/4T	Not Available	35, 40, 30	Not Available
Oconee 3				
Top Shell Forging	C 1/5 T[1]	+40	76, 82, 46	116
	C 1/4 T	+30	85, 77, 78	136
	C 1/2 T	+30	82, 55, 91	119
Bottom Shell Forging	C 1/5 T[1]	+20	49, 83, 43	155
	C 1/4 T	+40	39, 50, 66	152
	C 1/2 T	+20	24, 34, 14	154
Oconee 3				
Top Weld Deposit (WF 200)	1/4 T	Not Available	36, 35, 26	Not Available
Outer Weld Deposit (WF 67)	1/4 T	Not Available	29, 35, 30	Not Available
Bottom Weld Deposit (WF 169-1)	1/4 T	Not Available	42, 29, 46	Not Available

Note:

1. Circumferential, 2 inches from surface.
2. In addition to the impact tests required by the ASME Code, the Nil-Ductility Temperature and Charpy V-notch energy levels at several temperatures were obtained for the two

	Specimen Description	Drop Weight NDT (F)	Cv Energy at +10°F (ft - lb)	Approximate Upper Shelf Cv Energy (ft-lb)

forgings that comprise the core region of the reactor vessels. The forging material is ASTM A508-64 Class 2 as modified by Code Case 1332-4. The impact tests were taken at 2 inches from surface, 1/4 and 1/2 of the forging thickness, and oriented in the circumferential direction with the length of the notch of the Charpy V-notch perpendicular to the surface of the material. The weld deposits of the core region (circumferential welds) were impact tested at plus 10°F using Charpy V-notch specimens oriented perpendicular to the direction of welding with the notch normal to the surface. No upper shelf fracture energy levels were obtained for the weld deposits.

Table 5-15. Reactor Coolant Flow Distribution with Less than Four Pumps Operating

	Oconee 1 (10^6 lb/hr)	Oconee 2 or 3 (10^6 lb/hr)
"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"		
3 Pumps		
Flow in loop with two pumps	68.92	71.1
Flow in loop with one pump	29.95	29.5
Flow of pump in one pump loop	43.50	43.6
Idle pump reverse flow	13.55	14.1
2 Pumps - 2 Loops		
Pump flow each loop	44.49	44.5
Steam generator flow each loop	32.67	32.6
Reverse flow each idle pump	11.82	11.9
2 Pumps - 1 Loop		
Operating loop flow	71.22	73.6
Idle loop reverse flow	10.82	11.9
1 Pump		
Operating pump flow	45.06	45.0
Operating loop idle pump reverse flow	10.65	10.6
Idle loop reverse flow	5.23	5.5

Note:

1. For the configurations with both loops in operation the temperature in the cold legs will be the core inlet temperature (about 554°F). The hot leg fluid will be at about 604°F.
2. The reactor will not be operated at power in the 2 pump - single loop configuration.

Table 5-16. Reactor Coolant Pump - Design Data (Oconee 1)

Design Pressure/Operating Pressure, psig	2500/2185
Hydrostatic Test Pressure (cold), psig	4100
Design Temperature (casing), °F	650
Operating Speed, rpm	1190
Suction Temperature, °F	554
Developed Head, ft	350
Capacity, gal/min	88,000
Seal Water Injection, gal/min	8
Seal Return, gal/min	2.2 (1A1, 1B2), 2.0 (1A2, 1B1)
Pump Discharge Nozzle i.d., in.	28
Pump Suction Nozzle i.d., in.	31
Overall Unit Height, ft-in. (Pump - Motor)	29' 9"
Weight (dry), lb (without motor)	99,600
Coolant Volume, ft^3	56
Pump-motor moment of inertia, $lb\text{-}ft^2$	70,000
Injection Water Temperature, °F	125
Cooling Water Temperature, °F	105
Motor Data	
Type	Squirrel Cage Induction Single Speed, Water Cooled
Voltage	6600
Phase	3
Frequency, Hz	60
Insulation Class	F
Starting Current, amp	4350
Power, HP (Nameplate)	9000

Table 5-17. Reactor Coolant Pump - Design Data (Oconee 2, 3) (Data per Pump)

Design Pressure/Temperature, psig/°F	2500/650
Hydrotest Pressure, psig	3750
RPM at Nameplate Rating	1190
Developed Head, ft	362
Capacity, gal/min	92,200
Seal Water Injection, gal/min	10
Seal Water Return, gal/min	1.5
Injection Water Temperature, °F	120°F ± 10°F
Cooling Water Temperature, °F	105
Pump Discharge Nozzle i.d., in.	28
Pump Suction Nozzle i.d., in.	28
Overall Height, (Pump-Motor), ft-in.	29-4
Dry Weight Without Motor, lb	100,000
Coolant Volume, ft^3	98
Pump-motor Moment of Inertia, $lb\text{-}ft^2$	70,000
Motor Data	
Type	Squirrel Cage Induction Single Speed, Water Cooled
Voltage	6600
Phase	3
Frequency, Hz	60
Insulation Class	F
Starting Current, amp	4350
Power, HP (Nameplate)	9000

Table 5-18. Reactor Coolant Pump Casings – Code Allowables (Applies to Oconee 2 and 3)

Component	Material	Area	Governing Code III Para.	Condition (See Note 1)	Allowable Stress or Stress Intensity (psi)	Maximum Stress or Stress Intensity (psi)
Discharge/ Suction Nozzle (Outside Reinforcement)	ASTM A351 CF8M	Extreme Fibers	N414.3	D	1.5 S_m = 28,050	9,176
		Extreme Fibers	N414.3	A + [(B + C)/2] + P	1.5 S_m = 28,050	18,164
		Extreme Fibers	N414.4	A + [(B + C)/2] + D + P	3.0 S_m = 56,100	18,908
		Extreme Fibers	N414.3	P	1.5 S_m = 28,050	18,426
		Extreme Fibers	Note 1	A + B + C + P	1.2 x 1.5 S_m = 33,660	18,214
		Extreme Fibers	Note 1	A + B + C + D + P	1.2 x 3.0 S_m = 67,320	23,072
		Centerline Fibers	N417.9	D	1.5 S_m = 28,050	8,420
		Centerline Fibers	N417.9	A + [(B + C)/2]+ P	1.0 S_m = 18,700	16,202
		Centerline Fibers	N414.4	A + [(B + C)/2] + D + P	3.0 S_m = 56,100	18,791
		Centerline Fibers	N414.1	P	1.0 S_m = 18,700	16,380
		Centerline Fibers	Note 1	A + B + C + P	1.2 S_m = 22,440	16,490

Component	Material	Area	Governing Code III Para.	Condition (See Note 1)	Allowable Stress or Stress Intensity (psi)	Maximum Stress or Stress Intensity (psi)
		Centerline Fibers	Note 1	A + B + C + D + P	1.2 x 3.0 S_m = 67,320	22,621
Discharge/ Suction Nozzle (Inside Reinforcement)	ASTM A351 CF8M	Extreme Fibers	N414.3	A + [(B + C)/2] + D + P	1.5 S_m = 28,050	18,440
		Extreme Fibers	See Note 2	A + B + C + D + P	1.2 x 1.5 S_m = 33,660	18,362
		Centerline Fibers	N417.8	A + [(B + C)/2] + D + P	1.0 S_m = 18,700	15,970
		Centerline Fibers	See Note 2	A + B + C + D + P	1.2 S_m = 22,440	16,139
Bowl Section	ASTM A351 CF8M	Extreme Fibers	N414.3	P	1.5 S_m = 28,050	14,750
		Centerline Fibers	N414.1	P	1.0 S_m = 18,700	10,000
Cover	ASTM A182 Grade F316	Extreme Fibers	N712.1	Hydrostatic Test Pressure	0.9 S_y = 17,160	See Note 3
		Extreme Fibers	N414.3	Operating Pressure	1.5 S_m = 25,780	20,807 Note 4
		Centerline Fibers	N712.1	Hydrostatic Test Pressure	1.35 S_y = 25,740	See Note 3
		Centerline Fibers	N414.1	Operating Pressure	1.0 S_m = 17,190	14,527

Component	Material	Area	Governing Code III Para.	Condition (See Note 1)	Allowable Stress or Stress Intensity (psi)	Maximum Stress or Stress Intensity (psi)
		All Fibers	N412(m)(1)	Operating Thermal	2.0 S_y = 38,140	62,469 Note 5
		All Fibers	N414.4	Operating Pressure & Thermal	3.0 S_m = 51,570	48,440 Note 6

Notes:

1. A = Dead Load Reactions
   B = Vertical Seismic Reactions (SSE)
   C = Horizontal Seismic Reactions (SSE)
   D = Thermal Expansion Reactions
   P = 2500 psia (operating design pressure)
2. Allowable Stress specified by B & W for Reactor Coolant Piping reactions on Pump.
3. No maximum stress associated with this case, this requirement determines the hydrostatic test pressure necessary to produce the allowable stress.
4. Element 18 has maximum stress $P_m + P_b$ = 29,102, which is acceptable versus allowable 1.5S_m = 30,000 psi @ 225^o F.
5. All thermal stresses for wet and dry cooling jackets meet the provisions of paragraph N414(m)(1) vs. the allowable of 2.0 x Y.S. At several locations at the lower inside radius the localized thermal stresses exceed 2.0 x Y.S. These stresses are deemed to be peak stresses and as such are required only to be considered from a fatigue standpoint, per paragraph N412(m)(2), N412(k) and N4i4.5.
6. Three elements have maximum stress $P_m + P_b + Q$ qualified versus allowable at lower temperature, 3.0S_m = 60,000. One element has maximum stress $P_m + P_b + Q$ that exceeds allowable at lower temperature, 3.0S_m = 60,000 but this stress is considered a peaking stress, and thus the requirements of N414.4 don't apply.

Table 5-19. Deleted Per 2000 Update.

Table 5-20. Steam Generator Design Data (Data per Steam Generator)

Original Steam Generator		
Deleted row(s) per 2004 update		
Replacement Steam Generator		
Steam Conditions at Full Load, Outlet Nozzles		
	Steam Flow, lbm/hr	$5.4*10^6$
	Steam Temperature, °F	597 (BOL) / 591 (EOL), 570 (Design)
	Steam Pressure, psig	910
Feedwater Temperature, °F		460
Reactor Coolant Flow, lbm/hr		$65.66 * 10^6$ (Thermal Design Flow)
Reactor Coolant Side		
	Design Pressure, psig	2500
	Design Temperature, °F	650
	Hydrotest Pressure, psig	3125
	Coolant Volume (Hot), ft^3	2001.45 (Note 1)
	Full Load Temperature, °F	604 (inlet) / 554 (outlet) @ TDF
Secondary Side		
	Design Pressure, psig	1150 Secondary Side 1200 Feedwater
	Design Temperature, °F	630
	Hydrotest Pressure, psig	1500
	Net Volume, ft^3	3486.3
	Mass of Steam and Water at Full Load, lbm	54,696
	Energy Content of Steam and Water at Full Load, (BTU)	29.8 (BOL) / 34.0 (EOL) * 10^6
Dimensions		
	Tube, Nom. OD/Min Wall, in.	0.625/0.034
	Overall Height (Including stool), ft-in.	73-3 1/16
	Shell OD, in.	148-1/8
	Shell Minimum Thickness, in.	3

Shell Minimum Thickness at Tubesheets and F.W. Connections, in.	5
Tube Sheet Minimum Thickness, in.	22 1/16
Dry Weight, lbm	929600
Tube Length Between Tubesheets ft-in.	52-5

Function	**No.**	**ID, in.**	**Material**
Nozzles - Reactor Coolant Side			
Inlet	1	36	Carbon Steel - SS Clad
Outlet	2	28	Carbon Steel - SS Clad
Drain	N/A	N/A	N/A
Manways	2	16	Carbon Steel - SS Clad
Handholes	1	6	Carbon Steel - SS Clad
Nozzles - Secondary Side			
Steam	2	24	Carbon Steel
Vent	1	1-1/2 Sch 80	E7018-A1 SFA5.5 buildup
Drains	6	1-1/2 Sch 80	E7018-A1 SFA5.5 buildup
Level Sensing	8	1 Sch 80	E7018-A1 SFA5.5 buildup
Temperature Well	3	1-1/2" NPT	Alloy 690 buildup
Manways	2	16	Carbon Steel
Feedwater Connections	32	3 Sch 80	2 ¼ Cr-Mo piping & nozzles, Alloy 600 spargers
Emergency Feedwater Connections	6	3 Sch 80	2 ¼ Cr-Mo piping & nozzles, Alloy 600 sleeves
Handholes	5	6	Alloy 690
Inspection Ports	30	3	Carbon Steel

Note:

1. OSC-2729 Oconee Nuclear Station RETRAN Transient Analysis Model, Rev. 9, App K

Table 5-21. Reactor Coolant Piping Design Data

Reactor Inlet Piping	
Pipe i.d., in.	28
Design Pressure/Temperature, psig/°F	2500/650
Hydrotest Pressure, psig	3125
Minimum Thickness, in.	2-1/4
Coolant Volume (Hot - System Total), ft^3	1085
Dry weight, System Total, lb	214,000
Reactor Outlet Piping	
Pipe i.d. in.	36
Design Pressure/Temperature, psig/°F	2500/650
Hydrotest Pressure, psig	3125
Minimum Thickness, in.	2-7/8
Coolant Volume (Hot - System Total), ft^3	979
Dry Weight, System Total, lb	200,000
Pressurizer Surge Piping	
Pipe Size, in.	10, Schd 140
Design Pressure/Temperature, psig/°F	2500/670
Hydrotest Pressure, psig	3125
Coolant Volume, hot, ft^3	20
Dry Weight, lb	5000
Pressurizer Spray Piping	
Pipe Size, in.	2-1/2, Sch 160
Design Pressure/Temperature, psig/°F	2500/650 & 670
Hydrotest Pressure, psig	3125
Coolant Volume, hot, ft^3	2
Dry Weight, lb	650

Nozzles:

Function	**No.**	**ID, in.**	**Material**
On Reactor Inlet Piping			
High Pressure Injection	4	2-1/2 Sch 160	[1]
Pressurizer Spray	1	2-1/2 Sch 160	Stainless Steel
Drain/Letdown	1	2-1/2 Sch 160	[2]

Nozzles:

Function	No.	ID, in.	Material
Drain	3	1-1/2 Sch 160	[3]
Pressure Sensing	4	1 Sch 160	
Temperature Well	4	0.375	Inconel
Temperature Sensing	4	0.613	Inconel
On Reactor Outlet Piping			
Decay Heat	1	12 Sch 140	[2]
Vent	2	1 Sch 160	[3]
Conn. on Flow Meters	4	1 Sch 160	[3]
Pressure Sensing	4	1 Sch 160	[3]
Temperature Well	2	3/8	Inconel
Temperature Sensing	6	0.613	Inconel
Surge Line	1	10 Sch 140	[2]
On Pressurizer Surge Piping			
Drain	1	1 Sch 160	Stainless Steel
On Pressurizer Spray Piping			
Auxiliary Spray	1	1-1/2 Sch 160	Stainless Steel
Spray Valve Bypass	2	1/2 Sch 160	Stainless

Note:

1. Carbon Steel - SS Clad - With Stainless Steel Safe End Added after Stress Relief
2. Carbon Steel - SS Clad - with Inconel Safe End
3. SS pipe with Alloy 690 nozzles
4. Deleted per 2004 update

Table 5-22. Pressurizer Design Data

Design/Operating Pressure, psig			2500/2166
Design/Operating Temperature, °F			670/648
Steam Volume, ft^3			700
Water Volume, ft^3			800
Hydrotest Pressure, psig [3]			3125
Electric Heater Capacity, kW			1638[4]
Dimensions			
Overall Height, ft-in.			44-11-3/4
Shell o.d., in.			96-3/8
Shell Minimum Thickness, in.			6.188
Dry Weight, lb.			291,000
Nozzles			
Function	**No.**	**ID, in.**	**Material**
Surge Line	1	10 Sch 140	Carbon Steel - SS Clad[1]
Spray Line	1	4 Sch 120	Carbon Steel - SS Clad[2]
Relief Valve	3	2-1/2	Carbon Steel - SS Clad[1]
Vent	1	1 Sch 160	Inconel[7]
Sample	1	1 Sch 160	Carbon Steel - SS Clad[6]
Temperature Well	1	3/8	Inconel
Level Sensing	6	1 Sch 160	Carbon Steel - SS Clad[6]
Heater Bundle	3	19-1/8	Carbon Steel - SS Clad
Manway	1	16	Carbon Steel - SS Clad

Note:

1. With stainless steel safe end added after stress relief.
2. With Inconel safe end.
3. Pressure retaining part (inlet bushing) of pressurizer relief valves shop hydrotested at 3750 psig.
4. Total kw could be less depending on operational status of some heater elements.
5. Operating pressure is nominal steam space pressure based on 2155 psig at the hot leg nozzle for the pressure transmitter.
6. With Inconel or stainless steel (SA-479 Type 316) safe end.
7. With Inconel or stainless steel (SA-479 Type 316) vent nozzle.

Table 5-23. Operating Design Transient Cycles for Pressurizer Surge Line

Transient Number	Transient Description - (ASME Category)	Design Cycles		
		Oconee - 1/	-2/	-3
1A	Heatup from 70°F to 8% Full Power (Normal)			
	1A1	11	13	10
	1A2	12	14	6
	1A3	64	70	33
	1A4	45	43	51
	1A5	228	220	260
	Total Heatup Events	360	360	360
1B	Cooldown from 8% Full Power (Normal)			
	1B1	60	60	60
	1B2	300	300	300
	Total Cooldown Events	360	360	360
2	Power Change 0 to 15% and 15 to 0% (Normal)			
	2A		1,400	
	2B		1,440	
3	Power Loading 8% to 100% Power (Normal)		18,000	
4	Power Unloading 100% to 8% Power (Normal)		18,000	
5	10% Step Load Increase (Normal)		8,000	
6	10% Step Load Decrease (Normal)		8,000	
7	Step Load Reduction (100% to 8% Power) (Upset)		310	
8	Reactor Trip (Upset)			
	Type A		80	
	Type B		172	
	Type C		90	
	Type D		70	
	Total Reactor Trips		412	
9	Rapid Depressurization (Upset)		40	

Transient Number	Transient Description - (ASME Category)	Design Cycles		
		Oconee - 1/	-2/	-3
10	Change of Flow (Upset)		412	
11	Rod Withdrawal Accident (Upset)		[(1)]	
12	Hydrotests (Test)		[2]	
13	Steady-State Power Operations		1.4E5	
14	Control Rod Drop (Upset)		60	
15	Loss of Station Power (Upset)		[1]	
16	Steam Line Failure (Faulted)		[2]	
17A	Loss of Feedwater to One Steam Generator (Upset)		[1]	
17B	Stuck Open Turbine Bypass Valve (Emergency)		[1]	
18	Loss of Feedwater Heater (Upset)		-	
19	Feed and Bleed Operations (Normal)		4,000	
20	Miscellaneous (Normal)			
	A - Change in Makeup Flow Rate		30,000	
	B - Miscellaneous Spray Actuation		20,000	
	C - Change in Makeup Flow Rate		4.0E6	
	D1 - Pzr Boron Equilibration (on/off valve)		2.55E4	
	D2 - Pzr Boron Equilibration (modulating valve)		8.5E3	
21	Loss of Coolant (Faulted)		[2]	
22	Test Transients (Test)			
	A1 - High Pressure Injection System Test		5	
	B1 - High Pressure Injection System Test		15	
	C1 - High Pressure Injection System Test		10	
	D1 - High Pressure Injection System Test		10	
	Total Safety Injection Tests		40	
	A2 - HPI Check Valve Tests	8	8	8
	B2 - HPI Check Valve Tests	48	48	48

Transient Number	Transient Description - (ASME Category)	Design Cycles Oconee - 1/	-2/	-3
	C2 - HPI Check Valve Tests	15	12	9
	D2 - HPI Check Valve Tests	80	84	88
	Total Safety Injection Tests	151	152	153
23	Steam Generator Filling, Draining, Flushing and Cleaning (Normal)		-	
24	Hot Functional Testing (Test)		[3]	

Note:

1. Included in Transient 8, Reactor Trip.
2. Refer to the appropriate RCS Functional Specification for number of transient event cycles.
3. Included in Transient 1, Plant Heatup and Cooldown
4. Some Surge Line components are evaluated to less than the design number of cycles and are tracked within the ONS Thermal Fatigue Management program. The number of actual events are expected to remain below the analyzed number of events throughout the current 60-year plant life.

Table 5-24. Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 1

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	NI wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm^2 Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	AHR 54	ZV-2861	A 508 Cl. 2	0.16	0.65	+3	119.3	1.11E+18	52.2	70.7	126.0	270
Intermediate Shell Plate	C2197-2	C2197-2	SA-302 Gr. BM[1]	0.15	0.50	+1	104.5	1.18E+19	109.3	63.6	174.0	270
Upper Shell Plate	C3265-1	C3265-1	SA-302 Gr. BM[1]	0.10	0.50	+1	65.0	1.31E+19	69.9	63.6	134.5	270
Upper Shell Plate	C3278-1	C3278-1	SA-302 Gr. BM[1]	0.12	0.60	+1	83.0	1.31E+19	89.2	63.6	153.9	270
Lower Shell Plate	C2800-1	C2800-1	SA-302 Gr. BM	0.11	0.63	+1	74.5	1.31E+19	80.0	63.6	144.7	270
Lower Shell Plate	C2800-2	C2800-2	SA-302 Gr. BM[1]	0.11	0.63	+1	74.5	1.31E+19	80.0	63.6	144.7	270
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.23	0.52	-5	157.4	1.11E+18	69.0	68.5	132.4	300
IS Longit. Weld (Both 100%)	SA-1073	1P0962	ASA/Linde 80	0.21	0.64	-5	170.6	9.24E+18	166.8	68.5	230.3[(2)]	270
IS to US Circ. Weld (ID 61%)	SA-1229	71249	ASA/Linde 80	0.23	0.59	+10	167.6	1.19E+19	175.7	56.0	241.7	300

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	NI wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm^2 Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
US Longit. Weld (Both 100%)	SA-1493	8T1762	ASA/Linde 80	0.19	0.57	-5	152.4	1.12E+19	157.3	68.5	220.8	270
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.22	0.54	-5	158.0	1.27E+19	168.5	68.5	232.0	300
LS Longit. Weld (100%)	SA-1426	8T1762	ASA/Linde 80	0.19	0.57	-5	152.4	1.08E+19	155.8	68.5	219.3	270
LS Longit. Weld (100%)	SA-1430	8T1762	ASA/Linde 80	0.19	0.57	-5	152.4	1.08E+19	155.8	68.5	219.3	270
10 CFR 50.61 (Surveillance Data)												
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.23	0.52	-5	141.1	1.11E+18	61.8	48.3	105.1	300
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.22	0.54	-5	145.2	1.27E+19	155.8	48.3	199.1	300

Note:

1. SA-302 Grade B modified by ASME Code Case 1339
2. Controlling value of RT_{PTS} reference temperature

Table 5-25. Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 2

Material Description				**Chemical Composition**								
Reactor Vessel Beltline Region Location	**Matl. Ident.**	**Heat Number**	**Type**	**Cu wt%**	**NI wt%**	**Initial RT_{NDT}**	**Chemistry Factor**	**Fluence, n/cm^2 Inside Surface**	**ΔRT_{NDT}, F at 48 EFPY**	**Margin**	**RT_{PTS}, F at 48 EFPY**	**Screening Criteria**
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	AMX77	123T382	A 508 Cl. 2	0.13	0.76	+3	95.0	1.19E+19	99.6	70.7	173.3	270
Upper Shell Forging	AAW 163	3P2359	A 508 Cl. 2	0.04	0.75	+20	26.0	1.28E+19	27.8	27.8	75.6	270
Lower Shell Forging	AWG 164	4P1885	A 508 Cl. 2	0.02	0.80	+20	20.0	1.27E+19	21.3	21.3	62.7	270
LNB to US Circ. Weld (100%)	WF-154	406L44	ASA/Linde 80	0.27	0.59	-5	182.6	1.19E+19	191.5	68.5	255.0	300
US to LS Circ. Weld (100%)	WF-25	299L44	ASA/Linde 80	0.34	0.68	-5	220.6	1.23E+19	233.3	68.5	296.8[1]	300
10 CFR 50.61 (Surveillance Data)												
None												

Note:

1. Controlling value of RT_{PTS} refereence temperature

Table 5-26. Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 3

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	NI wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm^2 Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	4680	4680	A 508 Cl. 2	0.13	0.91	+3	96.0	1.14E+19	99.5	70.7	173.2	270
Upper Shell Forging	AWS 192	522314	A 508 Cl. 2	0.01	0.73	+40	20.0	1.26E+19	21.3	21.3	82.6	270
Lower Shell Forging	ANK 191	522194	A 508 Cl. 2	0.02	0.76	+40	20.0	1.26E+19	21.3	21.3	82.6	270
LNB to US Circ. Weld (100%)	WF-200	821T44	ASA/ Linde 80	0.24	0.63	-5	178.0	1.14E+19	184.6	68.5	248.1	300
US to LS Circ. Weld (ID 75%)	WF-67	72442	ASA/ Linde 80	0.26	0.60	-5	180.0	1.22E+19	190.0	68.5	253.5(1)	300
10 CFR 50.61 (Surveillance Data)												
Upper Shell Forging	AWS 192	522314	A 508 Cl. 2	0.01	0.73	+40	36.0	1.26E+19	38.3	34.0	75.5	270
Lower Shell Forging	ANK 191	522194	A 508 Cl. 2	0.02	0.76	+40	17.4	1.26E+19	18.5	17.0	112.3	270
LNB to US Circ. Weld (100%)	WF-200	821T44	ASA/ Linde 80	0.24	0.63	-5	158.3	1.14E+19	159.5	48.3	202.8	300

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	NI wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm^2 Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria

Note:

1. Controlling value of RT_{PTS} reference temperature

Table 5-27. Evaluation of Reactor Vessel Extended Life (48EFPY) Charpy V-Notch Upper-Shelf Energy - Oconee Unit 1

Material Description								
Reactor Vessel Beltline Region Location	**Matl. Ident.**	**Heat Number**	**Type**	**Copper Composition w/o**	**Initial CvUSE, ft-lbs**	**48 EFPY Fluence T/4 Location n/cm^2**	**Estimated 48 EFPY CvUSE at T/4**	**48 EFPY % Drop at T/4**
Regulatory Guide 1.99, Revision 2, Position 1								
Lower Nozzle Belt Forging	AHR-54	ZV-2861	A508 Cl.2	0.16	109	6.64E+17	95	13
Intermediate Shell Plate	C2197-2	C2197-2	SA-302 Gr. B M	0.15	81	7.06E+18	63	22
Upper Shell Plate	C3265-1	C3265-1	SA-302 Gr. B M	0.10	81	7.84E+18	66	18
Upper Shell Plate	C3278-1	C3278-1	SA-302 Gr. B M	0.12	81	7.84E+18	65	20
Lower Shell Plate	C2800-1	C2800-1	SA-302 Gr. B M	0.11	81	7.84E+18	66	19
Lower Shell Plate	C2800-2	C2800-2	SA-302 Gr. B M	0.11	81	7.84E+18	66	19
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.23	70	6.64E+17	56	19
IS Longit. Weld (Both 100%)	SA-1073	1P0962	ASA/Linde 80	021	70	5.53E+18	49	30
IS to US Circ. Weld (61%ID)	SA-1229	71249	ASA/Linde 80	0.23	70	7.12E+18	46	34
IS to US Circ. Weld (39%OD)	WF-25	299L44	ASA/Linde 80	0.34	70	--	--	--
US Longit. Weld (Both 100%)	SA-1493	8T1762	ASA/Linde 80	0.19	70	6.70E+18	49	30
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.22	70	7.60E+18	46	34
LS Longit. Weld (100%)	SA-1430	8T1762	ASA/Linde 80	0.19	70	6.46E+18	49	30
LS Longit. Weld (100%)	SA-1426	8T1762	ASA/Linde 80	0.19	70	6.46E+18	49	30
Regulatory Guide 1.99, Revision 2, Position 2								
Upper Shell Plate	C3265-1	C3265-1	SA-302 Gr. B M	--	108	7.84E+18	91	16

Material Description								
Reactor Vessel Beltline Region Location	**Matl. Ident.**	**Heat Number**	**Type**	**Copper Composition w/o**	**Initial CvUSE, ft-lbs**	**48 EFPY Fluence T/4 Location n/cm^2**	**Estimated 48 EFPY CvUSE at T/4**	**48 EFPY % Drop at T/4**
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	--	70	6.64E+17	55	22
IS to US Circ. Weld (61%ID)	SA-1229	71249	ASA/Linde 80	--	70	7.12E+18	46	34
IS to US Circ. Weld (39%OD)	WF-25	299L44	ASA/Linde 80	--	70	--	--	--
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	--	70	7.60E+18	48	32

Table 5-28. Evaluation of Reactor Vessel Extended Life (48 EFPY) Charpy V-Notch Upper-Shelf Energy - Oconee Unit 2

Material Description								
Reactor Vessel Beltline Region Location	**Matl. Ident.**	**Heat Number**	**Type**	**Copper Composition w/o**	**Initial CvUSE, ft-lbs**	**48 EFPY Fluence T/4 Location n/cm^2**	**Estimated 48 EFPY CvUSE at T/4**	**48 EFPY % Drop at T/4**
Regulatory Guide 1.99, Revision 2, Position 1								
Lower Nozzle Belt Forging	AMX-77	123T382	A508 C1.2	0.13	109	7.12E+18	87	20
Upper Shell Forging	AAW-163	3P2359	A508 C1.2	0.04	128	7.66E+18	113	12
Lower Shell Forging	AWG-164	4P1885	A508 C1.2	0.02	140	7.60E+18	126	10
LNB to US Circ. Weld (100%)	WF-154	406L44	ASA/Linde 80	0.27	70	7.12E+18	43	38
US to LS Circ. Weld (100%)	WF-25	299L44	ASA/Linde 80	0.34	70	7.36E+18	39	40
Regulatory Guide 1.99, Revision 2, Position 2								
Upper Shell Forging	AAW-163	3P2359	A508 C1.2	--	128	7.66E+18	101	21
NB to US Circ. Weld (100%)	WF-154	406L44	ASA/Linde 80	--	70	7.12E+18	45	36
US to LS Circ. Weld (100%)	WF-25	299L44	ASA/Linde 80	--	70	7.60E+18	44	37

Table 5-29. Evaluation of Reactor Vessel Extended Life (48 EFPY) Charpy V-Notch Upper-Shelf Energy - Oconee Unit 3

Material Description								
Reactor Vessel Beltline Region Location	**Matl. Ident.**	**Heat Number**	**Type**	**Copper Composition w/o**	**Initial CvUSE, ft-lbs**	**48 EFPY Fluence T/4 Location n/cm^2**	**Estimated 48 EFPY CvUSE at T/4**	**48 EFPY % Drop at T/4**
Regulatory Guide 1.99, Revision 2, Position 1								
Lower Nozzle Belt Forging	4680	4680	A508 C1.2	0.13	109	6.82E+18	87	20
Upper Shell Forging	AWS-192	522314	A508 C1.2	0.01	90	7.54E+18	82	9
Lower Shell Forging	ANK-191	522194	A508 C1.2	0.02	110	7.54E+18	99	10
LNB to US Circ. Weld (100%)	WF-200	821T44	ASA/Linde 80	0.24	70	6.82E+18	46	35
US to LS Circ. Weld (75%ID)	WF-67	72442	ASA/Linde 80	0.26	70	7.30E+18	44	37
US to LS Circ. Weld (25%OD)	WF-70	72105	ASA/Linde 80	0.32	70	-----	-----	-----
Regulatory Guide 1.99, Revision 2, Position 2								
Upper Shell Forging	AWS-192	522314	A508 C1.2	-----	90	7.54E+18	77	15
Lower Shell Forging	ANK-191	522194	A508 C1.2	-----	110	7.30E+18	85	23
NB to US Circ. Weld (100%)	WF-200	821T44	ASA/Linde 80	-----	70	6.82E+18	55	21
US to LS Circ. Weld (25%OD)	WF-70	72105	ASA/Linde 80	-----	70	-----	--	--

Appendix 5B. Figures

Figure 5-1. Reactor Coolant System (Unit 1)

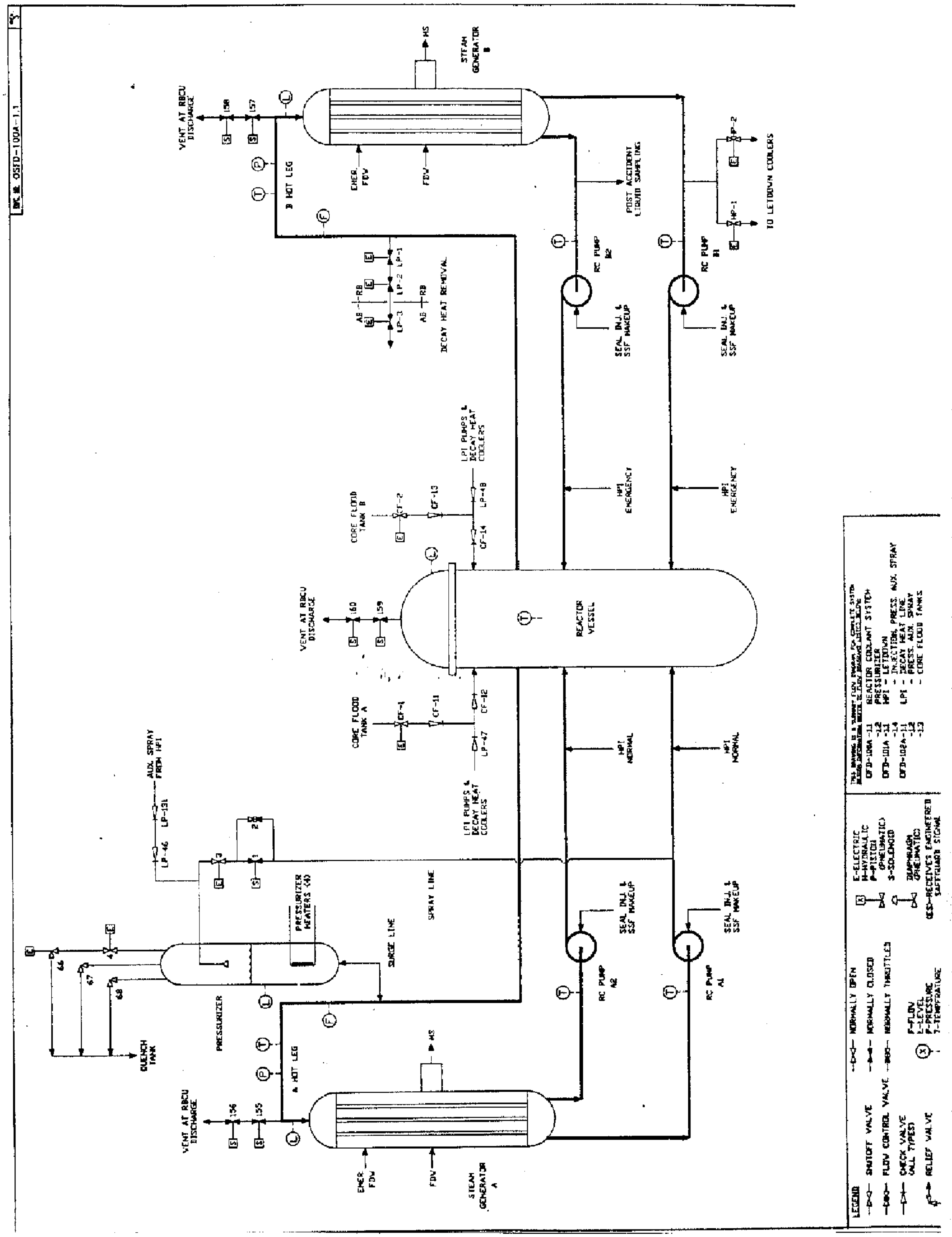


Figure 5-2. Reactor Coolant System (Units 2 & 3)

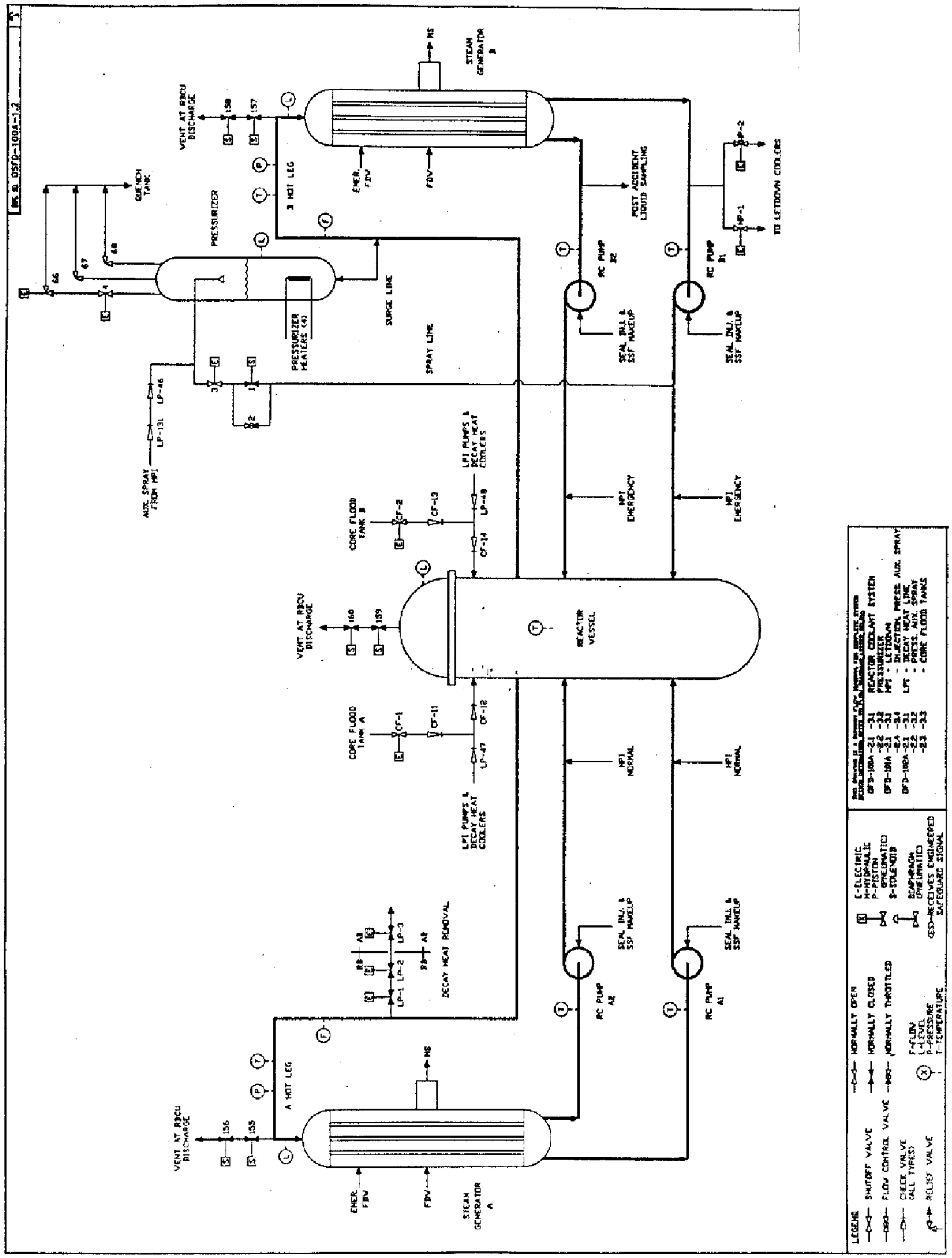


Figure 5-3. Reactor Coolant System, Arrangement Plan (Unit 1)

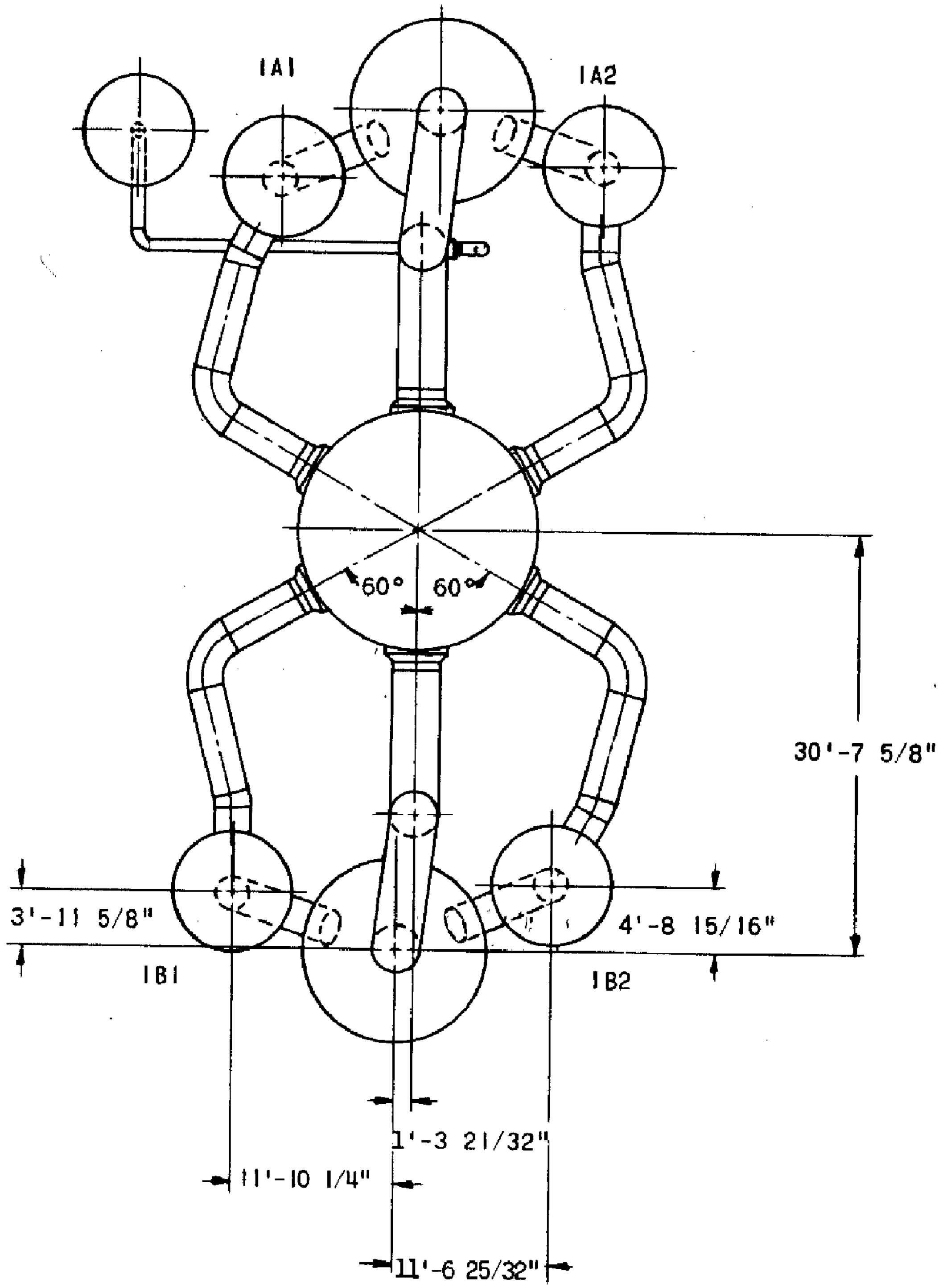


Figure 5-4. Reactor Coolant System, Arrangement Elevation (Unit 1)

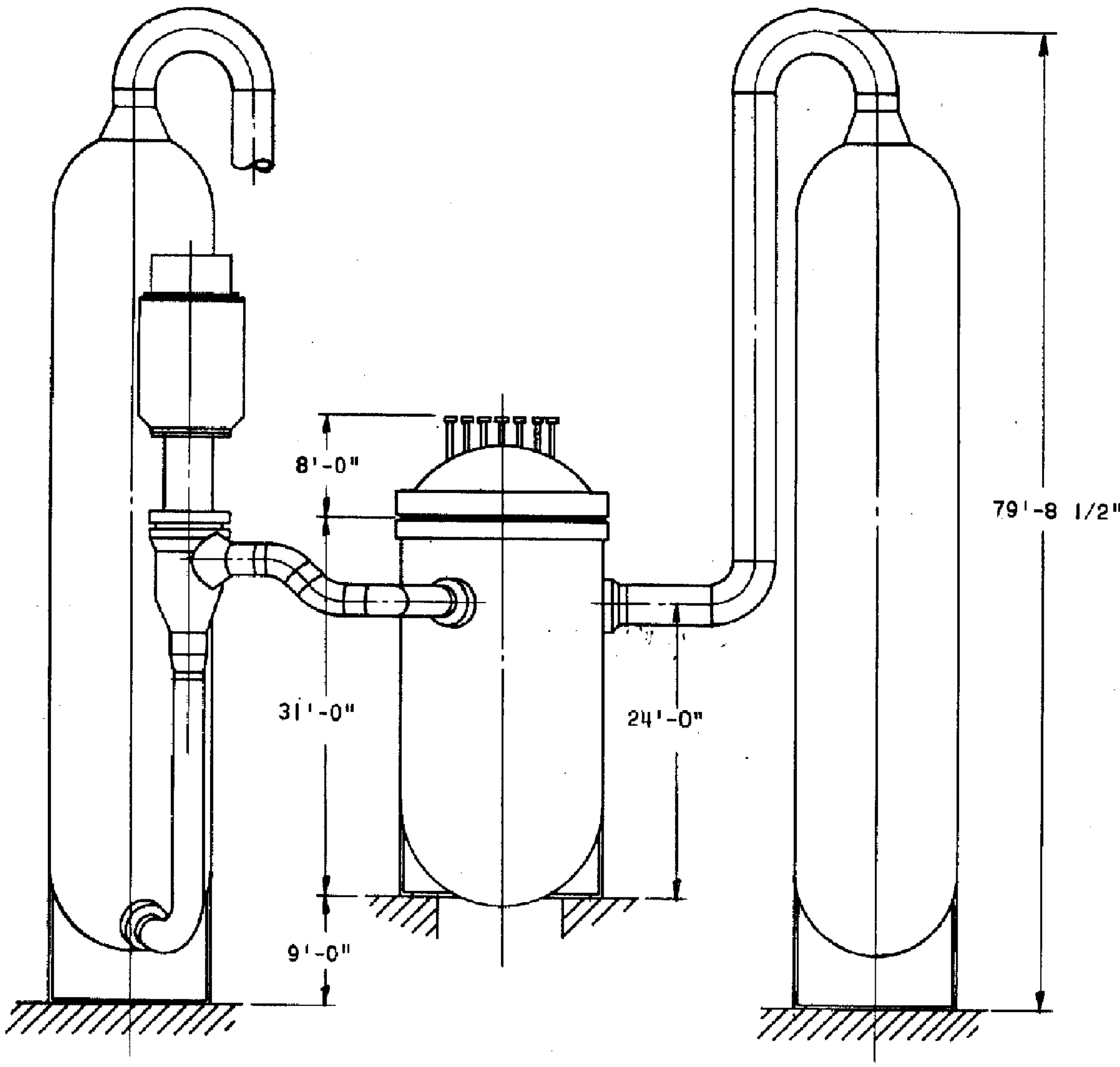


Figure 5-5. Reactor Coolant System, Arrangement Plan (Unit 2)

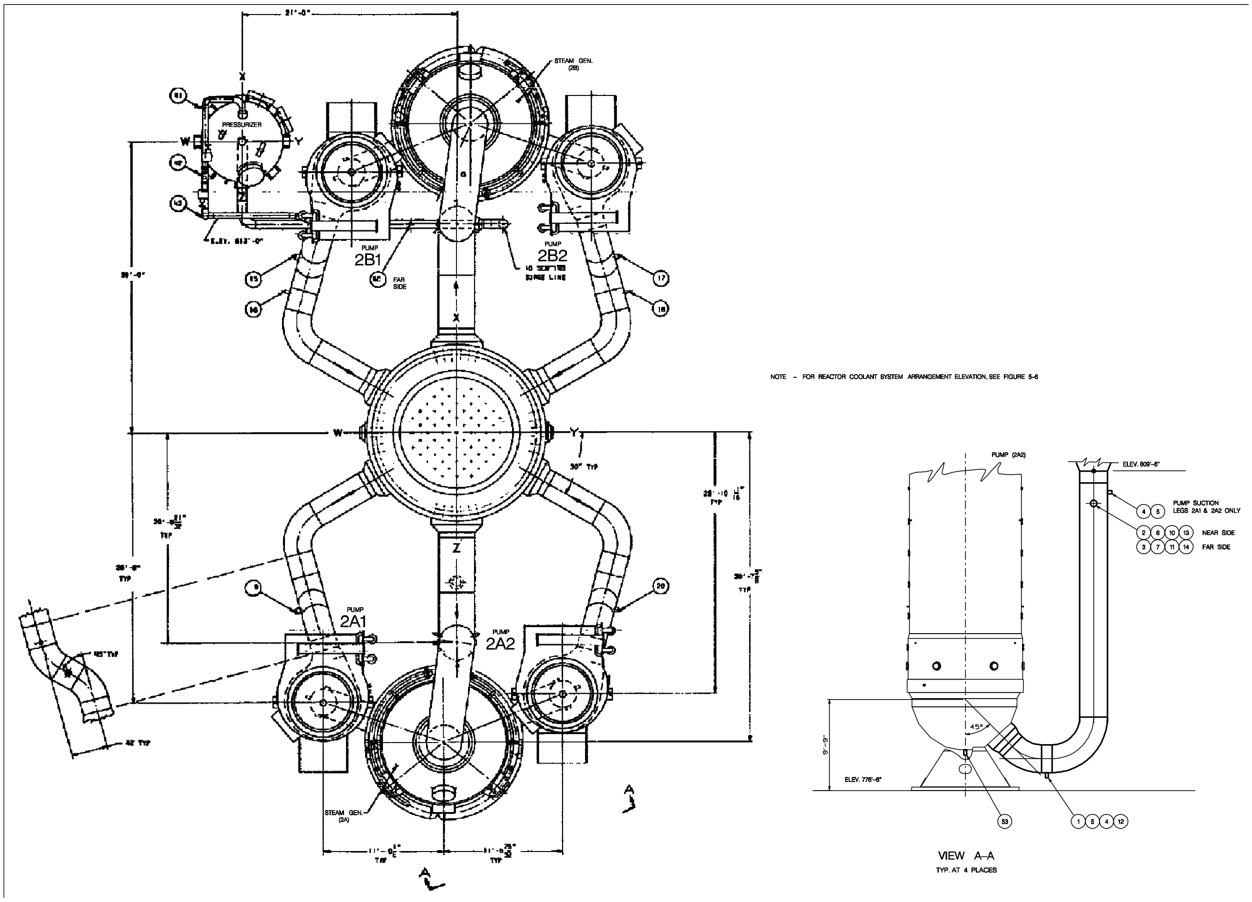
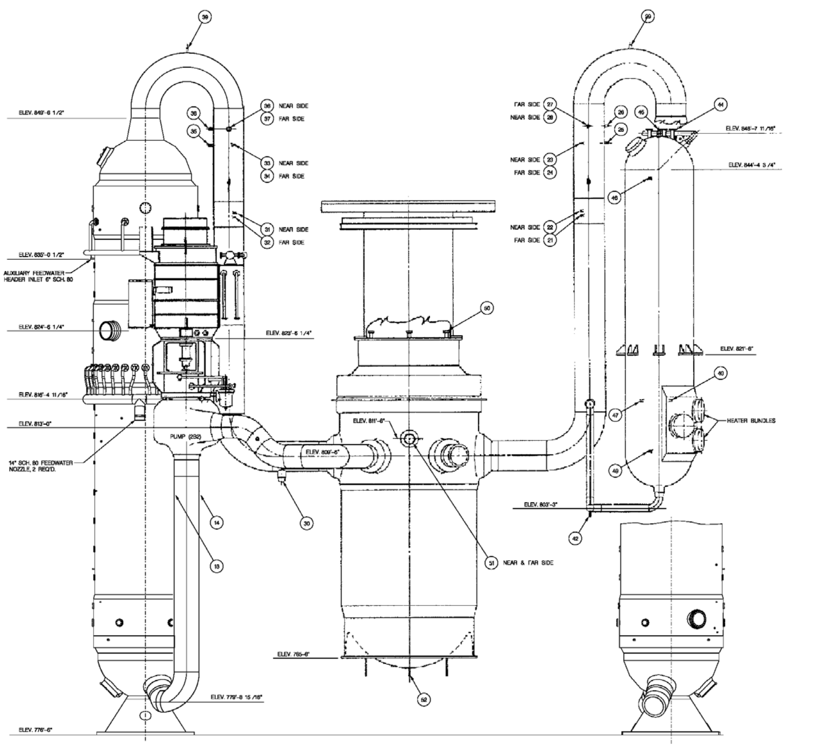


Figure 5-6. Reactor Coolant System, Arrangement Elevation (Unit 2)



LIST OF AUXILIARY CONNECTIONS TO PIPING & VESSELS			
PIPING LEG OR VESSEL	NOZZLE NO.	QUANTITY	DESCRIPTION AND SIZE
STEAM GENERATOR (1A) TO PUMP (1A1)	1	1	DRAIN – 1 1/2" SCH. 160
	2	1	FAST RESPONSE RTE CONNECTION
	3	1	STANDARD RTE CONNECTION
	4	1	PRESSURE TAP – 1" SCH. 160
STEAM GENERATOR (1A) TO PUMP (1A2)	5	1	DRAIN – 1 1/2" SCH. 160
	6	1	FAST RESPONSE RTE CONNECTION
	7	1	STANDARD RTE CONNECTION
	8	1	PRESSURE TAP – 1" SCH. 160
STEAM GENERATOR (1B) TO PUMP (1B1)	9	1	DRAIN – 2 1/2" SCH. 160
	10	1	FAST RESPONSE RTE CONNECTION
	11	1	STANDARD RTE CONNECTION
STEAM GENERATOR (1B) TO PUMP (1B2)	12	1	DRAIN – 1 1/2" SCH. 160
	13	1	FAST RESPONSE RTE CONNECTION
	14	1	STANDARD RTE CONNECTION
PUMP 1A1 TO REACTOR VESSEL	15	1	HIGH PRESSURE INJECTION – 2 1/2" SCH. 160
	16	1	PRESSURE TAP – 1" SCH. 160
PUMP 1A2 TO REACTOR VESSEL	17	1	HIGH PRESSURE INJECTION – 2 1/2" SCH. 160
	18	1	PRESSURE TAP – 1" SCH. 160
PUMP 1B1 TO REACTOR VESSEL	19	1	HIGH PRESSURE INJECTION – 2 1/2" SCH. 160
PUMP 1B2 TO REACTOR VESSEL	20		HIGH PRESSURE INJECTION – 2 1/2" SCH. 160
REACTOR VESSEL TO STEAM GENERATOR (1A)	21	1	FLOW METER CONN. – 1" SCH. 160
	22	1	FLOW METER CONN. – 1" SCH. 160
	23	1	FAST RESPONSE RTE CONNECTION
	24	1	FAST RESPONSE RTE CONNECTION
	25	1	FAST RESPONSE RTE CONNECTION
	26	1	PRESSURE TAP – 1" SCH. 160
	27	1	STANDARD RTE CONNECTION (PLUGGED)
	28	1	PRESSURE TAP – 1" SCH. 160
	29	1	VENT CONNECTION – 1" SCH. 160
REACTOR VESSEL TO STEAM GENERATOR (1B)	30	1	DECAY HEAT CONNECTION – 18" SCH. 140
	31	1	FLOW METER CONN. – 1" SCH. 160
	32	1	FLOW METER CONN. – 1" SCH. 160
	33	1	FAST RESPONSE RTE CONNECTION
	34	1	FAST RESPONSE RTE CONNECTION
	35	1	FAST RESPONSE RTE CONNECTION
	36	1	STANDARD RTE CONNECTION (PLUGGED)
	37	1	PRESSURE TAP – 1" SCH. 160
	38	1	PRESSURE TAP – 1" SCH. 160
	39	1	VENT CONNECTION – 1" SCH. 160
SURGE LINE TO PRESSURIZER	40	1	DRAIN – " SCH. 160
SPRAY LINE TO PRESSURIZER	41	1	AUX. SPRAY LINE – 1 1/2" SCH.160
	42	1	BY-PASS CONN. – " SCH. 160
	43	1	BY-PASS CONN. – " SCH. 160
PRESSURIZER	44	3	RELIEF VALVE – "
	45	1	VENT – " SCH. 160
	46	3	LEVEL SENSING – 1" SCH. 160
	47	1	SAMPLE – 1" SCH. 160
	48	1	THERMOWELL
	49	3	LEVEL SENSING – 1" SCH. 160
REACTOR VESSEL	50	69	CONTROL ROD DRIVE
	51	2	CORE FLOODING – 14" SCH. 160
	52	52	INCORE INSTRUMENTATION – " SCH. 160

* PIPING TO LETDOWN COOLERS CONNECTS TO THIS DRAIN LINE

NOTE: FOR REACTOR COOLANT SYSTEM ARRANGEMENT PLAN, SEE FIGURE 5-5

Oconee Nuclear Station
Figure 5-6. Reactor Coolant System, Arrangement Elevation (Unit 2)
UFSAR Figure 5-6 (Page 1 of 1)

Figure 5-7. Reactor Coolant System, Arrangement Plan (Unit 3)

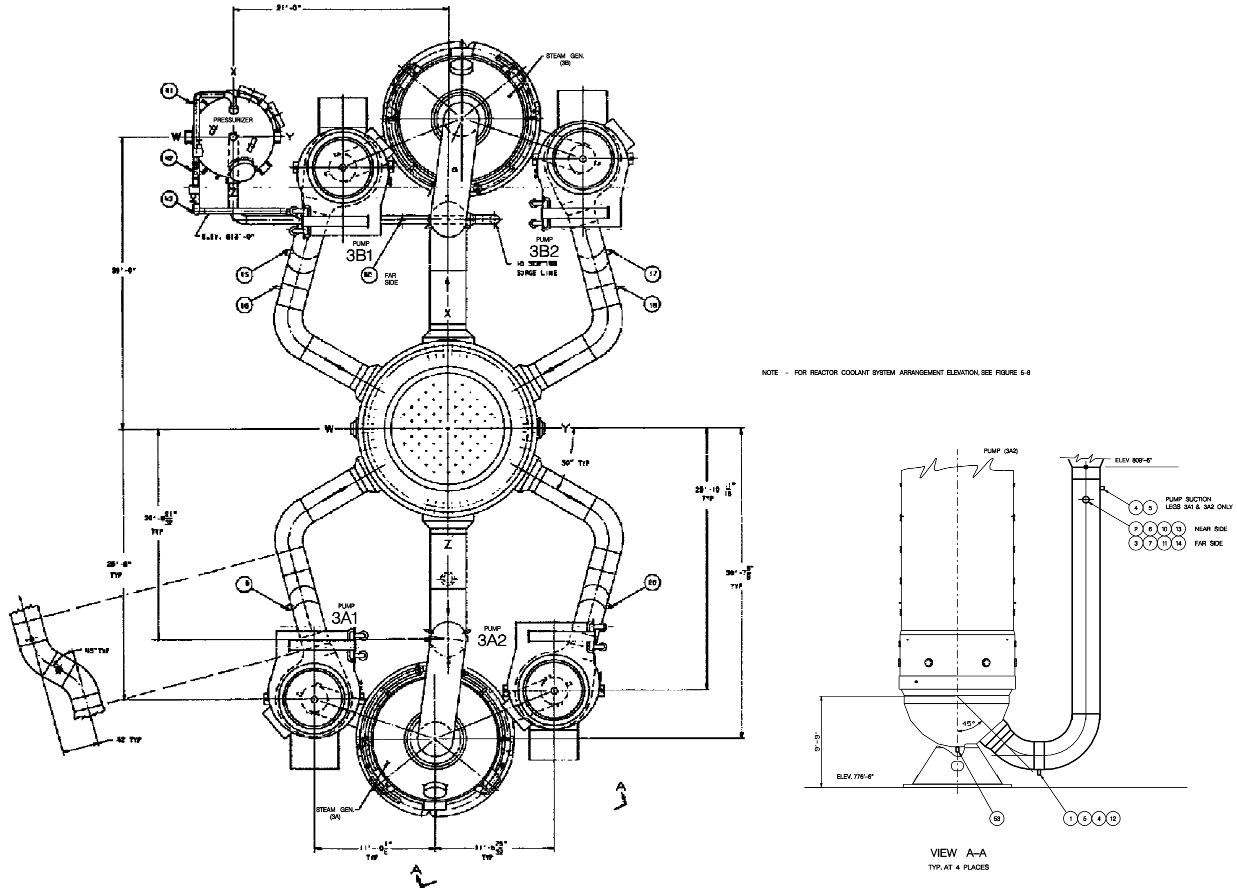
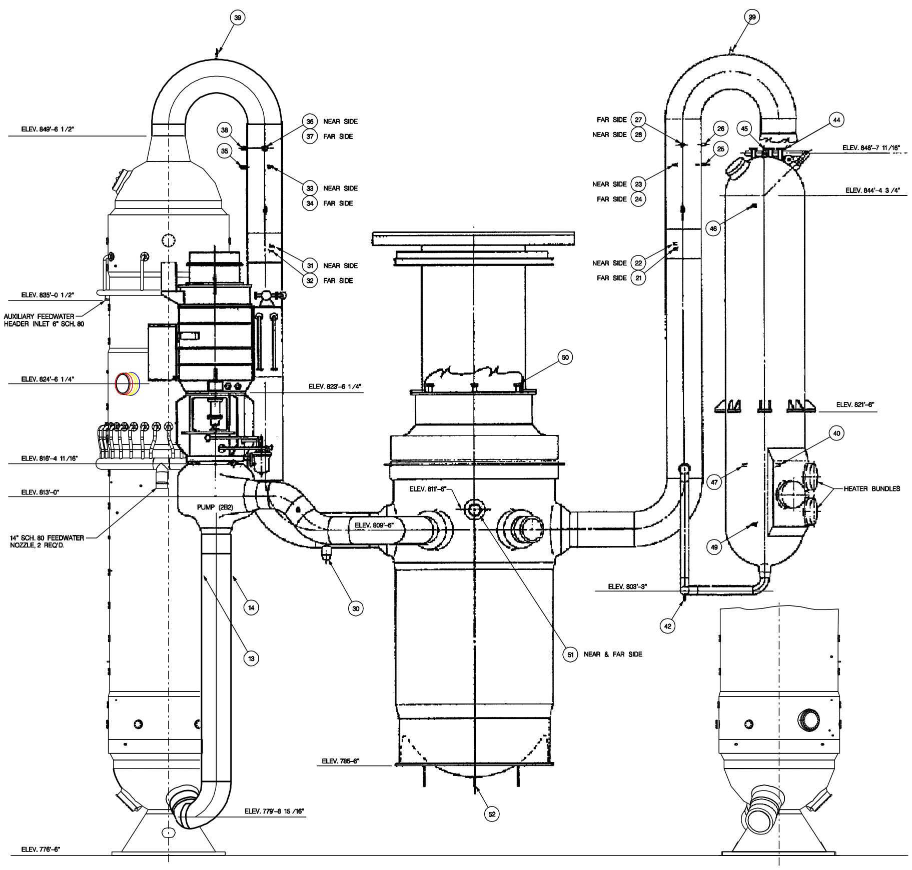


Figure 5-8. Reactor Coolant System, Arrangement Elevation (Unit 3)



LIST OF AUXILIARY CONNECTIONS TO PIPING & VESSELS			
PIPING LEG OR VESSEL	NOZZLE NO.	QUANTITY	DESCRIPTION AND SIZE
STEAM GENERATOR (1A) TO PUMP (1A1)	1	1	DRAIN – 1 1/2" SCH. 160
	2	1	FAST RESPONSE RTE CONNECTION
	3	1	STANDARD RTE CONNECTION
	4	1	PRESSURE TAP – 1" SCH. 160
STEAM GENERATOR (1A) TO PUMP (1A2)	5	1	DRAIN – 1 1/2" SCH. 160
	6	1	FAST RESPONSE RTE CONNECTION
	7	1	STANDARD RTE CONNECTION
	8	1	PRESSURE TAP – 1" SCH. 160
STEAM GENERATOR (1B) TO PUMP (1B1)	9	1	DRAIN – 2 1/2" SCH. 160
	10	1	FAST RESPONSE RTE CONNECTION
	11	1	STANDARD RTE CONNECTION
STEAM GENERATOR (1B) TO PUMP (1B2)	12	1	DRAIN – 1 1/2" SCH. 160
	13	1	FAST RESPONSE RTE CONNECTION
	14	1	STANDARD RTE CONNECTION
PUMP 1A1 TO REACTOR VESSEL	15	1	HIGH PRESSURE INJECTION – 2 1/2" SCH. 160
	16	1	PRESSURE TAP – 1" SCH. 160
PUMP 1A2 TO REACTOR VESSEL	17	1	HIGH PRESSURE INJECTION – 2 1/2" SCH. 160
	18	1	PRESSURE TAP – 1" SCH. 160
PUMP 1B1 TO REACTOR VESSEL	19	1	HIGH PRESSURE INJECTION – 2 1/2" SCH. 160
PUMP 1B2 TO REACTOR VESSEL	20		HIGH PRESSURE INJECTION – 2 1/2" SCH. 160
REACTOR VESSEL TO STEAM GENERATOR (1A)	21	1	FLOW METER CONN. – 1" SCH. 160
	22	1	FLOW METER CONN. – 1" SCH. 160
	23	1	FAST RESPONSE RTE CONNECTION
	24	1	FAST RESPONSE RTE CONNECTION
	25	1	FAST RESPONSE RTE CONNECTION
	26	1	PRESSURE TAP – 1" SCH. 160
	27	1	STANDARD RTE CONNECTION
	28	1	PRESSURE TAP – 1" SCH. 160
	29	1	VENT CONNECTION – 1" SCH. 160
REACTOR VESSEL TO STEAM GENERATOR (1B)	30	1	DECAY HEAT CONNECTION – 18" SCH. 140
	31	1	FLOW METER CONN. – 1" SCH. 160
	32	1	FLOW METER CONN. – 1" SCH. 160
	33	1	FAST RESPONSE RTE CONNECTION
	34	1	FAST RESPONSE RTE CONNECTION
	35	1	FAST RESPONSE RTE CONNECTION
	36	1	STANDARD RTE CONNECTION
	37	1	PRESSURE TAP – 1" SCH. 160
	38	1	PRESSURE TAP – 1" SCH. 160
	39	1	VENT CONNECTION – 1" SCH. 160
SURGE LINE TO PRESSURIZER	40	1	DRAIN – " SCH. 160
SPRAY LINE TO PRESSURIZER	41	1	AUX. SPRAY LINE – 1 1/2" SCH.160
	42	1	BY-PASS CONN. – " SCH. 160
	43	1	BY-PASS CONN. – " SCH. 160
PRESSURIZER	44	3	RELIEF VALVE – "
	45	1	VENT – " SCH. 160
	46	3	LEVEL SENSING – 1" SCH. 160
	47	1	SAMPLE – 1" SCH. 160
	48	1	THERMOWELL
	49	3	LEVEL SENSING – 1" SCH. 160
REACTOR VESSEL	50	69	CONTROL ROD DRIVE
	51	2	CORE FLOODING – 14" SCH. 160
	52	52	INCORE INSTRUMENTATION – " SCH. 160

* PIPING TO LETDOWN COOLERS CONNECTS TO THIS DRAIN LINE

NOTE: FOR REACTOR COOLANT SYSTEM ARRANGEMENT PLAN, SEE FIGURE 5-7

Figure 5-9. Reactor and Steam Temperatures versus Reactor Power.(Replacement Steam Generator)

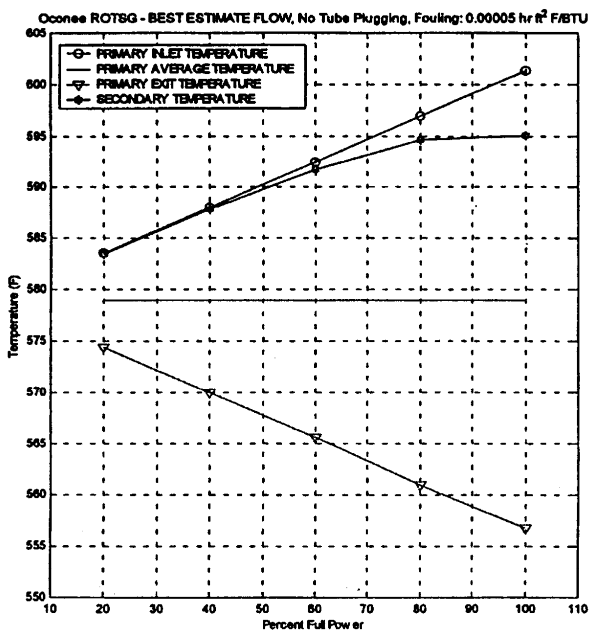


Figure 5-10. Points of Stress Analysis for Reactor Vessel

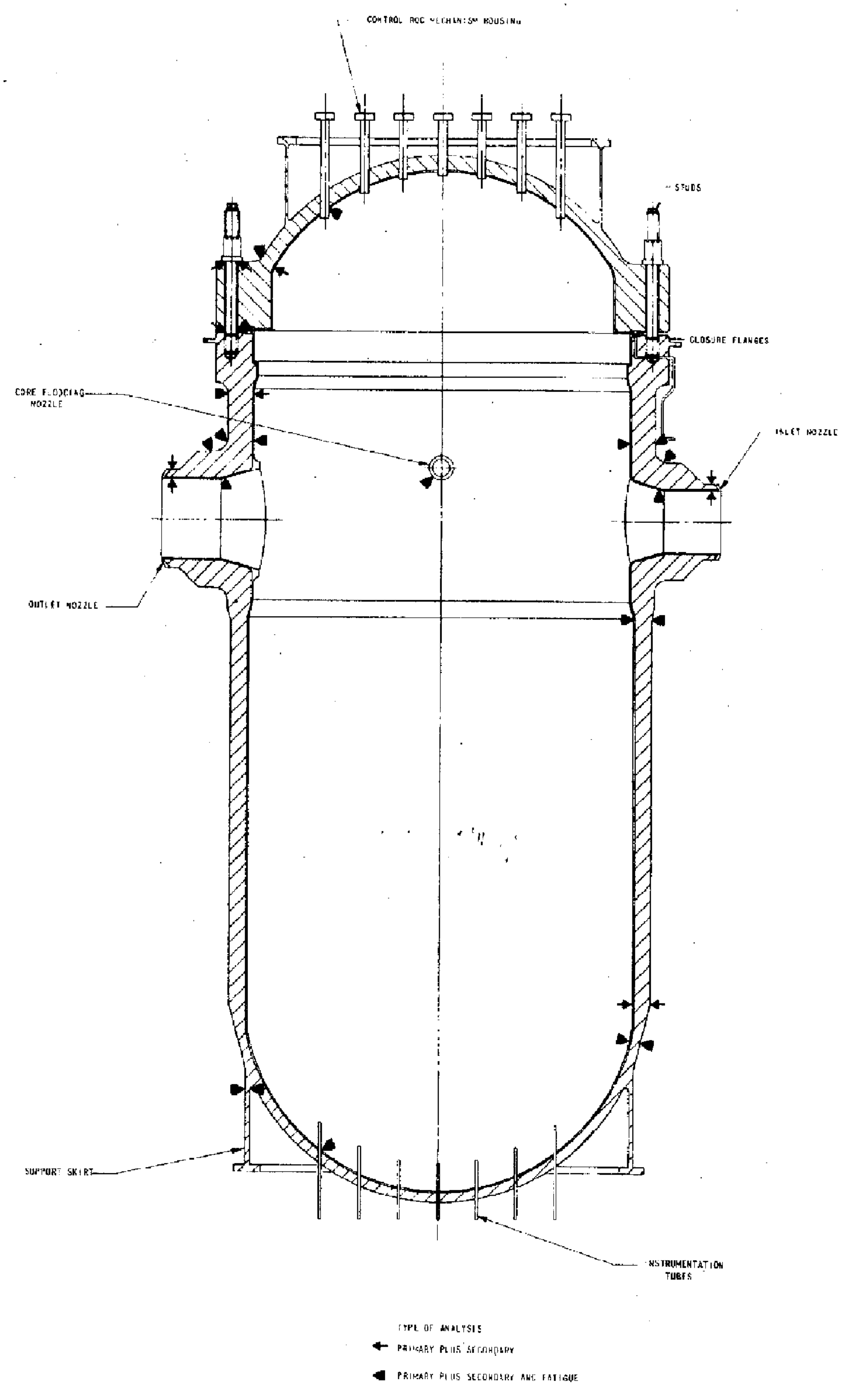


Figure 5-11. Location of Replacement Steam Generator Weld

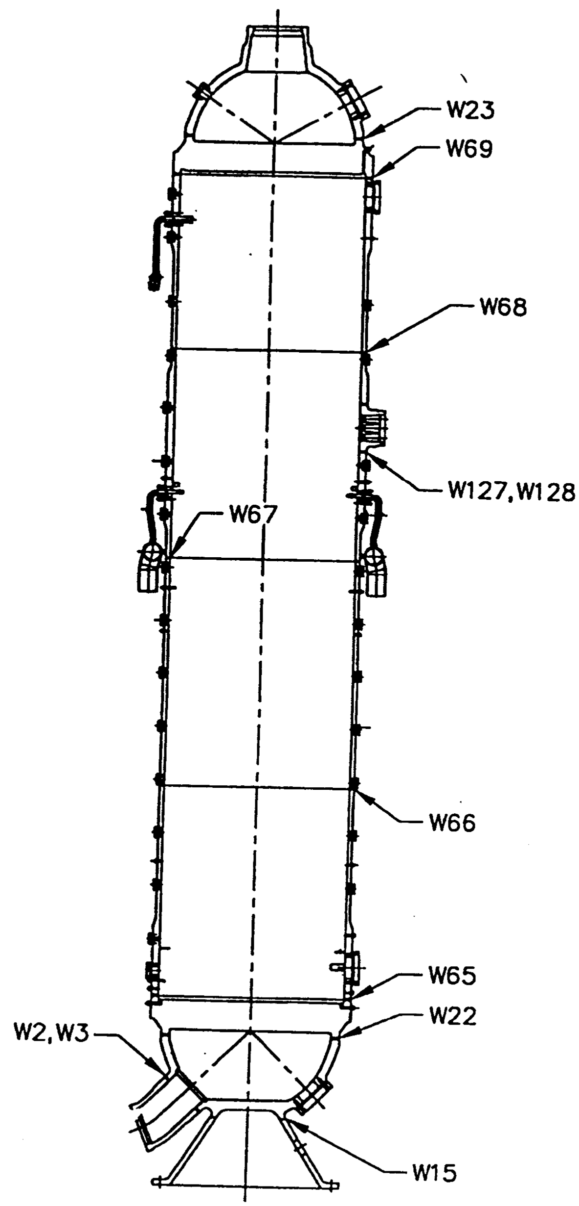
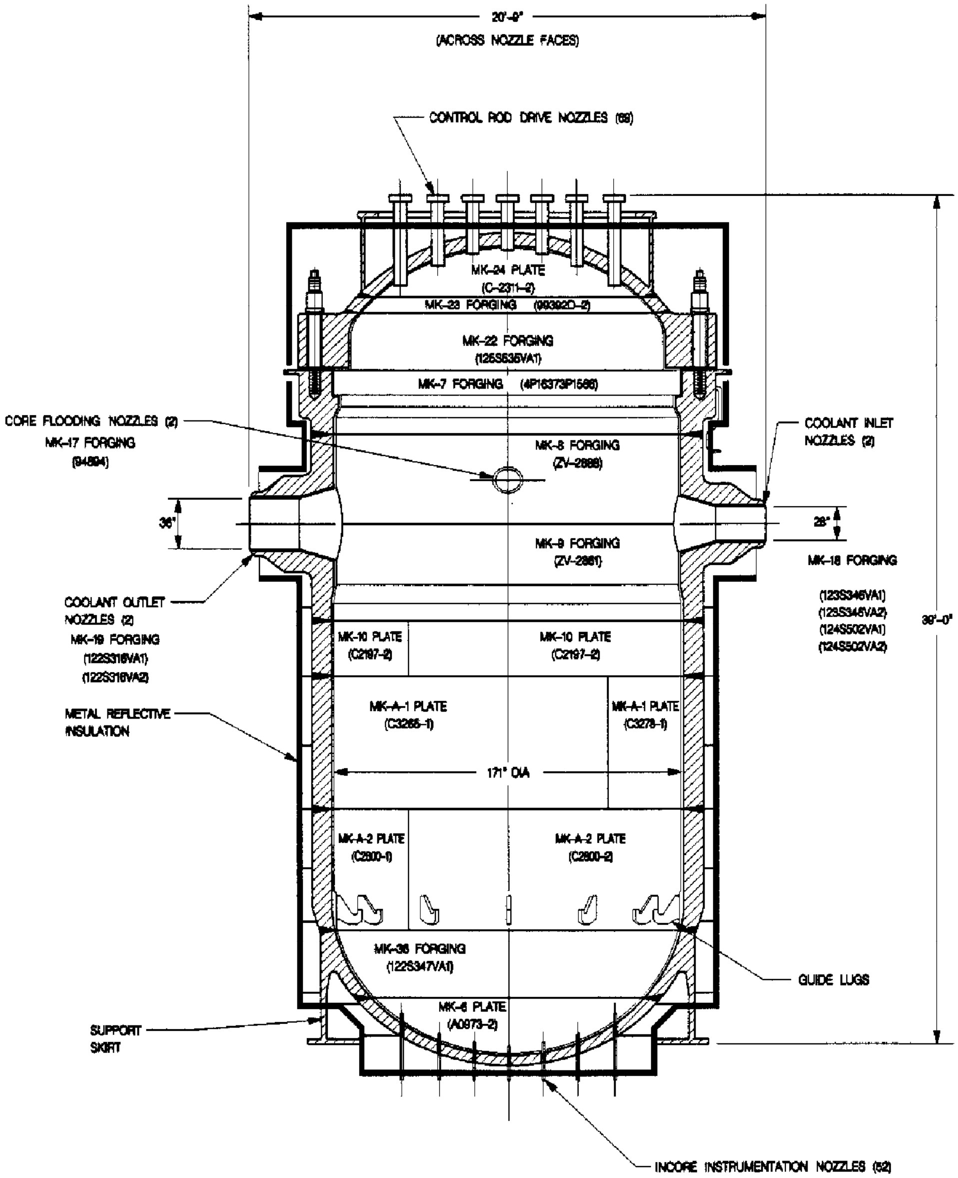


Figure 5-12. Deleted Per 1991 Update

Figure 5-13. Deleted Per 1991 Update

Figure 5-14. Reactor Vessel Outline (Unit 1). **(Shown with original reactor vessel head)**



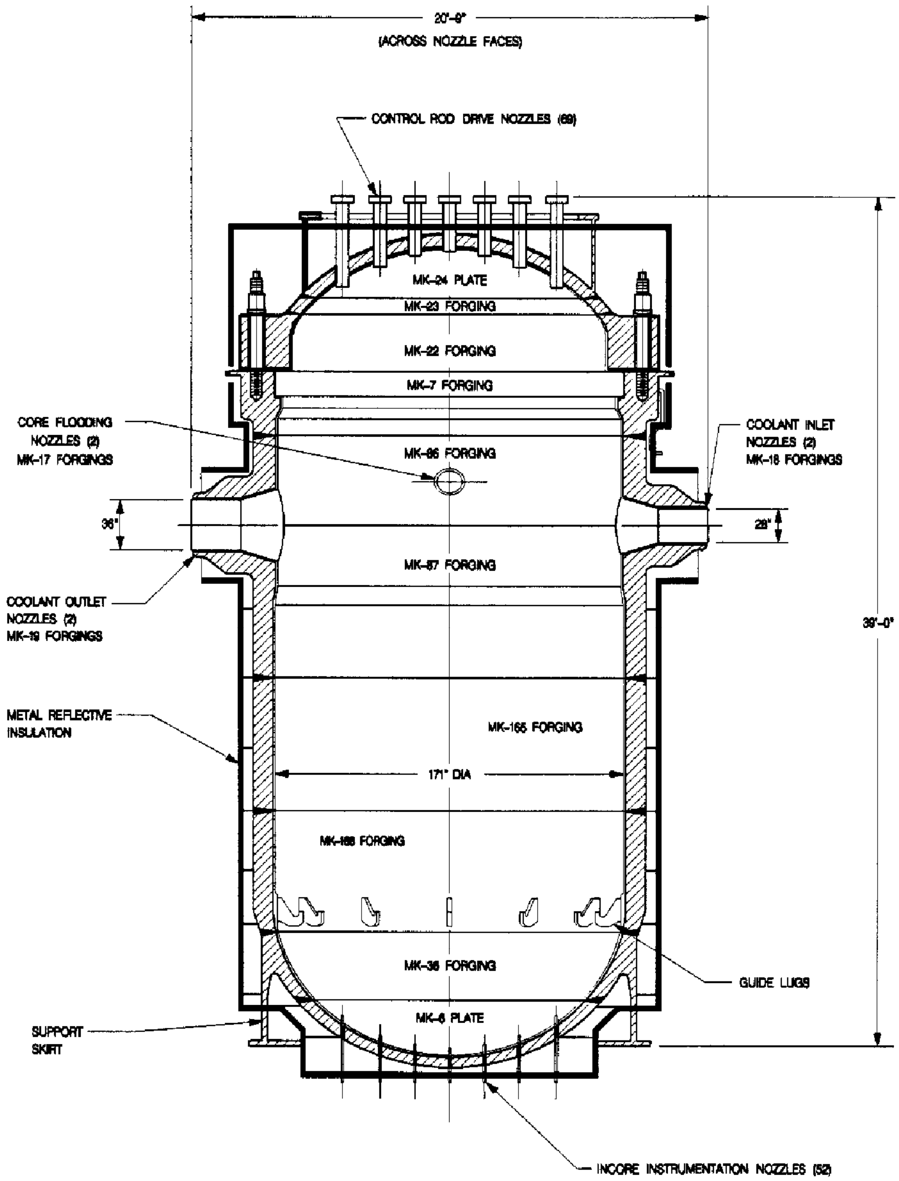


Figure 5-15. Reactor Vessel Outline (Unit 2). (Shown with original reactor vessel head)

Figure 5-16. Reactor Vessel Outline (Unit 3). (Shown with original reactor vessel head)

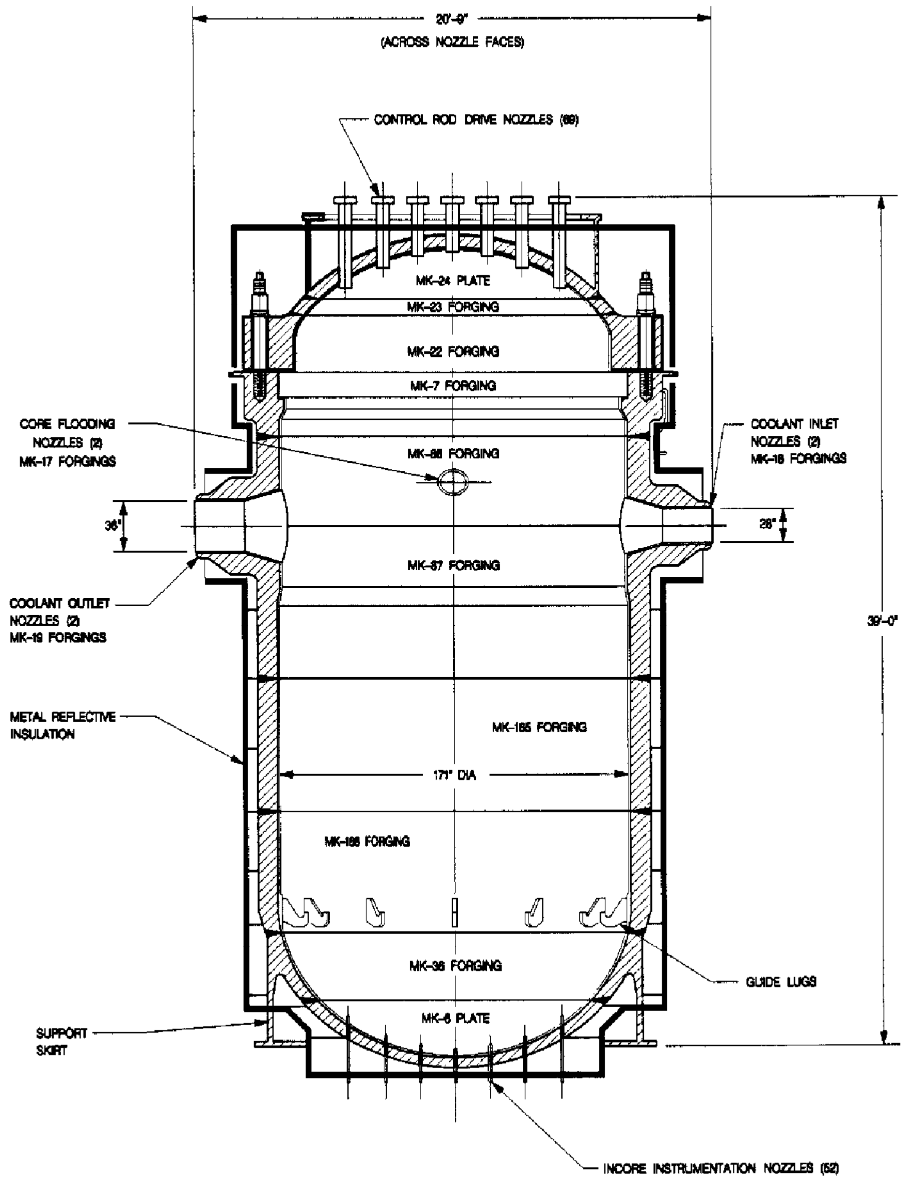


Figure 5-17. Reactor Coolant Controlled Leakage Pump (Unit 1)

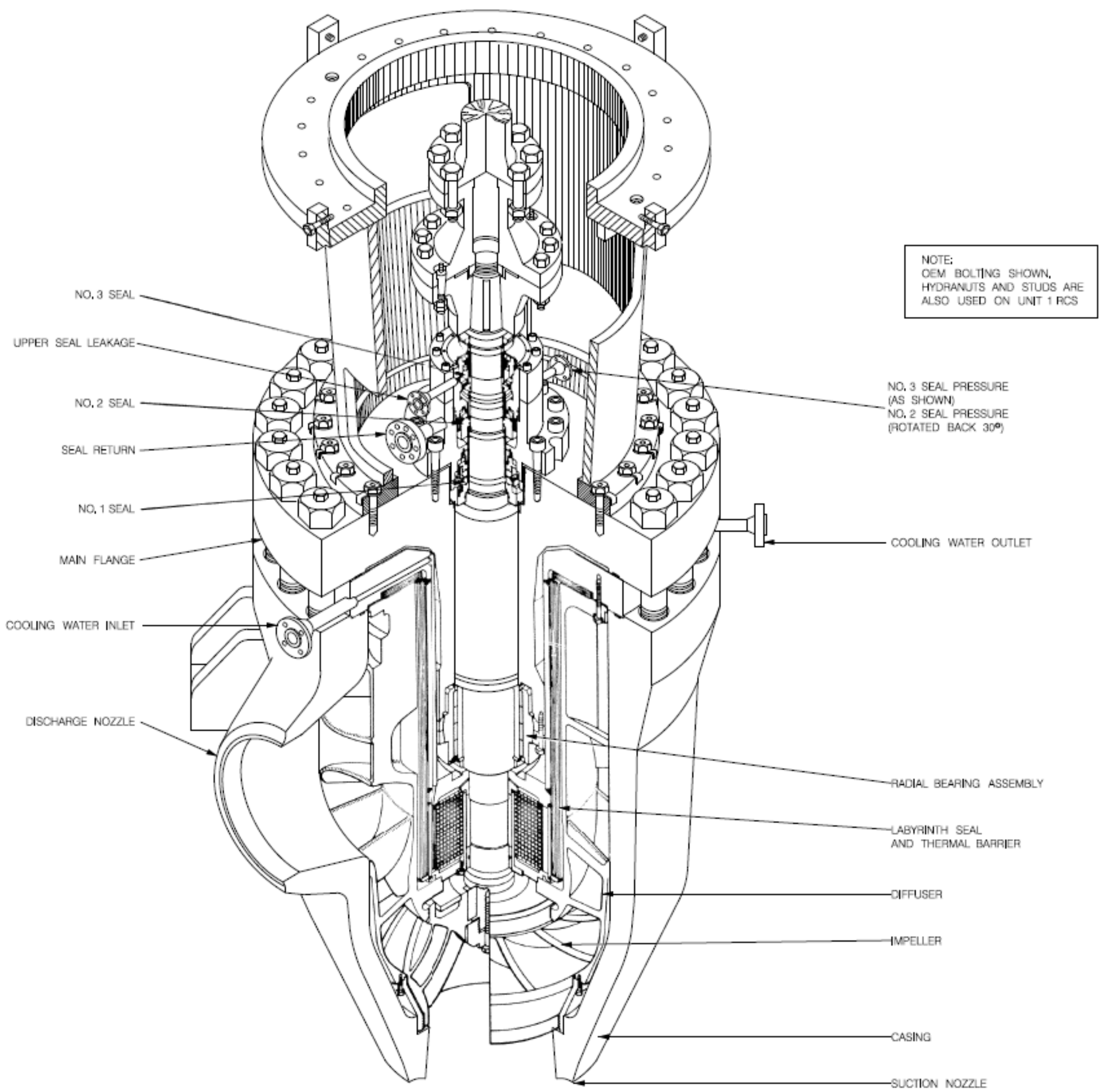


Figure 5-18. Reactor Coolant Punp Estimated Performance Characteristic (Unit 1)

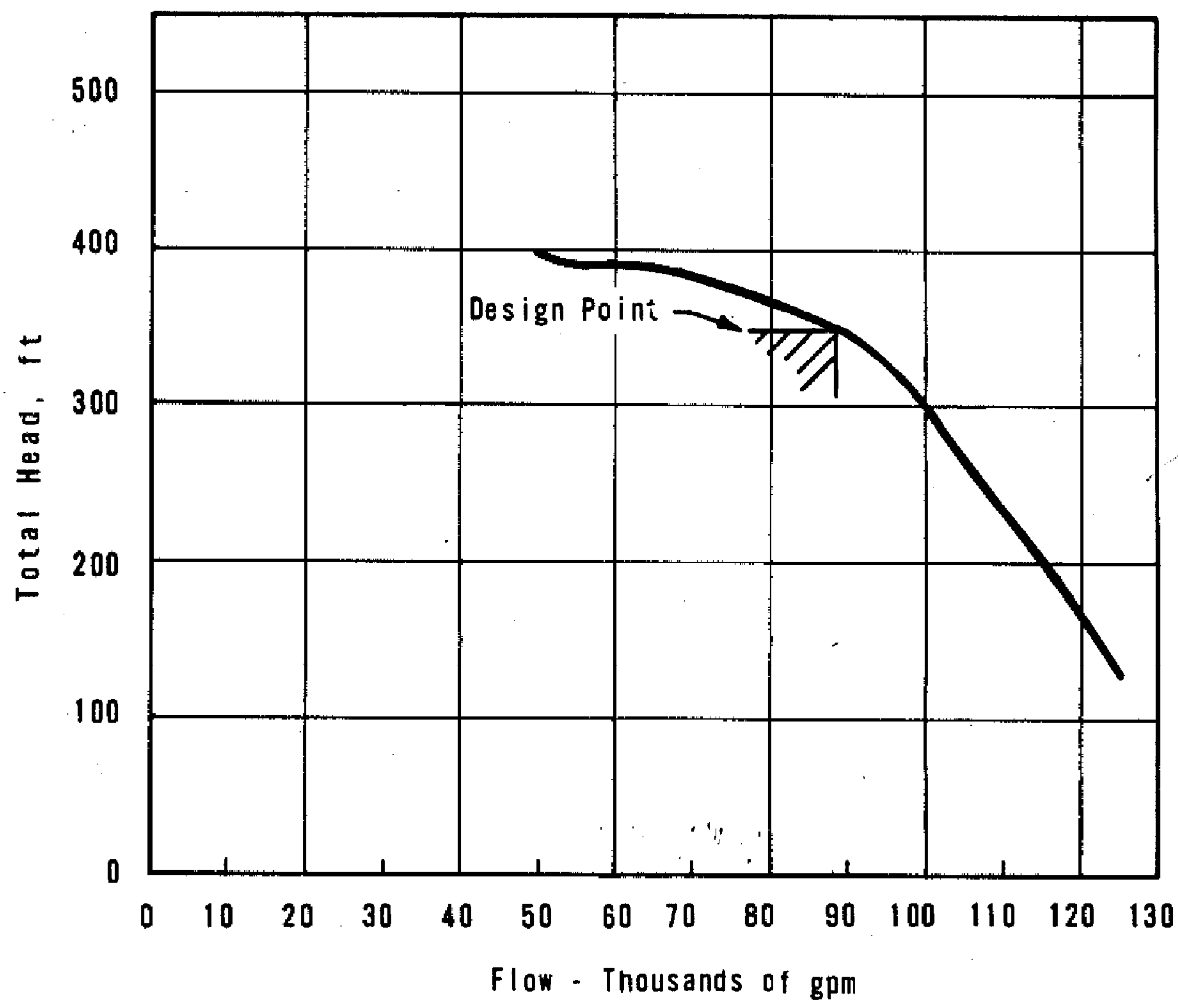


Figure 5-19. Reactor Coolant Pump (Units 2, 3)

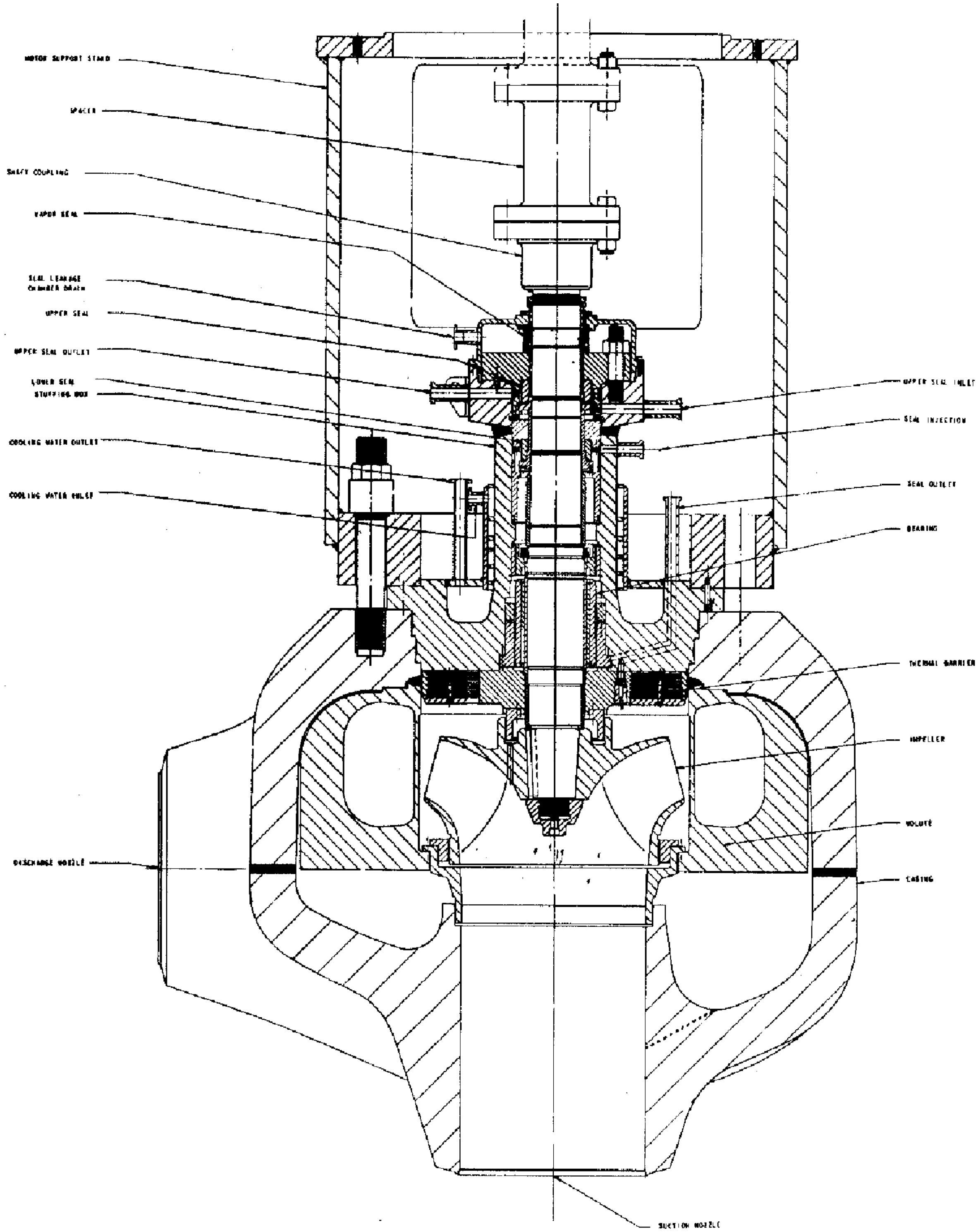


Figure 5-20. Reactor Coolant Pump Estimated Performance Characteristic (Units 2, 3)

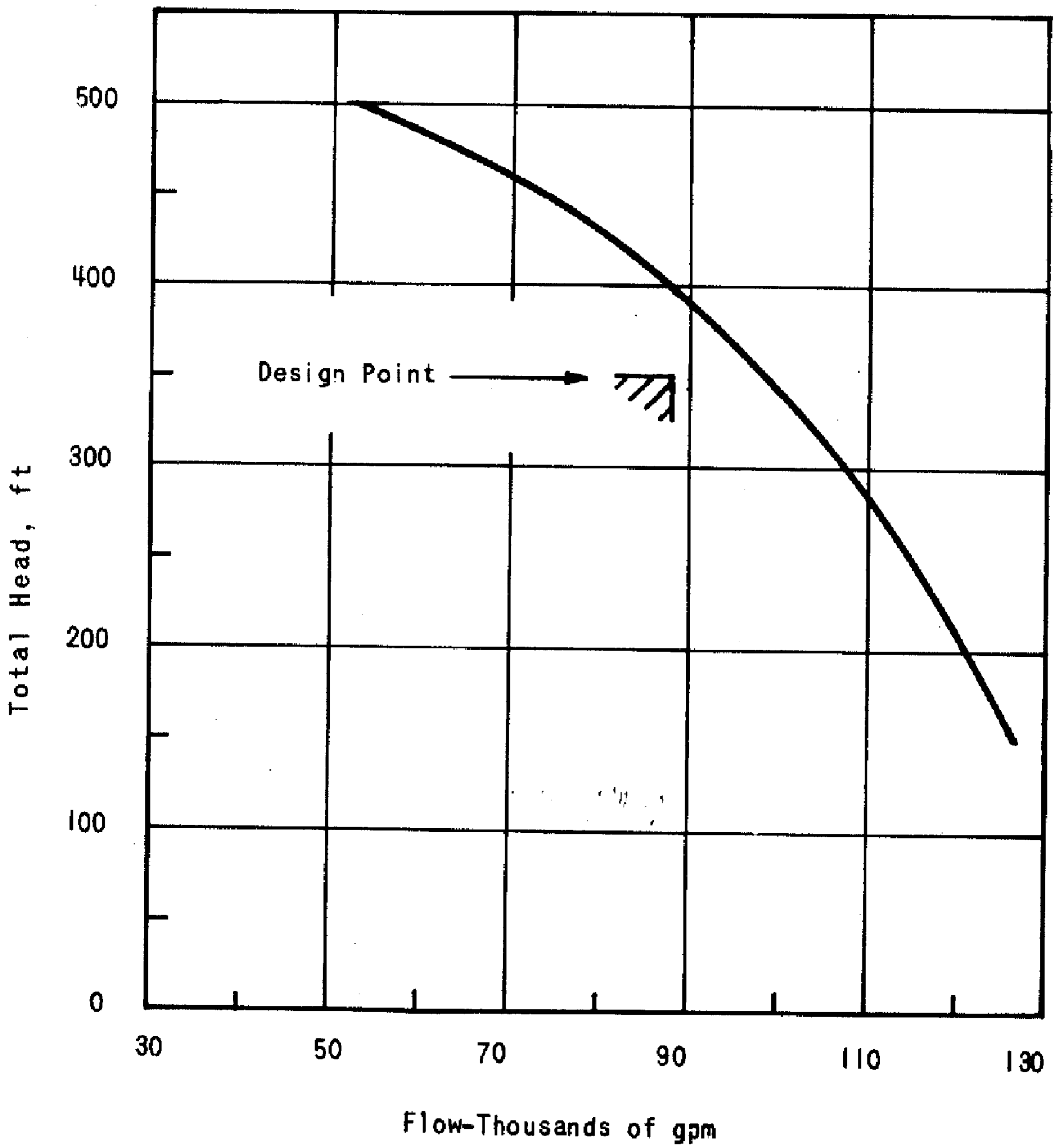
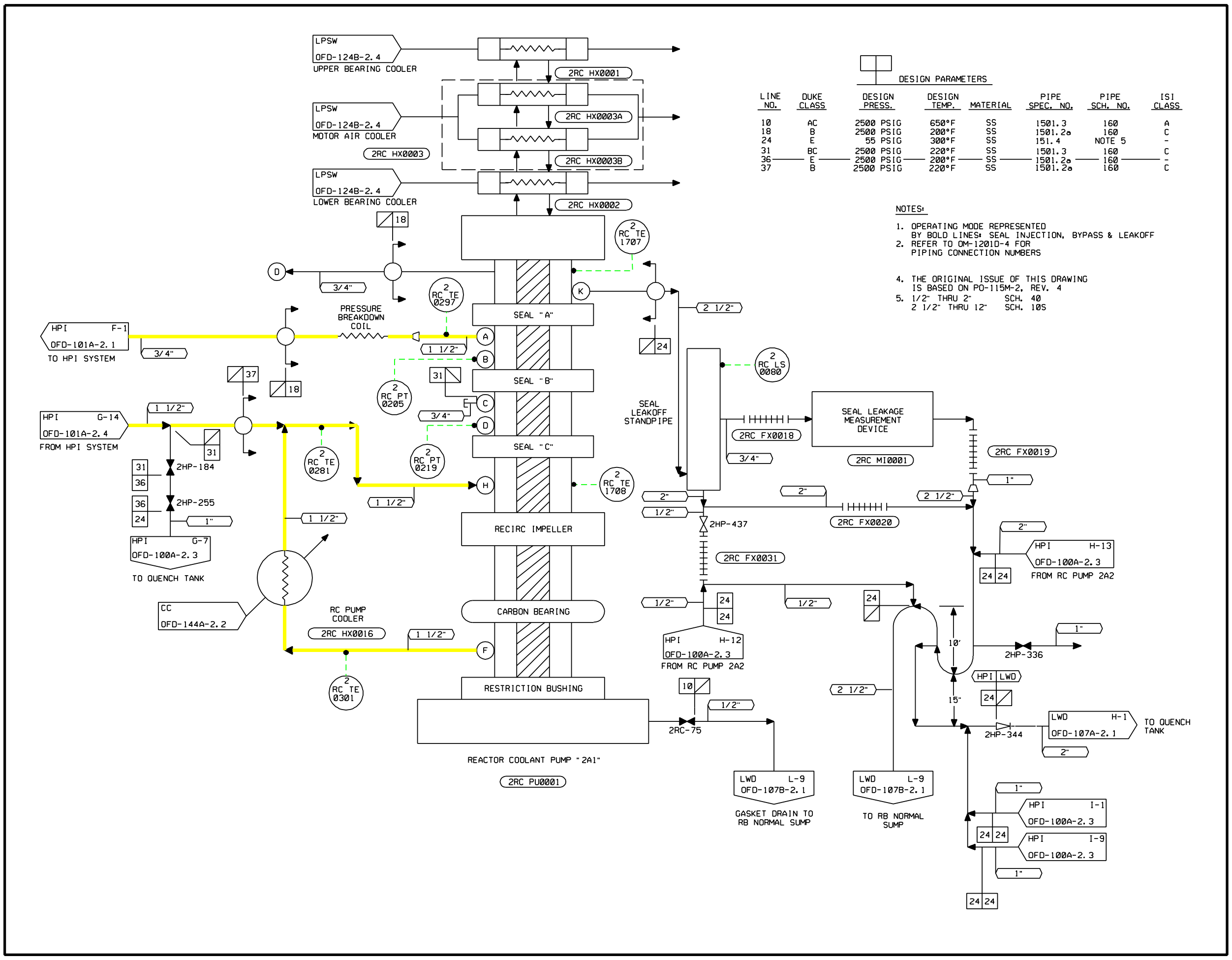
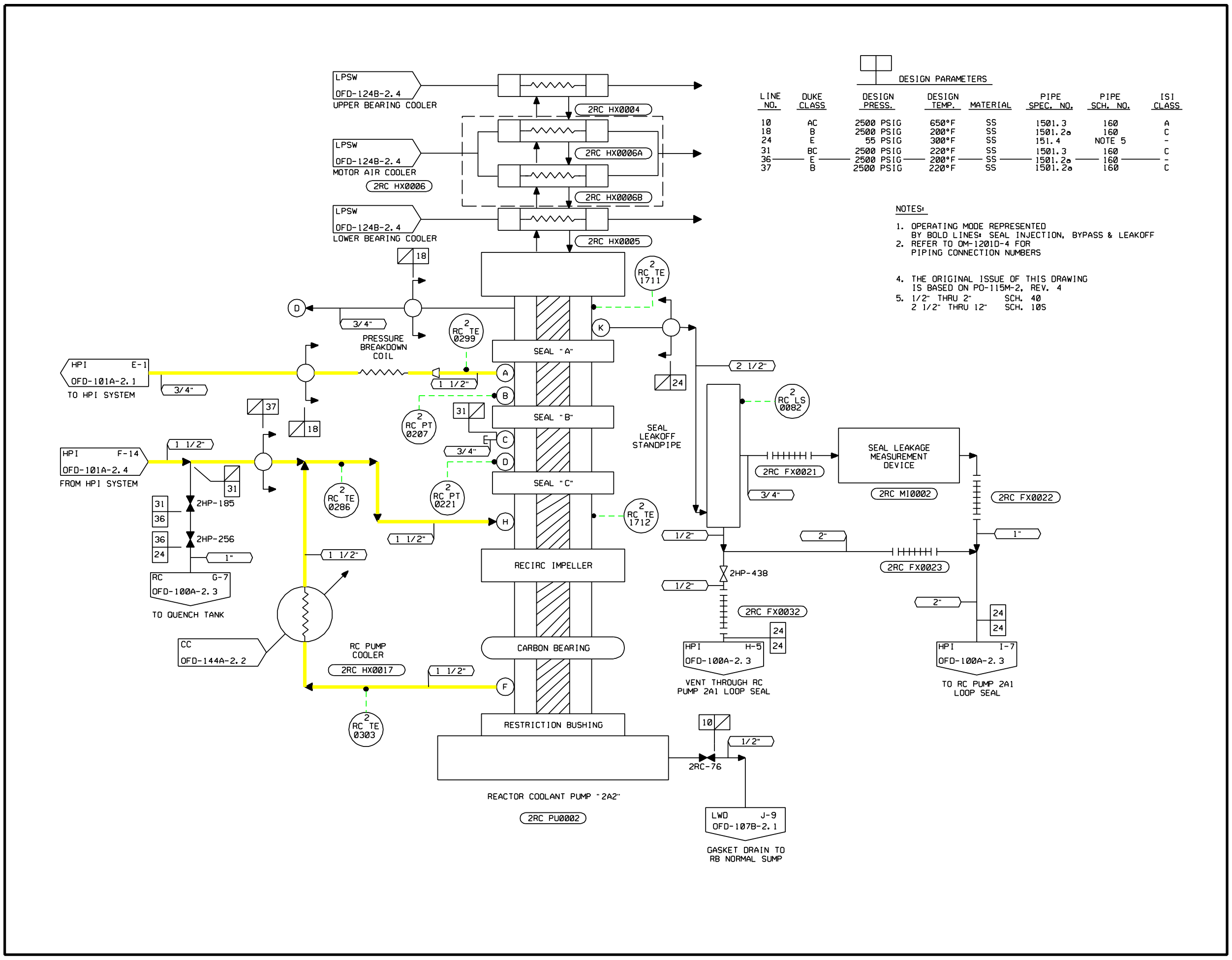
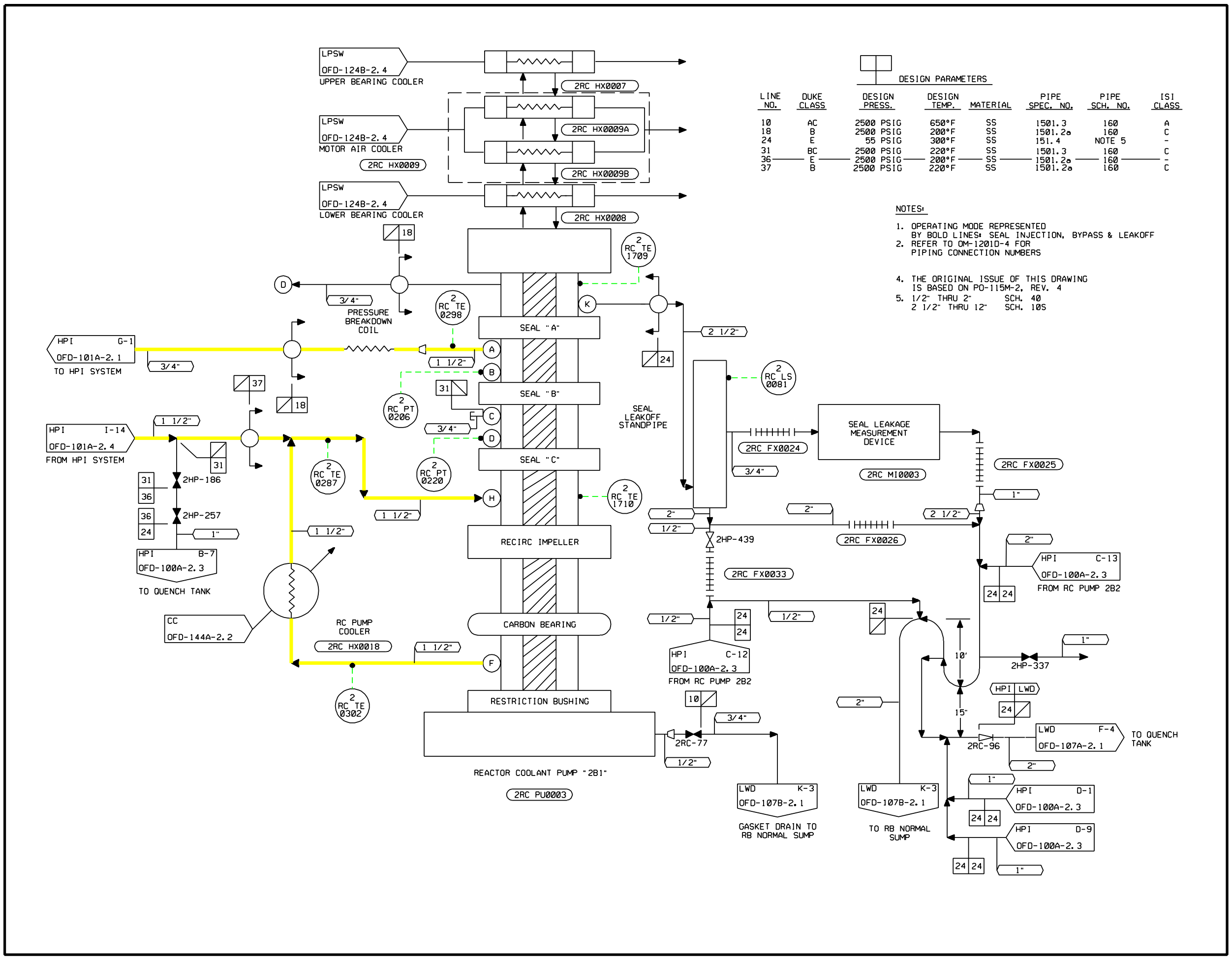
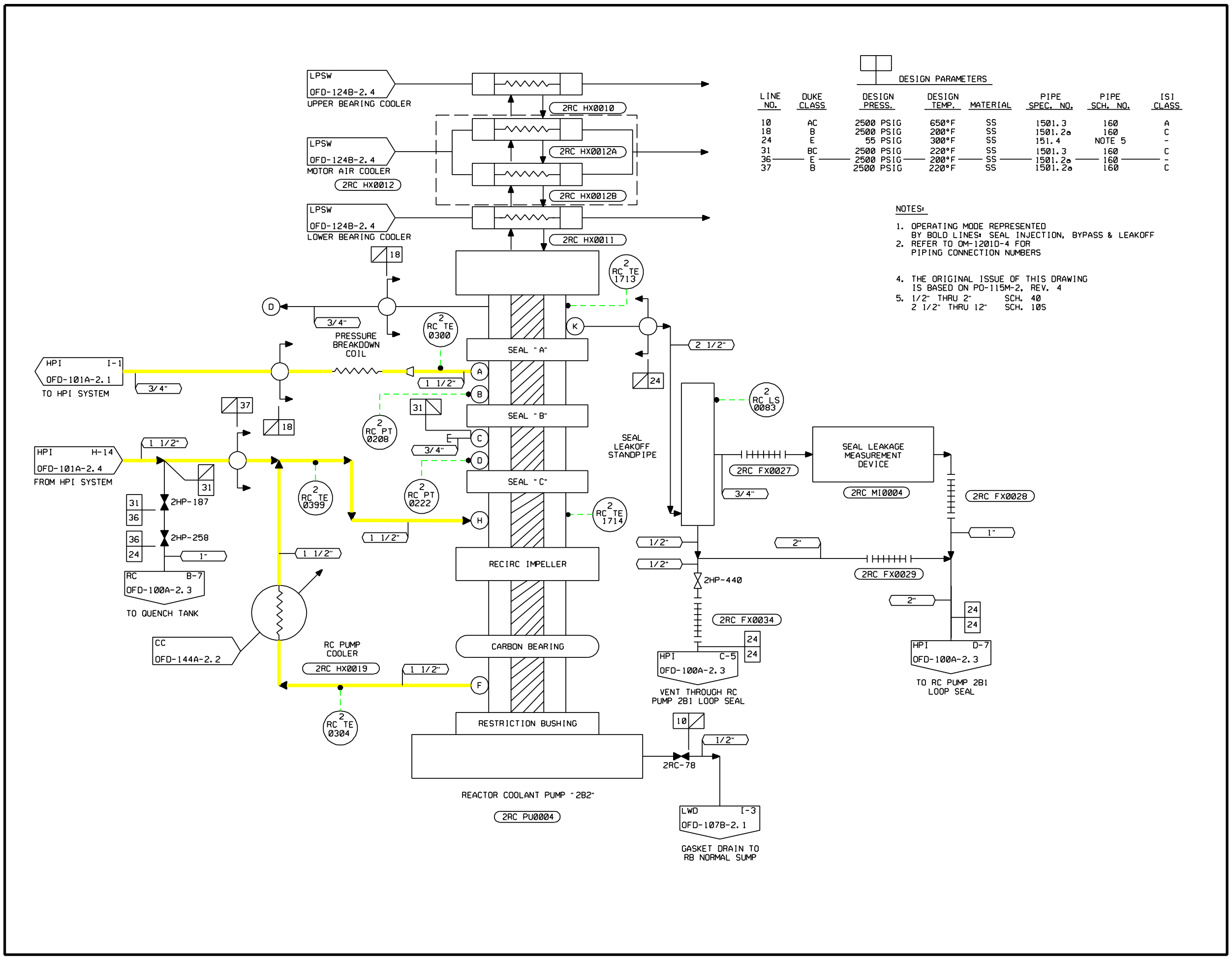


Figure 5-21. Flow Diagram of Bingham Reactor Coolant Pump-Piping Diagram



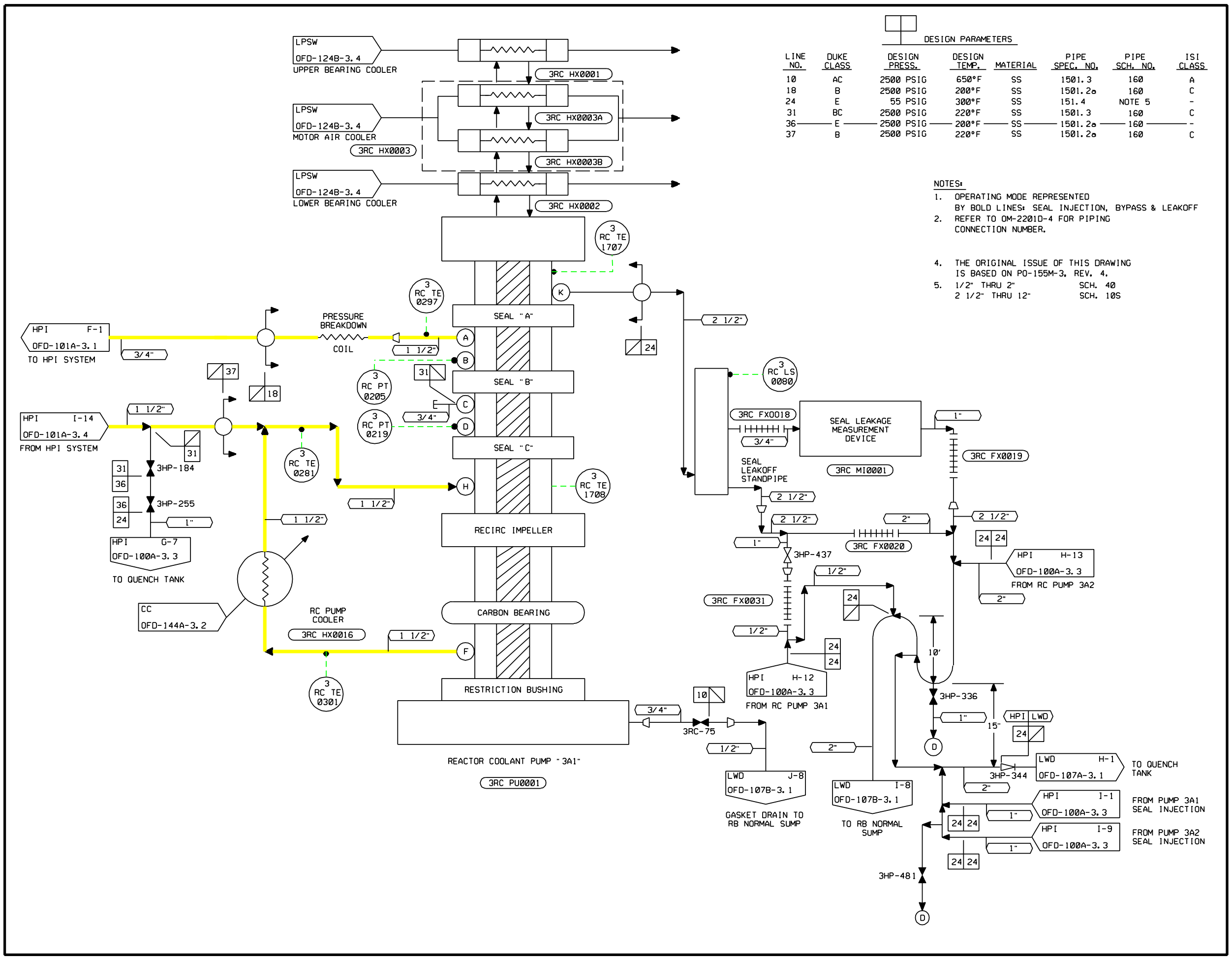

DESIGN PARAMETERS
LINE NO. | DUKE CLASS | DESIGN PRESS. | DESIGN TEMP. | MATERIAL | PIPE SPEC. NO. | PIPE SCH. NO. | ISI CLASS
10 AC 2500 PSIG 650°F SS 1501.3 160 A
18 B 2500 PSIG 200°F SS 1501.2a 160 C
24 E 55 PSIG 300°F SS 151.4 NOTE 5 -
31 BC 2500 PSIG 220°F SS 1501.3 160 C
36 E 2500 PSIG 200°F SS 1501.2a 160 -
37 B 2500 PSIG 220°F SS 1501.2a 160 C
NOTES:
1. OPERATING MODE REPRESENTED BY BOLD LINES: SEAL INJECTION, BYPASS & LEAKOFF
2. REFER TO OM-1201D-4 FOR PIPING CONNECTION NUMBERS
4. THE ORIGINAL ISSUE OF THIS DRAWING IS BASED ON PO-115M-2, REV. 4
5. 1/2" THRU 2" SCH. 40
2 1/2" THRU 12" SCH. 10S
LPSW
OFD-124B-2.4
UPPER BEARING COOLER
2RC HX0004
MOTOR AIR COOLER
2RC HX0006
2RC HX0006A
2RC HX0006B
LOWER BEARING COOLER
2RC HX0005
HPI E-1
OFD-101A-2.1
TO HPI SYSTEM
PRESSURE BREAKDOWN COIL
SEAL "A"
SEAL "B"
SEAL "C"
SEAL LEAKOFF STANDPIPE
SEAL LEAKAGE MEASUREMENT DEVICE
2RC MI0002
2RC FX0021
2RC FX0022
2RC FX0023
2RC FX0032
HPI F-14
OFD-101A-2.4
FROM HPI SYSTEM
2HP-185
2HP-256
2HP-438
RC G-7
OFD-100A-2.3
TO QUENCH TANK
RECIRC IMPELLER
CARBON BEARING
RESTRICTION BUSHING
CC
OFD-144A-2.2
RC PUMP COOLER
2RC HX0017
HPI H-5
OFD-100A-2.3
VENT THROUGH RC PUMP 2A1 LOOP SEAL
HPI I-7
OFD-100A-2.3
TO RC PUMP 2A1 LOOP SEAL
REACTOR COOLANT PUMP "2A2"
2RC PU0002
2RC-76
LWD J-9
OFD-107B-2.1
GASKET DRAIN TO RB NORMAL SUMP


DESIGN PARAMETERS
LINE NO. | DUKE CLASS | DESIGN PRESS. | DESIGN TEMP. | MATERIAL | PIPE SPEC. NO. | PIPE SCH. NO. | ISI CLASS
10 | AC | 2500 PSIG | 650°F | SS | 1501.3 | 160 | A
18 | B | 2500 PSIG | 200°F | SS | 1501.2a | 160 | C
24 | E | 55 PSIG | 300°F | SS | 151.4 | NOTE 5 | -
31 | BC | 2500 PSIG | 220°F | SS | 1501.3 | 160 | C
36 | E | 2500 PSIG | 200°F | SS | 1501.2a | 160 | -
37 | B | 2500 PSIG | 220°F | SS | 1501.2a | 160 | C
NOTES:
1. OPERATING MODE REPRESENTED BY BOLD LINES: SEAL INJECTION, BYPASS & LEAKOFF
2. REFER TO OM-1201D-4 FOR PIPING CONNECTION NUMBERS
4. THE ORIGINAL ISSUE OF THIS DRAWING IS BASED ON PO-115M-2, REV. 4
5. 1/2" THRU 2" SCH. 40
2 1/2" THRU 12" SCH. 10S
LPSW
OFD-124B-2.4
UPPER BEARING COOLER
2RC HX0007
MOTOR AIR COOLER
2RC HX0009
2RC HX0009A
2RC HX0009B
LOWER BEARING COOLER
2RC HX0008
PRESSURE BREAKDOWN COIL
SEAL "A"
SEAL "B"
SEAL "C"
SEAL LEAKOFF STANDPIPE
SEAL LEAKAGE MEASUREMENT DEVICE
2RC MI0003
2RC FX0024
2RC FX0025
2RC FX0026
2RC FX0033
RECIRC IMPELLER
CARBON BEARING
RESTRICTION BUSHING
REACTOR COOLANT PUMP "2B1"
2RC PU0003
RC PUMP COOLER
2RC HX0018
HPI G-1
OFD-101A-2.1
TO HPI SYSTEM
HPI I-14
OFD-101A-2.4
FROM HPI SYSTEM
HPI B-7
OFD-100A-2.3
TO QUENCH TANK
CC
OFD-144A-2.2
2HP-186
2HP-257
2HP-439
2HP-337
2RC-77
2RC-96
HPI C-12
OFD-100A-2.3
FROM RC PUMP 2B2
HPI C-13
OFD-100A-2.3
FROM RC PUMP 2B2
LWD K-3
OFD-107B-2.1
GASKET DRAIN TO RB NORMAL SUMP
LWD K-3
OFD-107B-2.1
TO RB NORMAL SUMP
LWD F-4
OFD-107A-2.1
TO QUENCH TANK
HPI D-1
OFD-100A-2.3
HPI D-9
OFD-100A-2.3
RC TE 1709
RC TE 0298
RC PT 0206
RC PT 0220
RC TE 0287
RC TE 1710
RC TE 0302
RC LS 0081



DESIGN PARAMETERS
LINE NO. | DUKE CLASS | DESIGN PRESS. | DESIGN TEMP. | MATERIAL | PIPE SPEC. NO. | PIPE SCH. NO. | ISI CLASS
10 AC 2500 PSIG 650°F SS 1501.3 160 A
18 B 2500 PSIG 200°F SS 1501.2a 160 C
24 E 55 PSIG 300°F SS 151.4 NOTE 5 -
31 BC 2500 PSIG 220°F SS 1501.3 160 C
36 E 2500 PSIG 200°F SS 1501.2a 160 -
37 B 2500 PSIG 220°F SS 1501.2a 160 C
NOTES:
1. OPERATING MODE REPRESENTED BY BOLD LINES: SEAL INJECTION, BYPASS & LEAKOFF
2. REFER TO OM-1201D-4 FOR PIPING CONNECTION NUMBERS
4. THE ORIGINAL ISSUE OF THIS DRAWING IS BASED ON PO-115M-2, REV. 4
5. 1/2" THRU 2" SCH. 40
2 1/2" THRU 12" SCH. 10S
LPSW OFD-124B-2.4 UPPER BEARING COOLER
2RC HX0010
LPSW OFD-124B-2.4 MOTOR AIR COOLER
2RC HX0012
2RC HX0012A
2RC HX0012B
LPSW OFD-124B-2.4 LOWER BEARING COOLER
2RC HX0011
PRESSURE BREAKDOWN COIL
HPI I-1 OFD-101A-2.1 TO HPI SYSTEM
HPI H-14 OFD-101A-2.4 FROM HPI SYSTEM
2HP-187
2HP-258
RC B-7 OFD-100A-2.3 TO QUENCH TANK
CC OFD-144A-2.2
RC PUMP COOLER
2RC HX0019
SEAL "A"
SEAL "B"
SEAL "C"
RECIRC IMPELLER
CARBON BEARING
RESTRICTION BUSHING
REACTOR COOLANT PUMP "2B2"
2RC PU0004
2RC-78
LWD I-3 OFD-107B-2.1
GASKET DRAIN TO RB NORMAL SUMP
SEAL LEAKOFF STANDPIPE
SEAL LEAKAGE MEASUREMENT DEVICE
2RC MI0004
2RC FX0027
2RC FX0028
2RC FX0029
2RC FX0034
2HP-440
HPI C-5 OFD-100A-2.3
VENT THROUGH RC PUMP 2B1 LOOP SEAL
HPI D-7 OFD-100A-2.3
TO RC PUMP 2B1 LOOP SEAL
2 RC TE 1713
2 RC TE 0300
2 RC PT 0208
2 RC TE 0399
2 RC PT 0222
2 RC TE 1714
2 RC TE 0304
2 RC LS 0083

Figure 5-22. Flow Diagram of Bingham Reactor Coolant Pump-Piping Diagram



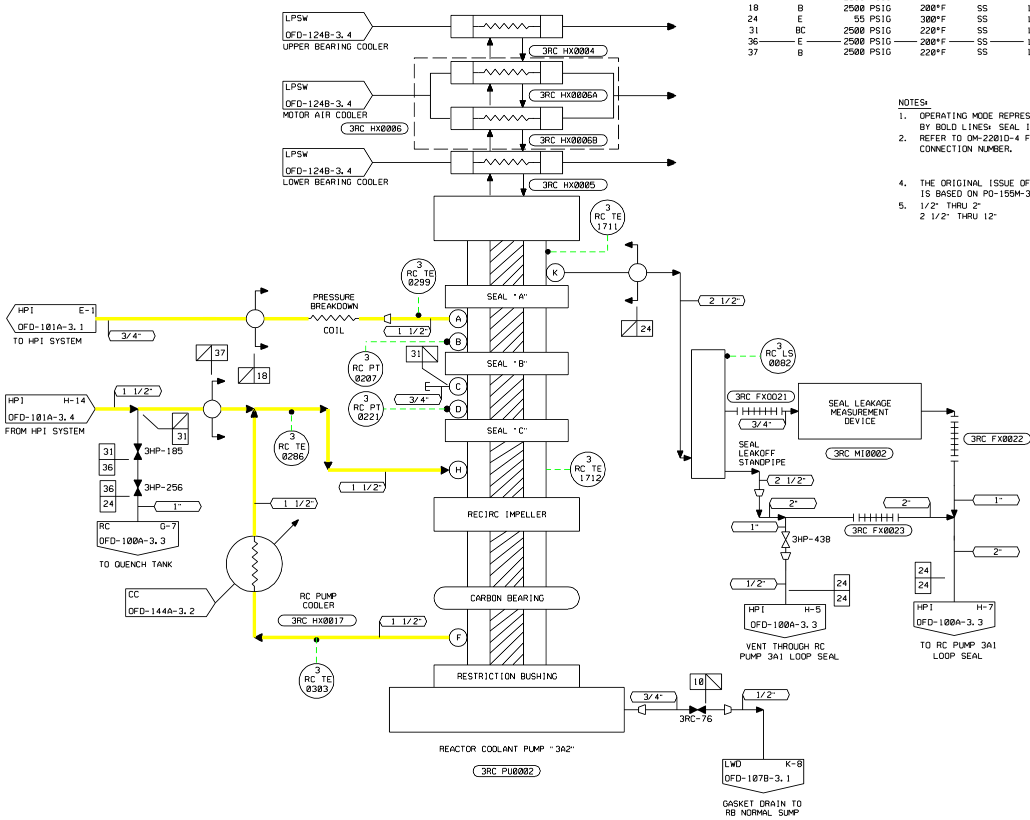
DESIGN PARAMETERS

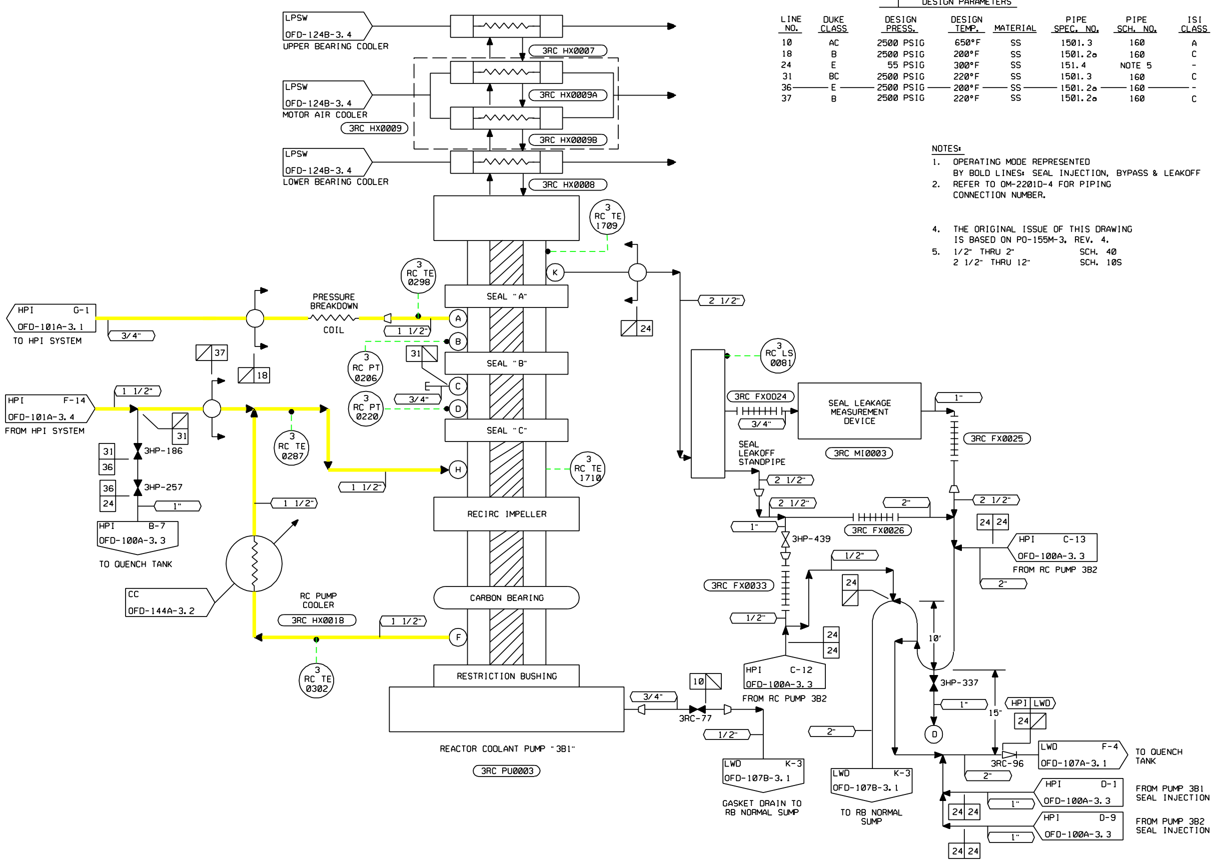
LINE NO.	DUKE CLASS	DESIGN PRESS.	DESIGN TEMP.	MATERIAL	PIPE SPEC. NO.	PIPE SCH. NO.	ISI CLASS
10	AC	2500 PSIG	650°F	SS	1501.3	160	A
18	B	2500 PSIG	200°F	SS	1501.2a	160	C
24	E	55 PSIG	300°F	SS	151.4	NOTE 5	-
31	BC	2500 PSIG	220°F	SS	1501.3	160	C
36	E	2500 PSIG	200°F	SS	1501.2a	160	-
37	B	2500 PSIG	220°F	SS	1501.2a	160	C

NOTES:

1. OPERATING MODE REPRESENTED BY BOLD LINES: SEAL INJECTION, BYPASS & LEAKOFF
2. REFER TO OM-2201D-4 FOR PIPING CONNECTION NUMBER.

4. THE ORIGINAL ISSUE OF THIS DRAWING IS BASED ON PO-155M-3, REV. 4.
5. 1/2" THRU 2" SCH. 40
   2 1/2" THRU 12" SCH. 10S





DESIGN PARAMETERS

LINE NO.	DUKE CLASS	DESIGN PRESS.	DESIGN TEMP.	MATERIAL	PIPE SPEC. NO.	PIPE SCH. NO.	ISI CLASS
10	AC	2500 PSIG	650°F	SS	1501.3	160	A
18	B	2500 PSIG	200°F	SS	1501.2a	160	C
24	E	55 PSIG	300°F	SS	151.4	NOTE 5	-
31	BC	2500 PSIG	220°F	SS	1501.3	160	C
36	E	2500 PSIG	200°F	SS	1501.2a	160	-
37	B	2500 PSIG	220°F	SS	1501.2a	160	C

NOTES:

1. OPERATING MODE REPRESENTED BY BOLD LINES: SEAL INJECTION, BYPASS & LEAKOFF
2. REFER TO OM-2201D-4 FOR PIPING CONNECTION NUMBER.

4. THE ORIGINAL ISSUE OF THIS DRAWING IS BASED ON PO-155M-3, REV. 4.
5. 1/2" THRU 2" SCH. 40
   2 1/2" THRU 12" SCH. 10S

DESIGN PARAMETERS

LINE NO.	DUKE CLASS	DESIGN PRESS.	DESIGN TEMP.	MATERIAL	PIPE SPEC. NO.	PIPE SCH. NO.	ISI CLASS
10	AC	2500 PSIG	650°F	SS	1501.3	160	A
18	B	2500 PSIG	200°F	SS	1501.2a	160	C
24	E	55 PSIG	300°F	SS	151.4	NOTE 5	-
31	BC	2500 PSIG	220°F	SS	1501.3	160	C
36	E	2500 PSIG	200°F	SS	1501.2a	160	-
37	B	2500 PSIG	220°F	SS	1501.2a	160	C

NOTES:

1. OPERATING MODE REPRESENTED BY BOLD LINES: SEAL INJECTION, BYPASS & LEAKOFF
2. REFER TO OM-2201D-4 FOR PIPING CONNECTION NUMBER.

4. THE ORIGINAL ISSUE OF THIS DRAWING IS BASED ON PO-155M-3, REV. 4.
5. 1/2" THRU 2" SCH. 40
   2 1/2" THRU 12" SCH. 10S

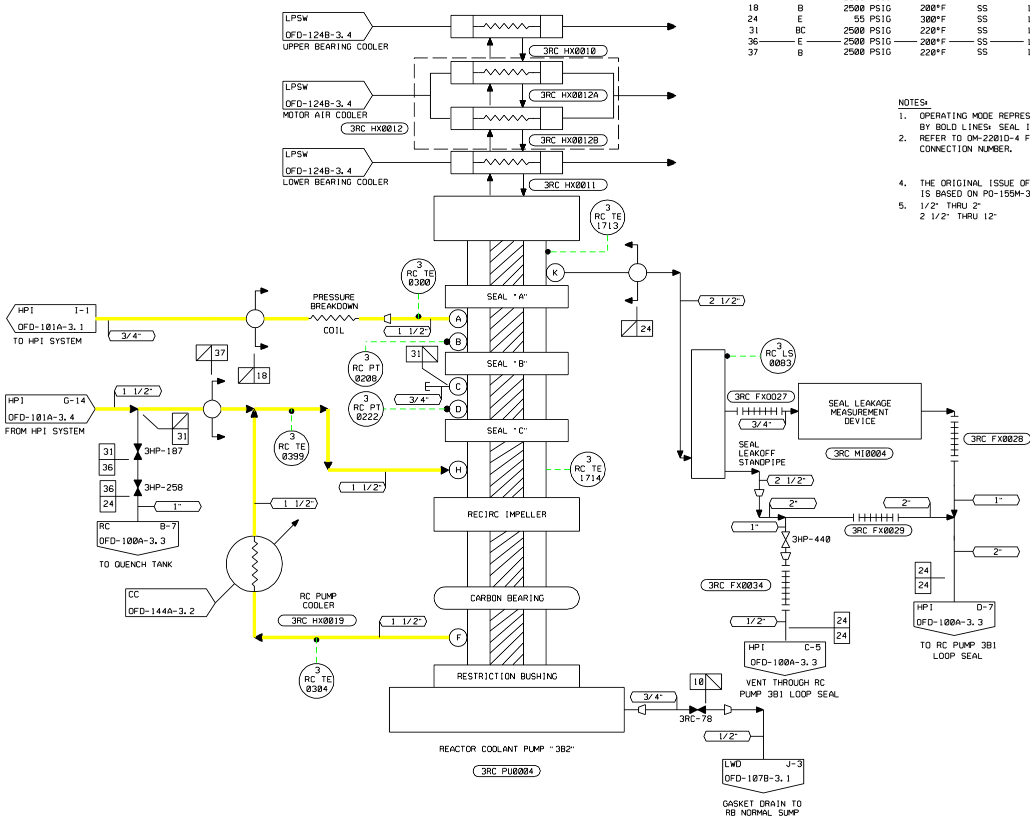


Figure 5-23. Code Allowables and Reinforcing Limits Nozzles and Bowls

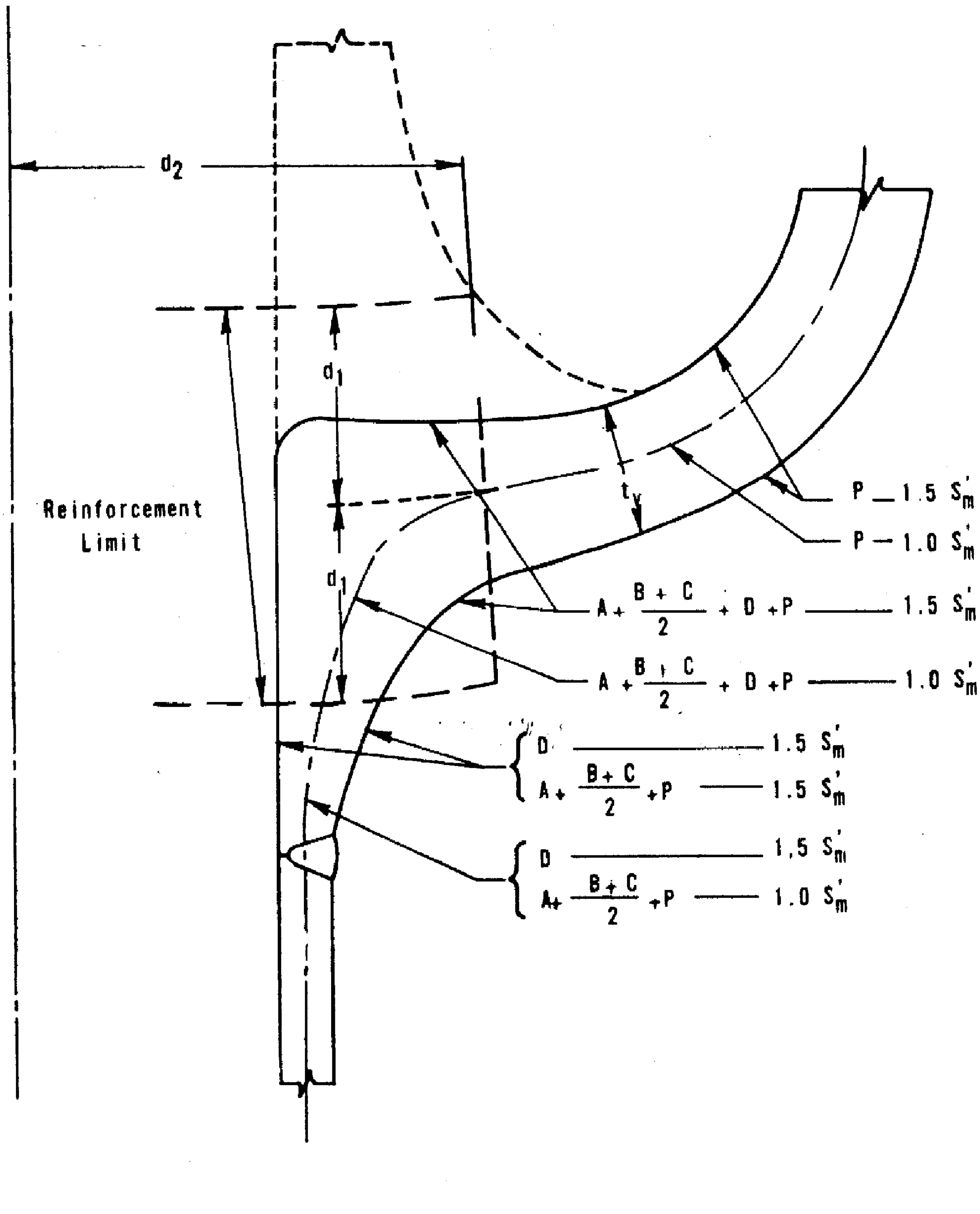


Figure 5-24. Code Allowables, Cover

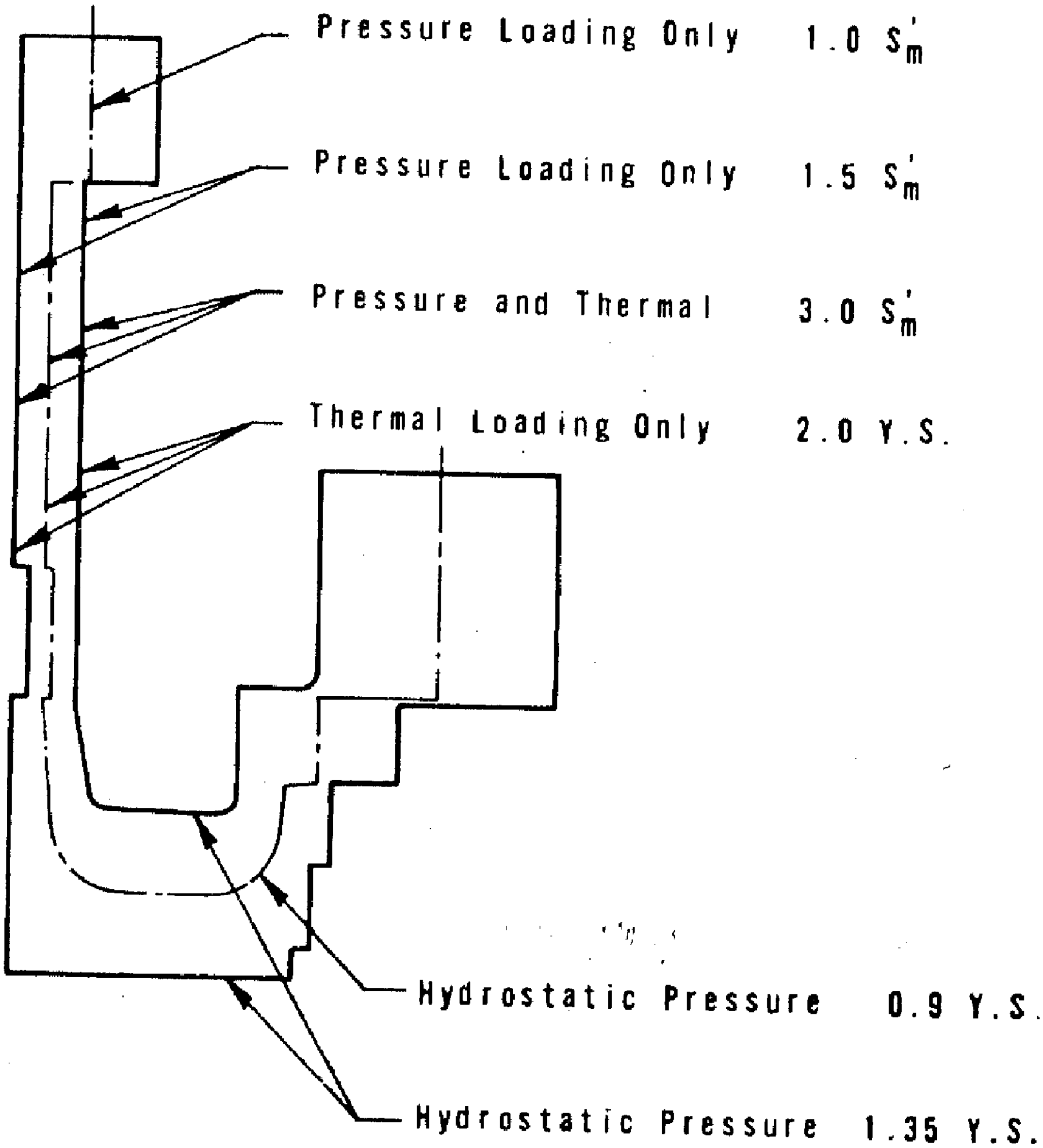


Figure 5-25. Steam Generator Outline

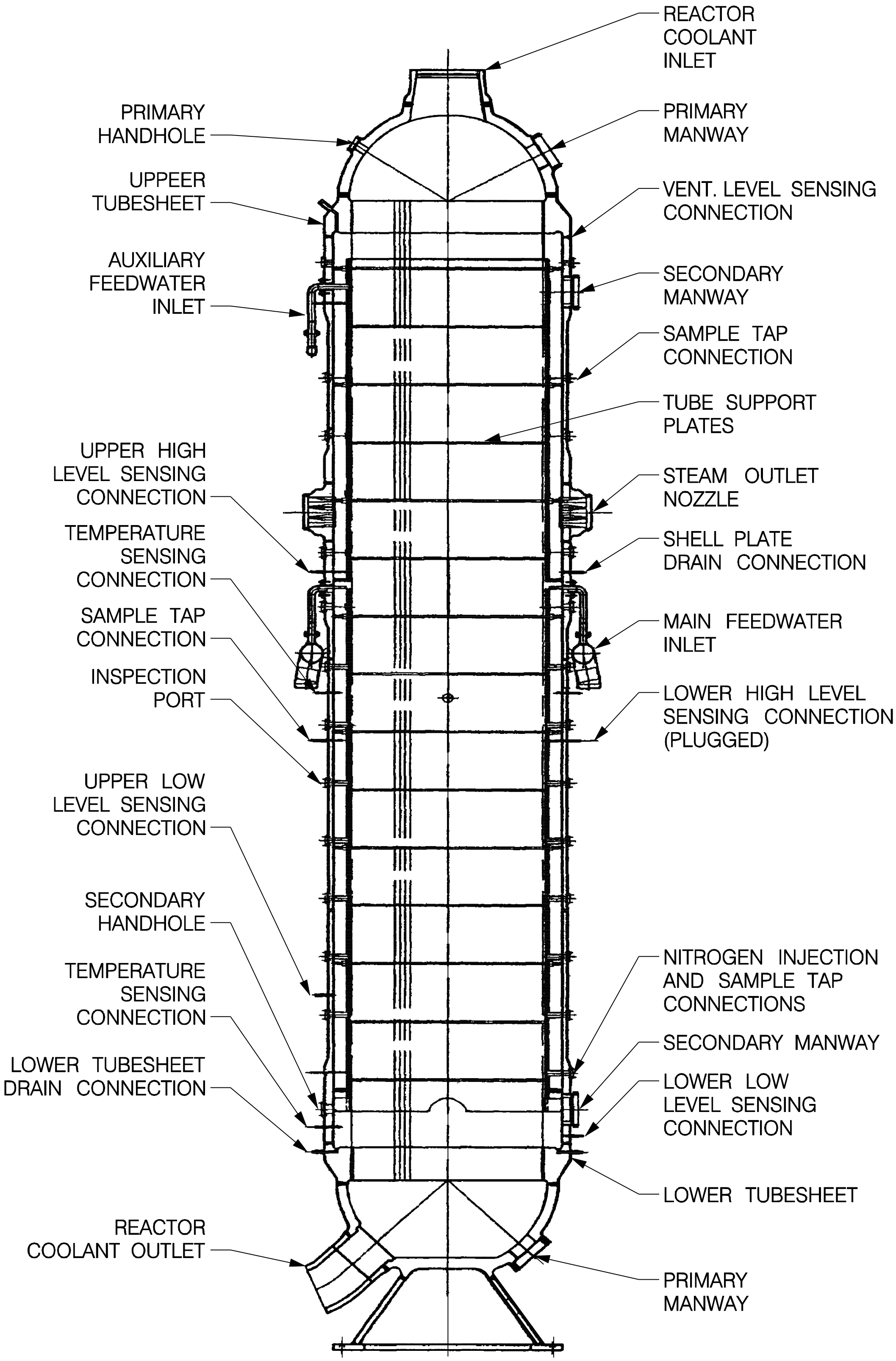


Figure 5-26. Deleted Per 2004 Update

Figure 5-27. Turbine Generator Speed Response Following Load Rejection

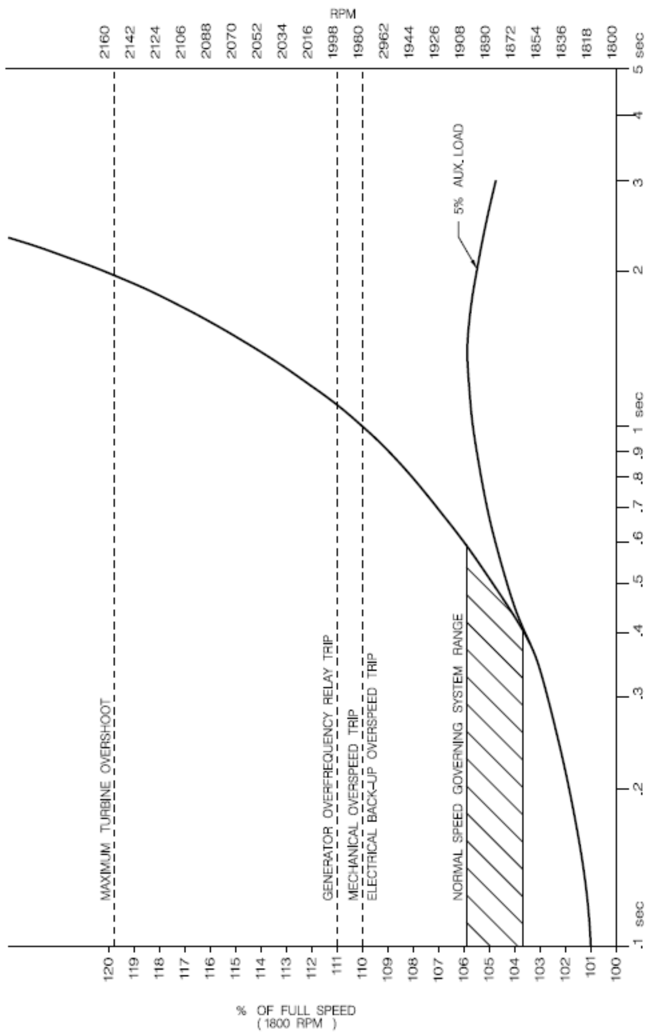


Figure 5-28. Pressurizer Outline

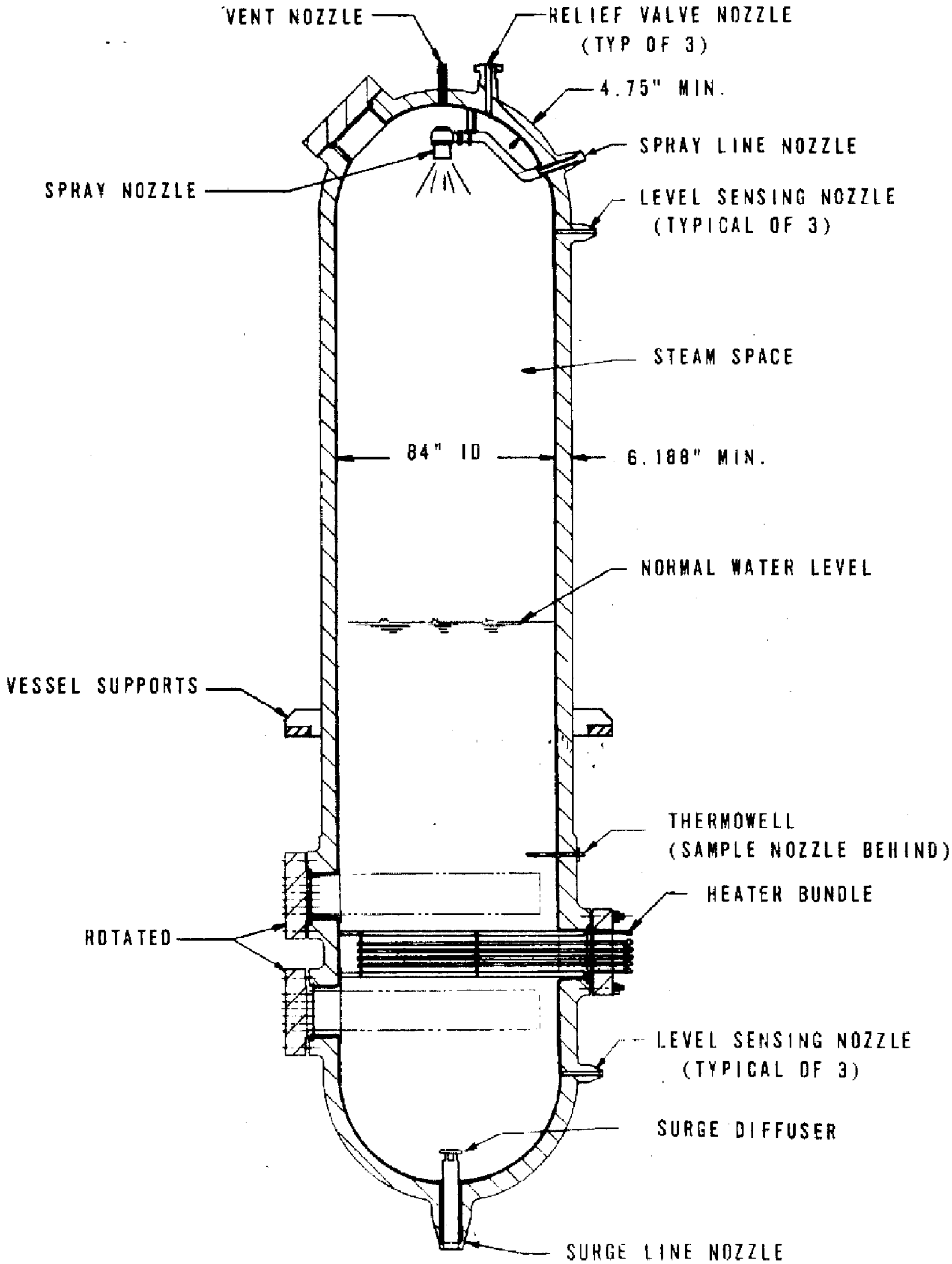


Figure 5-29. Reactor Coolant System Arrangement Elevation (Typical)

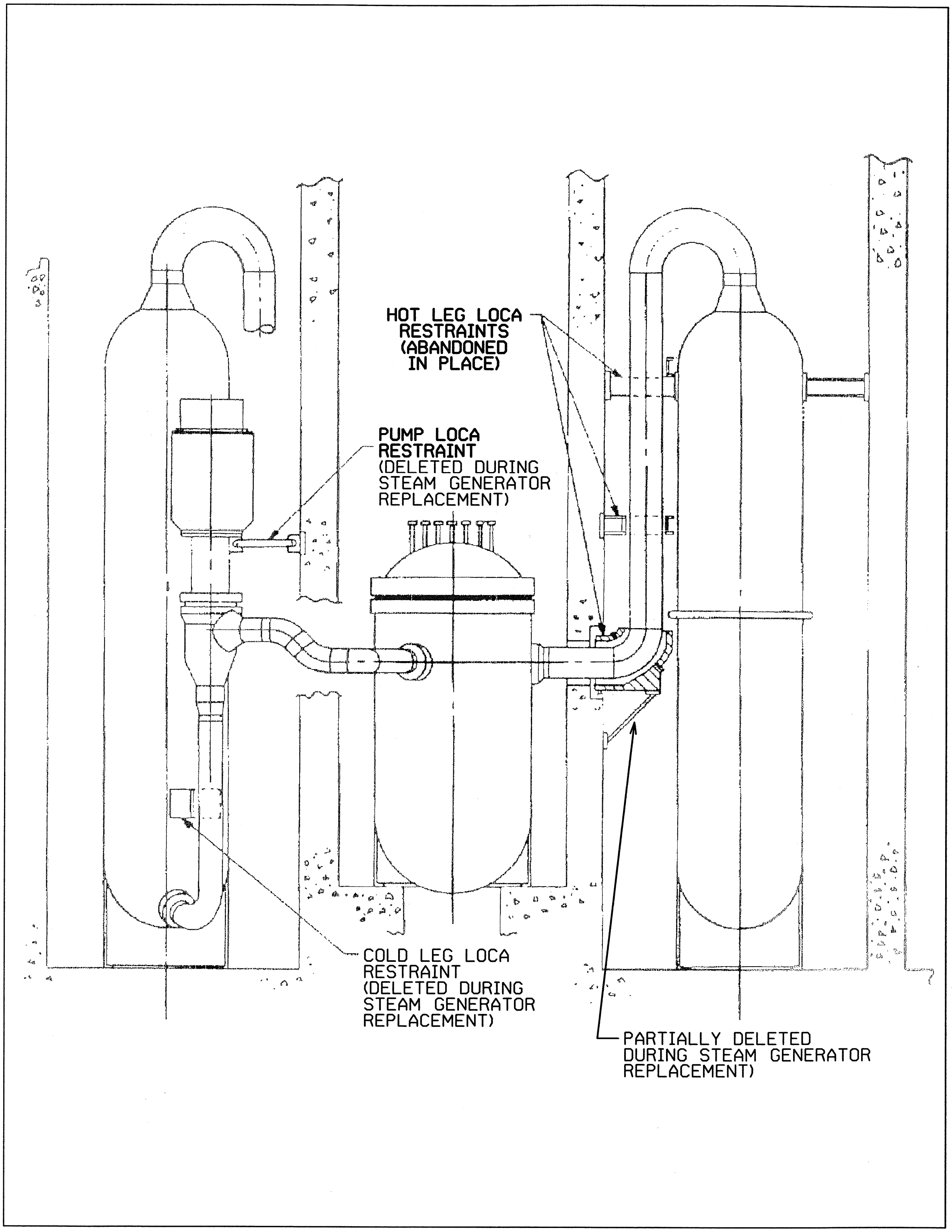


Figure 5-30. Reactor Coolant System Arrangement - Plan (Typical)

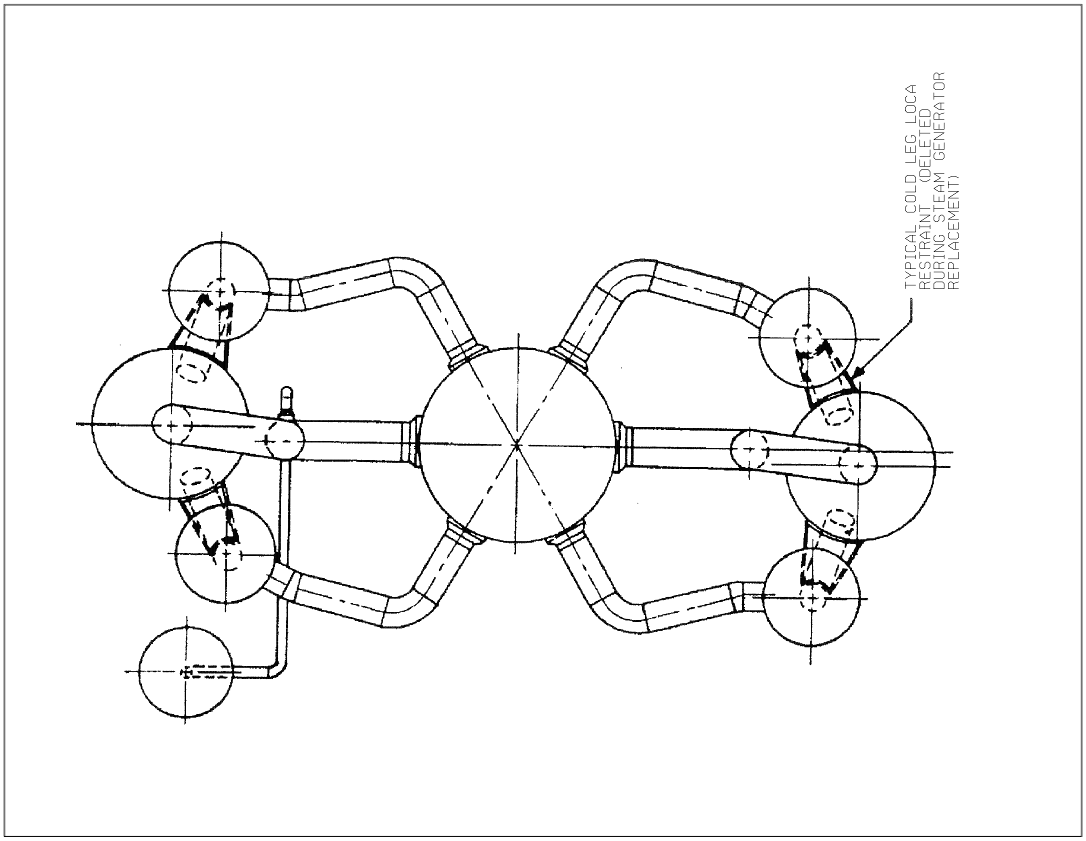
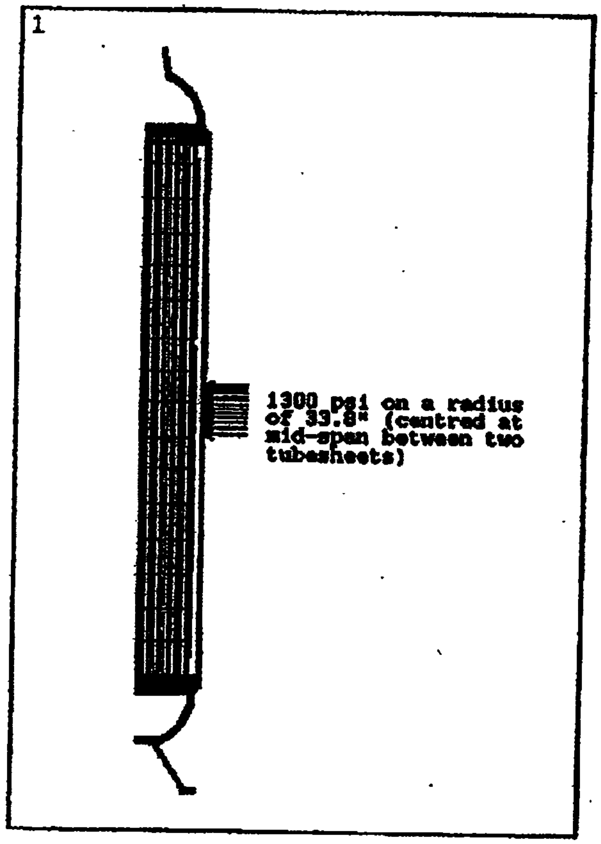


Figure 5-31. Jet Impingement Load on the Replacement Steam Generator



Notes:

[1] Base support and upper lateral support Level D loads already include the effect of this jet impingement load.

[2] For the determination of shell stresses, the shell can be considered fixed at the lower tubesheet and simply supported at the upper tubesheet.

Figure 5-32. Deleted Per 2003 Update

Figure 5-33. Replacement Reactor Vessel Closure Head Outline

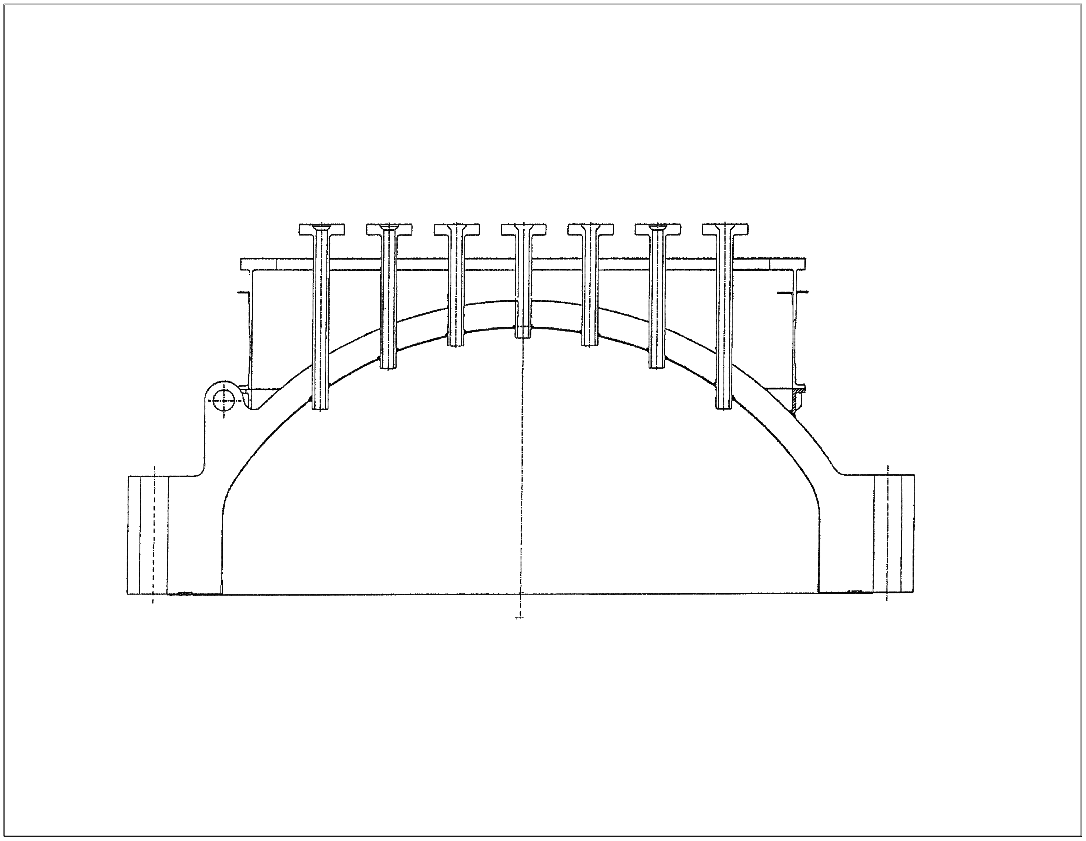


Table of Contents

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List of Tables

List of Figures

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6.0 Engineered Safeguards

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6.1 Engineered Safeguards

Engineered safeguards are those systems and components designed to function under accident conditions to prevent or minimize the severity of an accident or to mitigate the consequences of an accident. During accident conditions when reactor coolant is lost, or in the event of secondary system pipe breaks, the engineered safeguards act to provide emergency cooling to assure structural integrity of the core, to maintain the integrity of the Reactor Building, and to collect and filter Potential Reactor Building penetration leakage. Separate and independent engineered safeguards are provided for each of the three reactor units at Oconee. Special precautions are taken to assure high quality in the system design and components.

The engineered safeguards include provisions for:

a. High pressure injection.

b. Low pressure injection.

c. Core flooding.

d. Two types of Reactor Building cooling.

e. The collection and control of Reactor Building penetration leakage.

f. Reactor Building isolation.

Figure 6-1 and Figure 6-4 depict the portion of the Engineered Safeguards System related to core and building protection (see (a) through (d) above). A general description of the engineered safeguards provisions is presented below and a more detailed description is presented in the latter portion of this section. Since each reactor unit has the same arrangement of Emergency Safeguard Systems, the performance of the systems is described on a unit basis.

6.1.1 General Systems Description

The High and Low Pressure Injection Systems and the Core Flooding Tanks are designed to form collectively an overall Emergency Core Cooling System (ECCS), which is designed to prevent melting or physical disarrangement of the core over the entire spectrum of Reactor Coolant System break sizes. Figure 6-1 shows the Emergency Core Cooling Systems for one reactor unit. The High Pressure Injection System is arranged so that three pumps are available for emergency use. The Low Pressure Injection System is arranged to assure that two pumps are normally available and a third pump is installed but normally valved off. The Core Flooding System for each unit is composed of two separate pressurized tanks containing borated water at Reactor Building ambient temperature. These tanks automatically discharge their contents into the reactor vessel at a preset Reactor Coolant System pressure without reliance on any actuating signal, any electrical power or any external actuated component.

Reactor Building integrity is assured by two pressure reducing systems operating on different principles; the Reactor Building Spray System and the Reactor Building Emergency Cooling System. (Refer to Figure 6-2 and Figure 6-3). These systems have the redundancy required to meet the single failure criterion. These systems operate to lower Reactor Building pressure over the spectrum of Reactor Coolant System break sizes and to reduce the driving force for leakage of radioactive materials from the Reactor Building. They also serve to reduce Reactor Building pressure and temperature in the event of a main steam line break.

The Reactor Building Penetration Room Ventilation System shown on Figure 6-4 collects and filters air leakage to control and minimize the release of radioactive material from Reactor Building penetrations following an accident. Two full capacity filtering paths are provided. This system is no longer required due to adoption of the alternate source term. The system is not credited for event mitigation and serves an ALARA function only.

6.1.2 Equipment Operability

Operability of engineered safeguards equipment is assured in several ways. Much of the equipment in these systems serves a function during normal reactor operation. In those cases where equipment is used for emergency functions only such as the Reactor Building Spray System, systems have been designed to permit meaningful periodic tests. Operational reliability is achieved by using proven component design, and by conducting tests where either the component or its application was considered unique. In-house quality control procedures are imposed on the components of the Engineered Safeguards Systems. These procedures include use of accepted codes and standards as well as supplementary test and inspection requirements to assure that all components will perform their intended function under the design conditions following a loss-of-coolant accident. See also Section 6.3.4.3 for additional considerations related to Engineered Safeguards system operability.

The purpose of this section is to describe the physical arrangement, design, and operation of the Engineered Safeguards Systems as related to their safety function.

Reactor Building isolation is described in Section 6.2. Other sections of the report contain information which is pertinent to the Engineered Safeguards Systems. Chapter 7 describes the actuation instrumentation of these systems. Chapter 15 describes the analysis of the Engineered Safeguards Systems' capability to provide adequate protection during accident conditions. Chapter 9 discusses functions performed by these systems during normal operation and gives further design details and descriptive information concerning those systems.

6.1.3 Leakage and Radiation Considerations

The use of normally operating equipment for engineered safeguards functions and location of some of this equipment outside the Reactor Building require that consideration be given to direct radiation levels after fission products have accumulated in these systems and leakage from these systems.

The shielding for components of the engineered safeguards is designed to meet the following objectives in the event of a maximum hypothetical accident:

a. To provide protection for personnel to perform all operations necessary for mitigation of the accident.

b. To provide sufficient accessibility in all areas around the station to permit safe continued operation of the unaffected nuclear units.

Summary of Post-Accident Recirculation

Following a loss-of-coolant accident, flow is initiated in the Low Pressure Injection System from the borated water storage tank to the reactor vessel. Flow is also initiated by the Reactor Building Spray Systems to building spray headers. When most of the borated water storage tank inventory is exhausted, the operators initiate steps to transfer the pump suction to the Reactor Building emergency sump for both the reactor core cooling flow and the Reactor Building sprays. System resistance will maintain Reactor Building Spray pumps flow rates between 700 and 1200 gpm to ensure adequate NPSH during injection and recirculation modes, with no throttling required. The post-accident recirculation system includes all piping and equipment both internal and external to the Reactor Building as shown on Figure 6-1, up to the stop and test line valves leading to the borated water storage tank.

The NPSH available to the Low Pressure Injection and Reactor Building Spray pumps during the post-LOCA recirculation phase has been calculated based on:

a. "As Built" piping drawings.

b. Pipe and fitting losses calculated using the information in Crane Technical Paper No. 410, Cameron Hydraulic Data, and Idelchik Handbook of Hydraulic Resistance.

c. Total flow in a single string (i.e., consisting of one Low Pressure Injection Pump and one Reactor Building Spray pump served by a single sump suction line) is determined through hydraulic analysis.

d. BS pump flow is allowed to vary while LPI flow is maximized. Resistances have been added to the BS system piping so that flow rates are limited to a range of 700-1200 gpm. This provides improvements in NPSH available, and eliminates the requirements for throttling the flow to maintain pump NPSH. The system hydraulic analysis reflect those additional system resistances and the elimination of pump throttling.

e. Sump water temperatures and Reactor Building pressures were determined from analysis of hot leg break with conservative building cooling assumptions (LPSW temperature, RBCU capacity, etc.).

f. Reactor Building Spray pump shaft center line at elevation 760 ft. 1 in.

g. Low Pressure Injection pump shaft center line at elevation 761 ft. 1 in.

h. Water level in the Reactor Building sump is at elevation 781.28 ft. based on the following assumptions: (height above Reactor Building basement level is 4.4 ft.)

    1) The Technical Specification minimum initial levels were used for the BWST and the CFT's, with six feet of level remaining in the BWST at completion of switchover to RBES.

    2) Some water is maintained in the Reactor Building atmosphere as vapor. The quantity was determined using the results of a FATHOMS Computer Run for a 14.1 ft^2 break.

    3) The break is conservatively assumed to occur at the top of the hot leg, thereby keeping the Reactor Coolant System full.

i. Unit-specific and train-specific models were constructed to maximize the friction losses in the LPI and BS pump suction piping.

Results of the NPSH analysis are presented in Table 6-33. Credit is taken for 0.44 psi of reactor building overpressure in the calculation of available NPSH for the RBS and LPI pumps from approximately 3,000 seconds to approximately 30,000 seconds post-accident.

Available NPSH has been determined to meet or exceed the required NPSH for worst case accident conditions with conservative inputs as identified above. Curves of total dynamic head and NPSH versus flow are shown in Figure 6-5 for the Reactor Building Spray Pumps and in Figure 6-17 for the Low Pressure Injection Pumps. These curves are representative in nature and are provided for information only. They are not intended to constitute design commitments or performance requirements for the pumps. Refer to the Inservice Test Program for actual performance requirements for BS and LPI pumps.

The NRC issued Generic Letter 97-04, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," on October 7, 1997, requesting that licensees submit information necessary to confirm the adequacy of the net positive suction head (NPSH) available for emergency core cooling (including core spray and decay heat removal) and containment heat removal pumps. A review of the current design-basis analyses used to determine the available NPSH for the applicable pumps was performed and report submitted by the letter from M. S. Tuckman to the NRC, dated January 5, 1998 (Reference 2). This report concluded that the available NPSH for these pumps is adequate under all design-basis accident scenarios. As a result of a subsequent review by Duke, the NPSH calculations were determined to be outside the design basis as discussed in a letter from W. R. McCollum to the NRC, dated Septemer 17, 1998 (Reference 3). A License Admendment was submitted to revise the UFSAR to be consistent with the design basis calculations. License Amendments 305/305/305 approving incorporations of the UFSAR changes to the NPSH bases were issued in a letter from D. E. LeBarge (NRC) to W. R. McCollum (Duke), dated July 19, 1999 (Reference 4).

Bases of Leakage Estimates

While the reactor auxiliary systems involved in the recirculation complex are closed to the Auxiliary Building atmosphere, leakage is possible through component flanges, seals, instrumentation, and valves.

The leakage sources considered are:

a. Valves
    1) Disc leakage when valve is on recirculation system boundary.
    2) Stem leakage.
    3) Bonnet flange leakage.
b. Flanges
c. Pump shaft seals

While leakage rates have been assumed for these sources, maintenance and periodic testing of these systems will preclude all but a small percentage of the assumed amounts. With the exception of the boundary valve discs, all of the potential leakage paths may be examined during periodic tests or normal operation. Boundary valves which have been identified to have leakage paths are tested periodically. All other valve disc leakage is retained in the other closed systems and, therefore, will not be released to the Auxiliary Building.

While valve stem leakage has been assumed for all valves, a number of manual valves in the recirculation complex are backseating and do not rely on packing alone to prevent stem leakage.

Leakage Assumptions

Source	Quantities
a. Valves - Process	
1. Disc Leakage	10 cc/hr./in. of nominal disc diameter
2. Stem leakage	1 drop/min.

Source		Quantities
	3. Bonnet flange	10 drops/min.
b.	Valves - Instrumentation	
	Bonnet flange and stem	1 drop/min.
c.	Flanges	10 drops/min.
d.	Pump seals	50 drops/min.

For the analysis, it was assumed that the water leaving the Reactor Building was at 252 °F. This assumption is conservative as this peak temperature would only exist for a short period during the post-accident condition. Water downstream of the coolers was assumed to be 115 °F. The Auxiliary Building was assumed to be at 70 °F and 30 percent relative humidity. Under these conditions, approximately 22 percent of the leakage upstream of the coolers and 4 percent of the leakage downstream of the coolers would flash into vapor. For the analysis, however, it was assumed that 50 percent of the leakage upstream of the coolers would become vapor because of additional heat transfer from the hot metal.

Design Basis Leakage

The design basis leakage for the LPI, HPI, and BS systems is 12 gallons per hour.

Leakage Analysis Conclusions

It was concluded from analysis of the 12 gph limit (in conjunction with the discussion and analysis in Section 15.15.4) that leakage from Engineered Safeguards Systems outside the Reactor Building does not pose a public safety problem.

6.1.4 Quality Control Standards

Quality Control Standards for the Engineered Safeguards Systems are listed in Table 6-3.

6.1.5 Piping Design Conditions

Piping Design Conditions for the Engineered Safeguards Systems are listed on Table 6-4.

6.1.6 Engineered Safeguards Materials

Materials used in Engineered Safeguards components are addressed in applicable sections where appropriate.

6.1.7 References

1. Nuclear Regulatory Commission, Letter to Holders of Operating Licenses for Nuclear Power Plants, Except Those Who Have Permanently Ceased Operations and Have Certified That Fuel Has Been Permanently Removed for the Reactor Vessel, from Jack W. Roe, October 7, 1997, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps (Generic Letter 97-04)."

2. Duke Power Company, Letter from M. S. Tuckman to the NRC, January 5, 1998, re: Response to Generic Letter 97-04, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps."

3. Duke Power Company, Letter from W. R. McCollum to the NRC, dated September 17, 1998. Re: Response to Request for Additional Information Related to Generic Letter 97-04, dated August 11, 1998.

4. D. E. LeBarge (NRC) to W. R. McCollum (Duke), dated July 19, 1999, re: Issuance of Amendments (License Amendments 305/305/305 for NPSH changes related to Generic Letter 97-04).

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6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.1 Containment Structure

6.2.1.1.1 Design Bases

The Reactor Building completely encloses the Reactor Coolant System to minimize release of radioactive material to the environment should a serious failure of the Reactor Coolant System occur. The structure provides adequate biological shielding for both normal operation and accident situations. The Reactor Building is designed for an internal pressure of 59 psig. The leakage rate will not exceed 0.2 percent by volume in 24 hours under the conditions of the maximum hypothetical accident as described below.

The Reactor Building is designed for an external pressure 3.0 psi greater than the internal pressure. The design external pressure of 3.0 psi corresponds to a margin of 0.5 psi above the differential pressure that could be developed if the building is sealed with an internal temperature of 120°F with a barometric pressure of 29.0 inches of Hg and the building is subsequently cooled to an internal temperature of 80°F with a concurrent rise in barometric pressure to 31.0 inches of Hg. The weather conditions assumed here are conservative since an evaluation of National Weather Service records for this area indicates that from 1918 to 1970 the lowest barometric pressure recorded is 29.05 inches of Hg and the highest of 30.85 inches of Hg.

The principal design basis for the structure is that it be capable of withstanding the internal pressure resulting from a loss-of-coolant accident or a secondary line rupture with no loss of integrity. In a LOCA, the total energy contained in the water of the Reactor Coolant System is assumed to be released into the Reactor Building through a break in the reactor coolant piping. In a secondary line break event the energy contained in the water in the secondary coolant system, as well as energy transferred across the steam generator tubes from the Reactor Coolant System is assumed to be released into the Reactor Building through a break in the steam line piping. However, in the case of a secondary line break, the release of energy essentially stops when the faulted steam generator empties and is no longer being supplied with feedwater. In either case, subsequent pressure behavior is determined by the building volume, engineered safeguards, and the combined influence of energy source and heat sinks.

Energy is available for release into the containment structure from the following sources:

LOCA	Secondary Line Break
Reactor Coolant Stored Energy	Secondary Coolant Stored Energy
Reactor Stored Energy	Secondary System Stored Energy
Reactor Decay Heat	Reactor Coolant Stored Energy
Metal-Water Reactions	Reactor Stored Energy
Secondary Coolant Stored Energy	Reactor Decay Heat
Secondary System Stored Energy	

6.2.1.1.2 Design Features

Since the design of the Engineered Safeguards Systems and their operation is discussed more fully in Section 6.3, only their relation to the basis of Reactor Building design is discussed below. The Engineered Safeguards Systems are provided to limit the consequences of an accident. Their energy removal capabilities limit the internal pressure after the initial peak so that Reactor Building design limits are not exceeded and the potential for release of fission products is minimized.

Following a LOCA, the Emergency Core Cooling Systems inject borated water into the Reactor Coolant System to remove core decay heat and to minimize metal-water reactions and the associated release of heat and fission products. Flashed primary coolant, Reactor Coolant System sensible heat, and core decay heat transferred to Reactor Building are removed by two engineered safeguards systems: the Reactor Building Spray and/or the Reactor Building Cooling Systems.

Following a secondary line break at power, main feedwater and turbine-driven emergency feedwater flow to the faulted steam generator are isolated by the Automatic Feedwater Isolation System (AFIS) on low steam line pressure. AFIS will also isolate motor-driven emergency feedwater to the affected steam generator on a high rate of steam line depressurization concurrent with low steam line pressure. For break sizes that do not exceed the AFIS rate of depressurization setpoint, manual operator action is credited at 10 minutes to isolate motor-driven emergency feedwater flow to the affected steam generator. Section 6.2.1.4.4 discusses AFIS actions during secondary line blowdown into containment. Section 7.9 provides a detailed description of AFIS operation.

The Reactor Building Spray System removes heat directly from the Reactor Building atmosphere by cold water quenching of the Reactor Building steam.

The air recirculation and cooling systems remove heat directly from the Reactor Building atmosphere to the Service Water System with recirculating fans and cooling coils.

The low pressure injection coolers remove heat from the containment sump liquid to the Service Water System with heat exchange through tubes.

Section 3.8 provides a detailed description of the Reactor Building design.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 LOCA Short Term Containment Pressure Response

This section provides analyses of the short-term (3 minutes) pressure response of the containment to a spectrum of postulated Reactor Coolant System pipe ruptures. The analyses results provide the bounding post-LOCA containment responses with respect to the containment design pressure, with all input assumptions and boundary conditions chosen to provide a conservatively high containment pressure per the methodology presented in Reference 1. The break size and location of each postulated loss of coolant accident is given in Table 6-21. The pressure and temperature response of the four break location sensitivity studies, Cases 1A through 1D, are given in the following figures:

Figure 6-28 Containment pressure for a 14.1 ft^2 break at the reactor vessel outlet (1A)
Figure 6-29 Containment pressure for a 14.1 ft^2 break at the steam generator inlet (1B)
Figure 6-30 Containment pressure for a 8.55 ft^2 break at the RCP discharge (1C)
Figure 6-31 Containment pressure for a 8.55 ft^2 break at the RCP suction (1D)
Figure 6-32 Containment temperature for a 14.1 ft^2 break at the reactor vessel outlet (1A)

Figure 6-33 Containment temperature for a 14.1 ft^2 break at the steam generator inlet (1B)
Figure 6-34 Containment temperature for a 8.55 ft^2 break at the RCP discharge (1C)
Figure 6-35 Containment temperature for a 8.55 ft^2 break at the RCP suction (1D)

Analysis Method and Computer Codes

The analysis method used in this section is described in Reference 1. The computer codes used in this section are RELAP5/MOD2-B&W (Reference 2) for calculating the mass and energy releases and FATHOMS (Reference 3) for calculating the containment pressure and temperature response.

Mass and Energy Release Rate Data

The mass and energy release rate data used for the LOCA analyses described in this section are given in Section 6.2.1.3.

Initial Condition Assumption Conservatisms

Initial condition assumptions in the LOCA containment peak pressure response analyses are adjusted to give a conservative answer:

1. The initial pressure assumption is equal to the upper Technical Specification limit. Instrument uncertainty is taken into account through operation of the Reactor Building purge, before this upper limit is reached.
2. The initial temperature assumption is conservatively low for full power operation. This maximizes the initial containment air mass, which maximizes the air partial pressure contribution to the pressure peak.
3. The nominal containment free volume is reduced by 2% from the Table 6-22 value.
4. A low initial relative humidity is used to maximize the initial air mass.

The initial conditions used are tabulated in Table 6-22.

Containment Heat Removal Systems

No credit is taken in the LOCA peak pressure analysis for either the Reactor Building cooling units or the Reactor Building Spray System. The peak pressure occurs within the first 20 seconds after the postulated break, prior to the assumed actuation of either of these heat removal systems.

Emergency Core Cooling Systems

The emergency core cooling systems are not explicitly modeled in FATHOMS for the LOCA peak pressure analysis, but are considered in the mass and energy releases discussed in Section 6.2.1.3.

Single Failure

A component single failure generally has little impact on the peak pressure analysis. This is because peak pressures usually occur before the engineered safeguards equipment has time to activate and become effective.

Structural Heat Sinks

The structural heat sinks within containment are divided into nine groups for the purposes of containment pressure and temperature response modeling. These nine structures are tabulated in Table 6-23. The concrete and steel portions of the building cylinder, the building dome, and the building base are combined in three structures of two materials each.

6.2.1.1.3.2 LOCA Long-Term Containment Temperature Response

This section provides analyses of the long-term (>1 day) temperature response of the containment to a spectrum of postulated Reactor Coolant System pipe ruptures. The analyses results provides the bounding long-term containment temperature response for use in Equipment Qualification (EQ) evaluation of equipment within the Reactor Building. The bounding post-LOCA containment pressure responses are discussed in Section 6.2.1.1.3.1, while the bounding short-term containment temperature results are discussed in Section 6.2.1.1.3.3. The long-term large break containment analysis considers only a single break size and location: a double-ended guillotine break located at the A1 cold leg pump discharge. There is no need to analyze a spectrum of large break locations since a suitably bounding site can be chosen by inspection. The qualitative bases for this position is explained in the following paragraphs. Reference 1 also extensively analyzed the mass and energy releases from and containment response to small break LOCAs. The conclusion of these analyses is that small break LOCAs are not more limiting than large break LOCAs with respect to challenging the containment equipment qualification acceptance criteria.

The basis for choosing a cold leg break as opposed to a hot leg break is obvious once the characteristics of each break are considered. Although it is true that an identical quantity of decay heat will be generated regardless of the break location, the manner in which this energy is partitioned between the vapor and liquid break flow streams is the dominant consideration.

Because the long-term containment response is concerned with temperature in containment as a function of time, it is expected that an energy release profile which is dominated by steam relief will generate a more severe containment response. This is because steam relief to the atmosphere will have a greater impact on containment temperature than if the energy is released primarily in the liquid phase, which has only a slight interaction with the containment atmosphere (convection at the pool surface). Indeed, this observation has been validated with the GOTHIC computer code in numerous analyses. It might appear that the Reactor Building Spray System acts to homogenize the containment atmosphere such that the phase in which the energy is released is insignificant. However, when the complicated interactions between the equipment used to cool the containment atmosphere (Reactor Building coolers and sprays) and the equipment used to cool the containment sump (LPI coolers) are examined by analysis, it is apparent that containment will never become completely homogenized. Therefore, the partitioning of energy released to containment between the vapor and liquid phases is the dominant factor in the long-term containment response.

Due to the geometry of a B&W reactor system, steaming from a cold leg break location will never become completely suppressed. This means that steam will always exit the break no matter how much the decay heat power drops. In contrast, it is possible to completely suppress steaming from a hot leg break site as decay power decreases. Decay heat will eventually be absorbed as sensible heat by the injection fluid and thus steaming from the break will cease. Naturally, when this occurs, decay heat will be transferred to containment in the liquid phase, resulting in a less severe containment response.

The cold leg pump discharge break location is selected rather than the pump suction location. For a pump suction break the cold HPI fluid injected into the broken cold leg pump discharge piping will interact with steam exiting the core through the vent valves and condense a large portion of this steam before it reaches the break. Thus, the steam release will be less for a pump suction break. Consequently, the pump discharge break location is limiting.

An accident chronology is presented in Table 6-24 for the most limiting LOCA, an 8.55 ft^2 double-ended guillotine cold leg break at the reactor coolant pump outlet. Table 6-25 presents results for various combinations of initial Reactor Building temperature, LPSW temperature and RBCU heat removal rate. The results of the limiting case are presented in the following figures:

Figure 6-36 Containment pressure
Figure 6-37 Containment atmosphere temperature
Deleted row(s) per 2003 update

These cases represent the combinations of minimum and maximum LPSW temperature and RBCU heat removal rate. All cases assume LPI cooler heat removal performance which conservatively bounds that for the coolers at all three Oconee units. The equipment qualification criteria for all equipment required for LOCA mitigation are documented in the Oconee Environmental Qualification Criteria Manual, referred to UFSAR Section 3.11. These criteria are met for all cases analyzed.

Analysis Method and Computer Codes

The analysis method used in this section is described in Reference 1. The computer codes used in this section are RELAP5/MOD2-B&W (Reference 2) for calculating the mass and energy releases during the first 30 minutes, BFLOW (Reference 1) for calculating the longer term LOCA mass and energy releases, and GOTHIC (Reference 17) for calculating the containment pressure and temperature response.

Mass and Energy Release Rate Data

The mass and energy release rate data used for the LOCA analyses described in this section are given in Section 6.2.1.3.

Initial Condition Assumption Conservatisms

Initial condition assumptions in the containment response analyses are adjusted to give a conservative answer:

1. A nominal initial pressure is used, although this parameter has very little effect due to the long duration of this analysis.
2. The initial temperature assumption is conservatively high for full power operation.
3. The nominal containment free volume is reduced by 2% from the Table 6-22 value.
4. A high initial relative humidity is used, although this parameter has very little effect due to the long duration of this analysis.

The initial conditions used are tabulated in Table 6-22

Containment Heat Removal Systems

The Reactor Building Cooling Units (RBCUs) are modeled based on performance at design conditions. This reference is based on the heat removal rate associated with:

1. Low Pressure Service Water (LPSW) temperature of 75°F
2. Containment air temperature of 286°F
3. Containment air/stream mixture characteristic of 70°F and 14.7 psia initial condition
4. Entering air flow rate of 54,000 acfm

The performance of the two operating coolers (refer to single failure discussion below) is adjusted for the safety analysis to reflect different air/stream mixtures based on the higher containment initial temperatures and higher LPSW temperatures assumed in the safety analysis. The RBCU performance requirements are adjusted back to the reference performance conditions above to compare with periodic cooler performance test results.

Low Pressure Injection (LPI) Cooler test data at various flow rates are used to determine the relationships between cooler degradation (number of plugged tubes and amount of tube surface fouling) and thermal performance parameters such as fluid flow rates and temperatures. These relationships are then modeled to determine an LPI Cooler overall heat transfer coefficient as a function of LPI inlet temperature. Since assumed cooler degradation, fluid flow rates, and LPSW temperature are constant during a simulation, and since LPI inlet temperature changes during the accident, this change determines the LPI cooler heat removal rate for a particular case. No credit is taken for heat removal by the LPI coolers during the injection phase.

Calculations using hydraulic models of the Oconee Reactor Building Spray (RBS) System result in a minimum flow rate of 750 gpm during the injection phase, taking suction from the Borated Water Storage Tank (BWST). Likewise, minimum flow rates of 900 gpm during the sump recirculation phase (taking suction from the Reactor Building Emergency Sump (RBES)) are demonstrated. In the GOTHIC containment response analyses, the RBS flow rate during injection mode is conservatively assumed to be 700 gpm. During sump recirculation mode, the RBS flow rate is assumed to be 900 gpm. The injection phase temperature used is a conservatively high for the borated water storage tank, the source of RBS water during the injection phase. The recirculation phase RBS temperature is the sump temperature calculated by GOTHIC. No credit is taken for aligning the RBS pumps to take suction from the outlet of the LPI coolers.

Assumed values for containment heat removal equipment performance parameters are given in Table 6-26.

Emergency Core Cooling Systems

The single operating Low Pressure Injection (LPI) pump (refer to single failure discussion below) is assumed in the GOTHIC computer code to be supplying a conservatively low flow rate to the reactor vessel. The injection phase temperature used is a conservatively high for the borated water storage tank, the source of LPI water during the injection phase. The recirculation phase temperature is calculated by FATHOMS based on the heat removal from the LPI coolers.

The two operating High Pressure Injection (HPI) pumps (refer to single failure discussion below) are assumed to be supplying a conservatively low flow rate to the cold legs. The HPI water injected into the broken cold leg is added directly to the containment sump. The injection phase temperature used is a conservatively high for the borated water storage tank, the source of HPI water during the injection phase. No credit is taken for HPI flow during the recirculation phase.

Liquid injection from the core flood tanks is not explicitly modeled in GOTHIC but is considered in the mass and energy releases discussed in Section 6.2.1.3. The nitrogen cover gas from these tanks is assumed to be injected to increase the containment pressure calculated by GOTHIC. The amount of injected nitrogen is based on the mass which would be present at the pressure and temperature initial conditions of the mass and energy release calculation.

Assumed values for ECCS equipment performance parameters are given in Table 6-26.

Single Failure

While a component single failure generally has little impact on the peak pressure analysis described in the previous section, it has a much greater impact on the long-term containment response. The most limiting single failure is therefore chosen to yield a conservative long-term containment response. The most restrictive single failure is chosen as the one which disables the greatest number of containment heat removal components.

An evaluation was performed to determine the most limiting single failure with respect to containment cooling. This evaluation indicated that the failure of a 4160V switchgear represents the most limiting single failure. Electrical switchgear power a myriad of safety related equipment including injection systems and containment cooling systems. The failure of one of the three available switchgear will result in the loss of the following components:

1. One HPI pump
2. One LPI pump
3. One RBS pump
4. One RBCU

All other ECCS equipment is available following a nominal, transient-specific actuation delay.

The switchgear failure is more limiting than a loss of offsite power (LOOP) and failure of one Keowee hydroelectric unit because the second hydroelectric unit is available to power the standby busses through CT-4 (underground) or through the switchyard (overhead). Therefore, all ECCS equipment would be available after a small time delay.

Structural Heat Sinks

The structural heat sinks within containment are those described in Section 6.2.1.1.3.1 and tabulated in Table 6-23. For the LOCA long-term containment response calculation the surface areas of these heat structures are reduced by 1% for conservatism.

6.2.1.1.3.3 Steam Line Break Containment Pressure and Temperature Response

This section provides analyses of the pressure and temperature response of the containment to postulated secondary system pipe ruptures. A spectrum of break sizes is analyzed to determine the limiting break size for peak containment pressure and temperature. For peak containment pressure, the response depends mainly on the steam mass flow rate. The limiting break size for peak containment pressure and temperature is the double-ended guillotine break (12.6 ft^2). This break size results in the highest initial rate of mass and energy release to the containment and thus maximizes the increase in containment pressure and temperature during the steam line break transient.

The results of the limiting case are given in Table 6-27. The pressure and temperature response of these limiting cases are given in Figure 6-42 (containment pressure) and Figure 6-43 (containment temperature). The period of time during which the calculated temperature exceeds the equipment qualification limit is very short compared to the time that the equipment is exposed to high temperatures during its qualification testing. This short duration of calculated temperatures above the equipment qualification limit is not long enough to cause the equipment internal temperatures to reach values as high as those reached during the qualification testing.

Analysis Method and Computer Codes

The analysis method used in this section is described in Reference 1. The computer codes used in this section are RETRAN-3D (Reference 9) for calculating the steam line break mass and energy releases and FATHOMS (Reference 3) for calculating the containment pressure and temperature response.

Mass and Energy Release Rate Data

The mass and energy release rate data used for the steam line break analyses described in this section are given in Section 6.2.1.4.

Initial Condition Assumption Conservatisms

Initial condition assumptions in the containment response analyses are adjusted to give a conservative answer:

1. The initial pressure assumption is equal to the upper Technical Specification limit for cases in which high initial pressure is conservative.
2. The initial temperature assumption is conservatively high for full power operation. It is known from the LOCA analyses described in the previous section that a lower initial temperature maximizes the containment peak pressures due to a higher initial air mass. However, a higher initial temperature reduces the cooling capacity of the structural heat sinks, outweighing the impact of a higher initial air mass.
3. The nominal containment free volume is reduced by 2% from the Table 6-22 value.
4. A low initial relative humidity is used to maximize the initial air mass.

The initial conditions used are tabulated in Table 6-22.

Containment Heat Removal Systems

The Reactor Building cooling units (RBCUs) are modeled as described in Section 6.2.1.1.3.2. The steam line break peak pressure is reached long before the borated water storage tank empties. Therefore the recirculation phase is not simulated, and no credit is taken for heat removal by the LPI coolers during the injection phase. The RBS is modeled as described in Section 6.2.1.1.3.2 for the injection phase.

Single Failure

The assumed single failure is the same as discussed above for LOCA, the failure of a 4160 V switchgear, resulting in the loss of one HPI pump, one LPI pump, one RBS pump and one RBCU.

Structural Heat Sinks

The structural heat sinks within containment are those described in Section 6.2.1.1.3.1 and tabulated in Table 6-23. For the steam line break containment response calculation the surface areas of these heat structures are reduced by 1% for conservatism.

6.2.1.1.3.4 Functional Capability of Normal Containment Ventilation Systems

Normal containment ventilation is provided by four Reactor Building auxiliary cooling units (RBACUs) and two of the three RBCUs. The function of these units during normal operation is described in Section 9.4.6. Upper and lower limits on containment pressure during normal operation are maintained by complying with the Technical Specifications.

6.2.1.1.3.5 Post-Accident Monitoring of Containment Conditions

Post-accident monitoring instrumentation is provided for the following containment parameters:

Reactor Building pressure
Reactor Building air temperature
Reactor Building normal sump level
Reactor Building emergency sump level
Reactor Building wide range sump level
Reactor Building hydrogen concentration

Section 7.5 discusses the range, accuracy, and response of this instrumentation and the tests conducted to qualify the instruments for use in the post-accident containment environment.

6.2.1.2 Containment Subcompartments

The pressure response of the Reactor Building subcompartments following the design basis LOCA has been evaluated using mass and energy release rates calculated by the CRAFT code (Reference 4) using the system model in Reference 5, with the pressure response calculated by the COPRA code (Reference 6). The Reactor Building subcompartments include the reactor compartment and the east and west steam generator compartments. For each compartment the worst case LOCA break size and location is identified, including the effect of piping restraints on the maximum break size. The flow through the subcompartment vents is calculated using a sonic choking model for a homogeneous steam-water-air mixture, with a vent discharge coefficient of 0.6. A discharge coefficient of 1.0 is used for the system blowdown calculation.

The reactor compartment has a volume of 5520 ft^3, one 6 ft^2 vent flowpath, and concrete shield plugs with a total flow area of 69 ft^2. Only the vent flowpath is assumed to be available for pressure relief. Although the maximum break area within the compartment has been determined to be 3.0 ft^2, hot leg breaks of 8.0, 5.0, and 3.0 ft^2 were analyzed, as well as the maximum cold leg break of 8.55 ft^2. The CRAFT mass and energy release rates are given in Figure 6-44 and Figure 6-45. The resulting pressure differential across the compartment walls are shown in Figure 6-46. The peak pressure of 160 psi, which occurs for the 8.0 ft^2 hot leg break, is only 78 percent of the design differential pressure of 205 psi.

The west steam generator compartment has a volume of 61,700 ft^3 and a total vent flow area of 1333 ft^2. The east compartment has a volume of 60,400 ft^3 and a flow area of 1222 ft^2. The discharge coefficients for each of the flowpaths and the effective discharge coefficient calculated to result in the correct choked flow are given in Table 6-28 and Figure 6-47. The maximum hot leg break of 14.1 ft^2 was analyzed using the CRAFT mass and energy release rates in Figure 6-44 and Figure 6-45. The resulting pressure differentials across the compartment walls are shown in Figure 6-48. The structural integrity of the compartments is sufficient to withstand 130 percent of the peak differential pressure of 15 psi.

6.2.1.3 Mass and Energy Release Analyses for Postulated Loss-of-Coolant Accidents

6.2.1.3.1 Short-Term Mass and Energy Release Data

From hot leg and cold leg break studies, the limiting break location for peak containment pressure is the hot leg at the steam generator inlet. Studies have shown that reduced reactor coolant system average temperature and differential cold leg temperature cases do not result in the limiting peak containment pressure response. The short-term LOCA peak pressure mass and energy releases are given in Table 6-29. The short-term LOCA peak pressure mass and energy releases using the replacement steam generators are given in Table 6-35.

6.2.1.3.2 Long-Term Mass and Energy Release Date

The long-term LOCA mass and energy releases calculated by RELAP5/MOD2-B&W for the cold leg injection phase of the transient are given in Table 6-30. The mass and energy releases beyond this point are calculated within the GOTHIC code using input from the BFLOW code (Reference 1).

6.2.1.3.3 Energy Sources

The generated energy sources considered in the LOCA mass and energy release calculations are fission power, fission product and actinide decay energy, and metal-water reaction. The analyzed (actual) core power level is conservatively assumed to be 2% above the licensed (indicated) power. The assumed core axial power distribution is chosen to maximize the amount of steam exiting the break. Fission product and actinide decay power is calculated as a function of time based on the methodology from Reference 7. For conservatism an upper bound of two standard deviations above the mean value is used. The modeling of metal-water reaction energy is discussed in Section 6.2.1.3.6.

The stored energy sources considered in the LOCA mass and energy release calculations are fluid stored energy in the initial primary and secondary system inventories, stored energy in the primary and secondary structural metal components, stored energy in the fuel rods, and the energy content of the fluid added to the primary and secondary systems during the accident.

6.2.1.3.3.1 Short-Term Energy Sources

The short-term LOCA mass and energy release calculation conservatively determines fission power by modeling moderator density, fuel, temperature, and boron feedbacks as described in Reference 1.

The specific conservatisms used in modeling the stored energy sources considered in the short-term LOCA mass and energy release calculations are:

1. The nominal volume of the Reactor Coolant System calculated based on cold dimensions is increased by 1% to account for the increase in volume due to thermal expansion to operating temperatures.
2. Initial pressurizer liquid mass is increased by assuming an initial level corresponding to the maximum Technical Specification allowable value of 285 inches plus an indication uncertainty of 25 inches.
3. The assumed reactor vessel average temperature is the nominal at power value, 579°F, plus a 2°F uncertainty allowance. This maximizes the stored energy in the Reactor Coolant System.
4. Reactor Coolant System pressure is at the nominal at power value, 2155 psig, plus a 30 psi uncertainty allowance. This maximizes the saturation temperature and therefore the energy content of the pressurizer fluid.
5. The core flood tank (CFT) temperature is assumed to be a conservatively high value of 130°F. This minimizes available sensible heat capacity of the CFT liquid and therefore maximizes the break steaming rate.
6. The CFT initial pressure used is the upper Technical Specification limit plus a 30 psi instrument uncertainty. This maximizes the amount of noncondensible gas released to containment and therefore the containment pressure.
7. The CFT liquid volume is the lower Technical Specification limit less an instrument uncertainty of 38 ft3. This minimizes available sensible heat capacity of the CFT liquid and maximizes the amount of noncondensible gas released to containment, both of which, as explained above, tend to increase containment pressure and temperature.
8. The main steam safety valve lift setpoints incorporate 3% drift and 4% blowdown to minimize the potential for steam relief. This maximizes the amount of hot secondary side fluid remaining in the steam generators and able to transfer its energy via the primary side to containment.
9. The BWST temperature is assumed to be a conservatively high value of 115°F, which minimizes available sensible heat capacity of the BWST liquid and therefore maximizes the break steaming rate.

10. Main feedwater temperature is at the nominal at power value, 453°F, plus a 7°F uncertainty allowance. This maximizes the potential energy release to containment. For further conservatism this assumed main feedwater temperature is maintained during the analysis although actual temperature would decrease as bleed steam was lost due to the break.
11. Main feedwater flow is maximized by controlling flow to the higher natural circulation setpoint even before the reactor coolant pumps are tripped. The nominal level setpoint is increased by a 12.5% operating range allowance for instrument uncertainty. This is conservative since it maximizes the amount of higher energy secondary side inventory available to transfer heat to the containment via the primary side.
12. Emergency feedwater temperature is at a conservatively high value of 130°F. This maximizes the potential energy release to containment.

6.2.1.3.3.2 Long-Term Energy Sources

The long-term LOCA mass and energy release calculation conservatively determines fission power by modeling moderator density, fuel, temperature, and boron feedbacks as described in Reference 1.

The specific conservatisms used in modeling the stored energy sources considered in the long-term LOCA mass and energy release calculations are:

1. The nominal volume of the Reactor Coolant System calculated based on cold dimensions is increased by 1% to account for the increase in volume due to thermal expansion to operating temperatures.
2. Initial pressurizer liquid mass is increased by assuming an initial level corresponding to the maximum Technical Specification allowable value of 285 inches plus an indication uncertainty of 25 inches.
3. The assumed reactor vessel average temperature is the nominal at power value, 579°F, plus a 2°F uncertainty allowance. This maximizes the stored energy in the Reactor Coolant System.
4. Reactor Coolant System pressure is at the nominal at power value, 2155 psig, plus a 30 psi uncertainty allowance. This maximizes the saturation temperature and therefore the energy content of the pressurizer fluid.
5. The core flood tank (CFT) temperature is assumed to be a conservatively high value of 130°F. This minimizes available sensible heat capacity of the CFT liquid and therefore maximizes the break steaming rate.
6. The CFT initial pressure used is the upper Technical Specification limit plus a 30 psi instrument uncertainty. This maximizes the amount of noncondensible gas released to containment and therefore the containment pressure.
7. The CFT liquid volume is the lower Technical Specification limit less an instrument uncertainty of 38 ft3. This minimizes available sensible heat capacity of the CFT liquid and maximizes the amount of noncondensible gas released to containment, both of which, as explained above, tend to increase containment pressure and temperature.
8. The main steam safety valve lift setpoints incorporate 3% drift and 4% blowdown to minimize the potential for steam relief. This maximizes the amount of hot secondary side fluid remaining in the steam generators and able to transfer its energy via the primary side to containment.

9. The BWST temperature is assumed to be a conservatively high value of 115°F, which minimizes available sensible heat capacity of the BWST liquid and therefore maximizes the break steaming rate.
10. Main feedwater temperature is at the nominal at power value, 453°F, plus a 7°F uncertainty allowance. This maximizes the potential energy release to containment. For further conservatism this assumed main feedwater temperature is maintained during the analysis although actual temperature would decrease as bleed steam was lost due to the break.
11. Main feedwater flow is maximized by controlling flow to the higher natural circulation setpoint even before the reactor coolant pumps are tripped. The nominal level setpoint is increased by a 10.0% operating range allowance for instrument uncertainty. This is conservative since it maximizes the amount of higher energy secondary side inventory available to transfer heat to the containment via the primary side.
12. Emergency feedwater temperature is at a conservatively high value of 130°F. This maximizes the potential energy release to containment. This assumption is only relevant for cases that assume a loss of offsite power. Long-term large break analyses with offsite power conservatively use hotter main feedwater.

6.2.1.3.4 Description of Analytical Models

The mass and energy releases during the blowdown and core reflood periods of a postulated LOCA are calculated by the RELAP5/MOD2-B&W computer code (Reference 2). The methodology for applying this code is given in Reference 1. RELAP5/MOD2-B&W is used to calculate the mass and energy releases during the cold leg injection period of a postulated LOCA. Beyond this point the BFLOW and GOTHIC codes are used to calculate mass and energy releases for the remainder of the accident as detailed in Reference 1.

6.2.1.3.5 Single Failure Analysis

The assumed single failure is the same as discussed above for the containment response analysis, the failure of a 4160 V switchgear, resulting in the loss of one HPI pump and one LPI pump.

6.2.1.3.6 Metal-Water Reaction

The energy released by steam/cladding metal-water reaction is considered in the short-term LOCA mass and energy release calculation. Reference 1 provides the methodology for modeling this energy source. The energy from the metal-water reaction is also considered in the long-term LOCA mass and energy release analysis.

6.2.1.4 Mass and Energy Release Analyses for Postulated Secondary System Pipe Ruptures Inside Containment

The limiting secondary system pipe rupture from a containment response point of view is the steam line break. This is because the feedwater exiting a steam line break will have been heated to a higher temperature inside the steam generator via heat transfer across the steam generator tubes. In contrast, the feedwater exiting a feedwater line break will only be as hot as the outlet of the last feedwater heater upstream of the break location. Therefore, only steam line breaks are evaluated in this section. The model used is adjusted as described in Reference 1 to prevent any predicted liquid entrainment from decreasing the break enthalpy below the enthalpy of dry steam.

A spectrum of break sizes is analyzed to determine the limiting break size for peak containment pressure and temperature. For peak containment pressure, the response depends mainly on the steam mass flow rate.

For peak containment temperature, the response depends on both steam mass flow rate and on steam enthalpy The limiting break size for peak containment temperature and pressure is the double-ended guillotine break (6.305 ft^2). This break size results in a higher initial rate of mass and energy release to the containment and thus maximizes the increase in containment temperature during the steam line break transient.

6.2.1.4.1 Mass and Energy Release Data

The mass and energy release data for the limiting break, a 6.3 ft^2 (34" ID pipe) double-ended guillotine break of a main steam line near the steam generator outlet, is presented in Table 6-32.

6.2.1.4.2 Single Failure Analysis

The failure of an emergency feedwater control valve is chosen as the single failure for the steam line break mass and energy release analysis. Other potential single failures were considered:

1. Failure of a 4160V switchgear was also analyzed. The failure of one of the three available switchgear results in the loss of one train of LPI and one train of HPI. This failure also results in the loss of one Reactor Building Cooling Unit and one Reactor Building Spray train as discussed in Section 6.2.1.1.3.2. Note that this single failure continues to be conservatively assumed in the containment response analysis.
2. There are no steam line isolation valves at Oconee.
3. Although the feedwater isolation valves receive a feedwater isolation signal, this is used only to provide a redundant means of accomplishing the feedwater isolation function. The steam line break mass and energy release analyses credit the faster closing feedwater control valves to provide the feedwater isolation function. Therefore the failure of a feedwater isolation valve has no effect on these analyses.
4. It is assumed that failure of a feedwater control valve to close on a feedwater isolation signal is beyond the licensing basis.
5. Credit is taken for the trip of the main feedwater pumps in the mass and energy release analyses for steam line breaks with automatic feedwater isolation available.
6. Main feedwater is initially assumed to be in manual control. Upon reactor trip, the ICS reverts to automatic and controls steam generator levels.
7. It is conservatively assumed that offsite power is maintained in order to maximize primary-to-secondary heat transfer and feedwater addition to the affected steam generator.

6.2.1.4.3 Initial Conditions

The criteria presented in Reference 8 are used as the bases for the choices of initial conditions in the steam line break mass and energy release analyses. The specific conservatisms are:

1. End of core life conditions are chosen to maximize the energy addition to the primary system. The initial fuel temperature used is 1315°F.
2. 102% power is assumed, corresponding to the licensed core thermal power plus a 2% measurement uncertainty allowance. This maximizes the available generated energy and stored core energy for release to the secondary side.

3. The assumed reactor vessel average temperature is the nominal at power value, 579°F, plus a 2°F uncertainty allowance. This maximizes the stored energy in the Reactor Coolant System.
4. The assumed Reactor Coolant System pressure is the nominal value, 2155 psig, plus a 30 psi uncertainty allowance. This maximizes time to reactor trip and thus the energy transferred to the secondary system.
5. Steam line pressure is left at the nominal value rather than being increased to delay the generation of a feedwater isolation signal. This is required so that RETRAN-3D model calculated steam generator tube heat transfer areas correspond to the physical tube areas.
6. A conservatively large steam generator initial fluid mass is assumed to maximize the inventory available for release through the break.
7. End of core life fuel and moderator temperature feedback is assumed to maximize positive reactivity insertion from the cooldown.
8. The control rods are assumed to be positioned such that a reactor trip inserts only the amount of negative reactivity which produces and maintains the minimum shutdown margin required by the Technical Specifications.
9. The core boron concentration is assumed to be zero, which is consistent with end of core life conditions.

6.2.1.4.4 Description of Blowdown Model

The RETRAN-3D computer code, described in Reference 9 is used to generate the mass and energy releases for steam line breaks inside containment. The models used for this calculation are generally described in Reference 10 with modifications for the containment mass and energy release calculations as described in Reference 1. The calculational methods for applying this code and model to calculate mass and energy releases for steam line breaks are also described in Reference 1. Reference 1 also discusses and justifies the conservatisms in this calculational method. Reference 9 presents the heat transfer correlations used to calculate the heat transferred from the steam generator tubes and shell and justifies their application. No liquid entrainment is assumed in the break flow. The analysis methodology credits the Automatic Feedwater Isolation System (AFIS) to isolate main feedwater and turbine-driven emergency feedwater to the affected steam generator on low steam line pressure. AFIS will also isolate motor-driven emergency feedwater to the affected steam generator on a high rate of steam line depressurization concurrent with low steam line pressure. For break sizes that do not exceed the AFIS rate of depressurization setpoint, manual operator action is credited at 10 minutes to isolate motor-driven emergency feedwater flow to the affected steam generator.

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies on Emergency Core Cooling System

The pressure response of the containment to a LOCA is analyzed to determine the backpressure in the containment as a boundary condition for the reflood analysis and the calculation of the peak clad temperature. The assumptions used in these analyses result in a conservatively calculated minimum containment pressure response. This method has been shown to result in the maximum peak clad temperature.

The analysis of the minimum containment pressure response for the reflood analysis is performed using the methodology detailed in Reference 11 with Oconee-specific inputs. The mass and energy release to the Reactor Building and the resulting pressure response for the worst case LOCA, 8.55 ft^2 cold leg break at the pump discharge, is shown in Figure 6-50 (mass releases), Figure 6-51 (energy releases), and Figure 6-52 (pressure response). These figures reflect the analysis for the Mark-B11 fuel design. The containment results for the other fuel designs are similar and therefore not presented.

6.2.1.6 Coating Materials

The original coating materials applied to all structures within the containment during plant construction were qualified by withstanding autoclave tests designed to simulate LOCA conditions. The qualification testing of Service Level I substitute coatings now used for new applications or repair/replacement activities inside containment was in accordance with ANSI N 101.2 for LOCA conditions and radiation tolerance. The substitute coatings when used for maintenance over the original coatings were tested, with appropriate documentation, to demonstrate a qualified coating system.

The original, maintenance, and new coating systems defining surface preparation, type of coating, and dry film thickness are tabulated in Table 3-12 (Containment Coatings).

The elements of the Oconee Coatings Program are documented in a Nuclear Generation Department Directive. The Oconee Coatings Program includes periodic condition assessments of Service Level I coatings used inside containment. As localized areas of degraded coatings are identified, those areas are evaluated for repair or replacement, as necessary.

6.2.2 Containment Heat Removal Systems

6.2.2.1 Design Bases

Two engineered safeguards systems, the Reactor Building Spray System and the Reactor Building Cooling System, are provided to remove heat from the containment atmosphere following an accident.

Portions of the Reactor Building Spray system are credited to meet the Extensive Damage Mitigation Strategies (B.5.b) commitments, which have been incorporated into the Oconee Nuclear Station operating license Section H – “Mitigation Strategy License Condition”.

6.2.2.2 System Design

6.2.2.2.1 Piping and Instrumentation Diagrams

A schematic diagram of the Reactor Building Spray (BS) System is shown in Figure 6-2. The system serves no function during normal operation.

Removal of post-accident energy is accomplished by directing borated water spray into the Reactor Building atmosphere. The system consists of two pumps, two Reactor Building Spray headers, isolation valves, and the necessary piping, instrumentation and controls. The pumps and remotely operated valves for each unit can be operated from the control room.

A high Reactor Building pressure signal of less than or equal to 15 psig (typical value is 10 psig) from the Engineered Safeguards System (Channels 7 and 8) initiates operation of the BS system. The two pumps start, taking suction initially from the borated water storage tank through the intertie with the Low Pressure Injection System, and initiate building spray through the spray headers and nozzles. After the water in the borated water storage tank reaches an emergency low level, the spray pump suction is transferred to the Reactor Building sump manually when the operator places the Low Pressure Injection System in the recirculation mode. The Reactor Building emergency sump water is cooled by the Low Pressure Injection System as described in Section 6.3.

This system shares borated water storage tank capacity with the Low Pressure Injection System and the High Pressure Injection System.

Figure 6-3 illustrates the Reactor Building Cooling Units (RBCU's). Each cooling unit consists of a fan, cooling coils, and the required distribution duct work. The Reactor Building atmosphere is circulated past cooling coils by fans and returned to the building. Cooling water for the cooling units is supplied by the Low Pressure Service Water System. During normal operation these units serve to cool the Reactor Building atmosphere. The Engineered Safeguards System (Channels 5 and 6) is actuated when the Reactor Building pressure reaches 3 psig (4 psig Technical Specification Limit). Upon ES actuation, the fan motors associated with the RBCU's operating at high speed or low speed automatically stop, then restart in low speed after a 3 minute time delay, and any idle unit(s) is also energized at low speed after 3 minute time delay. The LPSW return header will be isolated during a LOOP by the LPSW RB Waterhammer Prevention System (See Section 9.2.2.2.3). Flow is restored once emergency power is available, which is well before the point in time when the RBCU fans restart.

Performance of the cooling system is monitored by flow and temperature instrumentation in the service water supply and return lines for each cooler; by relative humidity and temperature transmitters in the RBCU ductwork; and by the Reactor Building temperature and pressure instrumentation.

6.2.2.2.2 Codes and Standards

BS System equipment is designed to the applicable codes and standards given in Table 6-3.

The cooling coils for the RBCU's are constructed in accordance with ASME Section III, Class 3 guidelines. The Low Pressure Service Water System is designed to USAS B31.1.

6.2.2.2.3 Materials Compatibility

All materials in the BS System are compatible with the reactor coolant. The major components of the system are constructed of stainless steel. Minor parts such as pump seals utilize other corrosion resistant materials.

The materials for the RBCU's have been selected to be compatible with the use of untreated service water to minimize corrosion in accordance with ASME guidelines.

6.2.2.2.4 Component Design

BS Pumps

The Reactor Building Spray pumps are similar to those used in refinery service. These pumps are liquid-penetrant tested by methods described in the ASME Boiler and Pressure Vessel Code Section VIII and are hydrotested and qualified to be able to withstand pressures greater than 1.5 times the design pressure. The pumps are designed so that periodic testing may be performed to assure operability at all times.

Curves of total dynamic head and NPSH versus flow are shown in Figure 6-5. These curves are included as representative information only and are not intended as performance commitments. For design purposes, actual performance data should be obtained from manufacturer's certified performance test curves.

BS Valves

The remotely operated valves of the Reactor Building Spray System are designed and manufactured to the same requirements as the valves in the Emergency Core Cooling Systems. Refer to Section 6.3.

RB Spray Headers and Nozzles

For each Unit, there are approximately 60 full cone spray nozzles arranged on each of the two Reactor Building Spray headers. The spray nozzles are spaced in the headers to give uniform spray coverage of the Reactor Building volume above the operating floor.

BS Piping

Except for the sections of lines requiring flanged connections for maintenance, the entire system is welded construction. Table 6-4 lists the design conditions for this system.

RBCU Coolers

The cooling surface of the cooling units has been designed for and satisfactorily tested under simulated post-accident conditions. A conservative design has resulted in a heat exchanger which has a design heat transfer capability in excess of the expected heat transfer requirements.

The Reactor Building cooler is located in the discharge ducting for the fan. The air-steam mixture flows across the tube bank, resulting in condensation of a portion of the steam and removal of sensible heat from the air. Figure 6-6 shows the design heat transfer capability of each unit at various Reactor Building temperature conditions. Figure 6-6 is based on a Low Pressure Service Water temperature of 75°F. Actually, the cooling water is drawn from a point near the bottom of the lake and the anticipated service water temperature would be in the range of 45 to 85°F. Therefore, the curve shown in Figure 6-6 is conservative for most of the year. Figure 6-7 shows how the Reactor Building cooling rate varies with the air-steam mixture flow rate. It can be seen that even if the mixture flow rate decreases by 40 percent, the cooling capability decreases by less than 7 percent.

RBCU Fans

Circulation of the Reactor Building atmosphere under accident conditions is by the same fans used for normal ventilation. Upon actuation by an engineered safeguards signal, the fan motors operating in high or low speed automatically stop and then restart in low speed after 3 minutes and any idle unit(s) is also started at low speed (Section 6.2.2.2) after 3 minute time delay. The fans are tested each refueling outage to verify they can pass the required air flow rate across the coils. The control circuitry of the RBCU fans has been modified to remain in the ES state after reset of the ES channels. This modification ensures that deliberate separate action is required to shutdown the RBCU's. This modification is made pursuant to the requirements of IE Bulletin 80-06.

6.2.2.2.5 Reliability Considerations

A failure analysis has been made on all active components of the BS System to show that the failure of any single active component will not prevent fulfilling the design function. This analysis is shown in Table 6-5.

Inside the Reactor Building, the RBCU's are located outside the secondary shield at an elevation above the water level in the bottom of the Reactor Building during post-accident conditions. In this location the units are protected from being flooded.

The major equipment of the Reactor Building Cooling Units is arranged in three independent strings with three duplicate service water supply lines. In the unlikely event of a failure in one of the three cooling units, half of the Reactor Building Spray System capacity combined with the remaining two cooling units, will provide cooling capacity in excess of that required. Fan-motor operation under design LOCA condition has been demonstrated by prototype test.

A failure analysis of the cooling units is presented in Table 6-6.

6.2.2.2.6 Missile Protection

BS System protection against missile damage is provided by direct shielding or by physical separation of duplicate equipment. The spray headers are located outside and above the primary and secondary concrete shield.

The RBCU's and associated piping are located outside the secondary concrete shielding. The ductwork required to operate during an accident is located outside of the secondary shielding.

6.2.2.2.7 System Actuation

The Reactor Building Spray System will be activated when Reactor Building pressure reaches a setpoint of less than or equal to 15 psig (typical value is 10 psig). The system components may also be actuated by operator action from the control room for performance testing. During non-design basis events mitigated by the Standby Shutdown Facility (SSF) (e.g., Fire Event and Turbine Building Flood Event), the BS pumps of the affected ONS unit(s) may be manually removed from service in order to prevent inadvertent building spray that could impact operation of the SSF Reactor Coolant Makeup Pump.

In the event of a loss-of-coolant accident, the RBCU's are initiated at a Reactor Building pressure of 3 psig (4 psig Technical Specification Limit). The cooling units are placed in operation as follows:

a. Deleted paragraph(s) per 2006 update.

   LPSW system supplies water to RBACs through a separate piping loop that is independent of the RBCUs. During a LOCA, the RBACs and the piping loop are automatically isolated from the LPSW system by air-operated containment isolation valves (LPSW-1054, 1055, 1061, and 1062) on engineered safeguard (ES) signals.

b. The Low Pressure Service Water valves at the discharge of the coolers go to the full open position. Normally, these valves are operating with an intermediate setting (1200-1400 gal/min per loop).The design service water flow rate to the RBCUs is 1,400 gpm. The flow rate under accident conditions may be less than the design flow; however, sufficient containment heat removal is maintained.

c. The idle cooling unit fan(s) is started; after a 3 minute delay and the remaining fans operating in high or low speed automatically stop and then restart in low speed after a 3 minute time delay. The switch to low speed is required due to the changed HP requirements generated by the denser building atmosphere.

d. Fusible dropout plates have been completely removed from all units on “A” "B" and “C” RBCU ductwork, assuring that a positive path for recirculation of the Reactor Building atmosphere is available.. This prevents the fans from operating in stalled conditions. See Figure 6-3.

e. Depending upon the severity of the accident, the blowout plates at the bottom of the downcomer are designed to be forced out by any shock wave, allowing attenuation of the wave before it reached the cooling coils. Analysis has shown this to be a highly unlikely scenario due to duct deformation, and therefore the blowout plates are not needed for this function. In addition, the blowout plates are not considered functional.

6.2.2.2.8 Environmental Considerations

None of the electrically operated active components of the Reactor Building Spray System are located within the Reactor Building, so none are required to operate in the steam-air environment produced by the accident.

Figure 6-8 depicts the Reactor Building post-accident steam-air conditions. The RBCU fans and motors are designed for operation in the post-accident conditions. Cooling capability of the coolers has been satisfactorily tested in this environment.

6.2.2.2.9 Quality Control

Quality standards for the Reactor Building Spray System components are given in Table 6-3.

6.2.2.3 Design Evaluation

The Reactor Building Spray System, acting with the Reactor Building Cooling System, is capable of keeping the containment pressure and temperature within environmental qualification (EQ) limits after a loss-of-coolant or steam line break accident. Assuming a single failure, the post-accident Reactor Building cooling load is provided by two cooling units and the Reactor Building Spray System at one-half capacity. The Reactor Building Spray System and Reactor Building Cooling Systems are designed for long term post-accident operation.

Both the Reactor Building Spray System and the Reactor Building Cooling System, with either at full capacity, are individually capable of maintaining the containment pressure below the design limit following a LOCA or MSLB. This capability satisfies the requirements of the design criteria given in Section 3.1.52.

The Reactor Building Spray System can deliver 700-1200 gal/min per train through the spray nozzles within approximately 119 seconds after the Reactor Building pressure reaches the Reactor Building Spray System actuation setpoint (typical value is 10 psig).

The Reactor Building Cooling System provides the design heat removal capacity with two of three coolers operating by continuously circulating the steam-air mixture past the cooling tubes to transfer heat from the containment atmosphere to the low pressure service water.

Building pressure is limited below the design pressure. The design heat load at these conditions is 240 x 10^6 Btu/hr. The design inlet cooling water is 75°F, although the expected cooling water range is 45 - 85°F. The design heat removal capacity for these units is shown in Figure 6-6. The safety analyses given in Section 6.2.1 demonstrate system effectiveness.

6.2.2.4 Tests and Inspection

The active components of the Reactor Building Spray System can be tested as follows:

Reactor Building Spray Pumps

The delivery capability of one pump at a time can be tested by opening the valve in the line from the borated water storage tank, opening the corresponding valve in the test line, and starting the corresponding pump. Pump discharge pressure and flow indication demonstrate performance.

Borated Water Storage Tank Outlet Valves

These valves will be tested in performing the pump test above.

Reactor Building Spray Injection Valves

With the pumps shut down and the pump suction valves closed, these valves can each be opened and closed by operator action. These valves are required to be manually operable (both remote and local) for accident mitigation.

Reactor Building Spray Nozzles

With the Reactor Building Spray inlet valves closed, low pressure air or fog can be blown through the test connections. Visual observation will indicate flow paths are open.

During these tests, the equipment can be visually inspected for leaks. Valves and pumps will be operated and inspected following maintenance on the system to assure proper operation.

The RBCU equipment, piping, valves, and instrumentation are arranged so that they can be visually inspected. The cooling units and associated piping are located outside the secondary concrete shield. Personnel can enter the Reactor Building during power operations to inspect and maintain this equipment. The service water piping and valves outside the Reactor Building are inspectable at all times. Operational tests and inspections are performed prior to initial startup after each refueling outage.

The cooling units will be tested periodically as follows:

a. The fans will be started and inspected for proper operation.

b. The return line service water valves will be opened, and the lines checked for flow.

Additional discussion of tests of the containment heat removal systems is provided in Section 3.8.

6.2.3 Containment Isolation System

6.2.3.1 Design Bases

The general design basis governing isolation requirements is:

> Leakage through all fluid penetrations not serving accident-consequence limiting systems is to be minimized by a double barrier so that no single, credible failure or malfunction of an active component can result in loss-of-isolation or intolerable leakage. The installed double barriers take the form of closed piping systems, both inside and outside the Reactor Building, and various types of isolation valves.

Reactor Building Essential and Non-essential Isolation occurs on an Engineered Safeguards signal of 3 psig (4 psig Technical Specification value) in the Reactor Building. Reactor Building Non- essential Isolation occurs on an Engineered Safeguards signal of 1600 psig(1590 psig Technical Specification Value). For details on Reactor Building Essential and Non- essential Isolation, refer to Section 7.3, "Engineered Safeguards Protective System" and Table 7-2 and Table 7-3. Valves which isolate the Reactor Building purge flow path will also be closed on a high radiation signal during the movement of recently irradiated fuel. The Reactor Building sump drain flow path will also be isolated by closing a valve on a high radiation signal. Recently irradiated fuel is fuel that has occupied part of a critical reactor core within the previous 72 hours. The radiation monitor signal is not an Engineered Safeguards signal. Although normally open to the Reactor Building, the Reactor Building Gaseous Radiation Monitor penetrations are not closed on a high radiation signal; they remain open (except during ES isolation) to provide continuous monitoring.

The isolation system closes all fluid penetrations, not required for operation of the engineered safeguards systems, to prevent the leakage of radioactive materials to the environment.

All remotely operated Reactor Building isolation valves that are active to close for containment isolation have position limit indicators in the control room. All solenoid valves used in actuating pneumatic RB isolation valves are environmentally qualified to the requirements of the IE Bulletin 79-01B.

6.2.3.2 System Design

The fluid penetrations which require isolation after an accident may be classed as follows:

Type A.	Each line connecting directly to the Reactor Coolant System has two Reactor Building isolation valves. One valve is inside and the other is outside the Reactor Building. These valves may be either a check valve and an automatic remotely operated valve, two automatic remotely operated valves, or two check valves, depending upon the direction of normal flow.
Type B.	Each line connecting directly to the Reactor Building atmosphere has two isolation valves. At least one valve is outside and the other may be inside or outside the Reactor Building. These valves may be either a check valve and an automatic remotely operated valve, or one check valve and one, normally closed manual valve, or two automatic remotely operated valves, or two check valves, depending upon the direction of normal flow. For piping not part of the process flow, double isolation will be used. One or more of the isolations will be a normally closed manual valve located on the vent, drain, or test connection. The other isolation valve may be located on the process piping.
Type C.	Each line not directly connected to the Reactor Coolant System or not open to the Reactor Building atmosphere has at least one valve, either a check valve or an automatic remotely operated valve. This valve is located outside the Reactor Building. A seismic closed loop forms the inside barrier for most Type C penetrations. Since the Component Cooling System has a non-seismic closed loop, penetrations for this system have an additional automatic remotely operated valve or check valve located inside the Reactor Building. A variation to a non-seismic closed loop piping system inside containment is the LPSW piping to and from the Reactor Building Auxiliary Coolers. Penetrations for this piping system have additional automatic remotely operated valve located outside the Reactor Building. Note that the closed loop piping is actually Seismic Category II, but is not treated as such since it is not QA Condition I that is required for containment boundary items (UFSAR Section 3.1.1.1).
Type D.	Each line connected to either the Reactor Building atmosphere or the Reactor Coolant System, but which is not normally open during reactor operation, has two isolation valves. They may be

	manual valve(s) with provisions for locking in a closed position, check valve(s), and/or remotely operated valve(s), depending upon the direction of the normal flow.

There are additional subdivisions in each of these major groups. The individual system flow diagrams show the manner in which each Reactor Building isolation valve arrangement fits into its respective system. For convenience, each different valve arrangement is shown in Table 6-7 and Figure 6-9 of this section. The symbols on Figure 6-9 are described at the end of Table 6-7. This table lists the mode of actuation, the type of valve, its normal position and its position under Reactor Building isolation conditions. The specific system penetrations to which each of the arrangements is applied is also presented. It may be noted that only electric motor-operated, manual normally closed, or check valves are used inside the Reactor Building. Each valve will be tested periodically during normal operation or during shutdown conditions to assure its operability when needed. The valves in the reactor building purge flow path are required to be maintained closed in Modes where the engineered safeguards system is required operable. This is a requirement of NUREG 0737, Item II.E.4.2.6. Therefore Engineered Safeguards system testing of these reactor building purge valves is not required.

As the result of Generic Letter 96-06, the issue of thermal overpressurization of certain containment penetrations was addressed by installation of relief valves, check vavles, or other appropriate devices. Additionally, specific penetration(s) required administrative controls to prevent thermal overpressurization. The NRC accepted Oconee's response to Generic Letter 96-06 in correspondence dated December 6, 2007. A check valve provides thermal overpressurization protection for the piping segment between Units 1, 2, 3LP-1 and 1, 2, 3LP-2.

Fluid penetrations which do not require isolation after an accident are also classified as Type A through D, however the redundant containment isolation provisions described above are not applicable. Such penetrations are identified on Figure 6-9 as "PA" for Post Accident.

There is sufficient redundancy in the instrumentation circuits of the engineered safeguards protective system to minimize the possibility of inadvertent tripping of the isolation system. Further discussion of this redundancy and the instrumentation signals which trip the isolation system is presented in Chapter 7.

6.2.3.3 Periodic Operability Tests

Each containment isolation valve will be tested periodically during normal operation or during shutdown conditions to assure its operability when needed. A description of periodic testing programs for containment isolation valves and other penetrations is provided in Section 3.8.1.7.4.

6.2.4 Containment Leakage Testing

6.2.4.1 Periodic Leakage Testing

Tests and surveillance are performed periodically to verify that leakage from the containment is maintained within acceptable limits. These tests include:

Integrated Leak Rate Tests

Local Leak Detection

These tests are discussed in detail in Section 3.8.1.7.4.

6.2.4.2 Continuous Leakage Monitoring

No continuous Reactor Building leakage monitoring system is provided.

The comprehensive program for preoperational testing, inspection, and postoperational surveillance is described in detail in Section 3.8.

6.2.5 References

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6.3 Emergency Core Cooling System

Deleted Paragraph(s) per 2009 Update

6.3.1 Design Bases

The Emergency Core Cooling System (ECCS) is designed to cool the reactor core and provide shutdown capability following initiation of the following accident conditions:

1. Loss-of-coolant accident (LOCA) including a pipe break or a spurious relief or safety valve opening in the RCS which would result in a discharge larger than that which could be made up by the normal make-up system.
2. Rupture of a control rod drive mechanism causing a rod cluster control assembly ejection accident.
3. Steam or feedwater system break accident including a pipe break or a spurious relief or safety valve opening in the secondary steam system which would result in an uncontrolled steam release or a loss of feedwater.
4. A steam generator tube rupture.

The primary function of the ECCS is to remove the stored and fission product decay heat from the reactor core during accident conditions.

The ECCS provides shutdown capability for the accident above by means of boron injection. It is designed to tolerate a single active failure (short term) or single active or passive failure (long term). It can meet its minimum required performance level with onsite or offsite electrical power and under simultaneous Safe Shutdown Earthquake loading.

The Emergency Core Cooling System for one reactor unit is shown in Figure 6-1. The overall Emergency Core Cooling System is comprised of the following independent subsystems:

a. High Pressure Injection System
b. Low Pressure Injection System
c. Core Flooding System

The principal design basis for the Emergency Core Cooling System as described in the proposed AEC General Design Criterion 44 has been met. Protection for the entire spectrum of break sizes is provided. Two separate and independent flow paths containing redundant active components are provided in the HPI and LPI portions of the ECCS. Redundancy in active components assures performing the required functions should a single failure occur in any of the active components. Separate power sources are provided to the redundant active component. Separate instrument channels are used to actuate the systems. The adequacy of the installed ECCS to prevent fuel and clad damage is discussed in Chapter 15.

The Core Flooding System is passive in nature, receiving no external actuation signal and requiring no electrical motive power. The check valves in the Core Flooding System are technically active components; however, due to the simplicity and inherent safety of their design, no failure of these components is postulated. Both Core Flooding System Tanks and flow paths are required to function for successful mitigation of large break Loss of Coolant Accidents.

The ECCS is designed to operate in the following modes:

a. Injection of borated water from the borated water storage tank by the High Pressure Injection System.

b. Rapid injection of borated water by the Core Flooding System.

c. Injection of borated water from the borated water storage tank by the Low Pressure Injection System.

d. Long term core cooling by recirculation of injection water from the Reactor Building sump to the core by the Low Pressure Injection pumps.

e. Gravity drain from the reactor outlet piping to the Reactor Building emergency sump by the Low Pressure Injection System.

Although the high and low pressure emergency injection systems operate to provide full protection across the entire spectrum of break sizes, each system may operate individually and each is initiated independently. High pressure injection prevents uncovering of the core for small coolant piping leaks where high system pressure is maintained, and to delay uncovering of the core for intermediate-sized leaks. The core flooding and low pressure injection systems are designed to re-cover the core at intermediate-to-low pressures, and to assure adequate core cooling for break sizes ranging from intermediate breaks to the double-ended rupture of the largest pipe. The Low Pressure Injection System is also designed to permit boron concentration control and long-term core cooling in the recirculation mode after a LOCA. The injection and core flooding functions are subdivided so that there are two separate and independent strings, each including one high pressure pump, one low pressure pump, and one core flooding tank.

Much of the equipment in these systems serves a function during normal reactor operation. In those cases where equipment is used for emergency functions only, such as the Core Flood System, systems have been designed to permit meaningful periodic tests. Operational reliability is achieved by using proven component designs, and by conducting tests where either the component or its application was considered unique. Quality control procedures are imposed on the components of the engineered safeguards systems. These procedures include use of accepted codes and standards as well as supplementary test and inspection requirements to assure that all components will perform their intended function under the design conditions following a LOCA.

RBES and Strainer Design Bases and Generic Safety Issue (GSI)-191

The Reactor Building Emergency Sump and strainers at Oconee were originally designed by Babcock and Wilcox (B&W) to meet the requirements of B&W Specification 2036 dated February 10, 1972. The specification provided guidance for which included the following elements:

1. Minimum piping lengths to the Low Pressure Injection (LPI) and Reactor Building Spray (BS) pump suctions to minimize friction losses
2. Free communication with the containment basement areas where most of the water has collected
3. Provisions for missile protection
4. A raised lip around the periphery to prevent refuse and dirt from entering the sump
5. Raised sump outlet lines to prevent dirt and debris from entering the recirculation piping
6. Consideration of adequate submergence of the sump outlets to prevent vortex formation and air entrainment
7. Sloping of the sump outlet lines to avoid the entrapment of air

8. Sufficient elevation of the sump above the LPI and BS pump suctions to provide adequate NPSH considering minimum water level, minimum subcooling, maximum piping friction, runout pump flow conditions, and Safety Guide 1 safety margin
9. Adequate provision for draining
10. Protective covering to protect personnel during normal operation, prevent large debris from entering during accident conditions, and allowance for personnel access for maintenance
11. A coarse mesh screen (floor grating) and a fine mesh screen
12. A free flow area that will allow a maximum fluid velocity of one foot per second with a 50% blockage of screen area
13. A vertical screen orientation to promote "self cleaning"
14. Screen cover and supports designed to withstand earthquake loading and prevent collapse from water pressure due to a blockage of 50% of the screen area

In 1979, as a result of industry operating experience and evolving staff concerns about the adequacy of emergency sump designs, the NRC opened Unresolved Safety Issue (USI) A-43, "Containment Emergency Sump Performance". To support the resolution of USI A-43, the NRC undertook an extensive research program, the technical findings of which are summarized in NUREG-0897, "Containment Emergency Sump Performance," dated October 1985. The resolution of USI A-43 was subsequently documented in Generic Letter (GL) 85-22, "Potential for Loss of Post-LOCA Recirculation Capability Due to Insulation Debris Blockage", dated December 3, 1985. Through the resolution of USI A-43, the NRC found that the 50 percent blockage assumption (under which most nuclear power plants had been licensed) identified in Regulatory Guide (RG) 1.82, Rev. 0, "Sumps for Emergency Core Cooling and Containment Spray Systems," dated June 1974, should be replaced with more comprehensive guidance. Events at Boiling Water Reactors (BWRs) subsequently challenged the NRC's conclusion that no new requirements were necessary to prevent clogging of ECCS strainers at operating BWRs. A number of generic communications were issued to address this issue, with a focus on BWR plants. Following the successful resolution of the issue with BWRs, the research conducted at the time raised questions concerning the adequacy of PWR sump designs to prevent clogging. These findings prompted the NRC to open GSI-191, "Assessment of Debris Accumulation on PWR Sump Performance" and subsequently led to NRC issuing Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors" on June 9, 2003, and GL 2004-02 "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors" on September 13, 2004 as a follow-on to the bulletin. The GL requested licensees to perform a new, more realistic analysis of sump performance using an NRC-approved methodology and confirm the functionality of the ECCS and Containment Spray System (CSS) during design basis accidents requiring containment sump recirculation. Through the Nuclear Energy Institute (NEI), industry developed evaluation guidance which was issued as NEI 04-07, "Pressurized Water Reactor Sump Performance Evaluation Methodology" dated November 19, 2004. This guidance document was subsequently incorporated in its entirety, with NRC amendments, and issued in a Safety Evaluation Report dated December 6, 2004.

The approved evaluation methodology requires evaluation of sump performance to include the following elements:

1. Break selection to maximize debris
2. Debris generation evaluation, including conservative Zone of influence and debris characteristics

3. Latent debris evaluation
4. Debris transport evaluation
5. Head loss evaluation
6. Sump structural analysis
7. Vortex evaluation
8. Upstream effects evaluation
9. Downstream effects evaluation in accordance with WCAP 16406-P, Rev. 1, Evaluation of Downstream Sump Debris Effects in Support of GSI-191
10. In-vessel effects evaluation in accordance with WCAP 16793-NP, Rev 0, Evaluation of Long-Term Cooling Considering Particulate, Fibrous, and Chemical Debris in the Recirculating Fluid
11. Chemical effects evaluation in accordance with WCAP 16530-NP, Rev. 0, Evaluation of Post-Accident Chemical Effects in Containment Sump Fluids to Support GSI-191 (Minor deviations from the WCAP were discussed in Duke's GL response dated February 29, 2008.)

Oconee has performed all GL 2004-02 required analyses and evaluations in accordance with the approved methodology. As a result of these evaluations, Oconee made a number of plant modifications and programmatic enhancements, such as:

1. Modification of the Reactor Building Emergency Sump strainers on all three units to increase the strainer surface area. The original surface area was approximately 100 square feet on all units. The current surface area is approximately 4800 square feet on Unit 1 and approximately 5000 square feet on Units 2 and 3.
2. Replacement of HPI pump internals to provide more wear-resistant materials.
3. Replacement of the seal flush orifices and cyclone separators on the HPI, LPI, and BS pumps.
4. Removal of fibrous insulation from areas in containment where it would be potentially affected by a pipe break jet (Zone of Influence or ZOI).
5. Enhancement of plant labeling process to limit potential for tags and stickers to become post-accident debris sources.
6. Enhancement of plant containment coatings program to ensure that degraded coatings identified from maintenance inspections are evaluated for potential effects on RBES evaluations.
7. Enhancement of Foreign Material Exclusion (FME) controls to ensure that any scaffolding remaining in containment during power operation is evaluated for potential chemical effects.
8. Enhancement of plant design change process to ensure that plant modifications are evaluated for impact to RBES evaluations performed in support of GSI-191.
9. Revision to plant Technical Specifications to remove reference to trash racks and screens and add reference to strainers.

A single open item remains to close the GL for Oconee, as the NRC has not yet issued an SER on WCAP-16793-NP. Oconee will address any forthcoming changes to the WCAP when the SER is issued.

6.3.2 System Design

6.3.2.1 Schematic Piping and Instrumentation Diagrams

The schematic diagrams for the Emergency Core Cooling System are shown in Figure 6-1. Instrumentation is shown schematically in Chapter 7.

6.3.2.2 ECCS Operation

6.3.2.2.1 High Pressure Injection System

During normal reactor operation, the High Pressure Injection System recirculates reactor coolant for purification and for supply of seal water to the reactor coolant circulating pumps. This normal operation mode is described in Chapter 9. The High Pressure Injection System is initiated at: (a) a low Reactor Coolant System pressure of 1,600 psig (1590 psig Technical Specification Value) or (b) a Reactor Building pressure of 3 psig (4 psig Technical Specifications Value). Automatic actuation of the valves and pumps by the actuation signals switches the system from its normal operating mode to the emergency operating mode to deliver water from the borated water storage tank into the reactor vessel through the reactor coolant inlet lines. The following automatic actions accomplish this change:

a. The isolation valves in the purification letdown line and in the seal return lines close.

b. The high pressure injection pumps start.

c. The throttle valve in each high pressure injection line opens.

d. The valves in the lines connecting to the borated water storage tank outlet header open.

In addition to the automatic action described, the pumps and valves may be remote manually operated from the control room. During non-design basis events mitigated by the Standby Shutdown Facility (SSF) (e.g., Fire Event and Turbine Building Flood Event), the HPI pumps of the affected ONS unit(s) may be manually removed from service in order to prevent HPI pump operation interfering with the function of the SSF Reactor Coolant Makeup Pump.

Operation of the High Pressure Injection System in the emergency mode will continue until the system action is manually terminated. The HPI system is not designed to withstand a single passive failure since the duration of system usage during an accident is not considered to be long term; however, the portion of HPI system piping which is used to return any LPI-to-HPI system leakage to the Reactor Building Emergency sump is evaluated for passive failures since this portion of HPI piping could be utilized during long term cooling following a LOCA.

6.3.2.2.2 Low Pressure Injection System

The Low Pressure Injection System is designed to 1) maintain core cooling for larger break sizes and 2) control the boron concentration in the core while operating in the recirculation mode. The Low Pressure Injection System operates independently of and in addition to the High Pressure Injection System. A description of the normal reactor operation mode for the system is given in Chapter 9.

Automatic actuation of the Low Pressure Injection System is initiated at: (a) Reactor Coolant System pressure of 550 psig (500 psig Technical Specification value) or (b) a Reactor Building pressure of 3 psig (4 psig Technical Specification value). Initiation of operation provides the following actions:

a. Deleted row(s) per 2002 Update.

b. The low pressure injection pumps start on receipt of an engineered safeguards signal.

c. The inlet valves in the low pressure injection lines open.

d. Low pressure service water pumps start.

Low pressure injection is accomplished through two separate but cross-connected flow paths, each including one pump and one heat exchanger and terminating directly in the reactor vessel through core flooding nozzles located on opposite sides of the vessel. Each pump has minimum flow recirculation loop to protect the pumps from dead-heading. The orifice in the minimun flow recirculation loop was resized in response to NRC Bulletin 88-04 (Potential Safety-Related Pump Loss). The new minimum flow rate, along with procedure guidance for low flow conditions directs operators to take appropriate actions to protect the pump near shut-off head conditions. All ECCS analysis were met with the new orifices.

The initial emergency operation of the Low Pressure Injection System involves pumping water from the borated water storage tank into the reactor vessel. With all ES actuated pumps operating and assuming the maximum break size, this mode of operation lasts for a minimum of about 30 minutes. When most of the borated water storage tank inventory is exhausted, the operators initiate steps to transfer the pump suction to the Reactor Building emergency sump, permitting recirculation of the spilled reactor coolant and injection water from the Reactor Building emergency sump.

For certain small break LOCA's where the RCS pressure remains above LPI shut-off pressure, the BWST will deplete and the LPI will be aligned in series with the HPI pumps to provide recirculation until the RCS is depressurized (piggy-back mode). In this case, there are short durations where the LPI flowrates are expected to be less than the manufacturer's minimum flow requirements. Appropriate procedures have been revised to alert the operators of the minimum flow conditions and to take appropriate actions. This case would only exist during the transition period before long term cooling is supplied by LPI, at which time, flowrates would satisfy the manufacturer's long term requirements.

Following a large break LOCA located in the reactor inlet piping, the boric acid concentration within the core region will increase. Recrystallized boric acid could deposit on fuel assemblies and hinder heat transfer. The LPI system provides two redundant gravity flow paths from the reactor outlet piping to the Reactor Building Emergency Sump (RBES) to maintain continuous liquid flow through the core and assure post-LOCA boric acid solubility. Additionally, the design of the reactor vessel and vessel internals around the hot leg nozzles provides a third path that can assure post-LOCA boric acid solubility. At least two of the three paths will always be available.

In the event of an accident where the Reactor Coolant System piping remains intact, then the Low Pressure Injection System will operate in the recirculation mode with suction being taken from the normal decay heat line. If in this mode of operation a decay heat isolation valve should fail closed, then a bypass line to the emergency sump would be opened. Recirculation would then take place with suction being taken from the emergency sump.

During non-design basis events mitigated by the Standby Shutdown Facility (SSF) (e.g., Fire Event and Turbine Building Flood Event), the LPI pumps of the affected ONS unit(s) may be manually removed from service in order to prevent extended and potentially damaging operation of an LPI pump in a deadheaded configuration.

6.3.2.2.3 Core Flooding System

The Core Flooding System provides core protection continuity for intermediate and large Reactor Coolant System pipe failures. It automatically floods the core when the Reactor Coolant System pressure drops below approximately 600 psig. The Core Flooding System is self-contained, self-actuating, and passive in nature. The combined coolant volume in the two tanks is sufficient to re-cover the core assuming no liquid remains in the reactor vessel following the loss-of-coolant accident.

The discharge pipe from each core flooding tank (CFT) is attached directly to a reactor vessel core flooding nozzle. Each core flooding line at the outlet of the CFT's contains an electric motor operated stop valve adjacent to the tank and two in-line check valves in series. The stop valves at the core flooding tank outlet are fully open during reactor power operation. Valve position indication is shown in the control room. During power operation when the Reactor Coolant System pressure is higher than the Core Flooding System pressure, two series check valves between the flooding nozzles and the CFT's prevent high pressure reactor coolant from entering the core flooding tanks.

The driving force to inject the stored borated water into the reactor vessel is supplied by pressurized nitrogen which occupies approximately one-third of the core flooding tank volume. Connections are provided for adding both borated water and nitrogen during power operation so that the proper level and pressure can be maintained. Each core flooding tank is protected from overpressurization by a relief valve installed directly on the tank. The size of these relief valves is based upon maximum water makeup rate to the tank. Redundant level and pressure indicators and alarms are provided in the control room for each tank.

6.3.2.3 Equipment and Component Descriptions

6.3.2.3.1 Piping

The high pressure injection and low pressure injection lines are designed for the normal operating conditions. The system temperature and pressure requirements are greater than those encountered during emergency operation. The Low Pressure Injection System piping and valves are subjected to more severe conditions during decay heat removal operation than during emergency operation and, therefore, operate well within the design conditions. Table 6-4 gives the design pressure and temperatures of these systems. To assure system integrity, major piping has welded connections except where flanges are dictated for maintenance reasons.

6.3.2.3.2 Pumps

The pumps used in the Emergency Core Cooling Systems are of proven design and have been used in many other applications. Pumps similar to the high pressure injection pumps have been used in boiler feed pump service and in high pressure makeup pump nuclear reactor service. Pumps similar to the low pressure injection pumps are used extensively in refinery service. The low pressure injection pump seals have been tested satisfactorily under the conditions which would be encountered during the loss-of-coolant accident. Both the high pressure and low pressure injection pump casings are liquid penetrant tested by methods described in the ASME Boiler and Pressure Vessel Code, Section VIII, and have been hydrotested and qualified to be able to withstand pressures as great or greater than 1.5 times the system design pressure. The pumps are designed so that periodic testing may be performed to assure operability and ready availability. The operating characteristics of each engineered safeguard pump are verified by shop testing before installation of the pumps.

6.3.2.3.3 Heat Exchangers

The low pressure injection system heat exchangers (decay heat removal coolers) are designed and manufactured to the requirements of the ASME Boiler and Pressure Code, Section III and Section VIII, and the TEMA-R Standards. In addition to these requirements, uniformity of the tubes is assured by eddy current testing, and the tubes are seal welded to the tube sheet to decrease the possibility of leakage. All tube welded ends are liquid penetrant tested to assure the absence of welding flaws. The heat exchangers have been fabricated with surface areas greater than those dictated by the most severe heat transfer conditions.

6.3.2.3.4 Valves

All remotely operated valves in the Emergency Core Cooling Systems are manufactured and inspected in accordance with the intent of the ASME Nuclear Power Piping Code B31.7 or FSAR Section 3.2.2.2 which provides allowances for substitute codes. Liquid penetrant, radiography, ultrasonic, and hydrotesting are performed as the Code classification requires.

The seats and discs of these valves are manufactured from materials which will be free from galling and seizing. All valve material is certified to be in accordance with ASTM specifications.

6.3.2.3.5 Coolant Storage

The letdown storage tank has a total coolant volume of 600 ft^3 and normally contains approximately 3,200 gallons of water. This tank provides water to the high pressure injection pumps until the borated water storage tank outlet valves are opened. The letdown storage tank is designed and inspected in accordance with the requirements of ASME III-C.

Each unit is provided with a borated water storage tank as described in Chapter 9.

Provisions are made for sampling the water and adding concentrated boric acid solution or demineralized water.

Each core flooding tank contains approximately 7,000 gallons of borated water with a boron concentration maintained in accordance with the Core Operating Limits Report.

6.3.2.3.6 Pump Characteristics

Curves of total dynamic head and NPSH versus flow are shown in Figure 6-16 for the high pressure injection pumps and in Figure 6-17 for the low pressure injection pumps. These curves are representative in nature and are provided for information only. They are not intended to constitute design commitments or performance requirements for the pumps. Refer to the Inservice Test Program for actual performance requirements for HPI and LPI pumps.

6.3.2.3.7 Heat Exchanger Characteristics

The decay heat removal coolers are designed to remove the decay heat generated during a normal shutdown. In addition, each cooler is capable of cooling the injection water during the recirculation mode following a loss-of-coolant accident to provide for removal of decay heat which provides adequate core cooling. The heat transfer capability of a decay heat removal cooler as a function of recirculated water temperature is illustrated in Figure 6-18. Note that this figure is representative in nature and is provided for information only. It is not intended to constitute design commitments or performance requirements for the coolers.

6.3.2.3.8 Relief Valve Settings

Relief valves are provided to protect the low pressure injection piping and components from overpressure. On Units 1 and 2 these relief valves will be set at 370 psig, the system design pressure at 300°F for the "B" LPI Coolers and at 515 psig, the system design pressure at 250°F for the "A" LPI Coolers. On Unit 3 the relief valves will be set at 505 psig, the system design pressure at 250°F.

6.3.2.3.9 Component Data

Component data for each ECCS System is given in the following tables:

1. High Pressure Injection System - Table 6-8
2. Low Pressure Injection System - Table 6-9
3. Core Flooding System - Table 6-10

6.3.2.3.10 Quality Control

Quality Standards for the Emergency Core Cooling System components are given in Table 6-3.

6.3.2.4 Applicable Codes and Classifications

The High Pressure Injection, Low Pressure Injection, and Core Flooding Systems are designed and manufactured to the Codes and Standards in Table 6-3 or FSAR Section 3.2.2.2 which allows use of substitute codes.

6.3.2.5 Material Specifications and Compatibility

All components with surfaces in contact with water containing boric acid are protected from corrosion and deterioration. The High Pressure Injection System, which operates continuously with borated reactor coolant, is constructed of stainless steel, for those portions in contact with borated water. With the exception of the borated water storage tank, the major components in low pressure injection are constructed of stainless steel, for those portions in contact with borated water. The borated water storage tank is carbon steel with an interior phenolic coating. The core flooding piping and valves are stainless steel and the tanks are constructed of stainless clad carbon steel.

6.3.2.6 System Reliability

System reliability is assured by the system functional design including the use of normally operating equipment for safety functions, testability provisions, and equipment redundancy; by proper component selection; by physical protection and arrangement of the system; and by compliance with the intent of the AEC General Design Criteria. There is sufficient redundancy in the Emergency Core Cooling System to assure that no credible single failure can lead to significant physical disarrangement of the core. This is demonstrated by the single failure analysis presented in Table 6-11. This analysis was based on the assumption that a major loss-of-coolant accident had occurred and coincidentally an additional malfunction or failure occurred in the Engineered Safeguards System. For example, the analysis included malfunctions or failures such as electrical circuit or motor failures, valve operator failures, etc. It was considered incredible that valves would change to the opposite position by accident if they were in the required position when the accident occurred. Table 6-11 also presents an analysis of possible malfunctions of the core flooding tanks that could reduce their post-accident availability. It is shown that these malfunctions result in indications that will be obvious to the operators so appropriate action can be taken. In general, failures of the type assumed in this analysis are considered highly improbable since a program of periodic testing will be incorporated in the station operating procedures. The adequacy of equipment sizes in the ECCS is demonstrated by the post-accident performance analysis described in Chapter 15.

6.3.2.6.1 High Pressure Injection Operability

A cross connect line with electric operated valves (HP-409 and HP-410, both normally closed) is installed between the "A" and "B" headers to ensure that two paths and two pumps can be aligned to inject to the RCS. During full power operation, two pumps through two trains must be available during an accident to ensure adequate flow reaches the core. In the case of either of valves HP-26 or HP-27 failing to open during an accident situation, the cross connect via valve HP-409 or HP-410 would be utilized to provide flow through the train with the failed valve.

6.3.2.6.2 Core Flood Tank Valve Operability

To assure that the Core Flood Tank isolation valves will not be accidentally closed while the reactor is at power, the circuit breaker supplying power to these valves will be kept open and under administrative control. Power to the starter controls comes from this same circuit breaker through a control transformer and will be disconnected when the circuit breaker is open.

Lights in the control room indicate valve position (open or closed). These lights have a power supply separate from the circuit breaker serving the Core Flood Tank isolation valves and are operated from limit switches on the valve operator. Another limit switch on the valve operator will cause an annunciator alarm in the control room anytime a Core Flood Tank isolation valve is away from the wide open position. The annunciator system has a power supply separate from that used to operate the valve or indicating lights.

6.3.2.6.3 Active Valve Operability

On January 2, 1973, the AEC requested that Duke Power Company determine an acceptable program that would demonstrate operability of active valves. The testing was to simulate conditions associated with normal system operation as well as loading conditions that would appropriately demonstrate seismic and accident vibratory responses. The AEC request was further clarified by stating the "the test program may be based upon selectively testing a representative number of active valves in the piping system according to valve type, seismic and accident load level, size, etc. on a prototype basis". On May 1, 1973, Duke Power Company responded by adding a supplement (Supplement 15) to the FSAR which described various testing (environmental, vibrational, life cycle, etc.) on a subset of active valves. From a historical perspective, the request by the AEC predated the formalization of the established programs and testing requirements which are currently in place that ensure that active valves properly function during normal and post accident conditions. Such programs include, but are not limited to, the following examples: Environmental Qualification (EQ) program (10CFR50.49), MOV Testing and Periodic Verification program (GL 89-10 and GL 96-05), Inservice Testing Program (10CFR50.55a and GL 89-04), Inservice Inspection Program (10FR50.55a), Containment Leakage Program (10CFR50 Appendix J), and Quality Assurance Program (10CFR50 Appendix B). Prior to the formulation and development of such programs, the AEC's request was relevant. However, with the current programs in place, the AEC's 1973 request is deemed historical in nature. The final intent of the request, which was assurance of the operability of active valves, is deemed to be included within current requirements associated with the design, maintenance, and testing of active components.

6.3.2.6.3.1 Deleted per 1999 Update

6.3.2.6.3.2 Deleted per 1999 Update

6.3.2.6.3.3 Deleted per 1999 Update

6.3.2.6.3.4 Deleted per 1999 Update

6.3.2.7 Protection Provisions

6.3.2.7.1 Seismic Design

Components in the Emergency Core Cooling System are designated as Class I equipment and are designed to maintain their functional integrity during an earthquake discussed in Section 2.5.2.6.

6.3.2.7.2 Missile Protection

Protection against missile damage is provided by either direct shielding or by physical separation of duplicate equipment. For most of the routing inside the Reactor Building, the ECCS Piping will be outside the primary and secondary shielding, and hence, protected from missiles originating within these areas. The portions of the injection lines located between the primary reactor shield and the reactor vessel wall are not subject to missile damage because there are no credible sources of missiles in this area.

The high pressure injection lines enter the Reactor Building via penetrations on opposite side of the building. Each injection line splits into two lines inside the Reactor Building, but outside the secondary (missile) shield, to provide four injection paths to the Reactor Coolant System. The four connections to the Reactor Coolant System are located between the reactor coolant pump discharge and the reactor inlet nozzles. There are four injection lines penetrating the missile shield, minimizing the effect on injection flow in the unlikely event of missile damage to the injection lines inside the secondary shield.

Protection from missiles is given to the low pressure injection lines within the Reactor Building. The portion of the Low Pressure Injection System located in the Reactor Building consists of two redundant injection lines which are connected to injection nozzles located on opposite sides of the vessel. Both redundant suction lines from the sump are missile protected. The sump suction is located outside of the secondary shielding and there are no possible missile trajectories that could impact the function of the sump suction.

The entire Core Flooding System is located within the Reactor Building. The core flooding tanks and two of the three valves in each core flooding line are located outside of the secondary shield.

6.3.2.8 Post-Accident Environmental Consideration

The major operating components of the Emergency Core Cooling System are external to the Reactor Building and will not be exposed to the post-accident building environment.

The major electrical and mechanical equipment within the Reactor Building which are required to be operable during and subsequent to a LOCA and/or steam line break are:

a. Reactor Coolant System pressure transmitters.

b. Reactor Building isolation valves and associated position indications.

c. Reactor Building air cooling unit fans and cooling coils.

d. Instrument cables for pressure transmitters, level, and valve position indication.

e. Power cables for the Reactor Building fan motors and isolation valves.

f. Isolation valves and flow verification instrumentation in the gravity flow path from the reactor outlet piping to the Reactor Building emergency sump.

Paragraph(s) Deleted Per 2000 Update.

Environmental conditions in the Auxiliary Building are controlled to ensure proper operation of ECCS pumps during accident conditions. Operability of HPI, LPI, and RBS pumps is dependent upon initial pump room temperature and the availability of natural convection flow paths as described in UFSAR Section 9.4.3.

Other equipment and components located in the primary containment or elsewhere in the plant must be operable during and subsequent to a loss-of-coolant or steam-line-break accident. A complete listing of the equipment which is evaluated for environmental qualification can be found in the Oconee Nuclear Station Equipment Data Base.

Current material qualification for these components is addressed by the Environmental Qualification (EQ) program discussed in Section 3.11. The Oconee Nuclear Station Environmental Qualification Maintenance Manual, EQMM-1393.01, lists the requirements for maintaining equipment qualifications, and is a major element of the Oconee Nuclear Station EQ Program.

6.3.3 Performance Evaluation

In establishing the required component redundancy for the Emergency Core Cooling System, several factors related to equipment availability were considered:

a. The probability of a major Reactor Coolant System failure is very low; i.e., the probability that the equipment will be needed to serve its emergency function is low.

b. The fractional part of a given component lifetime for which the component is unavailable due to maintenance is estimated to be very small. On this basis, the probability that a major Reactor Coolant System accident would occur while a component from the Emergency Core Cooling System was out of service for maintenance is several orders of magnitude below the low basic accident probability.

c. The maintenance period for important equipment can usually be scheduled for a period of time when the reactor is shut down. Where maintenance of an engineered safety feature component is required during operation, the periodic test frequency of the similar redundant components can be increased to insure availability.

d. Where the systems are designed so that the components serve a normal function in addition to the emergency function or where meaningful periodic tests can be performed, there is also a low probability that the required emergency action would not be performed when needed; i.e., equipment reliability is improved by using the equipment for other than emergency functions.

6.3.3.1 High Pressure Injection System (HPI)

One high pressure injection string can deliver 450 gal/min at 585 psig reactor vessel pressure. For full power operation, the safety analysis in Chapter 15 has shown that two high pressure injection pumps through two injection trains are sufficient to prevent core damage for those smaller leak sizes which do not allow the Reactor Coolant System pressure to decrease rapidly to the point where the Low Pressure Injection System is initiated.

After receiving an actuation signal, the HPI system valves for injection will open sufficiently to admit the required flow within 14 seconds and the HPI pumps will reach full speed within 6 seconds. One of the three high pressure injection pumps is normally in operation and a positive static head of water assures that all pipe lines are filled with coolant. The high pressure injection lines contain thermal sleeves at their connections into the reactor coolant piping to prevent over stressing the pipe juncture.

Operation of this system does not depend on any portion of another engineered safety feature. The system can be operated in conjunction with the Low Pressure Injection System if the HPI System must be operated in the recirculation mode.

6.3.3.2 Low Pressure Injection and Core Flooding Systems

Deleted paragraph(s) per 2004 update.

After receiving an actuation signal, the low pressure injection valves will reach full open within 36 seconds and the low pressure injection pumps will reach full speed within 5 seconds.

Injection response of the Core Flooding System is dependent upon the rate of reduction of Reactor Coolant System pressure. For the maximum pipe break (14.1 ft^2), the Core Flooding System is capable of reflooding the core to the hot spot in less than 25 seconds after a rupture has occurred.

Special attention has been given to the design of core flooding nozzles to assure that they will take the differential temperature imposed by the accident condition. Special attention has also been given to the ability of the injection lines to absorb the expansion resulting from the recirculating water temperature.

The gravity flow path from the reactor outlet piping to the Reactor Building emergency sump will maintain a minimum core flow in excess of 40 gal/min to assure boric acid solubility. The flow path is open within 9 hours following a large LOCA.

The Low Pressure Injection System is connected with other safeguards systems in three respects, i.e., (1) the High Pressure and Low Pressure Injection Systems and the Reactor Building Spray System take their suction from the borated water storage tank; (2) the low pressure injection pumps and the Reactor Building spray pumps share common suction lines from the Reactor Building sump during the coolant recirculation mode; and (3) the Low Pressure Injection System and the Core Flooding System utilize common injection nozzles on the reactor vessel.

6.3.3.2.1 Boron Precipitation Evaluation

In response to the RCS depressurization associated with a LOCA, the ECCS actuates and begins injecting borated water into the system to reflood the core, keep the reactor subcritical, and provide for long term cooling. The boiloff of the ECCS delivered water along with flow stagnation in the reactor vessel can result in an increase in the boron concentration. If unrealized, this process could result in localized recrystallization of the boric acid and the potential for deposits to build up on the fuel assemblies and internals and hinder effective heat removal. In order to prevent this occurrence, analytically based operating procedures have been developed to assure sufficient circulation and dilution of the coolant.

In the initial long term phase of post-LOCA heat removal, a natural circulation flowpath from the core through the vent valves to the downcomer occurs which sufficiently circulates the coolant through the core. At some point in time the flowpath through the vent valves will no longer be available as the decay heat becomes insufficient to drive the flow. In addition, natural circulation flow through the gaps between the reactor vessel hot leg nozzles and the reactor internals has also been evaluated to be available. Operator action must be taken to initiate at least one of the two gravity flow paths to provide further assurance that flow is established and post-LOCA boric acid solubility is maintained. The method for performing this function is by means of a drain line from the hot leg to the Reactor Building sump which draws coolant from the top of the core, thereby inducing core circulation. It should be noted that the opening of the primary and alternate boron dilution flow paths must be limited by RCS conditions to prevent damage of the drain flow path, damage of the RBES, and flushing in the LPI pump suction piping (Reference 9 and 10). The system has been designed with redundant drain lines and has been shown to be single failure proof. The boron concentration of the liquid leaving through the drain line is equal to the core boron concentration. Most of the core decay heat is removed by steam flow through the vent valves. ECCS pump flow will continue to be provided to the RCS cold legs and will preclude any boron concentration buildup in the vessel for breaks in the hot leg.

An analysis has been performed to determine the allowable time for the operator to align the post-LOCA boron dilution drain line to prevent unacceptable boron concentrations in the reactor vessel. The analysis determines the rate at which boron concentrates in the reactor vessel following a large cold leg break LOCA with conservative assumptions regarding decay heat, vessel mixing volume, vent valve flow, containment pressure, LPI injection flow and temperature, and initial boron concentrations in the RCS, BWST and core flood tanks. The values of these parameters are given in Table 6-20. The analysis credits a conservative minimum flow through the reactor vessel internals vent valves as predicted by the BFLOW code methodology. The BFLOW code is described in Reference 6.

The results of the analysis show the maximum allowable boric acid concentration establishd by the NRC, which is the boric acid solubility limit minus 4 weight percent, will not be exceeded in the vessel if a boron dilution flow of 40 gpm (Reference 7) from the hot leg to the sump is initiated within 9 hours following a LOCA.

Since there are redundant methods to establish this dilution flow, no diverse means is required to be provided to prevent the buildup of boron concentration. All components of the ECCS are ANS Safety Class 2 and Seismic Category 1.

6.3.3.3 Loss of Normal Power Source

Following a loss-of-coolant accident assuming a simultaneous loss of normal power sources to the LOCA unit, the emergency power source and the Low Pressure Injection Systems will be in full operation within 74 seconds after actuation, even assuming a single failure, and the High Pressure Injection System will be in full operation within 48 seconds after actuation. The electrical power system design is based on the assumption that ESG actuation in one unit occurs simultaneously with a loss of offsite power to all three units. However, accident scenarios in FSAR Section Chapter 15 assume loss of offsite power to the LOCA unit only. Except for large break LOCA (as described in UFSAR Section 15.14.3.3.6), all calculations for the Oconee Units have assumed a 48 second delay from receipt of the actuation signal to start flow for the HPI system and a 74 second delay for the LPI System. Upon loss of normal power sources including the startup source and initiation of an engineered safeguards signal, the 4160 volt engineered safeguards power line is connected to the underground feeder from Keowee hydro (Section 8.3.1). The Keowee hydro unit will start up and accelerate to full speed in 23 seconds or less. An analysis has shown that by energizing the HPI and LPI valves (which have opening times of 14 seconds, to deliver required flow, and 36 seconds respectively at normal bus voltage) and pumps after a 10 second swapover time (required by the single failure), the design injection flow rate (HPI - 450 gal/min, LPI - 3000 gal/min) will be obtained within 48 and 74 seconds, respectively.

6.3.3.4 Single Failure Assumption

UFSAR Section 15.14.4.3.6 discusses ECCS performance and the single failure assumption.

6.3.4 Tests and Inspections

6.3.4.1 ECCS Performance Tests

Table 6-15 summarizes performance testing for the Emergency Core Cooling System.

6.3.4.2 Reliability Tests and Inspections

All active components, listed in Table 6-15, of the Emergency Injection System will be tested periodically to demonstrate system readiness. The High Pressure Injection System will be inspected periodically during normal operation for leaks from pump seals, valve packing, and flanged joints. During operational testing of the low pressure injection pumps, the portion of the system subjected to pump pressure will be inspected for leaks. Items for inspection will be pump seals, valve packing, flange gaskets, heat exchangers, and safety valves for leaks to atmosphere.

6.3.4.3 Gas Management

On January 11, 2008 the NRC issued Generic Letter (GL) 2008-01 to address the issue of gas management in the ECCS, decay heat removal, and containment spray systems. The GL requested licensees to evaluate their licensing basis, design, testing, and corrective action program and to submit information to demonstrate that the subject systems are in compliance with current licensing and design bases and applicable regulatory requirements, and that suitable design, operational, and testing control measures are in place for maintaining this compliance. Oconee Nuclear Station performed the required evaluations for the HPI, LPI, CF, and BS systems, and took the following additional actions:

1. Identified potential gas sources for the systems identified in the GL
2. Identified additional sites where gas accumulation potential exists
3. Performed ultrasonic testing to quantify gas or verify water solid conditions at selected locations where both a potential source and acummulation site were identifed
4. Implemented addional periodic monitoring using techniques to quantify gas
5. Established quantified acceptance criteria for surveillance activities/procedures
6. Added requirements for entry into the corrective action program for gas findings in excess of acceptance criteria
7. Added vent valves in selected locations fo facilitate gas removal
8. Made changes to system fill and vent, startup, operating, maintenance, and test procedures to minimize the potential for introducing gas and to facilitate its effective removal

9. Performed Engineering evaluation of gas which could not be readily removed
10. Strengthened trending of gas accumulation rate to ensure surveillance frequency is adequate

These gas management activities demonstrate that Oconee recognizes the presence of gas in the ECCS, DHR, and BS system as a condition adverse to quality. Oconee responded to the GL by letter describing the results of the required evaluations (Reference 11). The actions described above and in the GL response ensure that Oconee remains in compliance with applicable regulations and the licensing basis as it applies to these systems.

6.3.5 Instrumentation Requirements

The High Pressure Injection System is actuated automatically by a low Reactor Coolant System pressure of 1,600 psig (1590 Technical Specification Value) or by a Reactor building pressure of 3 psig (4 psig Technical Specification Value). All of the pumps and valves can also be remotely operated from the control room. Flow instrumentation is available in each HPI train during an accident.

The Low Pressure Injection System is automatically actuated by a low Reactor Coolant System pressure of 550 psig (500 psig Technical Specification value) or Reactor Building pressure of 3 psig (4 psig Technical Specification value). All of the pumps and automatic valves can also be remotely operated from the control room. In the event valve operators are not functional for ES valves on the LPI pump suction, these valves may be left in their ES position during operation.

The Core Flooding System is actuated at a Reactor Coolant System pressure of 600 psig. At this point the differential pressure across the inline check valves allows them to open releasing the contents of the tanks into the reactor vessel.

The Engineered Safeguards Actuation instrumentation for the Emergency Core Cooling System is provided with redundant channels and signals as described in Chapter 7. The control room layout is arranged so that all indicators and alarms are grouped in one sector at a convenient location for viewing. Switches and controls are also located conveniently.

6.3.6 References

1. Qualification test of Limitorque valve operator, motor brake, and other units in a simulated reactor containment post-accident environment, Final Report F-C3327, July, 1972.
2. Qualification test of Limitorque valve operators in a simulated reactor containment post-accident steam environment, Final Report F-C3441, September 1972.
3. Deleted Per 1997 Update
4. Deleted Per 1997 Update
5. Instruction Manual for Rotork Valve Actuators, OM-245-1023.'
6. DPC-NE-3003-PA, "Duke Energy Corporation Oconee Nuclear Station Mass and Energy Release and Containment Response Methodology", Revision 1b, August 2014.
7. Jones, R. C., Biller, J. R., Dunn, B. M., ECCS Analysis of B&W's 177-FA Lowered-Loop NSSS, Babcock & Wilcox, BAW-10103 Rev. 3, July 1977.
8. Qualification Test Report for Two Valve Operators (11NAZT1 and 90NAZT1) for Rotork Controls, Inc., Report No. 43979-1, Revision A, December 1978.
9. OSC-4678 Boron Dilution Line Discharge Velocity Evaluation.

10. OSC-3862 Uncertainty Estimation for ICCM and OAC Subcooled Margin Indication.
11. Letter from Thomas P. Harrall to U.S. Nuclear Regulatory Commission dated October 13, 2008.

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6.4 Habitability Systems

6.4.1 Design Bases

Oconee Nuclear Station's design pre-dates General Design Criterion 19 (GDC-19) of Appendix A to 10 CFR 50, however control room habitability was a design consideration at Oconee as discussed in Section 3.1.11.

The Oconee Nuclear Station control rooms are located in the Auxiliary Building. Oconee 1 and 2 have a shared control room while Oconee 3 has a separate control room. Figure 6-19 shows the location of the two control rooms with regard to other major structures of the station. Figure 6-20 and Figure 6-21 show the Oconee 1 and 2 and Oconee 3 control room general arrangement, respectively.

The facility is provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection is provided to permit access, even under accident conditions, to equipment in the control room or other areas as necessary to shut down and maintain safe control of the facility without radiation exposures of personnel in excess of 10CFR20 limits. The control room shielding meets the NUREG-0578 requirements. It is possible to shut the reactor down and maintain it in a safe condition if access to the control room is lost.

In 2004 Duke implemented changes to the control room unfiltered air inleakage assumptions as a result of new test data and adopted a revised analysis methodology using the Alternate Source Term. A new licensing basis was established, and re-analysis of the control room radiological consequences of design basis accidents was provided to the NRC (Reference 4).

Duke performed a review of plant shielding to provide for adequate access to vital areas as a result of NUREG-0737, Item II.B.2.2. The review resulted in plant modifications and corrective actions to improve shielding. Based on review of the plant shielding design review, inspection of plant modifications and corrective actions, and performance of an independent assessment of vital area accessibility and personnel doses in a post-accident condition, NRC concluded that the requirements of NUREG-0737, Item II.B.2.2 have been met and are acceptable (Reference 3).

6.4.2 System Design

6.4.2.1 Definition of Control Room Envelope

The control room envelope includes the control room and all rooms the control room personnel may require access to during emergency plant operation. This envelope is designated as the Control Room Zone and is comprised of the Control Room, Offices, Computer Rooms, Operator's Break Area, and Operator's Toilet Room.

All controls and displays necessary to bring the plant to a safe shutdown condition are included within the control room envelope.

6.4.2.2 Ventilation System

The Control Room Ventilation System is described in detail in Section 9.4.1. The ventilation system was designed and installed in accordance with HVAC Industry Standards and practices for commercial and industrial systems. The CRV system is not an "Engineered Safeguards" (ES) System.

6.4.2.3 Leak Tightness

Outside air filter trains are provided as part of the Control Room Ventilation System to provide filtered pressurization air to offset the exfiltration from the control room zone. This minimizes uncontrolled infiltration into the control room zone by creating a positive pressure with respect to adjacent zones.

The Oconee 1 and 2, and Oconee 3 Control Room Ventilation Systems are designed as independent ventilation systems; two outside air filter trains can each maintain unfiltered infiltration to their respective control room zones within acceptable limits.

6.4.2.4 Interaction With Other Zones and Pressure-Containing Equipment

The control room envelope is bounded on the north, south, and west by the Auxiliary Building and on the east by the Turbine Building. The Ventilation Systems serving the Auxiliary Building and Turbine Buildings are separate from the Control Room Ventilation System.

Interaction with other areas is minimal as air for pressurizing the Control Room Zone is taken from outside and is filtered through charcoal filters to eliminate airborne radioactive contaminants.

Pressure retaining equipment generally is not permitted in the control room zone. Exceptions to this are several hand held fire extinguishers for local fire control and several self-contained breathing apparatus with additional bottles of replenishment air.

6.4.2.5 Toxic Gas Protection

Some gases used on site are Ammonia, Hydrazine, Hydrogen, Liquid Nitrogen, and welding gases. Protection of control room operators against potential toxic gas release accidents has been found to be adequate by the NRC (Reference 1).

Self-contained type breathing apparatus are available to operator personnel. The Oconee 1 and 2 Control Room has six apparatus with twelve refill bottles and the Oconee 3 Control Room has three apparatus with six refill bottles.

Greenville Water Works utilizes chlorine at the Adkins Water Treatment plant on Lake Keowee. Potential accidents at this facility have been evaluated and determined not to impact Oconee based on Regulatory Guide 1.78 and 1.95 guidance (Reference 2).

6.4.3 Testing and Inspection

The Control Room Ventilation System is normally operable and is accessible for periodic inspection. The testing of the pressurization portion of the system is described in Technical Specification 5.5.23, “Control Room Envelope Habitability Program.” Temperatures in the Control Rooms, Cable Rooms, and Electrical Equipment Rooms are periodically surveyed, as required by SLC's to ensure the CRVS is functioning properly.

6.4.4 Instrumentation Requirements

Sufficient indications in the form of status lights and performance readouts are provided in the control room to evaluate system operation and indicate system malfunctions.

A radiation monitor is located in the return air side of the Control Room Ventilation System as described in Section 9.4.1.1.

A chlorine detector is located in the Outside Air Intake duct of each Control Room Ventilation System Booster fan as described in Section 9.4.1.2.

6.4.5 References

1. J. F. Stolz (NRC) to H. B. Tucker (Duke) November 24, 1986.
2. OSC-6206, Evaluation of Potential Off-Site Toxic Gas Releases.
3. J.F.Stolz (NRC) to H.B. Tucker (Duke) April 6, 1983.
4. Leonard N. Olshan (NRC) to Mr. Ronald A. Jones (Duke), June 1, 2004, Issuance of Amendments 338, 339, and 339 incorporating changes resulting from use of an alternate source term.

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6.5 Fission Product Removal and Control Systems

The systems addressed below reduce accidental release of fission products following a design basis accident.

6.5.1 Engineered Safeguards (ES) Filter Systems

Included in this section is a discussion of the Reactor Building Penetration Room Ventilation System. This system is no longer required due to adoption of the Alternate Source Term, Reference 2, and serves an ALARA function only.

6.5.1.1 Design Bases

The Reactor Building Penetration Room Ventilation System (PRVS) is designed to collect and process potential Reactor Building penetration leakage to minimize environmental activity levels resulting from post-accident Reactor Building leaks. Experience (Reference 1) has shown that Reactor Building leakage is more likely at penetrations than through the liner plates or weld joints.

Deleted paragraph(s) per 2005 update.

6.5.1.2 System Design

This section addresses the design only as related to fission product removal. More details of system design and operation are addressed in Section 9.4.7.2.

The system schematic and characteristics are shown on Figure 6-4 and Figure 6-22, respectively. Figure 6-23 and Figure 6-24 show penetration and opening locations in the penetration rooms. Mechanical openings, electrical openings, and construction details are illustrated in Figure 6-25, Figure 6-26, and Figure 6-27, respectively.

Penetration rooms are formed adjacent to the outside surface of each Reactor Building by enclosing the area around the majority of the penetrations.

Each unit's penetration room is provided with two fans and two filter assemblies. Both fans, discharging through a single line to the unit vent, may be controlled from the main control room.

During normal operation, this system is held on standby with each fan aligned with a filter assembly. The engineered safeguards signal from the Reactor Building will actuate the fans. Control room instrumentation monitors operation.

Particulate filtration is achieved by a medium efficiency pre-filter and a high efficiency (HEPA) filter. Adsorption filtration is accomplished by an activated charcoal filter.

Dampers are placed in the system inlets to prevent moisture from being carried through by natural circulation.

The only penetrations which do not pass through the penetration rooms are:

1. Reactor Building Fuel Transfer Tube and Reactor Coolant SSF Makeup (Penetration No. 11a).
2. Reactor Building Fuel Transfer Tube and Reactor Coolant SSF Letdown (Penetration No. 12a).
3. One Main Steam Line per unit --1B (Penetration No. 28) and 2A & 3A (Penetration No. 26).
4. Normal Personnel Access Lock (Penetration No. 90).

5. Permanent Equipment Hatch which contains a double-gasketed closure (Penetration No. 91).
6. Emergency Personnel Access Lock (Penetration No. 92).
7. Reactor Building Normal Sump Drain (Penetration No. 5a).
8. Reactor Coolant Post-Accident Liquid Sample Lines (Penetration No. 5b).
9. Reactor Coolant Quench Tank Drain (Penetration No. 29).
10. Reactor Building Emergency Sump Recirculation A (Penetration No. 36).
11. Reactor Building Emergency Sump Recirculation B (Penetration No. 37).
12. Reactor Building Emergency Sump Drain (Penetration No. 40).
13. Reactor Coolant Decay Heat Drop Line and Post-Accident Boron Dilution Line (Penetration No. 62 -- Units 2 and 3 only).

Of the listed penetrations, line items 7 through 13 are embedded lines.

The above lines, including the main steam lines, are not considered a source of significant leakage because they are welded to the liner plate. The access openings can be tested during normal operation and are not considered sources of significant leakage. There are double seals at each of these access openings, and the space between these double seals is connected to the penetration room. The refueling tube is equipped with a blind flange which is only opened during shutdown for transfer of fuel to the spent fuel pool.

6.5.1.3 Design Evaluation

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Adequate instrumentation is provided to detect loss of air flow through either filter. Reduction in air flow below a preset minimum would result in low Penetration Room vacuum and cause an alarm in the control room. Flow indication with readout outside the penetration filter area is furnished for each filter.

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Even in the event of unfiltered leakage of all the iodine input to the penetration room due to high wind velocity, the improvement in atmospheric dilution more than compensates for bypassing of the penetration room filter by this portion of the iodine. At a wind velocity of greater than 8.1 mph, the improvement in X/Q compensates for the complete loss of the filtering system in the calculation of offsite dose. A wind velocity of 8.1 mph will cause a reduction in pressure of .032 in. H_20 along the penetration room wall. (This assumes that wind velocity is exactly parallel to the wall which is the worst case assumption).

The equipment in this system is designed and rated in accordance with the following standards:

<u>Pre-Filter</u>- Filter efficiency is determined by the "American Filter Institute Dust Spot Test" utilizing atmospheric dust.

<u>Absolute Filter</u>- The basic design criteria for this filter is set forth in AEC Health and Safety Bulletin 212 (6-25-65) which incorporates U.S. Military Specification MIL-F-51068A captioned "Filter, Particulate, High Efficiency, Fire Resistant".

In addition, the dust holding capacity is determined by utilizing the test procedures of AFI "Code of Testing Air Cleaning Devices Used in General Ventilation", Section I (1952).

Adsorptive (Carbon) Filter- The specified ignition temperature of the carbon is checked using the methodology of ASTM D-3803-1989. This test is conducted on one sample from each lot of carbon.

Fans- Fan performance is determined by prototype test according to procedures set forth by the Air Moving and Conditioning Association (AMCA) 1960 Standard Test Code.

6.5.1.4 Tests and Inspections

The Reactor Building PRVS may be actuated during normal operation for testing and inspection. The high efficiency particulate air (HEPA) filters and the charcoal iodine filters may be tested if required to demonstrate that they are able to remove airborne materials from penetration leakage.

Sight glasses in the PRVS drain lines and humidity sensors are available for monitoring the penetration room humidity. External carbon sample canisters are installed on the filters to facilitate sampling if required. Provision is made to check penetration room pressure relative to either the Auxiliary Building or the outside.

Deleted paragraph per 2015 Update.

6.5.1.5 Instrumentation Requirements

Instrumentation is used only to monitor system performance and has no control function other than to guide the operator in adjusting the final control elements.

Penetration room pressure and humidity and loss of air flow through either filter are monitored.

6.5.1.6 Materials

Carbon steel and suitable coatings are used to obtain desired service life.

6.5.2 Containment Spray Systems

Credit is taken for this system for fission product removal in the MHA off-site dose analyses only. (see 15.15.1).

6.5.3 Deleted per 2001 Update

6.5.4 References

1. Cottrell, W. B. and Savolainen, A. W., Editors, U. S. Reactor Containment Technology, *ORNL-NSIC-5, Volume II*.
2. License Amendment No. 338, 339, and 339 (date of issuance – June 1, 2004); Adoption of Alternate Source Term.

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6.6 Inservice Inspection of Class 2 and 3 Components

6.6.1 Components Subject to Examination

Class 2 and 3 components, indicated in the Oconee Inservice Inspection Plan, are equivalent to Quality Groups B and C respectively of Regulatory Guide 1.26. These components will be examined in accordance with the provisions of the ASME Boiler and Pressure Vessel Code Section XI in effect as specified in 10CFR50.55a(g) to the extent practical. Requests for relief from inservice inspection requirements determined to be impractical will be submitted to the NRC for review in accordance with NRC guidelines for submitting such requests.

6.6.2 Accessibility

Class 2 and 3 systems at Oconee were installed before any inservice inspection requirements existed for these systems. In most cases adequate clearance is available to perform the inspection required by Section XI. In cases where adequate clearance is not available, the use of alternate inspection techniques will be investigated. If no alternate techniques appear practical, relief will be requested.

6.6.3 Examination and Procedures

The examination techniques to be used for inservice inspection include radiographic, ultrasonic, magnetic particle, liquid penetrant, eddy current, and visual examination methods. For all examinations, both remote and manual, specific procedures will be prepared describing the equipment, inspection technique, operator qualifications calibration standards, flaw evaluation, and records. These techniques and procedures will meet the requirements of the Section XI edition in effect as stated in Section 6.6.1.

6.6.4 Inspection Intervals

The inservice inspection interval for ASME Class 2 and 3 components is 10 years. The inspection schedule will be developed in accordance with IWC-2400 and IWD-2400. Detailed inspection listings and scheduling will be contained in the Oconee Inservice Inspection Plan.

6.6.5 Examination Categories and Requirements

The examination categories to be used are those listed in Tables IWC-2500-1 and IWD-2500-1 of ASME Section XI. Specific examinations will be identified by an Item Number, composed of the Item Number assigned in Tables IWC-2500-1 and IWD-2500-1 of ASME Section XI, plus an additional number to uniquely identify that examination.

6.6.6 Evaluation of Examination Results

Evaluation of examination results shall be in accordance with the Section XI in effect as stated in Section 6.6.1 where these evaluation standards are contained in Section XI. For examination where evaluation standards are not contained in Section XI, evaluation shall be performed in accordance with the original construction code.

6.6.7 System Pressure Tests

Classes 2 and 3 system pressure testing complies with Section XI Articles IWC-5000 and IWD-5000 in effect as stated in Section 6.6.1.

6.6.8 Augmented Inservice Inspection to Protect Against Postulated Piping Failures

Class 2 high energy fluid piping systems will be inspected in accordance with Article IWC-2000 of Section XI up to the isolation valve outside containment. The examination areas, methods, extent, and frequency will be as specified in Article IWC-2000. Those lines requiring augmented inservice inspection will be contained in the Oconee Nuclear Station Inservice Inspection Plan.

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Appendix 6A. Tables

Table 6-1. Deleted per 1995 Update

Table 6-2. Deleted per 2000 Update

Table 6-3. Quality Control Standards for Engineered Safeguards Systems

Summary of Requirements for Core Flooding Tanks	
CLASSIFICATION: ASME III, Class C, Paragraph N-2113 and the requirements of ASME VIII, Paragraph UW-2(a) (lethal substances)	
Inspection Requirements	**Acceptance Standard**
1. Inspection of raw materials and review of certificates	ASME III material
2. Hydro test	ASME III
3. Radiograph	ASME VIII
Summary of Requirements for Low Pressure Injection Heat Exchanger	
CLASSIFICATGION: Shell ASME VIII, Tube ASME III, Class C (lethal)	
Inspection Requirements	**Acceptance Standard**
1. Inspection of raw materials and review of material certificates	ASME II, III, VIII
2. Seal weld on tubes-to-tube sheet	TEMA-R-7 and additional requirements
3. Liquid penetrant inspection on tube-to-tube sheet	ASME III, N-627 and additional requirements
4. Hydro test	ASME III, VIII, TEMA-R
5. Leak test and seal weld (air)	
Summary of Requirements for Valves	
Inspection Requirements	Acceptance Standard
Class I and II Valves	
1. Radiographic inspection of the body casing	USAS B31.7
2. Inspection of material and review of material	USAS B31.7 certificates
3. Liquids penetrant inspection of the valve body	USAS B31.7
4. Hydro test of valve assembly	USAS B16.5 and additional requirements
5. Seat Leakage test	MSS-SP-61 and additional requirements
Class III Valves	
1. Inspection of material and review of material	USAS B31.7 certificates
2. Hydro test of valve assembly	USAS B16.5
3. Seat leakage test	MSS-SP-61 and additional requirements
In addition to these inspections listed above, all valve materials must meet the ASTM material specification.	
Summary of Requirements for Engineered Safeguards Systems Pumps	

Inspection Requirements	**Acceptance Standard**
1. Inspection of materials and review of material	ASTM certificates
2. Liquid-penetrant inspection of castings	ASME VIII
3. Performance test	Hydraulic Institute Standard
Additional requirements:	
Low Pressure Injection Pumps	
1. Hydrotest casing to 600 psig. Test pressure is held for 30 minutes per inch of thickness with a minimum holding time of 30 minutes. This exceeds the hydrotest requirements of ASME VIII Paragraph UG-99 (> 1.5 x design pressure).	
Reactor Building Spray Pumps	
1. Hydrotest casing to 1,200 psig. Test pressure is held for 30 minutes per inch of thickness with a minimum holding time of 30 minutes. This exceeds the hydrotest requirements of ASME VIII Paragraph UG-99 (> 1.5 x design pressure).	
High Pressure Injection Pumps	
1. Ultrasonic examination of pump barrel.	
2. Hydrotest nozzle head and pump barrel to 4,575 psig. Test pressure is held for 30 minutes per inch of thickness with a minimum holding time of 30 minutes. This exceeds the hydrotest requirements of ASME VIII Paragraph UG-99 (> 1.5 x design pressure of 3,050 psig).	
Low Pressure Service Water Pumps	
1. Documented quality control records and certified caliper measurements of the entire casting thickness will be furnished.	
2. Witness performance test will be performed. Acceptance standards are per Hydraulic Institute Standard.	
3. A documented, non-witness, hydro-test will be performed. Acceptance standards are per ASME code.	

Table 6-4. Engineered Safeguards Piping Design Conditions

		Temp (F)	Press. (psig)
1.	High Pressure Injection System		
a.	From the pump discharge to upstream of the check valves inside the secondary shielding.	200/150	3,040/3120
b.	High pressure injection pump.	200/150	3,040/3,120
c.	From upstream of the check valves to the reactor inlet line.	650	2,500
2.	Low Pressure Injection System		
a.	From the borated water storage tank to upstream of the borated water storage tank outlet valves.	150	Static
b.	From upstream of the borated water storage tank outlet valve to upstream of the electric motor operated valves in the borated water feed lines. (Unit 2 only, is to the check valves in the borated water feed lines)	200	100
c.	From upstream of the electric motor operated valves in the borated water feed lines to upstream of the valves at the pump inlets. (Unit 2 only, is from the check valves in the borated water feed lines)	300	200
d.	From upstream of the system inlet valves at the pump inlets to the pump inlet. Trains 1A, 1C, 2A, 2C	300/250	470/505
	Trains 1B, 2B	300	370
e.	From the pump outlet to upstream of the throttle valves at the cooler discharge. Trains 1A, 1C, 2A, 2C [1]	300/250	470/515
	Trains 1B, 2B	300	370
f.	From upstream of the throttle valves at the cooler discharge to upstream of the LPI Header isolation valves. Trains 1A, 2A	300/250	470/515
	Trains 1B, 2B	300	470/505
g.	From upstream of the system inlet valves to upstream of the check valves in the core flooding lines.	300	2,500
h.	From upstream of the check valves in the core flooding lines to the reactor vessel.	650	2,500
i.	From the Reactor Building emergency sump to upstream of the valves in the recirculation lines.	300	59
3.	Reactor Building Spray System		

		Temp (F)	Press. (psig)
a.	From downstream of the pump inlet valves to downstream of the Reactor Building valves.	250	495
b.	From downstream of the inlet valves through the nozzles[2].	250/286	200
4.	Low Pressure Service Water System		
a.	Condenser circulating water crossover to low pressure service water pump suction.	100	50
b.	Pump discharge	100	100
	(OCONEE 3 ONLY)		
1.	Low Pressure Injection System		
a.	From the borated water storage tank to upstream of the borated water storage tank outlet valves.	150	Static
b.	From upstream of the borated water storage tank outlet valve to upstream of the check valves in the borated water feed lines.	200	100
c.	From upstream of the check valves to upstream of the motor operated valves in the borated water feed lines.	300	300
d.	From upstream of the electric motor operated valves in the borated water feed lines to upstream of the valves at the pump inlets.	300	388
e.	From upstream of the system inlet valves at the pump inlets to upstream of the LPI Header Isolation valves.	300/250	470/505
f.	From upstream of the system inlet valves to upstream of the check valves in the core flooding lines.	300	2,500
g.	From upstream of the check valves in the core flooding lines to the reactor vessel.	650	2,500
h.	From the Reactor Building emergency sump to upstream of the valves in the recirculation lines.	300	59

Note:

1. For the C Train Connection to the B Train Cooler, design conditions are 300°F and 370 psig beginning downstream of the cross over valve.
2. A 286 F design temperature is applicable due to the Post-LOCA and Post-MSLB environmental temperature inside containment. All other plant conditions that require integrity of this pipe are enveloped by the 250 F design temperature.

Table 6-5. Single Failure Analysis Reactor Building Spray System

Component	Malfunction	Comments
1. Reactor Building the spray pump.	Fails to start.	Since each of the two strings of Reactor Building Spray System is equally sized, the remaining string will provide heat removal capability at a reduced rate. In combination with the Reactor Building Cooling System, heat removal capability in excess of the requirements will be provided.
2. Building isolation valve.	Fails to open.	(Same as above.)
3. Check valve in suction or discharge line.	Fails to open.	(Same as above.)

Table 6-6. Single Failure Analysis For Reactor Building Cooling System

Component	Malfunction	Comments
1. Circulating fan	Fails to operate.	The cooling capacity of the cooling units is reduced; however, 2 of 3 cooling units provide the required cooling.
2. Cooler service water outlet valve. (LPSW-18, -21, -24)	Fails to open fully	Valve will normally be partially open. If the valve fails to open fully, the unit will operate under reduced heat removal capability. The required cooling load will be met by 2 of 3 cooling units.
3. Cooler service water inlet valve. (LPSW-16, -19, -22)	Inadvertently left closed.	The flow through this string will be unavailable for cooling. It is unlikely that this condition would occur during an accident since the position and flow are monitored during normal operation. The required cooling load will be met by 2 of 3 cooling units.
4. Service water pump (1A, 1B, 1C).	Fails to operate.	The two remaining pumps will provide full low pressure service water flow to all components.
5. Service water pump (3A, 3B).	Fails to operate.	The one remaining pump will provide full low pressure service water flow to all components.

Table 6-7. Reactor Building Penetration Valve Information

			Inside Penetration Valve Data									Outside Penetration Valve Data								
								Valve Position									Valve Position			
Pen	Description	Vlv Arrg	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation
1(16)	Pressurizer Sample	1	2	¾	SH	EMO	ES	OP	AI	CL	YES	1	1/2	SH	AIR	ES	OP	CL	CL	YES
2	OTSG A Sample	8	Closed Loop Inside Containment									1	1/2	SH	AIR	ES	CL	CL	CL	YES
3	Component Cooling Inlet	3	1	6	CK	-	-	OP	-	CL	NO	1	6	CK	-	-	OP	-	CL	NO
4	OTSG B Drain	7	Closed Loop Inside Containment									1	4	SH	EMO	ES	OP	AI	CL	YES
5A	RB Normal Sump Drain	24	None									-	-	-	-	-	-	-	-	-
												5	1	SH	MAN	-	CL	-	CL	NO
												1	2	SH	EMO	ES	OP	AI	CL	YES
												1	2	SH	AIR	ES	OP	CL	CL	YES
5B	Post Accident Liquid Sample	13	None									2(5)	1	SH	SOL(5)	-	CL	CL(5)	CL(15)	YES(5)
6	RC Letdown	1	2	2	SH	EMO	ES	OP	AI	CL	YES	1	2	SH	AIR	ES	OP	CL	CL	YES
7	RC Pump Seal Return	4	1	3,4(7)	SH	EMO	ES	OP	AI	CL	YES	1	2	SH	AIR	ES	OP	OP(1)	CL	YES
8A	Pressurizer Aux Spray	3	1	1,11/2(11)	CK	-	-	OP	-	CL	NO	1	1,11/2(11)	CK	-	-	OP	-	CL	NO
8B	Loop A Nozzle Warming	3	1	1,11/2(11)	CK	-	-	OP	-	CL	NO	1	1,11/2(11)	CK	-	-	OP	-	CL	NO
9	HP Injection Loop A	2	1	4	CK	-	-	OP	-	OP	NO	None								
10A	RC Pump Seal Injection	3	1	1	CK	-	-	OP	-	CL	NO	1	1,11/2(6)	CK	-	-	OP	-	CL	NO
10B	RC Pump Seal Injection	3	1	1	CK	-	-	OP	-	CL	NO	1	1	CK	-	-	OP	-	CL	NO

			Inside Penetration Valve Data									Outside Penetration Valve Data								
								Valve Position									Valve Position			
Pen	Description	Vlv Arrg	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation
11	Fuel Transfer Tube	19				Special Closure (Flange)										None				
			1	3	SH	EMO	-	CL	AI	CL	YES									
			1	4	SH	EMO	-	CL	AI	CL	YES									
12	Fuel Transfer Tube	18				Special Closure (Flange)										None				
			1	3	SH	EMO	-	CL	AI	CL	YES									
			1	2 1/2	SH	SOL	-	CL	CL	CL	YES									
			2	2 1/2	SH	EMO	-	CL	AI	CL	YES									
			1	1 1/2	SH	EMO	-	CL	AI	CL	YES									
			1	1	SH	MAN	-	CL	-	CL	NO									
13	RB Spray Inlet	2	1	8	CK	-	-	CL	-	OP	NO					None				
14	RB Spray Inlet	2	1	8	CK	-	-	CL	-	OP	NO					None				
15	LPI Inlet	2	1	10	CK	-	-	CL	-	OP	NO					None				
16	LPI Inlet	2	1	10	CK	-	-	CL	-	OP	NO					None				
17	OTSG B EFW Injection	5				Closed Loop Inside Containment										None				
18	Quench Tank Vent	4	1	2	SH	EMO	ES	OP	AI	CL	YES	1	2	SH	AIR	ES	OP	CL	CL	YES
19	RB Purge Inlet	4	1	48	SH	EMO	ES	CL	AI	CL	YES	1	48	SH	AIR	ES	CL	CL	CL	YES
20	RB Purge Outlet	4	1	48	SH	EMO	ES	CL	AI	CL	YES	1	48	SH	AIR	ES	CL	CL	CL	YES
21	LPSW to RCP Coolers	7				Closed Loop Inside Containment						1	10	SH	EMO	ES	OP	AI	CL	YES
22	LPSW from RCP Coolers	7				Closed Loop Inside Containment						1	10	SH	EMO	ES	OP	AI	CL	YES
23A	RC Pump Seal Injection	3	1	1	CK	-	-	OP	-	CL	NO	1	1	CK	-	-	OP	-	CL	NO
23B	RC Pump Seal	3	1	1	CK	-	-	OP	-	CL	NO	1	1	CK	-	-	OP	-	CL	NO

			Inside Penetration Valve Data									Outside Penetration Valve Data								
								Valve Position									Valve Position			
Pen	Description	Vlv Arrg	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation
	Injection																			
24A	RB Hydrogen Analyzer	10	None									1	1/2,3/8[12]	SH	SOL	-	CL	CL	CL[2]	YES
24B	RB Hydrogen Analyzer	10	None									1	1/2,3/8[12]	SH	SOL	-	CL	CL	CL[2]	YES
25	OTSG B Feedwater Line	6	Closed Loop Inside Containment									1	24	CK	-	-	OP	-	CL	NO
26	OTSG A Main Stream Line	5	Closed Loop Inside Containment									None								
27	OTSG A Feedwater Line	6	Closed Loop Inside Containment									1	24	CK	-	-	OP	-	CL	NO
28[20]	OTSG B Main Steam Line	5	Closed Loop Inside Containment									None								
29	Quench Tank Drain	4	1	4	SH	EMO	ES	OP	AI	CL	YES	1	2	SH	AIR	ES	OP	CL	CL	YES
30	LPSW to RBCU	5	Closed Loop Inside Containment									None								
31	LPSW to RBCU	5	Closed Loop Inside Containment									None								
32	LPSW to RBCU	5	Closed Loop Inside Containment									None								
33	LPSW from RBCU	5	Closed Loop Inside Containment									None								
34	LPSW from RBCU	5	Closed Loop Inside Containment									None								
35	LPSW from RBCU	5	Closed Loop Inside Containment									None								
36	RB Emergency Sump Recirc	12	None									1	14	SH	EMO	-	CL	AI	OP	YES
37	RB Emergency Sump Recirc	15	None									1	14	SH	EMO	-	CL	AI	OP	YES
												1	1	SH	MAN	-	CL	-	OP	NO

			Inside Penetration Valve Data									Outside Penetration Valve Data								
								Valve Position									Valve Position			
Pen	Description	Vlv Arrg	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation
38	Quench Tank Cooler Inlet	3	1	11/2	CK	-	-	OP	-	CL	NO	1	11/2,2(9)	CK	-	-	OP	-	CL	NO
39a(17)	Core Flood Tank Vent	16	1	1	SH	MAN	-	CL	-	CL	NO	2	1	SH	MAN	-	CL	-	CL	NO
39b	HP Nitrogen Supply	20	1	1	CK	-	-	CL	-	CL	NO	1	1/2	SH	MAN	-	CL	-	CL	NO
												1	1	CK	-	-	CL	-	CL	NO
												1	1	SH	MAN	-	CL	-	CL	NO
40	RB Emergency Sump Drain	14	None									1	2	SH	MAN	-	CL	-	CL	NO
												2	2	CK	-	-	CL	-	OP	NO
												2	3/4	SH	MAN	-	CL	-	CL	NO
41	Instrument Air Supply	9	1	3	SH	MAN	-	CL	-	CL	NO	1	3	SH	MAN	-	CL	-	CL	NO
42A	RB Hydrogen Analyzer	10	None									1	1/2,3/8(12)	SH	SOL	-	CL	CL	CL(2)	YES
42B	RB Hydrogen Analyzer	10	None									1	1/2,3/8(12)	SH	SOL	-	CL	CL	CL(2)	YES
43	OTSG A Drain	7	Closed Loop Inside Containment									1	4	SH	EMO	ES	OP	AI	CL	YES
44	Component Cooling to CRD	3	1	21/2	CK	-	-	OP	-	CL	NO	1	21/2	CK	-	-	OP	-	CL	NO
45A	Leak Rate Test Line	9	1	1/2	SH	MAN	-	CL	-	CL	NO	1	1/2	SH	MAN	-	CK	-	CL	NO
45B	Leak Rate Test Line	9	1	1/2	SH	MAN	-	CL	-	CL	NO	1	1/2	SH	MAN	-	CL	-	CL	NO
45C(17)	Leak Rate Test Line	9	1	1/2	SH	MAN	-	CL	-	CL	NO	1	1/2	SH	MAN	-	CL	-	CL	NO
48	Breathing Air Supply to RB	9	1	2	SH	MAN	-	CL	-	CL	NO	1	2	SH	MAN	-	CL	-	CL	NO
49(16)	LP Nitrogen Supply to RB	22	1	11/2	CK	-	-	CL	-	CL	NO	2	1	SH	MAN	-	CL	-	CL	NO

			Inside Penetration Valve Data									Outside Penetration Valve Data								
								Valve Position									Valve Position			
Pen	Description	Vlv Arrg	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation
50	OTSG A EFW Injection	5	Closed Loop Inside Containment									None								
51	LRT Supply and Exhaust	11	Special Closure (Flange)									1	8	SH	AIR	-	CL	AI	CL	NO
												1	1/2,(10)	SH	MAN	-	CL	-	CL	NO
52	HP Injection B Loop	2	1	4	CK	-	-	CL	-	OP	NO	None								
53A	HP Nitrogen to CFT	20	1	1	CK	-	-	CL	-	CL	NO	1	1/2, 1(8)	SH	MAN	-	CL	-	CL	NO
												1	1	SH	MAN	-	CL	-	CL	NO
												1	1	CK	-	-	CL	-	CL	NO
53B(17)	LP Nitrogen Supply to RB	21	1	11/2	CK	-	-	CL	-	CL	NO	1	2	SH	MAN	-	CL	-	CL	NO
54	Component Cooling Outlet	4	1	8	SH	EMO	ES	OP	AI	CL	YES	1	8	SH	AIR	ES	OP	OP(1)	CL	YES
55	Demin Water Supply	9	1	4	SH	MAN	-	CL	-	CL	NO	1	4	SH	MAN	-	CL	-	CL	NO
56	Spent Fuel Canal Fill/Drain	9	1	8	SH	MAN	-	CL	-	CL	NO	1	8	SH	MAN	-	CL	-	CL	NO
57(16)	DHR Return Line	28	1	12	SH	EMO	-	CL	AI	CL14	YES	None								
			1	10	SH	MAN	-	CL	-	CL	NO									
			1	8	SH	EMO	-	CL	AI	CL14	YES									
58A(17)	Pressurizer Sample Line	1	2	3/4 1(13)	SH	EMO	ES	OP	AI	CL	YES	1	1/2	SH	AIR	ES	OP	CL	CL	YES
58B	OTSG B Sample	8	Closed Loop Inside Containment									1	1/2	SH	AIR	ES	CL	CL	CL	YES
59	Core Flood Tank Sample	17	`2	1	SH	EMO	-	CL	AI	CL	YES	2	1	SH	MAN	-	CL	-	CL	NO
60	RB Sample Line (Outlet)	23	1	2	SH	EMO	ES	OP	AI	CL	YES	1	2	SH	AIR	ES	OP	OP1	CL	YES
			1	2,3(4)	SH	EMO	-	CL	AI	CL	YES	1	1/2, 1(3)	SH	MAN	-	CL	-	CL	NO

			Inside Penetration Valve Data									Outside Penetration Valve Data								
								Valve Position									Valve Position			
Pen	**Description**	**Vlv Arrg**	**Qty**	**Size**	**Type**	**Oper**	**Signal**	**Norm**	**Fail**	**Post Acc**	**Indi-cation**	**Qty**	**Size**	**Type**	**Oper**	**Signal**	**Norm**	**Fail**	**Post Acc**	**Indi-cation**
61	RB Sample Line (Intlet)	25	1	2	SH	EMO	ES	OP	AI	CL	YES	1	2	SH	AIR	ES	OP	OP[1]	CL	YES
			1	2	SH	EMO	-	CL	AI	CL	YES									
62[17]	DHR Return Line	29	1	12	SH	EMO	-	CL	AI	CL[14]	YES	None								
			1	10	SH	MAN	-	CL	-	CL	NO									
63	LPSW RBACs Supply	27	None									2	6	SH	AIR	ES	OP	CL	CL	YES
64	LPSW RBACs Return	27	None									2	6	SH	AIR	ES	OP	CL	CL	YES

REACTOR BUILDING PENETRATION VALVE INFORMATION LEGEND 7 NOTES

LEGEND

Valve Arrgt – Refer to Figure 6-9.

Qty – Quantity of comparable penetration valves shown

Type - Valve types:

SH (Shut Off Valve) - gate, globe, ball, plug, butterfly, diaphragm or other type on/off valve with the ability to shut off flow.
CK (Check Valve) - stop check, swing check, tilting disc check, lift check, or other type of check valve whose function is to prevent flow in the reverse direction.

Size – Valve size in inches

Oper - Valve operator types

MAN - manual
EMO - electric motor operator
AIR - diaphragm operator
HYD - hydraulic operator
SOL - solenoid

Signal - Noted "ES" if the valve receives an Engineered Safeguards signal. Refer to Section 7.3 for further discussion of ES signals.

Valve Positions - Norm: position during normal operation, Fail: position without operator motive force, Post Acc: desired post-accident position

OP - Open
CL - Closed
AI - As Is

Indication – remove valve position indication

			Inside Penetration Valve Data										Outside Penetration Valve Data							
								Valve Position									Valve Position			
Pen	Description	Vlv Arrg	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation	Qty	Size	Type	Oper	Signal	Norm	Fail	Post Acc	Indi-cation

Notes:

1. Penetrations 7, 54, 60, and 61 outboard isolation valves fail open on loss of ES power to their associated solenoid valves provided air is available to open the valves. With ES power energizing the solenoid valves, the isolation valves close with or without supply air.
2. Although initially closed for Reactor Building isolation, valves associated with penetrations 24 and 42 can be opened for post-accident hydrogen monitoring.
3. For Penetration 60, the Unit 3 outside, manual penetration valve is ½ inch while the Unit 1 and Unit 2 outside, manual penetration valve is 1 inch.z
4. For Penetration 60, the Unit 3 inside, non-ES actuated penetration valve is 3 inch while the Unit 1 and Unit 2 inside, non-ES actuated penetration valve is 2 inch.
5. For Penetration 5b, there are two outside penetration solenoid valves for Units 1 and 2. There are two outside penetration manually operated valves for Unit 3. Only the solenoid valves on Units 1 & 2 fail closed and have remote position indication.
6. For Penetration 10a, the Unit 2 outside penetration valve is 1.5 inches while the Unit 1 & 3 outside penetration valves are 1 inch.
7. For Penetration 7, the Unit 2 inside penetration valve is 3 inch while the Unit 1 and Unit 3 inside penetration valves are 4 inch.
8. For Penetration 53a, the Unit 1 outside penetration valve is 1 inch while the Unit 2 and Unit 3 outside penetration valves are ½ inch.
9. For Penetration 38, the Unit 1 outside penetration valve is 1.5 inches while the Unit 2 and Unit 3 outside penetration valves are 2 inches.
10. For Penetration 51, the Unit 1 outside penetration valve is 1 inch while the Unit 2 and Unit 3 outside penetration valves are ½ inch.
11. For Penetration 8a & 8b, the Unit 1 inside and outside penetration valve sizes are 1.5 inches. The Units 2 and 3 inside and outside penetration valve sizes are 1 inch.
12. For Penetration 24 & 42, the Unit 1 and 3 outside penetration valve sizes are ½ inch while the Unit 2 outside penetration valve sizes are 3/8 inch.
13. For Penetration 58a, the two Unit 2 inside penetration valve sizes are 1 inch while the two Unit 3 inside penetration valve sizes are ¾ inch and 1 inch.
14. Although initially closed for Reactor Building isolation, valves associated with penetrations 57 and 62 (DHR Drop Line) can be opened for post-accident boron dilution.
15. Although initially closed for Reactor Building isolation, valves associated with penetration 5b may be opened post-accident for post accident liquid samples (PALS).
16. Penetration number applies to Unit 1 only.
17. Penetration number applies to Unit 2 and Unit 3 only.
18. Deleted per 2005 Update.
19. Deleted per 2005 Update.
20. For Penetration 28, the OTSG B Main Steam Line piping exits the Reactor Building to the yard.

Table 6-8. High Pressure Injection System Component Data

High Pressure Injection Pump	
Type	Vertical, multistage, centrifugal, mechanical seal
Capacity, gal/min	(See Figure 6-16)
Head, ft H_20 (at sp. gr. = 1)	(See Figure 6-16)
Motor Horsepower, nameplate hp	600
Pump Material	SS wetted parts
Design Pressure, psig	3,040/3,120
Design Temperature, F	200/150
Letdown Cooler	
Type	Shell and spiral tube
Heat Transferred, Btu/hr	16.0×10^6
Letdown Flow, lb/hr	3.5×10^4
Letdown Cooler lnlet/Outlet Temperature, F	555/120
Material, shell/tube	CS/SS
Design Pressure, psig	2,500
Design Temperature, F	600
Component Cooling Water Flow (ea.), lb/hr	2×10^5
Code	ASME Sec. III-C & VIII
Reactor Coolant Pump Seal Return Cooler	
Type	Shell and tube
Heat Transferred, Btu/hr	2.2×10^6
Seal Return Flow, lb/hr	1.25×10^5
Seal Return Temperature Change, F	145 - 127
Material, shell/tube	SS/SS
Design Pressure, psig	150
Design Temperature, F	286 (Unit 1), 200 (Units 2&3)
Recirculated Cooling Water Flow (ea.), lb/hr	1.25×10^5
Code	ASME Sec. III-C & VIII
Letdown Storage Tank	
Volume, ft^3	600
Design Pressure, psig	100
Design Temperature, F	200

Material	SS
Code	ASME Sec. III-C
Purification Demineralizer	
Type	Mixed bed, boric acid saturated
Material	SS
Resin Volume, ft^3	50
Flow, gal/min	70
Vessel Design Pressure, psig	150
Vessel Design Temperature, F	200
Code	ASME Sec. III-C
Letdown Filter	
Design Flow Rate, gal/min	80
Material	SS
Design Temperature	200
Design Pressure	150
Code	ASME Sec. III-C

Table 6-9. Low Pressure Injection System Component Data

Pump (each)	
Type	Single stage, centrifugal
Capacity, gpm	3,000
Head at Rated Capacity, ft H_20	350
Motor Horsepower, hp	400
Material	SS (wetted parts)
Design Pressure, psig	560/580
Design Temperature, F	300/250
Cooler (each)	
Type	Shell and tube
Capacity (at 140 F), Btu/hr	60×10^6
Reactor Coolant Flow, gal/min	6,000
Low Pressure Service Water Flow, gal/min	6,000
Low Pressure Service Water Inlet Temp, F	75
Material, Shell/Tube	CS/SS
Design Pressure, Shell	150
Design Pressure, Tube	515[(1)]/370[(2)] (470/505 for Unit 3 only)
Design Temperature, F	250[(1)]/300[(2)] (300/250 for Unit 3 only)
Code	ASME Section III-C, III and VIII
Borated Water Storage Tank (each)	
Capacity, gal	388,000
Material	CS/Coated inside
Design Pressure	Vessel Full plus 10 ft Hydro Head
Design Temperature, F	150
Code	AWWA D-100

Note:

1. A Cooler Units 1 & 2
2. B Cooler Units 1 & 2

Table 6-10. Core Flooding System Components Data

Core Flooding Tanks	
Number	2
Design Pressure, psig	700
Operating Pressure, psig	600
Minimum Pressure, psig	575
Design Temperature, F	300
Operating Temperature, F	110
Total Volume, ft^3	1,410
Normal Water Volume, ft^3	1,040
Minimum Water Volume, ft^3	1,010
Material of Construction	Carbon steel lined with SS
Check Valves	
Number per Flood Line	2
Size, in.	14
Material	316 SS
Design Pressure, psig	2,500
Design Temperature	
Valve nearest reactor, F	650
Valve nearest tank, F	300
Isolation Valves	
Number per Flood Line	1
Size, in.	14
Material	304 SS
Design Pressure, psig	2,500
Design Temperature, F	300

Piping	**Reactor to First Check Valve**	**First Check Valve to Isolation Valve**	**Isolation Valve to Tank**
Size, in.	14	14	14
Material	316 SS	304 SS	304 SS
Design Pressure, psig	2,500	2,500	700
Design Temperature, F	650	300	300

Table 6-11. Single Failure Analysis - Emergency Core Cooling System

Component		Malfunction	Comments
A. High Pressure Injection System			
1.	Suction valve for high pressure injection pump from borated water storage tank.	Fails to open.	The parallel valve will supply the required flow to one pump string.
2.	High pressure injection valve	Fails to open.	The alternate line and the two cross connect lines will provide the total required flow.
3.	High pressure injection pump (operating).	Fails (stops).	Two backup pumps are available to deliver the flow.
4.	High pressure injection pump.	Fails to start.	Two backup pumps are available to deliver the flow.
5.	Seal return line isolation valve.	Fails to close on ES signal.	The other isolation valve will close eliminating this fluid path.
6.	Letdown cooler isolation valve.	Fails to close on ES signal.	The other isolation valve will close the flow path.
7.	LDST-RBES return line isolation valve	Fails to open.	The other isolation valve will provide a LDST-RBES return flow path.
B. Low Pressure Injection System			
1.	Low pressure injection pump.	Fails to start.	Adequate injection is provided by the other pump.
2.	Low pressure injection isolation valve.	Fails to open.	Other line admits necessary flow through both injection headers via the passive cross-over line.
3.	Valve in suction line from the Reactor Coolant System	Fails to open.	Drain line upstream of the first isolation valve opens admitting flow to the emergency sump. The LPI System then operates in the recirculation mode.
4.	LPI Cooler isolation valve (LPSW-4, -5)	Fails to open.	Other LPSW train admits necessary flow.
5.	Service water pump - 1A, 1B, 1C	Fails to operate	The two remaining pumps will provide full low pressure service water flow to all components.

Component		Malfunction	Comments
6.	Service water pump - 3A, 3B	Fails to operate	The one remaining pump will provide full low pressure service water flow to all components.
	(RECIRCULATION FROM REACTOR BUILDING EMERGENCY SUMP)		
1.	Valve in suction line from emergency sump.	Fails to open.	Other line admits necessary flow.
2.	Valve in suction line from BWST.	Fails to close after initiating recirculation.	Check valve prevents flow into BWST.
3.	Low pressure injection pump.	Loss of pump.	Reactor core protection will be maintained by alternate pump and low pressure injection string.
4.	Valve in post accident boron dilution flow path from reactor outlet to emergency sump.	Fails to open	Redundant post accident boron dilution path admits necessary flow.
C.	Core Flooding System		
1.	Isolation valve in discharge line.	Closes during normal operation.	If the valve cannot be manually opened, the reactor must shut down or operations limited as specified in Technical Specifications.
2.	Tank relief valve.	Opens during normal operation.	Loss of nitrogen pressure and consequent loss of ability of tank to perform. Reactor must be shut down or operations adjusted to Technical Specification limits and relief valve must be repaired.
3.	Check valves in charge line.	Excessive leak detected during normal reactor operation.	It is extremely unlikely that both check valves would permit excessive leakage. Leakage would be indicated by core flooding tank pressure and level changes. If leakage becomes progressively worse or is unacceptably high, reactor must be shut down while the check valves are repaired.

Table 6-12. Oconee Nuclear Station Analysis of Valve Motors Which May Become Submerged Following A LOCA

No.	Valve Identification Description	Evaluation
1CF-1 2CF-1 3CF-1	"A" Core Flood Tank Discharge Valve	No effect on ECCS capability or containment integrity. Valve is locked open during operation and is not operated subsequent to a LOCA. Valve is not a containment isolation valve.
1CS-5[1] 2CS-5[1] 3CS-5[1]	Reactor Building Isolation Valve for Quench Tank Drain	No effect on ECCS capability or containment integrity. Valve is normally closed. Redundant isolation valve on outside of containment is not affected.
1HP-1 2HP-1 3HP-1	Reactor Coolant Inlet to "A" Letdown Cooler	No effect on ECCS capability or containment integrity. Letdown coolers are not used following a LOCA. Valve is not a containment isolation valve.
1HP-2 2HP-2 3HP-2	Reactor Coolant Inlet to "B" Letdown Cooler	No effect on ECCS capability or containment integrity. Letdown coolers are not used following a LOCA. Valve is not a containment isolation valve.
1HP-3[1] 2HP-3[1] 3HP-3[1]	Reactor Coolant Outlet from "A" Letdown Cooler and Reactor Building Isolation Valve	No effect on ECCS capability or containment integrity. Letdown coolers are not used following a LOCA. Redundant isolation valve on outside of containment is not affected.
1HP-4[1] 2HP-4[1] 3HP-4[1]	Reactor Coolant Outlet from "B" Letdown Cooler and Reactor Building Isolation Valve	No effect on ECCS capability or containment integrity. Letdown coolers are not used following a LOCA. Redundant isolation valve on outside of containment is not affected.
1CC-1 2CC-1 3CC-1	Component Cooling Water Inlet to "A" Letdown Coolers	No effect on ECCS capability or containment integrity. Letdown coolers are not used following a LOCA. Valve is not a containment isolation valve.
1CC-2 2CC-2 3CC-2	Component Cooling Water Inlet to "B" Letdown Coolers	No effect on ECCS capability or containment integrity. Letdown coolers are not used following a LOCA. Valve is not a containment isolation valve.

Note:

1. Valve is an ES valve and would shut upon ES actuation before becoming submerged.

Table 6-13. Equipment Operational During An Accident and Located Outside Containment

4160 Volt Station Auxiliary Switchgear
600 Volt Load Centers
600 Volt and 208 Volt Motor Control Center
Batteries
Chargers and Inverters
Panelboards
Low Pressure Injection Pump Motors
High Pressure Injection Pump Motors
Reactor Building Spray Pump Motors
Low Pressure Service Water Pump Motors
Cables

Table 6-14. Equipment Operational During an Accident and Located Within the Containment

Equipment	Accident Environmental Tests
Reactor Building Cooling Fans and Motors	After preaging a prototype motor for an extrapolated 40 years insulation life and Fan testing it for operation under seismic conditions, the motor and fan assembly was placed in a pressure vessel. Steam is then injected into the chamber to a pressure of 70 to 80 psia and chemicals similar to those used in the spray system are introduced. The pressure cycle is repeated four additional times and then pressure is reduced to the level to be expected following the accident. The motor then is run continuously for a minimum of 7 days in the test chamber.
Cables	Representative samples of preaged cables are tested under high pressure, temperature and humidity conditions equal to or exceeding those specified for the LOCA. These cables are preaged for forty years of radiation and temperature prior to testing.
Valves	A typical production valve and actuator was tested as follows under simulated accident conditions. After preaging heat test and shock and vibration tests, the production valve and actuator was subjected to the following environmental tests: 1. Saturated steam at 90 psig for one hour. 2. Boric acid spray for the next two hours at 70 psig followed by a pressure drop to 40 psig with the spray continuing for an additional half hour. 3. Steam pressure was maintained at 40 psig for a period of 1½ hours followed by a pressure dropoff of 20 psig. 4. Steam pressure was maintained at 20 psig for the remaining nineteen hours of the first day followed by a pressure decrease to 10 psig. 5. Steam pressure at 10 psig was then maintained for six days yielding a total test time of seven days. 6. Valve operation was conducted at the beginning and the end of each level of pressure in 1, 2, 3, 4, and 5 above.
Electrical Penetrations	Qualification tests have been performed on one production assembly of each type that is required to function during or following the loss-of-coolant accident to verify its functional capability. The interior end of the penetration assemblies were subjected to the following emergency conditions at 100 percent relative humidity in an autoclave built to duplicate Oconee Reactor Building concrete and nozzle design. 1. First fifteen minutes: Pressure of 65 psig at a temperature of 300 °F Rise time for normal operating conditions - less than ten seconds. 2. Next forty-five minutes: Pressure of 40 psig at a temperature of 260 °F 3. Next twenty-three hours: Pressure of 35 psig at a temperature of 250 °F
	During the environmental tests, functional capability was demonstrated by applying rated current to conductors in series at 600 volts r.m.s. above ground. The temperature along the nozzle and in the wire bundles was monitored throughout the test. Leak rate was measured and recorded during the test.

Equipment	Accident Environmental Tests
	The following tests were performed before and after the autoclave test: 1. Connector and conductor resistance test. Measured ohmic resistance of each conductor. 2. Dielectric withstand tests. 3. Conductor to ground and conductor to conductor. 4. Insulation resistance. Conductor to ground. 5. Leak rate test.
Reactor Coolant System Pressure Transmitters	Reactor coolant pressure transmitters required for use within the Reactor Building following an accident have been conservatively tested under conditions simulating the environment expected after the design base 14.1 ft^2 LOCA. The results of these tests show that the transmitters are acceptable for the required functions. A three phase test was performed to simulate the post-LOCA Reactor Building environment. The respective phases are given below:
	Phase I - Pre-accident test at the Babcock & Wilcox Nuclear Development Center (NDC) to simulate the environmental dose to the transmitters associated with the 40-year plant design lifetime.
	Phase II - Environmental autoclave test at Franklin Institute Research Laboratory to simulate the Reactor Building pressure and temperature history for a LOCA.
	Phase III - Post-accident test at NDC to simulate the maximum expected dose to the transmitters after an LOCA.
	Phase I consisted of irradiating the transmitters while the units were in a nonoperating mode. The transmitters were placed in a sealed aluminum box with two dosimeters attachment to each transmitter and positioned over two reactor fuel elements in the NDC storage pool.
	Phase II consisted of exposing the transmitters in the operating mode to a steam environment in a test autoclave for 24 hours. The units were supplied with a constant input of approximately 2/3 of full range and the resultant output/input ratio was measured for the test duration.
	Phase III consisted of irradiating the transmitters while the units were in the operating mode in much the same manner as Phase I except that the box was lowered into position beside one fuel element from the reactor. A constant input of approximately 2/3 of full range was maintained throughout the test. The resulting output signal inaccuracies for each test phase were analyzed and found to be acceptable.

Table 6-15. Emergency Core Cooling Systems Performance Testing

High Pressure Injection Pumps	One of two pumps operates continuously. The other pump will be operated periodically.
High Pressure Injection Line Valves	The remotely operated stop valves in each line are opened partially one at a time. The flow monitors will indicate flow through the lines.
High Pressure Injection Pump Suction Valves	The valves are opened and closed individually and console lights monitored to indicate valve position.
Low Pressure Injection Pumps	Pumps are used in normal service for shutdown cooling. These pumps are tested singly for operability by opening the borated water storage tank outlet valves and the bypass valves in the borated water storage tank fill line. This allows water to be pumped from the borated water storage tank through each of the injection lines and back to the tank.
Borated Water Storage Tank Outlet Valves	The operational readiness of these valves is established in completing the pump operational test discussed above. During this test, each valve is tested separately.
Low Pressure Injection Valves	With pumps shut down and borated water storage tank outlet valves closed, these valves can be opened and reclosed by operator action.
Sump Recirculation Suction Valves	With low pressure injection pumps shut down, operation of these valves can be checked.
Check Valves in Core Flooding Injection	With the reactor shut down, the check valves in each core flood line are checked for operability by closing the isolation valves, reducing the Reactor Coolant System pressure to provide ΔP slightly above the check valve opening pressure, and opening the isolation valves. Check valve operability is shown by tank pressure and level changes.

Table 6-16. Deleted Per 1999 Update

Table 6-17. Deleted Per 1999 Update

Table 6-18. Inventory of Iodine Isotopes in Reactor Building (at t = o)

Isotope	Initial Inventory
	Curies/MWt
Iodine 131	2.51×10^4
Iodine 132	3.81×10^4
Iodine 133	5.63×10^4
Iodine 134	6.58×10^4
Iodine 135	5.10×10^4

Table 6-19. Deleted Per 2015 Update

Table 6-20. Parameters for Boron Precipitation Analysis

Initial Reactor Core Power	2568 MWth
Decay Heat	120% of 1971 ANS
LPI Flow Rate	402 lbm/sec
Core Mixing Mass	60000 lbm
LPI Injection Enthalpy	123 Btu/lbm
Containment Pressure	25 psia
RCS Boron Concentration	2100 ppm
BWST Boron Concentration	3000 ppm
CFT Boron Concentration	4000 ppm

Table 6-21. Summary of Calculated Containment Pressures and Temperatures for LOCA Cases

Description	Peak Containment Pressure (psig)	Peak Containment Temperature (°F)	Time of Peak Pressure (sec)	Blowdown Energy Release ($x10^6$Btu)
Hot Leg SG Inlet Cases (14.1 ft^2 break size)				
100% RTP	56.95	281.68	14.5	316.23
Reduced Tavg	55.27	279.57	15.3	312.37
10°F ΔTcold	56.62	281.29	13.9	314.59
80% RTP	56.34	280.94	14.2	313.78
60% RTP	55.74	280.19	14.2	311.65
Max ECCS case	56.88	281.45	14.3	315.74
LOOP Case	56.82	281.54	14.2	315.39
Hot Leg RV Outlet Cases (14.1 ft^2 break size)				
100% RTP	56.69	281.40	13.0	316.56
Cold Leg Pump Discharge Case (8.55 ft^2 break size)				
100% RTP	52.52	276.00	16.8	313.31
Cold Leg Pump Suction Case (8.55 ft^2 break size				
100% RTP	53.50	277.31	23.6	303.47

Table 6-22. Containment Response Analyses Initial Conditions

General Information			
External containment design pressure (psid)	3.0		
Internal containment design pressure (psig)	59		
Containment design temperature (°F)			
Containment free volume (ft^3)	1,810,000		
Containment design leak rate (/1st day at peak accident pressure)	0.2%		
	Large LOCA Short Term	**Large LOCA Long-Term**	**Steam Line Break**
Initial Conditions			
Reactor power (MWt @ 102% design overpower)	2619	2619	2619
Average reactor coolant temperature (°F)	581	581	581
Containment pressure (psig)	1.2	0	1.5
Containment atmosphere temperature (°F)	80	variable	170
Containment atmosphere relative humidity (%)	0	100	0
Low pressure service water temperature (°F)	N/A	variable	N/A
Borated water temperature (°F)	N/A	115	120
Borated water storage tank level (ft)	N/A	46	N/A
Core flood tank volume (both, ft^3)	1944	1944	1940

Table 6-23. Containment Structural Heat Sink Data

Heat Sink	Painted Material Thickness (ft)	Unpainted Metal Thickness Group	Unpainted Metal Exposed Surface Area (ft^2)	Unpainted Metal Total Mass (lbm)	Total Surface Area (ft^2)
Carbon Steel Building Cylinder	0.0208				61,353
Concrete Building Cylinder	3.75				61,353
Carbon Steel Building Dome	0.0208				16,230
Concrete Building Dome	3.25				16,230
Carbon Steel Building Base	0.0208				8890
Concrete Building Base	8.5				8890
Internal Concrete	1.76				66,231
Internal Carbon Steel	0.0316				165,400
Internal Carbon Steel		1	63,727	300,000	63,727
Internal Stainless Steel		2	8628	258,000	8628
Internal Aluminum		1	9892	3828	9892
Internal Copper		4	727	23,268	727

Table 6-24. Accident Chronology for Limiting Break for Equipment Qualification

Event	Time(seconds)
Beginning of ECCS injection	6.0
Beginning of CFT injection	12.0
Peak containment pressure	20
End of blowdown phase	26.5
Beginning of RB Spray	142
Beginning of RBCU operation	302
Peak containment pressure after blowdown	N/A
End of core reflood phase	535
Beginning of sump recirculation phase	4529
End of RB Spray/Beginning of re-circ spray	4529
End of S/G energy release	N/A
Depressurization of containment (1/2 of design pressure)	within 2000 seconds (depending on RBCU assumptions)

Table 6-25. Minimum Acceptable Combinations of Containment Heat Removal Equipment Performance

Case No.	INPUT ASSUMPTIONS							RESULTS	
	LPI Overall Ht Transfer Coeff @250F LPI (Btu/hr-ft^2-ºF)	RBCU (MBtu/hr)	LPSW (ºF)	Rx Bldg Temp (ºF)	RBS (inj phase) (gpm)	RBS (recirc phase) (gpm)		T (1 day) (ºF)	T (15 days) (ºF)
P	250	64.00	90	130	700	900		198.1	155.7

Table 6-26. Engineered Safety Feature Assumptions in Containment Response Analyses

Passive safety injection system	Full Capacity	Large LOCA Short-Term	Large LOCA Long-Term	Steam Line Break
Number of core flood tanks	2	N/A	2	2
Core flood tank pressure setpoint (psig)	600	N/A	655	550
Active safety injection systems				
Number of HPI lines	2	N/A	1	1
Number of HPI pumps	3	N/A	2	2
HPI flow rate (gpm/pump)	300	N/A	variable	variable
Number of LPI lines	2	N/A	1	1
Number of LPI pumps	3	N/A	1	1
LPI flow rate (gpm/pump)	3000	N/A	variable	N/A
Containment spray system				
Number of injection spray lines	2	N/A	1	1
Number of injection spray pumps	2	N/A	1	1
Number of injection spray headers	2	N/A	1	1
Injection flow rate (gpm/pump)	700-1200	N/A	700	700
Number of recirculation spray lines	2	N/A	1	N/A
Number of recirculation spray pumps	2	N/A	1	N/A
Number of recirculation spray headers	2	N/A	1	N/A
Recirculation flow rate (gpm/pump)	1000	N/A	900	N/A
Containment fan cooler system				
Number of coolers (RBCUs)	3	N/A	2	2
Air side flow rate per RBCU (cfm)	108,000	N/A	54,000	54,000

Heat removal rate at design temperature (millions of Btu/hr)	80	N/A	variable	variable
Heat Exchangers	**Full Capacity**	**Large LOCA Short-Term**	**Large LOCA Long-Term**	**Steam Line Break**
System	LPI	N/A	LPI	N/A
Type	U-tube	N/A	U-tube	N/A
Number	2	N/A	1	N/A
Heat transfer area (ft^2)	3986	N/A	3900	N/A
Heat removal rate at design temperature (millions of Btu/hr)	60	N/A	variable	N/A
Recirculation side flow rate (gpm)	6000	N/A	2830	N/A
Exterior side flow rate (gpm)	6000	N/A	5000	N/A
Source of cooling water	LPSW	N/A	LPSW	N/A
Cooling begins (sec)	not calculated	N/A	5467	N/A
Deleted row (s) per 2011 update				

Table 6-27. Summary of Calculated Containment Pressures and Temperatures for Secondary System Pipe Rupture Cases

Break Location	Break Size	Peak Pressure (psig)	Peak Temperature (F)	Time of Peak Pressure (sec)	Energy Released to Containment up to End of Blowdown (10^6Btu)
Deleted row(s) per 2008 update					
S/G outlet	12.6	58.85	464	156	291

Table 6-28. Steam Generator Compartment Pressure Response Flowpath Discharge Coefficients

	Flow Area (ft^2)		
Vent Flowpath Location	**West Compartment**	**East Compartment**	**Discharge Coefficients**
Top	528	417	(Figure 6-46)
Bottom	522	522	0.85
Cross Compartment	116	116	(Figure 6-47)
Cross Compartment	167	167	0.60
Total	1,333 ft^2	1,222 ft^2	

Table 6-29. Peak Pressure Mass and Energy Release Data

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
0.0	3010.01	1184.97	49671.97	582.17	2193.5	3285.7	1185.3	53516.7	582.0	2194.5
0.1	3292.43	1186.06	48890.57	578.04	1181.629	3595.0	1186.3	50971.8	577.1	1197.0
0.2	3514.61	1187.31	47678.99	574.34	1159.982	3628.0	1188.2	46317.2	572.9	1107.1
0.3	3543.37	1188.18	44653.10	572.03	1110.159	3397.0	1190.1	41300.8	572.3	1029.7
0.4	3630.87	1189.37	40559.81	567.41	1049.93	3693.9	1191.7	35278.7	566.8	976.9
0.5	3635.68	1190.27	38647.09	565.67	1034.564	4278.5	1195.5	31515.0	552.9	936.0
0.6	3648.05	1190.44	38356.02	565.55	1035.154	4962.8	1201.0	30910.8	531.2	856.1
0.7	3669.39	1190.34	38597.74	565.83	1038.666	5331.4	1204.5	29974.4	516.3	804.5
0.8	3718.86	1190.34	38499.13	565.82	1039.054	5240.4	1205.9	28512.6	508.7	755.2
0.9	3792.57	1190.46	38007.04	565.60	1035.513	4979.0	1206.5	27982.4	503.2	731.9
1.0	3894.59	1190.67	37243.49	565.28	1032.616	4666.8	1206.5	28170.5	500.4	718.2
1.1	4040.05	1191.05	36056.67	564.56	1024.747	4338.3	1206.1	28843.6	499.1	714.5
1.2	4207.73	1191.60	34568.39	563.29	1013.115	4009.4	1205.6	29806.0	498.8	716.5
1.3	4365.54	1192.20	33138.08	561.69	1000.073	3717.0	1205.0	30817.1	499.0	720.2
1.4	4993.88	1195.85	32492.03	552.24	989.5376	3479.8	1204.6	31694.5	499.3	723.7
1.5	5680.12	1199.71	30794.20	538.92	875.3103	3300.6	1204.3	32345.0	499.5	726.3
1.6	5890.87	1201.23	29217.68	532.83	910.9592	3181.6	1204.1	32666.4	499.7	728.1
1.7	6230.52	1203.24	28865.65	528.18	886.991	3106.0	1204.0	32723.4	499.8	729.0
1.8	6589.77	1206.18	26964.95	519.59	803.0924	3052.9	1203.9	32680.9	499.6	728.4

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
1.9	6793.44	1208.29	24854.61	512.88	762.0923	3020.8	1203.9	32600.2	499.2	726.3
2.0	6987.48	1209.57	23543.95	509.93	757.0142	3010.7	1204.0	32499.2	498.5	722.8
2.1	7049.20	1210.37	22700.01	507.46	732.7446	3020.8	1204.1	32356.9	497.7	717.8
2.2	6982.30	1210.71	22352.82	505.43	722.8103	3050.3	1204.4	32131.9	496.6	711.7
2.3	6929.43	1211.04	21991.46	503.58	712.88	3106.2	1204.6	31730.6	495.4	705.0
2.4	6926.97	1211.55	21424.15	501.60	700.4492	3181.4	1204.9	31161.7	494.3	698.2
2.5	6972.51	1212.27	20638.07	499.39	686.8077	3257.5	1205.1	30565.0	493.1	691.1
2.6	7045.78	1213.19	19690.63	496.92	670.8762	3329.2	1205.4	29990.4	491.9	684.3
2.7	7104.95	1214.14	18744.18	494.28	653.8654	3396.4	1205.7	29409.8	490.6	677.1
2.8	7120.03	1214.90	17983.51	491.78	638.7917	3460.7	1206.0	28798.3	489.2	669.3
2.9	7090.58	1215.41	17449.85	489.58	626.4775	3523.6	1206.3	28153.2	487.6	660.6
3.0	7024.28	1215.70	17117.19	487.66	616.2853	3586.2	1206.7	27480.8	486.0	651.3
3.1	6931.13	1215.78	16983.97	486.12	608.9916	3650.1	1207.0	26806.2	484.1	641.6
3.2	6827.70	1215.69	16999.04	484.98	604.6638	3707.1	1207.4	26140.4	482.1	629.7
3.3	6723.07	1215.54	17071.12	484.04	601.1656	3751.8	1207.7	25494.8	480.1	619.2
3.4	6617.46	1215.36	17164.90	483.17	598.1012	3787.5	1208.0	24906.0	478.3	609.5
3.5	6513.70	1215.16	17283.34	482.42	595.6895	3819.2	1208.3	24363.3	476.7	601.6
3.6	6410.98	1214.94	17419.40	481.73	593.6919	3851.2	1208.6	23822.7	475.1	593.5
3.7	6306.66	1214.70	17580.36	481.12	592.0447	3885.2	1208.9	23248.5	473.4	584.7
3.8	6197.66	1214.45	17746.44	480.48	590.5136	3928.3	1209.2	22613.2	471.6	575.1

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
3.9	6091.36	1214.23	17887.72	479.78	588.2765	3975.1	1209.6	21950.0	469.7	565.2
4.0	5999.57	1214.06	17982.71	479.08	586.2639	4013.3	1209.9	21316.9	467.8	555.6
4.1	5919.56	1213.96	17999.05	478.23	582.8126	4041.9	1210.2	20723.0	465.9	546.1
4.2	5850.31	1213.91	17975.75	477.35	578.8416	4063.8	1210.5	20159.5	464.1	536.9
4.3	5785.93	1213.86	17948.31	476.51	575.8641	4081.9	1210.8	19619.1	462.2	527.8
4.4	5719.81	1213.82	17907.76	475.59	571.6936	4097.2	1211.1	19096.9	460.4	519.1
4.5	5657.05	1213.79	17859.65	474.68	567.8912	4109.7	1211.3	18589.4	458.6	510.5
4.6	5601.93	1213.77	17801.33	473.81	564.1906	4120.8	1211.6	18096.4	456.8	501.9
4.7	5556.08	1213.79	17707.59	472.91	560.3049	4130.3	1211.8	17625.7	455.1	493.9
4.8	5521.32	1213.86	17560.69	471.95	555.8145	4135.5	1212.1	17179.0	453.4	486.0
4.9	5497.49	1213.99	17366.12	470.94	550.9728	4136.0	1212.3	16743.6	451.7	478.2
5.0	5479.21	1214.14	17138.19	469.87	545.6119	4135.3	1212.5	16305.3	450.0	470.1
5.1	5461.59	1214.30	16903.19	468.77	540.1775	4138.0	1212.8	15863.6	448.2	462.2
5.2	5458.31	1214.41	16753.36	468.13	534.9559	4144.7	1213.0	15424.4	446.6	454.6
5.3	5452.41	1214.50	16629.87	467.58	537.133	4154.3	1213.3	14993.1	445.0	447.2
5.4	5418.88	1214.63	16392.82	466.31	527.8124	4167.1	1213.5	14579.1	443.5	440.3
5.5	5377.81	1214.79	16119.89	464.77	520.9561	4179.8	1213.8	14186.3	442.0	433.9
5.6	5331.54	1214.88	15926.04	463.43	514.8933	4187.2	1214.0	13802.8	440.6	427.4
5.7	5270.87	1214.87	15832.54	462.28	510.2204	4191.7	1214.2	13411.3	439.1	420.5
5.8	5202.57	1214.79	15800.48	461.26	506.3772	4199.3	1214.5	12999.4	437.5	413.4

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
5.9	5136.92	1214.70	15777.82	460.32	502.8705	4214.5	1214.9	12544.7	435.8	406.0
6.0	5084.95	1214.66	15709.59	459.38	499.2031	4227.8	1215.2	12095.1	434.1	398.1
6.1	5058.63	1214.74	15535.22	458.37	494.8307	4233.7	1215.5	11685.9	432.5	391.1
6.2	5061.77	1214.98	15214.89	457.19	488.941	4238.8	1215.8	11282.6	430.9	383.9
6.3	5087.59	1215.37	14763.62	455.79	481.5992	4242.2	1216.2	10887.3	429.3	376.9
6.4	5126.83	1215.87	14229.35	454.24	473.1572	4243.0	1216.5	10506.6	427.7	370.0
6.5	5166.82	1216.43	13671.74	452.60	464.2117	4241.2	1216.8	10139.1	426.1	363.3
6.6	5199.58	1216.96	13143.25	450.96	455.6055	4236.9	1217.0	9782.5	424.5	356.6
6.7	5225.96	1217.46	12655.68	449.39	447.4246	4230.4	1217.3	9435.8	422.9	349.9
6.8	5248.35	1217.96	12194.42	447.88	439.5559	4221.9	1217.6	9097.6	421.3	343.4
6.9	5268.13	1218.45	11744.27	446.39	431.8085	4211.2	1217.9	8767.5	419.7	336.9
7.0	5285.42	1218.94	11299.63	444.91	424.1094	4197.9	1218.1	8446.1	418.1	330.4
7.1	5300.02	1219.44	10861.96	443.41	416.4128	4182.1	1218.4	8134.4	416.5	324.0
7.2	5312.88	1219.96	10430.75	441.92	408.7826	4163.6	1218.7	7835.1	414.9	317.6
7.3	5325.34	1220.51	9998.25	440.43	401.1175	4142.7	1219.0	7549.3	413.3	311.4
7.4	5335.32	1221.08	9568.11	438.92	393.3681	4119.8	1219.2	7275.8	411.7	305.4
7.5	5339.94	1221.65	9151.08	437.39	385.6325	4094.8	1219.5	7015.1	410.1	299.5
7.6	5338.68	1222.21	8748.44	435.83	377.9228	4068.1	1219.7	6768.1	408.5	293.7
7.7	5332.27	1222.75	8363.09	434.27	370.244	4039.8	1219.9	6534.3	406.9	288.1
7.8	5321.04	1223.26	7998.24	432.72	363.0505	4010.1	1220.1	6313.3	405.4	282.8

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
7.9	5303.07	1223.73	7652.23	431.15	355.3909	3979.5	1220.3	6103.5	403.9	277.5
8.0	5280.96	1224.18	7327.65	429.60	348.3742	3949.0	1220.4	5902.4	402.4	272.5
8.1	5255.83	1224.61	7021.56	428.07	341.5477	3919.4	1220.6	5705.6	401.0	267.6
8.2	5222.98	1225.02	6721.74	426.45	334.4929	3888.6	1220.8	5505.3	399.5	262.7
8.3	5178.24	1225.42	6421.44	424.64	326.976	3830.0	1220.8	5307.4	397.5	256.6
8.4	5121.44	1225.79	6125.63	422.63	318.8619	3733.0	1220.5	5167.8	394.9	249.3
8.5	5056.17	1226.14	5837.72	420.50	310.7606	3634.5	1220.1	5061.3	392.4	243.5
8.6	4982.49	1226.47	5555.02	418.23	302.328	3564.0	1220.0	4863.4	390.1	237.0
8.7	4898.50	1226.75	5286.03	415.81	293.5971	3523.9	1220.5	4527.7	387.7	229.0
8.8	4808.09	1226.93	5044.59	413.34	285.3314	3502.3	1221.3	4096.3	385.3	219.9
8.9	4711.35	1227.00	4833.97	410.86	277.262	3479.2	1222.3	3639.8	382.7	210.2
9.0	4606.88	1226.95	4657.63	408.31	269.5202	3436.9	1223.2	3223.6	379.9	200.3
9.1	4500.25	1226.80	4515.59	405.81	262.4702	3367.1	1223.8	2891.7	376.8	190.9
9.2	4393.63	1226.56	4395.57	403.35	255.7832	3271.4	1223.9	2665.5	373.5	182.4
9.3	4285.60	1226.25	4292.05	400.89	249.39	3159.3	1223.5	2537.1	370.1	175.4
9.4	4172.87	1225.85	4206.82	398.35	243.1775	3043.6	1222.8	2464.3	366.8	169.2
9.5	4056.84	1225.37	4138.37	395.77	236.9903	2935.8	1222.0	2423.7	363.8	164.0
9.6	3947.57	1224.86	4087.16	393.33	231.5702	2840.2	1221.2	2389.4	361.1	159.6
9.7	3835.90	1224.30	4041.69	390.82	226.4181	2761.6	1220.7	2326.7	358.6	154.9
9.8	3723.65	1223.79	3970.26	388.15	220.1975	2702.5	1220.5	2239.8	356.6	151.0

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
9.9	3637.49	1223.53	3852.26	385.81	214.6207	2655.9	1220.6	2113.9	354.7	146.8
10.0	3574.11	1223.47	3707.97	383.83	209.3918	2612.7	1220.9	1954.7	352.7	141.6
10.1	3516.03	1223.39	3588.09	382.03	204.7022	2568.8	1221.1	1814.3	350.7	137.2
10.2	3453.19	1223.16	3511.79	380.28	200.9402	2529.7	1221.5	1663.8	348.9	132.8
10.3	3387.37	1222.85	3449.77	378.51	197.0519	2502.7	1222.4	1463.3	347.3	127.5
10.4	3332.71	1222.68	3368.08	376.89	193.3959	2478.7	1223.5	1269.5	345.8	122.5
10.5	3291.35	1222.70	3256.39	375.45	189.7945	2451.0	1224.3	1115.5	344.4	118.4
10.6	3252.54	1222.80	3126.88	373.98	185.8833	2433.4	1225.5	959.8	343.3	114.4
10.7	3209.24	1222.88	2997.81	372.40	181.8303	2427.7	1227.2	776.2	342.7	110.4
10.8	3159.90	1222.89	2878.73	370.69	177.7135	2414.3	1229.0	598.8	342.1	105.9
10.9	3102.83	1222.81	2767.53	368.80	173.5954	2375.7	1229.9	481.5	340.7	101.7
11.0	3022.52	1222.51	2652.96	366.29	168.4726	2316.7	1229.9	432.5	338.6	98.3
11.1	2921.69	1222.01	2534.35	363.17	162.1219	2258.8	1229.5	408.8	336.6	95.6
11.2	2841.36	1221.68	2419.12	360.53	156.5801	2215.6	1229.5	367.6	335.1	93.0
11.3	2784.73	1221.45	2336.24	358.61	153.2978	2187.5	1230.1	299.6	334.1	90.4
11.4	2721.38	1221.00	2289.86	356.65	150.1807	2167.0	1231.1	219.2	333.3	87.8
11.5	2647.53	1220.47	2225.48	354.32	146.3128	2139.3	1231.8	148.1	332.4	85.3
11.6	2571.92	1219.92	2152.39	351.83	141.5976	2029.6	1226.9	103.5	328.2	82.5
11.7	2488.89	1219.16	2103.44	349.18	138.5105	1909.2	1219.9	86.3	322.5	89.6
11.8	2367.60	1217.94	2038.88	345.28	132.5417	1857.9	1217.9	82.1	320.5	88.9

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
11.9	2211.88	1216.15	1985.77	340.13	125.396	1811.1	1216.6	74.3	318.8	88.0
12.0	2080.26	1214.41	1975.41	335.77	120.0252	1755.1	1215.1	62.1	316.7	86.8
12.1	1976.69	1212.96	1984.45	332.23	116.7781	1687.3	1213.3	52.1	314.2	85.5
12.2	1861.60	1211.18	2028.49	328.28	112.3925	1621.1	1211.6	45.5	311.7	84.3
12.3	1741.18	1209.23	2069.41	324.04	108.2196	1572.0	1210.3	41.4	309.9	83.4
12.4	1656.14	1207.86	2074.89	320.78	103.8234	1542.5	1209.5	39.3	308.9	83.0
12.5	1638.77	1207.62	2064.24	319.99	104.8238	1522.9	1209.0	39.2	308.2	82.7
12.6	1615.17	1207.37	2011.97	318.74	101.6428	1501.4	1208.4	43.4	307.4	82.4
12.7	1570.89	1206.86	1922.47	316.35	98.20489	1473.8	1207.6	46.0	306.5	82.1
12.8	1552.09	1206.91	1808.22	314.80	96.26216	1432.9	1206.5	41.1	305.1	81.5
12.9	1513.04	1206.70	1663.76	312.22	91.32984	1391.3	1205.4	34.5	303.6	80.6
13.0	1441.60	1205.89	1529.09	308.12	86.44714	1370.8	1204.9	29.9	302.8	80.4
13.1	1359.13	1204.64	1441.25	303.62	81.8531	1341.3	1204.2	27.2	301.8	80.1
13.2	1285.69	1202.69	1399.98	300.88	81.00603	1261.1	1202.2	24.5	299.1	78.9
13.3	1228.48	1200.84	1361.43	299.37	81.01533	1169.0	1201.0	21.8	296.1	77.8
13.4	1194.66	1200.05	1321.72	297.96	80.41002	1112.3	1201.4	21.8	294.3	77.3
13.5	1163.71	1199.33	1295.32	296.58	79.40754	1078.9	1201.6	26.5	293.4	76.9
13.6	1120.23	1198.26	1262.64	294.55	77.6799	1043.2	1201.0	31.8	292.3	77.1
13.7	1082.17	1197.28	1236.92	293.01	77.24097	985.0	1200.0	32.5	290.7	76.3
13.8	1050.36	1196.44	1226.41	292.06	76.99243	925.1	1199.6	32.2	289.0	75.9

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
13.9	1020.71	1195.68	1219.63	291.20	76.7229	886.0	1199.2	39.4	287.9	75.7
14.0	972.68	1194.51	1198.88	289.84	76.36981	866.2	1198.3	55.0	287.5	75.6
14.1	900.88	1192.79	1158.71	287.89	75.62348	862.1	1197.5	70.2	287.4	75.7
14.2	827.53	1191.10	1109.10	286.04	75.25019	857.7	1197.0	76.0	287.3	75.7
14.3	771.08	1189.85	1064.41	284.73	74.94771	825.2	1196.5	70.2	286.5	75.5
14.4	738.42	1189.16	1044.59	284.05	74.85709	764.6	1195.9	62.2	285.0	75.0
14.5	722.98	1188.85	1059.36	283.76	74.9034	700.9	1195.2	61.0	283.5	74.6
14.6	701.42	1188.44	1056.75	283.32	74.7923	638.2	1194.4	63.0	282.2	74.3
14.7	655.77	1187.63	961.10	282.40	74.49541	567.0	1193.5	62.7	281.0	74.4
14.8	585.34	1186.84	825.49	281.11	74.0854	483.4	1192.9	58.9	279.8	73.6
14.9	506.65	1186.41	727.80	279.85	73.87328	366.5	1192.3	49.7	278.4	73.4
15.0	445.48	1186.14	661.92	279.03	73.8341	210.5	1192.0	33.0	277.2	73.6
15.1	411.78	1185.81	619.64	278.64	73.87054	64.4	1192.0	12.5	276.6	73.5
15.2	385.86	1185.49	592.75	278.37	73.83266	1.1	1190.4	1.0	276.2	73.6
15.3	349.27	1185.30	554.67	278.03	73.74274	0.0	100.0	0.0	10.0	73.6
15.4	319.59	1185.20	507.41	277.77	73.76365	0.0	100.0	0.0	10.0	73.6
15.5	325.76	1185.22	498.53	277.98	73.77338	0.0	100.0	0.0	10.0	73.6
15.6	369.42	1184.78	575.30	278.45	74.58835	0.0	100.0	0.0	10.0	73.5
15.7	346.74	1184.61	584.43	278.21	73.66819	0.0	100.0	0.0	10.0	73.5
15.8	262.52	1184.94	466.55	277.51	73.63993	0.0	100.0	0.0	10.0	73.4

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
15.9	218.42	1184.87	361.49	277.11	73.67149	0.0	100.0	0.0	10.0	73.3
16.0	222.61	1184.76	320.17	277.10	73.7808	0.0	100.0	0.0	10.0	73.3
16.1	256.26	1184.43	361.74	277.35	73.88752	0.0	100.0	0.0	10.0	73.5
16.2	314.87	1184.32	484.15	278.05	74.00542	0.0	100.0	0.0	10.0	73.5
16.3	399.70	1184.46	651.48	278.87	74.611	0.0	100.0	0.0	10.0	73.6
16.4	424.88	1184.86	697.94	278.89	73.8687	0.0	100.0	0.0	10.0	73.6
16.5	386.37	1185.31	628.68	278.39	73.86523	0.0	100.0	0.0	10.0	73.6
16.6	346.12	1185.35	566.91	278.02	73.71196	0.0	100.0	0.0	10.0	73.5
16.7	322.87	1185.29	517.31	277.81	73.76705	0.0	100.0	0.0	10.0	73.1
16.8	333.86	1185.05	522.15	277.92	73.94365	25.1	1184.8	0.1	275.9	73.8
16.9	347.65	1184.83	558.07	278.03	73.91508	35.5	1184.8	0.4	275.3	73.6
17.0	345.70	1184.89	568.38	277.99	73.85989	10.5	1185.0	0.3	275.0	73.5
17.1	350.61	1185.03	570.27	278.08	73.87688	0.0	100.0	0.0	10.0	73.6
17.2	379.62	1184.96	607.60	278.44	74.09661	0.0	100.0	0.0	10.0	73.8
17.3	404.80	1184.94	647.60	278.66	74.03583	0.0	100.0	0.0	10.0	73.7
17.4	435.72	1185.41	687.07	279.23	74.02745	0.0	100.0	0.0	10.0	73.7
17.5	598.94	1187.92	924.39	282.82	75.58422	18.0	1184.9	0.0	300.0	73.7
17.6	720.00	1188.90	1114.95	284.07	74.80801	96.3	1186.4	1.0	277.4	73.9
17.7	680.45	1188.07	1081.59	282.91	74.60171	83.9	1186.8	1.1	276.9	73.4
17.8	651.61	1187.52	1065.14	282.37	74.85718	52.1	1187.6	0.5	274.3	73.8

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
17.9	633.42	1187.19	1015.64	282.03	74.48551	59.0	1187.8	0.6	276.1	73.5
18.0	607.27	1186.78	915.49	281.51	74.38813	12.5	1189.0	0.2	282.2	73.6
18.1	587.60	1186.59	852.64	281.15	74.21064	0.0	100.0	0.0	10.0	73.7
18.2	553.74	1186.32	815.45	280.62	74.19325	0.3	1184.5	0.0	10.0	73.8
18.3	478.24	1186.12	732.12	279.57	73.75981	0.4	1183.7	0.0	10.0	73.6
18.4	429.67	1186.05	664.12	278.92	73.93896	2.3	1184.7	0.0	100.0	73.8
18.5	438.00	1185.61	678.40	279.04	74.11103	2.3	1184.8	0.0	100.0	73.2
18.6	457.94	1185.43	719.11	279.32	74.05242	0.0	100.0	0.0	10.0	71.4
18.7	482.49	1185.54	754.55	279.68	74.06602	0.0	100.0	0.0	10.0	71.3
18.8	504.59	1185.59	780.58	279.95	74.33266	0.0	100.0	0.0	10.0	72.4
18.9	503.49	1185.66	768.14	279.87	74.15369	49.5	1186.1	0.0	300.0	74.0
19.0	476.57	1185.79	724.02	279.47	73.98391	135.2	1189.1	0.1	280.0	73.8
19.1	466.39	1185.81	711.54	279.38	74.10407	161.5	1193.2	0.2	273.5	73.7
19.2	495.61	1185.75	756.43	279.88	74.2496	77.7	1195.9	0.1	280.0	73.5
19.3	525.03	1185.73	791.41	280.25	74.28757	1.9	1197.3	0.0	500.0	73.7
19.4	523.68	1185.85	767.50	280.16	74.18356	0.0	100.0	0.0	10.0	73.6
19.5	522.86	1186.05	749.64	280.17	74.31515	3.3	1186.5	0.0	10.0	73.8
19.6	533.74	1185.99	768.04	280.33	74.43989	3.3	1186.5	0.0	10.0	73.6
19.7	502.24	1185.92	730.49	279.85	73.89213	0.0	100.0	0.0	10.0	73.7
19.8	508.56	1186.34	734.64	280.20	74.19047	11.4	1187.3	0.0	10.0	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
19.9	616.57	1187.48	917.68	282.36	74.8431	64.5	1192.6	0.0	200.0	73.8
20.0	775.01	1190.10	1383.88	285.64	76.28355	28.5	1195.3	0.0	200.0	73.6
20.5	768.54	1189.90	1293.07	285.24	75.66263	6.5	1198.0	0.0	10.0	72.1
21.0	737.11	1189.18	1175.02	284.21	74.90845	70.9	1196.7	0.0	276.0	69.2
21.5	735.01	1189.12	1277.36	284.25	75.24608	80.3	1196.4	0.0	280.0	73.5
22.0	720.92	1188.88	1432.47	284.08	75.57133	9.4	1194.6	0.0	100.0	73.7
22.5	726.28	1189.06	1447.13	284.21	75.18275	61.9	1195.8	0.0	10.0	72.5
23.0	773.58	1189.98	1180.22	284.93	75.54347	73.5	1197.0	0.0	10.0	73.7
23.5	743.87	1189.42	909.58	284.23	74.70858	12.2	1202.9	0.0	10.0	73.7
24.0	653.24	1187.68	951.56	282.29	74.38791	40.8	1196.2	0.0	10.0	73.4
24.5	622.69	1187.07	1153.75	281.98	74.78619	57.5	1198.2	0.0	10.0	73.7
25.0	591.01	1186.75	1165.02	281.47	74.57095	26.6	1201.6	0.0	10.0	73.7
25.5	517.97	1185.79	1246.63	280.26	74.32353	11.5	1197.8	0.0	10.0	73.7
26.0	470.72	1184.94	1528.44	279.77	74.51925	29.9	1203.0	0.0	10.0	73.7
26.5	438.75	1184.57	1620.52	279.41	74.44828	37.2	1204.4	0.0	10.0	73.7
27.0	395.58	1184.51	1391.44	278.83	74.1436	15.0	1205.2	0.0	10.0	73.6
27.5	354.94	1184.46	1206.39	278.25	74.01461	11.1	1205.5	0.0	10.0	73.7
28.0	323.82	1184.30	1180.52	277.94	73.94646	12.2	1205.8	0.0	10.0	73.7
28.5	292.90	1184.23	1080.88	277.65	73.87787	7.0	1205.2	0.0	10.0	73.7
29.0	264.78	1184.22	925.93	277.40	73.82074	0.4	1197.2	0.0	10.0	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
29.5	245.07	1184.19	783.58	277.24	73.79306	0.7	1191.1	0.0	10.0	73.7
30.0	229.02	1184.14	675.89	277.13	73.76751	2.4	1191.5	0.0	10.0	73.7
30.5	213.60	1184.07	602.43	277.03	73.76419	2.1	1191.2	0.0	10.0	73.7
31.0	198.66	1183.96	559.76	276.95	73.75786	0.4	1189.1	0.0	10.0	73.7
31.5	186.45	1183.85	523.38	276.88	73.75477	0.7	1186.9	0.0	10.0	73.7
32.0	177.71	1183.74	519.98	276.84	73.75468	11.1	1197.0	0.0	10.0	73.7
32.5	169.39	1183.59	570.67	276.81	73.75427	28.1	1203.4	0.0	10.0	73.7
33.0	159.81	1183.43	642.99	276.77	73.74869	32.7	1208.1	0.0	10.0	73.7
33.5	151.10	1183.28	707.65	276.75	73.77543	28.2	1206.7	0.0	10.0	73.7
34.0	146.42	1183.16	789.63	276.74	73.76569	13.4	1203.3	0.0	10.0	73.6
34.5	144.36	1183.05	1033.98	276.76	73.78262	0.1	1206.4	0.0	10.0	72.9
35.0	141.69	1182.90	1571.86	276.82	73.81935	6.3	1186.6	0.0	10.0	71.2
35.5	137.42	1182.69	2171.55	276.87	73.89374	41.0	1191.9	0.0	200.0	73.9
36.0	135.44	1182.48	2562.42	276.95	73.96019	53.1	1192.8	0.0	200.0	73.8
36.5	134.63	1182.34	2833.52	277.00	74.03759	24.5	1193.0	0.0	10.0	73.6
37.0	131.47	1182.28	2925.39	276.99	74.02323	27.0	1195.9	0.0	10.0	73.5
37.5	127.70	1182.29	2813.08	276.94	73.99922	22.8	1197.0	0.0	10.0	73.7
38.0	123.37	1182.32	2700.79	276.88	73.9596	2.6	1197.9	0.0	10.0	73.7
38.5	118.40	1182.32	2638.13	276.83	73.92158	11.2	1193.1	0.0	10.0	73.8
39.0	114.06	1182.31	2613.86	276.80	73.92563	16.2	1193.1	0.0	10.0	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
39.5	108.28	1182.30	2554.13	276.70	73.88004	7.8	1192.9	0.0	10.0	73.7
40.0	100.17	1182.31	2396.29	276.57	73.70213	3.1	1192.8	0.0	10.0	73.7
40.5	92.79	1182.32	2230.38	276.51	73.70171	1.8	1191.0	0.0	10.0	73.7
41.0	87.72	1182.29	2155.10	276.49	73.70168	7.2	1195.5	0.0	10.0	73.7
41.5	84.54	1182.24	2182.41	276.49	73.70219	13.5	1199.4	0.0	10.0	73.7
42.0	82.74	1182.21	2261.05	276.48	73.70177	14.1	1203.9	0.0	10.0	73.7
42.5	83.64	1182.15	2397.74	276.49	73.70461	15.0	1206.8	0.0	10.0	73.7
43.0	88.05	1181.99	2703.09	276.51	73.70767	16.8	1208.7	0.0	10.0	73.7
43.5	92.99	1181.86	3081.04	276.53	73.71006	18.3	1210.4	0.0	10.0	73.7
44.0	97.06	1181.81	3345.76	276.55	73.713	19.8	1211.8	0.0	10.0	73.7
44.5	100.77	1181.80	3464.22	276.57	73.71436	20.3	1213.0	0.0	10.0	73.7
45.0	102.87	1181.82	3440.50	276.57	73.71311	20.2	1214.0	0.0	10.0	73.7
45.5	102.00	1181.87	3331.83	276.56	73.70994	20.2	1214.8	0.0	10.0	73.7
46.0	98.34	1181.93	3218.84	276.55	73.70684	21.2	1215.5	0.0	10.0	73.7
46.5	94.03	1181.96	3146.64	276.53	73.70648	23.9	1216.1	0.0	10.0	73.7
47.0	92.13	1181.94	3165.32	276.53	73.70738	27.5	1216.5	0.0	10.0	73.7
47.5	94.10	1181.87	3291.14	276.54	73.71215	29.7	1216.9	0.0	10.0	73.7
48.0	96.45	1181.83	3429.04	276.55	73.71077	26.7	1217.1	0.0	10.0	73.7
48.5	94.99	1181.86	3441.09	276.54	73.7085	25.4	1217.3	0.0	10.0	73.7
49.0	90.01	1181.96	3220.39	276.52	73.70547	25.6	1217.5	0.0	10.0	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
49.5	79.93	1182.12	2782.82	276.49	73.69555	13.3	1217.6	0.0	10.0	73.7
50.0	65.72	1182.28	2336.62	276.46	73.69418	1.5	1217.7	0.0	10.0	73.7
50.5	51.69	1182.43	1936.11	276.44	73.69373	0.0	100.0	0.0	10.0	73.7
51.0	39.33	1182.59	1511.38	276.42	73.69345	0.0	100.0	0.0	10.0	73.7
51.5	31.34	1182.63	1108.77	276.42	73.69723	0.0	100.0	0.0	10.0	73.6
52.0	26.53	1182.53	784.76	276.41	73.6967	0.0	100.0	0.0	10.0	73.6
52.5	21.48	1182.40	524.23	276.40	73.70061	4.4	1188.1	0.0	10.0	73.7
53.0	17.17	1182.48	320.55	276.40	73.69612	4.7	1188.0	0.0	10.0	73.7
53.5	14.90	1182.73	196.09	276.40	73.69675	9.1	1191.8	0.0	10.0	73.7
54.0	14.21	1182.97	107.19	276.41	73.69689	31.5	1198.0	0.0	10.0	73.7
54.5	14.48	1183.19	44.46	276.42	73.6972	54.1	1204.5	0.0	10.0	73.7
55.0	16.08	1183.41	16.26	276.33	73.69724	62.3	1209.8	0.0	10.0	73.7
55.5	22.12	1183.51	19.64	276.40	73.69837	54.2	1213.2	0.0	10.0	73.7
56.0	30.62	1183.12	130.51	276.41	73.69796	41.6	1215.0	0.0	10.0	73.7
56.5	34.60	1182.53	378.40	276.41	73.69784	25.4	1215.8	0.0	10.0	73.7
57.0	33.66	1182.14	581.39	276.41	73.69814	9.4	1216.4	0.0	10.0	73.7
57.5	32.50	1181.98	662.14	276.41	73.6994	8.6	1217.1	0.0	10.0	73.7
58.0	31.96	1181.85	730.39	276.41	73.69713	13.9	1217.5	0.0	10.0	73.7
58.5	29.60	1181.70	720.18	276.41	73.69666	16.6	1217.9	0.0	10.0	73.7
59.0	23.23	1181.54	549.73	276.40	73.69803	18.5	1218.2	0.0	10.0	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)
59.5	16.54	1181.55	318.06	276.40	73.6974	15.3	1218.4	0.0	10.0	73.7
60.0	14.63	1182.30	100.15	276.40	73.69705	10.3	1218.8	0.0	10.0	73.7
61.0	14.80	1182.92	27.07	276.41	73.69739	14.4	1219.2	0.0	10.0	73.7
62.0	14.93	1183.46	3.28	276.49	73.69757	26.0	1219.2	0.0	10.0	73.7
63.0	15.01	1183.93	0.42	276.52	73.69798	29.6	1219.0	0.0	10.0	73.7
64.0	14.08	1184.38	0.07	270.27	73.69649	23.7	1218.9	0.0	10.0	73.7
65.0	11.02	1184.53	0.06	277.31	73.6967	21.6	1219.0	0.0	10.0	73.7
66.0	7.83	1184.36	0.05	284.31	73.69694	22.3	1219.1	0.0	10.0	73.7
67.0	8.98	1184.83	0.03	264.15	73.6979	22.8	1219.2	0.0	10.0	73.7
68.0	13.77	1185.80	0.02	258.06	73.69794	24.3	1219.2	0.0	10.0	73.7
69.0	19.57	1185.76	0.82	276.83	73.6981	26.4	1219.1	0.0	10.0	73.7
70.0	22.80	1184.37	36.64	276.41	73.69612	28.4	1219.1	0.0	10.0	73.7
71.0	21.97	1183.10	150.45	276.40	73.69683	29.5	1219.0	0.0	10.0	73.7
71.68426	20.81	1182.71	265.61	276.40	73.69853	29.8	1219.0	0.0	10.0	73.7

Table 6-30. RELAP5 Long-Term Mass and Energy Release Data

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
0.0	2.61	1190.80	45034.67	560.04	2294.67	622.72	1195.07	24082.41	538.81	2296.60	0.00
0.5	1.35	1190.73	45002.73	561.03	1141.73	701.17	1195.39	23503.53	536.92	946.56	0.00
1.0	1.97	1189.03	43883.38	561.31	1112.71	821.86	1195.63	22712.44	535.16	946.49	0.00
1.5	14.86	1188.96	41138.78	560.56	1113.47	940.61	1195.69	22178.90	535.45	952.13	0.00
2.0	50.78	1188.48	37445.88	561.23	1121.34	1048.83	1196.19	20838.21	536.12	928.40	0.00
2.5	131.14	1188.16	33748.12	562.75	1143.21	1085.61	1196.58	19040.70	538.38	895.71	0.00
3.0	295.10	1188.29	31133.46	563.51	1137.55	1165.81	1196.70	17346.79	538.67	874.28	0.00
3.5	499.44	1188.67	29332.74	562.72	1127.36	1339.95	1197.43	15457.64	534.17	837.95	0.00
4.0	702.87	1189.19	27711.68	561.28	1120.62	1789.77	1201.47	13673.54	517.80	797.22	0.00
4.5	973.92	1190.10	25969.13	558.99	1104.83	2328.37	1205.61	11416.29	495.80	685.83	0.00
5.0	1308.56	1191.25	23634.97	556.36	1072.47	2574.99	1207.92	9250.46	482.53	620.76	0.00
5.5	1580.32	1191.83	20906.55	556.08	1032.60	2641.20	1209.04	8241.40	475.89	590.78	0.00
6.0	1802.31	1192.39	18632.19	555.19	1003.97	2628.75	1209.53	7834.36	472.11	577.39	0.00
6.5	2004.58	1193.41	17055.64	550.93	979.81	2676.06	1210.49	7089.30	467.57	557.19	7.51
7.0	2142.47	1194.57	15821.38	545.99	951.27	2816.47	1212.28	5780.78	460.58	509.76	15.21
7.5	2201.87	1195.71	14909.52	540.90	924.81	2904.60	1213.70	4810.09	454.21	479.95	23.09
8.0	2201.25	1196.85	14343.35	535.83	901.26	2906.34	1214.35	4396.83	450.43	464.32	31.11
8.5	2432.66	1200.19	14060.63	524.56	844.18	2868.05	1214.66	4167.69	447.20	451.84	39.38
9.0	2754.27	1203.35	13282.68	512.71	792.59	2818.77	1214.99	3900.91	443.34	435.95	47.90

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
9.5	2871.87	1204.91	12016.15	506.08	753.66	2771.95	1215.55	3502.50	438.36	413.89	56.67
10.0	2910.01	1206.30	10930.33	499.17	715.22	2732.74	1216.38	2996.00	432.48	387.73	65.73
10.5	2893.94	1207.56	9959.00	491.68	672.61	2681.48	1217.16	2516.27	426.21	362.25	75.14
11.0	2866.07	1208.79	9014.42	483.96	632.15	2594.28	1217.52	2178.14	419.90	338.86	84.77
11.5	2839.38	1209.99	8060.30	475.90	588.69	2485.06	1217.59	1934.33	413.70	318.78	94.71
12.0	2659.09	1210.53	7615.43	466.52	551.69	2376.03	1217.67	1697.65	407.37	296.84	104.83
12.5	2069.41	1209.75	8732.67	450.07	490.74	2281.22	1217.91	1430.96	401.09	277.06	115.14
13.0	1475.93	1208.24	10159.54	433.27	422.92	2207.90	1218.48	1111.64	394.91	255.52	125.01
13.5	1223.13	1207.47	10460.70	418.41	371.54	2140.84	1219.30	783.30	388.66	234.91	134.01
14.0	1074.33	1206.66	10258.17	404.44	322.90	2054.75	1220.00	502.83	382.03	213.44	143.03
14.5	959.22	1205.72	9831.20	392.62	285.56	1945.08	1220.32	301.89	374.90	194.07	152.06
15.0	825.84	1204.48	9494.08	382.34	261.44	1814.99	1220.50	154.67	368.23	172.93	161.10
15.5	687.19	1202.93	9221.88	372.02	235.30	1648.52	1219.51	91.58	356.60	155.28	170.15
16.0	582.34	1201.44	8886.18	361.07	214.06	1471.92	1217.77	73.06	349.40	136.72	179.21
16.5	522.33	1200.11	8517.77	347.47	201.93	1310.72	1219.71	25.72	342.61	118.47	188.27
17.0	462.30	1198.49	8201.79	333.03	181.54	1140.02	1232.42	2.62	335.89	101.48	197.34
17.5	388.14	1196.14	8086.54	320.25	154.66	982.25	1247.77	0.09	319.35	88.88	206.40
18.0	334.42	1193.50	8097.22	308.14	132.07	856.27	1250.00	0.11	310.19	79.00	215.45
18.5	300.17	1190.66	8172.03	296.34	111.48	745.49	1246.15	0.13	303.05	75.32	224.50
19.0	249.01	1187.99	7975.41	285.43	93.94	648.70	1239.56	0.21	294.81	72.42	233.54

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
19.5	171.69	1185.35	7496.61	273.86	88.14	572.76	1221.23	1.02	285.27	70.02	242.58
20.0	125.51	1181.92	7477.24	258.83	68.46	510.71	1203.59	5.30	281.20	68.44	251.61
20.5	85.76	1178.12	7206.32	234.47	58.72	461.12	1198.73	16.35	279.10	67.69	251.64
21.0	41.52	1172.48	6823.43	209.85	43.15	423.82	1195.20	34.96	277.24	67.20	251.67
21.5	24.30	1169.09	6869.18	199.55	37.14	393.55	1190.35	56.72	275.83	66.92	251.68
22.0	16.74	1167.35	6706.53	193.57	35.06	368.52	1186.88	77.95	274.67	66.61	251.69
22.5	13.23	1166.81	6332.16	191.06	33.87	343.15	1185.05	100.84	273.64	66.33	251.70
23.0	11.13	1166.81	5975.03	190.89	35.99	318.22	1184.14	118.38	272.77	66.03	251.72
23.5	8.81	1166.62	5793.32	188.98	33.97	297.75	1183.51	129.30	272.05	65.84	251.73
24.0	6.98	1166.70	5463.94	188.53	33.11	278.42	1182.96	137.99	271.41	65.63	251.74
24.5	6.18	1167.51	5209.50	188.10	33.87	260.48	1182.47	137.95	270.81	65.37	251.75
25.0	8.81	1172.33	5088.87	192.17	34.44	239.74	1182.10	129.04	270.16	65.16	251.77
25.5	13.66	1177.36	5061.48	191.39	49.33	221.36	1181.90	121.85	269.57	64.91	251.77
26.0	13.92	1179.01	4819.75	183.61	49.14	210.18	1182.30	112.02	269.24	64.80	251.79
26.5	12.38	1178.14	4099.11	191.56	55.62	183.79	1184.18	87.49	268.66	64.46	251.81
27.0	9.08	1178.57	3385.51	196.88	54.40	152.31	1187.39	61.24	267.95	64.29	251.80
27.5	4.62	1182.12	2978.50	191.22	56.41	118.94	1190.83	41.35	267.47	64.12	251.83
28.0	1.67	1186.52	1546.48	190.48	62.83	56.84	1193.16	20.05	267.00	63.94	251.86
28.5	0.00	1173.07	97.41	190.70	61.92	8.18	1191.67	4.20	266.56	63.85	251.86
29.0	0.00	1169.54	0.00	261.52	55.11	0.00	1174.65	0.00	261.50	63.81	251.87

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
29.5	0.00	1168.90	0.00	261.67	53.33	0.00	1174.36	0.00	261.63	63.35	251.87
30.0	0.00	1169.17	0.00	261.47	54.14	0.00	1174.26	0.00	261.68	63.14	251.87
31	0.00	1167.33	0.00	262.99	49.67	0.00	1173.95	0.00	261.82	62.58	251.89
32	0.00	1168.81	0.00	261.39	52.98	14.15	1207.90	0.04	269.33	62.69	251.87
33	0.00	1172.52	0.00	262.87	60.22	14.24	1207.93	0.04	267.47	63.33	251.85
34	0.00	1169.02	0.00	260.98	53.42	9.28	1202.56	0.02	260.61	62.61	251.87
35	0.00	1170.08	0.00	260.67	55.62	11.91	1199.71	0.02	264.86	62.76	251.86
36	12.25	1202.55	120.64	226.64	56.40	31.16	1216.23	0.04	265.91	62.79	251.86
37	12.81	1201.81	133.73	225.33	62.25	31.38	1219.40	0.05	265.31	62.82	251.86
38	114.71	1187.73	259.64	265.32	63.96	70.37	1251.25	0.03	265.62	63.18	251.82
39	287.46	1190.16	392.15	268.51	64.44	148.11	1233.85	2.85	266.58	62.71	251.80
40	379.29	1189.84	362.22	270.53	64.37	177.09	1205.36	16.57	266.97	62.71	251.80
41	391.99	1187.18	375.78	270.82	65.50	184.09	1191.36	34.19	266.69	62.76	251.78
42	357.15	1185.55	421.36	270.33	63.22	170.81	1187.04	46.01	266.36	62.37	251.81
43	371.22	1186.09	475.78	270.67	67.23	177.56	1184.23	62.23	266.42	62.80	251.78
44	358.14	1185.62	373.60	269.60	63.36	168.68	1183.55	65.23	266.10	62.24	251.80
45	301.98	1183.54	317.79	267.52	62.84	140.01	1184.02	64.73	265.36	62.03	251.81
46	292.95	1183.15	305.97	267.16	62.79	130.70	1182.49	81.70	265.12	61.95	251.81
47	298.85	1183.16	315.79	267.17	62.58	130.47	1181.63	93.87	265.01	61.80	251.82
48	302.29	1183.22	337.72	267.17	62.67	131.96	1181.30	98.58	264.91	61.71	251.81

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
49	304.79	1183.28	336.95	267.10	62.59	132.09	1180.90	105.03	264.78	61.60	251.81
50	299.65	1183.10	328.89	266.84	62.38	128.95	1180.52	113.38	264.61	61.47	251.81
51	282.29	1182.63	313.69	266.34	62.12	122.57	1180.41	117.85	264.39	61.34	251.82
52	260.99	1182.20	300.55	265.76	61.72	114.38	1180.57	117.71	264.14	61.17	251.82
53	249.94	1181.97	302.22	265.43	61.58	109.41	1180.67	117.90	263.94	61.04	251.82
54	245.26	1181.81	306.17	265.23	61.48	108.17	1180.58	119.63	263.79	60.92	251.82
55	232.70	1181.79	292.61	264.89	61.24	104.07	1180.70	117.76	263.60	60.78	251.83
56	218.64	1181.80	281.43	264.50	60.99	98.82	1180.94	114.52	263.40	60.63	251.83
57	212.67	1181.80	277.39	264.28	60.85	96.38	1181.04	113.40	263.23	60.50	251.83
58	205.27	1181.90	258.90	264.02	60.70	93.57	1181.17	111.40	263.06	60.37	251.83
59	205.83	1182.09	295.46	264.49	60.46	90.84	1181.39	109.86	262.91	60.23	251.83
60	241.80	1182.13	361.54	265.08	62.43	110.30	1180.18	132.93	263.20	60.43	251.82
61	242.62	1181.86	314.13	264.64	60.52	113.22	1180.08	130.16	263.16	60.12	251.83
62	216.16	1181.77	243.87	263.80	60.43	96.33	1181.28	102.44	262.73	60.06	251.83
63	211.13	1182.03	224.70	263.67	60.31	93.84	1181.45	100.33	262.66	60.01	251.83
64	196.74	1182.09	212.49	263.41	60.20	88.70	1181.63	101.00	262.57	59.96	251.84
65	188.06	1182.12	205.51	263.26	60.15	85.51	1181.76	102.27	262.50	59.93	251.84
66	184.70	1182.18	191.29	263.15	60.05	83.60	1181.90	101.57	262.45	59.89	251.84
67	176.40	1182.12	189.67	262.97	59.98	81.07	1182.14	98.32	262.38	59.85	251.84
68	205.52	1181.96	268.47	263.92	59.93	96.50	1181.12	115.51	262.77	59.82	251.84

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
69	228.28	1181.58	314.22	264.12	60.56	105.73	1180.77	114.93	262.83	59.86	251.82
70	211.39	1181.50	260.95	263.51	60.05	96.34	1181.79	87.90	262.43	59.76	251.84
71	205.62	1182.15	211.03	263.29	60.03	92.69	1182.19	83.58	262.34	59.74	251.83
72	195.59	1182.56	181.51	263.07	59.89	87.25	1182.01	91.87	262.25	59.69	251.84
73	186.06	1182.68	167.17	262.88	59.81	82.39	1181.86	101.60	262.17	59.66	251.84
74	182.09	1182.72	152.77	262.73	59.73	79.81	1181.80	106.64	262.12	59.62	251.84
75	174.34	1182.42	167.84	262.59	59.67	78.35	1181.84	107.38	262.07	59.59	251.84
76	167.76	1182.02	194.13	262.51	59.66	78.08	1181.88	106.55	262.03	59.55	251.84
77	171.14	1181.79	211.29	262.57	59.62	79.29	1181.86	105.66	262.00	59.52	251.84
78	180.39	1181.60	229.44	262.71	59.74	82.74	1181.66	106.10	262.00	59.51	251.84
79	186.18	1181.59	227.52	262.75	59.70	85.12	1181.56	105.29	261.98	59.47	251.84
80	187.40	1181.76	216.34	262.72	59.65	85.92	1181.56	103.65	261.95	59.44	251.84
81	189.20	1182.09	193.61	262.68	59.61	85.20	1181.72	99.97	261.91	59.39	251.84
82	189.21	1182.36	169.14	262.61	59.52	83.05	1182.06	93.54	261.84	59.36	251.84
83	182.44	1182.30	174.37	262.46	59.48	81.51	1182.24	90.08	261.79	59.32	251.84
84	173.12	1182.11	187.45	262.29	59.40	79.56	1182.26	91.10	261.73	59.28	251.84
85	166.15	1181.96	191.34	262.15	59.35	77.67	1182.18	95.13	261.68	59.25	251.84
86	160.21	1181.90	185.84	262.03	59.28	75.57	1182.12	99.01	261.62	59.21	251.84
87	154.33	1181.85	180.63	261.92	59.22	73.36	1182.13	101.85	261.57	59.17	251.84
88	150.02	1181.84	173.45	261.83	59.17	71.37	1182.12	104.41	261.51	59.14	251.84

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
89	146.81	1181.87	163.70	261.75	59.12	69.25	1182.01	106.84	261.46	59.10	251.84
90	145.08	1182.03	144.75	261.71	59.08	66.73	1181.81	108.90	261.40	59.06	251.84
91	142.31	1182.13	132.30	261.67	59.06	64.49	1181.63	110.74	261.37	59.05	251.85
92	140.24	1182.31	118.47	261.65	59.05	62.77	1181.49	112.28	261.34	59.03	251.85
93	138.59	1182.51	101.62	261.63	59.03	60.68	1181.37	111.96	261.31	59.02	251.85
94	135.67	1182.75	90.54	261.61	59.01	58.76	1181.30	109.76	261.28	59.00	251.85
95	132.34	1183.11	75.58	261.59	59.00	57.23	1181.30	105.54	261.26	58.99	251.85
96	128.05	1183.34	66.81	261.55	58.98	56.13	1181.38	99.03	261.24	58.97	251.85
97	124.92	1183.63	56.19	261.53	58.97	55.40	1181.51	91.22	261.22	58.96	251.85
98	121.64	1183.88	47.33	261.51	58.96	54.29	1181.62	83.38	261.20	58.95	251.85
99	117.13	1184.02	40.18	261.48	58.94	52.44	1181.65	77.13	261.17	58.93	251.85
100	111.09	1184.10	33.74	261.45	58.92	50.11	1181.58	73.41	261.14	58.92	251.85
101	104.19	1184.15	29.03	261.41	58.91	47.06	1181.40	72.24	261.12	58.90	251.85
102	97.68	1184.23	25.76	261.34	58.91	43.21	1181.17	71.12	261.09	58.89	251.85
103	92.03	1184.39	23.33	261.28	58.89	39.93	1180.96	69.33	261.06	58.87	251.85
104	87.56	1184.59	21.68	261.25	58.87	38.11	1180.82	68.30	261.04	58.86	251.85
105	85.72	1185.08	20.35	261.23	58.87	37.50	1180.80	66.37	261.02	58.85	251.85
106	84.95	1186.62	18.17	261.22	58.86	37.70	1180.95	61.67	261.02	58.84	251.85
107	84.60	1188.89	15.56	261.21	58.86	40.14	1181.38	54.67	261.02	58.83	251.85
108	86.92	1190.59	14.32	261.18	58.84	43.40	1181.91	49.81	261.02	58.84	251.85

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
109	85.56	1191.89	11.98	261.16	58.83	39.54	1181.95	42.35	261.00	58.81	251.85
110	79.56	1193.00	8.41	261.13	58.82	34.12	1181.74	33.81	260.96	58.80	251.85
111	75.29	1193.63	6.58	261.07	58.81	33.16	1181.58	34.06	260.94	58.79	251.85
112	73.24	1194.03	6.34	261.02	58.80	32.67	1181.17	41.18	260.92	58.78	251.85
113	73.47	1193.95	7.97	261.02	58.79	33.24	1180.87	49.57	260.91	58.77	251.85
114	74.47	1193.93	10.91	261.08	58.77	34.71	1180.96	51.47	260.91	58.76	251.85
115	75.20	1194.45	12.40	261.06	58.77	37.11	1181.63	43.45	260.92	58.76	251.85
116	76.21	1195.58	10.62	261.03	58.77	39.94	1183.13	29.36	260.93	58.75	251.85
117	77.94	1196.99	6.96	260.98	58.75	43.21	1185.50	16.82	260.93	58.75	251.85
118	76.80	1198.30	3.77	260.92	58.74	43.01	1186.48	12.18	260.92	58.73	251.85
119	73.04	1198.00	3.72	261.02	58.73	40.91	1185.19	16.21	260.90	58.72	251.85
120	71.80	1192.62	17.04	260.98	58.73	43.25	1181.99	53.40	260.88	58.71	251.85
125	76.74	1192.45	19.02	260.97	58.67	44.71	1181.31	66.34	260.85	58.68	251.85
130	80.32	1193.99	13.63	260.95	58.63	44.73	1183.14	49.67	260.81	58.63	251.85
135	77.98	1198.43	4.59	260.88	58.58	42.47	1189.86	15.96	260.75	58.58	251.85
140	106.76	1198.56	54.64	261.64	58.54	54.59	1188.32	19.19	260.86	58.53	251.85
145	141.38	1190.46	106.37	261.59	58.50	65.70	1182.93	53.92	260.85	58.49	251.85
150	151.29	1183.48	116.84	261.51	58.49	66.58	1181.41	74.15	260.80	58.49	251.85
155	159.11	1182.54	125.19	261.45	58.43	69.29	1181.15	83.06	260.75	58.44	251.85
160	163.67	1182.52	124.93	261.41	58.37	68.87	1180.80	90.80	260.70	58.38	251.85

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
165	163.65	1182.12	142.01	261.30	58.86	70.41	1180.88	85.43	260.66	58.48	251.84
170	156.93	1181.96	146.92	261.14	58.30	68.83	1180.92	83.45	260.57	58.29	251.85
175	149.54	1182.01	134.68	261.00	58.27	64.30	1180.75	88.06	260.48	58.25	251.85
180	146.79	1182.10	131.98	260.94	58.19	61.47	1180.38	95.10	260.41	58.19	251.85
185	136.31	1184.21	101.69	260.81	58.14	55.55	1180.44	83.27	260.32	58.14	251.85
190	118.19	1185.09	74.19	260.50	58.09	49.80	1181.02	58.11	260.19	58.08	251.85
195	93.44	1184.22	69.65	260.36	58.01	44.53	1183.00	28.88	260.13	58.01	251.85
200	61.38	1188.49	36.98	260.22	57.96	34.83	1183.95	9.20	259.98	57.95	251.85
205	34.94	1195.83	6.77	260.06	57.90	22.27	1182.35	6.50	259.91	57.90	251.86
210	18.66	1201.86	0.15	259.81	57.86	15.18	1181.60	4.62	259.81	57.86	251.86
215	12.87	1206.61	0.03	257.58	57.81	15.20	1183.23	3.73	259.77	57.81	251.86
220	12.25	1209.83	0.02	256.04	57.76	15.49	1184.96	1.68	259.71	57.76	251.86
225	13.75	1210.42	0.02	257.86	57.71	14.96	1203.17	0.89	259.70	57.71	251.86
230	34.98	1205.70	0.75	259.95	57.67	18.79	1249.57	0.02	260.50	57.67	251.86
235	58.49	1200.67	20.78	259.72	57.57	26.81	1245.36	0.59	259.53	57.61	251.85
240	63.22	1191.11	77.61	259.73	57.57	32.35	1205.38	4.95	259.54	57.57	251.86
245	59.61	1185.05	110.68	259.69	57.52	31.36	1188.44	5.09	259.53	57.53	251.86
250	58.98	1183.14	250.47	260.07	57.46	28.68	1195.90	1.86	259.42	57.48	251.86
255	76.45	1181.50	295.98	260.01	57.65	35.55	1190.11	8.87	259.38	57.44	251.85
260	85.21	1182.24	161.11	259.63	57.41	40.11	1183.19	32.03	259.32	57.38	251.85

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
265	70.56	1183.17	115.93	259.52	57.35	33.17	1180.38	48.45	259.27	57.36	251.86
270	58.17	1182.98	108.49	259.40	57.31	26.47	1179.67	33.27	259.21	57.29	251.86
275	46.24	1183.17	86.62	259.30	57.24	20.51	1180.49	11.18	259.15	57.24	251.86
280	26.43	1185.23	34.42	259.18	57.19	11.67	1181.14	2.33	259.08	57.19	251.86
285	16.46	1190.90	3.02	259.06	57.15	7.89	1193.57	0.28	259.04	57.14	251.86
290	15.98	1195.10	0.74	258.89	57.10	8.23	1221.46	0.01	259.42	57.09	251.86
295	17.43	1189.80	14.99	258.90	57.05	8.47	1240.39	0.00	253.86	57.04	251.86
300	16.37	1184.34	24.97	258.86	56.99	8.31	1241.14	0.00	253.81	57.00	251.86
305	14.46	1184.34	21.97	258.80	56.96	7.54	1247.83	0.00	253.77	56.96	251.86
310	17.52	1183.79	35.47	258.75	56.92	8.48	1251.49	0.00	253.72	56.92	251.86
315	19.05	1183.48	39.99	258.72	56.88	8.37	1249.76	0.00	253.68	56.88	251.86
320	14.62	1183.70	30.07	258.66	56.83	6.54	1245.51	0.00	253.61	56.83	251.86
325	9.47	1183.70	25.79	258.60	56.79	5.94	1242.48	0.00	253.57	56.79	251.86
330	7.57	1183.88	16.45	258.56	56.76	5.54	1246.80	0.00	253.52	56.75	251.86
335	7.09	1184.10	10.49	258.49	56.71	5.11	1255.87	0.00	253.47	56.71	251.86
340	14.81	1183.32	43.87	258.47	56.67	7.70	1258.51	0.00	253.43	56.67	251.86
345	20.13	1183.07	65.11	258.44	56.63	9.05	1239.76	0.01	253.38	56.62	251.86
350	23.28	1182.59	75.27	258.40	56.59	9.91	1196.69	0.34	258.35	56.58	251.86
355	30.57	1181.98	105.94	258.39	56.55	12.29	1181.00	2.02	258.25	56.54	251.86
360	36.96	1180.30	143.28	258.36	56.51	13.69	1179.20	7.16	258.22	56.50	251.86

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
365	41.06	1178.74	172.25	258.34	56.48	14.17	1178.68	15.04	258.18	56.46	251.86
370	40.77	1178.35	174.37	258.30	56.43	13.65	1178.45	22.60	258.13	56.42	251.86
375	38.97	1178.34	169.67	258.25	56.39	12.99	1178.34	26.98	258.09	56.37	251.86
380	33.45	1178.37	140.89	258.18	56.34	11.07	1178.26	24.72	258.04	56.33	251.86
385	27.20	1178.63	98.55	258.09	56.30	7.50	1178.18	15.53	258.00	56.29	251.86
390	28.82	1178.66	99.17	258.02	56.26	7.00	1178.43	7.38	257.95	56.25	251.86
395	32.44	1178.47	115.24	258.00	56.22	9.47	1178.40	12.48	257.87	56.21	251.86
400	31.88	1178.37	106.91	257.95	56.18	10.31	1178.23	17.71	257.85	56.17	251.86
405	29.51	1178.32	101.09	257.89	56.13	10.26	1178.28	14.18	257.80	56.13	251.86
410	24.79	1178.47	87.79	257.83	56.09	8.95	1178.26	11.06	257.75	56.08	251.86
415	20.89	1178.63	76.83	257.75	56.05	6.85	1178.22	7.42	257.70	56.04	251.86
420	15.30	1178.65	60.79	257.68	55.99	5.07	1178.43	3.47	257.66	56.00	251.86
425	8.58	1179.04	31.53	257.62	55.94	3.36	1178.84	0.95	257.62	55.95	251.86
430	4.02	1179.46	14.93	257.58	55.90	1.87	1179.23	0.19	257.55	55.91	251.86
435	2.93	1179.87	13.75	257.53	55.87	1.39	1184.60	0.03	257.64	55.87	251.86
440	4.49	1180.02	15.59	257.49	55.78	1.67	1193.87	0.00	252.45	55.83	251.86
445	5.57	1180.39	23.49	257.42	55.79	2.67	1219.61	0.00	252.39	55.78	251.86
450	11.89	1179.28	66.46	257.35	55.75	5.21	1250.75	0.00	252.35	55.75	251.86
455	19.39	1178.21	138.34	257.35	55.71	7.91	1238.88	0.01	252.30	55.71	251.86
460	22.16	1177.81	196.83	257.34	55.67	9.88	1199.92	0.31	257.17	55.67	251.86

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
465	24.64	1177.94	243.61	257.31	55.65	10.55	1180.22	3.39	257.18	55.62	251.86
470	27.67	1179.91	298.59	257.29	55.60	10.26	1178.20	11.27	257.14	55.58	251.86
475	28.62	1181.51	325.73	257.25	55.54	9.68	1177.91	19.07	257.10	55.54	251.86
480	28.02	1182.12	333.19	257.20	55.50	9.05	1177.81	21.34	257.05	55.50	251.86
485	28.65	1182.16	335.36	257.15	55.47	8.39	1177.78	20.06	257.00	55.46	251.86
490	29.05	1181.28	336.11	257.10	55.43	7.47	1177.80	14.55	256.96	55.42	251.86
495	29.37	1181.87	337.37	257.05	55.38	7.05	1178.10	6.07	256.93	55.37	251.86
500	30.06	1181.96	314.79	257.00	55.34	6.56	1179.58	1.25	256.89	55.33	251.86
505	29.34	1181.65	297.75	256.94	55.30	5.94	1190.02	0.11	256.89	55.29	251.86
510	28.32	1182.08	311.80	256.89	55.26	6.03	1202.14	0.00	251.76	55.25	251.86
515	28.06	1181.89	317.88	256.84	55.22	5.93	1204.84	0.00	251.71	55.21	251.86
520	27.50	1182.20	300.49	256.78	55.17	5.60	1205.03	0.00	251.66	55.17	251.86
525	26.91	1182.39	290.72	256.73	55.11	5.56	1205.12	0.00	251.61	55.13	251.86
530	26.49	1181.89	289.91	256.68	55.09	5.43	1205.28	0.00	251.56	55.08	251.86
535	24.18	1182.01	262.12	256.62	55.05	4.72	1205.46	0.00	251.51	55.04	251.86
540	17.20	1181.75	153.46	256.56	55.00	2.76	1206.62	0.00	251.45	55.00	251.87
545	17.48	1178.41	119.78	256.47	54.96	5.26	1212.00	0.05	256.26	54.96	251.87
550	26.48	1177.45	191.53	256.46	54.92	7.48	1198.97	1.63	256.34	54.92	251.87
555	30.38	1179.49	256.27	256.44	54.88	6.17	1178.09	2.40	256.33	54.87	251.87
560	30.27	1181.52	287.52	256.39	54.84	6.18	1178.98	0.93	256.27	54.83	251.87

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
565	29.68	1182.10	289.02	256.34	54.80	5.81	1188.63	0.12	256.17	54.79	251.87
570	29.00	1182.49	319.90	256.30	54.76	6.16	1201.20	0.00	251.16	54.75	251.87
575	28.82	1181.95	349.48	256.26	54.72	6.22	1204.55	0.00	251.11	54.71	251.87
580	28.74	1181.58	335.08	256.21	54.67	5.72	1204.78	0.00	251.06	54.67	251.87
585	27.90	1181.53	317.08	256.14	54.63	5.57	1204.95	0.00	251.01	54.62	251.87
590	27.41	1181.83	332.46	256.10	54.59	5.59	1204.91	0.00	250.96	54.58	251.87
595	27.02	1181.85	350.62	256.05	54.55	5.76	1204.89	0.00	250.91	54.54	251.87
600	27.14	1181.99	337.96	256.00	54.51	5.61	1204.90	0.00	250.86	54.50	251.87
605	27.77	1182.06	322.40	255.94	54.46	5.39	1204.93	0.00	250.81	54.46	301.87
610	27.77	1181.46	288.88	255.89	54.42	5.23	1205.08	0.00	250.76	54.42	301.87
615	27.53	1181.16	250.34	255.82	54.38	5.07	1205.32	0.00	250.71	54.37	301.87
620	27.37	1180.31	236.36	255.77	54.34	4.90	1205.47	0.00	250.66	54.33	301.87
625	27.22	1180.09	225.57	255.71	54.30	4.86	1205.47	0.00	250.61	54.29	301.87
630	26.99	1180.08	227.60	255.66	54.26	4.82	1205.47	0.00	250.56	54.25	301.87
635	26.77	1180.58	241.34	255.61	54.21	4.96	1205.40	0.00	250.51	54.21	301.87
640	26.59	1180.51	255.24	255.57	54.17	5.13	1205.37	0.00	250.45	54.16	301.87
645	26.66	1180.38	247.06	255.52	54.13	4.77	1205.40	0.00	250.40	54.12	301.87
650	26.69	1180.58	248.12	255.47	54.09	4.85	1205.32	0.00	250.35	54.08	301.87
655	26.72	1180.03	252.04	255.42	54.05	5.15	1205.32	0.00	250.30	54.04	301.87
660	25.87	1178.97	226.41	255.37	54.01	4.74	1205.45	0.00	250.25	54.00	301.87

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
665	25.53	1177.48	234.07	255.31	53.96	4.81	1205.27	0.00	250.21	53.96	301.87
670	26.01	1178.19	258.72	255.01	53.92	5.81	1201.25	0.09	255.07	53.92	301.87
675	26.88	1178.10	255.58	254.96	53.88	5.90	1188.49	0.65	255.09	53.87	301.87
680	27.03	1176.99	222.88	255.18	53.84	5.51	1177.89	0.82	255.08	53.83	301.87
685	27.32	1177.77	234.35	255.13	53.79	5.89	1179.08	0.53	254.98	53.79	301.87
690	28.96	1178.60	266.16	255.09	53.75	6.21	1178.94	0.68	254.92	53.75	301.87
695	28.67	1178.30	285.31	255.04	53.71	6.39	1180.46	0.47	254.89	53.71	301.87
700	28.28	1177.69	275.35	254.99	53.67	5.93	1191.03	0.07	254.68	53.67	301.87
705	27.51	1177.10	221.73	254.92	53.63	5.34	1202.99	0.00	249.80	53.62	301.87
710	26.20	1176.76	226.97	254.87	53.59	5.30	1204.57	0.00	249.75	53.58	301.87
715	26.07	1176.68	231.41	254.82	53.55	5.32	1204.70	0.00	249.70	53.54	301.87
720	25.81	1176.68	231.83	254.77	53.50	5.36	1204.69	0.00	249.65	53.50	301.87
725	25.40	1176.71	237.27	254.72	53.46	5.36	1204.67	0.00	249.59	53.46	301.87
730	25.32	1176.70	229.92	254.67	53.42	5.25	1204.74	0.00	249.54	53.42	301.87
735	25.25	1176.68	222.03	254.61	53.38	5.06	1204.75	0.00	249.49	53.37	301.87
740	25.02	1176.65	217.70	254.56	53.34	5.17	1204.76	0.00	249.44	53.33	301.87
745	24.79	1176.65	220.01	254.51	53.29	5.22	1204.87	0.00	249.39	53.29	301.87
750	24.75	1176.63	213.97	254.46	53.25	5.01	1204.80	0.00	249.34	53.25	301.87
755	24.42	1176.63	220.85	254.40	53.21	5.22	1204.76	0.00	249.29	53.21	301.87
760	24.31	1176.56	224.99	254.35	53.17	5.13	1204.87	0.00	249.24	53.17	301.87

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
765	24.26	1176.52	215.18	254.30	53.13	4.96	1204.83	0.00	249.19	53.12	301.87
770	24.09	1176.51	209.85	254.25	53.09	5.17	1204.80	0.00	249.13	53.08	301.87
775	24.14	1176.53	208.88	254.20	53.04	4.88	1204.89	0.00	249.08	53.04	301.87
780	23.63	1176.59	229.88	254.15	53.00	5.03	1204.74	0.00	249.03	53.00	301.87
785	23.58	1176.58	239.83	254.10	52.96	5.18	1204.74	0.00	248.98	52.96	301.87
790	23.65	1176.55	235.12	254.05	52.92	4.94	1204.78	0.00	248.93	52.92	301.87
795	23.33	1176.54	234.43	254.00	52.88	5.02	1204.74	0.00	248.88	52.87	301.87
800	23.14	1176.52	231.85	253.94	52.84	5.20	1204.80	0.00	248.83	52.83	301.87
805	23.29	1176.48	218.85	253.89	52.80	4.81	1204.83	0.00	248.78	52.79	301.87
810	22.99	1176.78	229.13	253.70	52.75	5.11	1204.73	0.00	248.72	52.75	301.87
815	22.80	1176.78	225.98	253.45	52.71	5.01	1204.83	0.00	248.67	52.71	301.87
820	22.32	1176.52	210.71	252.33	52.67	4.71	1192.86	0.12	253.64	52.67	301.87
825	21.72	1177.67	227.24	249.12	52.63	5.20	1180.62	0.23	253.55	52.62	301.87
830	22.54	1177.92	222.46	246.63	52.59	4.78	1177.85	0.28	253.56	52.58	301.87
835	21.51	1177.71	240.40	242.95	52.54	4.79	1178.20	0.31	253.46	52.54	301.87
840	19.39	1178.97	280.58	235.87	52.50	5.22	1178.16	0.35	253.37	52.50	301.87
845	20.33	1178.39	266.18	229.96	52.47	4.81	1177.39	0.52	253.35	52.46	301.87
850	19.72	1177.20	243.59	230.57	52.41	4.86	1177.31	0.64	253.32	52.42	301.87
855	18.44	1178.05	299.71	226.22	52.37	5.30	1177.45	0.53	253.31	52.37	301.87
860	18.92	1179.02	326.12	214.84	52.34	5.05	1179.15	0.29	253.18	52.33	301.87

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
865	17.80	1178.83	252.70	216.09	52.29	3.99	1179.33	0.34	253.10	52.29	301.87
870	16.97	1179.99	271.38	218.34	52.24	4.75	1177.27	0.74	253.10	52.25	301.87
875	17.45	1180.78	310.02	210.19	52.21	5.82	1177.34	0.92	253.05	52.21	301.87
880	17.93	1179.19	232.52	217.26	52.16	4.08	1177.10	0.87	253.02	52.16	301.87
885	17.29	1179.86	254.57	215.56	52.17	4.74	1177.10	0.96	252.93	52.13	301.87
890	17.24	1180.18	310.69	205.39	52.08	5.53	1177.37	0.83	252.91	52.08	301.88
895	17.26	1178.74	256.64	212.66	52.03	3.82	1177.25	0.91	252.86	52.04	301.88
900	16.92	1180.56	265.04	213.30	52.00	5.05	1177.03	1.18	252.79	52.00	301.87
905	17.88	1180.52	252.95	206.59	51.97	5.21	1177.15	0.95	252.75	51.96	301.88
910	18.01	1179.30	244.00	209.84	51.94	3.74	1177.14	0.97	252.69	51.93	301.87
915	18.20	1180.43	248.91	212.02	51.90	4.87	1177.18	0.96	252.68	51.90	301.88
920	17.89	1179.43	178.18	222.76	51.87	6.27	1181.07	0.47	252.67	51.87	301.88
925	16.65	1179.34	166.34	223.40	51.83	6.84	1207.64	0.14	252.61	51.83	301.88
930	16.95	1178.97	137.39	223.31	51.80	6.70	1233.76	0.00	247.55	51.80	301.88
935	16.88	1178.70	176.77	227.14	51.77	6.93	1236.87	0.00	247.50	51.77	301.88
940	17.01	1178.26	174.69	228.48	51.73	7.04	1236.49	0.00	247.46	51.73	301.88
945	17.74	1177.65	193.15	237.64	51.70	6.00	1226.72	0.18	252.38	51.70	301.88
950	20.25	1179.17	266.62	232.52	51.67	5.46	1195.25	0.50	252.38	51.67	301.88
955	23.16	1177.96	249.89	239.34	51.61	4.86	1176.95	0.83	252.34	51.63	301.88
960	23.46	1178.00	278.10	240.43	51.60	4.36	1176.89	0.70	252.28	51.60	301.88

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
965	24.63	1177.51	209.56	239.31	51.57	4.08	1178.42	0.22	252.24	51.56	301.88
970	24.97	1175.87	147.55	252.24	51.53	4.27	1184.28	0.04	252.24	51.53	301.88
975	24.22	1175.78	184.87	252.27	51.50	4.60	1184.47	0.04	251.82	51.50	301.88
980	24.53	1175.75	196.38	252.24	51.47	4.23	1190.20	0.02	251.95	51.47	301.88
985	24.32	1175.77	212.19	252.20	51.44	4.58	1201.71	0.00	247.08	51.43	301.88
990	24.62	1175.77	208.66	252.16	51.40	4.09	1204.52	0.00	247.04	51.40	301.88
995	23.90	1175.83	231.24	252.11	51.37	4.34	1195.99	0.06	252.21	51.37	301.88
1000	23.39	1175.81	251.65	252.08	51.34	4.60	1184.97	0.14	251.92	51.33	301.88
1005	23.31	1175.75	234.44	252.03	51.30	4.37	1184.25	0.08	251.91	51.30	301.88
1010	23.02	1175.95	222.89	251.76	51.27	4.40	1195.80	0.00	246.87	51.27	301.88
1015	23.16	1176.03	246.80	251.63	51.24	4.31	1192.74	0.23	251.79	51.23	301.88
1020	22.90	1175.84	265.86	251.81	51.20	4.78	1180.37	0.42	251.79	51.20	301.88
1025	22.97	1175.79	252.45	251.86	51.17	4.68	1180.14	0.21	251.76	51.17	301.88
1030	23.05	1175.74	226.25	251.82	51.14	4.37	1191.89	0.02	252.25	51.13	301.88
1035	22.50	1175.75	218.13	251.77	51.10	4.53	1202.71	0.00	246.66	51.10	301.88
1040	22.45	1176.29	270.51	251.39	51.06	4.50	1204.33	0.00	246.62	51.07	301.88
1045	22.73	1176.19	269.50	251.35	51.03	4.37	1204.63	0.00	246.58	51.03	301.88
1050	22.53	1175.62	219.91	251.64	51.00	4.06	1204.65	0.00	246.53	51.00	301.88
1055	22.27	1175.59	207.85	251.59	50.97	4.18	1202.38	0.01	246.49	50.97	301.88
1060	21.94	1175.65	231.20	251.56	50.94	4.49	1190.07	0.07	251.53	50.93	301.88

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
1065	21.83	1175.66	239.80	251.52	50.90	4.40	1182.25	0.07	251.60	50.90	301.88
1070	21.74	1175.59	216.69	251.47	50.87	4.42	1193.73	0.01	246.36	50.87	301.88
1075	22.23	1175.53	184.92	251.42	50.84	4.05	1203.35	0.00	246.32	50.83	301.88
1080	21.72	1175.56	203.55	251.38	50.80	4.44	1191.70	0.16	251.25	50.80	301.88
1085	21.65	1175.54	224.82	251.34	50.77	4.44	1179.26	0.27	251.26	50.77	301.88
1090	21.68	1175.49	201.62	251.30	50.74	4.32	1177.75	0.17	251.15	50.73	301.88
1095	20.75	1176.03	208.73	243.76	50.70	4.34	1178.26	0.10	250.96	50.70	301.88
1100	21.15	1176.56	234.28	243.60	50.68	4.33	1179.36	0.13	251.23	50.67	301.88
1105	20.75	1176.57	274.99	244.68	50.61	4.84	1179.36	0.15	251.13	50.63	301.88
1110	19.43	1177.52	322.60	233.27	50.60	4.94	1186.80	0.06	251.02	50.60	301.88
1115	19.64	1177.89	294.36	228.42	50.57	4.14	1198.38	0.00	245.98	50.57	301.88
1120	18.01	1177.68	273.20	226.40	50.54	4.06	1188.84	0.28	250.85	50.53	301.88
1125	16.54	1179.09	332.81	213.41	50.50	5.01	1177.77	0.59	250.92	50.50	301.88
1130	17.76	1178.55	283.41	215.83	50.45	3.91	1176.57	0.54	250.86	50.47	301.88
1135	16.13	1177.66	266.68	213.73	50.44	3.98	1176.56	0.64	250.81	50.43	301.88
1140	14.99	1177.93	316.84	202.77	50.40	4.86	1176.71	0.61	250.80	50.40	301.88
1145	14.80	1176.97	237.35	213.26	50.37	4.66	1176.56	0.56	250.70	50.37	301.88
1150	13.70	1177.28	254.22	211.19	50.34	6.32	1178.75	0.58	250.71	50.33	301.88
1155	13.34	1177.99	268.99	199.08	50.30	6.66	1197.44	0.24	250.67	50.30	301.88
1160	13.50	1177.15	209.90	208.50	50.25	4.01	1208.01	0.08	250.46	50.26	301.88

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
1165	14.02	1178.05	254.88	205.99	50.24	4.17	1177.60	0.27	250.55	50.23	301.88
1170	14.37	1178.61	286.20	199.32	50.20	4.74	1177.27	0.37	250.50	50.20	301.88
1175	15.61	1177.42	256.10	209.72	50.18	3.42	1176.60	0.43	250.48	50.17	301.88
1180	16.30	1177.73	280.26	203.37	50.14	4.37	1176.61	0.51	250.44	50.13	301.88
1185	16.18	1177.32	235.82	204.44	49.91	3.76	1176.64	0.41	250.39	50.10	301.88
1190	16.31	1177.06	241.18	214.02	50.06	4.11	1176.55	0.55	250.32	50.07	301.88
1195	16.88	1178.14	308.80	204.13	50.03	5.04	1176.59	0.62	250.31	50.03	301.88
1200	17.66	1178.06	259.68	210.10	49.99	4.41	1176.40	0.66	250.23	50.00	301.88
1210	17.72	1177.84	240.85	215.72	49.94	4.63	1176.38	0.68	250.17	49.93	301.88
1220	17.51	1177.09	235.10	215.37	49.87	4.55	1176.45	0.62	250.08	49.87	301.88
1230	18.72	1176.41	231.44	219.72	49.81	4.31	1176.40	0.59	249.99	49.80	301.88
1240	21.09	1176.21	207.39	233.01	49.74	4.09	1177.28	0.37	249.93	49.73	301.88
1250	23.14	1175.55	202.50	246.80	49.67	4.20	1184.65	0.12	249.94	49.67	301.88
1260	23.98	1174.94	193.33	249.71	49.60	4.40	1191.81	0.03	250.09	49.60	301.88
1270	23.41	1174.80	185.95	249.75	49.54	4.34	1198.41	0.00	244.65	49.53	301.88
1280	22.81	1174.84	211.46	249.67	49.47	4.26	1203.96	0.00	244.56	49.47	301.88
1290	22.16	1174.87	218.76	249.58	49.40	4.26	1204.00	0.00	244.48	49.40	301.88
1300	21.47	1174.88	225.03	249.49	49.34	4.22	1203.81	0.00	244.39	49.33	301.88
1310	21.03	1175.37	244.42	248.91	49.27	4.15	1203.36	0.00	244.30	49.27	301.88
1320	20.14	1176.36	269.26	245.05	49.20	4.26	1203.45	0.00	244.22	49.20	301.88

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
1330	19.25	1177.07	302.52	241.29	49.14	4.13	1203.83	0.00	244.13	49.13	301.88
1340	17.51	1177.87	301.64	228.48	49.06	4.13	1201.34	0.01	248.64	49.07	301.88
1350	15.22	1178.03	299.56	215.78	49.00	4.21	1189.09	0.05	248.88	49.00	301.89
1360	13.85	1176.85	268.95	213.24	48.94	3.84	1178.18	0.06	248.96	48.93	301.89
1370	12.01	1177.05	264.88	200.87	48.86	4.28	1181.28	0.06	248.66	48.87	301.89
1380	10.33	1177.45	267.46	196.56	48.81	4.51	1180.14	0.19	248.65	48.80	301.89
1390	10.13	1176.65	210.18	197.46	48.73	3.92	1176.10	0.31	248.61	48.73	301.89
1400	13.37	1176.88	335.28	194.41	48.65	6.34	1177.45	20.09	248.47	48.67	301.88
1410	16.72	1176.82	355.03	201.37	48.60	6.40	1177.10	24.47	248.45	48.60	301.89
1420	17.47	1176.03	279.69	205.55	48.53	4.81	1175.22	11.82	248.33	48.53	301.89
1430	18.74	1175.81	219.60	201.59	48.47	4.62	1175.42	8.40	248.27	48.46	301.89
1440	20.18	1176.11	184.84	213.17	48.41	4.33	1175.43	7.14	248.14	48.41	301.89
1450	19.34	1175.89	193.95	219.68	48.34	4.64	1175.29	7.45	248.11	48.33	301.89
1460	16.65	1175.97	141.72	232.04	48.27	5.12	1179.23	1.76	248.02	48.27	301.89
1470	14.30	1176.75	188.04	225.87	48.20	6.17	1202.78	0.33	247.93	48.20	301.89
1480	13.06	1176.69	212.12	224.13	48.14	6.01	1224.85	0.00	242.81	48.13	301.89
1490	13.28	1176.35	206.06	225.06	48.07	5.92	1225.40	0.00	242.73	48.07	301.89
1500	19.00	1176.82	335.32	222.56	48.00	6.27	1204.08	0.22	247.64	48.00	301.89
1510	24.99	1176.14	328.41	228.87	47.96	6.10	1180.85	0.72	247.58	47.96	301.89
1520	26.02	1175.15	185.76	246.53	47.93	5.44	1185.14	0.51	247.57	47.92	301.89

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
1530	26.49	1175.75	175.36	247.48	47.88	5.28	1198.68	0.00	242.48	47.88	301.89
1540	26.34	1175.74	199.51	247.53	47.84	5.15	1202.14	0.00	242.42	47.84	301.89
1550	25.25	1175.40	250.22	241.71	47.80	5.24	1201.94	0.00	242.37	47.80	301.89
1560	25.43	1175.75	245.85	241.44	47.76	5.32	1201.89	0.00	242.31	47.76	301.89
1570	25.50	1177.09	206.55	246.32	47.72	5.14	1202.04	0.00	242.26	47.72	301.89
1580	24.59	1178.05	200.98	246.37	47.68	4.99	1202.03	0.00	242.21	47.68	301.89
1590	24.11	1177.08	197.40	247.25	47.64	5.01	1201.98	0.00	242.16	47.64	301.89
1600	22.33	1177.17	232.84	247.20	47.60	5.13	1201.87	0.00	242.10	47.60	301.89
1610	20.28	1177.76	254.97	244.06	47.56	5.24	1201.79	0.00	242.05	47.56	301.89
1620	17.68	1177.26	247.30	231.92	47.53	5.06	1200.06	0.00	242.00	47.52	301.89
1630	13.96	1176.36	262.39	213.34	47.48	4.86	1190.71	0.06	246.79	47.48	301.89
1640	11.02	1176.44	321.56	198.17	47.40	4.98	1179.97	0.35	246.87	47.44	301.89
1650	9.39	1176.63	306.59	193.47	47.41	4.56	1176.27	0.45	246.83	47.40	301.89
1660	7.78	1175.66	237.10	189.19	47.35	4.41	1183.71	0.19	246.85	47.36	301.89
1670	6.12	1175.64	267.73	186.38	47.24	4.36	1201.56	0.03	247.18	47.32	301.89
1680	5.19	1176.46	255.85	187.94	47.28	3.62	1215.01	0.00	241.67	47.28	301.89
1690	6.41	1175.88	239.39	191.14	47.25	3.63	1213.63	0.00	241.62	47.24	301.89
1700	7.59	1176.08	290.02	192.98	47.11	4.02	1210.67	0.00	241.57	47.20	301.89
1710	7.88	1176.07	266.98	195.92	47.16	3.82	1210.99	0.00	241.51	47.16	301.89
1720	9.09	1175.35	249.26	198.13	47.13	4.02	1212.99	0.00	241.45	47.12	301.89

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
1730	9.61	1175.52	275.56	199.15	47.05	4.39	1212.27	0.00	241.40	47.08	301.89
1740	9.98	1175.72	249.71	204.12	47.04	4.40	1211.30	0.00	241.35	47.04	301.89
1750	11.00	1177.76	270.22	208.78	47.00	4.31	1203.13	0.80	246.24	47.00	301.89
1760	21.34	1176.20	356.99	214.03	46.98	5.01	1183.15	2.13	246.23	46.95	301.89
1770	24.77	1174.79	240.94	216.75	46.92	5.12	1176.04	1.38	246.22	46.92	301.89
1780	17.12	1174.84	98.05	213.69	46.88	5.13	1190.72	0.06	246.18	46.88	301.89
1790	16.22	1174.80	116.91	228.22	46.84	6.10	1204.39	0.00	241.08	46.84	301.89
1800	17.25	1174.23	127.18	243.23	46.80	6.28	1207.93	0.00	241.02	46.80	301.89
1810	17.50	1174.08	141.14	245.99	46.76	6.22	1207.68	0.00	240.97	46.76	301.89
1820	16.84	1174.39	161.10	245.97	46.72	6.10	1207.41	0.00	240.92	46.72	301.89
1830	15.45	1174.72	204.02	241.42	46.68	6.01	1207.04	0.00	240.86	46.68	301.89
1840	14.44	1175.16	274.64	228.25	46.70	5.46	1200.52	0.01	240.81	46.64	301.89
1850	15.13	1175.41	289.94	225.31	46.58	4.76	1186.36	0.04	245.58	46.60	301.89
1860	15.53	1175.41	225.40	232.52	46.56	4.72	1182.65	0.05	245.57	46.56	301.89
1870	14.74	1175.39	215.79	226.43	46.52	4.67	1184.99	0.04	245.49	46.52	301.89
1880	15.10	1175.49	241.89	223.04	46.48	4.10	1183.17	0.03	245.44	46.48	301.89
1890	15.33	1175.40	263.41	217.54	46.45	3.42	1186.32	0.02	245.79	46.44	301.89
1900	13.46	1175.00	275.44	208.62	46.41	3.96	1195.75	0.01	240.47	46.40	301.89
1910	13.27	1175.31	278.26	210.65	46.33	4.46	1190.70	0.05	245.41	46.36	301.89
1920	14.26	1175.39	272.39	210.74	46.32	4.12	1182.76	0.06	245.43	46.32	301.89

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
1930	14.31	1175.81	249.44	205.85	46.28	4.02	1182.61	0.02	245.33	46.28	301.89
1940	14.21	1176.77	246.04	203.64	46.24	3.81	1184.61	0.01	244.97	46.24	301.89
1950	14.93	1177.36	223.18	209.53	46.20	2.89	1190.19	0.00	240.21	46.19	301.89
1960	15.10	1178.01	240.46	209.78	46.16	2.42	1197.24	0.00	240.15	46.16	301.89
1970	14.28	1178.43	257.28	205.60	46.13	3.13	1199.86	0.00	240.09	46.12	301.89
1980	13.36	1177.80	264.47	200.20	46.09	3.40	1201.40	0.00	240.03	46.08	301.90
1990	12.99	1176.04	257.97	198.59	45.91	2.69	1205.61	0.00	239.98	46.04	301.90
2000	12.92	1174.94	254.80	203.30	46.00	2.51	1205.71	0.00	239.92	46.00	301.90
2010	12.75	1174.22	245.29	206.08	45.97	2.53	1200.04	0.00	239.88	45.97	301.90
2020	11.55	1173.98	257.56	198.31	45.95	2.63	1200.30	0.00	239.84	45.94	301.90
2030	10.08	1174.43	292.00	191.62	45.86	2.54	1203.35	0.00	239.80	45.91	301.90
2040	10.09	1174.63	235.62	195.59	45.88	2.07	1203.49	0.00	239.76	45.88	301.90
2050	10.03	1175.88	241.87	195.99	45.86	2.85	1202.80	0.00	239.72	45.85	301.90
2060	9.86	1177.89	293.14	191.70	45.79	3.07	1201.26	0.00	239.68	45.82	301.90
2070	9.78	1179.03	261.28	191.51	45.79	2.56	1200.54	0.00	239.64	45.79	301.90
2080	10.01	1178.70	214.97	194.45	45.76	2.73	1199.97	0.00	239.59	45.76	301.90
2090	10.58	1177.97	268.62	193.91	45.72	2.74	1200.03	0.00	239.55	45.73	301.90
2100	11.03	1178.51	288.25	195.35	45.71	2.91	1199.45	0.02	244.64	45.70	301.90
2110	12.18	1178.52	238.53	201.04	45.63	2.96	1192.60	0.02	244.40	45.67	301.90
2120	13.02	1178.10	206.77	205.20	45.64	2.95	1194.38	0.01	243.49	45.64	301.90

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
2130	13.30	1178.00	204.62	203.40	45.61	3.39	1191.05	0.02	244.14	45.61	301.90
2140	14.27	1178.18	235.21	203.05	45.58	3.30	1188.69	0.01	239.34	45.58	301.90
2150	14.87	1177.50	229.89	206.74	45.55	2.59	1194.16	0.00	239.30	45.55	301.90
2160	14.37	1177.31	230.56	206.44	45.52	2.61	1196.63	0.00	239.26	45.52	301.90
2170	13.85	1177.59	254.91	205.77	45.49	3.45	1197.19	0.00	239.22	45.49	301.90
2180	14.12	1177.95	262.08	209.85	45.44	3.12	1197.23	0.00	239.18	45.46	301.90
2190	13.81	1179.09	255.27	207.35	45.43	2.43	1199.91	0.00	239.13	45.43	301.90
2200	14.07	1177.70	214.48	208.84	45.40	2.37	1195.09	0.00	239.09	45.40	301.90
2210	13.43	1176.81	187.24	212.76	45.37	2.76	1198.58	0.00	239.05	45.37	301.90
2220	13.32	1177.65	242.68	210.36	45.34	2.50	1201.72	0.00	239.01	45.34	301.90
2230	13.82	1178.41	282.79	208.21	45.31	2.34	1196.71	0.00	238.97	45.31	301.90
2240	13.14	1178.98	268.70	207.36	45.26	3.09	1198.51	0.00	238.93	45.28	301.90
2250	13.53	1178.46	261.03	209.29	45.26	2.76	1202.82	0.00	238.88	45.25	301.90
2260	13.32	1178.04	274.96	202.13	45.22	2.67	1199.81	0.00	238.84	45.22	301.90
2270	13.28	1177.08	269.13	200.05	45.19	2.99	1194.71	0.00	238.80	45.19	301.90
2280	13.33	1176.87	250.29	201.40	45.16	2.62	1192.34	0.00	238.76	45.16	301.90
2290	13.31	1176.55	236.84	202.66	45.13	2.36	1198.39	0.00	238.72	45.13	301.90
2300	13.13	1176.26	228.27	202.59	45.10	2.20	1203.37	0.00	238.67	45.10	301.90
2310	12.83	1176.65	232.93	200.49	45.07	2.56	1193.79	0.00	238.63	45.07	301.90
2320	13.65	1177.12	250.72	200.33	45.03	2.25	1190.38	0.00	238.59	45.04	301.90

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
2330	13.36	1178.13	253.86	198.64	45.01	2.28	1198.25	0.00	238.55	45.01	301.90
2340	11.86	1178.02	243.56	202.12	44.98	3.20	1201.87	0.00	238.51	44.98	301.90
2350	12.58	1177.50	249.14	206.92	45.24	2.72	1202.30	0.00	238.46	44.95	301.90
2360	13.07	1177.71	257.10	204.79	44.92	2.12	1200.34	0.00	238.42	44.92	301.90
2370	12.57	1177.12	243.77	202.99	44.89	2.35	1193.70	0.01	238.38	44.89	301.90
2380	13.04	1177.21	233.84	203.63	44.86	2.67	1194.61	0.00	238.34	44.86	301.90
2390	13.07	1178.08	275.37	199.92	44.83	2.08	1198.56	0.00	238.29	44.83	301.90
2400	12.37	1177.64	282.07	195.14	44.80	2.41	1201.80	0.00	238.25	44.80	301.90
2410	12.32	1177.33	269.60	196.07	44.74	2.68	1201.89	0.00	238.21	44.77	301.90
2420	12.20	1177.24	254.49	198.27	44.74	1.93	1198.91	0.00	238.17	44.74	301.90
2430	11.72	1176.69	221.21	196.59	44.71	2.23	1194.68	0.00	238.13	44.71	301.90
2440	12.69	1177.22	252.21	196.43	44.68	1.99	1193.15	0.00	238.08	44.68	301.90
2450	12.51	1177.78	265.72	193.28	44.65	2.36	1199.83	0.00	238.04	44.65	301.90
2460	12.65	1178.19	254.90	194.74	44.63	2.47	1197.10	0.00	238.00	44.62	301.90
2470	12.85	1178.38	251.42	196.83	44.59	2.11	1194.65	0.00	237.96	44.59	301.90
2480	12.48	1178.28	235.33	200.14	44.53	2.40	1196.66	0.00	237.91	44.56	301.90
2490	12.49	1177.67	235.09	201.13	44.53	2.05	1197.94	0.00	237.87	44.53	301.90
2500	12.50	1177.55	232.66	200.30	44.50	2.24	1194.70	0.00	237.83	44.50	301.90
2510	12.63	1178.05	241.38	201.11	44.47	2.20	1193.51	0.00	237.79	44.47	301.90
2520	12.50	1177.46	253.89	198.59	44.42	2.32	1193.52	0.00	237.74	44.44	301.90

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
2530	12.36	1177.08	256.25	196.96	44.39	2.90	1195.30	0.00	237.70	44.41	301.90
2540	12.42	1176.77	276.94	194.54	44.37	2.37	1198.47	0.00	237.66	44.38	301.90
2550	13.02	1176.60	270.95	194.95	44.36	2.10	1200.07	0.00	237.62	44.35	301.90
2560	12.83	1176.32	239.93	195.60	44.32	2.76	1202.47	0.00	237.57	44.32	301.90
2570	12.63	1176.57	260.29	194.28	44.30	2.35	1199.10	0.00	237.53	44.29	301.90
2580	13.01	1176.58	262.47	194.97	44.26	2.07	1195.19	0.00	237.49	44.26	301.90
2590	12.49	1176.20	241.81	193.09	44.24	2.80	1199.10	0.00	237.45	44.23	301.90
2600	11.90	1176.68	263.70	192.76	44.20	2.62	1199.78	0.00	237.40	44.20	301.90
2610	11.92	1177.05	256.18	193.58	44.17	2.66	1198.93	0.00	237.36	44.17	301.90
2620	11.74	1176.89	254.17	193.50	44.12	2.58	1196.77	0.00	237.32	44.14	301.90
2630	11.57	1176.38	257.59	196.02	44.10	2.36	1197.02	0.00	237.28	44.11	301.90
2640	11.49	1176.99	233.90	196.75	44.08	2.34	1201.14	0.00	237.23	44.08	301.90
2650	11.75	1177.26	223.96	195.71	44.05	2.11	1201.55	0.00	237.19	44.05	301.90
2660	12.17	1177.16	238.23	192.24	44.02	2.47	1201.57	0.00	237.15	44.02	301.90
2670	12.37	1177.10	249.44	192.82	43.99	2.21	1200.03	0.00	237.10	43.99	301.90
2680	12.45	1177.07	242.01	195.94	43.96	2.18	1200.83	0.00	237.06	43.96	301.90
2690	12.55	1177.10	253.23	193.86	43.93	2.62	1202.68	0.00	237.02	43.93	301.90
2700	11.92	1176.98	266.46	190.97	43.90	2.49	1200.44	0.00	236.97	43.90	301.90
2710	11.78	1176.70	248.67	191.94	43.86	2.66	1198.77	0.00	236.93	43.87	301.90
2720	11.79	1176.34	263.58	192.28	43.82	2.56	1198.63	0.00	236.89	43.84	301.90

Time (seconds)	Reactor Vessel Side Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Pump Discharge Side Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
2730	12.10	1175.81	268.62	192.53	43.82	2.37	1198.77	0.00	236.84	43.81	301.90
2740	12.14	1175.67	245.70	191.94	43.78	2.82	1200.23	0.00	236.80	43.78	301.90
2750	12.50	1176.39	287.69	192.08	43.76	2.21	1202.02	0.00	236.76	43.75	301.90
2760	12.47	1176.72	290.53	194.33	43.66	1.71	1204.48	0.00	236.72	43.72	301.90
2770	11.48	1176.15	242.01	198.55	43.69	2.05	1202.19	0.00	236.67	43.69	301.90
2780	11.35	1175.76	240.22	199.20	43.66	1.66	1200.45	0.00	236.63	43.66	301.90
2790	11.56	1175.37	265.35	194.94	43.60	1.76	1199.10	0.00	236.59	43.63	301.90
2800	12.02	1174.67	261.00	194.16	43.58	2.51	1200.63	0.00	236.54	43.60	301.90
2810	11.42	1175.70	270.84	192.43	43.56	2.38	1201.49	0.00	236.50	43.57	301.90
2820	11.30	1176.67	264.28	191.41	43.55	2.59	1198.99	0.00	236.46	43.54	301.90
2830	11.65	1177.26	263.93	191.62	43.52	2.50	1195.94	0.00	236.41	43.51	301.90
2840	11.49	1177.21	261.57	192.70	43.48	2.43	1196.19	0.00	236.37	43.48	301.90
2850	12.04	1177.02	258.58	194.77	43.45	2.38	1196.77	0.00	236.33	43.45	301.90
2860	12.31	1176.92	271.84	191.11	43.42	2.01	1198.09	0.00	236.28	43.42	301.90
2870	11.55	1176.27	241.87	189.90	42.95	2.57	1202.40	0.00	236.24	43.39	301.90
2880	11.20	1177.21	238.23	196.05	43.36	2.66	1201.80	0.00	236.20	43.36	301.90
2890	12.36	1177.88	251.71	195.46	43.33	2.17	1200.89	0.00	236.15	43.33	301.90
2900	12.87	1177.12	267.37	191.13	43.30	1.98	1201.10	0.00	236.11	43.30	301.90
2910	11.76	1176.44	248.01	191.13	43.27	2.23	1201.34	0.00	236.07	43.27	301.90
2920	12.12	1177.06	240.84	193.95	43.24	2.28	1198.69	0.00	236.02	43.24	301.90

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
2930	11.36	1176.82	231.17	190.99	43.21	2.33	1199.43	0.00	235.98	43.21	301.90
2940	10.44	1176.89	220.55	193.30	43.18	2.55	1202.91	0.00	235.94	43.18	301.91
2950	10.96	1176.79	210.61	198.58	43.15	2.17	1202.53	0.00	235.89	43.15	301.91
2960	10.72	1176.04	223.22	195.07	43.12	2.22	1200.24	0.00	235.85	43.12	301.90
2970	11.24	1175.52	296.82	192.76	43.09	2.08	1198.37	0.00	235.81	43.09	301.90
2980	11.56	1174.62	272.49	191.73	43.06	2.22	1196.87	0.00	235.76	43.06	301.90
2990	9.97	1175.47	240.42	189.17	43.03	2.80	1199.91	0.00	235.72	43.03	301.90
3000	10.14	1175.85	276.97	190.89	42.99	2.39	1201.57	0.00	235.68	43.00	301.91
3010	10.85	1174.77	266.93	192.80	42.95	2.43	1199.28	0.00	235.60	42.95	301.91
3020	10.78	1173.96	266.06	192.12	42.91	2.48	1196.46	0.00	235.53	42.90	301.91
3030	11.91	1174.53	280.03	189.86	42.85	2.13	1196.89	0.00	235.45	42.85	301.91
3040	11.60	1175.13	245.12	188.77	42.80	2.09	1200.95	0.00	235.38	42.80	301.91
3050	11.44	1175.69	246.09	192.54	42.75	2.23	1199.19	0.00	235.31	42.75	301.91
3060	11.98	1175.67	265.08	189.70	42.70	2.19	1199.65	0.00	235.24	42.70	301.91
3070	12.01	1174.81	245.72	189.16	42.65	1.81	1201.45	0.00	235.16	42.65	301.91
3080	11.90	1175.41	233.14	191.81	42.60	1.84	1198.47	0.00	235.09	42.60	301.91
3090	11.89	1175.40	249.55	189.99	42.56	2.20	1199.12	0.00	235.02	42.55	301.91
3100	12.42	1174.95	274.15	189.16	42.50	2.30	1201.26	0.00	234.94	42.50	301.91
3110	11.31	1175.87	250.18	187.79	42.45	2.38	1199.56	0.00	234.87	42.45	301.91
3120	9.81	1175.20	226.87	188.25	42.40	2.22	1198.76	0.00	234.80	42.40	301.91

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
3130	10.76	1173.55	252.44	191.54	42.35	2.18	1196.63	0.00	234.72	42.35	301.91
3140	10.61	1173.91	231.81	192.09	42.31	2.43	1198.10	0.00	234.65	42.30	301.91
3150	10.67	1175.36	243.62	190.04	42.25	2.06	1201.22	0.00	234.57	42.25	301.91
3160	11.37	1175.07	252.60	188.47	42.19	2.12	1199.26	0.00	234.50	42.20	301.91
3170	9.44	1174.08	237.32	184.24	42.13	2.50	1201.13	0.00	234.43	42.15	301.91
3180	10.16	1174.22	278.28	186.96	42.11	2.00	1199.73	0.00	234.36	42.10	301.91
3190	11.88	1174.80	281.80	188.48	42.05	2.04	1194.80	0.00	234.28	42.05	301.91
3200	10.94	1174.60	259.80	186.33	42.01	2.72	1198.03	0.00	234.21	42.00	301.91
3210	11.29	1174.51	270.78	189.28	41.96	2.31	1197.94	0.00	234.13	41.95	301.91
3220	11.79	1175.02	272.52	186.86	41.88	1.96	1196.61	0.00	234.06	41.90	301.91
3230	11.18	1174.45	247.16	184.92	41.83	2.58	1199.79	0.00	233.98	41.85	301.91
3240	11.76	1174.89	255.00	189.21	41.81	2.15	1199.01	0.00	233.91	41.80	301.91
3250	12.15	1175.34	258.45	185.20	41.74	1.79	1198.39	0.00	233.84	41.75	301.91
3260	10.98	1174.26	232.62	182.65	41.67	2.49	1201.26	0.00	233.76	41.70	301.91
3270	10.09	1174.60	229.02	189.72	41.65	2.84	1201.43	0.00	233.69	41.65	301.91
3280	11.21	1175.25	259.39	190.17	41.60	2.27	1199.10	0.00	233.61	41.60	301.91
3290	11.05	1174.29	237.82	186.57	41.55	2.10	1199.82	0.00	233.54	41.55	301.91
3300	9.52	1173.82	223.23	190.19	41.51	2.37	1202.43	0.00	233.46	41.50	301.91
3310	10.85	1174.76	262.36	194.21	41.45	2.18	1199.64	0.00	233.39	41.45	301.91
3320	11.71	1174.76	278.39	188.92	41.40	2.04	1198.48	0.00	233.31	41.40	301.91

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
3330	11.45	1173.77	283.97	184.57	41.35	2.00	1200.66	0.00	233.24	41.35	301.91
3340	10.98	1173.70	253.54	186.97	41.23	2.39	1200.86	0.00	233.16	41.30	301.91
3350	10.40	1173.84	238.19	192.40	41.25	2.49	1200.87	0.00	233.09	41.25	301.91
3360	11.72	1173.56	280.22	192.54	41.20	2.38	1199.29	0.00	233.01	41.20	301.91
3370	12.35	1174.15	309.63	188.37	41.15	2.24	1199.26	0.00	232.93	41.15	301.91
3380	10.98	1173.75	271.47	187.54	41.10	2.06	1201.13	0.00	232.86	41.10	301.91
3390	11.35	1172.80	257.33	192.04	41.01	2.03	1197.94	0.00	232.78	41.05	301.91
3400	11.89	1173.28	284.53	187.19	41.00	2.04	1197.32	0.00	232.71	41.00	301.91
3410	10.48	1173.17	253.59	182.37	40.95	2.38	1200.25	0.00	232.63	40.95	301.91
3420	9.87	1172.69	225.14	189.86	40.90	2.45	1200.19	0.00	232.56	40.90	301.91
3430	11.02	1173.17	250.89	190.08	40.85	2.22	1196.80	0.00	232.48	40.85	301.91
3440	11.53	1173.16	273.45	183.56	40.80	2.04	1195.69	0.00	232.40	40.80	301.91
3450	10.31	1172.61	251.21	184.09	40.75	2.23	1200.09	0.00	232.33	40.75	301.91
3460	9.87	1173.07	230.68	190.11	40.70	2.26	1201.45	0.00	232.25	40.70	301.91
3470	11.17	1173.39	247.89	189.20	40.65	2.06	1199.01	0.00	232.18	40.65	301.91
3480	10.27	1173.42	238.36	185.45	40.60	2.24	1199.52	0.00	232.10	40.60	301.91
3490	9.49	1173.67	233.68	188.23	40.55	2.11	1201.82	0.00	232.02	40.55	301.91
3500	11.04	1173.69	263.30	188.84	40.49	2.05	1197.76	0.00	231.95	40.50	301.91
3510	10.55	1173.12	258.89	185.97	40.43	2.04	1197.49	0.00	231.87	40.45	301.91
3520	10.51	1172.61	258.87	186.41	40.40	2.05	1198.80	0.00	231.80	40.40	301.91

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
3530	11.16	1172.76	279.20	184.26	40.35	2.19	1197.73	0.00	231.72	40.35	301.91
3540	9.47	1172.40	243.04	183.41	40.31	2.14	1200.30	0.00	231.64	40.30	301.91
3550	9.56	1172.24	225.68	188.63	40.25	1.91	1202.55	0.00	231.56	40.25	301.91
3560	10.95	1172.36	254.66	187.57	40.21	2.00	1199.87	0.00	231.49	40.20	301.91
3570	9.27	1172.45	229.46	182.82	40.15	2.26	1199.84	0.00	231.41	40.15	301.92
3580	9.86	1172.80	230.74	188.24	40.10	1.85	1202.37	0.00	231.33	40.10	301.91
3590	11.01	1172.95	258.78	189.85	40.04	2.02	1198.04	0.00	231.26	40.05	301.91
3600	8.87	1173.06	244.76	184.16	40.00	2.34	1198.71	0.00	231.18	40.00	301.92
3610	9.66	1172.73	267.47	188.44	39.93	1.76	1202.65	0.00	231.10	39.95	301.91
3620	10.89	1172.39	266.96	190.79	39.89	1.99	1200.09	0.00	231.02	39.90	301.91
3630	8.89	1172.53	250.00	185.78	39.82	2.44	1200.71	0.00	230.95	39.85	301.91
3640	9.60	1172.69	277.46	186.87	39.80	1.78	1201.49	0.00	230.87	39.80	301.92
3650	10.61	1172.42	259.62	187.01	39.76	2.03	1199.20	0.00	230.79	39.75	301.92
3660	8.63	1172.37	245.75	184.84	39.69	2.45	1201.23	0.00	230.72	39.70	301.92
3670	9.58	1172.57	272.09	187.39	39.66	1.69	1200.90	0.00	230.64	39.65	301.92
3680	10.56	1172.26	257.78	186.84	39.61	2.01	1198.09	0.00	230.56	39.60	301.92
3690	8.52	1172.17	243.60	185.49	39.56	2.51	1201.14	0.00	230.48	39.55	301.92
3700	9.29	1172.47	269.74	186.50	39.51	1.78	1199.23	0.00	230.41	39.50	301.92
3710	10.62	1172.17	279.28	183.99	39.45	1.72	1193.49	0.00	230.33	39.45	301.92
3720	9.70	1171.83	253.68	182.34	39.41	2.43	1198.44	0.00	230.25	39.40	301.92

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
3730	8.49	1171.85	242.06	183.93	39.36	2.65	1201.59	0.00	230.17	39.35	301.92
3740	9.35	1171.80	269.87	185.29	39.31	1.96	1199.08	0.00	230.09	39.30	301.92
3750	10.22	1171.70	263.03	184.42	39.25	2.21	1197.26	0.00	230.02	39.25	301.92
3760	10.74	1172.05	261.15	186.25	39.21	1.92	1196.64	0.00	229.94	39.20	301.92
3770	10.79	1172.45	248.31	186.01	39.14	1.76	1197.44	0.00	229.86	39.15	301.92
3780	8.65	1172.62	233.27	184.47	39.10	2.45	1202.15	0.00	229.78	39.10	301.92
3790	9.43	1172.48	271.43	184.97	39.04	1.73	1198.62	0.00	229.70	39.05	301.92
3800	10.57	1172.00	275.24	182.16	38.96	1.61	1193.60	0.00	229.62	39.00	301.92
3810	9.56	1171.51	253.48	182.76	38.95	2.32	1200.18	0.00	229.54	38.95	301.92
3820	8.21	1171.63	245.66	185.51	38.91	2.50	1203.09	0.00	229.46	38.90	301.92
3830	9.47	1172.09	263.98	186.24	38.85	1.76	1199.94	0.00	229.39	38.85	301.92
3840	10.17	1171.87	249.10	183.42	38.80	1.93	1198.00	0.00	229.31	38.80	301.92
3850	7.95	1171.64	232.95	182.63	38.72	2.45	1201.86	0.00	229.23	38.75	301.92
3860	9.05	1171.98	269.68	184.88	38.69	1.80	1198.24	0.00	229.15	38.70	301.92
3870	10.19	1171.68	283.63	182.05	38.65	1.65	1194.28	0.00	229.07	38.65	301.92
3880	9.07	1171.29	257.36	180.86	38.60	2.37	1199.05	0.00	228.99	38.60	301.92
3890	8.28	1171.48	238.84	184.94	38.53	2.60	1201.44	0.00	228.91	38.55	301.92
3900	9.73	1171.90	258.76	185.13	38.50	1.82	1198.38	0.00	228.83	38.50	301.92
3910	10.26	1171.61	249.68	183.10	38.43	1.95	1196.49	0.00	228.75	38.45	301.92
3920	8.19	1171.33	239.06	184.13	38.39	2.51	1201.56	0.00	228.67	38.40	301.92

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
3930	9.26	1171.75	267.74	184.79	38.33	1.71	1198.80	0.00	228.59	38.35	301.92
3940	10.34	1171.57	274.24	182.10	38.28	1.52	1193.40	0.00	228.51	38.30	301.92
3950	9.31	1171.18	249.18	180.42	38.25	2.36	1199.07	0.00	228.43	38.25	301.92
3960	8.41	1171.22	236.40	184.16	38.21	2.61	1201.60	0.00	228.35	38.20	301.92
3970	9.49	1171.60	262.67	185.68	38.16	1.82	1199.09	0.00	228.27	38.15	301.92
3980	10.19	1171.41	254.87	183.44	38.10	1.98	1197.48	0.00	228.19	38.10	301.92
3990	8.31	1171.13	233.62	182.92	38.06	2.48	1200.93	0.00	228.11	38.05	301.92
4000	9.27	1171.57	265.68	185.35	38.01	1.60	1199.94	0.00	228.03	38.00	301.92
4010	9.95	1171.42	261.01	184.42	37.98	1.95	1197.56	0.00	228.00	37.98	301.92
4020	7.83	1171.15	231.08	181.53	37.96	2.45	1200.64	0.00	227.96	37.96	301.92
4030	8.32	1171.46	262.98	182.16	37.95	1.66	1199.92	0.00	227.93	37.94	301.92
4040	9.58	1171.38	279.54	181.17	37.93	1.71	1194.91	0.00	227.90	37.92	301.92
4050	9.63	1171.29	243.89	180.34	37.90	1.96	1196.73	0.00	227.87	37.90	301.92
4060	9.22	1171.41	250.01	179.99	37.86	2.12	1198.53	0.00	227.84	37.88	301.92
4070	7.81	1171.39	245.93	178.64	37.86	2.41	1199.85	0.00	227.80	37.86	301.92
4080	8.57	1171.10	232.45	182.74	37.84	1.94	1201.65	0.00	227.77	37.84	301.92
4090	9.49	1171.31	270.79	182.32	37.83	2.00	1196.98	0.00	227.74	37.82	301.92
4100	7.93	1171.58	259.83	177.64	37.80	2.53	1197.61	0.00	227.70	37.80	301.92
4110	7.80	1171.16	245.77	179.51	37.79	2.12	1201.20	0.00	227.67	37.78	301.92
4120	8.83	1171.19	278.95	181.37	37.76	1.92	1197.70	0.00	227.64	37.76	301.92

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	**Gas Mass Flow (lbm/sec)**	**Gas Enthalpy (Btu/lbm)**	**Liquid Mass Flow (lbm/sec)**	**Liquid Enthalpy (Btu/lbm)**	**Pressure (psi)**	**Gas Mass Flow (lbm/sec)**	**Gas Enthalpy (Btu/lbm)**	**Liquid Mass Flow (lbm/sec)**	**Liquid Enthalpy Btu/lbm)**	**Pressure (psi)**	**Spilled HPI Flow (gpm)**
4130	9.40	1171.32	294.00	180.76	37.74	2.14	1197.71	0.00	227.61	37.74	301.92
4140	8.84	1171.05	259.29	181.26	37.72	2.35	1200.85	0.00	227.58	37.72	301.92
4150	7.81	1170.92	236.50	182.66	37.70	2.24	1201.08	0.00	227.54	37.70	301.92
4160	8.71	1171.34	269.84	180.62	37.68	2.01	1197.83	0.00	227.51	37.68	301.92
4170	9.78	1171.49	288.14	177.12	37.66	1.99	1195.90	0.00	227.48	37.66	301.92
4180	8.84	1171.25	251.75	177.17	37.63	2.27	1199.09	0.00	227.45	37.64	301.92
4190	7.64	1171.02	225.48	180.25	37.62	2.51	1200.45	0.00	227.41	37.62	301.92
4200	8.56	1171.15	259.92	181.14	37.61	1.79	1197.77	0.00	227.38	37.60	301.92
4210	8.83	1171.04	260.28	180.29	37.58	1.98	1198.06	0.00	227.35	37.58	301.92
4220	7.68	1170.80	231.08	180.48	37.56	2.53	1200.87	0.00	227.32	37.56	301.92
4230	8.64	1171.13	260.93	181.44	37.51	1.72	1197.92	0.00	227.28	37.54	301.92
4240	8.86	1171.02	262.73	181.09	37.49	1.93	1197.24	0.00	227.26	37.52	301.92
4250	7.42	1170.73	231.38	180.81	37.50	2.65	1200.46	0.00	227.22	37.50	301.92
4260	8.01	1171.01	262.96	182.08	37.48	1.96	1198.33	0.00	227.19	37.48	301.92
4270	8.72	1170.94	285.16	181.24	37.46	1.56	1194.49	0.00	227.16	37.46	301.92
4280	8.44	1170.61	247.85	181.18	37.45	2.27	1198.63	0.00	227.12	37.44	301.92
4290	7.80	1170.67	228.28	181.93	37.42	2.59	1200.44	0.00	227.09	37.42	301.92
4300	8.35	1170.99	247.21	181.42	37.40	1.80	1199.75	0.00	227.06	37.40	301.92
4310	8.52	1170.99	252.46	180.96	37.37	1.94	1199.63	0.00	227.02	37.38	301.92
4320	7.62	1170.79	234.23	180.11	37.33	2.62	1200.60	0.00	226.99	37.36	301.92

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
4330	8.43	1170.95	249.61	182.54	37.33	1.97	1200.64	0.00	226.96	37.34	301.92
4340	8.73	1171.02	269.58	182.15	37.29	1.85	1197.56	0.00	226.93	37.32	301.92
4350	8.42	1170.71	275.62	179.86	37.30	2.30	1197.67	0.00	226.89	37.30	301.92
4360	7.78	1170.69	267.45	179.40	37.28	2.41	1199.53	0.00	226.86	37.28	301.92
4370	7.85	1170.66	252.31	179.68	37.26	2.07	1200.66	0.00	226.83	37.26	301.92
4380	8.70	1170.86	276.49	179.26	37.23	1.93	1198.14	0.00	226.80	37.24	301.92
4390	8.21	1171.02	268.59	178.83	37.22	2.26	1197.91	0.00	226.76	37.22	301.92
4400	8.19	1170.81	265.48	178.96	37.21	2.13	1199.06	0.00	226.73	37.20	301.92
4410	8.20	1170.76	256.66	179.61	37.18	2.17	1199.36	0.00	226.70	37.18	301.93
4420	9.08	1170.85	238.18	182.57	37.16	2.01	1199.14	0.00	226.67	37.16	301.93
4430	9.68	1170.75	219.16	183.90	37.14	2.18	1199.48	0.00	226.63	37.14	301.93
4440	9.09	1170.61	183.19	187.03	37.09	2.63	1200.84	0.00	226.60	37.12	301.93
4450	10.95	1171.02	203.00	187.54	37.11	1.77	1197.62	0.00	226.57	37.10	301.92
4460	11.53	1170.84	188.86	187.19	37.06	1.77	1197.09	0.00	226.54	37.08	301.93
4470	10.30	1170.51	149.90	192.53	37.07	2.48	1200.49	0.00	226.50	37.06	301.92
4480	11.30	1170.70	166.68	194.43	37.04	1.90	1199.90	0.00	226.47	37.04	301.92
4490	11.98	1170.96	206.84	189.31	37.02	1.94	1197.44	0.00	226.44	37.02	301.92
4500	11.31	1171.09	209.05	186.73	37.00	2.35	1198.85	0.00	226.40	37.00	301.93
4510	11.75	1171.37	213.42	185.15	36.98	2.06	1200.17	0.00	226.37	36.98	301.93
4520	11.15	1171.45	199.03	182.99	36.96	2.19	1200.78	0.00	226.34	36.96	301.93

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
4530	11.20	1171.08	178.13	186.70	36.94	1.62	1199.63	0.00	226.31	36.94	301.93
4540	11.64	1171.08	161.19	191.30	36.92	1.69	1200.28	0.00	226.27	36.92	301.93
4550	10.37	1171.17	151.73	191.07	36.88	2.67	1201.38	0.00	226.24	36.90	301.92
4560	10.79	1171.34	173.37	193.32	36.88	2.43	1200.64	0.00	226.20	36.88	301.93
4570	10.97	1171.65	194.79	195.90	36.86	1.76	1200.82	0.00	226.17	36.86	301.93
4580	10.96	1171.31	200.58	201.77	36.84	1.98	1201.21	0.00	226.14	36.84	301.93
4590	11.05	1171.47	177.91	203.20	36.82	2.58	1200.99	0.00	226.11	36.82	301.93
4600	10.51	1172.67	170.85	197.66	36.80	2.54	1200.77	0.00	226.07	36.80	301.93
4610	10.78	1173.10	187.47	196.40	36.78	2.28	1200.15	0.00	226.04	36.78	301.93
4620	11.62	1172.95	226.93	191.94	36.76	2.02	1197.61	0.00	226.01	36.76	301.93
4630	11.50	1172.03	205.17	191.31	36.74	2.23	1198.60	0.00	225.97	36.74	301.93
4640	10.31	1171.54	170.63	189.53	36.72	2.57	1200.30	0.00	225.94	36.72	301.93
4650	11.19	1171.65	193.55	189.14	36.70	1.64	1197.90	0.00	225.91	36.70	301.93
4660	11.65	1170.83	179.24	192.84	36.68	1.59	1198.06	0.00	225.88	36.68	301.93
4670	10.55	1170.33	152.38	193.82	36.65	2.60	1200.44	0.00	225.84	36.66	301.93
4680	10.34	1171.21	155.21	194.04	36.64	2.53	1200.68	0.00	225.81	36.64	301.93
4690	11.01	1172.55	189.43	192.97	36.62	1.97	1199.58	0.00	225.77	36.62	301.93
4700	11.96	1172.31	206.45	192.35	36.60	1.68	1197.70	0.00	225.74	36.60	301.93
4710	11.04	1172.09	192.96	190.64	36.58	2.20	1199.62	0.00	225.71	36.58	301.93
4720	8.36	1171.58	141.13	186.65	36.56	1.90	1201.74	0.00	225.68	36.56	301.93

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
4730	7.88	1169.89	149.45	193.70	36.54	1.75	1205.09	0.00	225.64	36.54	301.93
4740	10.20	1169.97	196.81	199.19	36.52	2.07	1203.34	0.00	225.61	36.52	301.93
4750	12.21	1170.61	213.27	192.22	36.50	1.93	1198.06	0.00	225.58	36.50	301.93
4760	11.78	1170.83	205.44	184.99	36.48	2.27	1197.56	0.00	225.54	36.48	301.93
4770	12.33	1170.70	173.88	188.62	36.39	1.56	1196.97	0.00	225.51	36.46	301.93
4780	12.95	1170.99	155.65	194.43	36.45	1.57	1197.99	0.00	225.48	36.44	301.93
4790	11.51	1171.13	130.54	198.92	36.41	2.46	1200.27	0.00	225.44	36.42	301.93
4800	11.31	1171.13	142.54	201.12	36.40	2.42	1200.97	0.00	225.41	36.40	301.93
4810	12.07	1171.12	164.12	200.56	36.38	2.06	1200.60	0.00	225.38	36.38	301.93
4820	12.76	1171.64	184.21	200.05	36.36	2.00	1199.69	0.00	225.34	36.36	301.93
4830	12.12	1171.61	167.15	201.13	36.34	2.48	1200.21	0.00	225.31	36.34	301.93
4840	11.29	1170.67	154.12	202.44	36.32	2.57	1201.25	0.00	225.28	36.32	301.93
4850	11.51	1170.75	168.96	204.22	36.30	2.36	1201.23	0.00	225.24	36.30	301.93
4860	12.62	1171.65	200.72	203.69	36.28	2.03	1200.84	0.00	225.21	36.28	301.93
4870	12.30	1171.85	196.58	202.07	36.26	2.26	1200.88	0.00	225.17	36.26	301.93
4880	11.02	1171.47	160.80	203.24	36.24	2.61	1200.99	0.00	225.14	36.24	301.93
4890	10.97	1171.48	153.73	206.70	36.22	2.60	1200.96	0.00	225.11	36.22	301.93
4900	11.71	1171.59	171.45	206.11	36.20	2.07	1200.23	0.00	225.07	36.20	301.93
4910	12.14	1172.28	241.08	193.92	36.18	1.96	1200.19	0.00	225.04	36.18	301.93
4920	12.09	1172.20	259.43	186.75	36.16	1.90	1200.09	0.00	225.01	36.16	301.93

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
4930	11.78	1170.56	177.50	187.97	36.14	2.00	1201.03	0.00	224.98	36.14	301.93
4940	11.07	1170.22	131.88	194.56	36.12	2.57	1201.30	0.00	224.94	36.12	301.93
4950	10.44	1170.87	146.73	197.05	36.08	2.55	1200.62	0.00	224.91	36.10	301.93
4960	9.28	1170.35	168.33	193.04	36.09	2.56	1200.66	0.00	224.87	36.08	301.93
4970	10.49	1170.20	194.53	193.47	36.07	1.78	1199.38	0.00	224.84	36.06	301.93
4980	11.78	1171.05	219.17	191.43	36.03	1.71	1196.08	0.00	224.81	36.04	301.93
4990	11.55	1171.41	237.87	186.73	36.02	2.35	1197.99	0.00	224.78	36.02	301.93
5000	11.19	1170.78	212.91	185.92	36.00	2.50	1200.24	0.00	224.74	36.00	301.93
5010	11.55	1171.29	189.32	181.28	36.00	1.93	1199.96	0.00	224.74	36.00	301.93
5020	11.52	1171.51	169.65	183.67	35.99	1.82	1201.35	0.00	224.74	36.00	301.93
5030	11.46	1170.93	145.48	193.38	36.01	1.80	1200.60	0.00	224.74	36.00	301.93
5040	11.46	1170.45	166.49	190.35	36.02	1.68	1197.49	0.00	224.74	36.00	301.93
5050	10.59	1170.00	192.87	185.94	36.00	2.36	1199.12	0.00	224.74	36.00	301.93
5060	11.61	1171.96	218.48	184.14	36.00	2.18	1199.63	0.00	224.74	36.00	301.93
5070	11.24	1172.88	194.70	183.39	36.00	2.26	1200.01	0.00	224.74	36.00	301.93
5080	11.71	1171.18	147.68	189.98	35.99	1.38	1199.77	0.00	224.74	36.00	301.93
5090	12.03	1170.10	138.18	193.57	36.00	1.23	1197.64	0.00	224.74	36.00	301.93
5100	10.14	1169.74	143.77	189.99	35.98	2.30	1199.77	0.00	224.74	36.00	301.93
5110	10.68	1170.81	188.41	190.05	36.00	1.96	1200.69	0.00	224.74	36.00	301.93
5120	9.20	1170.84	164.15	195.10	36.00	1.76	1198.68	0.00	224.74	36.00	301.93

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	**Gas Mass Flow (lbm/sec)**	**Gas Enthalpy (Btu/lbm)**	**Liquid Mass Flow (lbm/sec)**	**Liquid Enthalpy (Btu/lbm)**	**Pressure (psi)**	**Gas Mass Flow (lbm/sec)**	**Gas Enthalpy (Btu/lbm)**	**Liquid Mass Flow (lbm/sec)**	**Liquid Enthalpy Btu/lbm)**	**Pressure (psi)**	**Spilled HPI Flow (gpm)**
5130	13.53	1169.80	252.02	204.92	36.01	2.21	1197.54	0.00	224.74	36.00	301.93
5140	15.88	1169.76	261.95	200.50	36.00	2.63	1196.93	0.00	224.74	36.00	301.93
5150	13.46	1169.68	103.37	187.50	36.00	2.53	1195.41	0.00	224.74	36.00	301.93
5160	16.09	1170.32	95.15	188.75	35.98	1.66	1194.54	0.00	224.74	36.00	301.93
5170	16.14	1171.89	125.64	191.39	36.00	1.95	1196.84	0.00	224.74	36.00	301.93
5180	14.95	1173.17	145.74	191.47	36.00	2.56	1198.26	0.00	224.74	36.00	301.93
5190	15.00	1174.01	174.95	190.73	36.00	2.10	1198.94	0.00	224.74	36.00	301.93
5200	14.62	1174.12	172.55	191.32	36.00	2.36	1199.30	0.00	224.74	36.00	301.93
5210	14.50	1174.05	169.77	189.21	36.00	1.95	1199.56	0.00	224.74	36.00	301.93
5220	15.67	1173.70	171.43	194.64	36.01	1.34	1201.72	0.00	224.74	36.00	301.93
5230	15.48	1172.72	184.42	194.20	35.99	1.90	1201.36	0.00	224.74	36.00	301.93
5240	14.99	1173.54	233.19	186.76	36.00	2.28	1198.78	0.00	224.74	36.00	301.93
5250	14.92	1174.05	212.67	182.95	36.00	1.68	1197.46	0.00	224.74	36.00	301.93
5260	14.44	1172.88	145.09	188.87	36.00	1.89	1200.03	0.00	224.74	36.00	301.93
5270	14.40	1172.38	138.45	196.72	35.99	2.15	1200.55	0.00	224.74	36.00	301.93
5280	14.20	1173.00	170.10	190.18	36.00	1.79	1198.82	0.00	224.74	36.00	301.93
5290	12.57	1172.25	182.66	188.98	36.00	2.35	1199.72	0.00	224.74	36.00	301.93
5300	11.66	1171.87	180.78	184.95	36.00	2.56	1199.57	0.00	224.74	36.00	301.93
5310	11.66	1172.21	127.89	190.13	36.00	1.22	1198.03	0.00	224.74	36.00	301.93
5320	13.07	1169.96	185.42	212.05	35.98	1.34	1196.44	0.01	224.74	36.00	301.93

	Reactor Vessel Side					Pump Discharge Side					
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy Btu/lbm)	Pressure (psi)	Spilled HPI Flow (gpm)
5330	16.16	1168.56	177.12	215.15	35.96	2.60	1189.95	0.01	230.08	36.00	301.93
5340	16.29	1169.11	101.32	198.85	36.00	2.44	1189.32	0.00	224.74	36.00	301.93
5350	15.15	1170.34	158.45	180.98	36.00	2.09	1197.23	0.00	224.74	36.00	301.93
5360	14.68	1171.32	147.86	178.48	36.00	2.13	1199.31	0.00	224.74	36.00	301.93
5370	14.76	1171.98	117.27	186.78	36.00	1.66	1199.23	0.00	224.74	36.00	301.93
5380	15.86	1172.83	158.02	192.27	36.00	1.70	1196.44	0.00	224.74	36.00	301.93
5390	15.44	1173.84	201.41	190.11	36.00	2.35	1196.62	0.00	224.74	36.00	301.93
5400	13.60	1174.34	195.33	186.41	36.00	2.55	1198.57	0.00	224.74	36.00	301.93
5410	13.68	1173.84	181.14	183.49	36.00	1.92	1199.56	0.00	224.74	36.00	301.93
5420	15.41	1172.81	149.62	190.78	35.98	1.17	1201.90	0.00	224.74	36.00	301.93
5430	14.90	1173.15	154.24	194.17	35.99	2.03	1200.15	0.00	224.74	36.00	301.93
5440	13.31	1174.10	194.49	187.81	36.00	2.62	1199.03	0.00	224.74	36.00	301.93
5450	13.25	1175.02	215.33	182.62	36.00	2.30	1199.91	0.00	224.74	36.00	301.93
5460	14.59	1173.67	166.76	186.09	36.00	1.45	1199.67	0.00	224.74	36.00	301.93
5466.85	15.50	1171.05	70.54	218.83	36.00	0.58	1198.07	0.00	224.74	36.00	301.93

Table 6-31. Deleted Per Rev. 29 Update

38

Table 6-32. Steam Line Break Mass and Energy Releases for Double-Ended Guillotine Break

Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)
0.0	0.0	1261.9	944.1	2.1	6737.0	1270.7	834.7	4.2	3029.1	1275.1	784.7
0.1	16210.7	1262.9	933.9	2.2	6687.0	1270.8	833.4	4.3	2947.1	1275.2	783.2
0.2	11175.3	1265.2	909.5	2.3	6646.9	1271.0	831.8	4.4	2893.7	1275.3	781.8
0.3	9092.1	1266.6	895.2	2.4	6618.9	1271.1	830.0	4.5	2885.6	1275.3	780.2
0.4	8239.2	1267.5	884.4	2.5	6586.4	1271.4	827.3	4.6	2878.4	1275.3	778.4
0.5	8007.2	1268.1	876.9	2.6	6495.0	1271.6	824.4	4.7	2871.9	1275.4	776.1
0.6	8083.4	1268.6	871.5	2.7	6341.9	1271.9	821.6	4.8	2866.1	1275.6	773.8
0.7	8133.4	1268.9	867.3	2.8	6147.2	1272.0	818.8	4.9	2860.2	1275.8	771.5
0.8	8100.8	1269.1	863.6	2.9	5915.9	1272.2	816.1	5.0	2894.2	1276.0	769.4
0.9	7998.8	1269.3	860.4	3.0	5645.9	1272.4	813.3	5.5	2795.1	1276.6	759.4
1.0	7858.0	1269.6	856.9	3.1	5354.2	1272.6	810.7	6.0	2728.0	1277.4	743.2
1.1	7705.4	1269.9	853.0	3.2	5038.2	1272.7	808.3	6.5	2687.9	1277.7	724.7
1.2	7556.9	1270.2	849.0	3.3	4673.2	1272.9	806.1	7.0	2616.5	1277.3	712.3
1.3	7420.6	1270.5	845.3	3.4	4219.5	1273.1	803.7	7.5	2557.0	1277.7	693.3
1.4	7297.7	1270.7	842.3	3.5	3923.4	1273.3	801.4	8.0	2473.2	1277.6	674.9
1.5	7188.1	1270.7	840.0	3.6	3711.9	1273.6	798.6	8.5	2422.2	1277.4	658.9
1.6	7089.9	1270.7	838.1	3.7	3539.0	1273.9	795.7	9.0	2364.1	1276.5	649.7
1.7	7005.0	1270.6	837.4	3.8	3391.3	1274.1	793.2	9.5	2351.6	1275.2	644.6
1.8	6929.4	1270.6	837.0	3.9	3278.9	1274.4	790.9	10.0	2322.4	1273.9	639.7
1.9	6859.9	1270.5	836.4	4.0	3196.1	1274.6	788.7	10.5	2309.3	1272.6	635.2
2.0	6795.3	1270.6	835.7	4.1	3117.8	1274.9	786.5	11.0	2289.4	1271.4	630.2

Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)
11.5	2263.4	1270.4	623.9	22.5	2165.9	1252.6	569.4	33.5	1832.3	1244.4	495.4
12.0	2234.8	1269.8	616.0	23.0	2109.0	1248.9	574.6	34.0	1824.5	1244.1	493.4
12.5	2199.7	1269.3	609.2	23.5	2098.7	1247.4	575.6	34.5	1817.9	1243.8	491.3
13.0	2176.4	1268.9	602.6	24.0	2088.9	1247.0	572.6	35.0	1809.5	1243.4	489.2
13.5	2131.2	1269.1	591.1	24.5	2077.7	1246.8	567.0	35.5	1801.6	1242.9	487.1
14.0	2088.8	1269.3	579.4	25.0	2063.4	1246.7	560.7	36.0	1792.4	1242.4	484.8
14.5	2035.1	1269.3	569.9	25.5	2049.0	1246.6	554.6	36.5	1782.9	1241.9	482.3
15.0	2026.8	1268.6	568.5	26.0	2030.4	1246.4	548.5	37.0	1773.0	1241.5	479.7
15.5	2040.1	1267.4	571.8	26.5	2008.4	1246.3	542.8	37.5	1762.5	1241.1	477.0
16.0	2054.8	1266.1	575.8	27.0	1990.3	1246.2	537.7	38.0	1751.8	1240.7	474.1
16.5	2069.9	1265.0	579.6	27.5	1971.6	1246.1	532.8	38.5	1740.8	1240.4	471.1
17.0	2091.3	1263.9	582.9	28.0	1956.4	1245.9	528.3	39.0	1729.9	1240.1	468.2
17.5	2091.6	1263.1	583.0	28.5	1940.4	1245.8	524.3	39.5	1718.4	1239.8	465.1
18.0	2090.9	1262.7	580.1	29.0	1926.8	1245.6	520.6	40.0	1707.5	1239.5	462.1
18.5	2097.9	1262.1	577.6	29.5	1913.8	1245.5	517.5	40.5	1695.8	1239.3	458.9
19.0	2083.5	1261.5	575.2	30.0	1901.5	1245.3	514.3	41.0	1685.6	1239.1	455.9
19.5	2067.7	1260.8	574.1	30.5	1889.7	1245.2	511.0	41.5	1674.8	1238.9	453.0
20.0	2053.4	1260.2	573.3	31.0	1878.2	1245.2	507.9	42.0	1664.8	1238.8	449.9
20.5	2052.9	1259.4	572.2	31.5	1867.4	1245.1	504.8	42.5	1653.9	1238.6	447.1
21.0	2060.6	1258.6	569.7	32.0	1856.7	1245.0	502.1	43.0	1644.1	1238.4	444.6
21.5	2081.0	1257.6	566.8	32.5	1848.0	1244.8	499.8	43.5	1634.8	1238.3	442.1
22.0	2066.0	1256.3	565.5	33.0	1839.3	1244.6	497.6	44.0	1625.9	1238.1	440.1

Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)
44.5	1617.3	1238.0	437.7	56.0	1445.1	1235.1	391.5	79.0	1235.5	1231.0	338.7
45.0	1609.4	1237.8	436.3	57.0	1432.4	1234.9	388.9	80.0	1227.6	1230.9	336.5
45.5	1602.7	1237.6	434.3	59.0	1412.0	1234.4	384.5	81.0	1219.2	1230.8	334.4
46.0	1595.5	1237.4	432.5	60.0	1403.8	1234.1	382.9	82.0	1210.9	1230.6	332.3
46.5	1589.0	1237.3	430.4	61.0	1396.1	1233.8	380.9	83.0	1203.1	1230.5	330.4
47.0	1582.0	1237.0	429.0	62.0	1387.7	1233.5	378.9	85.0	1188.4	1230.4	326.3
47.5	1575.5	1236.9	426.8	63.0	1378.7	1233.3	376.2	86.0	1181.2	1230.3	324.3
48.0	1568.3	1236.7	424.8	64.0	1369.2	1233.1	373.3	87.0	1173.5	1230.2	322.3
48.5	1561.9	1236.5	423.3	65.0	1358.7	1233.1	370.6	88.0	1165.9	1230.0	320.4
49.0	1554.6	1236.3	421.3	66.0	1348.7	1233.0	368.0	89.0	1158.6	1229.7	318.7
49.5	1547.4	1236.1	419.5	67.0	1338.3	1233.0	364.4	90.0	1150.9	1229.4	316.6
50.0	1540.0	1236.0	417.6	68.0	1326.6	1232.9	361.2	91.0	1142.4	1229.1	314.2
50.5	1532.4	1235.9	414.8	69.0	1317.5	1232.8	359.4	92.0	1133.3	1228.8	312.2
51.0	1524.4	1235.8	412.4	70.0	1309.8	1232.5	357.5	93.0	1123.3	1228.5	309.1
51.5	1515.7	1235.7	410.4	71.0	1302.9	1232.2	356.0	94.0	1112.9	1228.2	306.6
52.0	1507.3	1235.6	408.2	72.0	1294.8	1232.1	353.7	95.0	1102.1	1227.8	303.7
52.5	1499.5	1235.5	406.3	73.0	1285.4	1232.0	351.4	96.0	1090.8	1227.5	301.1
53.0	1491.6	1235.4	404.2	74.0	1275.8	1231.9	348.9	97.0	1078.3	1226.9	297.8
53.5	1483.5	1235.3	401.9	75.0	1266.3	1231.7	346.5	98.0	1064.5	1226.4	294.4
54.0	1475.3	1235.2	400.1	76.0	1257.7	1231.6	344.4	99.0	1051.0	1226.0	291.0
54.5	1466.7	1235.2	397.8	77.0	1250.1	1231.4	342.4	100.0	1039.2	1226.0	287.9
55.0	1459.7	1235.1	396.0	78.0	1242.9	1231.2	340.8	101.0	1028.7	1226.6	283.8

Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)
102.0	1019.3	1227.2	280.9	124.0	895.0	1220.9	252.5	146.0	709.1	1222.7	206.6
103.0	1009.5	1227.8	277.7	125.0	886.7	1220.4	250.6	147.0	681.2	1223.4	202.9
104.0	1000.0	1228.1	274.9	126.0	878.0	1220.3	248.4	148.0	714.2	1223.9	198.7
105.0	991.5	1227.9	273.2	127.0	871.4	1220.5	246.6	149.0	689.0	1223.9	194.5
106.0	984.6	1227.3	272.3	128.0	867.7	1220.8	244.9	150.0	662.3	1224.0	190.2
107.0	977.9	1226.5	271.5	129.0	863.1	1221.0	243.1	151.0	640.4	1224.1	184.7
108.0	971.1	1225.7	270.4	130.0	855.0	1221.1	240.7	152.0	623.1	1224.1	178.6
109.0	964.3	1224.9	268.8	131.0	846.8	1220.9	238.7	153.0	607.7	1224.3	172.1
110.0	958.3	1224.5	267.1	132.0	838.0	1220.3	236.7	154.0	591.5	1225.0	164.6
111.0	951.9	1224.3	264.9	133.0	828.7	1219.8	234.1	155.0	571.4	1226.1	156.5
112.0	945.5	1224.3	262.8	134.0	819.0	1219.5	231.4	156.0	545.0	1227.4	147.4
113.0	938.6	1224.0	260.9	135.0	811.1	1219.6	229.1	157.0	511.4	1228.8	138.1
114.0	930.6	1223.7	259.2	136.0	804.5	1220.0	227.0	158.0	471.5	1230.1	128.1
115.0	924.6	1223.3	257.6	137.0	799.3	1220.4	225.5	159.0	429.0	1231.2	118.0
116.0	918.2	1223.4	256.2	138.0	795.6	1220.6	224.3	160.0	387.2	1232.2	107.8
117.0	911.6	1223.7	255.1	139.0	793.9	1220.4	223.6	161.0	346.1	1233.3	97.2
118.0	909.1	1224.0	254.7	140.0	781.4	1220.6	222.1	162.0	305.5	1234.5	86.1
119.0	910.5	1224.0	254.8	141.0	773.9	1220.5	220.3	163.0	275.5	1235.4	77.5
120.0	911.9	1223.6	255.3	142.0	765.9	1220.5	218.2	164.0	249.6	1236.1	70.5
121.0	911.2	1223.0	255.7	143.0	755.4	1220.6	215.4	165.0	224.6	1236.7	64.0
122.0	908.2	1222.4	255.3	144.0	743.9	1221.1	212.5	166.0	201.9	1237.5	57.6
123.0	902.3	1221.7	254.1	145.0	731.9	1221.9	209.5	167.0	195.1	1238.1	55.1

Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)	Time (sec)	Flow (lbm/sec)	Enthalpy (Btu/lbm)	Pressure (psia)
168.0	173.0	1239.5	49.5	177.0	55.7	1243.3	27.4	186.0	37.9	1245.2	27.8
169.0	151.3	1241.0	44.1	178.0	53.3	1243.3	27.6	187.0	37.0	1245.2	27.6
170.0	174.4	1240.9	49.1	179.0	51.4	1243.7	27.4	188.0	32.6	1245.2	27.5
171.0	154.1	1241.7	45.2	180.0	46.8	1244.3	27.3	190.0	32.4	1245.2	27.9
172.0	137.3	1242.3	40.9	181.0	43.0	1244.8	27.5	192.0	26.8	1245.3	27.6
173.0	122.7	1242.6	37.5	182.0	45.0	1245.1	27.7	194.0	28.3	1246.0	28.1
174.0	112.1	1242.8	34.7	183.0	43.6	1245.3	27.5	196.0	22.1	1246.9	27.8
175.0	98.5	1243.1	31.4	184.0	39.1	1245.3	27.3	198.0	25.0	1246.8	28.3
176.0	87.7	1243.3	28.6	185.0	35.3	1245.2	27.7	200.0	17.7	1246.5	27.9

Table 6-33. NPSH Available and Required for LPI and BS Pumps (Limiting Flow Case)

	Flow	NPSHr	NPSHa
BS	1110 gpm	15.0 ft	21.33 ft
LPI	3840 gpm	16.5 ft	18.09 ft

Note:

The above information is currently being revised as part of the Reactor Building Emergency Sump Screen replacement project and will be replaced with updated valves at the completion of that effort.

Table 6-34. Deleted Per 2008 Update

Table 6-35. ROTSG Peak Pressure Mass and Energy Release Data

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
0.0	2952.54	1185.14	50071.66	586.96	2194.9	3246.74	1185.47	53239.03	586.22	2195.9
0.1	3252.01	1186.21	49158.25	582.61	1184.1	3591.04	1186.39	50260.68	580.74	1187.2
0.2	3480.73	1187.49	47758.00	578.56	1155.1	3667.39	1188.29	44940.82	575.74	1078.4
0.3	3491.71	1188.37	44815.42	576.24	1108.5	3528.65	1190.47	39264.74	574.99	1010.7
0.4	3572.82	1189.50	40849.95	571.75	1049.1	3814.95	1192.29	33527.03	569.28	962.7
0.5	3582.23	1190.37	38848.06	569.99	1033.8	4077.28	1194.93	30429.58	558.98	923.0
0.6	3603.98	1190.57	38417.86	569.85	1032.2	4555.21	1200.03	30843.14	537.92	849.1
0.7	3631.00	1190.50	38565.54	570.09	1034.6	4940.88	1203.72	31095.94	521.43	807.9
0.8	3681.98	1190.50	38455.83	570.10	1035.7	4877.74	1204.80	29888.32	515.67	776.7
0.9	3757.54	1190.61	37989.32	569.90	1031.9	4689.83	1205.30	29486.80	511.62	754.1
1.0	3857.08	1190.78	37278.62	569.65	1029.8	4451.19	1205.38	29643.73	509.03	742.1
1.1	3998.17	1191.12	36168.17	569.06	1022.8	4192.05	1205.19	30189.31	507.64	736.7
1.2	4164.63	1191.64	34711.18	567.89	1012.0	3936.15	1204.89	30906.12	506.99	735.4
1.3	4325.52	1192.23	33257.31	566.34	999.0	3706.45	1204.57	31632.17	506.74	735.9
1.4	4885.59	1195.32	32760.04	558.32	988.0	3515.74	1204.30	32257.22	506.65	736.9
1.5	5584.34	1199.42	30882.26	544.85	873.7	3370.40	1204.10	32701.09	506.54	737.3
1.6	5860.66	1201.32	29087.52	537.20	912.6	3273.78	1203.98	32895.95	506.36	737.1
1.7	6167.30	1203.04	28953.62	533.36	884.2	3214.41	1203.93	32897.65	506.07	736.0
1.8	6527.57	1205.91	27179.85	525.07	806.8	3178.33	1203.95	32817.10	505.55	733.3

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
1.9	6729.14	1208.08	25068.96	517.96	766.6	3163.92	1204.06	32678.24	504.79	729.2
2.0	6928.72	1209.35	23784.28	515.08	758.2	3172.02	1204.22	32466.24	503.84	723.8
2.1	7030.19	1210.21	22869.40	512.77	733.3	3207.95	1204.43	32106.56	502.78	717.6
2.2	6979.55	1210.67	22385.05	510.46	724.0	3265.28	1204.66	31601.79	501.67	711.2
2.3	6907.46	1210.93	22100.22	508.65	713.2	3329.78	1204.92	31039.75	500.48	704.3
2.4	6861.16	1211.26	21717.82	506.83	703.7	3397.75	1205.19	30450.86	499.22	696.9
2.5	6859.45	1211.75	21169.86	504.92	692.3	3468.03	1205.48	29853.11	497.92	689.3
2.6	6897.89	1212.43	20433.47	502.80	679.2	3538.34	1205.78	29265.49	496.63	681.9
2.7	6946.79	1213.25	19584.63	500.40	663.8	3606.07	1206.08	28677.95	495.32	674.5
2.8	6972.43	1214.01	18804.56	497.95	648.7	3670.47	1206.40	28063.32	493.89	666.5
2.9	6965.69	1214.59	18207.22	495.77	636.2	3733.35	1206.74	27429.91	492.32	657.7
3.0	6929.04	1214.96	17795.66	493.90	625.8	3792.59	1207.12	26777.52	490.47	647.6
3.1	6864.79	1215.14	17567.74	492.36	617.9	3842.57	1207.49	26105.76	488.42	636.0
3.2	6784.36	1215.15	17506.03	491.21	612.8	3877.66	1207.82	25467.85	486.44	625.4
3.3	6698.04	1215.06	17543.30	490.34	609.6	3895.99	1208.09	24920.13	484.63	616.2
3.4	6605.71	1214.92	17611.35	489.54	606.6	3926.78	1208.38	24355.35	482.94	607.4
3.5	6506.09	1214.76	17695.64	488.72	603.7	3983.00	1208.74	23690.59	481.19	597.9
3.6	6399.97	1214.56	17815.95	487.95	601.1	4041.44	1209.13	23004.56	479.38	588.2
3.7	6291.48	1214.31	17985.53	487.32	599.3	4091.37	1209.50	22330.49	477.50	578.4
3.8	6189.08	1214.05	18192.78	486.90	598.9	4132.22	1209.86	21676.24	475.58	568.2

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
3.9	6093.43	1213.81	18364.62	486.43	598.2	4166.94	1210.20	21051.50	473.67	558.5
4.0	6002.18	1213.65	18455.89	485.75	595.6	4197.72	1210.53	20464.28	471.84	549.2
4.1	5911.43	1213.51	18513.10	484.94	592.6	4223.01	1210.84	19912.58	470.07	540.3
4.2	5816.88	1213.37	18590.20	484.14	589.5	4242.05	1211.12	19393.09	468.34	531.6
4.3	5723.32	1213.20	18694.91	483.44	587.5	4255.78	1211.39	18902.81	466.64	523.3
4.4	5636.97	1213.05	18782.69	482.76	585.1	4265.65	1211.64	18437.72	464.97	515.2
4.5	5564.71	1212.95	18826.56	482.08	582.7	4272.74	1211.89	17995.82	463.35	507.6
4.6	5509.04	1212.91	18804.40	481.36	579.8	4277.21	1212.11	17578.40	461.79	499.9
4.7	5462.44	1212.92	18716.22	480.50	575.8	4278.83	1212.31	17196.05	460.31	493.2
4.8	5420.41	1212.96	18600.10	479.59	571.6	4275.28	1212.50	16828.26	458.83	486.3
4.9	5384.66	1213.01	18470.19	478.68	567.3	4271.12	1212.70	16445.34	457.27	479.1
5.0	5355.41	1213.09	18322.90	477.77	563.1	4271.49	1212.92	16042.20	455.68	471.8
5.1	5331.29	1213.19	18153.43	476.84	558.7	4276.89	1213.18	15619.78	454.08	464.4
5.2	5313.06	1213.31	17958.80	475.89	554.0	4287.63	1213.45	15191.15	452.52	457.0
5.3	5301.69	1213.46	17733.09	474.89	549.1	4300.49	1213.72	14774.33	451.03	450.1
5.4	5294.20	1213.64	17480.21	473.84	543.8	4312.15	1213.98	14377.30	449.60	443.4
5.5	5286.91	1213.82	17214.45	472.74	538.2	4322.38	1214.24	13995.30	448.20	437.0
5.6	5275.98	1214.00	16947.60	471.59	532.5	4331.98	1214.49	13619.61	446.82	430.6
5.7	5251.41	1214.14	16715.41	470.39	526.7	4341.53	1214.74	13244.54	445.44	424.3
5.8	5209.31	1214.20	16562.60	469.26	521.7	4351.99	1215.01	12866.73	444.06	417.9

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
5.9	5158.60	1214.20	16472.15	468.24	517.5	4364.10	1215.30	12483.40	442.68	411.5
6.0	5106.65	1214.18	16399.34	467.29	513.6	4377.46	1215.62	12092.86	441.28	405.1
6.1	5058.53	1214.18	16312.48	466.33	509.7	4391.25	1215.96	11695.23	439.85	398.5
6.2	5021.41	1214.22	16171.40	465.30	505.4	4405.59	1216.32	11292.11	438.40	391.8
6.3	5008.39	1214.37	15923.55	464.18	500.1	4420.27	1216.70	10885.50	436.94	385.1
6.4	5028.54	1214.69	15526.34	462.92	493.6	4434.26	1217.10	10478.32	435.47	378.3
6.5	5073.99	1215.17	14990.52	461.44	485.4	4446.69	1217.50	10073.97	433.98	371.4
6.6	5131.58	1215.76	14374.32	459.81	476.3	4457.04	1217.91	9674.69	432.48	364.6
6.7	5192.27	1216.42	13736.12	458.12	466.8	4465.40	1218.32	9281.44	430.98	357.7
6.8	5249.12	1217.09	13113.67	456.44	457.3	4472.38	1218.73	8892.40	429.48	350.9
6.9	5296.99	1217.74	12529.17	454.80	448.2	4478.43	1219.16	8504.16	427.96	344.0
7.0	5332.93	1218.34	11994.73	453.20	439.6	4482.85	1219.62	8117.96	426.43	337.0
7.1	5356.00	1218.89	11511.85	451.64	431.4	4484.09	1220.10	7740.85	424.88	330.1
7.2	5366.87	1219.38	11074.62	450.09	423.4	4480.96	1220.57	7380.27	423.32	323.2
7.3	5367.60	1219.82	10674.91	448.55	415.8	4472.86	1221.03	7040.36	421.75	316.5
7.4	5360.53	1220.23	10304.23	447.02	408.4	4459.67	1221.46	6723.53	420.19	309.9
7.5	5347.24	1220.62	9952.78	445.47	401.1	4441.79	1221.87	6430.98	418.65	303.6
7.6	5329.40	1221.01	9610.96	443.89	393.9	4420.44	1222.25	6159.93	417.13	297.6
7.7	5309.32	1221.40	9272.87	442.29	386.5	4397.48	1222.62	5903.92	415.65	291.8
7.8	5289.64	1221.80	8939.86	440.72	379.4	4374.99	1222.97	5655.91	414.21	286.1

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	**Gas Mass Flow (lbm/sec)**	**Gas Enthalpy (Btu/lbm)**	**Liquid Mass Flow (lbm/sec)**	**Liquid Enthalpy (Btu/lbm)**	**Pressure (psi)**	**Gas Mass Flow (lbm/sec)**	**Gas Enthalpy (Btu/lbm)**	**Liquid Mass Flow (lbm/sec)**	**Liquid Enthalpy (lbm/sec)**	**Pressure (psi)**
7.9	5268.74	1222.20	8605.68	439.13	372.0	4354.75	1223.35	5409.71	412.83	280.6
8.0	5248.62	1222.62	8268.98	437.54	364.9	4337.88	1223.77	5160.27	411.50	275.1
8.1	5230.61	1223.05	7936.95	436.00	357.8	4324.49	1224.26	4904.01	410.20	269.7
8.2	5210.71	1223.48	7610.42	434.47	350.8	4314.28	1224.82	4639.68	408.94	264.2
8.3	5185.50	1223.90	7290.51	432.88	343.7	4306.97	1225.45	4368.42	407.72	258.6
8.4	5149.89	1224.29	6981.38	431.16	336.3	4301.07	1226.14	4090.33	406.52	253.0
8.5	5100.61	1224.64	6679.60	429.25	328.6	4294.15	1226.91	3802.16	405.28	247.1
8.6	5041.01	1224.99	6373.97	427.14	320.3	4284.88	1227.80	3496.22	403.95	240.7
8.7	4978.61	1225.36	6064.05	424.95	311.6	4274.21	1228.88	3160.36	402.53	233.6
8.8	4918.44	1225.77	5753.83	422.78	303.5	4264.47	1230.27	2780.89	401.03	225.7
8.9	4859.23	1226.22	5444.20	420.61	295.1	4251.25	1231.89	2383.49	399.48	216.8
9.0	4794.44	1226.62	5150.07	418.40	286.7	4228.88	1233.57	2005.01	397.92	208.0
9.1	4717.10	1226.84	4907.84	416.13	278.8	4188.11	1235.11	1676.80	396.21	199.4
9.2	4624.94	1226.89	4713.82	413.76	271.5	4112.29	1236.10	1442.54	394.02	191.3
9.3	4525.57	1226.87	4533.67	411.27	263.9	3998.83	1236.25	1317.06	391.19	183.9
9.4	4422.59	1226.80	4361.82	408.70	256.4	3861.17	1235.62	1286.28	387.94	177.7
9.5	4315.34	1226.64	4203.04	406.06	249.0	3715.11	1234.44	1319.44	384.55	172.6
9.6	4208.39	1226.45	4054.94	403.42	241.8	3573.79	1233.01	1380.84	381.29	168.3
9.7	4104.11	1226.25	3915.19	400.81	235.0	3445.38	1231.61	1443.70	378.29	164.5
9.8	4002.98	1226.03	3788.12	398.26	228.3	3332.54	1230.37	1493.29	375.59	161.1

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
9.9	3908.74	1225.76	3686.30	395.90	222.8	3235.32	1229.36	1523.70	373.18	157.8
10.0	3801.62	1225.32	3605.12	393.31	217.0	3153.27	1228.60	1532.33	371.06	154.7
10.1	3687.34	1224.80	3519.22	385.59	210.5	3071.49	1227.93	1523.21	363.94	151.6
10.2	3598.56	1224.52	3405.70	383.18	205.0	2967.43	1226.83	1549.42	361.12	147.2
10.3	3531.04	1224.44	3275.64	381.14	199.7	2870.76	1225.59	1600.47	358.61	144.8
10.4	3452.24	1224.25	3152.52	378.85	194.4	2817.51	1225.22	1574.44	357.04	142.2
10.5	3373.12	1224.02	3041.46	376.54	188.9	2800.35	1225.91	1439.72	356.10	138.8
10.6	3318.92	1223.97	2937.43	374.82	185.2	2805.61	1227.46	1230.88	355.62	134.6
10.7	3269.83	1223.96	2833.32	373.22	181.2	2817.97	1229.48	997.89	355.40	130.1
10.8	3218.68	1223.93	2728.20	371.54	177.3	2819.66	1231.40	793.71	355.12	125.7
10.9	3169.92	1223.96	2615.11	369.88	173.3	2801.31	1232.76	646.69	354.42	121.7
11.0	3125.78	1224.06	2493.59	368.29	169.4	2769.07	1233.57	549.41	353.39	118.3
11.1	3082.71	1224.18	2371.39	366.71	165.5	2733.85	1234.12	477.96	352.30	115.4
11.2	3033.10	1224.22	2253.22	364.98	161.5	2701.95	1234.66	411.81	351.34	112.6
11.3	2978.77	1224.19	2143.80	363.14	157.3	2674.46	1235.34	340.97	350.52	109.9
11.4	2917.64	1224.00	2054.52	361.15	153.5	2655.81	1236.24	261.71	349.97	107.4
11.5	2828.28	1223.26	2024.93	358.55	149.4	2634.93	1237.07	183.28	349.40	105.1
11.6	2701.04	1221.73	2072.60	355.13	145.6	2591.18	1237.36	132.54	348.04	102.0
11.7	2555.45	1219.84	2134.30	351.21	141.0	2532.07	1237.23	110.37	346.19	99.0
11.8	2436.12	1218.47	2116.77	347.68	136.2	2469.99	1237.01	96.33	344.28	96.2

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
11.9	2362.55	1218.10	1983.73	344.92	131.5	2387.35	1236.41	96.19	341.42	93.1
12.0	2299.06	1217.99	1823.81	342.21	125.6	2290.04	1235.13	128.95	337.94	88.7
12.1	2231.38	1217.45	1749.89	339.65	122.2	2214.12	1233.88	164.33	335.58	87.4
12.2	2156.97	1216.50	1740.04	337.15	119.1	2164.22	1233.34	169.13	333.89	85.3
12.3	2086.06	1215.54	1733.57	334.74	116.9	2115.02	1232.75	136.58	332.50	83.6
12.4	2000.08	1214.39	1719.46	331.65	113.3	1983.88	1227.32	85.18	328.13	89.1
12.5	1888.23	1212.76	1721.13	327.54	108.5	1842.30	1221.08	68.73	320.75	87.8
12.6	1790.06	1211.21	1731.31	323.87	104.3	1770.92	1219.50	84.20	318.18	87.0
12.7	1699.34	1209.85	1697.05	320.14	100.3	1696.64	1218.10	88.07	315.82	85.9
12.8	1635.43	1208.94	1652.94	317.23	96.5	1625.43	1218.07	69.02	313.51	84.1
12.9	1604.09	1208.60	1605.97	315.61	94.4	1597.64	1219.20	56.24	312.47	84.1
13.0	1562.55	1208.19	1524.04	313.36	91.8	1562.54	1218.43	60.74	311.14	83.7
13.1	1506.14	1207.46	1456.85	310.43	87.3	1478.04	1216.79	57.02	308.37	82.2
13.2	1426.02	1206.05	1435.39	306.58	83.5	1382.20	1215.66	50.38	304.67	80.9
13.3	1341.05	1204.34	1439.95	302.58	80.5	1271.34	1213.67	49.85	300.87	79.4
13.4	1284.05	1202.63	1427.75	300.78	77.8	1148.56	1212.05	44.11	296.93	77.9
13.5	1245.77	1201.26	1370.61	299.99	81.8	1055.04	1211.63	39.42	293.67	76.9
13.6	1219.57	1200.67	1313.42	298.86	80.6	992.54	1211.09	40.57	291.74	76.6
13.7	1176.63	1199.67	1294.43	297.08	79.7	921.42	1209.96	41.28	289.68	76.0
13.8	1109.17	1197.98	1281.82	294.30	77.6	847.66	1209.21	40.34	287.58	75.4

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
13.9	1036.37	1196.13	1258.32	291.69	76.8	783.40	1208.74	40.25	285.91	75.1
14.0	958.19	1194.18	1229.61	289.47	76.2	706.24	1207.53	42.45	284.02	74.6
14.1	872.95	1192.17	1177.32	287.22	75.5	615.42	1205.51	47.28	282.05	74.4
14.2	788.89	1190.28	1097.60	285.16	75.0	520.17	1203.40	51.66	280.37	74.2
14.3	718.62	1188.80	999.35	283.60	74.7	398.36	1202.09	48.53	278.82	73.8
14.4	656.81	1187.68	894.77	282.35	74.4	246.09	1201.97	35.16	277.43	73.6
14.5	600.47	1186.91	814.76	281.31	74.2	128.05	1201.52	20.20	276.64	73.6
14.6	552.32	1186.50	769.06	280.53	74.1	124.91	1198.52	19.51	276.67	73.8
14.7	506.53	1186.20	731.54	279.86	74.0	106.18	1197.65	18.85	276.60	73.6
14.8	466.33	1185.95	689.70	279.30	74.0	25.93	1197.03	6.47	276.43	73.6
14.9	424.01	1185.72	643.05	278.80	73.8	0.00	1178.28	0.12	284.00	73.7
15.0	375.60	1185.54	584.78	278.30	73.8	0.00	1178.14	0.00	271.42	73.5
15.1	337.56	1185.36	529.24	277.94	73.8	0.00	1178.24	0.00	271.43	73.6
15.2	317.03	1185.18	492.40	277.74	73.8	0.00	1178.09	0.00	271.49	73.4
15.3	305.80	1184.98	477.44	277.63	73.8	0.00	1178.09	0.00	271.52	73.4
15.4	281.06	1184.75	461.91	277.46	73.7	0.00	1178.04	0.00	271.59	73.3
15.5	236.22	1184.58	411.74	277.23	73.7	0.00	1177.90	0.00	271.73	73.1
15.6	190.97	1184.41	336.17	276.98	73.7	0.00	1177.81	0.00	271.85	72.9
15.7	159.07	1184.23	273.40	276.77	73.7	0.00	1177.80	0.00	271.87	72.8
15.8	145.83	1184.09	237.46	276.71	73.7	0.00	1177.78	0.00	271.89	72.8

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
15.9	162.79	1184.08	234.57	276.80	73.8	0.00	1177.83	0.00	271.87	72.9
16.0	204.82	1183.92	287.14	277.05	73.9	0.00	1178.21	0.00	271.48	73.6
16.1	263.22	1183.94	395.96	277.64	73.9	0.00	1178.06	0.00	271.58	73.3
16.2	353.08	1184.07	577.52	278.45	74.5	0.00	1177.94	0.00	271.69	73.1
16.3	364.98	1184.35	642.89	278.36	73.7	0.00	1177.56	0.00	272.04	72.5
16.4	300.17	1184.95	529.82	277.74	73.7	0.00	1177.06	0.00	272.62	71.5
16.5	302.18	1185.10	470.69	277.74	73.9	111.37	1197.18	0.18	277.14	74.1
16.6	346.51	1184.78	526.70	278.13	74.0	132.52	1198.18	0.22	277.78	73.4
16.7	377.87	1184.68	605.16	278.38	74.0	21.16	1203.47	0.05	280.00	73.2
16.8	388.91	1184.93	629.58	278.46	74.0	0.00	1178.09	0.00	271.51	73.4
16.9	404.55	1185.15	643.68	278.67	74.0	0.00	1178.13	0.00	271.53	73.5
17.0	426.13	1185.16	670.75	278.91	74.1	0.00	1178.10	0.00	271.59	73.4
17.1	423.44	1185.24	669.67	278.82	74.0	0.00	1178.20	0.00	271.49	73.6
17.2	414.13	1185.43	651.39	278.72	74.0	0.00	1178.21	0.00	271.48	73.6
17.3	419.35	1185.35	656.09	278.80	74.1	0.00	1178.01	0.00	271.53	73.3
17.4	422.88	1185.38	662.39	278.86	73.9	0.00	1177.81	0.00	271.83	72.9
17.5	463.43	1185.55	718.56	279.57	74.3	0.00	1177.77	0.00	271.92	72.8
17.6	533.97	1185.84	823.64	280.52	74.6	0.00	1178.08	0.00	271.65	73.3
17.7	513.09	1186.16	791.87	280.13	73.8	6.58	1187.22	0.00	272.09	72.2
17.8	450.98	1186.10	693.63	279.12	73.9	106.67	1198.85	0.00	272.62	74.5

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
17.9	478.30	1186.17	730.24	279.88	74.0	110.32	1200.25	0.00	271.27	73.5
18.0	573.32	1186.80	877.21	281.40	75.3	10.23	1206.49	0.00	271.40	73.7
18.1	587.98	1186.84	889.92	281.30	74.1	62.46	1208.55	0.00	271.41	73.8
18.2	531.31	1186.47	779.51	280.27	74.0	94.26	1210.86	0.00	271.75	73.6
18.3	536.99	1186.32	791.79	280.43	74.9	31.80	1215.40	0.00	271.42	73.5
18.4	525.84	1186.22	792.74	280.25	73.9	15.26	1195.91	0.00	271.48	73.6
18.5	483.93	1186.08	736.24	279.57	74.0	82.90	1210.27	0.00	271.91	73.9
18.6	514.15	1186.25	780.92	280.32	74.1	70.67	1213.79	0.00	271.28	73.5
18.7	617.22	1187.39	950.24	282.25	75.1	3.04	1219.95	0.00	271.49	73.4
18.8	667.82	1187.83	1102.16	282.78	74.9	0.00	1178.30	0.00	271.48	73.7
18.9	645.51	1187.42	1141.82	282.31	74.7	0.00	1178.22	0.00	271.48	73.6
19.0	628.92	1187.12	1126.53	282.04	74.6	4.03	1186.52	0.00	271.72	73.1
19.1	622.35	1187.00	1097.76	281.92	74.6	26.97	1193.74	0.00	271.80	74.0
19.2	627.60	1187.10	1089.15	282.03	74.6	22.94	1195.01	0.00	271.96	72.5
19.3	634.07	1187.20	1089.87	282.13	74.8	0.00	1176.90	0.00	272.77	71.2
19.4	628.25	1187.10	1061.93	281.98	74.7	0.00	1176.11	0.00	273.36	69.7
19.5	615.30	1186.87	1021.49	281.73	74.5	0.00	1175.67	0.00	273.59	68.8
19.6	615.67	1186.88	1017.16	281.75	74.6	0.00	1175.75	0.00	273.56	68.9
19.7	622.13	1187.00	1031.23	281.91	74.5	0.00	1176.61	0.00	273.12	70.5
19.8	641.78	1187.36	1071.28	282.31	75.0	131.44	1201.24	0.01	266.67	74.1

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
19.9	660.65	1187.68	1105.49	282.65	74.7	297.04	1208.90	0.03	280.00	73.9
20.0	693.38	1188.33	1156.25	283.34	74.9	99.94	1213.59	0.01	272.33	73.6
20.5	670.39	1187.93	1106.57	282.89	74.9	29.06	1212.19	0.00	271.41	73.6
21.0	627.19	1187.19	1024.96	282.00	75.2	2.35	1214.04	0.00	271.42	73.5
21.5	622.60	1187.31	942.12	282.04	74.2	6.47	1192.30	0.00	271.41	73.6
22.0	686.28	1188.48	987.12	283.37	75.0	17.12	1198.12	0.00	271.40	73.6
22.5	750.89	1189.44	1103.70	284.44	75.1	19.11	1206.91	0.00	271.34	73.6
23.0	685.30	1188.72	852.21	283.60	74.5	8.32	1214.00	0.00	271.44	73.5
23.5	615.57	1187.41	753.03	281.84	74.2	47.88	1208.63	0.00	271.54	73.6
24.0	637.82	1187.44	1130.65	282.45	75.3	59.58	1208.17	0.00	271.45	73.7
24.5	634.17	1187.47	1069.06	282.31	74.6	14.91	1206.76	0.00	271.43	73.7
25.0	574.77	1186.80	887.07	280.95	74.2	4.34	1203.16	0.00	271.41	73.6
25.5	537.79	1185.98	1117.72	280.56	74.5	5.24	1197.52	0.00	271.43	73.7
26.0	511.36	1185.64	1195.69	280.22	74.4	7.49	1198.95	0.00	271.41	73.7
26.5	458.63	1185.30	1158.46	279.44	74.2	12.45	1207.33	0.00	271.43	73.7
27.0	411.02	1184.92	1179.36	278.87	74.2	13.00	1213.62	0.00	271.40	73.7
27.5	372.88	1184.54	1296.24	278.46	74.1	12.37	1221.75	0.00	271.45	73.7
28.0	344.56	1184.22	1409.40	278.22	74.1	9.15	1221.44	0.00	271.41	73.7
28.5	317.63	1184.07	1368.75	277.94	74.0	2.74	1206.24	0.00	271.42	73.7
29.0	291.03	1184.01	1290.63	277.67	74.0	4.29	1207.32	0.00	271.39	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
29.5	262.84	1183.99	1173.69	277.42	73.9	2.42	1208.45	0.00	271.37	73.7
30.0	239.91	1183.99	1028.93	277.24	73.8	0.17	1208.16	0.00	271.42	73.7
30.5	222.83	1183.93	933.73	277.12	73.8	0.30	1186.83	0.00	271.40	73.7
31.0	206.51	1183.84	852.42	277.02	73.8	1.01	1188.83	0.00	271.39	73.7
31.5	196.63	1183.76	776.21	276.96	73.8	4.08	1201.34	0.00	271.39	73.7
32.0	190.70	1183.69	775.96	276.93	73.8	13.68	1223.72	0.00	271.42	73.7
32.5	179.66	1183.56	854.17	276.88	73.8	19.86	1235.99	0.00	271.40	73.7
33.0	162.66	1183.39	903.59	276.81	73.8	14.99	1240.65	0.00	271.40	73.7
33.5	148.17	1183.26	783.13	276.74	73.7	6.54	1231.93	0.00	271.40	73.7
34.0	141.77	1183.20	623.80	276.71	73.7	3.27	1203.22	0.00	271.33	73.6
34.5	145.56	1183.16	679.51	276.74	73.8	4.76	1210.38	0.00	271.41	73.7
35.0	148.67	1183.06	1109.38	276.79	73.8	2.59	1216.08	0.00	271.40	73.8
35.5	143.83	1182.84	1858.91	276.87	73.8	16.90	1208.62	0.00	271.55	73.4
36.0	137.78	1182.56	2537.08	276.93	73.9	23.19	1208.76	0.00	271.46	73.8
36.5	132.72	1182.38	2826.84	276.96	74.0	12.90	1214.29	0.00	271.42	73.7
37.0	129.98	1182.29	2876.72	276.97	74.0	9.91	1219.01	0.00	271.40	73.7
37.5	128.23	1182.24	2964.72	276.99	74.0	8.40	1208.43	0.00	271.49	73.8
38.0	127.47	1182.17	3154.39	277.03	74.1	8.06	1204.87	0.00	271.40	73.7
38.5	126.26	1182.12	3340.97	277.06	74.1	6.62	1217.32	0.00	271.41	73.7
39.0	123.70	1182.09	3378.19	277.04	74.1	9.45	1230.39	0.00	271.40	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
39.5	119.88	1182.10	3245.16	276.97	74.1	13.37	1239.57	0.00	271.40	73.7
40.0	115.99	1182.13	3085.22	276.91	74.0	17.92	1244.92	0.00	271.41	73.7
40.5	113.36	1182.14	3022.42	276.89	74.0	17.58	1246.55	0.00	271.41	73.7
41.0	111.45	1182.12	3045.18	276.88	74.0	18.08	1247.27	0.00	271.41	73.7
41.5	108.87	1182.10	3107.73	276.87	74.0	18.19	1247.50	0.00	271.38	73.7
42.0	105.23	1182.09	3179.22	276.85	74.0	18.37	1247.68	0.00	271.42	73.7
42.5	100.54	1182.08	3197.31	276.81	74.0	18.19	1247.58	0.00	271.41	73.7
43.0	95.27	1182.06	3102.78	276.71	73.9	17.86	1247.60	0.00	271.42	73.7
43.5	89.48	1182.07	2936.29	276.57	73.7	16.11	1247.82	0.00	271.41	73.7
44.0	81.96	1182.14	2729.48	276.49	73.7	6.77	1246.77	0.00	271.40	73.7
44.5	73.11	1182.20	2494.15	276.47	73.7	1.37	1242.27	0.00	271.39	73.7
45.0	63.95	1182.27	2241.93	276.46	73.7	0.01	1232.88	0.00	271.40	73.7
45.5	55.22	1182.38	1956.43	276.44	73.7	0.00	1178.26	0.00	271.40	73.7
46.0	47.90	1182.48	1663.32	276.43	73.7	0.00	1190.48	0.00	271.40	73.7
46.5	42.12	1182.55	1402.24	276.42	73.7	0.00	1190.48	0.00	271.40	73.7
47.0	38.02	1182.57	1176.52	276.42	73.7	0.00	1178.26	0.00	271.40	73.7
47.5	35.43	1182.54	984.30	276.42	73.7	0.00	1178.26	0.00	271.40	73.7
48.0	33.13	1182.46	796.83	276.41	73.7	0.00	1178.27	0.00	271.40	73.7
48.5	27.86	1182.33	576.53	276.41	73.7	0.00	1178.26	0.00	271.40	73.7
49.0	20.12	1182.33	360.50	276.40	73.7	0.00	1178.26	0.00	271.40	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	**Gas Mass Flow (lbm/sec)**	**Gas Enthalpy (Btu/lbm)**	**Liquid Mass Flow (lbm/sec)**	**Liquid Enthalpy (Btu/lbm)**	**Pressure (psi)**	**Gas Mass Flow (lbm/sec)**	**Gas Enthalpy (Btu/lbm)**	**Liquid Mass Flow (lbm/sec)**	**Liquid Enthalpy (lbm/sec)**	**Pressure (psi)**
49.5	15.66	1182.63	205.44	276.40	73.7	2.83	1199.98	0.00	271.40	73.7
50.0	14.31	1182.88	109.99	276.40	73.7	10.68	1224.31	0.00	271.41	73.7
50.5	13.18	1183.07	50.45	276.42	73.7	16.67	1242.89	0.00	271.40	73.7
51.0	12.51	1183.25	19.05	276.40	73.7	18.05	1252.86	0.00	271.40	73.7
51.5	12.21	1183.43	6.73	276.36	73.7	19.22	1253.45	0.00	271.41	73.7
52.0	11.87	1183.61	2.34	276.42	73.7	18.79	1252.25	0.00	271.41	73.7
52.5	11.56	1183.83	0.85	276.80	73.7	18.10	1251.16	0.00	271.40	73.7
53.0	10.61	1184.05	0.31	275.97	73.7	19.19	1250.40	0.00	271.41	73.7
53.5	8.27	1184.17	0.11	268.52	73.7	20.75	1249.60	0.00	271.41	73.7
54.0	7.05	1184.30	0.04	282.05	73.7	25.68	1248.39	0.00	271.41	73.7
54.5	7.30	1184.63	0.02	294.12	73.7	31.30	1246.59	0.00	271.42	73.7
55.0	7.41	1185.11	0.01	271.39	73.7	33.32	1244.62	0.00	271.42	73.7
55.5	9.39	1185.63	0.01	271.40	73.7	31.63	1243.25	0.00	271.42	73.7
56.0	12.10	1185.99	0.01	250.00	73.7	25.44	1242.73	0.00	271.41	73.7
56.5	13.96	1186.32	0.01	307.69	73.7	22.89	1243.26	0.00	271.41	73.7
57.0	14.70	1186.66	0.01	307.69	73.7	24.77	1243.80	0.00	271.41	73.7
57.5	14.90	1186.69	0.03	264.71	73.7	25.35	1243.97	0.00	271.41	73.7
58.0	14.52	1186.24	0.09	271.74	73.7	25.52	1244.02	0.00	271.41	73.7
58.5	13.35	1185.60	0.16	280.49	73.7	25.61	1244.01	0.00	271.41	73.7
59.0	15.18	1185.26	0.22	277.27	73.7	25.57	1244.01	0.00	271.41	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
59.5	19.13	1185.31	0.23	273.50	73.7	25.64	1244.02	0.00	271.41	73.7
60.0	25.72	1184.02	99.31	276.41	73.7	25.82	1243.98	0.00	271.41	73.7
61.0	30.04	1182.83	427.22	276.41	73.7	26.16	1243.96	0.00	271.41	73.7
62.0	31.92	1182.15	831.35	276.41	73.7	27.06	1243.80	0.00	271.41	73.7
63.0	30.90	1182.08	1148.93	276.41	73.7	27.87	1243.49	0.00	271.41	73.7
64.0	30.37	1182.05	1655.04	276.43	73.7	28.48	1243.22	0.00	271.42	73.7
65.0	32.75	1182.00	2211.42	276.44	73.7	29.14	1242.96	0.00	271.42	73.7
66.0	37.71	1181.93	2669.84	276.46	73.7	29.89	1242.70	0.00	271.42	73.7
67.0	43.89	1181.88	3053.06	276.47	73.7	26.48	1242.64	0.00	271.42	73.7
68.0	46.17	1181.94	3056.26	276.46	73.7	24.54	1243.47	0.00	271.42	73.7
69.0	44.31	1182.08	2662.50	276.45	73.7	25.42	1244.21	0.00	271.41	73.7
70.0	42.25	1182.21	2283.35	276.44	73.7	24.27	1244.49	0.00	271.41	73.7
71.0	39.46	1182.33	1940.20	276.43	73.7	24.15	1244.81	0.00	271.41	73.7
72.0	36.35	1182.40	1619.69	276.42	73.7	24.19	1245.02	0.00	271.41	73.7
73.0	34.16	1182.41	1433.50	276.42	73.7	23.40	1245.13	0.00	271.41	73.7
74.0	32.39	1182.37	1420.85	276.42	73.7	15.34	1243.79	0.00	271.38	73.7
75.0	29.01	1182.34	1379.54	276.41	73.7	14.94	1246.29	0.00	271.41	73.7
76.0	25.21	1182.27	1133.99	276.41	73.7	21.09	1248.61	0.00	271.41	73.7
77.0	20.49	1182.07	768.40	276.41	73.7	13.71	1248.25	0.00	271.40	73.7
78.0	13.07	1182.03	327.82	276.40	73.7	8.49	1249.98	0.00	271.40	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
79.0	6.98	1182.44	52.21	276.41	73.7	7.54	1252.99	0.00	271.40	73.7
80.0	7.00	1183.19	4.79	276.36	73.7	10.24	1257.64	0.00	271.40	73.7
81.0	13.08	1183.97	0.48	275.68	73.7	28.12	1253.17	0.00	271.42	73.7
82.0	16.95	1184.69	0.08	281.44	73.7	38.06	1248.07	0.00	271.43	73.7
83.0	16.93	1185.64	0.02	275.00	73.7	32.77	1243.86	0.00	271.42	73.7
84.0	15.74	1186.35	0.00	271.40	73.7	29.90	1243.17	0.00	271.42	73.7
85.0	12.49	1186.69	0.00	271.40	73.7	29.73	1243.22	0.00	271.42	73.7
86.0	9.03	1186.89	0.00	271.39	73.7	30.38	1243.21	0.00	271.42	73.7
87.0	7.06	1187.06	0.00	271.39	73.7	31.34	1243.04	0.00	271.42	73.7
88.0	7.32	1187.16	0.00	271.39	73.7	31.83	1242.80	0.00	271.42	73.7
89.0	8.50	1187.17	0.00	271.39	73.7	33.49	1242.50	0.00	271.42	73.7
90.0	9.96	1187.12	0.00	271.40	73.7	25.08	1242.66	0.00	271.40	73.7
91.0	9.49	1186.28	0.10	279.19	73.7	11.93	1244.52	0.00	271.41	73.7
92.0	6.89	1184.72	0.13	276.00	73.7	6.03	1238.16	0.00	271.40	73.7
93.0	5.98	1184.21	0.04	271.43	73.7	4.40	1229.30	0.00	271.39	73.7
94.0	11.56	1184.14	29.04	276.43	73.7	14.76	1250.61	0.00	271.41	73.7
95.0	20.35	1182.98	457.00	276.41	73.7	23.87	1252.59	0.00	271.41	73.7
96.0	24.11	1182.12	1181.10	276.42	73.7	22.32	1250.36	0.00	271.41	73.7
97.0	26.24	1182.04	1662.26	276.43	73.7	11.46	1247.09	0.00	271.39	73.7
98.0	30.59	1182.00	2074.41	276.44	73.7	2.40	1210.96	0.00	271.41	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
99.0	33.02	1182.01	2352.03	276.44	73.7	2.51	1199.28	0.00	271.41	73.7
100.0	34.11	1182.08	2242.85	276.44	73.7	3.16	1199.39	0.00	271.39	73.7
101.0	41.00	1182.01	2530.23	276.45	73.7	2.13	1199.49	0.00	271.41	73.7
102.0	43.05	1182.07	2549.61	276.45	73.7	1.54	1195.93	0.00	271.40	73.7
103.0	40.88	1182.19	2217.35	276.44	73.7	3.94	1201.74	0.00	271.40	73.7
104.0	42.66	1182.17	2200.29	276.44	73.7	8.60	1226.53	0.00	271.40	73.7
105.0	42.50	1182.22	2064.81	276.43	73.7	7.67	1236.21	0.00	271.40	73.7
106.0	39.63	1182.30	1863.45	276.43	73.7	10.23	1248.74	0.00	271.40	73.7
107.0	35.08	1182.36	1655.03	276.42	73.7	19.95	1251.28	0.00	271.41	73.7
108.0	31.95	1182.34	1542.39	276.42	73.7	22.72	1251.14	0.00	271.41	73.7
109.0	30.93	1182.29	1489.64	276.42	73.7	26.43	1248.84	0.00	271.42	73.7
110.0	31.95	1182.24	1542.24	276.42	73.7	29.30	1246.86	0.00	271.42	73.7
111.0	34.72	1182.19	1710.75	276.43	73.7	29.98	1245.53	0.00	271.42	73.7
112.0	38.13	1182.15	1939.91	276.43	73.7	29.70	1244.89	0.00	271.42	73.7
113.0	41.41	1182.12	2170.53	276.44	73.7	29.36	1244.79	0.00	271.41	73.7
114.0	45.61	1182.06	2419.51	276.45	73.7	30.54	1244.69	0.00	271.42	73.7
115.0	47.92	1182.05	2583.92	276.45	73.7	20.10	1243.91	0.00	271.40	73.7
116.0	41.84	1182.20	2215.63	276.44	73.7	10.62	1236.42	0.00	271.40	73.7
117.0	31.86	1182.38	1646.20	276.42	73.7	8.76	1237.16	0.00	271.41	73.7
118.0	21.12	1182.35	1068.09	276.41	73.7	3.06	1247.95	0.00	271.40	73.7

	Reactor Vessel Side					Steam Generator Side				
Time (seconds)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Pressure (psi)	Gas Mass Flow (lbm/sec)	Gas Enthalpy (Btu/lbm)	Liquid Mass Flow (lbm/sec)	Liquid Enthalpy (lbm/sec)	Pressure (psi)
119.0	7.80	1182.31	382.58	276.41	73.7	1.84	1196.98	0.00	271.40	73.7
120.0	1.89	1182.72	58.32	276.40	73.7	20.89	1228.71	0.00	271.42	73.7
121.0	2.77	1182.88	9.00	276.35	73.7	38.09	1231.78	0.00	271.42	73.7

Appendix 6B. Figures

Figure 6-1. Flow Diagram of Emergency Core Cooling System

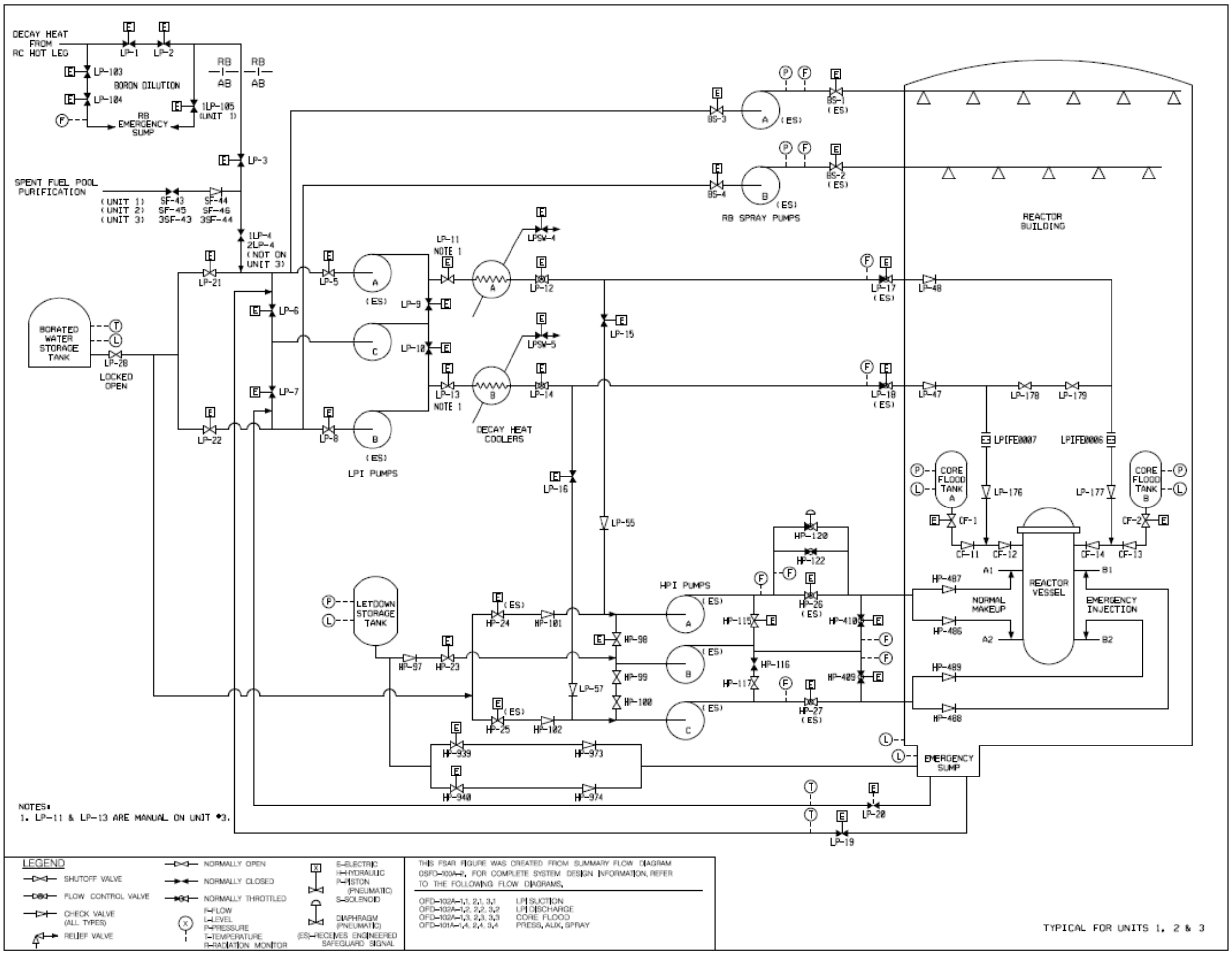


Figure 6-2. Flow Diagram of Reactor Building Spray System

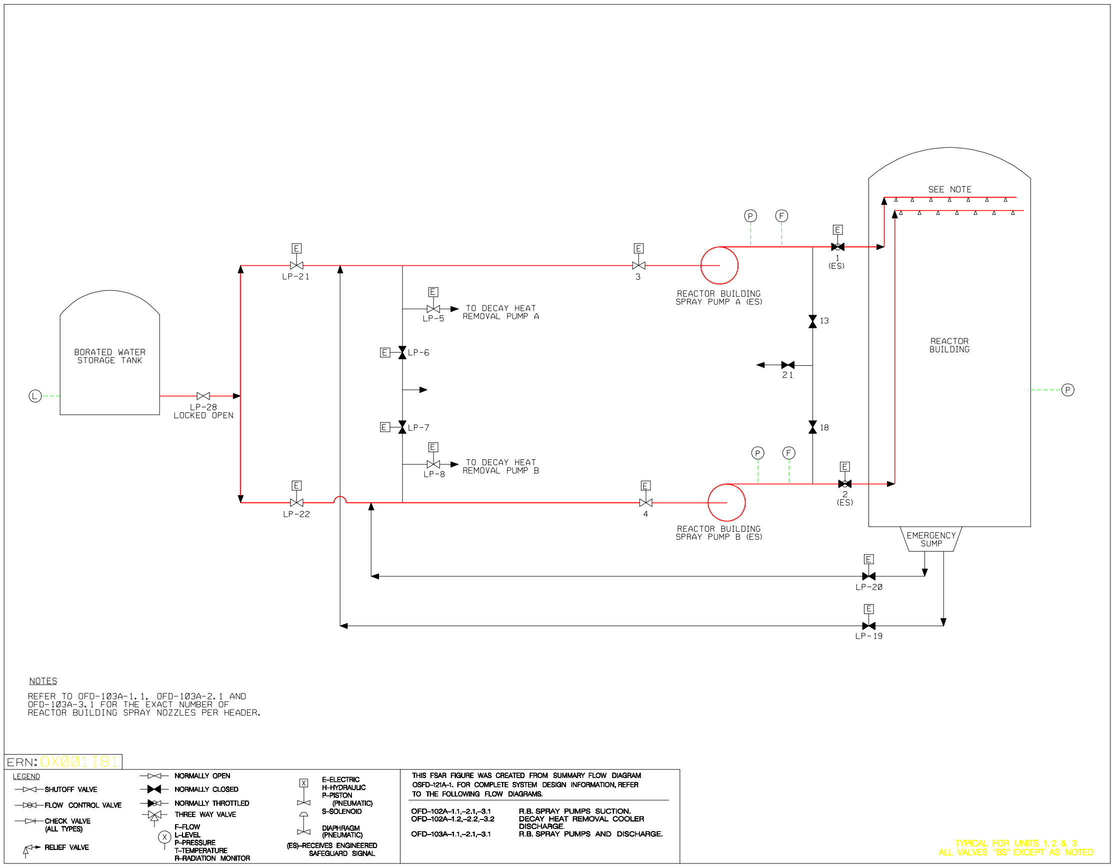


Figure 6-3. Reactor Building Cooling Schematic

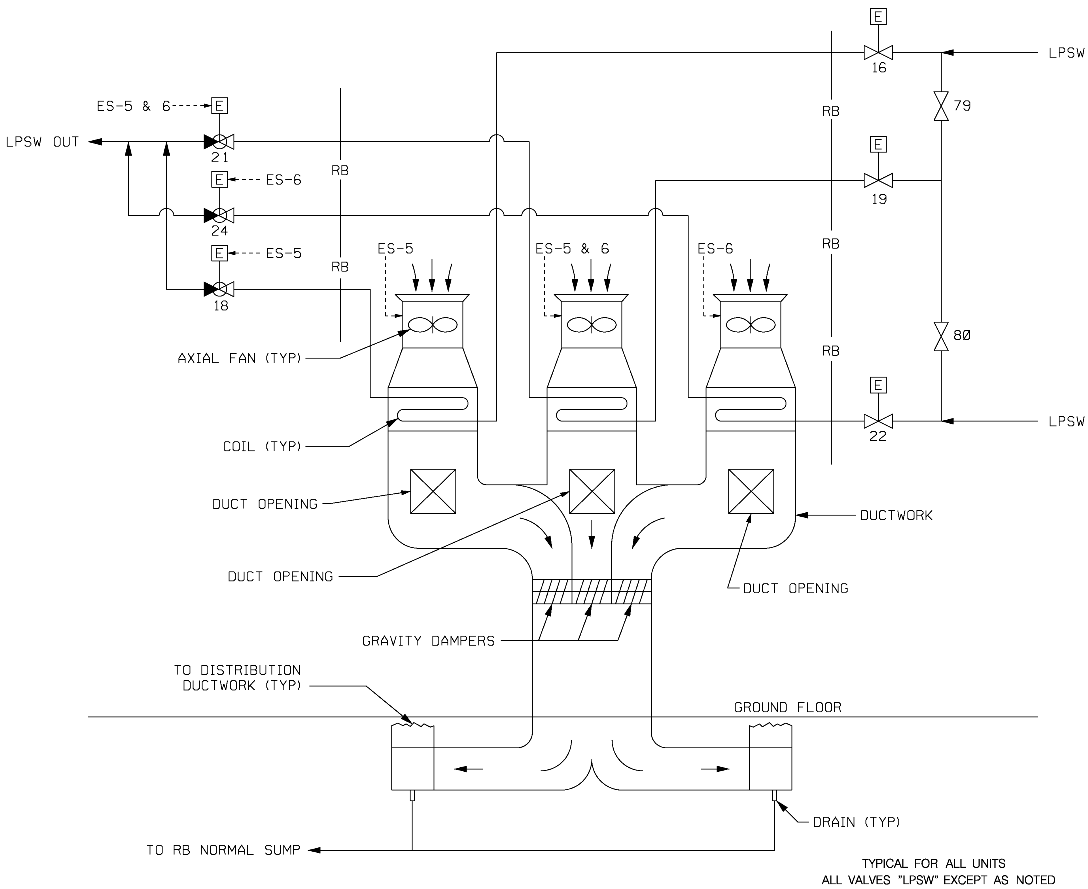


Figure 6-4. Reactor Building Purge and Penetration Ventilation System

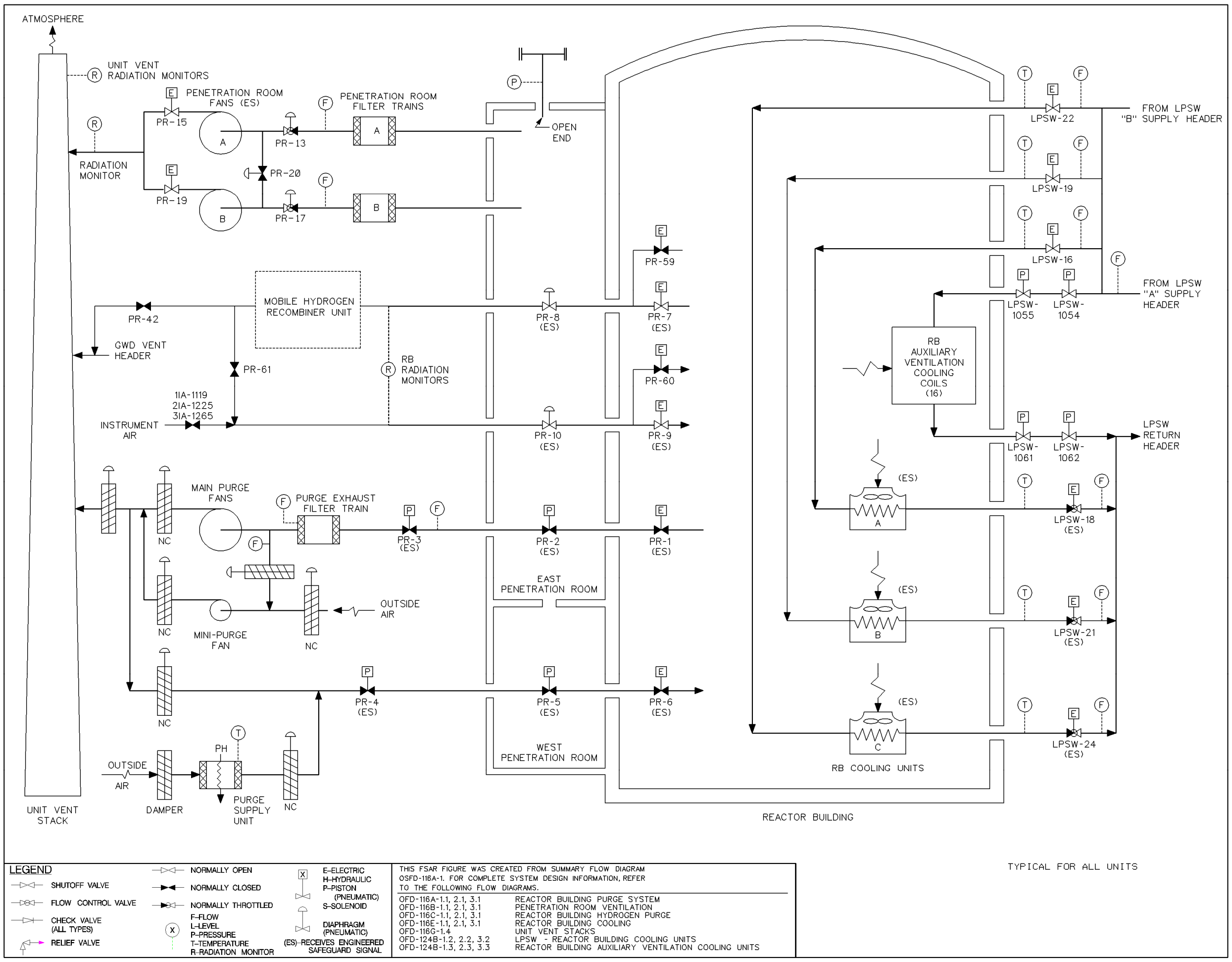
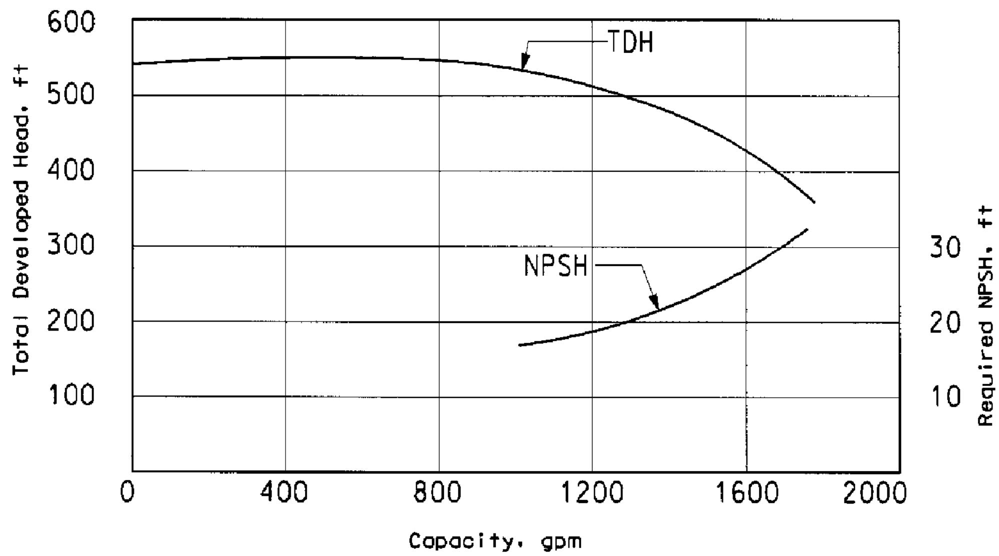


Figure 6-5. Reactor Building Spray Pump Characteristics



NOTE: THIS CURVE IS PROVIDED AS REPRESENTATIVE INFORMATION ONLY AND MAY NOT ACCURATELY REFLECT ACTUAL PERFORMANCE OF ANY SPECIFIC REACTOR BUILDING SPRAY PUMP. FOR DESIGN PURPOSES, ACTUAL PERFORMANCE DATA SHOULD BE OBTAINED FROM MANUFACTURER'S CERTIFIED PERFORMANCE TEST CURVES.

Figure 6-6. Reactor Building Cooler Heat Removal Capacity

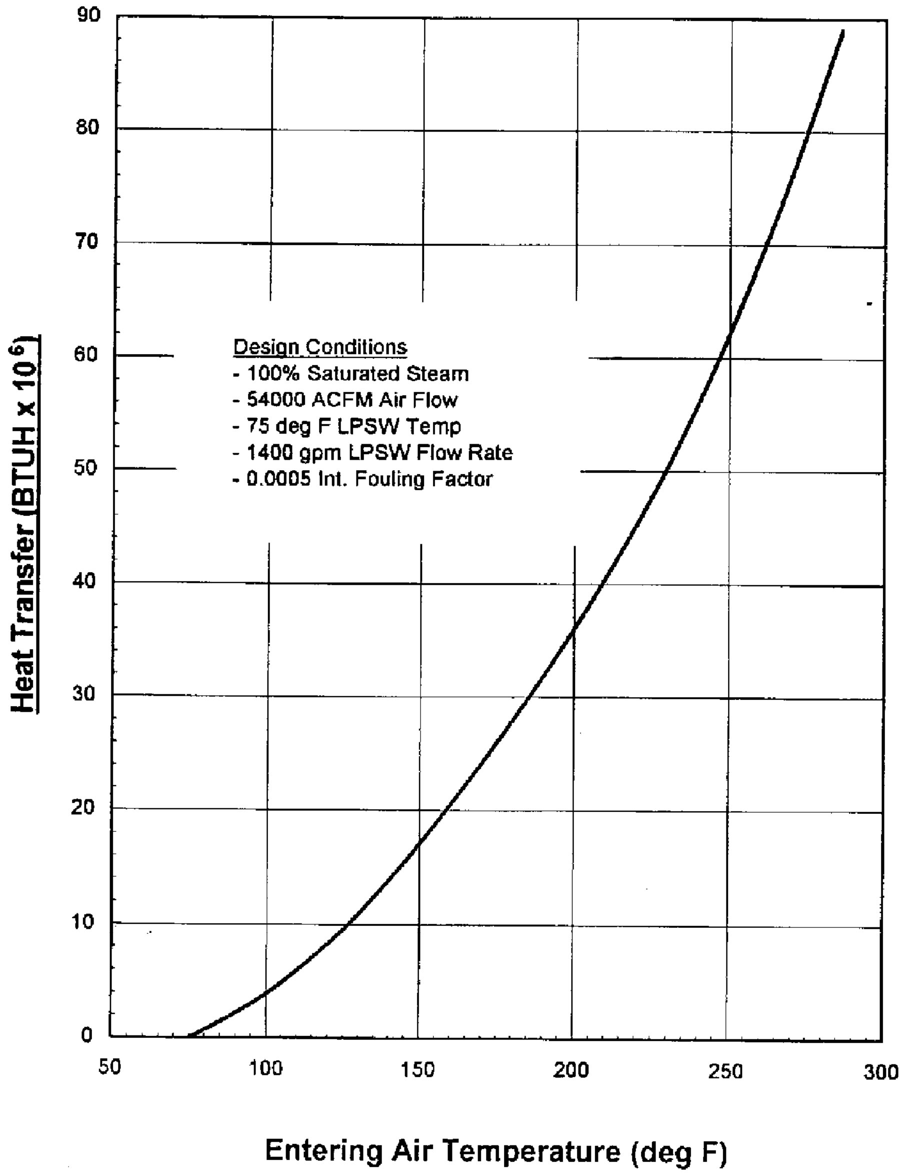


Figure 6-7. Reactor Building Cooler Heat Removal Capability as a Function of Air-Steam Mixture Flow

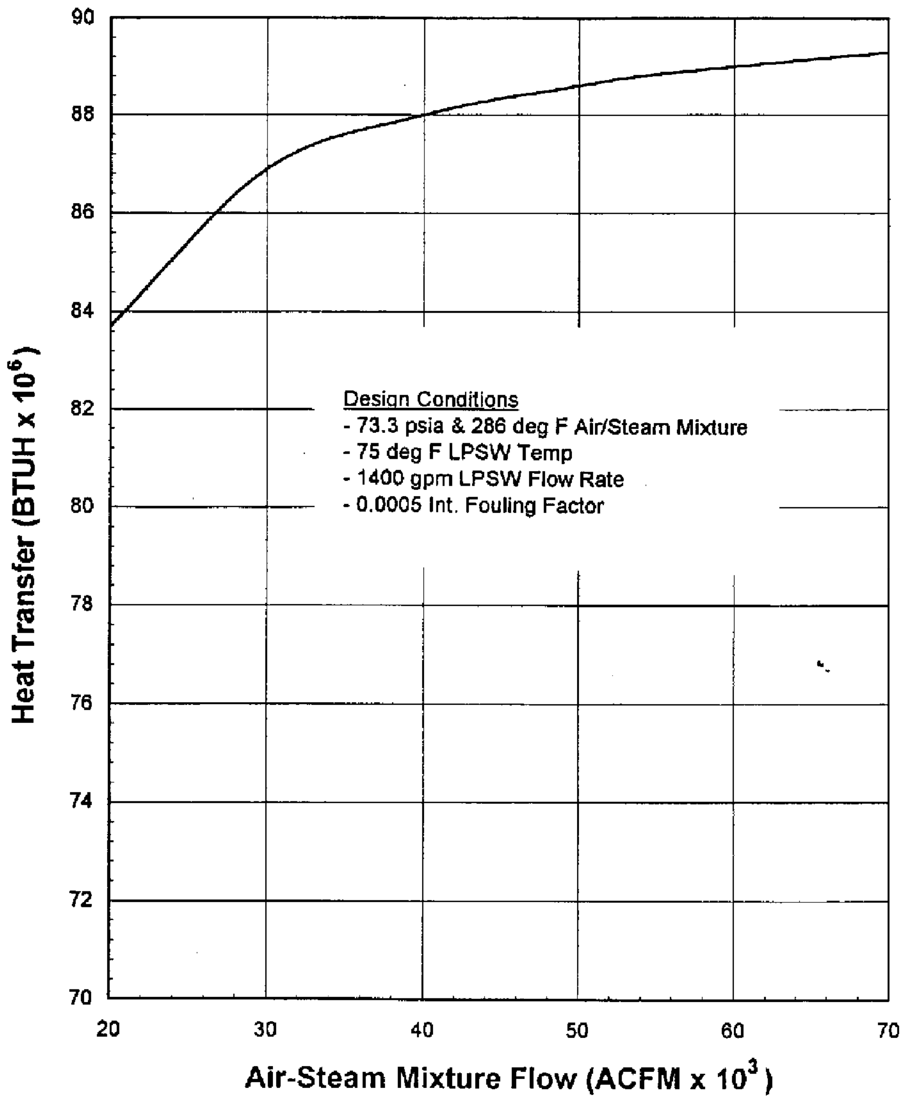
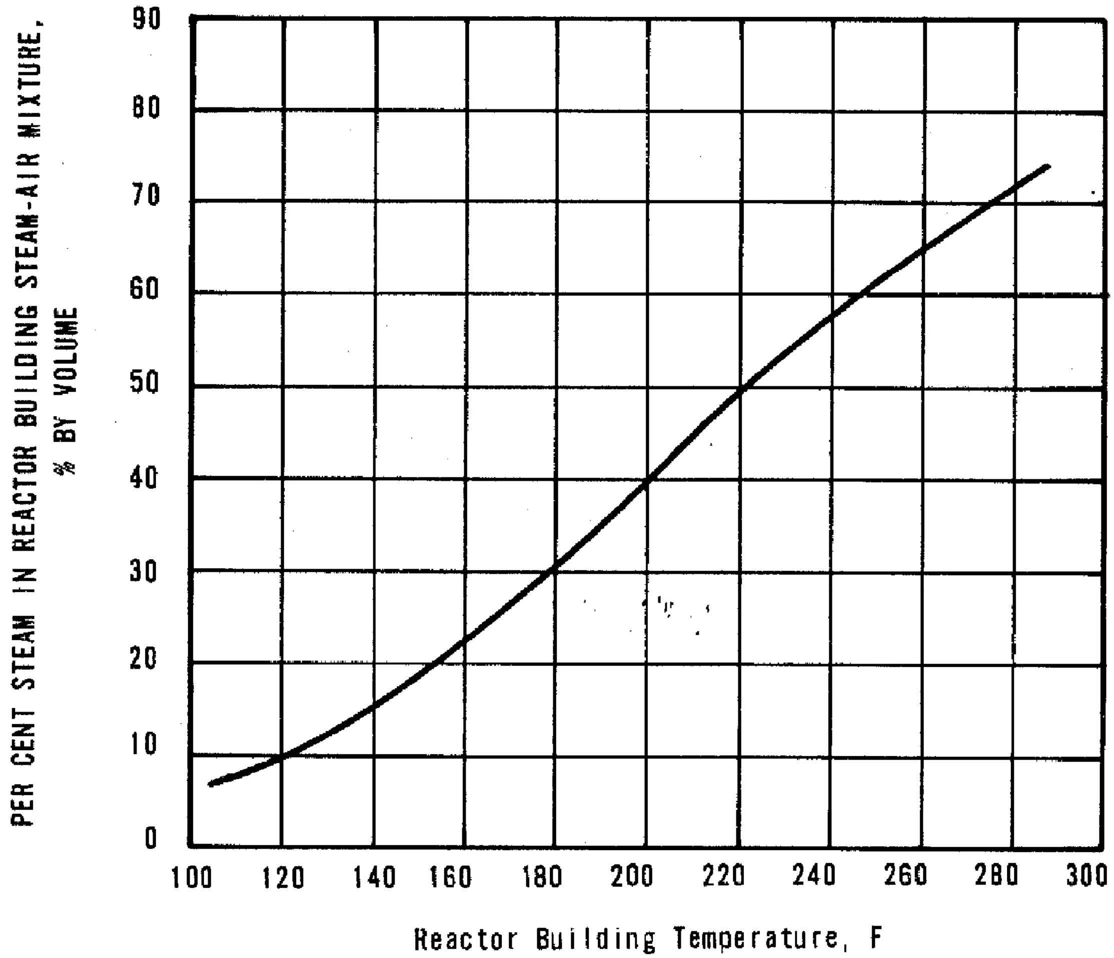
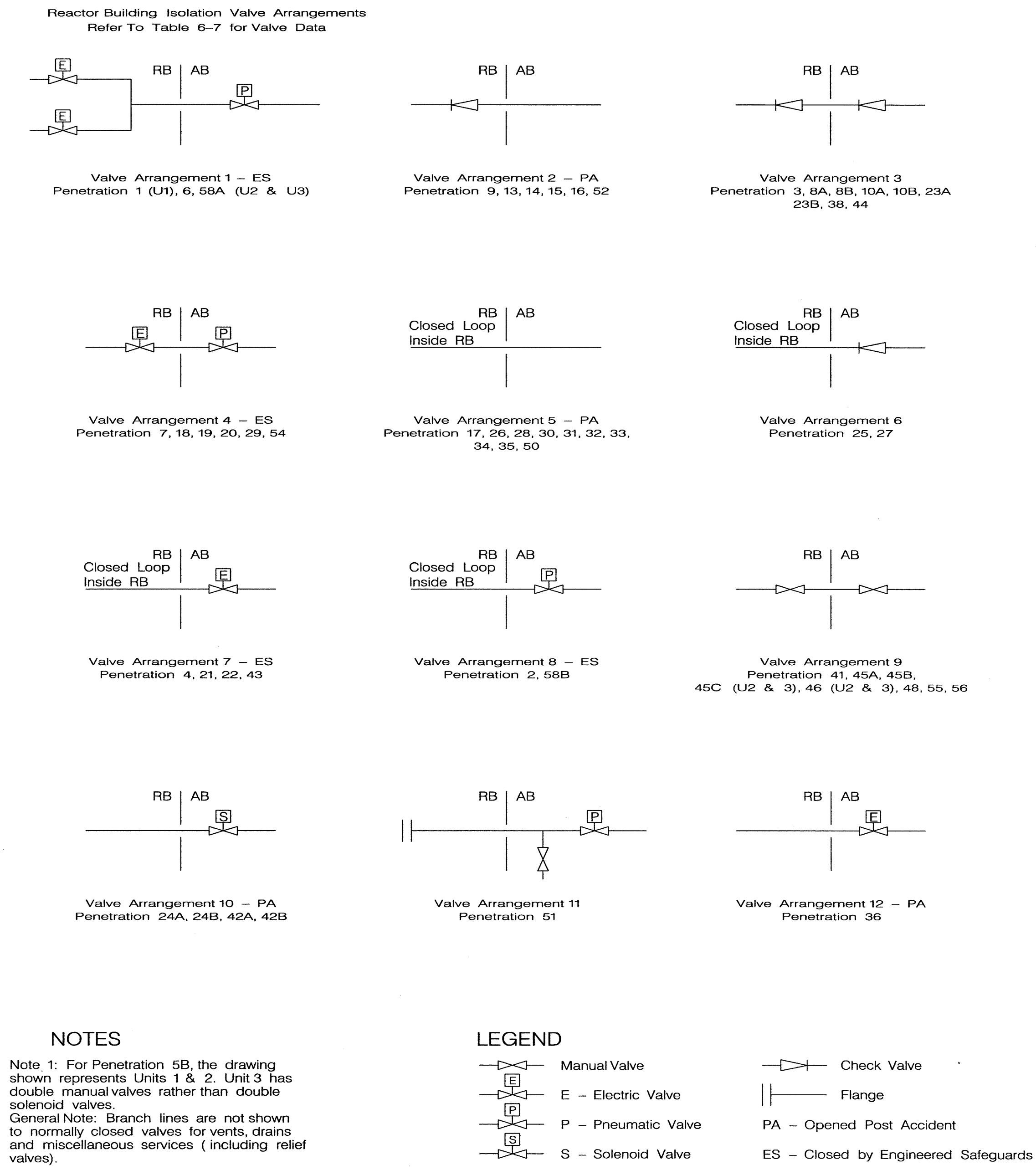


Figure 6-8. Reactor Building Post-Accident Steam-Air Mixture Composition

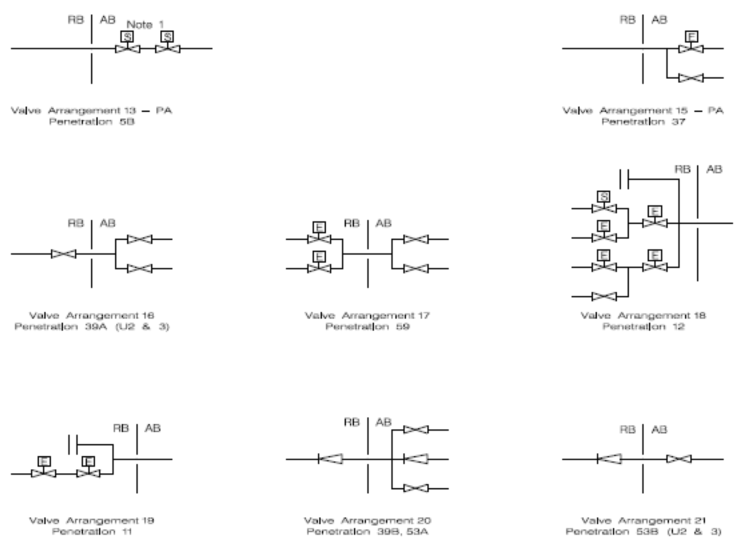


REACTOR BUILDING POST-ACCIDENT
STEAM-AIR MIXTURE COMPOSITION

Figure 6-9. Reactor Building Isolation Valve Arrangements



Reactor Building Isolation Valve Arrangements
Refer To Table 6-7 for Valve Data



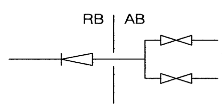
NOTES

General Note; Branch lines are not shown to normally closed valves for vents, drains and miscellaneous services (Including relief valves).

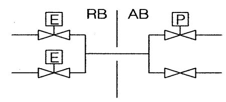
LEGEND

- Manual Valve
- E – Electric Valve
- P – Pneumatic Valve
- S – Solenoid Valve
- Check Valve
- Flange
- PA – Opened Post Accident
- ES – Closed by Engineered Safeguards

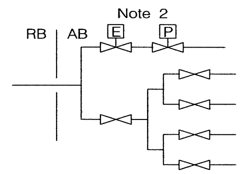
Reactor Building Isolation Valve Arrangements
Refer To Table 6–7 for Valve Data



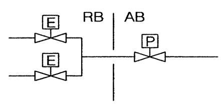
Valve Arrangement 22
Penetration 49 (U1)



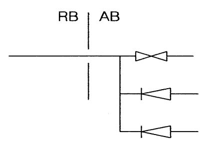
Valve Arrangement 23 – ES, PA
Penetration 60



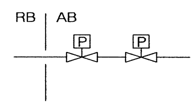
Valve Arrangement 24 – ES, PA
Penetration 5A



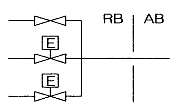
Valve Arrangement 25 – ES, PA
Penetration 61



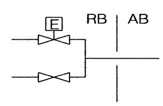
Valve Arrangement 26 – PA
Penetration 40



Valve Arrangement 27 – ES
Penetrations 63 & 64



Valve Arrangement 28 – PA
Penetration 57 (U1)



Valve Arrangement 29 – PA
Penetration 62 (U2 & U3)

NOTES

Note 2: For Penetration 5A, the drawing shown represents Units 2 & 3. For Unit 1, the electric and pneumatic valves are reversed.
General Note: Branch lines are not shown to normally closed valves for vents, drains and miscellaneous services (including relief valves).

LEGEND

Manual Valve
E – Electric Valve
P – Pneumatic Valve
S – Solenoid Valve
Check Valve
Flange
PA – Opened Post Accident
ES – Closed by Engineered Safeguards

Figure 6-10. Deleted Per 1993 Update

Figure 6-11. Deleted Per 1993 Update

Figure 6-12. Deleted Per 1993 Update

Figure 6-13. Deleted Per 1999 Update

Figure 6-14. Deleted Per 1999 Update

Figure 6-15. Deleted Per 1991 Update

Figure 6-16. High Pressure Injection Pump Characteristics

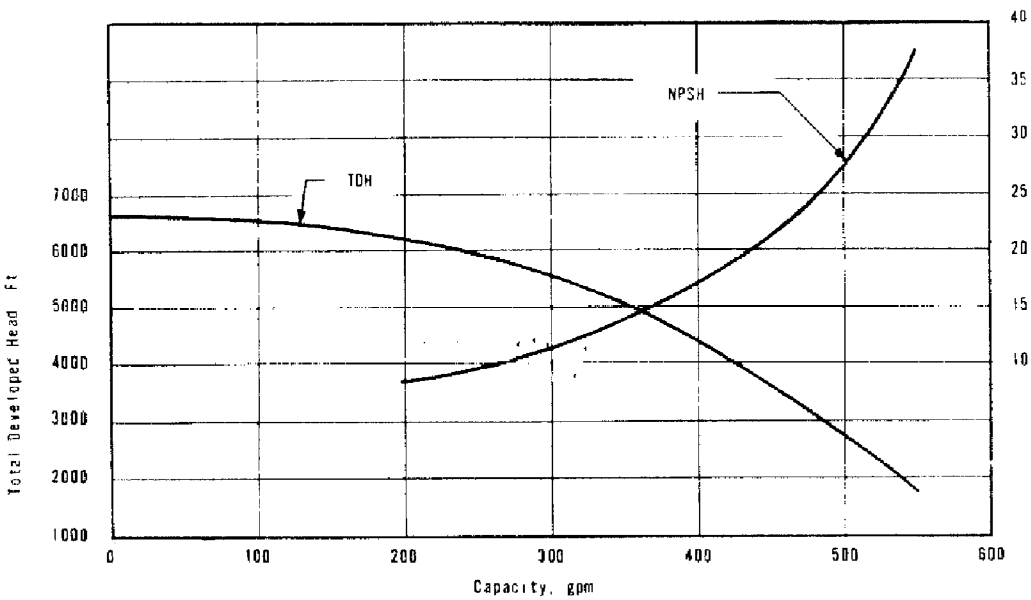


Figure 6-17. Low Pressure Injection Pump Characteristics

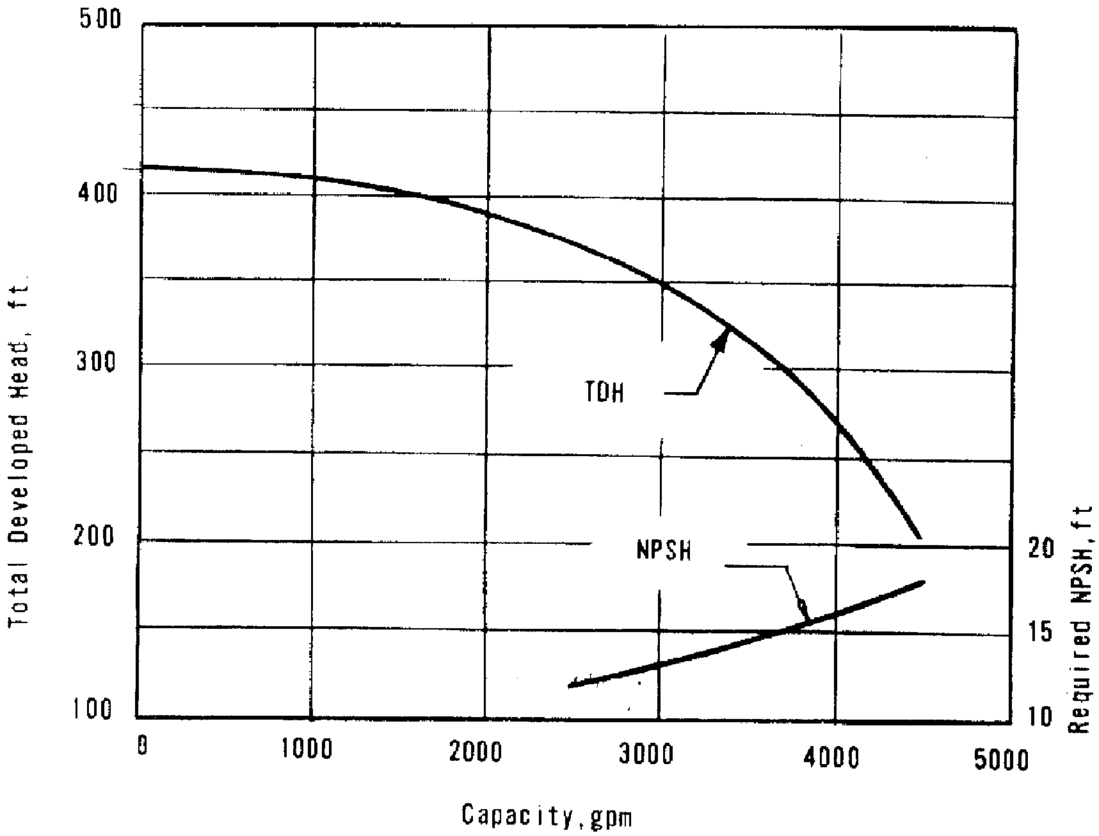


Figure 6-18. Low Pressure Injection Cooler Capacity

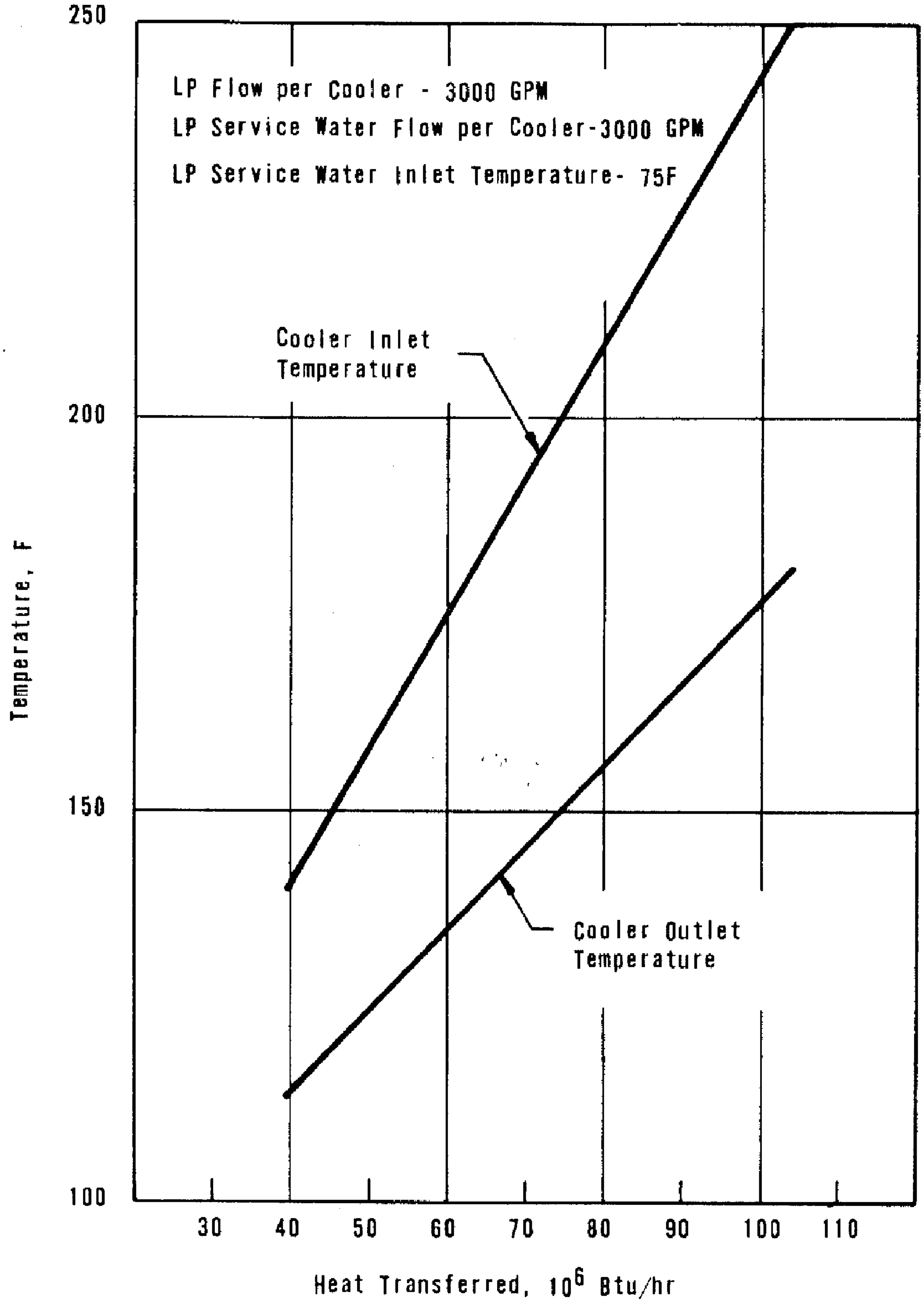


Figure 6-19. Control Rooms 1-2 And 3 Locations

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 6-20. General Arrangement Control Room 1-2

Security-Related Withheld Under 10 CFR 2.390

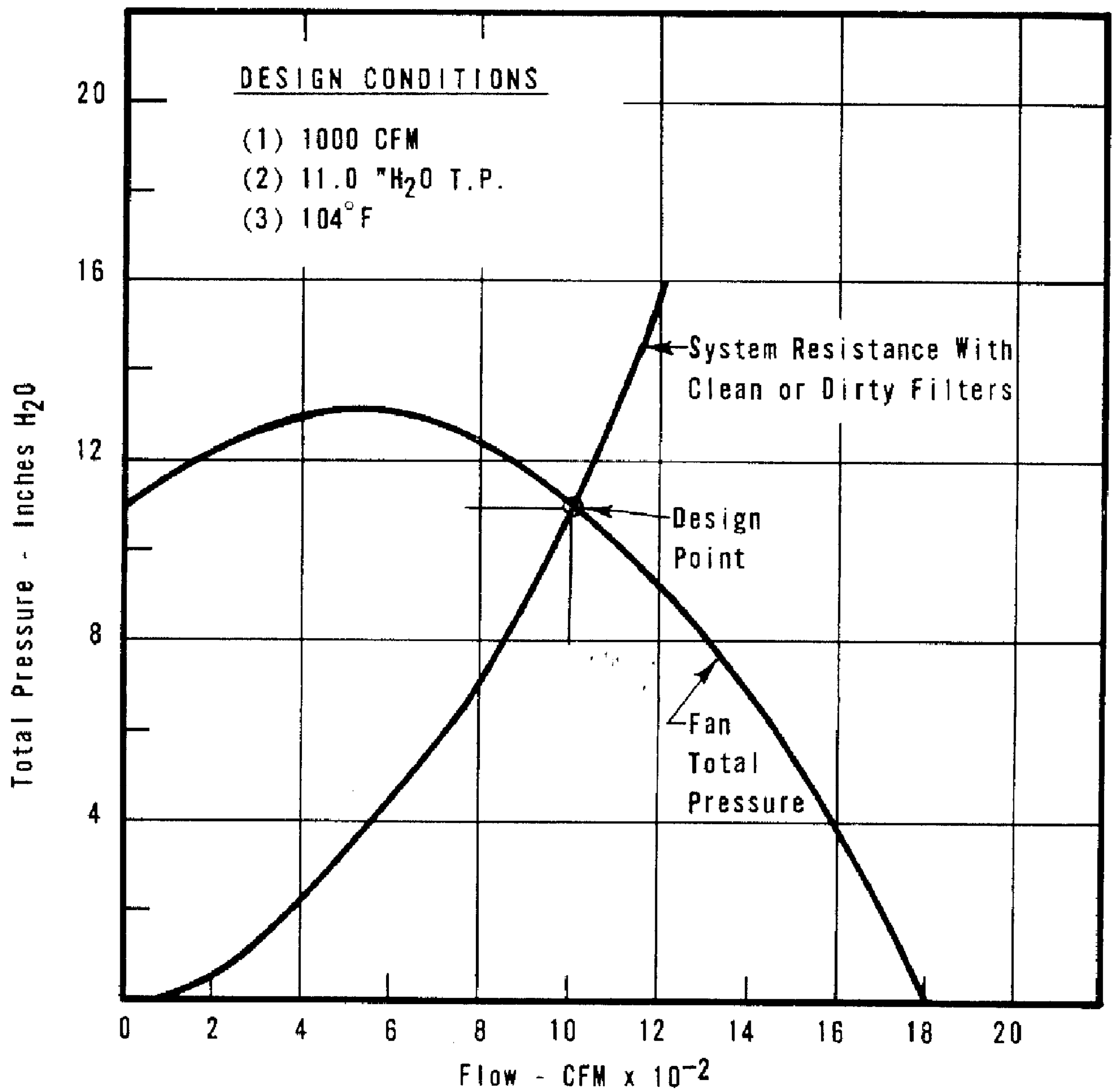
[redacted]

Figure 6-21. General Arrangement Control Room 3

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 6-22. Penetration Room Ventilation Fan And System Characteristics



PENETRATION ROOM VENTILATION FAN AND SYSTEM CHARACTERISTICS

Figure 6-23. Penetrations In Penetration Room 809'3" Floor And Wall Areas

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 6-24. Penetrations In Penetration Room 838'0" Floor

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 6-25. Penetration Rooms Details, Mechanical Openings

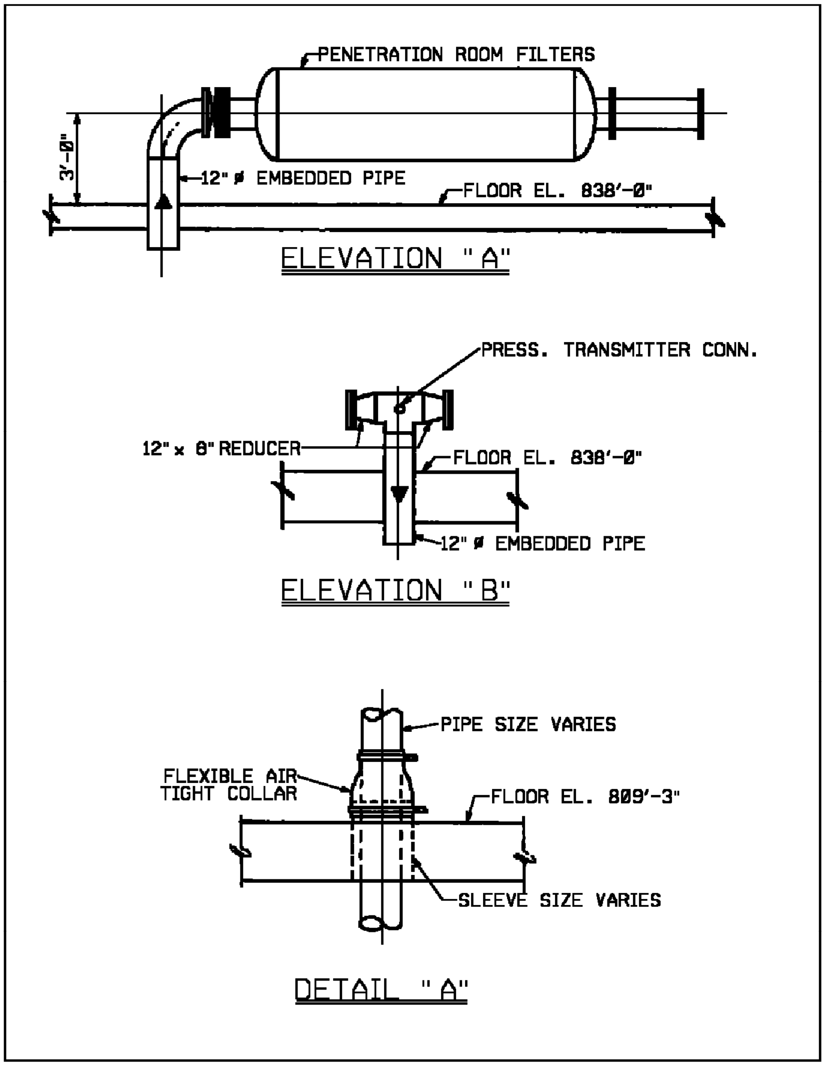


Figure 6-26. Penetration Rooms Details, Electrical Openings

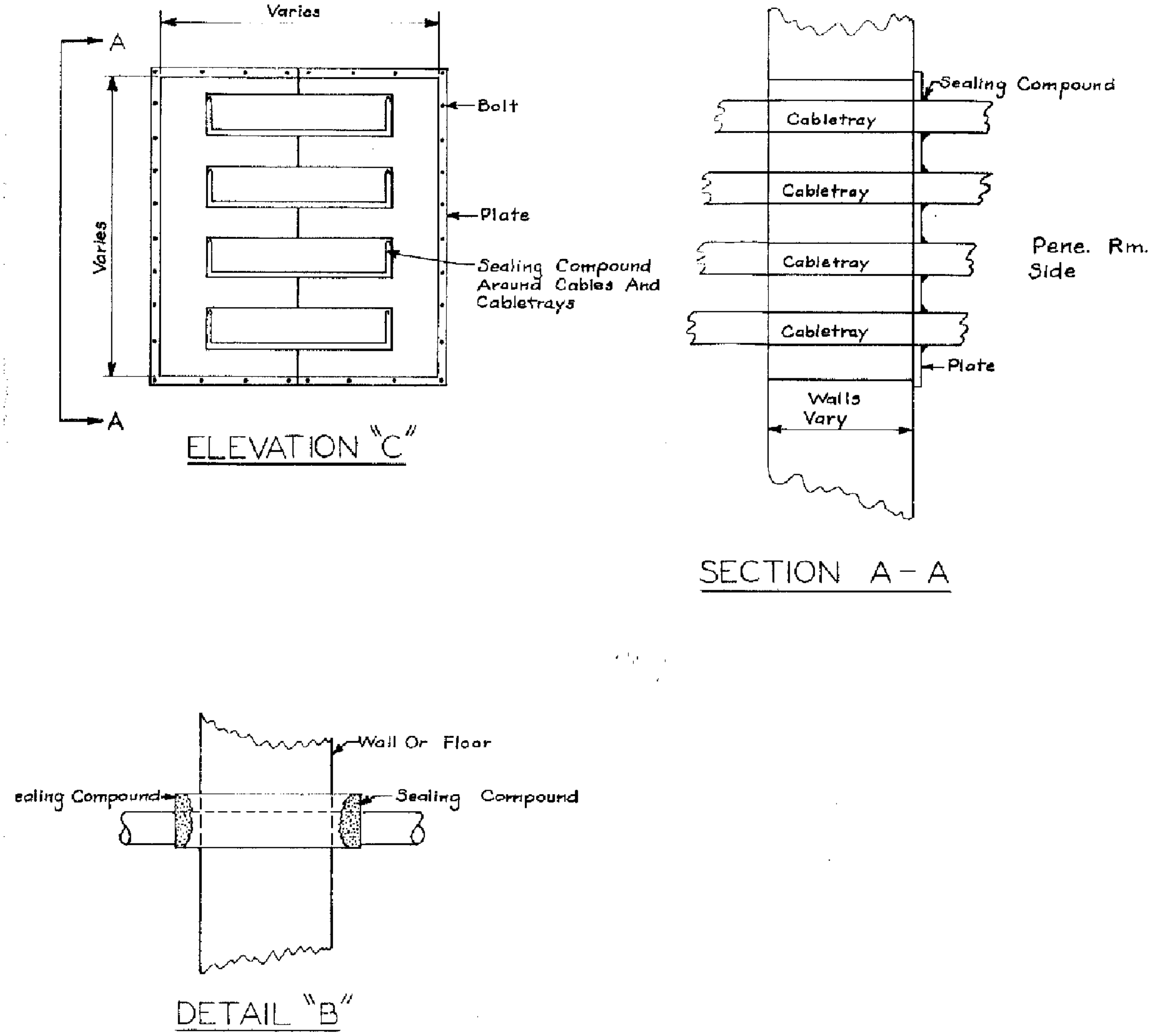
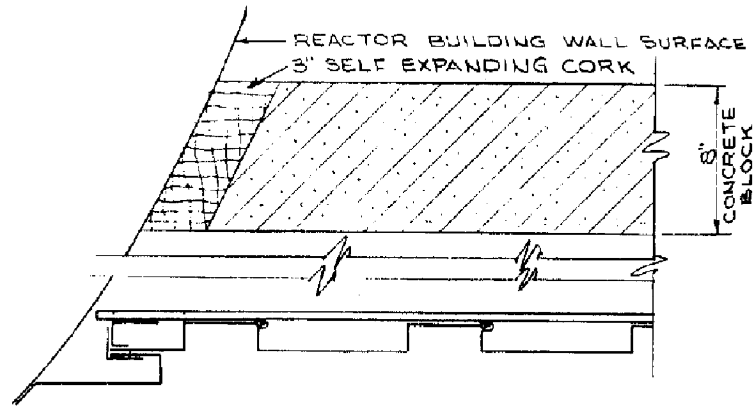
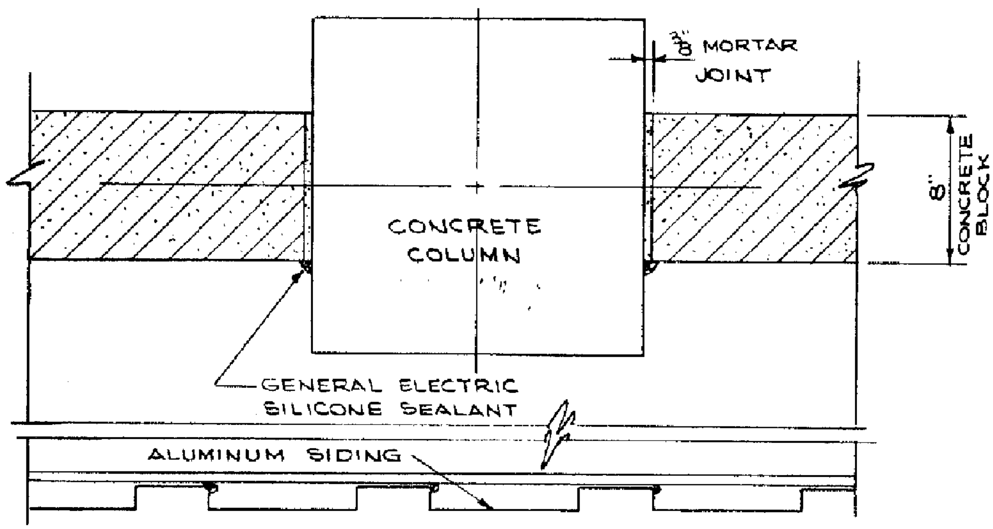


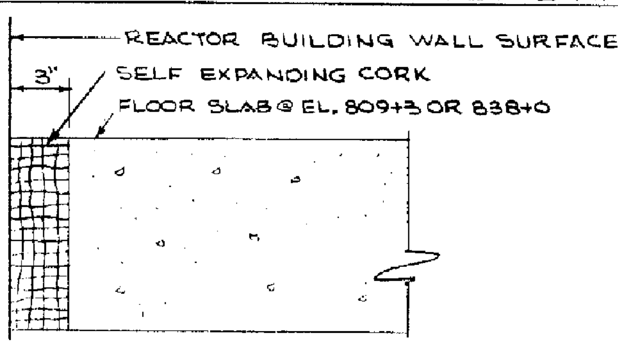
Figure 6-27. Penetration Rooms Details Construction Details



DETAIL "C" - PLAN OF WALL DETAIL AT REACTOR BUILDING



DETAIL "D" - PLAN OF WALL DETAIL AT COLUMN



DETAIL "E" - SLAB INTERSECTING WITH REACTOR BUILDING

Figure 6-28. ONS ROTSG Peak Pressure Analysis. 14.1 ft^2 break – Rx Vessel Outlet

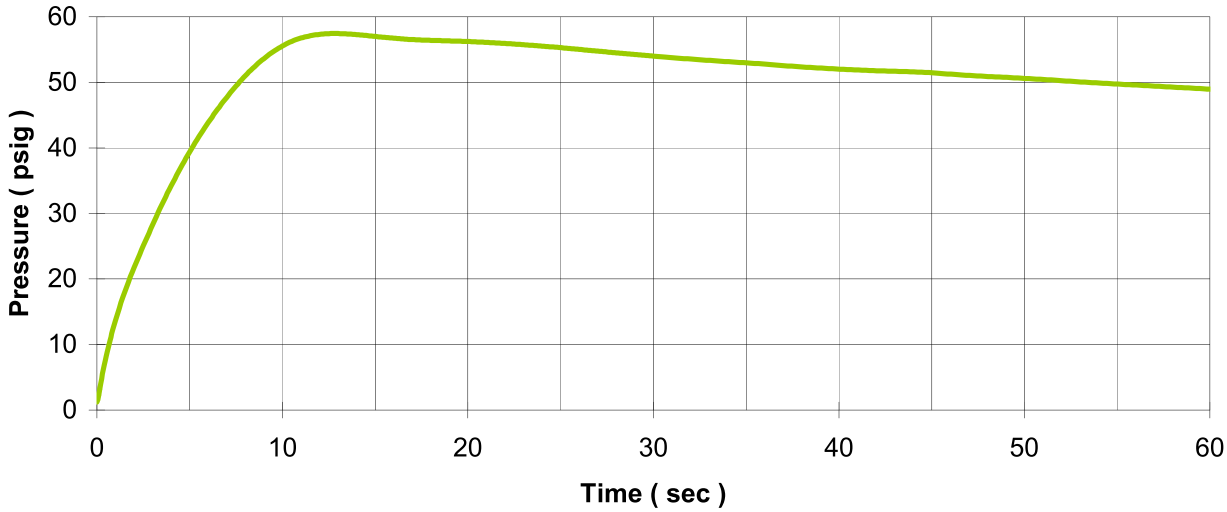


Figure 6-29. ONS ROTSG Peak Pressure Analysis. 14.1 ft^2 break – S/G Inlet

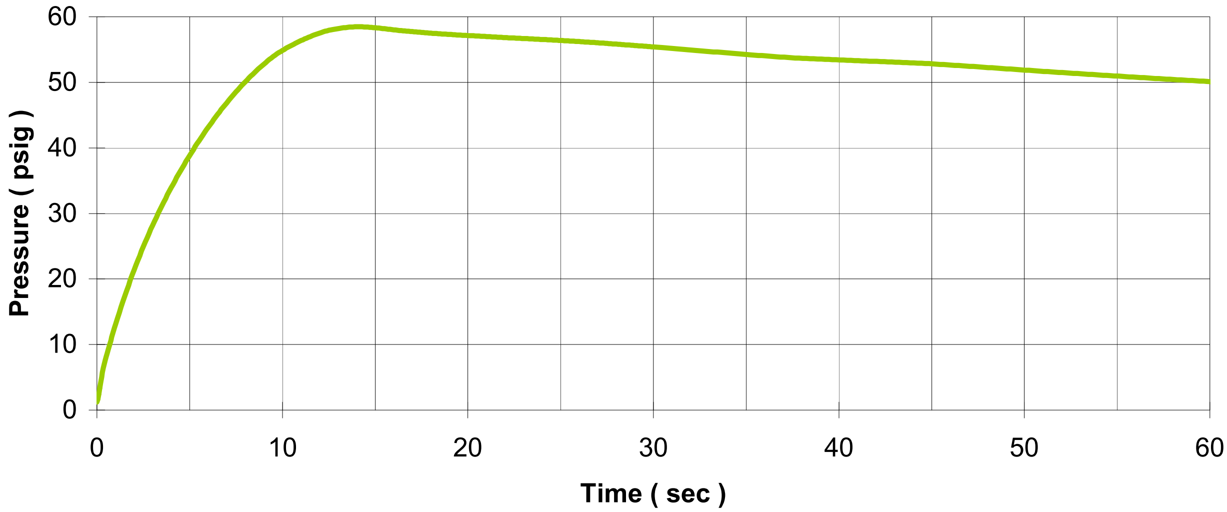


Figure 6-30. ONS ROTSG Peak Pressure Analysis. 8.55 ft^2 break – Cold Leg Pump Discharge

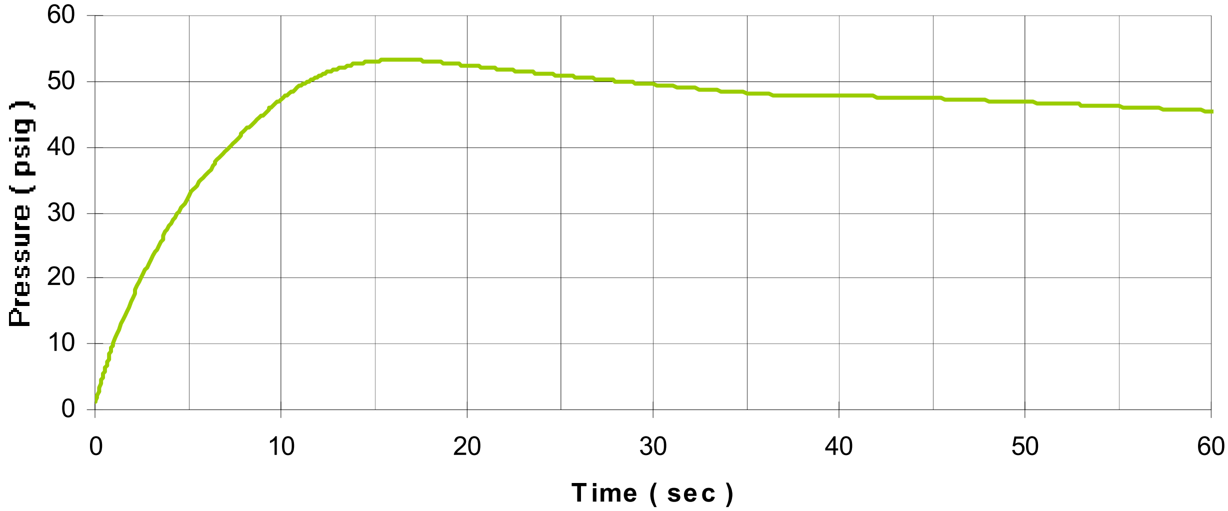


Figure 6-31. ONS ROTSG Peak Pressure Analysis. 8.55 ft^2 break – Cold Leg Pump Suction

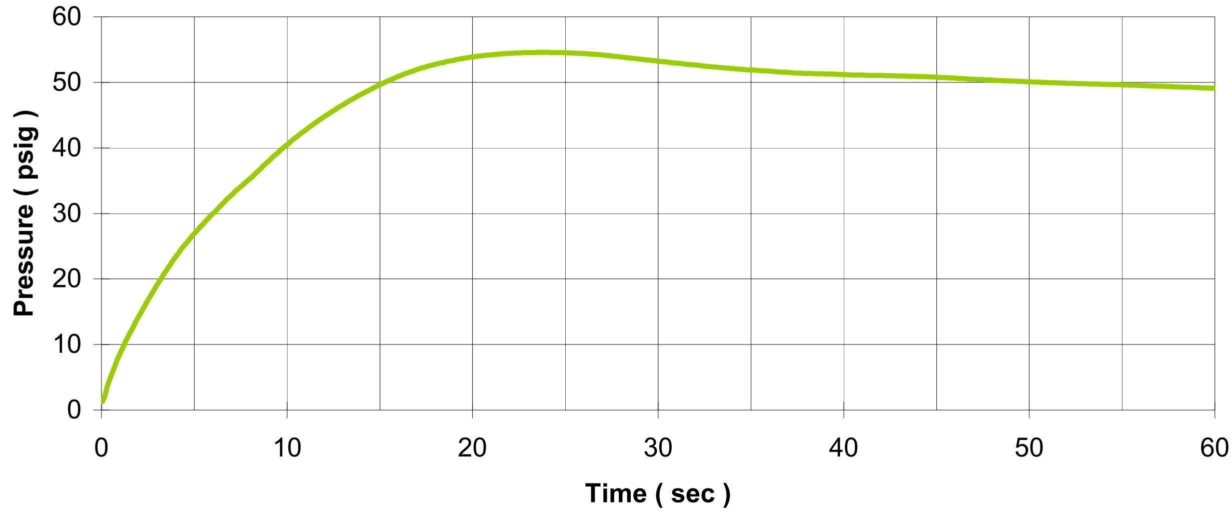


Figure 6-32. ONS ROTSG Peak Pressure Analysis. 14.1 ft^2 break – Rx Vessel Outlet

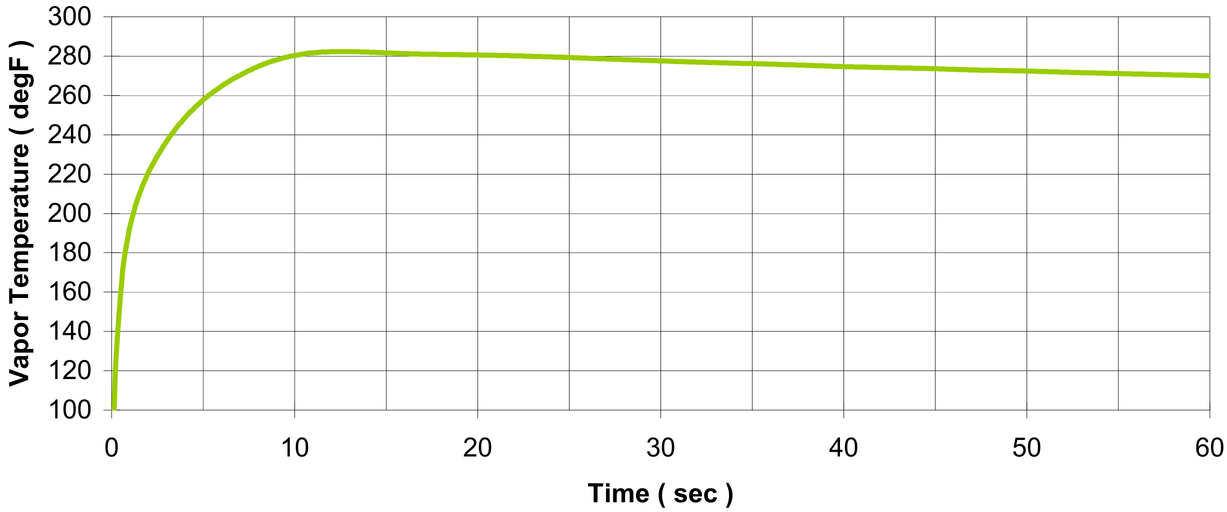


Figure 6-33. ONS ROTSG Peak Pressure Analysis. 14.1 ft^2 break – S/G Inlet

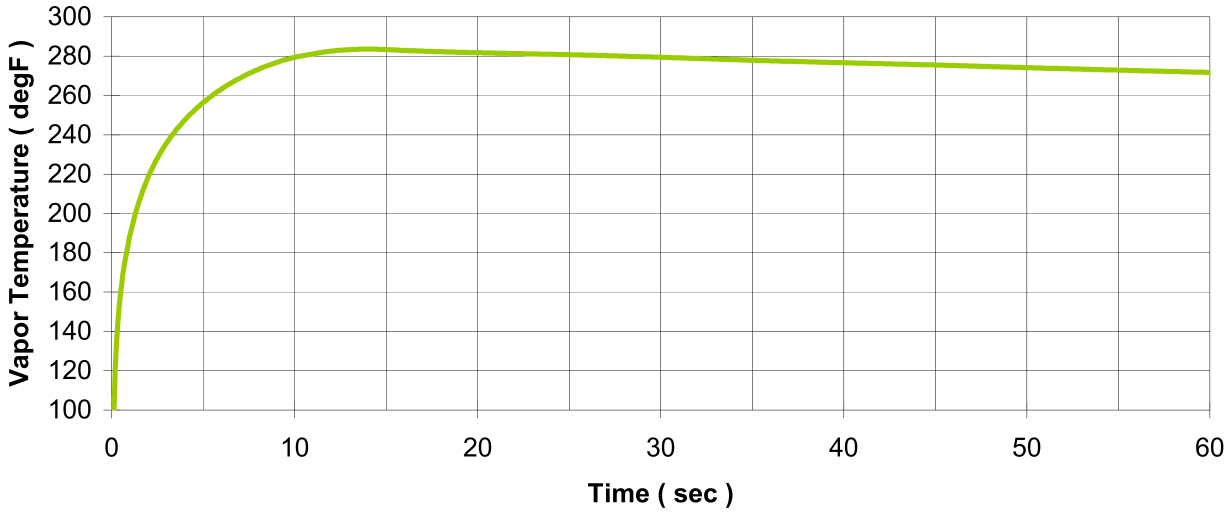


Figure 6-34. ONS ROTSG Peak Pressure Analysis. 8.55 ft^2 break – Cold Leg Pump Discharge

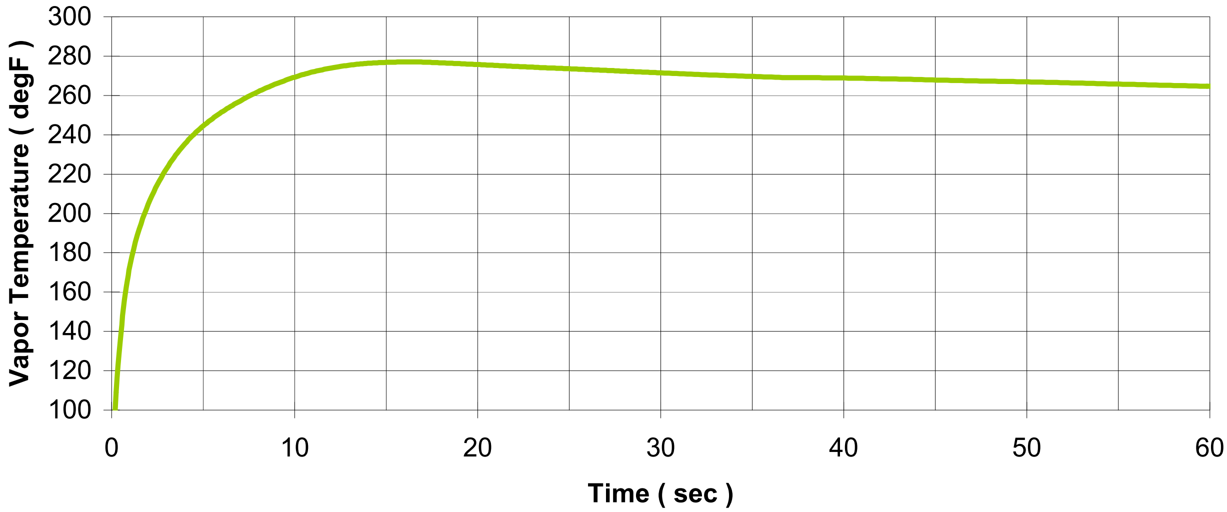


Figure 6-35. ONS ROTSG Peak Pressure Analysis. 8.55 ft^2 break – Cold Leg Pump Suction

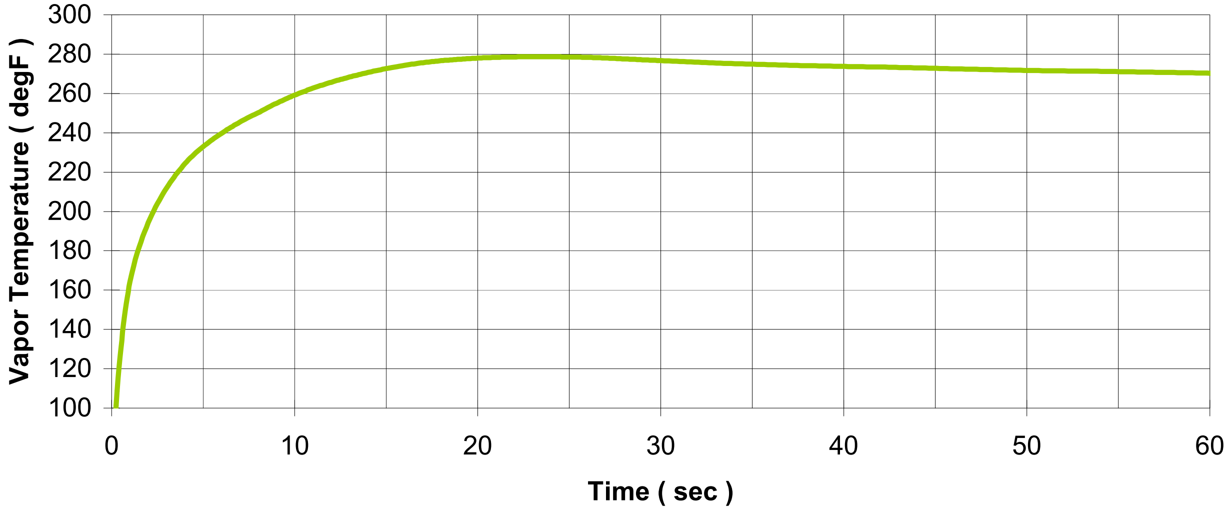


Figure 6-36. Oconee Large Break LOCA Long-term Containment Response. Limiting Reactor Building Pressure Profile

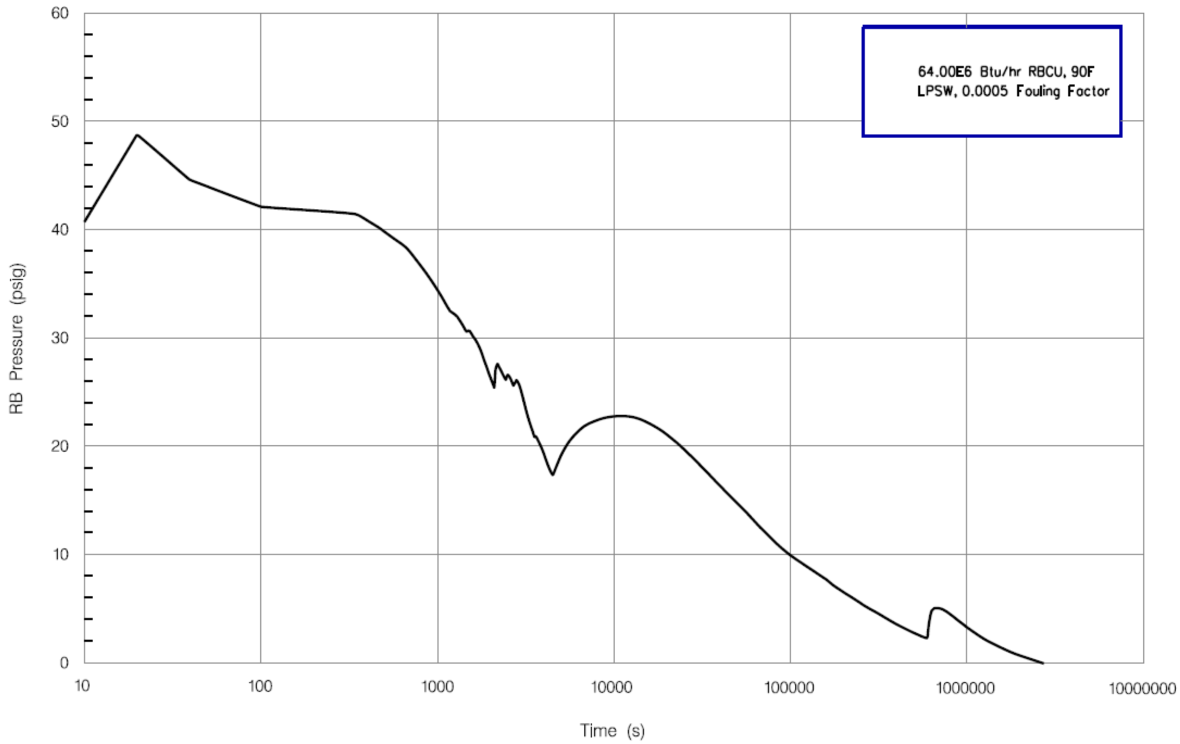


Figure 6-37. Oconee Large Break LOCA Long-term Containment Response. Limiting Reactor Building Temperature Profile

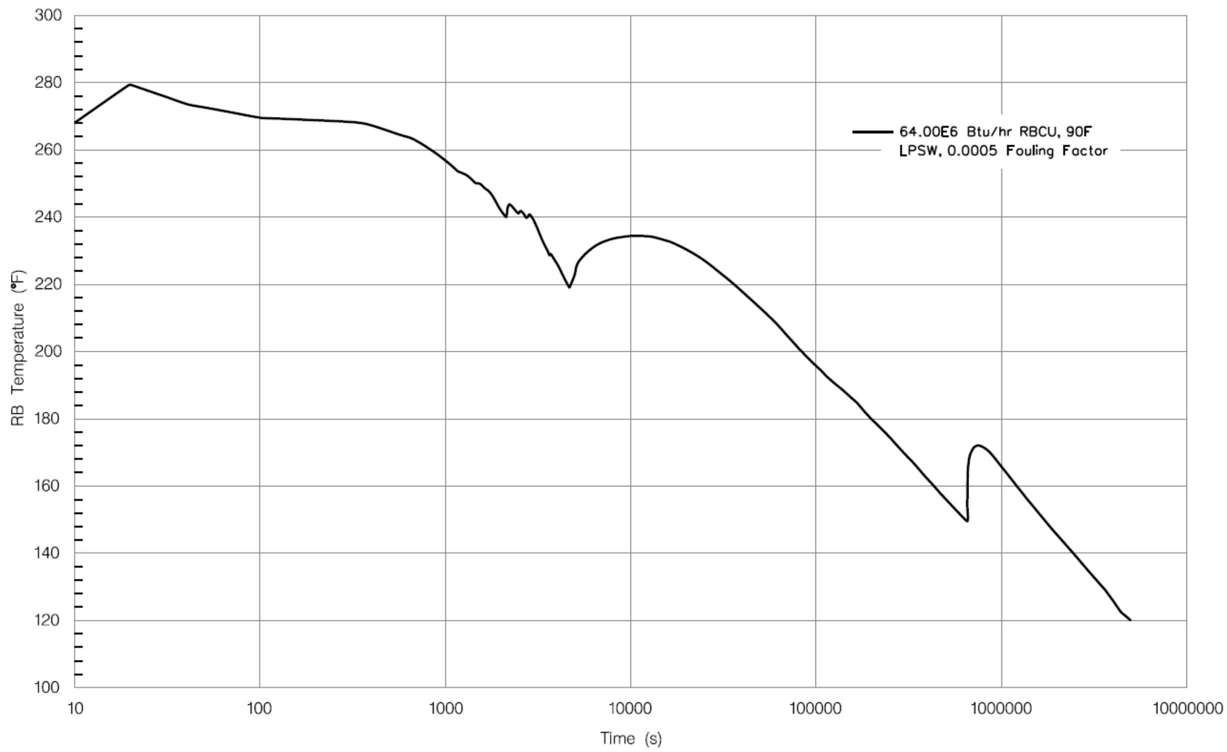


Figure 6-38. Deleted Per 2003 Update

Figure 6-39. Deleted Per 2003 Update

Figure 6-40. Deleted Per 2003 Update

Figure 6-41. Deleted Per 2003 Update

Figure 6-42. Oconee Steam Line Break:Containment Pressure. With Automatic MFW Isolation

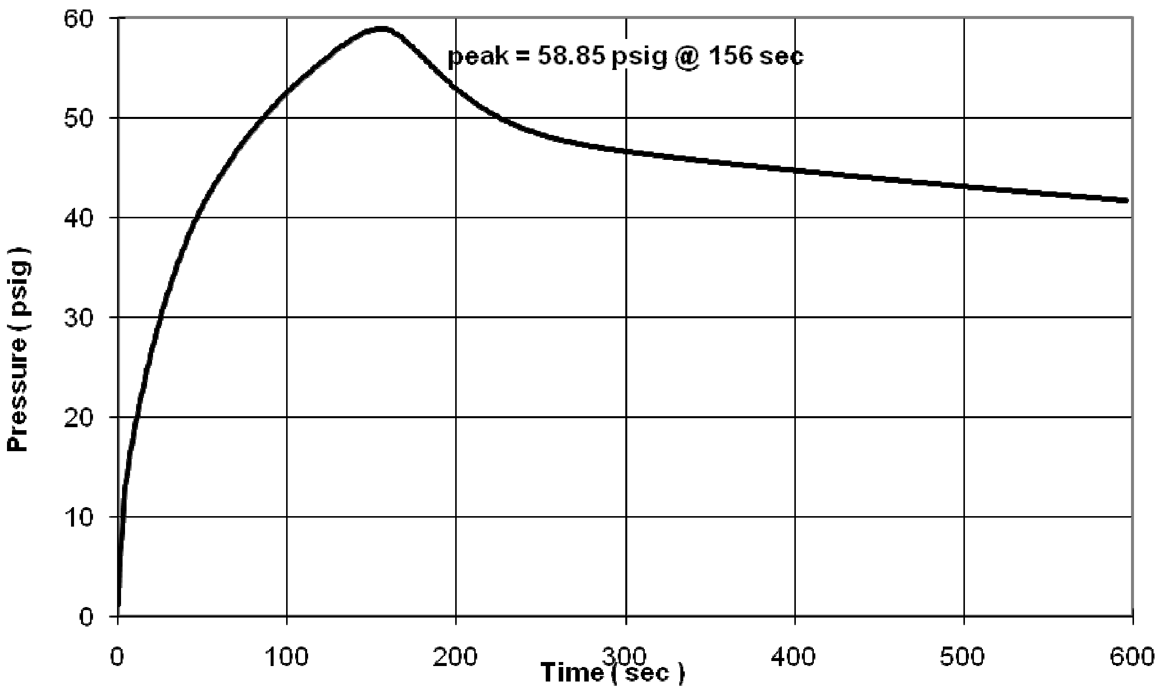


Figure 6-43. Oconee Steam Line Break:Containment Temperature. With Automatic MFW Isolation

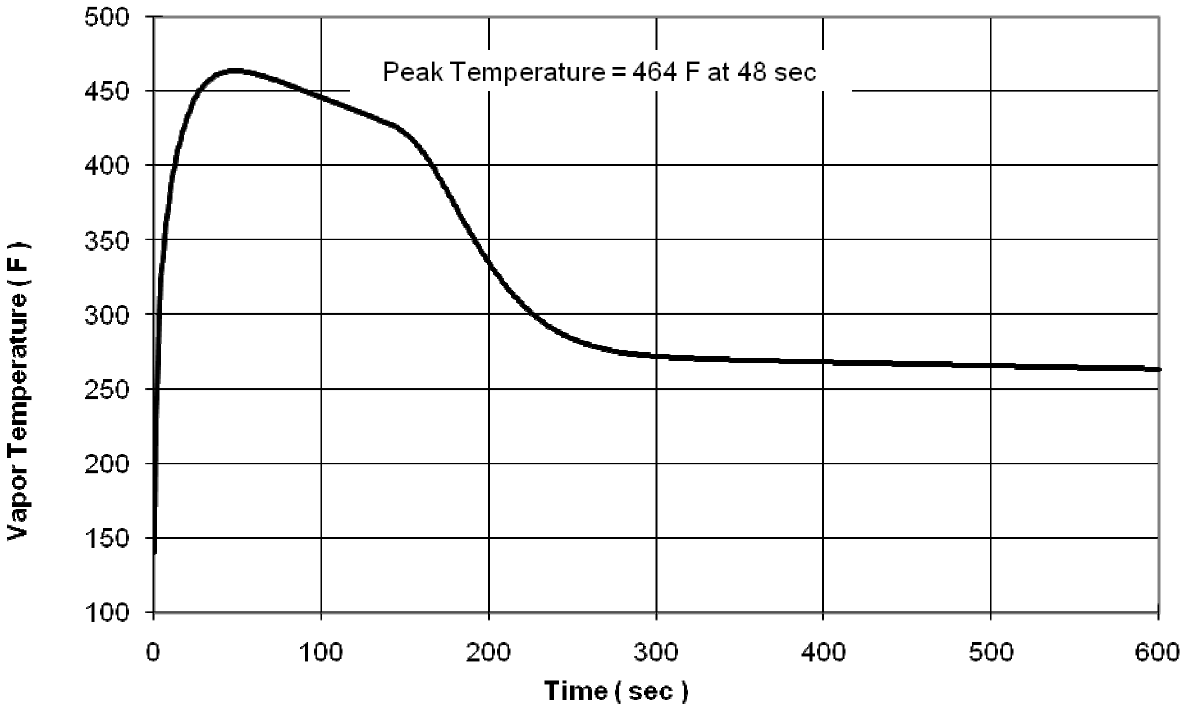
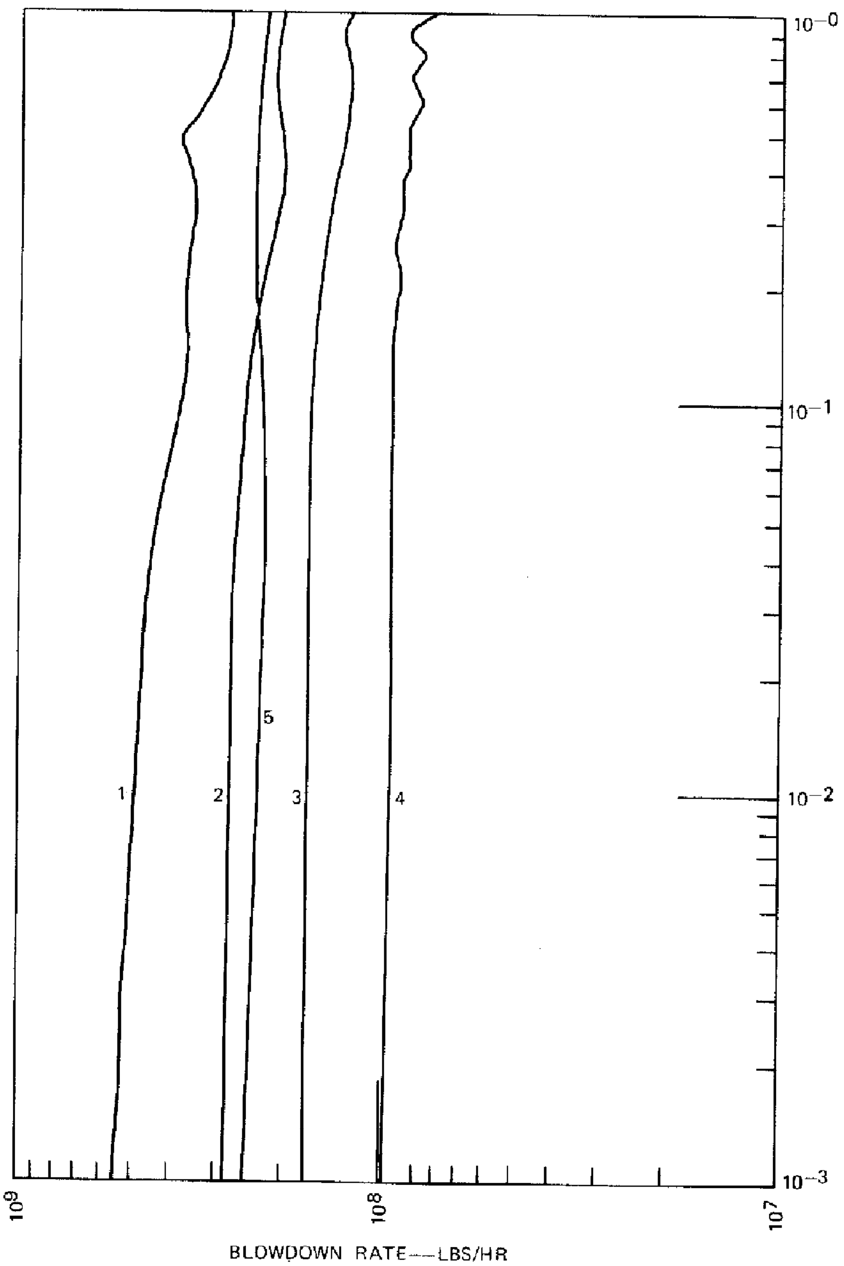
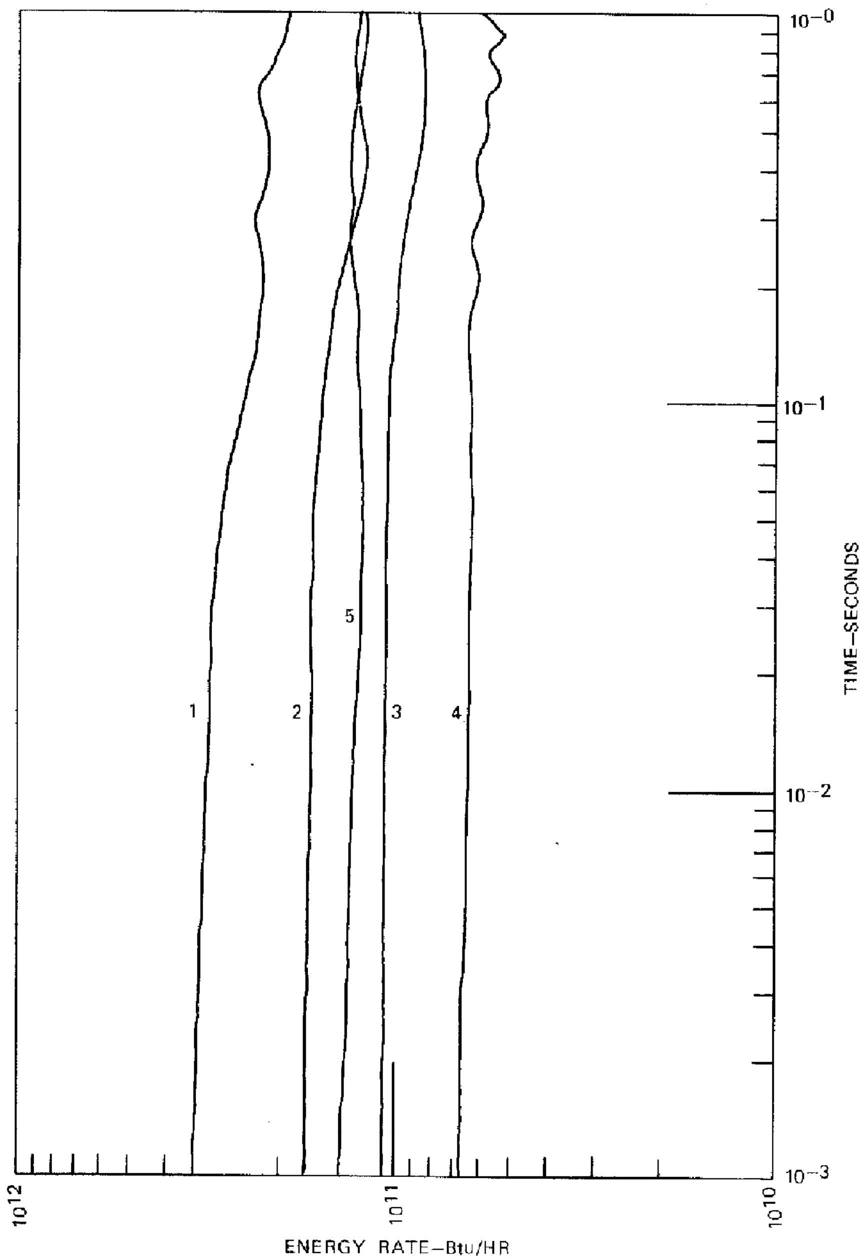


Figure 6-44. LOCA-Mass Release for the Subcompartment Pressure Response Analysis



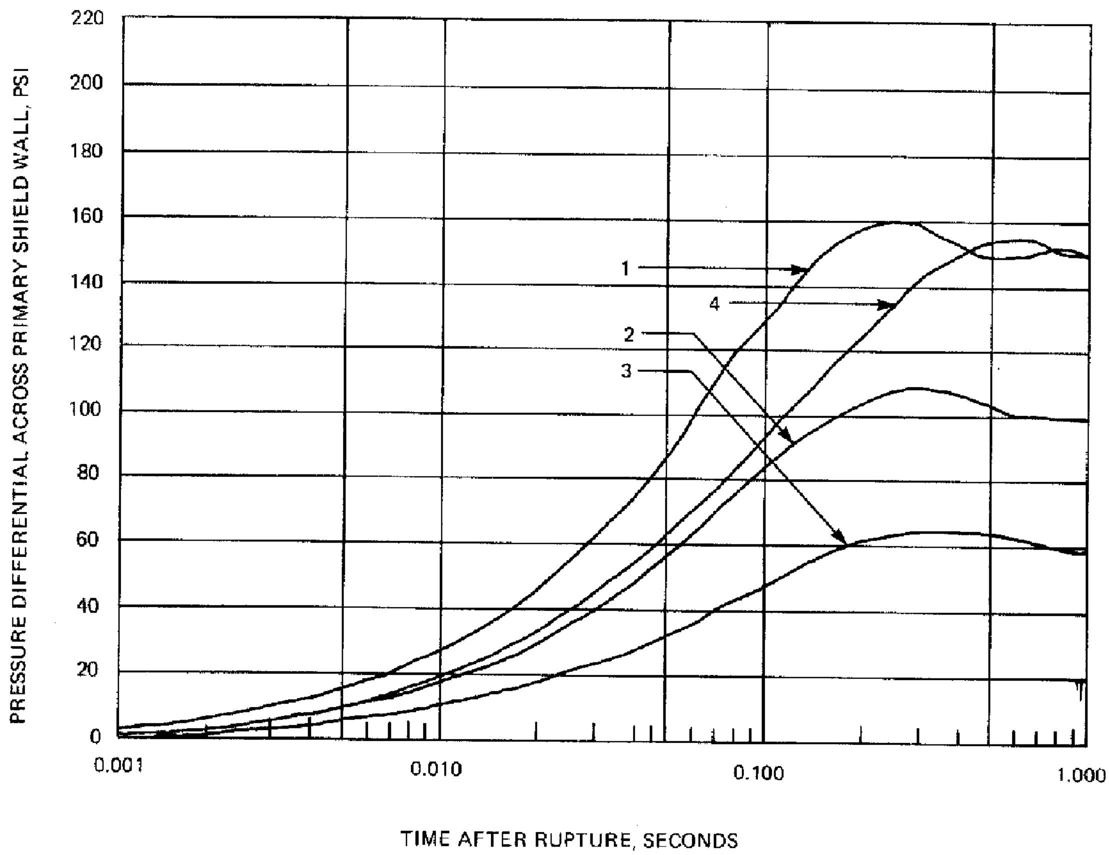
CASE	EXPLANATION
1	14.1 FT^2 RUPTURE IN 36–INCH HOT LEG
2	8 FT^2 RUPTURE IN 36–INCH HOT LEG
3	5 FT^2 RUPTURE IN 36–INCH HOT LEG
4	3 FT^2 RUPTURE IN 36–INCH HOT LEG
5	8.55 FT^2 RUPTURE IN 28–INCH COLD LEG

Figure 6-45. LOCA-Energy Release Rate for the Subcompartment Pressure Response Analysis



CASE	EXPLANATION
1	14.1 FT^2 RUPTURE IN 36–INCH HOT LEG
2	8 FT^2 RUPTURE IN 36–INCH HOT LEG
3	5 FT^2 RUPTURE IN 36–INCH HOT LEG
4	3 FT^2 RUPTURE IN 36–INCH HOT LEG
5	8.55 FT^2 RUPTURE IN 28–INCH COLD LEG

Figure 6-46. LOCA-Reactor Compartment Pressure Response



CURVE	BREAK SIZE	DESCRIPTION
1*	8 FT^2 H.L	ROUGHLY CORRESPONDS TO MAXIMUM BREAK SIZE PREVIOUSLY REPORTED REACTOR CAVITY COULD WITHSTAND
2*	5 FT^2 H.L.	INTERMEDIATE SIZE BREAK
3	3 FT^2 H.L.	CORRESPONDS TO MAXIMUM HOT LEG BREAK WHICH CAN OCCUR WITHIN THE REACTOR CAVITY
4	8.55 FT^2 C.L.	CORRESPONDS TO LARGEST PREVIOUSLY REPORTED BREAK OF HOT LEG

* ALTHOUGH THE 3 FT^2 BREAK SIZE IS THE LARGEST POSSIBLE WITHIN THE REACTOR CAVITY, IT WAS CONSERVATIVELY ASSUMED ALL OF THE BREAK IS WITHIN THE CAVITY.

Figure 6-47. LOCA-Steam Generator Compartment Vent Discharge Coefficient

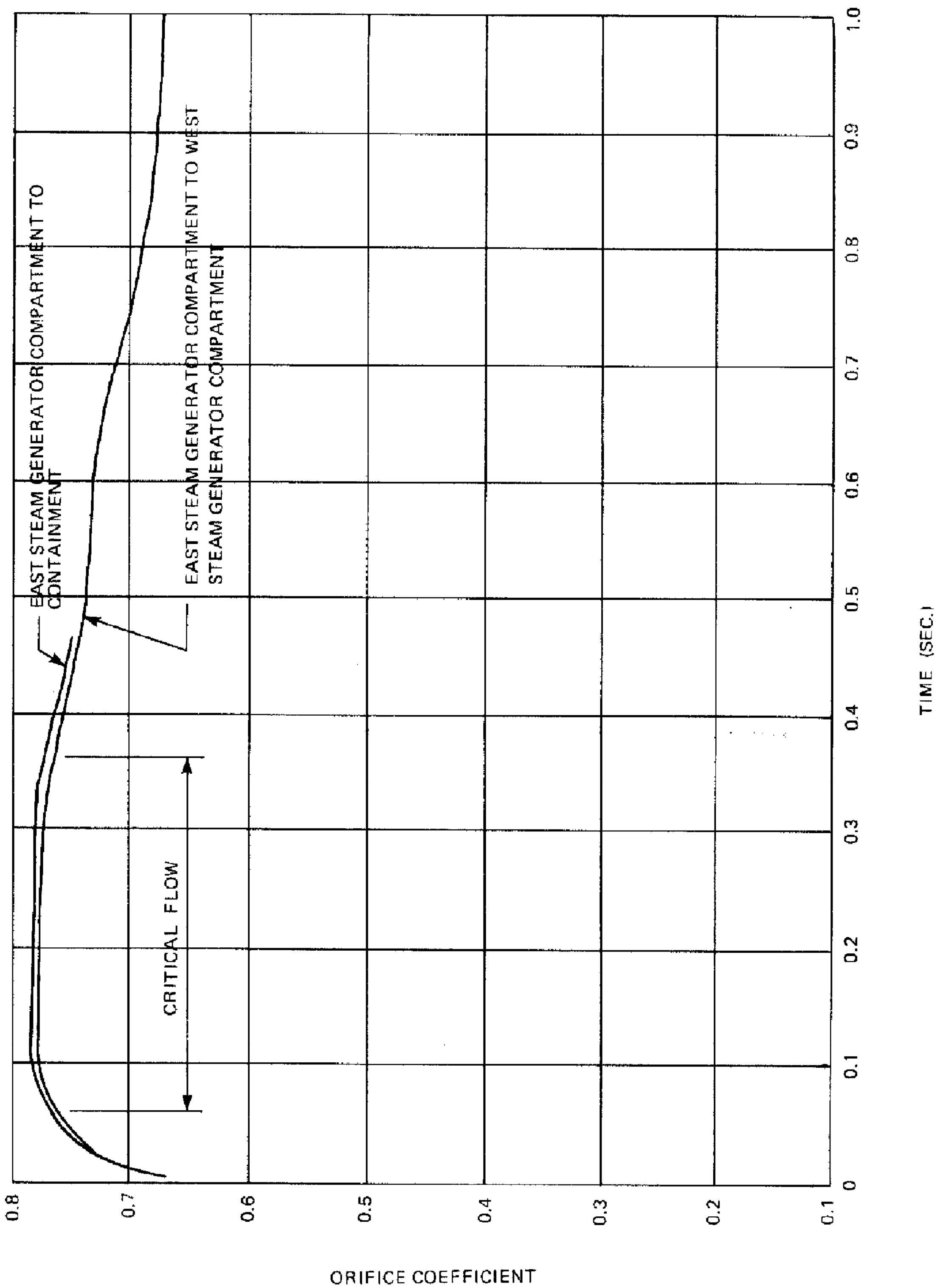
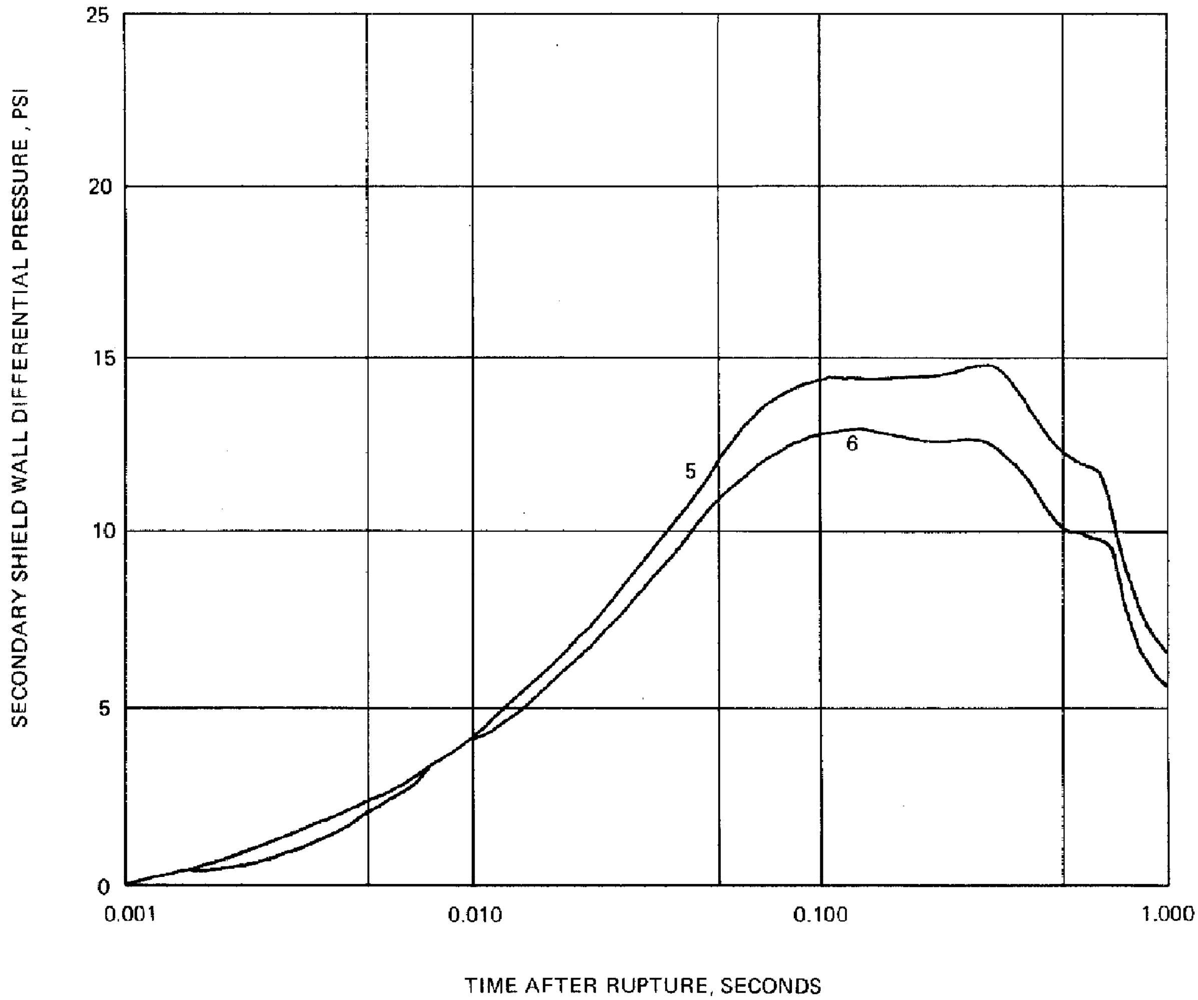


Figure 6-48. LOCA-Steam Generator Compartment Pressure Response



CURVE	BREAK SIZE	DESCRIPTION
5	14.1 FT^2 HOT LEG	RUPTURE OF 36 INCH HOT LEG IN EAST STEAM GENERATOR COMPARTMENT
6	14.1 FT^2 HOT LEG	RUPTURE OF 36 INCH HOT LEG IN WEST STEAM GENERATOR COMPARTMENT

Figure 6-49. Deleted Per 2003 Update

Figure 6-50. LOCA-Mass Released to the Reactor Building. For the 8.55 ft^2 Cold Leg Pump Discharge Break

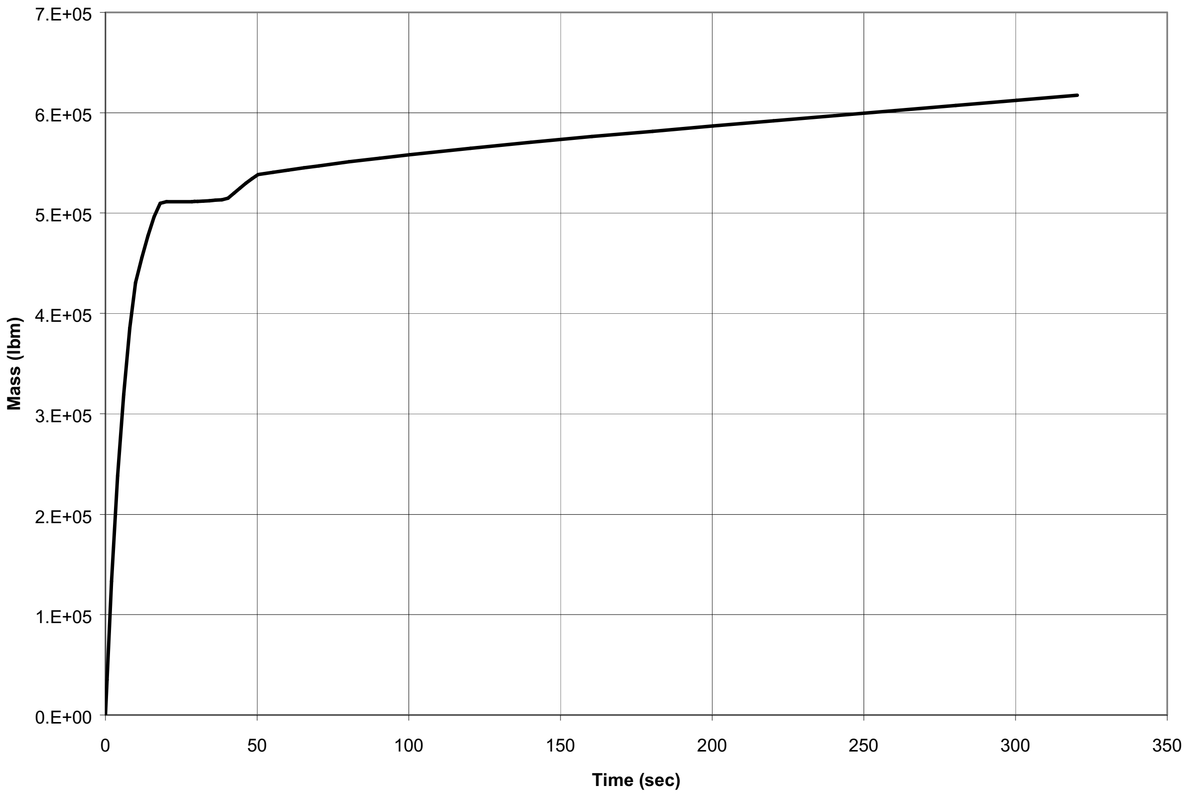


Figure 6-51. LOCA-Energy Released to the Reactor Building. For the 8.55 ft^2 Cold Leg Pump Discharge Break

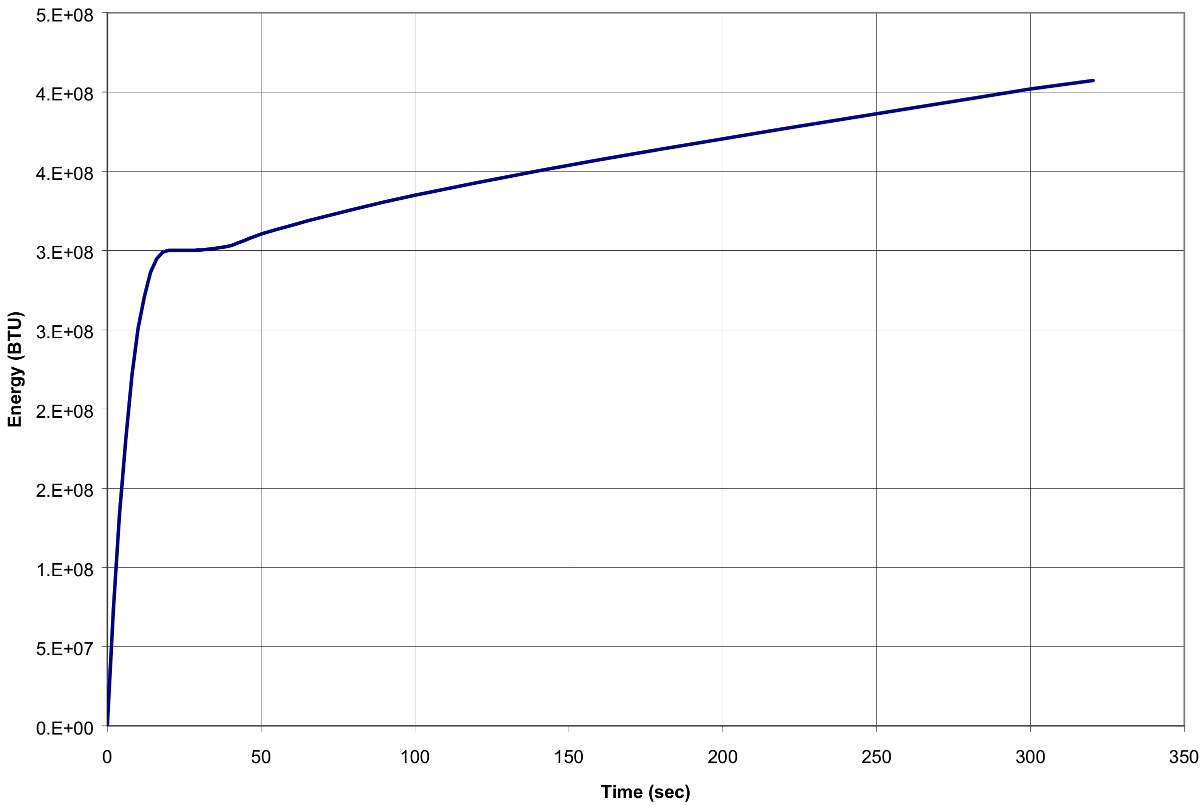


Figure 6-52. LOCA-Reactor Building Pressure. For the 8,55 ft^2 Cold Leg Pump Discharge Break

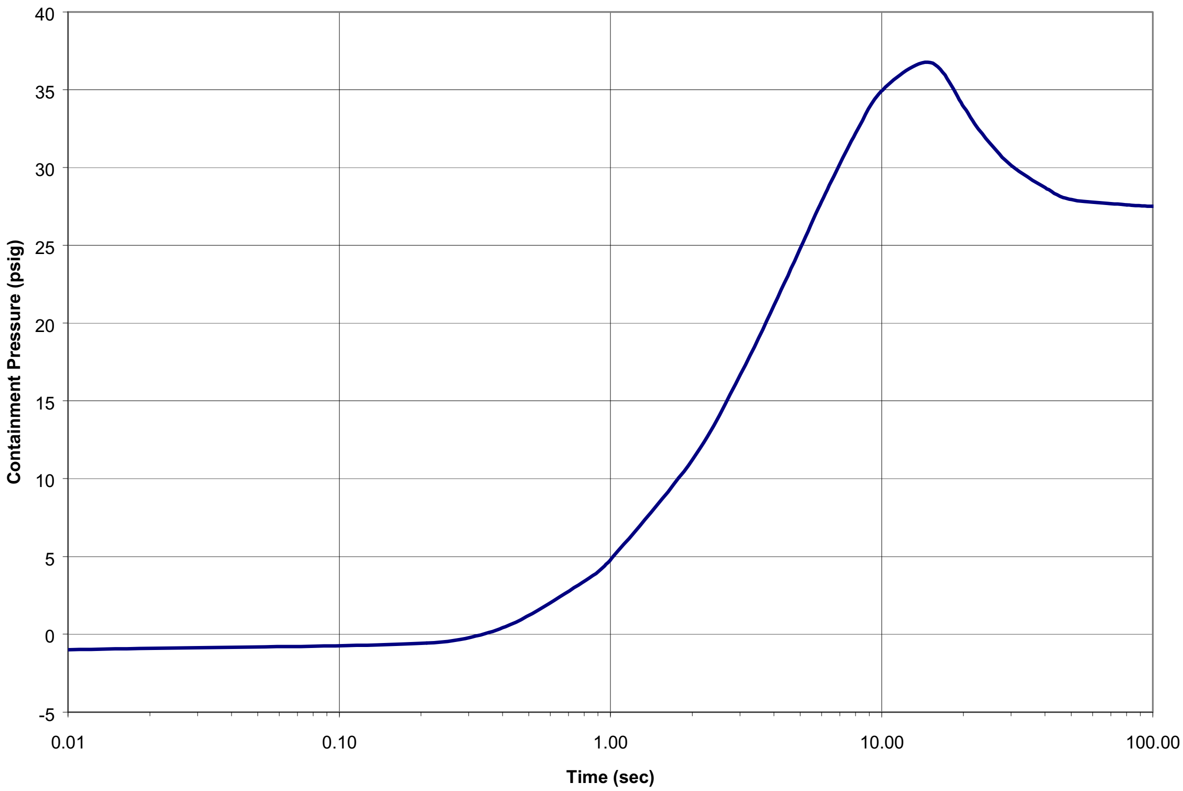


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Table of Contents

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List of Tables

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7.0 Instrumentation and Control

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7.1 Introduction

Instrumentation and control systems include the Reactor Protective System, the Engineered Safeguards Protective Systems, the Rod Drive Control System, the Integrated Control System, the Nuclear Instrumentation System, the Non-Nuclear Instrumentation System, the Incore Monitoring System and the Automatic Feedwater Isolation System.

7.1.1 Identification of Safety-Related Systems

The protective systems, which consist of the Reactor Protective Systems, the Engineered Safeguards System and the Automatic Feedwater Isolation System perform important control and safety functions. The protective systems extend from the sensing instruments to the final actuating devices, such as circuit breakers and pump or valve motor contactors.

7.1.2 Identification of Safety Criteria

7.1.2.1 Design Bases

The protective systems are designed to sense plant parameters and actuate emergency actions in the event of abnormal plant parameter values. They meet the intent of the Proposed IEEE "Criteria for Nuclear Power Plant Protection Systems" dated August, 1968. (IEEE No. 279). The RPS/ESPS also meets the intent of IEEE Std 603-1998. Protective system equipment located in the Control Room, Cable Room, and Aux Building is designed for a mild environment, not LOCA conditions (i.e. 59 psig, 273°F).

7.1.2.2 Single Failure

The protective options meet the single failure criterion of IEEE No. 279 and IEEE Std 603-1998 to the extent that:

1. No single component failure will prevent a protective system from fulfilling its protective functions when action is required.
2. No single component failure will initiate unnecessary protective system action where implementation does not conflict with the criterion above.

7.1.2.3 Redundancy

All protective system functions are implemented by redundant sensors, measuring channels, logic, and actuation devices. These elements combine to form the protective channels.

7.1.2.4 Independence

Redundant protective channels are electrically independent and are packaged to provide physical separation.

7.1.2.5 Separation

Protective channels are physically separate and are electrically isolated from regulating instrumentation. Only one string of instrumentation may be selected at a given time for use in a system control function, and electrical isolation is assured through the use of appropriate isolation devices. A fifth channel of regulating instrumentation not associated with protection is employed for additional control purposes.

Protective channels of the RPS and ESPS are interconnected with fiber optic cabling for inter-channel communication. These cables are used for diagnostic data that is shared between protective channels over fiber optic communications links, do not serve a mutually redundant safety related function, and are not required for the RPS and ESPS to perform their safety related functions. Therefore, these fiber optic cables do not require physical separation. The fiber optic cables that run between safety-related cabinets or enclosures are colored red. Fiber optic media without metallic shields or armor inherently provides sufficient Class 1E electrical isolation for data exchange pathways between devices. Fiber optic cable that is used for mutually redundant safety related functions are required to be physically separated.

7.1.2.6 Manual Trip

Manual trip switches, independent of the automatic trip instrumentation, are provided.

7.1.2.7 Testing

Manual testing facilities are built into the protective systems to provide for:

1. Preoperational testing to give assurance that a protective system can fulfill its required protective functions.
2. On-line testing to prove operability and to demonstrate reliability.
3. In the Automatic Feedwater Isolation System (AFIS), BWNT STAR module provides both manual and automated test capability, and self diagnostic tests performed during start-up and operation. The front panel of the STAR module has LED indicators which indicate module status.
4. The RPS/ESPS provides a test mode and a manual bypass are provided. The system provides the capability to perform start-up and operational testing through the Graphical Service Monitor when the test mode is enabled. The system performs continuous testing through self checking routines.

7.1.3 Identification of Protective Equipment

All safety related sensors, transmitters, transducers, cabinets, etc. located outside the control room are physically identified by placement of a permanent, conspicuous tag on or adjacent to the device. A typical tag bears the wording “Safety Related.” The following are examples of equipment that should be tagged:

Swgr 1TC

LD Ctr IX8

MCC IXSI

ESG channel 1, 3, 5, & 7

DC Pnlbd 1DIA

Vital Pwr Pnlbd 1KVIA

RPS Ch A

AFIS Analog Channel 1

Swgr 1TD

LD Ctr 1X9

MCC 1XS2

ESG channel 2, 4, 6, & 8

DC Pnlbd 1DIB

Vital Pwr Pnlbd 1KVIB

RPS Ch B

AFIS Analog Channel 2

Swgr 1TE

MCC IXS3

DC Pnlbd 1DIC

Vital Pwr Pnlbd 1KVIC

RPS Ch C

AFIS Analog Channel 3

AFIS Digital Channel 1

ESG Channel Even-Odd

DC Pnlbd 1DID

Vital Pwr Pnlbd 1KVID

RPS Ch D

AFIS Analog Channel 4

AFIS Digital Channel 2

7.1.4 NRC IE BULLETIN 90-1 AND SUPPLEMENT 1

The NRC issued IE Bulletin 90-1, "Loss of Fill-Oil in Transmitters Manufactured by Rosemount," on March 9, 1990. IE Bulletin 90-01 requested that licensees promptly identify and take appropriate corrective actions for Model 1153 Series B, Model 1153 Series D, and Model 1154 transmitters manufactured by Rosemount that may be leaking fill-oil. Duke Power Company's Bulletin response actions included identification of transmitters from the suspect lots for Oconee Nuclear Station which were in use in safety-related applications, review of applicable calibration records to inspect transmitters for loss of fill-oil behavior, and development of an enhanced surveillance program to monitor applicable transmitters for symptoms of loss of fill-oil. Additionally, the IE Bulletin 90-01 requested that upon identification of any suspect Rosemount transmitters in use in reactor protection or engineered safety features actuation systems, operability determinations be performed for this equipment until the equipment could be replaced. In its response (letter form H. B. Tucker to NRC, dated August 10, 1990) DPC found no suspect transmitters installed in the reactor protection or engineering safety features actuation systems of Oconee Nuclear Station.

The NRC issued Supplement 1 to IE Bulletin 90-01, "Loss of Fill-Oil in Transmitters Manufacturecd by Rosemount," on December 22, 1992, providing further details on monitoring programs for the transmitters described in the original bulletin. Duke Power Company responded on May 24, 1993 by the letter from H. B. Tucker to the NRC. Subsequently, the NRC issued its Safety Evaluation Report (SER) on May 19, 1995 which provided approval and closeout of IE Bulletin 90-01 and Supplemental 1 for the Oconee Nuclear Station.

7.1.5 References

1. Nuclear Regulatory Commission, Letter to All Holders of Operating Licenses or Construction Permits for Nuclear Power Reactors, from Charles E. Rossi, March 9, 1990, NRC Bulletin No. 90-01, “Loss of Fill-Oil in Transmitters Manufactured by Rosemount.”
2. Duke Power Company, Letter from H.B. Tucker to NRC, August 10, 1990, re: Response to NRC Bulletin no. 90-01, “Loss of Fill-Oil in Transmitters Manufactured by Rosemount.”
3. Duke Power Company, Letter from H.B. Tucker to NRC, May 24, 1993, re: Response to NRC Bulleting No. 90-01, Supplement 1, “Loss of Fill Oil in Transmitters Manufactured by Rosemount.”
4. Nuclear Regulatory Commission, Letter from L. A. Wiens to J. W. Hampton (DPC), May 19, 1995, “NRC Bulletin 90-01 Supplement 1, Loss of Fill Oil in Transmitters Manufactured by Rosemount.”

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7.2 Reactor Protective System

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The Reactor Protective System (RPS) monitors parameters related to safe operation and trips the reactor to protect the reactor core against fuel rod cladding damage. It also assists in protecting against Reactor Coolant System damage caused by high system pressure by limiting energy input to the system through reactor trip action.

7.2.1 Design Bases

The RPS includes all design basis features of Section 7.1.2 with the following additions:

7.2.1.1 Loss of Power

A loss of power to a reactor protective channel will cause that protective channel to trip.

7.2.1.2 Equipment Removal

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Removal of a computer card from the RPS will initiate a protective channel trip. Removal of an input card will fault the input signals on that card and alarm, but will not initiate a protective channel trip. Removal of an output card will generate a channel trouble alarm and will initiate a half-channel trip (both of the outputs from the affected card assume a tripped state which creates a half-channel trip).

7.2.1.3 Diverse Means of Reactor Trip

In the unlikely event of a systematic or complete failure of the Reactor Coolant System low pressure signals to trip the reactor following the initiation of emergency core cooling, there is a separate, diverse means of assuring reactor trip. A high pressure in the Reactor Building is independently sensed by four sensors, and independent signals are fed from these sensors to the four Reactor Protective System channels to provide the desired diverse reactor trip signal.

7.2.2 System Design

7.2.2.1 System Logic

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The RPS consists of four independent protective channels, as shown in Figure 7-1. Each RPS protective channel contains the sensor input modules, output modules, a channel computer, four hardwired reactor trip relays (RTRs) and associated contacts. When the protective channel inputs are in the normal, or untripped, state the RTR is energized and no trip signal is sent to the CRD trip devices. Channel A provides input signals to its associated Channel A RTR within its cabinet and also sends this signal to each of its remaining Channel RTRs in the Channel B, C, and D cabinets. Each channel cabinet has the four RTR contact sets configured to provide 2-out-of-4 coincidence trip logic. When a protective channel trips, it sends the protective channel trip signal to its corresponding relays in each protective channel. When any two RPS protective channels receive channel trip signals, the RTR logic in each protective channel actuates to remove power from its associated CRD trip device. All RTRs trip whenever any two of the four protective channels trip.

The coincidence logic contained in the RPS protective channel A RTR controls breaker A in the Control Rod Drive (CRD) System as shown in Figure 7-1. Protective Channels B, C, and D will control breakers B, C, and D respectively in the Control Rod Drive System. Breakers A and C are placed in series in one parallel path and breakers B and D are in series in the other parallel path. All 600VAC 3-phase power to the rod drives is via these parallel paths. Combinations that could initiate a trip, in Boolean logic terms, are AB + AD + BC + CD (+ meaning logic "or"). This is 1-out-of-2 logic taken twice and is referred to as (1-out-of-2) x 2 logic. It should be noted that when any two out of four RPS protective channels trip, all RTRs trip, commanding all CRD trip breakers to open.

Independence is maintained in the four protective channels which are interconnected via fiber-optic data links. These links provide the means to exchange data, which is used for signal validation, fault and deviation detection, and trip actuation. This provides additional fault detection. If interchannel communications are lost, the associated signals are faulted as well. Faulted signals are eliminated from use in the signal selection logic. With only the hardwired signal as valid, the signal is passed directly to the subsequent logic, thus ensuring protective channel independence. The second maximum (2.MAX) and second minimum (2.MIN) signal selection functions are used for analog inputs, and 2-out-of-4 selection logic is used for contact inputs. The 2.MAX and 2.MIN functions remain until less than two valid signals are present. The 2-out-of-4 logic function reduces to a 2-out-of-3 logic for any condition that causes an input signal fault, including loss of power.

Three of the four RPS channel computers (A, B, and C) also perform a redundant ESPS logic function (Section 7.3.2). Therefore, three of the four RPS protective channel computers calculate both RPS and ESPS functions. RPS protective channel D calculates only RPS functions.

The undervoltage coils of the control rod drive breakers receive their power from the protective channel associated with each breaker. The manual reactor trip switch is interposed in series between each breaker's RTR logic and the assigned breakers undervoltage coil.

In response to NRC Generic Letter 83-28 automatic actuation of the AC breaker shunt trip attachments for the Reactor Trip System and Manual Trip Actuation have been installed. This upgrade improves the reactor trip breaker reliability.

For the reactor trip breakers in each channel a relay is installed with its operating coil in parallel with the existing undervoltage device. The output contacts of these relays control the power to the shunt trip devices. Thus, when power is removed from the breaker undervoltage trip attachment on either a manual or automatic trip signal, the shunt trip attachment is energized to provide an additional means to trip the breaker. Test switches are installed to permit independent testing of the shunt and undervoltage trip devices. Loss of shunt trip control power is annunciated in the control room indicating that the shunt trip device is not operable.

7.2.2.2 Summary of Protective Functions

The four Reactor Protective System protective channels are identical in their functions, which combine in the system logic to trip the reactor automatically and protect the reactor core for the following conditions:

1. When the reactor power, as measured by neutron flux, exceeds a fixed maximum limit.

2. When the reactor power, as measured by neutron flux, exceeds the limit set by the reactor coolant flow and power imbalance.
3. When the reactor power exceeds the limit set by the number and combination of reactor coolant pumps in operation.
4. When the reactor outlet temperature exceeds a fixed maximum limit.
5. When a specified reactor pressure-outlet temperature relationship is exceeded.
6. When the reactor pressure falls below a fixed minimum limit.
7. When Reactor Building pressure exceeds a fixed maximum limit.
8. The RPS automatically trips the reactor to protect the Reactor Coolant System whenever the reactor pressure exceeds a fixed maximum limit.
9. The RPS automatically trips the reactor upon main turbine trip or trip of both main feedwater pumps.

The abnormal conditions that initiate a reactor trip are keyed to the above listing and tabulated in Table 7-1.

7.2.2.3 Description of Protective Channel Functions

The functions of the RPS described below apply to each protective channel. Reference Figure 7-1 for Control Logic.

7.2.2.3.1 Over Power Trip

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The nuclear instrumentation provides a linear neutron flux signal in the power range to the four protective channels. The protective channel signals are then compared and when the 2.MAX neutron flux signal exceeds the trip setpoint in two or more protective channels, a reactor trip is generated. Reference Trip #1 of Figure 7-1 for control logic.

7.2.2.3.2 Nuclear Over Power Trip Based on Flow and Imbalance

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Neutron flux and the reactor coolant flow are continuously monitored. Upper and Lower flux signals are received from the nuclear instrumentation and a total flux and a delta flux reading is calculated by each RPS protective channel. Total reactor coolant flow is calculated by each RPS protective channel from the differential pressure reading for each loop. A power level trip setpoint is established for each RPS protective channel based on the percentage reactor coolant flow rate multiplied by the flux to flow ratio and limited by the maximum allowed thermal power (Pmax). The value of Pmax is established to prevent exceeding the limits established by the COLR in the event that indicated reactor coolant flow increases due to instrument failure. The delta flux or imbalance (power in the top half of the core minus the power in the bottom half of the core) reduces the power level trip setpoint such that the four pump power-imbalance boundaries illustrated in Figure 7-3 are not exceeded. Less than four pump power-imbalance protection is provided by the power level trip setpoint decrease due to flow decrease. When the 2.MAX neutron flux signal exceeds the power level trip setpoints established by the total reactor coolant flow and the reactor power imbalance in two or more protective channels, a reactor trip is generated. Reference Trip #3 of Figure 7-1 for control logic.

All flow ∆P cells for a single loop are connected to common 1-inch "low" and "high" lines from the flow tube in that loop. Severance of the "low" line will result in maximum indicated flow for the loop in all four protective channels. All console indicators for the loop will go to 110 percent full flow. Severance of the "high" line will result in zero indicated flow for the loop and possibly a power/flow reactor trip. See Section 7.4.2.3.1 for more details.

7.2.2.3.3 Power/Reactor Coolant Pumps Trip

The reactor coolant (RC) pumps are monitored to determine that they are running. Loss of a single pump initiates four independent signals, one to each protective channel. This information is received by a pump monitor logic which counts the number of RC pumps in operation and identifies the coolant loop in which the pumps are operating. The inputs from the RC Pump monitors are processed by each RPS protective channel and a trip is generated for the conditions in Table 7-1. Reference Trip #11 of Figure 7-1 for control logic.

7.2.2.3.4 Reactor Outlet Temperature Trip

The reactor outlet temperature is measured by resistance elements.

One of the four reactor outlet temperatures is designated for each protective channel. When the 2.MAX RTD input exceeds the predetermined setpoint, the associated protective function is automatically placed in its tripped state. When the 2.MAX reactor outlet temperature exceeds the trip setpoint in two or more protective channels, a reactor trip is generated. Reference Trip #7 of Figure 7-1 for control logic.

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7.2.2.3.5 Pressure-Temperature Trip

Figure 7-2 shows typical operating reactor coolant pressure-temperature boundaries formed by the combined reactor high temperature, high pressure, low pressure, and the pressure-temperature comparator trip settings.

When reactor coolant 2.MAX or 2.MIN pressure or temperature exceeds these boundaries, a trip signal is generated within the protective channel. If two or more protective channels reach the trip condition, a reactor trip signal is generated. Reference Trip #6 of Figure 7-1 for control logic.

7.2.2.3.6 Reactor Coolant Pressure Trip

The reactor coolant system pressure is measured by four independent pressure transmitters, one pressure input to each RPS protective channel. When the 2.MAX or 2.MIN pressure input exceeds its setpoint (high or low), the associated protective function is automatically placed in its tripped state. When the 2.MAX or 2.MIN reactor coolant pressure exceeds the trip setpoints in two or more protective channels, a reactor trip is generated. Reference Trips #4 and #5 of Figure 7-1 for control logic.

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7.2.2.3.7 Main Turbine Trip

Pressure switches monitoring the hydraulic fluid pressure in the Turbine Emergency Trip System header will input an open indication to the RPS on turbine trip.

Each RPS protective channel A, B, C & D monitors one of four hydraulic fluid pressure switch contact inputs. The status of these four contact inputs is shared between protective channels over fiber optic communications links. If the reactor trip function is enabled and 2-out-of-4 Main Turbine hydraulic fluid pressure switch contacts are open, then that RPS protective channel produces a trip signal. If two or more RPS protective channels are in the tripped state, a reactor trip is generated via the 2-out-of-4 reactor trip relay logic. Reference Trip #10 of Figure 7-1 for control logic. This trip is bypassed below a predetermined flux level for unit startup.

7.2.2.3.8 Loss of Main Feedwater Trip

Hydraulic oil pressure switches for each feedwater pump turbine will input an open indication to the RPS on feedwater pump turbine trip.

Each RPS protective channel A, B, C & D monitors both feedwater pump turbines hydraulic oil pressure switch contact inputs. The status of these eight contact inputs is shared between protective channels over fiber optic communication links. If the reactor trip function is enabled and both feedwater pump turbines are tripped, then that RPS protective channel produces a trip signal. If two or more RPS protective channels are in the tripped state, a reactor trip is generated via the 2-out-of-4 reactor trip relay logic. Reference Trip #9 of Figure 7-1 for control logic. This trip is bypassed below a predetermined flux level for unit startup.

7.2.2.3.9 Reactor Building Pressure Trip

Each of the four protective channels receives Reactor Building pressure information from an independent pressure switch.

A 2-out-of-4 logic scheme is used within each RPS Protective Channel. The 2-out-of-4 logic within each RPS protective channel looks for a second open contact from the pressure switches to initiate a protective channel trip. This logic eliminates a single failure from tripping an RPS protective channel and will only provide a reactor trip when there is valid Reactor Building High Pressure (2-out-of-4). A single open contact will be annunciated via the respective protective channel's Trouble Statalarm and via the OAC computer. Reference Trip #8 of Figure 7-1 for control logic.

7.2.2.4 Setpoint Adjustments for Single Loop Operation

Following amendments 165/165/162 to the facility operating license, single loop power operation is prohibited.

7.2.2.5 Availability of Information

The reactor trip components associated with a single protective channel are wholly contained within two RPS cabinets.

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All system analog and binary input signals are monitored by the plant computer. Separate from the computer, equipment failures and trip actions are sequence-annunciated in the plant status annunciator. Such sequencing permits the operator to readily identify the protective channel trip actions. Process information including power, imbalance, flow, temperature, and pressure is also available on the main control console.

Plant annunciator windows provide the operator with immediate indications of changes in the status of the RPS. The following conditions are annunciated for each RPS protective channel:

1. channel trip
2. channel trouble
3. channel on test
4. NI power supply failure
5. shutdown bypass initiated
6. manual bypass initiated

Any time a test switch is in other than the operate position, a test annunciator will be lit and the associated protective channel must be administratively declared out of service.

The RPS system communicates with the plant OAC and annunciators through the Monitoring and Service Interface (MSI). The MSI has three communication functions which are to: provide unidirectional data to the OAC, provide bidirectional data to the Service Unit, and provide isolated communication between the safety related RPS and the non-safety plant systems such as annunciators and the ICS. The Graphical Service Monitor (GSM) resides on the Service Unit and provides an interface into the RPS for testing and maintenance. The OAC is sent unidirectional data through a gateway which provides real time information to the OAC. Reference Figure 7-1, pg 16 for a diagram of the MSI interface.

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7.2.3 System Evaluation

7.2.3.1 System Logic

The RPS is a four-channel, redundant system in which the four protective channels are brought together in four identical 2-out-of-4 logic networks of the reactor trip components. The Reactor Trip Component (RTC) is made up of two digital output modules and four Reactor Trip Relays (RTR) all contained within the respective RPS channel's cabinet. The RTC receives a channel trip signal in its own channel and channel trip signals from the digital output modules in the other three RPS channels. A trip in any 2 of the 4 protective channels initiates a trip of all four logic networks. The system to this point has the reliability and advantages of a pure 2-out-of-4 system.

Each of the reactor trip components (2-out-of-4 logic networks) controls a control rod drive breaker. A trip in any 2 of the 4 protective channels initiates a trip of all the breakers. The breakers are arranged in what is effectively a 1-out-of-2 logic taken twice (Figure 7-4). This system combines the advantages of the 2-out-of-4 and the 1-out-of-2 x 2 systems. The combination results in a system that is considered superior to either of the basic systems alone.

In evaluating system performance, it is arbitrarily assumed that "failure" can either prevent a trip from occurring or can initiate trip action.

The redundant Reactor Protective System inputs operate in a true 2-out-of-4 logic mode so that the failure of an input leaves the system in either a 2-out-of-3 or a 1-out-of-3 logic mode, with either state providing sufficient redundancy for reliable performance.

The system can tolerate several input function failures without a reduction in performance capability provided the failures occur in unlike variables in different protective channels, or are of a different mode in different protective channels, or all occur within one protective channel. When a single protective channel fails, the system is left in either a 2-out-of-3 or 1-out-of-3 logic mode as explained below.

The protective channel trip relay of each channel is located in the reactor trip component associated with the channel. Within each reactor trip component, there is a logic relay for each protective channel. These combine in each reactor trip component to form the 2-out-of-4 logic. A Failure Mode and Effects analysis of the reactor trip component has demonstrated that single failures within the reactor trip component or interconnections can produce only the following effects:

1. Trip the breaker associated with the reactor trip component.
2. Place the system in a 2-out-of-3 mode, as if the associated protective channel had a "cannot" trip failure.
3. Place the system in a 1-out-of-3 mode, as if the associated protective channel had tripped.

The combination of reactor trip components and control rod drive breakers form a 1-out-of-2 x 2 logic. At this level the system will tolerate a "cannot trip" type of failure of one reactor trip component, or of the breaker associated with one reactor trip component without degrading the system's ability to trip all control rods. The failure analysis demonstrates that no single failure involving a reactor trip component will prevent its associated breakers from opening.

7.2.3.2 Redundancy

The design redundancy of the Reactor Protective System allows the loss of a single protective channel. If that protective channel is in the Trip state, the remaining components and protective channels are operational in a 1-out-of-3 system logic. If that protective channel is in Manual Bypass, the remaining components and protective channels are operational in a 2-out-of-3 system logic.

7.2.3.3 Electrical Isolation

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Electrical isolation is inherent in the use of fiber-optic data links. In order to maintain electrical independence when input signals are shared between channels, a TXS communication link module is used to convert the signal from hard wire to fiber optic. The fiber optic communication equipment is qualified as Class 1E isolation and provides the required electrical separation between each protective channel. Fiber optic communication equipment is also used between protective channels and the Monitoring and Service Interface (MSI). Fiber optic isolation prevents internal electrical faults from propagating from one protective channel to other redundant channels.

All signals leaving the RPS to non-qualified systems (such as ICS) utilize qualified signal isolators to protect against faults occurring external to RPS.

Each input/output interface type was tested in both differential (across input/output) and common (input/output to ground) modes. Fault signals of 600 VAC and 250 VDC were applied for 30 seconds. This testing verified the RPS operation was not affected by the simulated faults.

7.2.3.4 Periodic Testing and Reliability

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The use of 2-out-of-4 logic between protective channels permits a channel to be tested online without initiating a reactor trip. Test circuits are supplied which utilize the redundant, independent, and coincidence features of the Protective Systems. This makes it possible to manually initiate online trip signals in any single protective channel in order to test trip capability in that channel without affecting the other protective channels. Surveillance requirements have been established for performance of protective channel calibrations and protective channel functional testing.

The RPS provides continual online automatic monitoring of each of the input signals in each channel, performs a signal online validation, and provides functional validation of hardware performance. The RPS has a Graphical Service Monitor (GSM) which supplies individual screens for monitoring and recording the analog and binary inputs during Protective Channel Calibration tests. To prevent adverse system actions, the analog or binary signals may be placed in Bypass using the GSM Trip/Bypass screens. There are also screens to exercise the reactor trip logic, statalarms, and events recorder. Each protective channel is provided with a key-operated Parameter Change Enable keyswitch. The system software controls access to the computer from each protective channel by controlling the operating modes of the computer. Under normal operating conditions, the computer is in the OPERATION mode. The PARAMETERIZATION Mode allows changes to specific parameters or performance of tests from the GSM screens. Permission to change from the OPERATION mode into the PARAMETERIZATION mode is provided by the Parameter Change Enable Keyswitch. After the permissive is provided from a system processor via its Keyswitch, communication from the Service Unit to that processor is allowed to change its operating mode. Placing the PROCESSOR into the FUNCTION TEST and DIAGNOSTIC modes requires first enabling the PARAMETERIZATION Mode with the keyswitch and then setting a separate parameter to enable these modes with the GSM. The FUNCTION TEST Mode allows disabling the application function and forcing the output signals (normally not used). The DIAGNOSTIC Mode allows download of new application software. The FUNCTION TEST and DIAGNOSTIC modes result in the processor ceasing its cyclic processing of the application functions. The Parameter Change Enable Keyswitches are administratively controlled (no hardware or software interlocks are provided). When a keyswitch is placed in the Parameter Change Enable Mode Position for any activity, the affected processor shall first be declared out of service. In addition to declaring the processor out of service (1) the affected RPS channel shall be bypassed and (2) either the affected ESPS input channel (A1, B1, or C1) shall be tripped OR the ESPS Set 1 voters shall be placed in Bypass for the following activities:

- Loading or revising the software in a processor.
- Changing parameters via the RPS High Flux Trip (Variable Setpoint) screen at the Service Unit.
- Changing parameters via the RPS Flux/Flow/Imbalance Parameters screen at the Service Unit.

Only one RPS channel at a time is allowed to be placed into Parameter Change Enable Mode Position for these activities. Parameter Change Enable Keyswitch status information is sent to a statalarm and is also sent to the OAC via the gateway.

The test scheme for the Reactor Protective System is based upon the use of comparative measurements between like variables in the four protective channels. Trip action is taken when the 2.MAX or 2.MIN value for analog signals or two out of four for binary inputs, based on the trip being tested, exceeds the actual protective function trip points. The alarms for the trip function for the channel under test will actuate when the trip condition for that channel's input is met.

The reliability of the system has been made very high so as to eliminate the need for frequent tests of the logic. The system software is not susceptible to transient, random, aging, or environmental related faults since it does not fail in the conventional sense. It can be reasonably expected to exhibit no degradation from these factors. The cyclic self-monitoring routine verifies that the code is not corrupted. The Mean Time Between Failure (MTBF) data for the Teleperm XS equipment calculates MTBF rates from 29 years to 267 years at 40°C (Reference 6).

All RPS protective channels, logic, and control rod drive power breakers are tested to demonstrate operability. Protective Channel Functional Testing, which is part of the Channel Calibration, is performed every refueling outage. The RPS software performs a continuous online automated cross Channel Check, separately for each protective channel, and continuous online signal error detection and validation. The combination of the self-testing features and the reliability of the TXS equipment support a protective channel functional test frequency of refueling outage. The setpoints in the software are manually verified every 92 days. The protective channel interposing relays are manually actuated every 92 days. RPS logic is re-verified every refueling outage by rebooting the channel computer and checksums are verified at that time.

The control rod drive breaker associated with a reactor trip component is tested prior to startup from a refueling outage and monthly during the fuel cycle.

In addition, power range protective channel readings are compared with a thermal calculation of reactor power. This check, the Channel Checks, and the continuous online self-monitoring of the system are designed to detect the majority of failures that might occur in the analog portions of the system as well as the self-annunciating type of failure in the digital portions of the system.

The periodic electrical tests are designed to detect more subtle failures that are not self-evident or self-annunciating and are detectable only by testing.

7.2.3.5 Physical Isolation

The need for physical isolation has been met in the physical arrangement of the protective channels within separate cabinets and wiring within the cabinets separating power and signal wiring so as to reduce the possibility of some physical event impairing system functions. The systems sensors are separated from each other. There are four pressure taps for the reactor coolant pressure measurements to reduce the likelihood of a single event affecting more than one sensor. Outside the Reactor Protective System cabinets, vital signals and wiring are separated and physically protected to preserve protective channel independence and maintain system redundancy against physical hazards.

Redundant detectors and transmitter applied in the Reactor Protective System are located to provide physical separation. Redundant out of core nuclear detectors are located in separate quadrants around the reactor vessels. Two resistance thermometers assigned to the RPS are located on each reactor coolant outlet header. Cables approach redundant temperature detectors from opposite directions. Redundant pressure transmitters are located outside the secondary shield in four separate quadrants of the Reactor Buildings. Two reactor coolant pressure transmitters for RPS are connected to each of the two loops. Separate flow transmitters for each RPS channel are applied to sense the flow in each loop. This arrangement results in detectors and transmitters associated with one RPS channel being located in essentially (the reactor vessels are not in the center of the Reactor Buildings) the same quadrant of a Reactor Building, and with redundant detectors and transmitters located in another quadrant of the Reactor Building. Since each RPS channel receives a flow signal from both loops, one of the flow transmitters for each channel is not located with the other RPS transmitters for that channel. Location and cable routing for these transmitters is such that separation of at least seven feet is provided between redundant channels inside the Reactor Buildings. Cables for redundant RPS and ES detectors and transmitters are routed in separate directions to four separate Reactor Building penetrations in trays carrying only nuclear instrumentation, RPS, ES, and accident monitoring instrumentation. These penetration assemblies are assigned to nuclear instrumentation, ES instrumentation, accident monitoring instrumentation, and RPS cables exclusively. Two of these penetration assemblies are located sixty feet apart in separate quadrants of each Reactor Building. One is used for RPS and ES channel A instrumentation; the other for RPS and ES channel B instrumentation. A penetration assembly for RPS and ES channel C instrumentation and one for RPS channel D are located on the opposite side of the Reactor Buildings thirty feet apart. Located under the control rooms between the outside of the Reactor Buildings and the cable and equipment rooms, four separate trays are provided per unit which carry nuclear, RPS, ES, and accident monitoring instrumentation cables. Three separate routes are followed by these trays. RPS channel C and RPS channel D follow the same route but are separated vertically by 1-1/2 feet. A detailed review of cable tray and pipe routing in this area indicates that no more than two RPS channels could be damaged by a single pipe failure or missile. Equipment locations in the Auxiliary Building provide the basis for vertical arrangement of trays following the same route from the Reactor Buildings. Switchgear for power equipment is located at lower elevations and instrumentation cabinets are located at higher elevations. Therefore, vertical separation of classes of cables in trays is as follows from top trays down:

1. Instrumentation cable trays
2. Control cable trays
3. Power and control cable trays
4. Power cable trays

Cables from each protective channel are routed in trays separate from those carrying cables from any other protective channel with the exception of fiber optic cables used for interchannel communication. Included in these trays are instrumentation cables from the Reactor Building, control and interconnecting cables associated with that protective channel, and non-protective instrumentation and control cables. Both protective and non-protective cables are individually armored, with the exception of fiber optic cables, and are flame retardant.

Reactor trip cables from the four RPS cabinets are routed separately to a reactor trip switch located on the main control board. From the trip switch, the cables follow four separate paths to the reactor trip breakers and the control rod drive cabinets.

Where overfill situations exist in the Unit 1, 2, and 3 Cable Rooms, and dedicated trays cannot be provided for individual channels, trays are allowed to carry protective and non-protective mutually redundant cable provided separation is maintained by distance (minimum of five inch air gap) or by barriers the continuous length where the cables are adjacent in the tray.

7.2.3.6 Primary Power

The primary source of 120V ac power for the Reactor Protective System comes from four vital buses, one for each protective channel, as described in Section 8.3.2.1.4.

7.2.3.7 Manual Trip

Manual trip may be accomplished from the control console by a trip switch. This trip is independent of the automatic trip system. Power to the control rod drive breakers' undervoltage coils comes from the reactor trip components (digital output modules and Reactor Trip Relays). The manual trip switch contacts are between the reactor trip component output and the breaker undervoltage coils. Opening of the switch contacts opens the lines to the breakers' undervoltage coils, tripping them. There is a separate set of switch contacts in series with the output of each reactor trip component. All switch contacts are actuated through a mechanical linkage from a single pushbutton.

7.2.3.8 Bypassing

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Each protective channel is provided with two key-operated bypass switches: Shutdown Bypass and Manual Bypass keyswitches. Software bypasses are available for the protective channels and individual input signals within a protective channel. These can be set via the Graphical Service Monitor (GSM) and the Change Enable keyswitch.

The RPS Shutdown Bypass feature allows the following RPS protective functions for a protective channel to be bypassed:

- Low RCS Pressure Trip

Variable Low RCS Pressure (based on RCS Temperature) Trip

- Flux/Flow/Imbalance Trip
- Reactor Coolant Pump/Power Monitor Trips

The RPS Shutdown Bypass function also initiates reductions to setpoints for the following RPS protective functions:

- Nuclear Overpower (High Neutron Flux)
- Reactor Coolant System High Pressure

This function provides the capability to perform control rod drive system testing after the reactor has been shut down and reactor coolant system pressure has been reduced. The RPS Shutdown Bypass keyswitches are administratively controlled (no hardware or software interlocks). All RPS Protective Channels may be placed in Shutdown Bypass as required. The RPS Shutdown Bypass keyswitch status information is sent to the Statalarm panels. Status information is also sent to the OAC via the Gateway.

The software bypass feature allows the following functions to be bypassed:

- Each of the protective channels as listed above
- Individual protective channels of Neutron Flux Power Range
- Individual protective channels of Reactor Coolant Hot leg Temperature
- Individual protective channels of Reactor Coolant Flow
- Individual protective channels of Reactor Coolant Pressure
- Individual protective channels of Reactor Building Pressure
- Individual protective channels of Main Feedwater Pump Turbine Trip
- Individual protective channels of Main Turbine Trip
- Individual protective channels of Reactor Coolant Pump/Power Monitor Trip

This function allows an individual input which has failed to be bypassed instead of bypassing an RPS channel. The system logic associated with the parameter which has one input bypassed would default to 2 out of 3 coincidence logic while the system logic associated with the remainder of the inputs would still maintain 2 out of 4 coincidence logic.

The Manual Bypass allows putting a complete RPS protective channel into bypass for maintenance activities. This includes the powerdown of the protective channel computer for each protective channel. If the Manual Bypass keyswitch is in the "ON" position, it provides 24V to the relays of the hardwired "2-out-of-4" trip logic in parallel to the output of the computer. This assures that the four output TRIP relays remain energized independent of the status of the TXS computer. It also sets the FAULT status of all input signals prior to sending input signal data to the other protective channels, via the fiber optic communication data links. Thus, during testing with an RPS channel in Manual Bypass, the system will operate in 2-out-of-3 coincidence logic. The Manual Bypass keyswitches are administratively controlled (no hardware or software interlocks are provided). Administrative control allows only one RPS Protective Channel in Manual Bypass at a time. Only one Manual Bypass key is available for each unit. Manual Bypass switch status information is sent to the Control Room Annunciators. Manual Bypass switch status information is also sent to the OAC via the Gateway.

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7.2.3.9 Post Trip Review

Post trip review data and information capabilities are provided by use of time history and sequence of events recording equipment. Time history data is provided by the transient monitoring application of the Process Monitoring Computer system (PMC). Sequence of events is determined by data from the sequence of events recorder (SER), the OAC, and the PMC system. This equipment, along with OAC input and operator interviews, provides sufficient information on plant parameters to assure that the course of the reactor trip can be reconstructed as well as provide root cause determination. In the event of failure of the PMC system, information necessary to conduct a post-trip review or transient investigation can be retrieved from other independent sources, such as the OAC and control room chart recorders. See Reference 1 and Section 7.7.2.

7.2.4 References

1. H. B. Tucker letter to H. R. Denton (NRC), November 4, 1983. Response to Generic Letter 83-28.
2. SER on GL 83-28, Item 1.1, Post Trip Review (Program Description and Procedure), May 15, 1985.
3. H. B. Tucker letter to J. F. Stolz (NRC), February 27, 1986. Response to GL 83-28, Item 1.2, Data and Information Capabilities.
4. SER on GL 83-28, Item 1.2, Post Trip Review (Data and Information Capability), September 11, 1986.
5. 10CFR50.59 USQ Evaluation, dated November 21, 2000, “Duke/ONS Commitment to GL 83-28…”.
6. AREVA Document 32-5061241, Oconee Nuclear Station, Unit 1, 2, and 3 RPS/ESFAS TXS Upgrade Availability Analysis (OM 201.N-0028-007)
7. Safety Evaluation Report for RPS/ESPS Digital Upgrade dated January 28, 2010, by the Office of NRR related to Amendment Numbers 366, 368, and 367 to renew Facility Operating Licenses DPR- 38, DPR-47, and DPR-55, Oconee Nuclear Station Units 1, 2, and 3 Docket Numbers 50-269, -270,-287

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7.3 Engineered Safeguards Protective System

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The Engineered Safeguards Protective System (ESPS) monitors parameters to detect the failure of the Reactor Coolant System and initiates operation of the High and Low Pressure Injection Systems, the Building Isolation, the Reactor Building Cooling and the Reactor Building Spray Systems. In addition, the signal is used to start the standby power source and initiate a transfer to the standby power source when required as described in Section 8.3.1.1.3.

7.3.1 Design Bases

The design basis of the system includes the items of Section 7.1.2 with the following additions:

7.3.1.1 Loss of Power

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1. The loss of vital bus power to an ESPS protective channel will not cause an automatic trip.
2. A loss of power to an input module of an input channel results in the associated signals being faulted.
3. The ESPS voters require power to energize the associated protective relays therefore loss of power to either the ODD or EVEN voter cabinets would result in the inability to automatically actuate the associated ESPS ODD or EVEN train.

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7.3.1.2 Equipment Removal

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1. Removal of an output card or computer card from the digital ESPS will result in an alarm but will not automatically initiate a protective channel trip.
2. Removal of a module in an ESPS protective channel while online does not inhibit the overall system functional design performance in other channels and will not initiate a system actuation.

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7.3.1.3 Control Logic of ESF Systems

All systems receiving the ES signal remain in the emergency mode required by the ES actuation after the signal is reset. A separate deliberate action is required to shut off the ES systems and power supplies.

The following systems have been modified to conform to the above requirement of I.E. Bulletin 80-06:

1. HPI Pumps
2. Penetration room exhaust fans
3. Reactor Building Cooling Unit fans
4. Keowee Start

7.3.2 System Design

7.3.2.1 System Logic

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The ESPS is a protective system which employs 2-out-of-3 coincidence logic to actuate engineered safeguards functions in the event that Reactor Coolant System pressure or reactor building pressure setpoints are exceeded. The functions include signal acquisition, data-processing, and actuation signal voting. The ESPS processes both analog and contact signals from the field for input into the ESPS instrument input channels. The input processors perform software logic and parameter checks on the analog and contact input signals and provide software logic outputs to the other ESPS instrument input channels as well as to the actuation logic channels. Each input variable is measured by three process sensors; the three redundant signals are processed within the input channel and voter processors, which provide an ESPS channel actuation through a set of output Ro relays (Ro1 and Ro2). The eight actuation logic channels are split between ODD and EVEN voters as shown in Figure 7-5, pg. 2. Either of the two voters is independently capable of initiating the required protective action through redundant equipment. The 2.MAX or 2.MIN (depending on the analog trip) is selected to compare to the trip setpoint. For binary inputs a 2 out of 3 trip logic is used to actuate the trip.

The ESPS processes both analog and contact signals from the field for input into the three ESPS instrument input channels. These three input channels are shared by 2 redundant ESPS Subsystems. Subsystem 2 operates in the ESPS cabinets and is designated as A2, B2 and C2. Subsystem 1 is designated as A1, B1 and C1 and operates in the Reactor Protective System (RPS) channel cabinets A, B, and C. Each of the ESPS and RPS processors performs software logic and parameter checks on the same analog and contact input signals and provides software logic outputs to the other instrument input channels as well as to the ESPS voter subsystems.

The ESPS subsystems are interconnected via fiber-optic data links. This provides a means to exchange data between subsystem inputs , which are used for signal validation, fault and deviation detection, and trip actuation. Alarms are initiated when signals fail validation tests or when failures or abnormal deviations are detected. Analog signals are faulted when extremely low signals (significantly below off-scale) are detected, indicating transmitter failure or power supply failure. If inter-channel communications are lost, the associated signals are faulted as well. Faulted signals are eliminated from use in the signal selection logic. An additional level of reliability is provided through the utilization of second maximum (2.MAX) and second minimum (2.MIN) signal selection functions for analog inputs and 2-out-of-3 selection logic for contact inputs. These functions reduce the probability of using an erroneous signal for determining trip conditions.

Independence is maintained in the subsystem inputs which are interconnected via fiber-optic data links. If interchannel communications are lost, the associated signals are faulted as well. Faulted signals are eliminated from use in the signal selection logic. With only the hardwired signal as valid, the signal is passed directly to the subsequent logic, thus ensuring instrument input channel independence. The 2.MAX and 2.MIN signal selection functions are used for analog inputs, and 2-out-of-3 selection logic is used for contact inputs. The 2.MAX and 2.MIN functions remain until less than two valid signals are present. The 2-out-of-3 logic function reduces to a 2-out-of-2 logic for any condition that causes an input signal fault, including loss of power.

The ODD/EVEN voter designation is associated with redundant actuation devices. The ODD1 and ODD2 voters provide output to ESPS actuation logic channels 1, 3, 5 and 7. The EVEN1 and EVEN2 voters provide output to ESPS actuation logic channels 2, 4, 6 and 8. There is an ODD/EVEN subsystem 1 and an ODD/EVEN subsystem 2, which correspond to the ESPS instrument input channels which provide signals to them. Voters ODD1 and EVEN1 receive input from ESPS instrument input channels A1, B1 and C1. Voters ODD2 and EVEN2 receive input from ESPS instrument input channels A2, B2 and C2. Either voter subsystem is capable of performing all required protective actions.

The instrument input channel trip signals are provided to the voters via fiber-optic data links. The voters use 2-out-of-3 logic on these trip signals for actuating the Ro relays.

The logic reduces to 2-out-of-2 for any condition that causes an input signal fault, including loss of power.

In addition, each voter (ODD1, EVEN1, ODD2 and EVEN2) is made up of a master and a checker processor, or 8 processors total. Each processor utilizes the same input information and executes the same software in performing an independent 2-out-of-3 logic for actuating the Ro relays (Ro1 and Ro2). At the end of each processing cycle, prior to sending output commands to redundant digital output boards that energize separate Ro relays, the master and checker processors compare results. If a calculation mismatch occurs between the Master and Checker processors, the respective subsystem automatically disables all of its output modules by shutting down the power supply to the output modules, generates an alarm, and initiates a reboot of the voter subsystem. This reduces the possibilities for inadvertently actuating the output Ro relays and subsequently energizing the Engineered Safeguards equipment when not required. Contacts from Ro1 and Ro2 are wired in series to prevent spurious actuation due to digital output board failure. Reference Figure 7-5 for trip logic diagrams.

The output Ro relays are normally de-energized. The contacts of the Ro relays are normally open within the control circuits of the individual Engineered Safeguards equipment. An ESPS actuation energizes the Ro relays and closes the Ro contacts which in turn energizes the control relays (CR) in each of the protective device (valve, pump, etc.) control circuits.

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7.3.2.2 High and Low Pressure Injection and Reactor Building Non-Essential Isolation Systems

There are three independent reactor coolant pressure sensors and three independent reactor building pressure sensors which provide input to the ESPS. Reactor coolant pressure and the reactor building pressure inputs are monitored by two independent signal processing subsystems. The non-faulted inputs are combined within the ESPS into 2-out-of-3 coincidence logic for initiating High Pressure Injection (HPI) system, Low Pressure Injection (LPI) system and Reactor Building Non-Essential Isolation actions. System Logic for ESPS is described in Section 7.3.2.1 and is shown in Trips #1 and #2 of Figure 7-5.

The instrumentation, logic, and actuation of the High Pressure Injection (HPI) and Low Pressure Injection (LPI) Systems are identical in design. The systems differ only in their actuation setpoints.

During reactor operation, HPI and the Reactor Building Non-Essential Isolation will initiate if 2-out-of-3 of the reactor coolant pressure sensors indicate a decrease in pressure below the RCS Low pressure setpoint, or if 2-out-of-3 reactor building pressure sensors indicate an increase in pressure beyond setpoint. These ESPS functions start Keowee Hydro Units, provide permissives for emergency power, start the HPI pumps and align various valves. Two ESPS actuation output logic channels are initiated either of which is independently capable of initiating the required protective action.

During reactor operation, LPI and the Low Pressure Service Water System (LPSW) will initiate if 2-out-of-3 of the reactor coolant pressure sensors indicate a decrease in pressure below the RCS Low-Low pressure setpoint, or if 2-out-of-3 reactor building pressure sensors indicate an increase in pressure beyond setpoint. These ESPS functions initiate LPI and LPSW pumps and align various valves. Two ESPS actuation output logic channels are initiated either of which is independently capable of initiating the required protective action.

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7.3.2.3 Reactor Building Cooling and Reactor Building Essential Isolation System

There are three independent reactor building pressure sensors which provide input to the ESPS. Reference Trip #3 of Figure 7-5 for trip logic diagram.

The non-faulted inputs are combined within the ESPS into a 2-out-of-3 coincidence logic for initiating Reactor Building Cooling (RBC) and Reactor Building Essential Isolation System actions. System Logic for ESPS is described above in Section 7.3.2.1.

RBC and the Reactor Building Essential Isolation System will initiate if 2-out-of-3 of the reactor building pressure sensors indicate an increase in building pressure above the high building pressure ESPS trip point. The second maximum of the sensor inputs is selected to compare to the trip setpoint. The three reactor building pressure inputs to ESPS are also utilized for HPI and LPI System initiations as previously discussed in Section 7.3.2.2. Two ESPS actuation output logic channels are initiated either of which is independently capable of initiating the required protective action.

This ESPS function starts RBC unit fans and penetration room fans as well as aligns certain component cooling water and LPSW valves when reactor building pressure increases above the ESPS setpoint. The Channel A Reactor Building Isolation signal is sent to the ICS to denote degraded containment conditions. The ICS is configured such that this signal is not utilized to initiate any action within the ICS.

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7.3.2.4 Reactor Building Spray System

Reactor building pressure switch inputs are monitored by 6 pressure switches. Two sets of three switches feed two independent digital processing input channels. The non-faulted inputs are combined within the ESPS into 2-out-of-3 coincidence logic for initiating Reactor Building Spray (RBS) actions. System Logic for ESPS is described above in Section 7.3.2.1 and is shown in Trip #4 of Figure 7-5 for the trip logic diagram.

RBS will initiate if 2-out-of-3 of the reactor building pressure switches indicate an increase in building pressure above the High High building pressure ESPS trip setpoint. Two ESPS actuation output logic channels are initiated either of which is independently capable of initiating the required protective action.

This ESPS function starts RBS pumps and aligns the RBS valves required for system operation.

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7.3.2.5 Availability of Information

All system signals are monitored by the plant computer. ESPS device position status is indicated on the ES Status panels and also is monitored by the plant computer. Statalarm panel alarms provide the following ESPS conditions:

- HPI and LPI bypass permit,
- Input channel bypass for HPI and LPI,
- Input channel trip,
- Input channel trouble,
- Input channel in test,
- Manual bypass for each of voters ODD1, ODD2, EVEN1 and EVEN2,
- EVEN and ODD voter trouble,
- EVEN and ODD voter in test,
- EVEN and ODD voter in emergency override,
- Actuation output logic channel trip,

The ESPS provides automatic analog and binary process signal monitoring for signal failure (Fault) and for Channel Deviation, which are alarmed via the trouble alarms. If an instrument input channel fails the acceptance criteria, it is alarmed (OAC alarms & Statalarm windows) so that the Control Room Operator can take appropriate action. This feature allows automation of the channel check surveillance.

The ESPS system communicates with the plant through the Monitoring and Service Interface (MSI). The MSI has three communication functions which are to: provide unidirectional data to the OAC, provide bidirectional data to the Service Unit, and provide isolated communication between the safety related ESPS and the nonsafety plant systems such as annunciators and the ICS. The Graphical Service Monitor (GSM) resides on the Service Unit and provides an interface into the ESPS for testing and maintenance. The OAC is sent unidirectional data through a gateway which provides real time information to the OAC. Reference Figure 7-1 for a diagram of the MSI.

Any time a test switch is in other than the operate position, a test annunciator will be lit and the associated protective channel must be administratively declared out of service.

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7.3.2.6 Summary of Protective Action

Actions initiated by the Engineered Safeguards Protection System are tabulated in Table 7-2. The devices actuated by the Engineered Safeguards Protection System are listed in Table 7-3. Channels indicated may be referred to applicable systems as shown in Figure 7-5. All actuated devices remain in their emergency modes after the reset of an engineered safeguards actuation signal until the devices are reset by operator action.

7.3.3 System Evaluation

The ESPS is a basic three-channel redundant system employing 2-out-of-3 coincidence between measured variables.

The system will tolerate the failure of one of three variables among either the reactor coolant pressure measurements or Reactor Building pressure measurements without losing its ability to perform its intended functions.

The High and Low Pressure Injection and Reactor Building Non-Essential Isolation Systems are actuated by either reactor coolant pressure or Reactor Building pressure, thus providing diversity in actuation. The system will tolerate single or multiple failures within one protective channel without affecting the operation of other protective channels. This is the result of keeping each of the protective channel logics independent of every other protective channel. The independence is carried through the protective channel logic and up to the final actuating CR control relay. This is best illustrated by considering the actuation arrangement for the high pressure injection pumps (Figure 7-5).

There are three High Pressure Injection System pumps which operate in the event of an accident. HP-P1A is under the control of protective channel 1, HP-P1C is under the control of protective channel 2, while HP-P1B is under the control of both channels. There is a single CR control relay controlled by the Ro relays within the motor control logic for HP-PIA and HP-PIC. Should any two of the three reactor coolant pressure variables drop below the RCS Low Pressure set point, both protective channel 1 and 2 logics will trip, energizing the appropriate CR relays, and start the pumps.

Within the motor control logic for HP-P1B there are two independent CR relay strings, each controlled by separate Ro relays from ESPS (the Ro relays in output channel 1 and the Ro relays in output channel 2). The arrangement is identical to the way a channel would control any device since all elements are independent and duplicated through the CR relay. The only common element is the power source for the CR relays which is common to the motor controller. Loss of this power prevents the motor control from operating as well as the pump. Relays that monitor actuator coils for each motor or valve control detect either an open coil or a loss of control power.

Independence is maintained in the three instrument input channels which are interconnected via fiber-optic data links. These links provide the means to exchange data, which is used for signal validation, fault and deviation detection, and trip actuation; thus providing additional fault detection. If interchannel communications are lost, the associated signals are faulted as well. Faulted signals are eliminated from use in the signal selection logic. The 2.MAX and 2.MIN signal selection functions are used for analog inputs, and 2-out-of-3 selection logic is used for contact inputs. The 2.MAX and 2.MIN functions remain until less than two valid signals are present. When only the hardwired signal is valid, then the 2.MAX and 2.MIN functions directly pass the signal to the subsequent logic. The 2-out-of-3 logic function reduces to a 2-out-of-2 logic for any condition that causes an input signal fault, including loss of power.

The voters maintain their independence in the ESPS. The ODD/EVEN voter designation is associated with redundant actuation devices. The ODD1 and ODD2 voters provide output to ESPS actuation output logic channels 1, 3, 5 and 7. The EVEN1 and EVEN2 voters provide output to ESPS actuation output logic channels 2, 4, 6 and 8. There is an ODD/EVEN subsystem 1 and an ODD/EVEN subsystem 2, which correspond to the ESPS input channels which provide signals to them. Voters ODD1 and EVEN1 receive input from ESPS input channels A1, B1 and C1. Voters ODD2 and EVEN2 receive input from ESPS input channels A2, B2 and C2. Either voter subsystem is capable of performing all required protective actions. The instrument input channel trip signals are provided to the voters via fiber-optic data links. The voters use 2-out-of-3 logic on these input channel trip signals for actuating the output Ro relays. The redundant Ro relays mitigate failure modes of the voter outputs.

An Override switch has been installed on the unit board for the ESPS ODD and EVEN voters which allows operators to override the ESPS system in case of an ESPS actuation caused by a Software Common Mode Failure. Once the override is initiated, operators are able to manually position ESPS components.

The example just presented shows the independence and redundancy of the system. There is redundancy of sensors, logic, and equipment. The redundancy is preserved and kept effective by independence of sensors, instrument strings, logic, and control elements in the final actuator. These characteristics enable the system to tolerate single failures at all levels.

The system protective devices (pumps, valves, etc.) require electrical power in order to operate and perform their functions. The power for operating the CR relays is taken from the power source of the associated device. Loss of power to a CR relay or device does not impair the system functions since there is a second redundant device for each required function. The power for the R_o relays, logic, and instruments is taken from the plant's system of battery backed vital buses since loss of power at this level could affect the performance capability of the system. The system will tolerate the loss of one vital bus without loss of protective capability.

7.3.3.1 Redundancy and Diversity

The system as evaluated above is shown to have sufficient diversity and redundancy to withstand single failures at every level.

7.3.3.2 Electrical Isolation

The use of isolation amplifiers will effectively prevent any faults (shorts, grounds, or cross connection of signals) on any analog signal leaving the system from being reflected into or propagating through the system. The direct connection of any analog signal to a source of electrical power can, at worst, negate information from the measured variable involved. The use of individual R_o relays for each controlled device effectively preserves the isolation of each device and of elements of one protective channel from another. Faults in the control wiring between an R_o relay and its CR relay in the controller of a protective device will not affect any other device or protective channel action.

Electrical isolation is inherent in the use of fiber-optic data links. In order to maintain electrical independence when input signals are shared between channels, a TXS communication link module is used to convert the signal from hard wire to fiber optic. The fiber optic communication equipment is qualified as Class 1E isolation and provides the required electrical separation between each protective channel. Fiber optic communication equipment is also used between protective channels and the Monitoring and Service Interface (MSI) and between the ESPS input channels and the Voters. Fiber optic isolation prevents internal electrical faults from propagating from one protective channel to other redundant protective channels.

Separation of redundant Engineered Safeguards (ES) functions is accomplished by assigning the eight actuation channels (Table 7-2) to three groups. Isolation for power, control, equipment location, and cable routing is maintained throughout. Channels I, 3, 5 and 7 are assigned to one group (odd actuation channels). Channels 2, 4, 6 and 8 are assigned to a second group (even actuation channels). Equipment which is actuated by both the even and odd actuation channels is assigned to a third group. All equipment required to perform a specific ES function is assigned to the same group. For example, a pump motor and all valves required for that pump to perform its function are assigned to the same group.

For Oconee 1, AC power for equipment controlled by the odd numbered actuation channels is supplied from Switchgear Group 1TC (4KV), motor control center 1XSI, 1XSF, and 1XS4 (600 and 208 volts), actuation power from Vital Power Panelboard 1KVIA and DC control power from DC Panelboard 1DIA. ES functions which are redundant to those controlled by the odd numbered actuation channels are controlled by the even numbered actuation channels. AC power for this equipment in Oconee 1 is supplied from Switchgear Group 1TD (4KV), Motor Control Center 1XS2 and 1XS5 (600 and 208 volts), from Vital Power Panelboard IKVIB, and DC control power from DC Panelboard 1DIB. Where a third unit of ES equipment is used to provide additional redundancy, it is actuated by both the even and odd actuation channels. AC power for this equipment in Oconee I is supplied from Switchgear Groups 1TE or 2TC (4KV), Motor Control Center 1XS3 (600 and 208 volts), actuation power from either Vital Power Panelboard 1KVIA for odd channel actuation or Vital Power Panelboard 1KVIB for even channel actuation, and DC power from DC Panelboard 1DIC. Similar arrangements are employed for ES equipment in Oconee 2 and 3 with different power and control sources for each unit. Motor Control Centers XS4, XS5 and XS6 are complements to Motor Control Centers XS1, XS2 and XS3 respectively. These are described in Section 8.3.

7.3.3.3 Physical Isolation

The arrangement of ESPS components within the system cabinets is designed to reduce the chance of physical events impairing system operation. Control wiring between the ESPS output components and the final actuating devices is physically separated and protected against damage which could impair system operation.

Separation between redundant channels of equipment, control cables, and power cables provides independence of redundant ES functions. The one exception to this separation are the fiber optic cables used for interchannel communication. Power and control cables for each group of ES equipment are routed in cable trays that contain no cable for redundant equipment or meet current separation criteria. Cables for Reactor Building cooling units enter each Reactor Building through three separate penetrations located at least 25 feet apart and are routed in three different directions to the cooling units. The only other ES equipment located inside the Reactor Buildings are electric motor operated isolation valves which are all common to the odd numbered actuation group discussed above.

7.3.3.4 Periodic Testing and Reliability

The ESPS input processors perform software logic and parameter checks on the analog and contact input signals and provide software logic outputs to the other input channels as well as to the voter output channels. Each input variable is measured by three process sensors. The 2.MAX and 2.MIN signal selection functions are used for analog inputs and 2-out-of-3 selection logic is used for contact inputs. Trip signals from the three input channels are processed within the voter processors which provide an ESPS output channel actuation through a set of Output Ro relays. The use of 2-out-of-3 logic between protective input channels and GO/NOGO (described below) testing of system outputs permits a protective channel to be tested online without initiating an output channel trip. The test circuits take advantage of the system redundancy, independence, and coincidence logic software to make it possible to manually initiate test signals in one protective channel without affecting the other channels. Surveillance requirements have been established for performance of protective channel calibrations and protective channel functional testing.

The ESPS provides continual online automatic monitoring of each of the input signals in each input channel, performs signal online validation, and provides functional validation of hardware performance.

The ESPS has a Graphical Service Monitor (GSM) which supplies individual screens for monitoring and recording the analog and binary inputs during Protective Channel Calibration tests. To prevent adverse system actions while performing these tests, the analog or binary signals under test may be placed in Bypass using the GSM Trip/Bypass screens. There are also screens to exercise the output channel trip logic, statalarms, and events recorder. Each protective channel can be tripped in a GO or NOGO test. A NOGO test will trip half of the output string and provide indication of a successful test on the GSM screen without moving the component. A GO test will trip both halves of the output string and provide indication of a successful test in the GSM and reposition the component to the ESPS position. Each protective channel is provided with a key-operated Parameter Change Enable keyswitch. The system software controls access to the computer from each protective channel by controlling the operating modes of the computer. Under normal operating conditions, the computer is in the OPERATION mode. The PARAMETERIZATION Mode allows changes to specific parameters or performance of tests from the GSM screens. Permission to change from the OPERATION mode into the PARAMETERIZATION mode is provided by the Parameter Change Enable Keyswitch. After the permissive is provided from a system processor via its Keyswitch, communication from the Service Unit to that processor is allowed to change its operating mode. Placing the PROCESSOR into the FUNCTION TEST and DIAGNOSTIC modes requires first enabling the PARAMETERIZATION Mode with the keyswitch and then setting a separate parameter to enable these modes with the GSM. The FUNCTION TEST Mode allows disabling the application function and forcing the output signals (normally not used). The DIAGNOSTIC Mode allows download of new application software. The FUNCTION TEST and DIAGNOSTIC modes result in the processor ceasing its cyclic processing of the application functions. The Parameter Change Enable Keyswitches are administratively controlled (no hardware or software interlocks are provided). When a keyswitch is placed in the Parameter Change Enable Mode Position for any activity, the affected processor shall first be declared out of service. In addition to declaring the processor out of service, when loading or revising software in an input channel processor, the affected ESPS inputs shall be tripped OR the associated ESPS voters shall be placed in Bypass. If this activity is being performed on an ES Input Channel in subsystem 1, the associated RPS channel shall also be placed in manual bypass. Only one ESPS channel at a time is allowed to be placed into Parameter Change Enable Mode Position for software loading/revision. In addition to declaring the processor out of service, when loading or revising software in a voter processor, the affected ESPS voter (Set 1 or Set 2) shall be placed in Bypass. Only one ESPS voter at a time is allowed to be placed into Parameter Change Enable Mode Position for software loading/revision. Parameter Change Enable Keyswitch status information is sent to a statalarm and is also sent to the OAC via the gateway.

The reliability of the system has been made very high so as to eliminate the need for frequent tests of the logic. The system software is not susceptible to transient, random, aging, or environmental related faults since it does not fail in the conventional sense. It can be reasonably expected to exhibit no degradation from these factors. The cyclic self-monitoring routine verifies that the code is not corrupted. The Mean Time Between Failure (MTBF) data for the Teleperm XS equipment calculates MTBF rates from 29 years to 267 years at 40°C. See Reference 1.

Protective Channel Functional Testing, which is part of the Protective Channel Calibration, is performed every refueling outage. The ESPS software performs a continuous online automated cross channel input check, separately for each input channel, and continuous online signal error detection and validation. The combination of the self-testing features and the reliability of the TXS equipment support a protective channel functional test frequency of every refueling outage. The setpoints in the software are manually verified every 92 days. The output channel output relays are manually actuated every 92 days. ESPS logic is re-verified every refueling outage by rebooting the channel computer and checksums are verified at that time.

Deleted per 2013 Update.

7.3.3.5 Manual Trip

Deleted per 2013 Update.

Each actuation channel (1 through 8) may be manually tripped from the Manual Trip pushbuttons on the Unit Board. This trip is independent of the software and may be initiated during any mode of operation. Each actuation channel (1 through 8) may be manually reset from the Reset pushbuttons on the Unit Board following either automatic or manual actuation of the channel. The ESPS manual actuation paths do not pass through the software, and therefore are not dependent on the correct functioning of the software.

7.3.3.6 Bypassing

The trip functions of the High and Low Pressure Injection and Reactor Building Non-Essential Isolation Systems are bypassed whenever the reactor is to be depressurized below the trip point of the systems. Bypassing must be initiated manually within a fixed pressure band above the protective system trip point. The High Pressure Injection and Reactor Building Non-Essential Isolation System may be bypassed only when the reactor pressure is 1,750 psi or less, and the Low Pressure Injection System may be bypassed only when the reactor pressure is 900 psi or less. The bypass is automatically removed when the reactor pressure exceeds the removal set point associated with the bypass values. This is in accordance with IEEE 279, Section 4.12 and IEEE Std 603-1998 Section 6.6 and 7.4. The removal set points are above the trip points in order to obtain a pressure band in which the trips may be bypassed during a normal cooldown. The bypasses do not prevent actuation of the HP and LP Injection and Reactor Building Non-Essential Isolation Systems on high Reactor Building pressure. Bypassing is under administrative control. Since the ESPS incorporates triple redundancy in its input subsystems, there are three HP injection bypass switches and three LP injection bypass switches. Two of the three switches must be operated to initiate a bypass. Once a bypass has been initiated, the condition is indicated by the plant annunciator and by lamps associated with the bypass switches.

7.3.3.7 References

1. AREVA Document 32-5061241, Oconee Nuclear Station, Unit 1, 2, and 3 RPS/ESFAS TXS Upgrade Availability Analysis (OM 201.N-0028-007).
2. Safety Evaluation Report for RPS/ESPS Digital Upgrade dated January 28, 2010, by the Office of NRR related to Amendment Numbers 366, 368, and 367 to renew Facility Operating Licenses DPR-38, DPR-47, and DPR-55, Oconee Nuclear Station Units 1, 2, and 3 Docket Numbers 50-269, -270,-287.

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7.4 Systems Required for Safe Shutdown

7.4.1 Nuclear Instrumentation

The nuclear instrumentation system is shown in Figure 7-6. The system meets the intent of the Proposed IEEE "Criteria for Nuclear Power Plant Protection Systems," dated August, 1968, (IEEE No. 279), for those elements associated with the Reactor Protective Systems.

7.4.1.1 Design Bases

The nuclear instrumentation (NI) system is designed to supply the reactor operator with neutron information over the full operating range of the reactor and to supply reactor power information to the RPS and to the Integrated Control System (ICS).

The system sensors and instrument strings are redundant in each range of measurement. Measurement ranges are designed to overlap to provide complete and continuous information over the full operating range of the reactor.

7.4.1.2 System Design

The nuclear instrumentation has eight channels of neutron information divided into three ranges of sensitivity: source range, wide range, and power range. The three ranges combine to give a continuous measurement of reactor power from source level to approximately 200 percent of rated power or ten $^{+}$ decades of information. A minimum of one decade of overlapping information is provided between successive higher ranges of instrumentation. The relationship between instrument ranges is shown in Figure 7-7.

The source range instrumentation has four redundant count rate channels originating in four high sensitivity fission chambers. These channels are used over a counting range of 0.1 to 10^5 counts/sec as displayed on the operator's control console in terms of log counting rate. The channels also measure the rate of change of the neutron level as displayed for the operator in terms of startup rate from -1 to +7 decades/min.

The wide range instrumentation has four log N channels originating in four electrically identical fission chambers. Each channel provides ten+ decades of flux level information in terms of the log of chamber count rate and startup rate. The fission chamber/wide range monitor output range is from 10^{-8} to 200% power. The startup rate range is from -1 to +7 decades/min. A high startup rate of +2 decades/min. in any channel will initiate a control rod withdraw inhibit.

The power range channels have four linear level channels originating in four composite uncompensated ion chambers. The channels output is directly proportional to reactor power and covers the range from 0 to 125 percent of rated power. The gain of each channel is adjustable providing a means for calibrating the output against a reactor heat balance.

Power range channels NI-5, -6, -7, and -8 supply reactor power level information continuously to the RPS. Dual indicators on the control console provide the operator with both total reactor power information (ϕ), and reactor power imbalance information ($\Delta\phi$), from each of the four channels. The method of obtaining ϕ and $\Delta\phi$ is described in Section 7.4.1.2.1.

Reactor power information is provided to the ICS from NI-5, NI-6, NI-7 and NI-8. Isolation amplifiers are used to provide isolation of the power range signals leaving the RPS cabinets. Isolation amplifiers are used to buffer the signals leaving the RPS cabinets, preventing the reflection of faults on external signal lines back into the RPS. The ICS uses 2nd highest median select logic for selection of NI-5, NI-6, NI-7, or NI-8 power range signal to be used for control and display on a recorder located on the control console above the power range indicators.

7.4.1.2.1 Neutron Detectors

The detectors used in the source range and wide range channels are fission chambers. The same detector/electronics string provides both source range and wide range outputs.

Uncompensated ion chambers are used in the power range channels. Power range detectors consist of two nominally 70-inch sections with a single high voltage connection and two separate signal connections. The outputs of the two sections are summed and amplified by the linear amplifiers in the associated power range channel to obtain a signal proportional to total reactor power (ϕ). A signal proportional to the difference in percent full power between the top and bottom halves of the core, the reactor power imbalance or $\Delta\phi$, is derived from the difference in currents from the top and bottom sections of the detector. The difference signal is displayed on the control console to permit the operator to maintain proper axial power distribution. The manual test and calibration facilities provide a means for reading the output of the individual sections of the detector. Each detector has a combined sensitive volume extending approximately from the bottom to the top of the reactor core.

The physical locations of the neutron detectors are shown in Figure 7-8, Figure 7-9, and Figure 7-10. The power range detectors for channels NI-5, -6, -7, and -8 are positioned adjacent to each of the four quadrants of the core. The source/wide range detectors are located adjacent to each of the four quadrants of the core.

Table 7-4 provides pertinent characteristics of the out-of-core neutron detectors. The flux ranges illustrated in Figure 7-7 are seen to be compatible with these characteristics. Nearly identical Westinghouse out-of-core detectors are presently in use at power reactors as follows:

Tube Type	Reactors	Utility
FC	Haddam Neck San Onofre Three Mile Island Crystal River 3	Connecticut Yankee Power Southern California Edison GPU Nuclear Florida Power Corp.
UCIC	Haddam Neck	Connecticut Yankee Power

7.4.1.2.2 Test and Calibration

Test and calibration facilities are built into the system to permit an accurate calibration of the system and the detection of system failures in accordance with the requirements of Reactor Protective System design and IEEE No. 279. The digital RPS systems are also subject to IEEE Std 603-1998 "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations".

7.4.1.3 System Evaluation

The nuclear instrumentation will monitor the reactor over a minimum 10+decade range from source range to 200 percent of rated power. The full power neutron flux level at the power range detectors will be approximately 3.2×10^9 nv. The detectors employed will provide a linear response up to approximately 1.5×10^{10} nv before they are saturated.

The wide range channels fully overlap the source range and the power range channels as shown in Figure 7-7, providing the continuity of information needed during startup.

The steady-state radial flux distribution within the reactor core will be measured by the incore neutron detectors (Section 7.6.1). Both the out-of-core (NI-5, -6, -7, and -8) and incore detectors will be used to obtain the axial power distribution. The sum of the outputs from the two sections of each (out-of-core) power range detector will be calibrated to a heat balance. The sum will be recalibrated whenever it is determined that the sum disagrees with the heat balance by 2 percent or more. The signals from the two sections of the detector may be individually read and compared independent of the sum of the outputs. The operator, therefore, may correlate the difference signal against the core power distribution obtained from the incore system.

7.4.1.3.1 Primary Power

The nuclear instrumentation draws its primary power from vital buses and uninterruptable buses described in Section 8.3.2.1.4 and Section 8.3.2.1.5.

7.4.1.3.2 Reliability and Component Failure

The requirements established for the Reactor Protective System apply to the nuclear instrumentation. All channel functions are independent of every other channel, and where signals are used for safety and/or control, electrical isolation is employed to meet the criteria of Section 7.1.2.

7.4.1.3.3 Relationship to Reactor Protective System

The relation of the nuclear instrumentation to the RPS is described in Section 7.2. Power range channels NI-5, -6, -7, and -8 are associated with the Reactor Protective System. NI-5, NI-6, NI-7 and NI-8 also provide information for the Integrated Control System through Isolation Amplifiers.

The periodic test requirements of the Reactor Protective System are not dictated by the accuracy of the power range channels. The accuracy of the linear amplifiers is better than ±0.2 percent including drift.

7.4.2 Non-Nuclear Process Instrumentation

7.4.2.1 Design Bases

The non-nuclear process instrumentation provides the required input signals of process variables for the reactor protective, regulating, and auxiliary systems. It performs the required process control functions in response to those systems and provides instrumentation for startup, operation, and shutdown of the reactor system under normal and emergency conditions.

7.4.2.2 System Design

The non-nuclear instrumentation provides measurements used to indicate, record, alarm, interlock, and control process variables such as pressure, temperature, level, and flow in the reactor coolant, steam supply, and auxiliary reactor systems as shown in system drawings in Chapter 5, Chapter 9, Chapter 10 and Chapter 11. Process variables required on a continuous basis for the startup, operation, and shutdown of the unit are indicated, recorded, and controlled at the control rooms. Alternate essential indicators and controls are provided at other locations to maintain the reactor in Mode 3 (with $T_{ave} \geq 525°F$) if the control rooms have to be evacuated. Other instrumentation is provided at auxiliary panels with alarm at the control rooms.

Response time and accuracy of measurements are adequate for reactor protective and regulating systems and other control functions to be performed.

7.4.2.2.1 Non-Nuclear Process Instrumentation in Protective Systems

Four independent measurement channels are provided for each process parameter for input to the Reactor Protective System.

Three independent measurement channels are provided for each process parameter and input to the Engineered Safeguards Protective System.

a. Reactor Outlet Temperature

   Reactor outlet temperature inputs to the Reactor Protective System are provided by two fast-response resistance elements and associated transmitters in each loop.

b. Reactor Coolant Flow

   Reactor coolant flow inputs to the Reactor Protective System are provided by eight high-accuracy differential pressure transmitters which measure flow through calibrated flow tubes welded into the reactor outlet pipe. The power/flow monitor of the reactor protective system utilizes this flow measurement to prevent reactor power from exceeding a permissible level for the measured flow. Operation of each reactor coolant pump breaker is also monitored as an indication of flow.

   RPS Channel E, provides reactor coolant loop A and loop B flow information to the ICS. Channel E is in no way associated with Reactor Protective functions. Reactor coolant loop A and B flow information is also provided to the ICS from RPS Channel A and RPS Channel B. Optical Isolators are used to provide isolation from the RPS. Optical Isolators are used to buffer the signals leaving the RPS cabinets, preventing the reflection of faults on external signal lines back into the RPS. The ICS uses median select logic for selection of the reactor coolant loop A and B flow signal to be used for control.

c. Reactor Coolant Pressure

   Reactor Protective System inputs of reactor coolant pressure are provided by two pressure transmitters in each loop.

   RPS Channel E, provides reactor coolant pressure information to the ICS. Channel E is in no way associated with Reactor Protective functions. Reactor coolant pressure information is also provided to the ICS from RPS Channel A and RPS Channel B. Optical Isolators are used to provide isolation from the RPS. The Optical Isolators are used to buffer the signals leaving the RPS cabinets, preventing the reflection of faults on external signal lines back into the RPS. The ICS uses median select logic for selection of the reactor coolant pressure signal to be used for control and display on a recorder located on the control console.

   Engineered Safeguards Protective System inputs of reactor coolant pressure in each loop are provided by redundant pressure transmitters. One pressure signal is utilized for recording, low pressure alarm, and interlock to decay heat removal return flow valve LP-1. This pressure signal can be supplied from either ES Channel A or B.

d. Reactor Building Pressure

   Reactor Building pressure inputs to the Engineered Safeguards Protective System are provided by:

1) Three pressure transmitters which are located outside the Reactor Building. These provide inputs for initiation of Reactor Building isolation, high pressure injection, low pressure injection, and Reactor Building cooling.

2) Three groups of two pressure switches each are located outside the Reactor Building. These provide input signals of high Reactor Building pressure for initiation of Reactor Building spray by safeguards actuation.

Table 7-5 provides pertinent information concerning the NNI sensors supplying inputs to the RPS and ESPS, respectively.

7.4.2.2.2 Non-Nuclear Process Instrumentation in Regulating Systems

Selective reduntant measurements and input signals are provided for the process variables required for critical control functions. Selection between the redundant measurements and input signals is performed within the ICS utilizing two types of equipment. The "Control STAR" ™ modules perform valid signal selection between certain redundant signals utilizing the median selection technique. Valid signal selection for the remaining critical control process variables is provided by a Smart Automatic Signal Selector (SASS). The SASS detects a rapid change in signal and automatically switches the SASS output signal to the remaining valid input signal.

The SASS instrumentation is located in ICS Cabinet 8 and provides automatic signal selection. The SASS instrumentation monitors the following process signals and selects the valid signal independent of the control board mounted key switch.

1. OTSG Operate Level Loop A
2. OTSG Operate Level Loop B
3. Pressurizer Level

The SASS can also detect a mismatch between the two input signals and provides indication of the mismatch on the SASS panel. The plant computer also receives the same signals as SASS and provides mismatch alarms to the operator via the plant computer.

The "Control STAR" modules are located in the ICS cabinets and provide automatic selection of the median signal for the following process parameters.

1. Reactor Coolant System Pressure
2. Reactor Coolant Flow Loop A
3. Reactor Coolant Flow Loop B
4. Power Range Neutron Flux
5. Feedwater Flow Loop A
6. Feedwater Flow Loop B
7. T-Hot Loop A
8. T-Hot Loop B
9. T-Cold Loop A
10. T-Cold Loop B
11. Turbine Header Pressure
12. OTSG Start-up Level Loop A

13. OTSG Start-up Level Loop B

TM - Control STAR is a trademark of Framatome Technologies.

The following inputs to the Integrated Control System are provided:

a. Reactor Outlet Temperature

Selected loop or unit average outlet temperature input is provided in each loop by two fast response resistance elements and associated transmitters.

b. Reactor Controlling Average Temperature

Loop or unit average temperature signals are selected for indication and input as controlling average temperature. Automatic selection determined by loop flows is provided for input of the appropriate signals.

Reactor inlet temperature signals required for loop, and unit average or differential temperatures are provided in each loop by two fast response resistance elements and associated transmitters.

c. Reactor Inlet Differential Temperature

Reactor inlet differential temperature is calculated, indicated and provided for input to the Integrated Control System.

d. Reactor Coolant Flow

Reactor coolant flow signals are provided for each loop and summed for total flow. Total flow is recorded and “low” total flow is alarmed.

Loop “low” flow signals provide the logic for automatic selection of reactor controlling average temperature.

Contacts from reactor coolant pump motor breakers provide fast indication to the ICS that a pump has tripped.

e. Feedwater Temperature

Feedwater temperature input is provided by three resistance elements and associated transmitters. The selected input also provides indication and feedwater flow temperature compensation.

f. Feedwater Flow

The main feedwater flow measurement in each loop is provided by three redundant differential pressure transmitters that measure flow through a flow nozzle. The automatically selected median feedwater flow signal for each loop is compensated by feedwater temperature. The compensated main feedwater flow signal for each loop is indicated, recorded and input to the ICS.

The start-up feedwater flow measurement in each loop is provided by a differential pressure transmitter that measures flow through a flow nozzle. The start-up feedwater flow signal for each loop is compensated by feedwater temperature. The start-up feedwater flow signal for each loop is indicated to the operator.

g. Feedwater Control Valves Differential Pressure

Pressure drop measurement across the valves is provided for input by redundant differential pressure transmitters. The selected input signal is also indicated.

h. Steam Generator Level

Selected “startup” level and “operate” level inputs are provided from each steam generator. Redundant measurements of each level are provided by differential pressure transmitters. Temperature compensation to augment the predetermined compensation for normal operating temperature is provided by two resistance elements and associated transmitters which measure steam generator lower downcomer temperature.

The selected “operate”. level input is recorded and “high” level alarmed. The selected “startup” level input is indicated and “low” level alarmed.

A full range level measurement is provided for indication of each steam generator level but does not provide protective or regulating systems input.

i. Steam Generator Outlet Pressure

Selected outlet pressure input is provided from each steam generator. Measurement is made by pressure transmitters in both outlet lines of each steam generator. The selected input is also indicated.

j. Turbine Header Pressure

Turbine header pressure measurement is provided for input by a pressure transmitter in each header line from the steam generators. The selected pressure signal is also recorded, and high and low pressures alarmed. Additional redundant transmitters in each header line provide indication only.

7.4.2.2.3 Other Non-Nuclear Process Instrumentation

The following instrumentation is provided for measurement and control of process variables necessary for proper operation:

1. Pressurizer Temperature

Pressurizer temperature is measured by three resistance elements and their associated transmitters. Two resistance elements provide temperature compensation of the Inadequate Core Cooling pressurizer level instrumentation. The third resistance element is used by the pressurizer heater controls to calculate reactor coolant system saturation pressure.

2. Pressurizer Level Control

Pressurizer level is measured by three differential pressure transmitters. One temperature compensated signal is selected for indication, recording, interlock and level control. The selected level control signal provides alarms and interlock to de-energize the pressurizer electric heaters on low level. The level controller output positions the makeup control valve in the High Pressure Injection System to maintain a preset level. Pressurizer level is lowered by reactor coolant letdown or by manual control at the control room.

3. Reactor Coolant Pressure Control

The reactor coolant pressure signal for control is provided by isolated signals from RPS Channel A, RPS Channel B and RPS Channel E (the fifth channel). The isolated RPS A, RPS B and the RPS E reactor coolant pressure signals are median selected within the ICS by the "Control Star" module to provide the selected RC Pressure control signal. The selected signal is used as an input to pressure switches which provide signals for automatic control of:

a. Pressurizer electric heaters.

b. Pressurizer spray control valve.

c. Pressurizer electromatic relief valve.

The heaters are grouped in banks which are energized below preset pressures.

The selected signal also provides input to a pressure controller which automatically modulates the output of one bank of heaters to maintain a preset pressure.

The spray and relief valve are opened at preset pressures above the desired reactor coolant system operating pressure.

The selected signal is recorded and high and low pressures alarmed.

Reactor coolant pressure is recorded on a multi-channel recorder. One Channel has a range of 1700-2500 PSIG, and its input is the median selected reactor coolant pressure signal selected for control. The other channel has a range of 0-2500 PSIG, and its input is from a transmitter in the “A” loop.

Reactor coolant temperature is also recorded on a multi-channel recorder. One channel has a range of 50°F to 650°F and its input is selectable from either of four cold leg RTDs, two located in "A" loop cold legs and two located in "B" loop cold legs. A second channel indicating average temperature receives its imput from the reactor coolant average temperature selected for control and has a range of 520°F to 620°F. A third channel has a range of 520°F to 620°F and receives its input from the selected "A" loop THOT signal. A fourth channel has a range of 520°F to 620°F and receives its input form the selected "B" loop THOT signal. A fifth channel has a range of 520°F to 620°F and receives its input from the selected Average THOT signal.

4. Coolant Pump Control

Interlock signals of reactor coolant inlet temperature are provided to each pump switching logic to prevent operation of more than three pumps during startup until a preset temperature is reached.

5. Feed and Bleed Control

The feed and bleed control instrumentation in the High Pressure Injection System provides control and interlocks to permit adjustment of the reactor coolant boron concentration.

7.4.2.3 System Evaluation

The quantity and types of process instrumentation have been selected to provide assurance of safe and orderly operation of all systems and processes over the full operating range of the plant. Some of the criteria for design are:

1. Separate instrumentation and Engineered Safeguards Protective System, Reactor Protective System and Steam Generator Level Control System isolated output signals are used for vital control circuits.
2. Time of response and accuracy of measurements are adequate for protective and control functions to be performed.
3. Where wide process variable ranges are required and precise control is involved, both wide range and narrow range instrumentation are provided.
4. All electrical and electronic instrumentation required for operation is supplied form redundant vital and uninterruptable instrumentation buses.

7.4.2.3.1 Failure in RC Flow Tube Instrument Piping

7.4.2.3.1.1 Reactor Coolant Flow Indication

In each primary loop, reactor coolant flow is detected by measuring the ΔP developed across a flow tube that is an integral part of the outlet piping of the loop. Each flow tube has a high pressure (HP) tap and a low pressure (LP) tap. Connections to the taps are made with 1-inch lines. The 1-inch lines are terminated at root valves located inside the secondary shield wall to HP and LP headers. Five ΔP transmitters are connected between the two headers. Four are used to provide information to the Reactor Protective System. The fifth is used to provide input to the ICS. Isolated output signals from RPS Channel A, RPS Channel B and the fifth transmitter are input to the ICS "Control STAR" modules. The median selected signal provides alarms and indication as described in Section 7.4.2.2.2.

Each of the four Reactor Protective System channels receives a ΔP signal from a different one of the four ΔP transmitters. In other words, one transmitter is exclusively assigned to one protective channel. The identical arrangement and assignment of transmitters is used for each of the two primary reactor coolant loops.

Within each Reactor Protective System channel, the square roots of the ΔP signals from each loop are extracted to obtain loop flow signals. The loop flow signals are summed to obtain a total reactor coolant flow signal. The three flow signals are displayed by connecting the STAR CTC to the channel's STAR module. The three signals are monitored by the plant computer.

The reactor operator can read the individual loop flows and total flow at the control console. The flow information is available to the operator on the plant computer for each unit.

7.4.2.3.1.2 Failures Considered

The following failures are considered:

1. Break in one of the 1-inch instrument lines.
2. Break in one of the 1/2-inch instrument lines.
3. A leak in one of the instrument lines.
4. Deleted per 2005 update.

7.4.2.3.1.2.1 Break in 1 Inch Instrument Lines

A break of a 1-inch instrument line will result in a reactor trip due to low RC pressure. If the break occurs in a HP line, the reactor will trip due to a high power/flow ratio if the power/flow limit is exceeded.

The operator will receive at least the following alarms and indications:

Alarms:

1. Break in 1-inch HP Instrument Line
    a. Low RC flow.
    b. Plant computer alarm and alarm log for low flow.
    c. Letdown storage low level.
    d. Pressurizer low level.
    e. Low reactor coolant pressure.

f. Plant computer alarm and alarm log for low RC pressure.

2. Break in a 1-inch LP Instrument Line

   Identical alarms as listed for HP line break except RC flow is alarmed on high value.

Indication:

1. Break in a 1-inch HP Instrument Line
   a. Control room indication of the Reactor Building atmosphere particulate and gas radioactivities increases.
   b. Loop flow indication on console falls to zero.
   c. Loop flow indication in each RPS channel falls to zero. Flow is not displayed in the RPS channel cabinets unless STAR CTC is connected to channel.
   d. Total flow indication on console falls approximately 50 percent.
   e. Total flow indication in each RPS channel falls approximately 50 percent. Flow is not displayed in the RPS channel cabinets unless STAR CTC is connected to channel.
   f. Makeup flow goes to maximum value.
   g. RC pressure falls on console indicators and with each RPS channel.
   h. Reactor Building pressure and temperature indication rises.
2. Break in a 1-inch LP Instrument Line

   Identical indication as listed for HP line break except all loop flow indication goes full scale, total flow indication increases above normal.

7.4.2.3.1.2.2 Break in a ½-inch Instrument Line

A break of a ½-inch instrument line will result in a reactor trip due to low RC pressure. If the break occurs in a HP line, the reactor will trip due to a high power/flow ratio if the power/flow limit is exceeded.

The operator will receive the same alarms and indication as described for the 1-inch instrument line break.

7.4.2.3.1.2.3 Leak in One of the Instrument Lines

If the leak occurs in a HP line the operator will receive a low flow alarm for a 5 percent change in indication flow and a high flow alarm for a similar leak in the LP line. At this alarm Point, the leakage is in excess of 1 gallon per minute, hence Reactor Building radiation monitors will readily detect such a condition and result in leak evaluation, and subsequent action as required by Technical Specifications.

Depending on the size of the leak, alarms and indication described in Section 7.4.2.3.1.2.1, may occur. If the leak occurs on either of the ∆P transmitters associated with the RPS-A, RPS-B or the fifth channel input, the ICS "Control STAR" modules will select the median signal for control and indication as described in Section 7.4.2.2.2.

7.4.2.3.1.2.4 Deleted per 2005 Update

7.4.2.3.1.3 Conclusion

The conclusion of this analysis is that the operator has adequate indication and alarm facilities to quickly recognize a common mode failure in the flow instrumentation for the reactor protection system. Corrective action would therefore be positive and prompt.

7.4.2.3.2 Coincident LOCA and Systematic Failure of Low RCS Pressure Trip Signal.

Several break sizes and locations for the loss-of-coolant accident have been investigated with an assumed systematic failure of the low Reactor Coolant System pressure trip signal. Although this failure is not considered credible, the analysis has shown that either the void shutdown mechanism or the power/flow comparator should provide backup to shut down the reactor and render the Emergency Core Cooling System (ECCS) effective.

7.4.3 Emergency Feedwater Controls

7.4.3.1 Emergency Feedwater and Pump Controls

7.4.3.1.1 Design Basis

The Emergency Feedwater (EFW) System is designed to start the EFW pumps automatically in the event of loss of both main feedwater pumps or low water level in either steam generator.

The EFW control valves are designed to control steam generator level when the EFW System is supplying feedwater to the steam generators.

All automatic initiation logic and control functions are independent from the Integrated Control System (ICS).

7.4.3.1.2 System Design

Three EFW pumps powered from diverse power sources are provided. These include two independent motor driven pumps, each supplying feedwater to one steam generator; and one turbine driven pump, supplying feedwater to both steam generators.

Each of the EFW pumps is supplied with its own independent starting circuit which will start automatically as outlined below. Automatic initiation of the EFW pumps by ATWS Mitigation System Actuation Circuitry is described in Section 7.8. These independent control circuits are powered by the 125 VDC station batteries. Each pump is also provided with a control switch with which the operator may start the pump manually.

Discharge flow from the EFW pumps is normally aligned and controlled by discharge control valves located in the supply line to each steam generator's emergency feedwater connection. The control valves limit or increase emergency feedwater as necessary to maintain steam generator inventory and cooldown rate. These valves may be automatically controlled, or manually controlled by the operator.

Indication is provided in the control room to allow the operator to monitor EFW System parameters during a cooldown.

Alarms are provided to alert the operator of conditions exceeding normal limits. Essential plant parameters are annunciated or alarmed by the process computer in addition to specific EFW System alarms.

<u>Motor Driven EFW Pumps (MDEFWP's):</u>

Power for the motor driven pumps is normally provided by the normal station auxiliary power system. During loss of offsite power operation, these pumps are aligned to the Emergency Power System

Automatic starting of the MDEFWP's is determined by the position of the control room selector switch for each pump. The MDEFWP's are provided with a four position selector switch which allows the operator to select between OFF, AUTO 1, AUTO 2 and RUN. When the selector switch is in the AUTO 1 position, LOW STEAM GENERATOR WATER LEVEL in either steam generator (OTSG) will start the pump after a time delay to prevent spurious actuations. When the selector switch is in the AUTO 2 position, LOW STEAM GENERATOR WATER LEVEL or LOSS OF BOTH MAIN FEEDWATER PUMPS will start the pump. Loss of both main feedwater pumps is sensed by pressure switches which monitor feedwater pump turbine hydraulic oil pressure.

Automatic starts of the MDEFWPs are disabled if a main steam line break is sensed by the Automatic Feedwater Isolation System (AFIS). Upon an AFIS actuation, the MDEFWP aligned to the affected steam generator will automatically stop and be inhibited from any further automatic starts. Once automatically started, the MDEFWPs will continue to operate until manually secured by the operator or disabled by an AFIS signal. The operator can manually start the MDEFWP by placing its selector switch to RUN.

Cooling water is initiated automatically, upon manual or automatic start of the MDEFWPs.

<u>Turbine Driven EFW Pump (TDEFWP):</u>

The steam supply for the TDEFWP turbine is provided from the main steam lines upstream of the main turbine stop valves and/or from the Auxiliary Steam System. Upon loss of station air, the supply is maintained by nitrogen bottle back-ups which are used on the pressure control valves. Should the nitrogen bottle back-ups fail, these control valves would fail to the open position.

The steam admission valve to the turbine, MS-93 is controlled by a normally energized solenoid valve. Upon receipt of a manual or automatic start signal, the solenoid valve will de-energize and immediately start the turbine by opening the steam admission valve. The steam admission valve will fail open upon loss of power to the normally energized solenoid valve or loss of supply air. The supply air is equipped with instrument air, auxiliary instrument air, and bottled Nitrogen backups. The EFW pump turbine speed is controlled by MS-95. The position of MS-95 is regulated by a hydraulic oil speed governing mechanism, with oil supplied from either the auxiliary oil pump or the shaft driven oil pump. MS-95 is designed to fail closed on loss of hydraulic oil pressure. An AFIS actuation will energize and close solenoid valve (TO-145) to isolate the hydraulic oil supply to close MS-95.

THE TDEFWP auxiliary oil pump is started automatically when the steam admission valve is opened, and provides hydraulic oil pressure for the operation of the TDEFWP governor control valve until the TDEFWP shaft driven oil pump is available. The TDEFWP auxiliary oil pump and its associated circuitry is required for automatic start of the TDEWFP. This equipment is powered from station batteries.

Automatic starting of the TDEFWP is determined by the position of the control room selector switch for the pump. The TDEFWP is provided with a three position-pull to lock selector switch. The operator can select between OFF, AUTO and RUN. When the selector switch is in the AUTO position, LOSS OF BOTH MAIN FEEDWATER PUMPS, with exception to loss due to the AFIS logic, will start the pump. Loss of both main feedwater pumps is sensed by pressure switches which monitor feedwater pump turbine hydraulic oil pressure. Automatic starts of the TDEFWP are disabled if a main steam line break is sensed by the AFIS circuitry. Upon an AFIS actuation, the TDEFWP will automatically stop and be inhibited from any further automatic starts. Once automatically started, the TDEFWP will continue to operate until manually secured by the operator or disabled by an AFIS signal. The operator can manually start the TDEFWP by placing the selector switch to RUN.

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Control Valves:

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Each emergency feedwater discharge line to each steam generator is provided with a control valve and a check valve. The air operated control valves receive an electric current signal that is converted to an air signal through an I/P converter. The converted signal is used for modulation of the valve in response to steam generator level, independent from the ICS. Each control valve has a Hand/Auto station mounted on the main control board. A pushbutton is provided on each Hand/Auto station to allow the individual EFW control valve to be placed in either an automatic level control mode or in a manual level control mode of operation. The Hand/Auto stations may be utilized to position the respective control valve when in the manual mode. Open/Closed valve position indication is provided for each control valve in the main control room. Power to the controller is battery backed DC converted to AC via the vital inverters.

The control valves are normally closed in the automatic mode due to steam generator level > setpoint. In automatic, an Auto/Manual relay for each control valve is de-energized, allowing the valve to be positioned automatically.

The control valves are arranged to fail to the automatic control mode upon loss of control power to the Hand/Auto station. If the selected train of automatic control experiences a loss of power, then the valve would fail open. Also, upon loss of station air, the valves will continue to control using the nitrogen supply. If the nitrogen supply fails the valve would fail open. These modes of operation show that Emergency Feedwater isolation will not result from valve control circuitry failure or motive force failure.

7.4.3.1.3 System Evaluation

Redundancy is provided with separate, full capacity, motor and turbine driven pump subsystems. Failure of either the motor driven pumps or the turbine driven pump will not reduce the EFW System below minimum required capacity. Pump controls, and instrumentation are separate and independent in design.

7.4.3.2 Steam Generator Level Control

7.4.3.2.1 Design Basis

The Steam Generator Level Control System (SGLCS) provides automatic Once Through Steam Generator (OTSG) water level control while the EFW System is supplying feedwater to the steam generators. SGLCS is designed to automatically control and modulate emergency feedwater supply to the steam generators during all initiating conditions for the EFW System (Section 7.4.3). Each OTSG has two independent level control systems each of which is capable of supplying a signal to the associated OTSG emergency feedwater level control valve.

The Steam Generator Level Control System (SGLCS) provides the automatic start signal for both MDEFWPs based on low level in either steam generator.

All automatic initiation logic and control functions are independent from the Integrated Control System (ICS).

7.4.3.2.2 System Design

Each OTSG is provided with two independent level control systems, each of which supplies a signal to that OTSG's emergency feedwater level control valve. The two systems provided for each OTSG monitor the 0-388 inch range (range at cold shutdown) of water in the OTSG. A signal deviation check between the two output signals is performed.

The SGLCS controls level higher than the normal ICS level setpoint to prevent control system conflict. Upon loss of all four reactor coolant pumps, such as during blackout conditions, the level control setpoint is automatically raised to promote natural circulation in the Reactor Coolant System.

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The operator has a selector switch on the main control board, which is used to select either control channel on each OTSG. Also provided on the main control board is a Hand/Auto station, which may be utilized to override the automatic level control signal. A control switch is provided on the control board for each EFW control valve that can be selected to bypass the Hand/Auto station. When this switch is selected to the bypass or off position only the automatic level control signal is sent to the respective valve. The Hand/Auto stations have redundant QA-1 power sources to minimize the possibility of losing the manual control capability of these valves.

7.4.3.2.3 System Evaluation

Each level channel is separate and independently powered from its counterpart on each OTSG. Redundancy is provided with two trains/channels monitoring each steam generator. Each level channel per steam generator is capable of performing the necessary control and modulation of the feedwater control valves. In addition, sufficient alarms and indications are provided to alert the operator to a system failure and ensure correct manual operation of a level control valve.

7.4.4 Reactor Building LPSW Low Pressure Instrumentation Circuitry

7.4.4.1 Design Basis

Generic Letter 96-06 required consideration of effect inside containment due to the change in environment during a Loss of Coolant Accident (LOCA). This consideration identified the potential for waterhammers in cooling water systems serving containment following a Loss of Offsite Power (LOOP) concurrent with a LOCA or Main Steam Line Break (MSLB). Analysis and system testing in response to GL 96-06 concluded that waterhammers could occur in the Low Pressure Service Water (LPSW) system during all LOOP events (e.g. LOCA/LOOP, MSLB/LOOP). The LPSW piping supplies the Reactor Building Cooling Units (RBCU), the Reactor Building Auxiliary Coolers (RBAC), and the Reactor Coolant Pump Motor Coolers (RCPMC). During Loss of Offsite Power (LOOP) events or Loss of Coolant Accident (LOCA) events coupled with a LOOP it was possible to create a Column Closure Waterhammer (CCWH) or Condensation Induced Waterhammer (CIWH) in the LPSW piping and components inside containment. CCWH could have occured when the LPSW pumps restart following a LOOP and rapidly close vapor voids with the system. CIWH could have occurred when heated steam voids interact with sub-cooled water in long horizontal piping sections.

7.4.4.2 System Design

The Reactor Building LPSW Low Pressure Instrumentation Circuitry consists of four (4) analog channels each powered from a separate safety related battery backed power panel board and two (2) digital actuation channels each powered from a separate safety related battery backed power panel board. Portions of the analog and digital channels are shared with the RBAC LPSW Low Pressure Instrumentation Circuitry which isolates the LPSW supply and return flow to the Reactor Building Auxiliary Coolers (RBAC).

The design function of the instrumentation circuitry is to close the pneumatic discharge isolation valves (LPSW-1121, 1122, 1123, and 1124) and open controllable vacuum breakers (LPSW-1150 and LPSW-1151) any time a low pressure condition occurs in the LPSW supply header. Closure of LPSW-1121, 1122, 1123, and 1124 and the opening of controllable vacuum breakers LPSW-1150 and LPSW-1151 on low LPSW pressure will maintain the LPSW piping inside the Reactor Building water solid thereby avoiding water hammers in the RBCU LPSW piping.

7.4.4.2.1 Analog Channels

A pressure transmitter for each of the four (4) analog channels monitors LPSW supply header pressure. When pressure decreases to the design set point as sensed by a particular channel, a trip relay and alarm relay are actuated for each of the respective channels that sensed the low pressure condition.

The low pressure output from each of the four (4) analog channels provide input to the two redundant 2 out of 4 trip logic paths in each of the two (2) digital logic trip channels.

7.4.4.2.2 Digital Channels

The inputs from the four analog channels are arranged in such a way as to provide different paths within each of the two redundant 2 out of 4 logic circuits. This assures the Reactor Building LPSW flow does not terminate to the Reactor Building due to a single failure of one of the other analog channels during an analog channel test.

The two redundant digital logic trip channels provide a close command signal to the solenoid valves for pneumatic discharge isolation valves LPSW-1121, 1122, 1123, and 1124. The two redundant digital logic trip channels also provide a trip open command signal to the solenoid valves for controllable vacuum breakers LPSW-1150 and LPSW-1151 when a low LPSW pressure condition occurs.

7.4.4.2.3 System Actuation and Reset

Upon actuation of the system, power is removed from solenoid valves LPSW-1121, 1122, 1123 and 1124 to cause each of the normally open pneumatic discharge isolation valves LPSW-1121, 1122, 1123, and 1124 to “Trip” (go to the closed position).

Simultaneously, power is applied to solenoid Valves LPSSV-1150 and LPSSV-1151 which in turn cause the normally closed controllable vacuum breakers LPSW-1150 and LPSW-1151 to “Trip” (i.e., go to the open position). Controllable vacuum breakers LPSW-1150 and LPSW-1151 will “Reset” (i.e., go to the closed position) if both low pressure trips have returned to their normal state. If this should fail to reset the controllable vacuum breaker for a particular train, then, the controllable vacuum breakers for that train will still reset when the normal pressure reset logic for that train has been satisfied as described below.

The low pressure LPSW trips reset to provide a permissive for the resetting of the Waterhammer Protection System (WPS) and the controllable vacuum breakers following the return to normal LPSW system pressure.

However, as stated above, pneumatic discharge isolation valves for a particular train will not actually re-open (Reset) until the low pressure trip for that particular train has also reset, which should have already occured by the time that the normal pressure reset logic circuit has been actuated. Therefore, when the LPSW supply pressure is restored to a value greater than its normal set point value as sensed on two of the four analog input channels, then, power will be reapplied to the solenoid valves that control the pneumatic discharge isolation vlaves LPSW-1121, 1122, 1123, and 1124 results in the re-opening of these valves. Simultaneously, the power path will be interrupted to the solenoid valves that control the controllable vacuum breakers LPSW-1150 and 1151 resulting in the re-closing of these valves, if they have not already done so by the removal of the two trip signals from the digital trip logic.

7.4.4.2.4 RBAC

As stated above, portions fo the pneumatic discharge isolation valves instrumentation circuitry are shared with the RBAC LPSW Low Pressure Instrumentation Circuitry. After the LPSW supply pressure is restored, LPSW Valves LPSW-1054, 1055, 1061, and 1062 will remain closed until the control room operator resets the circuitry by depressing the respective channel reset pushbutton on the control room vertical board and initiates a slow ramp open circuit to restore flow back to the RBAC units.

7.4.4.2.5 Loss of Electrical Power

The pneumatic discharge isolation valves LPSW-1121, 1122, 1123, and 1124 are spring loaded to open and require air to close. The controllable vacuum breakers, LPSW-1150 and LPSW-1151, are spring loaded to close and require air to open. The pneumatic discharge isolation valves and the controllable vacuum breakers all fail closed on loss of electrical power to their respective control solenoid valves.

7.4.4.2.6 System Evaluation

Each analog channel is powered from a separate safety related battery backed power panel board. Likewise, each digital channel is also powered from a separate safety related battery backed power panel board. Redundancy is provided by two pressure transmitters/analog channels monitoring each LPSW supply header. The two-out-of-four logic prevents actuation from the failure of a single transmitter. The LPSW Waterhammer Prevention System is QA1. The system is capable of performing the necessary control and modulation of the LPSW system.

7.4.5 References

1. *Evaluation of Transient Nuclear Instrumentation Power Range Flux Error* - Duke Power Company - March 1981.

2. Qualification Testing of Protective System Instrumentation Babcock and Wilcox - *BAW - 10003 Rev. 3 - April, 1974 and BAW - 10003A Rev. 4 - January, 1976*.

3. *Evaluation of Reactor Protective System Grounding Concern* Babcock and Wilcox - March, 1978.

4. *177 FA Plants NI/RPS Ground Problem Discussion and Recommended Test Scheme* Babcock and Wilcox - March, 1978.

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7.5 Display Instrumentation

7.5.1 Criteria And Requirements

7.5.1.1 Type A Variables

Type A variables are defined as those variables which are monitored to provide the primary information required to permit the Control Room operator to take specific manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis accidents. Primary information is defined as that which is essential for the direct accomplishment of the specified safety functions; it does not include those variables associated with contingency actions which may also be identified in written procedures.

Emergency Procedures provide the lead guidance for selection of Type A variables. The following variables are those determined to be Type A for Oconee Nuclear Station, as defined above:

1. Reactor Coolant System Pressure
2. Core Exit (Thermocouples) Temperature
3. Pressurizer Level
4. Degrees of Subcooling
5. Steam Generator Level
6. Steam Generator Pressure
7. Borated Water Storage Tank Level
8. High Pressure Injection Flow
9. Low Pressure Injection Flow
10. Deleted per 2006 update
11. Deleted per 2005 update
12. Upper Surge Tank Level
13. Low Pressure Service Water (LPSW) Flow to Low Pressure Injection (LPI) Coolers.

7.5.1.2 Type B and C Variables

Type B and C variable selection is based on the Safety Parameter Display System (SPDS) Critical Safety Functions. The SPDS, which meets the requirements of NUREG 0737, Supplement 1,is provided as an aid to the Control Room operating crew in monitoring the status of the Critical Safety Functions. The Critical Safety Functions monitored are those defined in the SPDS Critical Safety Function Fault Trees. The SPDS provides continuous status updated at regular intervals of the Critical Safety Functions.

Since these Critical Safety Functions constitute the basis of the Oconee SPDS, it is Duke Power's position that they should also be identified as the plant safety functions for accident monitoring (i.e., the basis for Type B & C variable selection).

Using the SPDS Critical Safety Functions as the basis for defining the accident monitoring instrumentation incorporates the concept of monitoring the multiple barriers to the release of radioactive material. The Critical Safety Functions monitored are those which assure the integrity of these barriers. The Fault Tree provides an explicit, systematic mechanism for organizing the plant data required to evaluate a Critical Safety Function. The prioritization of the Critical Safety Functions is consistent with the concept of multiple barriers to radiation release.

The Critical Safety Functions are:

1. Subcriticality

The subcriticality fault tree monitors the reactor core to assure that it is maintained in a subcritical condition following a successful reactor trip.

2. Inadequate Core Cooling

The inadequate core cooling fault tree monitors those variables necessary to evaluate the status of fuel clad heat removal.

3. Heat Sink

The heat sink fault tree monitors the ability to transfer energy from the reactor coolant to an ultimate heat sink.

4. Reactor Coolant System Integrity

The Reactor Coolant System integrity fault tree monitors those variables indicating a challenge to or a breach of the Reactor Coolant System pressure boundary.

5. Containment Integrity

The containment integrity fault tree monitors those variables which would indicate a threat to containment integrity or other undesirable conditions within containment.

6. Reactor Coolant System (RCS)

The RCS inventory fault tree monitors for indications of off-normal quantities of reactor coolant in the primary system.

7.5.1.3 System Operation Monitoring (Type D) and Effluent Release Monitoring (Type E) Instrumentation

7.5.1.3.1 Definitions

Type D: Those variables that provide information to indicate the operation of individual safety systems.

Type E: Those variables to be monitored as required for use in determining the magnitude of the release of radioactive materials and in continually assessing such releases.

The Type D and E variables are selected on the basis of individual plant specific system design requirements.

7.5.1.3.2 Operator Usage

The plant design has included variables and information display channels required to enable the Control Room operating personnel to:

1. Ascertain the operating status of each individual safety system to the extent necessary to determine if each system is operating or can be placed in operation to help mitigate the consequences of an accident. (Note: Type D and E are not always safety systems)

2. Monitor the effluent discharge paths to ascertain if there have been significant releases (planned or unplanned) of radioactive materials and to continually assess such releases.
3. Obtain required information through backup or diagnosis channel where a single channel may be likely to give ambiguous indication.

7.5.1.4 Design and Qualification Criteria

Design and qualification criteria used by Duke Power Company for plant instrumentation are provided below. The category designations are provided for reference to the Regulatory Guide 1.97 (Revision 2) document.

7.5.1.4.1 Design and Qualification Criteria - Category 1

Accident monitoring instrumentation which comprise this design and qualification category are considered by Duke Power to be Nuclear Safety Related and thus are classified as Quality Assurance Condition 1 (QA1).

1. QA1 instrumentation is environmentally qualified as described in the Oconee Nuclear Station IEB-79-01B Duke Power Company submittal and the Resolution of Safety Evaluation Reports for Environmental Qualification of Safety Related Electrical Equipment. Seismic qualification is in accordance with the Oconee Nuclear Station licensing basis as specified in Oconee FSAR Chapter 3 and the Duke Power Seismic Design Criteria (OSDC-0193.01-00-0001).
2. No single failure within either the accident monitoring instrumentation, its auxiliary supporting features, or its power sources, concurrent with the failures that are a condition or result of a specific accident, will prevent the operators from being presented the information necessary to determine the safety status of the plant and to bring the plant to and maintain it in a safe condition following that accident. Where failure of one accident-monitoring channel results in information ambiguity (i.e., the redundant displays disagree) that could lead operators to defeat or fail to accomplish a required safety function, additional information is provided to allow the operators to deduce the actual conditions in the plant. This is accomplished by providing additional independent channels of information of the, same variable (an identical channel) or by providing an independent channel to monitor a different variable that bear a known relationship to the multiple channels (a diverse channel). The information provided to the operator to eliminate ambiguity between redundant channels is needed only during a failure of one of the instrument loops. Therefore, it is considered acceptable to use installed instrumentation of equal design and qualification category, installed instrumentation of a lessor design and qualification category, temporary or portable instrumentation, or sampling to allow the operators to deduce the actual conditions in the plant. Redundant QA1 channels are electrically independent and physically separated from each other per the separation criteria described in Chapter 7 of the Oconee FSAR.

   At least one channel of QA1 instrumentation is displayed on a direct indicating or recording device. (Note: Within each redundant division of a safety system, redundant monitoring channels are not needed.)
3. The instrumentation is energized from the safety grade Emergency Power sources (as described in Chapter 8 of the Oconee FSAR) and is backed by batteries where momentary interruption is not tolerable.
4. The instrumentation channel will be available prior to an accident except as provided in Paragraph 4.11, "Exception" as defined in IEEE Standard 279-1971 or as specified in Technical Specifications. For the digital RPS/ESPS system, which includes the TXS

cabinets and their associated hardware, the instrumentation channel will be available as defined in IEEE Std 603-1998 Sections 5.7, 6.7, 7.5 and 8.3.

5. The following documents pertaining to quality assurance are referenced:
   a. Duke 1A, Duke Power Company Topical Report, "Quality Assurance Program"
   b. Oconee FSAR Chapter 17
6. Continuous indication display is provided. Where two or more instruments are needed to cover a particular range, overlapping of instrument span is provided.
7. Recording of instrumentation readout information is provided for at least one of the redundant channels. Recorders which are utilized as the primary display device will be seismically qualified. Where direct and immediate trend or transient information is essential for operator information or action, the recording is continuously available on dedicated recorders. Otherwise, it may be displayed on non-seismically qualified recorders or continuously updated, stored in computer memory, and displayed on demand. Intermittent displays such as data loggers and scanning recorders may be used if no significant transient response information is likely to be lost by such devices. All analog variables which are wired to the plant computer may be trended upon demand and a hard-copy can be generated as needed.

7.5.1.4.2 Design and Qualification Criteria - Category 2

7.5.1.4.2.1 Nuclear Safety Related (QA1) Category 2 Instrumentation

For instrumentation loops that are installed as nuclear safety related (QA1), environmental qualification is provided per the methodology described in the Oconee Nuclear Station IEB 79-01B submittal and the Resolution of Safety Evaluation Reports for Environmental Qualification of Safety Related Electrical Equipment. Seismic qualification is in accordance with the Oconee Nuclear Station Licensing basis as specified in the Oconee FSAR and Duke Power Seismic Design Criteria (OSDC-0193.01-00-0001). Quality Assurance of these QA Condition 1 instrumentation systems is described in the Duke Power Company Topical Report "Duke 1A" and Oconee FSAR Chapter 17. These instruments are powered from the safety grade Emergency Power sources (as described in Chapter 8 of the Oconee FSAR) and are backed by batteries where a momentary power interruption is not tolerable.

7.5.1.4.2.2 Non Nuclear Safety Related (Non-QA1) Category 2 Instrumentation

For instrumentation loops of lesser importance which are not nuclear safety related, appropriate qualification is provided. Environmental qualification is provided per the methodology described in the Oconee Nuclear Station IEB 79-01B submittal and the Resolution of Safety Evaluation Reports for Environmental Qualification of Safety Related Electrical Equipment.

Category 2 instrumentation which is of primary use during one phase of an accident need not be qualified for all phases of the event. For example, an instrument of primary importance prior to attained the recirculation mode need not be demonstrated to withstand post-recirculation radiation.

For non-QA1 Category 2 instrumentation, seismic qualification is not required unless seismic induced failure of the instrumentation would unacceptably degrade a safety system.

These instrumentation systems are designed, procured, and installed per Duke Power Company standard practices. Duke Power considers that this is adequate to assure the quality of the subject instrumentation.

Isolation devices are provided to interface between Nuclear Safety Related (QA1) and Non Nuclear Safety Related (non QA1) portions of any of the subject instrumentation loops.

The instrumentation is energized from a highly reliable power source, not necessarily safety grade Emergency Power, and is backed by batteries where momentary interruption is not tolerable.

7.5.1.4.2.3 All Category 2 Instrumentation

For both Nuclear Safety Related and Non Nuclear Safety Related Category 2 instrumentation:

The out-of-service interval should be based on normal Technical Specification requirements for the system it serves where applicable or where specified by -other requirements.

The instrumentation signal may be displayed on an individual instrument or it may be processed for display on demand by CRT or by other appropriate means.

The method of display may be by dial, digital, CRT, or stripchart recorder indication. Effluent radioactivity monitors and meteorology monitors will be recorded. Where direct and immediate trend or transient information is essential for operation information or action, the recording is continuously available on dedicated recorders. Otherwise, it may be continuously updated, stored in computer memory, and displayed on demand.

7.5.1.4.3 Design and Qualification Criteria - Category 3

These instruments do not play a key role in the management of an accident but they do add depth to the Category 1 and 2 instrumentation to the extent that they remain operable. The instrumentation is of high quality commercial grade and is selected to withstand the normal power plant service environment.

The method of display may be by dial, digital, CRT, or stripchart recorder indication. Effluent radioactivity monitors and meteorology monitors will be recorded. Where direct and immediate trend or transient information is essential for operator information or action, the recording is continuously available on dedicated recorders. Otherwise, it may be continuously updated, stored in computer memory, and displayed on demand.

7.5.1.4.4 Additional Criteria for Categories 1 and 2

In addition to the criteria of Duke Position 7.5.1.4, the following criteria apply to Categories 1 and 2:

1. For Nuclear Safety Related (QA1) signals which are transmitted to non-safety related (non QA1) equipment, isolation devices are utilized.
2. Dedicated control board displays for the instruments designated as Types A, B, and C, Category 1 or 2 and qualified for use throughout all phases of an accident will be specifically identified on the control panels so that the operator can discern that they are available for use under accident conditions.

7.5.1.4.5 Additional Criteria for All Categories

In addition to the above criteria, the following criteria apply to all instruments identified in this document:

1. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between tests will be less than the normal time interval between generating station shutdowns, the capability for testing during power operation is provided.
2. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.
3. The monitoring instrumentation design minimizes the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications which are potentially confusing to the operator. Human factors guidelines are used in determining type and location of displays. The Duke Control Room Review Team made recommendations as to the type and location of displays, for added instrumentation.
4. To the extent practicable, the instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.
5. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables.
6. To the extent practicable, the same instruments which are used for accident monitoring are used for the normal operations of the plant to enable the operators to use, during accident situations, instruments with which they are most familiar. However, where the required range of monitoring instrumentation results in a loss of necessary sensitivity in the normal operating range, separate instruments are used.
7. Periodic checking, testing, calibration, and calibration verification are in accordance with the applicable portions of the Oconee FSAR Chapter 7.

7.5.2 Description

Display instrumentation provided for Oconee operators is described below.

7.5.2.1 Reactor Coolant System Pressure

Three channels of Reactor Coolant System (RCS) Pressure indication are available through the plant operator computer (OAC), which receives the RCS Pressure signals through the Engineered Safety Features Actuation System (ESFAS) cabinets. This instrumentation is powered from a highly reliable battery backed source. These instrumentation channels monitor RCS pressure over the range 0 to 2500 psig. Two channels are recorded.

Two upgraded QA Condition 1 channels of Wide Range RCS Pressure indication are provided for post accident monitoring in response to Regulatory Guide 1.97. These instrumentation loops are seismically and environmentally qualified and are powered from safety grade emergency power sources. Signals to the Control Board readouts are processed through the Inadequate Core Cooling Monitoring (ICCM) system cabinets. The range for the readouts, 0-3000 psig, is in compliance with Regulatory Guide 1.97 specifications.

RCS pressure is a Type A Category 1 variable at Oconee, since the operator relies on this indication to determine when to switch from high pressure injection to low pressure injection.

Two upgraded QA Condition 1 channels of Low Range RCS Pressure indication are available via the Low Temperature Overpressure Protection (LTOP) System. These instrumentation loops are seismically and environmentally qualified and powered from safety grade emergency power sources. Although not required, the loops meet the RG 1.97 Category 1 instrumentation requirements of Section 7.5.1.4. The range for the readouts is 0-600 psig. The LTOP instrumentation loops are not credited in any design basis event. The instrumentation is classified as RG 1.97 Type D.

7.5.2.2 Inadequate Core Cooling Instruments

The Inadequate Core Cooling Monitor (ICCM) is of Westinghouse design. The ICCM system monitors hotleg level, reactor vessel head level, loop subcooling margin, core subcooling margin and core exit temperature and provides advanced warning of the approach to inadequate core cooling. The ICCM is a redundant two train Nuclear Safety-Related system powered by the vital instrumentation and control power system.

The microprocessor-based monitoring trains provide essential information to the control room operator so that conditions inherent to or leading to Inadequate Core Cooling (ICC) can be recognized and addressed.

The functions performed by the ICCM are as follows:

1. Assists in detecting a void or loss of level in the hotleg during natural circulation.
2. Indicates loss of subcooling margin.
3. Assists in detecting presence of a gas bubble or void in the reactor vessel head.
4. Assists in the detection of the approach to inadequate core cooling.

The ICCM system consists, on a per train basis of centrally located electronics/microprocessor cabinet, display electronics package, display selector key pad, and the plasma display unit on the main control board.

A description of each of the process sub-systems are described as follows.

7.5.2.2.1 Core Exit Temperature

There may be up to 52 Core Exit Thermocouples (CETs) per Oconee Unit. Twenty-four (12 per train) have been upgraded for accident monitoring and to meet seismic and environmental qualification requirements.

The plant computer is the primary display for up to 47 CETs of the 52. 5 CETs are displayed on the corresponding SSF unit console. The ICCM plasma displays (1 per train) located in the Control Room serve as safety related backup displays for the twenty-four nuclear safety qualified CETs. The range of the readouts is 50°F to 2300°F.

The ICCM CET function uses inputs from twelve incore thermocouples per train to calculate and display temperatures of the reactor coolant as it exits the core and to provide indication of thermal conditions across the core at the core exit.

Each of the twelve qualified thermocouples per train is displayed on a spatially oriented core map on the plasma display. The distribution of the monitored CETs in both trains assure minimum monitoring of at least four per core quadrant. Trending of CET temperature is available continuously on the plasma display. The average of the five hottest CETs is trendable for the past forty minutes.

Inputs to the plant computer for thermocouples used in the ICCM backup display is through qualified isolation devices. Power for the backup display is from safety grade emergency power sources, and power for the non-safety Operator Aid Computer (OAC) portion is from a highly reliable battery backed control bus. The plant computer and ICCM backup display are installed in a mild environment.

Core exit temperature is classified as a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (LOCA) to secure HPI and throttle LPI, (SBLOCA) to throttle HPI and begin forced HPI cooling if needed, (MSLB, OTSG Tube Rupture) throttle HPI and isolate affected OTSG.

(RE: NSMs ON-1/2/32401)

7.5.2.2.2 Degrees of Subcooling Monitoring

The margin to saturation for the hotlegs and the reactor core are calculated from Reactor Coolant System (RCS) pressure and temperature measurements. The hotleg subcooling margin is calculated from wide range RCS pressure measurements and individual hotleg RTD temperature measurements. The hotleg subcooling margins are displayed in the Control Room on the ICCM plasma display unit. Train A displays the RCS Loop A hotleg subcooling margin while the Train B display provides RCS Loop B hotleg subcooling margin. Computer inputs are also provided for both hotlegs.

The reactor core subcooling margin is displayed in the Control Room in an identical manner. The core subcooling margin is calculated from the average of the five highest qualified Core Exit Thermocouples (CET's) out of twelve inputs to each train of ICCM. This average value is then used with the RCS pressure measurement to calculate core subcooling margin.

The degrees of subcooling is also input to the plant computer through isolation buffers and is recorded on a recorder in the Control Room. The range of the degrees of subcooling readouts is 200°F subcooled to 50° superheat which envelopes the Regulatory Guide 1.97 range of 200°F subcooling to 35°F superheat.

Degrees of Subcooling Monitoring is classified as a Regulatory Guide 1.97, Rev. 2 Type A Category 1 variable at Oconee.

(RE: NSMs ON-1/2/32401)

7.5.2.2.3 Reactor Vessel Head and Hotleg Levels

The Reactor Vessel Head Level indicating system (RVHLIS) and Hotleg (HL) system are an adaptation of the Westinghouse RVLIS to the Babcock and Wilcox nuclear steam supply system. The HL and RVHLIS monitor the RCS for voids and loss of level conditions only under natural circulation.

The HL and RVHLIS uses two sets of two d/p (differential pressure) cells to measure both vessel and hot leg levels under natural circulation conditions. These cells are used to measure the pressure drop from the hot leg decay heat drop line connection to the top of the vessel, and from the hot leg decay heat drop line connection to the top of the candy cane on each hot leg. This differential pressure measuring system uses cells of differing ranges to cover natural circulation conditions.

This is a two train system containing Trains A and B which are physically separate and electrically isolated from each other. The trains perform the same function using identical but redundant inputs from differential pressure transmitters, impulse line temperature sensors, reactor coolant temperature sensors and wide range reactor coolant system pressure.

Software algorithms automatically perform compensation calculations required for variations in impulse line temperatures. Software also calculates and provides the necessary compensation for reactor coolant density.

Whenever the Reactor Coolant Pumps (RCPs) are running, the subcooling margin monitors and RCP monitor current meters are used to detect possible void conditions. Computer inputs are provided for both trains of level measurement. The Train A level measurements are recorded on a continuous recorder on the Main Control Board. The plasma displays for each train provide indication of both HL and RVHLIS in the Control Room.

Reactor Vessel Head and Hotleg Levels are classified as Regulatory Guide 1.97, Rev. 2 Type B Category 1 variables at Oconee.

7.5.2.3 Pressurizer Level

Two channels (2 level indications for Train “A” channel and 1 level indication for Train “B” channel)) of QA 1 instrumentation are provided for post accident monitoring the Pressurizer Level in response to Regulatory Guide 1.97, Revision 2. The indicated range is 0 to 400 inches which represents 11% to 84% level as a percentage of volume. Duke considers this range adequate for the intended monitoring function.

In order to determine the range or level that should be monitored for the pressurizer, it is important to understand how the pressurizer is sized and how the level taps are located. The pressurizer water volume is chosen such that the reactor coolant system can experience a reactor trip from full power without uncovering the level sensors in the lower shell and to maintain system pressure above the High Pressure Injection (HPI) system actuation setpoint. The steam volume is chosen such that the reactor coolant system can experience a turbine trip without uncovering level sensors in the upper shell. Oconee has a 0 to 400 in range for pressurizer level based on these criteria. Although the installed range of instrumentation is not in complete compliance with the recommendation of Regulatory Guide 1.97, Revision 2, that pressurizer level be monitored from bottom to top, it is consistent with B&W NSSS requirements and is adequate for the intended monitoring function, including monitoring to ensure continued safe operation of pressurizer heaters.

The qualified instrument channels are powered by safety grade emergency power sources. Continuous recording is provided for one channel. The range for the instrumentation channels is 0 to 400 inches which Duke considers adequate for the intended monitoring function as referenced in the above paragraph.

Pressurizer level is classifed a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (SBLOCA, OTSG Tube Rupture, MSLB) to throttle HPI.

(RE: NSMs ON-1/2/32448)

7.5.2.4 Steam Generator Level

Oconee has several different methods of Steam Generator level measurement and indication, as follows:

1. Start-up Range - Four transmitters (two per S/G) feed the ICS with signal ranges of 0" to 250". The four channels are used in the ICS for steam generator water level and feedwater control. The ICS employes median select between these signals and isolated signals from

Item 4 below to control level and feedwater. The ICS displays the controlling level signal on a dual scale gage on the main control board.

2. Operate Range - Four transmitters (two per S/G) are combined with temperature compensation to feed two recorders with ranges of 0-100% (96"-388"). The four channels are switch selectable for feeding the recorders.
3. Full Range - Two transmitters (one per S/G) feed one dual gauge with ranges of 0 to 100% (0-650").
4. Extended Startup Range - Four transmitters (two per S/G) feed four gauges with ranges of 0" to 388".

Items 1 through 3 are used during normal plant operating conditions and are not required to meet Regulatory Guide 1.97, Type A, Category 1 Variable Requirements. These instruments may be used as backup verification for post accident monitoring to the extent they are available.

The instrumentation in Item 4 above is safety related and is used for post-accident monitoring. This instrumentation is powered by safety grade emergency power sources and the transmitters are seismically and environmentally qualified. Signal conditioning is provided by seismically and environmentally qualified equipment. Two transmitters, one per steam generator, provide electrically isolated level signals to the ICS for use in steam generator water level and feedwater control. The ICS will display these level signals if they have been selected for control on the control room indicator described in Item 1 above.

During accident conditions, the required range for a B&W once through steam generator is based on that level in the steam generator needed to recover from loss of subcooling margin conditions. The installed range of 0" to 388" ensures that the level required to restore subcooling margin as given in the emergency procedures can be measured.

Steam Generator Level is classified a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (MSLB, OTSG Tube Rupture) to isolate affected OTSG.

(RE: NSMs ON-1/2/32447)

7.5.2.5 Steam Generator Pressure

Four QA Condition 1 channels, two channels per steam generator, are provided for post-accident monitoring steam generator outlet steam pressure in response to Regulatory Guide 1.97. Each instrument channel is seismically and environmentally qualified and powered from a safety grade source.

Each instrument channel inputs to the Inadequate Core Cooling Monitoring (ICCM) cabinets. The ICCM cabinets, Channel A and B respectively, provide safety inputs to two qualified indicators located on the Main Control Board in the Control Room. One channel per steam generator also provides an input to a recorder located in the Control Room. The ICCM system cabinets, channels A and B respectively, also provide non-safety inputs to the Operator Aid Computer (OAC). Safety train integrity is maintained by isolation buffers provided by the ICCM system cabinets. Additionally, each steam line has one QA Condition 1 channel of steam generator pressure instrumentation. These instrument channels along with corresponding ICCM steam generator instrumentation provide input signals into the Automatic Feedwater Isolation System (RE: NSM-ON-1/2/33053).

Each steam generator has two non-safety related channels of steam generator outlet pressure instrumentation (total of four) used for control by the ICS. In addition, two channels of QA-1 steam generator outlet pressure instrumentation used in the Automatic Feedwater Isolation System (AFIS) logic are electrically isolated and provided to the ICS for control. This makes a total of six pressure signals, three per steam generator, for use in the ICS for control. Each group of three pressure signals (3 - OTSG "A", 3 - OTSG "B") are used in median select strategy by the ICS for control. The control signal used in the ICS for each steam generator is provided for indication on the main control board. The indicated range is 0 - 1200 psig which corresponds to 14% above the lowest main steam safety relief valve setting and 8% above the highest safety valve setting. An additional channel of QA-steam generator outlet pressure instrumentation on each header is used in AFIS. All eight signals, four per steam generator, are also input to the plant computer (OAC) and trend recording is available to the control room operator if demanded. The non-safety related instrumentation is powered from highly reliable battery backed buses. The safety-related (QA-1) instrumentation is powered from the QA-1 vital instrumentation and control battery backed buses.

The main steam lines are provided with safety relief valves, atmospheric dump valves and condenser dump valves to prevent over pressurization of the lines as well as pressure control. Operability of the main steam safety valves (MSRVs) ensures that the secondary system pressure will not exceed 1155 psig (110% of system design pressure, 1050 psig) during the most severe anticipated system operating transient. In addition to the MSRV design functional capability, sufficiency of the 0 to 1200 psig range of the steam generator outlet pressure instrumentation with respect to Regulatory Guide 1.97 is ensured by maintaining: 1) the highest MSRV lift pressure setting at 1104 psig, 2) a steam relief capacity 17% or greater above the expected steam flow rate, and 3) plant operation within the power limits provided in the Facility Operating License, which correspondingly ensures that steam flow is limited to values that maintain an excess relief capacity..

Steam Generator Pressure is classified a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (MSLB, OTSG Tube Rupture) to isolate affected OTSG.

(RE: NSMs ON-1/2/32447)

7.5.2.6 Borated Water Storage Tank Level

Three QA Condition 1 channels of level instrumentation are provided for normal and post accident monitoring the Borated Water Storage Tank (BWST) level. Each channel is seismically qualified. Two channels are powered from a safety grade source and the third channel has a safety and a non-safety grade power distribution. Signals to the Control Board are processed through the Inadequate Core Cooling Monitoring (ICCM) system cabinets. The range for the readouts, 0 to 50 ft (13%-100% of volume), is in compliance with Regulatory Guide 1.97, Rev. 2.

Two of the three QA Condition 1 instrumentation channels provide inputs to the ICCM system cabinets, Train A and B respectively. The ICCM cabinets provides safety inputs to qualified indicators on the Control Board and non-safety inputs to the Operator Aid Computer (OAC). Safety train integrity is maintained through the use of isolation buffers provided by the ICCM system.

The third channel of qualified instrumentation provides a safety input from train B to a recorder (through a qualified isolator). This channel also provides input to the computer and various annunciators via an optical isolator which maintains safety train B integrity.

BWST level is classified a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (LOCA, SB LOCA) to realign LPI to take suction from RB sump.

(RE: NSMs ON-1/2/32450)

7.5.2.7 High Pressure Injection System and Crossover Flows

Two channels of QA condition 1 instrumentation are provided for post accident monitoring of High Pressure Injection (HPI) flow in response to Regulatory Guide 1.97. Each channel is seismically and environmentally qualified and powered from a safety grade source. Each channel signal, A and B respectively, inputs to a recorder and qualified indicator via the Inadequate Core Cooling Monitoring (ICCM) system cabinets. Two channels of QA condition 1 instrumentation are also provided for monitoring HPI crossover flow. These instrument channel signals directly input to qualified indicators on the Control Board. HPI System and Crossover Flow instrumentation channels monitor flow over the range 0 - 750 gpm which envelopes the 0 to 110% design flow criteria of Regulatory Guide 1.97, Rev. 2.

The ICCM cabinets also provide non-safety inputs to the Operator Aid Computer (OAC) and annunciator points. Safety channel integrity is maintained through the use of isolation buffers provided in the ICCM.

HPI System flow is a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (LOCA, SB LOCA, MSLP, OTSG Tube Rupture) to throttle HPI and initiate HPI bypass (if necessary).

(RE: NSMs ON-1/2/32589)

7.5.2.8 Low Pressure Injection System Flow

Two QA Condition 1 instrumentation channels are provided for normal and post accident monitoring Low Pressure Injection (LPI) flow in response to Regulatory Guide 1.97. Each channel is seismically and environmentally qualified and powered from a safety grade source. Each channel signal, train A and B respectively, inputs to a qualified indicator and a recorder via the Inadequate Core Cooling Monitoring (ICCM) system cabinets. These channels monitor LPI flow over the range 0-4000 gpm which envelopes the 0-110% of design flow criteria for Regulatory Guide 1.97.

The ICCM cabinets also provide non-safety inputs to the Operator Aid Computer (OAC) and annunciator points. Alarms generated in the ICCM cabinets provide high and low LPI flow and low Decay Heat removal flow for each train. Safety train integrity is maintained through the use of isolation buffers provided by the ICCM. Two non-qualified transmitters, one per train, also provide non-safety inputs to the OAC.

LPI System is a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (LOCA, SB LOCA) to terminate HPI flow.

(RE: NSMs ON-1/2/32587)

(RE: NSMs ON-1/2/33093)

7.5.2.9 Reactor Building Spray Flow

Two QA Condition 1 instrumentation channels are provided for post accident monitoring Reactor Building Spray flow in response to Regulatory Guide 1.97. Each instrumentation channel is seismically and environmentally qualified and powered from a safety grade source. Each instrument channel signal, train A and B respectively, inputs to a qualified indicator and a recorder via the inadequate core cooling monitoring (ICCM) cabinets. These channels monitor

Reactor Building Spray flow over the range 0-1500 gpm which envelopes the Regulatory Guide 1.97 range requirement of 0-110% of design flow.

The ICCM cabinets also provide non-safety inputs to the Operator Aid Computer (OAC), annunciator, and a non-safety indicator located in the Control Room. Safety train integrity is maintained through the use of isolation buffers provided by the ICCM system. Also provided is two non-safety instrument channels which provide non-safety inputs to the OAC.

For all units at Oconee, throttling is not required, and the RBS flow variable is classified as Type D Category 1 for indication of continued operation of the RBS system to support long term cooling requirements and iodine removal. However, this instrument is only required to meet Category 2 requirements.

(RE: NSMs ON-1/2/32588 and ON-1/2/33105)

7.5.2.10 Reactor Building Hydrogen Concentration

Two redundant channels of nuclear safety related instrumentation monitor reactor building hydrogen concentration. The reactor building hydrogen monitoring system meets the requirements of NUREG 0737, Item II.F.1.6, and is described in more detail in Section 9.3.7 of the UFSAR. The indicated range is from 0 to 10% concentration which envelopes the Regulatory Guide 1.97 range requirements.

Both channels are powered by safety grade emergency buses. Control of the sample line switching valves and sample selector solenoid valves is accomplished at the analyzer remote control panel. These instruments are seismically and environmentally qualified.

Reactor Building Hydrogen Concentration is classified as a Regulatory Guide 1.97, Rev. 2 Type E Category 3 variable at Oconee.

7.5.2.11 Upper Surge Tank and Hotwell Level

Oconee's Emergency Feedwater System (EFDW) draws condensate grade suction primarily from the Upper Surge Tanks and supplementarily from the Condenser Hotwell. Condensate may also be provided from the Condensate Storage Tank (CST) and the Makeup Demineralizers. Additional backup of the two normal condensate sources is provided by these same locations associated with the other two units. The level transmitters which monitor Upper Surge Tank and Hotwell level are located in the Turbine building which is a mild environment.

Instrumentation is available to monitor Hotwell level in the Control Room. The plant computer system is provided to display both current and past values of this variable. Hotwell level is not calssified as a Regulatory Guide 1.97 variable at Oconee.

Two QA Condition 1 instrumentation channels are provided for monitoring Upper Surge Tank (UST) level in response to Regulatory Guide 1.97. These instrument channels are seismically qualified and powered from a safety grade source. Each instrument channel, train A and B respectively, input to the Inadequate Core Cooling Monitoring (ICCM) system cabinets. The ICCM Train A cabinet provides safety inputs to a qualified indicator and to a recorder (through a qualified isolator), both located in the Control Room to provide UST level indication. The ICCM Train B cabinet also provides a safety input to a qualified indicator located in the Control Room. The range of UST level indication is 0 - 12 feet.

The ICCM cabinets, Train A and B respectively, also provide non-safety inputs to two computer alarm points and one annunciator window. Safety train integrity is maintained through the use of isolation buffers provided by the ICCM system.

Upper Surge Tank level is a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event.

(RE: NSMs ON-1/2/32449)

7.5.2.12 Neutron Flux

Oconee has four channels of neutron flux for the source range, and four wide range QA Condition 1 channels of full range neutron flux instrumentation which are environmentally qualified for post-accident monitoring. Four neutron flux channels exist for the power range. The indicated ranges are: Source Range 10^{-1} to 10^{5} cps, -1.0 to +7.0 decade/min. rate of change; Wide range (Post-Accident Monitoring channels) 10^{-8} to 200% power, -1 to +7 decade/min. rate of change; and Power Range, 0 to 125%.

NI-1,-2,-3, and -4 channels are environmentally qualified and powered from safety grade busses and encompass the 10^{-6} to 100% Full Power range in response to Regulatory Guide 1.97, Rev. 2. NI-1, -2, -3, and -4 channels are Type B Category 1 variables at Oconee. All other NI channels are designed for the normal Reactor Building Environment for the safety function of overpower reactor trip but they are not environmentally qualified for post-accident operation.

Operator information is provided as follows:

1. Twelve Control Room indicators (Four source, four wide, four power)
2. Twenty computer points (Eight source, eight wide range, and four power)
3. Trend recording on demand
4. One QA Condition 1 Wide Range channel recorded on a recorder. One source range, wide range, and power range channel recorded, four (two power range) channels accessible on a Non-QA Condition recorder.

(RE: NSMs ON-1/2/32596 and 1/2/32909)

7.5.2.13 Control Rod Position

Each control rod's position is indicated on an analog display which has two switchable input modes for the full 0 to 139 inch range. In addition, separate Full In and Full Out indicating lights are provided for each control rod. Analog computer points are provided for each control rod's position. Analog computer points are also provided for control rod groups 5, 6, 7 and 8, for zero to 100% rod position corresponding to the full 0 to 139 inch range. This instrumentation is powered from a highly reliable battery backed source. Control Rod Position is classified as a Regulatory Guide 1.97, Rev. 2 Type B Category 3 variable at Oconee. (Re: FSAR 4.5.3).

Operator information is provided as follows:

1. Indicating lights for Full In or Not Full In for all control rods.
2. Analog display full range for all control rods.
3. Computer inputs for all control rods and all control rod groups 5, 6, 7, and 8. Trend recording on demand.

7.5.2.14 RCS Soluble Boron Concentration

This variable is monitored by sampling and laboratory analysis. Primary system boron concentration is controlled manually with the sampling frequency determined by plant conditions and operating procedures.

7.5.2.15 Reactor Coolant System Cold Leg Water Temperature

Oconee has indication of Reactor Coolant System (RCS) Cold Leg Temperature for each of the four cold legs. The instrumentation is powered from a highly reliable battery backed source. The indicated range is 50° to 650°F. Additional diversity is provided by the Hot Leg Water Temperature and Core Exit Temperature Instruments.

The RCS Cold Leg Water Temperature is used as a backup for the key variable of Hot Leg Temperature and Core Exit Temperature. Because the Hot Leg and Cold Leg RTD's are located in the RCS loops and not in the reactor vessel, either forced or natural circulation is required through the steam generators for their indication to be representative of actual core conditions. When circulation is present, the 650°F high end of the range provides 18% excess measurement capability based on a steam generator design pressure of 1050 psig and a saturation temperature of approximately 553°F for the Oconee design. Because the RCS Cold Leg Temperature is not used in the ATOG guidelines and functions as backup to the other two variables, it is appropriate to classify this variable as a Type B Category 3. The existing design is adequate for the intended monitoring function.

7.5.2.16 Reactor Coolant System (RCS) Hot Leg Water Temperature

Two qualified, QA condition 1 channels, are provided for post-accident monitoring Wide Range RCS Hotleg Water Temperature in response to Regulatory Guide 1.97 Rev. 2. These instrument channels are powered from safety grade emergency power sources. The indication readouts are located in the Control Room in a mild environment. This variable inputs to the plant computer through isolation buffers and is recorded on a recorder in the Control Room. (RE: NSMs ON-1/2/32401). The range of the readouts is 50 to 700°F which Duke considers adequate for the intended monitoring function. Also note, this range is in compliance with the recommendations of Revision 3 to RG 1.97. Control room display is through the inadequate Core Cooling Monitoring system. RCS Hot Leg Water Temperature is classified as a Regulatory Guide 1.97, Rev 2 Type A Category 1 variable at Oconee.

7.5.2.17 Reactor Building Sump Water Level Narrow Range

Two channels of instrumentation monitor both the Normal Sump Level (0 to 2 feet, approximately 350 gallons excluding embedded piping) and the Emergency Sump Level (0 to 3 feet, approximately 4000 gallons). This instrumentation is environmentally qualified and powered from safety grade emergency power buses. Qualified backup indication is provided by the Wide Range Sump Level instrumentation. Reactor Building Sump Water Level Narrow Range is classified as a Regulatory Guide 1.97, Rev. 2 Type B Category 2 variable at Oconee and, with the Reactor Building Sump Water Level instrument in Section 7.5.2.18 below, meets the requirements of NUREG 0737, Item II.F.1.5 as described in Section 5.2.3.10.5 of the UFSAR.

(Re: FSAR 3.4.1.1.2).

(RE: NSM ON-2248)

7.5.2.18 Reactor Building Sump Water Level

Two redundant QA Condition 1 channels of level instrumentation are provided for measuring reactor building sump water level from the bottom of the Reactor Building to approximately five feet above the maximum flood elevation which exceeds the 600,000 gallon level. The indicated range is 0 to 15 feet. Redundancy/diversity is provided by the Borated Water Storage Tank Level and the Narrow Range Sump Level indicators. The instrumentation channels are environmentally and seismically qualified and powered by safety grade emergency power buses. Reactor Building Sump Water level is classified as a Regulatory Guide 1.97, Rev. 2 Type B Category 1 variable at Oconee and, with the Reactor Building Sump Water Level Narrow Range instrument described in Section 7.5.2.17 above, meets the requirements of NUREG 0737, Item II.F.1.5 as described in Section 5.2.3.10.5 of the UFSAR.

(Re: FSAR 3.4.1.1.2).

7.5.2.19 Reactor Building Pressure

Two redundant QA Condition 1 channels of instrumentation are provided for monitoring Reactor Building Pressure in accordance with the requirements of NUREG 0737, Item II.F.1.4. The instrumentation channels are environmentally and seismically qualified and powered by safety grade emergency power buses. The indicated range is -5 to 175 psig with the reactor building design pressure being 59 psig. This instrumentation range covers nearly 99% of the recommended Regulatory Guide 1.97, Revision 2, range of 10 psig to 3 times the design pressure (177 psig). Duke considers the indicated range adequate for the intended accident monitoring function. Reactor Building Pressure is classified as a Regulatory Guide 1.97, Rev. 2 Type B Category 1 variable at Oconee.

7.5.2.20 Reactor Building Isolation Valve Position

All electrically controlled reactor building isolation valves that are active to close for containment isolation have control switches on the main control boards. Actual valve position is provided by QA Condition 1 limit switches on the valves which operate both Closed-Not Closed, and Open-Not Open control switch indicating lights. These valves are powered by safety grade emergency power buses. Additional indication is provided by the computer. Redundancy is not necessary on a per valve basis since redundant barriers are provided for all fluid penetrations as discussed in the Oconee FSAR Section 6.2.3.2. Environmental qualification of the limit switches is described in the Oconee FSAR section 3.10 and the Oconee Nuclear Station Seismic Design Criteria (OSDC-0193.01-00-00001). Reactor Building Isolation Valve Position is classified as a Regulatory Guide 1.97, Rev. 2 Type B Category 1 variable at Oconee.

7.5.2.21 Deleted Per 2014 Update

Deleted paragraph(s) per 2005 update

7.5.2.22 Accident Sampling Capability, Primary Coolant, Primary Coolant Sump, Containment Air

The existing design of the sampling system for the primary coolant, the Reactor Building sump and Reactor Building air allows samples to be taken for laboratory analysis. Samples from other plant systems including various auxiliary building sumps can be obtained from sample points on system piping and/or storage tanks.

Deleted paragraph(s) per 2005 update

7.5.2.23 Reactor Building Area Radiation - High Range

Oconee has two redundant QA Condition 1 channels of Reactor Building high range radiation monitoring instrumentation. Each channel is powered by safety grade emergency power. The indicated range is 1 to 10^8 R/hr. Diversity is provided by portable instrumentation or by sampling and analysis. The instrumentation is seismically and environmentally qualified.

Reactor Building high range radiation monitoring instrumentation is classified as a Regulatory Guide 1.97, Rev. 2 Type C Category 1 variable at Oconee.

NRC Information Notice 97-45 Supplement 1 (Reference 2) discusses temperature-induced signal phenomena which could result in both false high and fail indications for containment high range radiation monitors during LOCA and MSLB accidents inside containment. The Oconee reactor building high range radiation monitors are not susceptible to the phenomena for accidents inside containment, as the detectors and cables are physically separated from the reactor building atmosphere (Reference 3). The monitors are only susceptible to the phenomena following a High Energy Line Break (HELB) in the Unit's East or West Penetration Room. Potential false indications following a Penetration Room HELB are expected to be of short duration (Reference 4). Furthermore, Penetration Room HELBs are not expected to result in LOCA or significant radiation release to the reactor building (Reference UFSAR 3.6.2 Item 1). The reactor building high range radiation monitors continue to comply with Duke's interpretation of Regulatory Guide 1.97, rev. 2 as clarified in UFSAR 7.5.1 and Reference 5 and as approved in Reference 6.

7.5.2.24 Airborne Process Radiation Monitors

Airborne process radiation monitors exist for monitoring ventilation exhausts and the condenser air ejector exhaust (see Oconee FSAR, Section 11.5 and Table 11-7). However, in accordance with RG 1.97, Rev. 2 these individual airborne process radiation monitors are not required for accident monitoring due to the fact that ventilation systems and the condenser air ejector exhaust to the common unit vent (See Oconee FSAR, Section 7.5.2.52).

7.5.2.25 Area Radiation

Oconee has an extensive Area Radiation Monitoring System installed for personnel protection. Channel detector locations were selected based on areas normally having free access and low radiation dose rates with the potential of having abnormal radiation levels. These channels have an indicated range of 10^{-1} to 10^{7} mr/hr. Redundant indication can be provided by portable instrumentation. The channels are powered by a highly reliable non load shed power bus capable of receiving power from the on-site emergency power sources. See the Oconee FSAR, Section 12.3.3.

The environmental qualification of some of the instrumentation is not in compliance with the recommendations of Regulatory Guide 1.97, Revision 2. However, the qualification is within the guidance provided for Type C Category 3 instrumentation which Duke considers adequate for the intended monitoring function. Also note, this is in compliance with the recommendations of RG 1.97, Rev. 3. Continuous recording is not required for the intended monitoring function.

7.5.2.26 Decay Heat Cooler Discharge Temperature

Each train of the Oconee LPI system contains instrumentation to monitor decay heat cooler discharge temperature which is referred to in Regulatory Guide 1.97, Revision 2, as RHR Heat Exchanger Outlet Temperature. The range for this instrumentation is 0 to 400°F, and the power supply is a highly reliable battery backed control bus. Each train is environmentally qualified per the IEB-79-01B submittal methodology and envelopes the Regulatory Guide 1.97, Rev. 2 range of 32° to 350°F. Decay Heat Cooler Discharge Temperature is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 2 variable at Oconee.

7.5.2.27 Core Flood Tank Level

Oconee has two channels of tank level instrumentation on each of the two core flood tanks. Power for these channels is provided by highly reliable battery backed buses. The indicated range for Units 1, 2 and 3 is 1.5 to 14 feet which corresponds to approximately 22% to 83% of the core flood tank volume. The equipment is located in a harsh environment.

The range and environmental qualification of this instrumentation is not in total compliance with the recommendations of RG 1.97, Rev. 2, which recommends a range of 10% to 90% volume and Category 2 classification.

The primary function of this instrumentation is to monitor the pre-accident status of the core flood tanks to assure that this passive safety system is prepared to serve its safety function. The indicated range envelopes the Technical Specification level requirements and Duke Power considers the range adequate to meet the intended monitoring function. This instrumentation plays no significant role in the subsequent management of an accident. Therefore, Core Flood Tank Level is not a key variable for accident monitoring and is considered to be Type D Category 3 instrumentation. The level of environmental qualification provided for the instrumentation in this system is consistent with the performance expectations of the system and meets the recommendations of Type D Category 3 in Duke's interpretation of RG 1.97, Rev. 2.

7.5.2.28 Core Flood Tank Pressure

Oconee has two channels of core flood tank pressure instrumentation on each of the two core flood tanks. Power for these channels is provided by highly reliable battery backed buses. The indicated range is 0 to 700 psig. The tanks are pressurized to 600 psig under normal operating conditions.

The primary function of this instrumentation is to monitor the pre-accident status of core flood tanks to assure that this passive safety system is prepared to serve its safety function. This instrumentation plays no significant role in the subsequent management of an accident. Therefore, Core Flood Tank Pressure is not a key variable for accident monitoring and is considered to be Category 3 instrumentation. The installed system meets the Duke interpretation of Type D Category 3 recommendations. Regulatory Guide 1.97, Revision 2, classifies this variable as Category 2.

The range of this instrumentation is not in total compliance with the recommended 0 to 750 psig range of Regulatory Guide 1.97, Revision 2. However, the indicated range covers approximately 0 to 117% of the operating pressure of the tanks. Because the purpose of this variable is to monitor and maintain Core Flood Tank pressure during normal operation to Technical Specification (TS) limits, the range of this variable should provide some margin above that TS limit. Since the Oconee TS limit is 600 ± 25 psig, a high range value of about 700 psig will provide greater than 10% excess range measurement capability and will therefore be sufficient. Duke Power considers the instrumentation adequate for the intended monitoring function.

7.5.2.29 Core Flood Tank Isolation Valve Position

The core flood tank isolation valves are provided with control switches on the main control board. During normal plant operation, power is removed from the valve operators to prevent a spurious signal from inadvertently closing the valves. The indicating lights are powered from a separate highly reliable battery backed bus and give actual valve position of both Closed-Not Closed and Open-Not Open. Environmentally qualified limit switches are provided for the core flood tank isolation valves.

Core Flood Tank Isolation Valve Position is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 2 variable at Oconee.

7.5.2.30 Boric Acid Charging Flow

Oconee NSSS does not include a charging system as part of the Emergency Core Cooling System (ECCS). Flow paths from the ECCS to the RCS include high pressure injection (HPI) and low pressure injection (LPI) with the BWST or the RB Sump as the suction source, and the Core Flood Tank injection. HPI and LPI flow rates are monitored, and BWST, Reactor Building Sump, and Core Flood Tank levels are monitored by RG 1.97 variables. Therefore, Boric Acid Charging Flow monitoring is not applicable to the operation of the ECCS and is not a Type D variable for Oconee.

7.5.2.31 Reactor Coolant Pump Status

The indicated range for RCP motor current is from 0 to 1200 amps. The instrumentation derives power from the monitored source and is adequate for the intended monitoring function. The RCP motor current instrumentation is classified as a Regulatory Guide 1.97, Rev. 2 Type D Categroy 3 variable at Oconee.

7.5.2.32 Power Operated Relief Valves Status

An acoustical leak detection monitoring system is the primary instrumentation for determining PORV position. It is a single channel system powered from a highly reliable battery backed bus. It provides the operator with positive indication of valve position by indicating fractional flow through the valve in ten steps from 0.01 to 1.0. Backup indication of PORV position is provided by limit switch operated indicating lights and PORV outlet temperature indication. The system was specified and is rated to operate in all environmental conditions for its location. Power Operated Relief Valves status is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 2 variable at Oconee.

(RE: NSMs ON-1/2/32594)

7.5.2.33 Primary System Safety Relief Valve Positions (Code Valves)

Acoustical leak detection monitoring systems are the primary instrumentation for determining code valves position. Each code valve has a single channel system powered from highly reliable battery backed bus. It provides the operator with positive indication of valve position by indicating fractional flow through the valve in ten steps from 0.01 to 1.0. Backup indication of code valve position is provided by valve outlet temperature indication. The system was specified, and is rated to operate in all environmental conditions for its location. Primary System Safety Relief Valve Position is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 2 variable at Oconee.

(RE: NSMs ON-1/2/32594)

7.5.2.34 Pressurizer Heater Status

Control indicating lights are used for indication of the ON/OFF status of the pressurizer heater groups. Indicating lights are powered by highly reliable battery backed busses. This monitoring instrumentation is located in a mild environment.

ON/OFF status of the pressurizer heaters provides the operator adequate information for Design Basis events. Additionally, RCS pressure can be monitored to determine the effectiveness of the heaters to maintain system pressure. Duke feels that this is adequate for the intended monitoring function, and that monitoring of electric current per Regulatory Guide 1.97, Revision 2, recommendations is not necessary. Pressurizer Heater status is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 2 variable at Oconee.

7.5.2.35 Quench Tank Level

The indicated range of Quench Tank Level is from 0 to 125" corresponding to tank volume of approximately 15-96%. This range is not in complete compliance with RG 1.97, Rev. 2, which recommended top to bottom tank monitoring, however, the upper range meets the intended monitoring function. No useful information would be gained by measuring tank volume from 0-15%. Normal level (pre-accident) is maintained above 15% and post-accident condition will only increase tank level. Therefore, the existing range is adequate for the intended monitoring function. Quench Tank Level is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 3 variable at Oconee.

7.5.2.36 Quench Tank Temperature

The indicated range of the Quench Tank temperature is from 50° to 350°F. The design temperature of the Quench Tank is 300°F which is approximately the maximum temperature reached in the tank during a design transient. The tank design pressure is 55 psig, and the rupture disc pressure is 55 psig. The saturation temperature for 55 psig is approximately 300°F. Thus, the indicated range of 50°F to 350°F will adequately measure the expected maximum temperature as well as saturation temperature for the Quench Tank. Quench Tank Temperature is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 3 variable at Oconee.

(RE: NSMs ON-1/2/32593)

7.5.2.37 Quench Tank Pressure

The indicated range of the Quench Tank pressure is from 0 to 60 psig. The tank rupture disc is designed to relieve at 55 psig, and the tank design pressure is 55 psig. Therefore, the installed instrumentation is adequate for the intended monitoring function. Quench Tank Pressure is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 3 variable at Oconee.

7.5.2.38 Main Steam Safety Valve Position

This variable is not monitored directly. The positions of the Main Steam Safety Valves (MSSV) are not required to mitigate the consequences of a design basis accident. Direct indication of safety valve position is not provided but indirect indication is provided via control room indication of steam generator pressure. During Duke's Control Room Design Review, a specific Task Analysis Evaluation of MSSV indication was undertaken. This evaluation dealt with steam leak transients with and without MSSV indication. As a result of this evaluation, direct MSSV indication was found not necessary. Also, sound emitted from the valves provides an audible indication to the operators when the valves lift. Duke feels that this is adequate indication for the intended monitoring function.

7.5.2.39 Main Feedwater Flow

Each feedwater line has three main feedwater flow transmitters. The indicated range for this variable is 0 to 6.0×10^6 lbs/HR which corresponds to 0 to 111% of design flow. Main Feedwater Flow is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 3 variable at Oconee.

7.5.2.40 Emergency Feedwater Flow

Oconee has four QA Condition 1 flow transmitters, two per steam generator monitoring Emergency Feedwater Flow from all EFDW pumps to each steam generator. The indicated range for this variable is 0 to 1200 GPM which corresponds to a range of 0 to 115% design flow. This instrumentation is powered from a safety grade emergency power source. Seismic qualification methodology for these transmitters is as described in the Oconee FSAR, Section 3.10. The indicators are located in the control room which is classified as a mild environment. Emergency Feedwater flow to each steam generator is recorded on separate recorders in the Control Room. Emergency Feedwater Flow is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 1 variable at Oconee.

7.5.2.41 Reactor Building Fan Heat Removal

The key variable for monitoring Reactor Building Cooler performance is Reactor Building Pressure instrumentation which is Type B Category 1. Backup instrumentation includes Nuclear Safety Related indication of each Reactor Building Cooler Fan motor starter status (high and low speed lights), each Fan motor starter status on the computer, indication of each Fan motor amperage, indication of inlet and outlet cooling water flow to each cooler, and inlet and outlet air temperature indication for each cooler. All of the above indications are provided in the Control Room. The installed instrumentation is adequate for the intended monitoring functions. For backup indications, the level of environmental qualification provided for the instrumentation is consistent with the performance expectations of the instrumentation and meets the recommendations of Type D Category 3 in Duke's interpretation of RG 1.97, Rev. 2.

7.5.2.42 Reactor Building Air Temperature

Thirteen dual element thermocouples are provided to measure Reactor Building air temperature on Units 1 & 2. Twelve dual element thermocouples are provided on Unit 3. One element of each T/C provides an input to the plant computer and the second element of each T/C, except for Unit 2, provides an input to a multi-channel recorder. On Units 1 and 3, the T/C input into the recorders is retransmitted to the OAC via an analog output card on board the recorders. Unit 2, for the present sends both T/C elements directly to the OAC. The plant computer and the recorders display a range of 0 to 400°F. The plant computer is powered by highly reliable battery backed busses.

The displayed ranges are adequate for the intended monitoring function. The worst case DBA temperature in the Reactor Building is 286°F. For accidents in which harsh RB environments are a result, pressure and temperature are coupled such that as RB pressure is reduced the temperature is also reduced. Therefore, RB pressure is considered the priority variable with temperature as a Category 3 backup variable. The level of environmental qualification provided for this instrumentation is consistent with its performance expectations and meets the recommendations of Type D Category 3 in Duke's interpretation of RG 1.97, Rev. 2.

7.5.2.43 Makeup Flow

The existing instrumentation for this variable provides continuous monitoring of reactor coolant makeup flow. The loop range is 0 to 160 gallons per minute which encompasses the Regulatory Guide 1.97, Rev.2 criteria of 0-110% of design flow. Design flow is 35 GPM. The instrumentation is located in a mild temperature environment.

The transmitter for this variable is not rated to withstand the anticipated maximum design basis accident radiation dose for the installed location. The installed instrumentation is adequate for the intended monitoring function. For accidents in which harsh environments are a result, the portion of the system containing this instrumentation is not required for the mitigation of these accidents and is automatically bypassed upon an ESF Actuation. Therefore, Makeup Flow is not a key variable for accident monitoring and is considered to be Category 3, instrumentation. The level of environmental qualification provided for the instrumentation in this system is consistent with the performance expectations of the system and meets the recommendations of Type D Category 3 in Duke's interpretation of RG 1.97, Rev. 2.

7.5.2.44 Letdown Flow

The existing instrumentation for this variable provides continuous monitoring of reactor coolant letdown flow. The loop range is 0 to 160 gallons per minute which envelopes the Regulatory Guide 1.97, Rev. 2 criteria of 0-110% of design flow. Design flow is 70 GPM. This instrument loop is powered from a highly reliable battery backed bus. The instrumentation is located in a mild temperature environment.

The transmitter for this variable is not rated to withstand the anticipated maximum design basis accident radiation dose for the installed location.

The installed instrumentation is adequate for the intended monitoring function. For accidents in which harsh environments are a result, the portion of the system containing this instrumentation is not required for the mitigation of these accidents and is automatically isolated upon an ESF Actuation. Therefore, Letdown Flow is not a key variable for accident monitoring and is considered to be Category 3 instrumentation. The level of environmental qualification provided for the instrumentation in this system is consistent with the performance expectations of the system and meets the recommendations of Type D Category 3 in Duke's interpretation of RG 1.97, Rev. 2.

7.5.2.45 Letdown Storage Tank Level

The existing instrumentation for this variable provides continuous monitoring of the letdown storage tank level. The loop range is 0 to 100 inches which covers the linear portion of the tank (approximately 16 to 84% of tank volume). This instrument loop is powered from a highly reliable battery backed bus. This instrumentation is located in a mild environment.

Minimum and maximum letdown storage tank levels are maintained within the range of the instrument. Extending the range into the domed portions of this tank would result in nonlinear readings at each extreme of the scale. The installed range is adequate for measuring letdown storage tank level. The installed instrumentation is adequate for the intended monitoring function. This tank is not required to be utilized during an accident. As a commitment to the NRC, Duke is voluntarily upgrading this LDST level instrumentation to Type D Category 2 Nuclear Safety Related (QA-1). This change was performed on Unit 3 during the 3EOC17 refueling outage, and will be implemented on the other units in subsequent outages. This upgraded instrumentation is also adequate to perform the intended monitoring function. (Ref NSM x-2885)

7.5.2.46 Low Pressure Service Water Temperature to ESF System

The Oconee system for providing cooling water to ESF components is the Low Pressure Service Water System (LPSW). The temperature of LPSW is essentially the same as the temperature of Lake Keowee at the CCW pump suction. There is no control over the temperature of the LPSW; therefore, there is no need to indicate the LPSW temperature in the control room since no operator action is taken based on this temperature and, by design, no useful information would be provided to the operator by such instrumentation.

7.5.2.47 Low Pressure Service Water Flow to ESF Systems (Pressure)

The Oconee system for providing cooling water to ESF components is the Low Pressure Service Water System (LPSW). Primary indication of proper LPSW system and pump operation is line pressure measured in each of the two LPSW headers. The indicated range is 0 to 100 psig for a system design pressure of 100 psig. These instruments are located in a mild environment and powered by a highly reliable battery backed source which meets Type D Category 2 requirements. LPSW header pressure is a valid measurement of system and pump operation and Duke considers the existing indications to meet the intent of Regulatory Guide 1.97, Rev. 2.

Additional instrument loops provide backup indication in the Control Room of proper system operation. These include LPSW pump motor amperage, valve position indication on valves operated in the control room, inlet and/or outlet cooling water flow for certain ESF coolers, and flow and pressure alarms. For backup variables, a design qualification of Type D Category 3 is adequate for the intended monitoring functions and consistent with the performance expectations of the instrumentation.

(RE: NSMs ON-1/32590)

7.5.2.48 RC Bleed Holdup Tank Level

The indicated range for this variable is 0 to 180 inches for the RC Bleed Holdup tank. This level indication corresponds to a tank volume of approximately 1% to 99%. Although the range is not in complete compliance with the recommendation for a RG 1.97, Rev. 2 Type D Category 3 variable (top to bottom), the tap to tap range of the installed instruments is adequate to provide tank level information for all design basis events. Duke considers the installed instrumentation adequate for the intended monitoring function.

7.5.2.49 Waste Gas Decay Tank Pressure

Oconee utilizes two tanks per unit for radioactive waste gas storage. The maximum operating pressure for these tanks is approximately 100 psig (per Oconee FSAR, Section 11.3). The indicated range is 0 to 150 psig for each tank, which is adequate for the intended monitoring function. Waste Gas Decay Tank Pressure is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 3 variable at Oconee.

7.5.2.50 Emergency Ventilation Valve Position

There are three Emergency Ventilation Systems at Oconee; Reactor Building Purge, Penetration Room Ventilation, and Reactor Building Cooling. Each system has indication that the required emergency alignment has been achieved in the control room. (Penetration Room Ventilation is no longer required due to adoption of alternate source term.)

For the Reactor Building Purge System direct indication of containment isolation valves position is provided. The in-containment isolation valves (PR-1, 6) are MOVs whose position indication is provided by internal limit switches. These valves are not in the EQ program because they are racked-out during normal operation and are not required to function during a design basis event. This instrumentation is powered from safety grade emergency power. The out-of-containment isolation valves (PR-2, 5) are AOVs and positive indication is provided by limit switches. Positive indication of these valves is required per RG 1.97 (PAM). Therefore environmental qualification is provided for these limit switches. This instrumentation is powered from safety grade emergency power. Reactor Building Purge is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 2 variable at Oconee.

For the Penetration Room Ventilation System, positive indication of system operation is provided by the Penetration Room Pressure Instrumentation. This instrumentation is pneumatic and is supplied by normal Station Air System. The Unit 1 and 2 instruments are located in mild environments; however, the Unit 3 instrumentation is located in a harsh environment. Penetration Room Ventilation System is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 2 variable at Oconee.

For a description of the instrumentation required to determine proper operation of the Reactor Building Cooling System see UFSAR Section 7.5.2.41.

7.5.2.51 Emergency Power System Status

All safety-grade emergency or battery backed control busses have undervoltage alarms in the Control Room with local diagnostic capabilities to enable an expedient assessment of abnormal situations. In addition, the 125 VDC distribution centers have analog indicators of voltage level in the Control Room. All of the Control Room alarms are on highly reliable battery backed busses. All of the sensing relays and alarm electronics are located in a mild environment. See FSAR Chapter 8. Emergency Power System Status is classified as a Regulatory Guide 1.97, Rev. 2 Type D Category 2 variable at Oconee.

7.5.2.52 Unit Vent Radioactive Discharge Monitors

Oconee has a normal range, high range and high-high range channel of unit vent radioactivity instrumentation. These channels are powered from a highly reliable non load shed power bus. The indicated range is 1 to 10^8 R/hr gross gamma for the high-high range monitor which envelopes the upper end of the recommended range. The indicated range is 10 to $1E^7$ cpm for the high range channel and 10 to $1E^7$ cpm for the normal range channel. The combined ranges of these monitors meet the requirements of Regulatory Guide 1.97, Rev. 2 Type C Category 2 variable. This instrumentation is installed in a mild environment.

7.5.2.53 Unit Vent Flow

The installed instrumentation indicates flow in the unit vent stack over the range of 0 to 110% of design flow. The design flow for the Unit 1 stack is 97,262 SCFM (98,880 for Unit 2; 114,506 for Unit 3). The indicator and recorder, Units 1, 2 and 3 respectively, actual dual ranges are the following:

Unit 1&2	-	0 to 60 x 10^3 SCFM
		0 to 120 x 10^3 SCFM
Unit 3	-	0 to 65 x 10^3 SCFM
		0 to 130 x 10^3 SCFM

The primary instrument loop which contains the transmitter, the plant computer and the retransmitter is powered by a highly reliable battery backed bus. The secondary instrument loop contains the retransmitter, indicator and recorder. The retransmitter and indicator are powered by a highly reliable auxiliary bus. The instrumentation is located in a mild environment and envelopes the Regulatory Guide 1.97, Rev. 2 Type E Category 2 variable range criteria of 0 to 110% of design flow.

7.5.2.54 Main Steam Line Radiation Monitors

Area radiation monitors are located adjacent to the main steam lines to detect radioactivity emitted from main steam. The monitors for all 3 units are located upstream of the main steam relief valves. Correlation curves allow conversion of the monitor readings in mR/hr to μCi/cc. The indicated range for the monitors is 10^{-2} to 10^{7} mR/hr. The monitors are powered from a highly reliable non load shed power bus capable of receiving power from the on-site emergency power sources. This instrumentation is rated to withstand the environmental conditions that would exist during accidents in which it is intended to operate. A steam line break in the vicinity of this instrumentation may cause the environment to exceed the rated temperature, however, the instrument is not required to remain operational for this event. Main Steam Line Radiation Monitors are classified as a Regulatory Guide 1.97, Rev. 2 Type E Category 2 variable at Oconee.

7.5.2.55 Wind Direction

Oconee has two channels of wind direction instrumentation. The indicated range is 0 to 540°. Wind direction is a Regulatory Guide 1.97 Category 3 Type E Variable. The range and accuracy of the installed instrumentation is adequate for its intended purpose.

7.5.2.56 Wind Speed

Oconee has two channels of wind speed instrumentation. The indicated range is 0 - 60 mph. Wind Speed is a Regulatory Guide 1.97 Category 3 Type E Variable. The range and accuracy of the installed instrumentation is adequate for its intended purpose.

7.5.2.57 Atmospheric Stability

The indicated range for atmospheric stability is -4° to 8°C for 44.7 meter interval. Loop accuracy is at least +0.15°C. This range is adequate for Oconee site meteorological conditions. Atmospheric Stability is classified as a Regulatory Guide 1.97, Rev. 2 Type E Category 3 variable at Oconee.

7.5.2.58 Low Pressure Service Water Flow to Low Pressure Injection Coolers

Two QA Condition 1 instrumentation channels are provided (one per train) for post accident monitoring of Low Pressure Service Water (LPSW) flow to the Low Pressure Injection (LPI) coolers in response to Regulatory Guide 1.97. Each instrument channel is seismically qualified and powered from a safety grade power source. Each instrument channel signal inputs to a qualified indicator and to the plant computer via a qualified signal isolator. These channels monitor LPSW flow to the LPI Coolers over a range of 0-8000 gpm which envelopes the 0-110% of design flow criteria for Regulatory Guide 1.97.

Two non-safety instrument channels are provided, one per train, for indication of LPSW flow to LPI Cooler and control of valves LPSW-251 and 252. Each instrument signal inputs to a controller which monitors flow and valve control. These channels monitor LPSW flow to the LPI Cooler over a range of 0-6000 gpm. These instrument channels are not required for Regulatory Guide 1.97 and are used for normal operation.

LPSW flow to LPI Coolers is a Type A Category 1 variable at Oconee because the operator relies on this information following a design basis event (LOCA) to throttle LPSW flow to LPI Coolers to maintain proper flow balance in the LPSW System.

7.5.2.59 Essential Siphon Vacuum Tank Pressure (Vacuum)

The instrumentation for this variable provides continuous display of Essential Siphon Vacuum (ESV) Tank Pressure. One instrument channel is provided for each train of ESV tank. The ESV system on a per unit basis consists of three pumps and two tanks. Each train consists of one tank and one pump. The third ESV pump serves as an in-place spare pump which can be aligned to either train. The instrumentation provides control room indication of tank vacuum from 30 In Hg to 0 In Hg. The instrumentation is seismically qualified in accordance with the Oconee licensing basis as specified in the Oconee UFSAR and Duke Power Seismic Design Criteria (OCSD-0193.01-00-0001). The instrumentation is located in the ESV building which is considered a Mild Environment. The installed equipment meets the requirements of RG 1.97, Rev 2 for Type D, Category 2 nuclear safety related (QA-1) instrumentation as described in Section 7.5.

This instrumentation monitors the Essential Siphon Vacuum Tanks for operation to provide information (two indicators, two computer alarms, and two annunciator alarms, all one per tank) to indicate the operation of the system in the event it is needed to mitigate the consequences of the design basis accident (LOCA/LOOP).

7.5.2.60 Essential Siphon Vacuum Tank Water Level

The instrumentation for this variable provides continuous local display of Essential Siphon Vacuum Tank Water level. One instrument is provided on each train of ESV tank. The level gage is physically located on the tank. The ESV system for each unit consists of three full capacity pumps and two tanks. Each train consists of one tank and one pump. The instrumentation range (0-24 inches) provides local indication of any accumulated water in the ESV Tanks. Manual action can be taken to drain the tanks as required. The instrumentation is seismically qualified in accordance with the Oconee licensing basis as specified in the Oconee UFSAR and Duke Power Seismic Design Criteria (OCSD-0193.01-00-0001). The instrumentation is located in the ESV building which is considered a Mild Environment. The installed equipment is adequate for its intended monitoring function and meets the requirements of RG 1.97, Rev. 2 for Type D, Category 2 nuclear safety related (QA-1) variables instrumentation as described in Section 7.5.

This variable monitors the Essential Siphon Vacuum Tanks for operation to provide local indication regarding the operation of the system in the event it is needed for continued post accident mitigation of the consequences of the design basis accident (LOCA/LOOP).

7.5.2.61 Siphon Seal Water Flow to Essential Siphon Vacuum Pumps

The instrumentation for this variable provides continuous local display of Siphon Seal Water (SSW) flow to the Essential Siphon Vacuum pumps as well as a signal to the plant computer for display in the control room. One instrument is provided on each SSW supply to an ESV pump. There are three ESV pumps per unit. A total of nine instruments are provided for the nine ESV pumps. A bargraph indicator is located on the local panel in the ESV Building for each Unit's three pumps. The ESV system consists of three pumps and two tanks. Each ESV train consists of one tank and one pump. The third pump is an installed spare. The instrumentation is seismically qualified in accordance with the Oconee licensing basis as specified in the Oconee UFSAR and Duke Power Seismic Design Criteria (OCSD-0193.01-00-0001). The instrumentation is located in a Mild environment. The installed equipment meets the requirements of RG 1.97, Rev. 2, Type D, Category 2 nuclear safety related (QA-1) instrumentation as described in Section 7.5.

The range (0 to 15 Gallons per Minute (GPM)) and the qualification requirements of the SSW flow to ESV pumps instrumentation is in compliance with the recommendations of RG 1.97, Rev. 2 for Type D variables. This variable monitors the Siphon Seal Water flow to the Essential Siphon Vacuum Pumps to provide information relative to the operation of the ESV system in the event it is needed for continued post accident mitigation of the consequences of the design basis accident (LOCA/LOOP).

7.5.2.62 Low Pressure Service Water Reactor Building Waterhammer Prevention System Valve Position

The Low Pressure Service Water (LPSW) Reactor Building (RB) Waterhammer Prevention System (WPS) is designed to maintain the LPSW piping inside containment water solid during events which cause a loss of LPSW such as LOOP, LOCA/LOOP, or MSLB/LOOP. The system's major components consist of check valves in the suply headers (LPSW-1111, 1116), pneumatic discharge isolation valves (LPSW-1121, 1122, 1123, 1124), pneumatic vent valves (a.k.a. controllable vacuum breakers) (LPSW-1150, 1151), and associated acutation circuitry.

The installed instrumentation provides valve position indication for the pneumatic discharge isolation valves (LPSW-1121, 1122, 1123, 1124). Position indication is provided by QA-1 indicating lamps at the control switches on the control board for the four pneumatic discharge isolation valves. These LPSW valve position indications associated with LPSW RB Waterhammer Prevention System are considered to be Regulatory Guide 1.97, Rev. 2, Type D Category 3 instrumentation.

7.5.3 References

1. NRC Information Notice No. 97-45: Environmental Qualification Deficiency for Cables and Containment Penetration Pigtails – July 2, 1997.
2. NRC Information Notice No. 97-45, Supplement 1: Environmental Qualification Deficiency for Cables and Containment Penetration Pigtails – February 17, 1998.
3. O-62C-001, rev 2, Reactor Building Units 1-3 Liner Plate Radiation Detector Penetrations.
4. OSC-11762, rev 0, "Oconee Penetration Room HRRM Cable Temperature Induced Current."
5. Letter from H.B. Tucker (Duke) to H.R. Denton (NRC), dated September 28, 1984, Subject: Revision 6 to Duke Power Company Response to Supplement 1 to NUREG-0737 for Oconee Nuclear Station.
6. Letter from H.N. Pastis (NRC) to H.B. Tucker (Duke), dated March 15, 1988, Subject: Emergency Response Capability – Conformance to Regulatory Guide 1.97, Revision 2.

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7.6 Control Systems Not Required for Safety

7.6.1 Regulation Systems

Reactor output is regulated by the use of movable control rod assemblies and soluble boron dissolved in the coolant. Control of relatively fast reactivity effects, including Doppler, xenon, and moderator temperature effects, is accomplished by the control rods. The control response speed is designed to overcome these reactivity effects. Relatively slow reactivity effects, such as fuel burnup, fission product buildup, samarium buildup, and hot-to-cold moderator reactivity deficit, are controlled by soluble boron.

Control rods are normally used for control of xenon transients associated with normal reactor power changes. Chemical shim shall be used in conjunction with control rods to compensate for equilibrium xenon conditions. Reactivity control may be exchanged between rods and soluble boron consistent with limitations on power peaking.

Reactor regulation is a composite function of the Integrated Control System and Control Rod Drive System. Design data for these subsystems are given in the following sections.

7.6.1.1 Control Rod Drive System

The Control Rod Drive System (CRD) includes drive controls, power supplies, position indicators, operating panels and indicators, safety devices, and enclosures.

7.6.1.1.1 Design Basis

The Control Rod Drive System design bases are categorized into safety considerations, reactivity rate limits, startup considerations, and operational considerations.

7.6.1.1.2 Safety Considerations

The control rod assemblies (CRA) are inserted into the core upon receipt of protective system trip signals. Trip command has priority over all other commands.

No single failure shall inhibit the protective action of the Control Rod Drive System.

7.6.1.1.3 Reactivity Rate Limits

The speed of the mechanism and group rod worth provide the reactivity change rates required. For design purposes, the maximum rate of change of reactivity that can be inserted by any group of rods has been set at a conservative value used within the Chapter 15 Section 15.3 and Section 15.2. The drive controls, i.e., the drive mechanism and rods combination, have an inherent speed-limiting feature.

7.6.1.1.4 Startup Considerations

The Control Rod Drive System design bases for startup are as follows:

Reactor regulation during startup is a manual operation.

Control rod “out” motion is inhibited when a high startup rate in the wide range is detected.

7.6.1.1.5 Operational Considerations

For operation of the reactor, functional criteria related to the control rod drive system are:

CRA Positioning

The Control Rod Drive System provides for controlled withdrawal, controlled insertion, and holding of the control rod assemblies (CRA) to establish and maintain the power level required for a given reactor coolant boron concentration.

Position Indication

Continuous rod position indication, as well as full-in and full-out position indication, are provided for each control rod drive.

System Monitoring

The Control Rod Drive System design includes provisions for routinely monitoring conditions that are important to safety and reliability.

7.6.1.1.6 System Design

The Control Rod Drive System provides for withdrawal and insertion of the control rod assemblies to maintain the desired reactor output. This is achieved either through automatic control by the Integrated Control System discussed in Section 7.6.1.2 or through manual control by the operator. As noted previously, this control compensates for short term reactivity changes. It is achieved through the positioning in the core of sixty-one control rod assemblies and eight axial power-shaping rod assemblies. The sixty-one rods are grouped for control and safety purposes into seven groups. Four groups function as safety rods, and three groups serve as regulating rods. An eighth group serves to regulate axial power peaking due to xenon poisoning. Seven of the eight groups may be assigned from four to twelve control rod assemblies. Eight rod assemblies are used in Group 8.

Control rods are arranged into symmetric (by core quadrant) groups by utilizing the Engineering Work Station (EWS) to edit a data base contained in the PLC software which defines the desired rod group patterns. Typically, thirty-six rods, including the axial power shaping rods, are assigned to the regulating groups, and thirty-three rods are assigned to the safety rod groups. A typical rod grouping arrangement is shown below:

Safety Rods	Regulating Rods	Axial Power Shaping Rods
Group 1 - 8	Group 5 - 12	Group 8 - 8
Group 2 - 8	Group 6 - 8	
Group 3 - 8	Group 7 - 8	
Group 4 - 9		

During startup, the safety rod groups are withdrawn first, enabling withdrawal of the regulating control groups. The sequence allows operation of only one regulating rod group at a time except where reactivity insertion rates are low (first and last 25 percent of stroke), at which time two adjacent groups are operated simultaneously in overlapped fashion. These insertion rates are shown in Figure 7-11.

As fuel is used, dilution of soluble boron in the reactor coolant is necessary. When Group 6 is more than 95 percent withdrawn, interlocks permit dilution. The reactor controls insert Group 6 to compensate for the reduction in boron concentration by dilution. The dilution is automatically terminated by a pre-set volume measuring device. Interlocks are also provided on Group 6 rod position to terminate dilution at a pre-set insertion limit.

7.6.1.1.7 System Equipment

The Control Rod Drive System consists of three basic components: (1) control rod drive motor power supplies; (2) system logic; and (3) trip breakers. The power supplies consist of 138 Single Rod Power Supply (SRPS) modules, with two identical wired as a redundant pair and connected to each CRDM. Each SRPS uses a six-phase half-wave (SCR) rectifier design. See Figure 7-4, Figure 7-12 and Figure 7-13.

SRPS, rectification and switching of power is accomplished through the use of Silicon Controlled Rectifiers (SCRs). This switching sequentially energizes first two, then three, then two of the six CRA motor stator windings in stepping motor fashion, to produce a rotating magnetic field for the control rod assembly motor to position the CRA. Switching is achieved by gating the six SCRs on for the period each winding must be energized. As each of the six windings utilize SCRs to supply power, six gating signals are required.

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Gating signals for the SRPS are generated by a Programmable Logic Controller (PLC) using software containing logic to accept automatic commands from the ICS, or direct manual commands from the Operator Control Panel (OCP). These commands are converted to sequential digital outputs which cause the mechanism motors to step at the proper speed and direction to provide a 3-2 hold control, which ensures two-coils are energized when there are no commands. If one coil becomes de-energized the control rod position will be maintained, but cannot be exercised. A second PLC is devoted exclusively to processing absolute and relative control rod position indication signals.

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The PLC is also known as a Triple Modular Redundant (TMR) Controller using a triplicated processor running in parallel, with redundant and automatic selection of the “good” signal in the event of failure or malfunction of the controlling “slice”. An auctioneering network determines if any anomalies exist and selects the most credible (via a two-out-of-three voting network) of the three available signals. Each processor executes the application program simultaneously and independently. Redundant power supplies are used for all CRD mechanisms, and each is capable of carrying the full load and each is fed from separate power sources with a common SCR gating signal control source.

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Major components of the system are the RPS interface Trip Breakers, Position Indication (PI) Panel, OCP, TMR Controllers, Engineering Work Station (EWS) – for software control inputs, and the SRPS.

Switches are provided at the operators control panel for selection of desired rod control mode. Control modes are: (1) Automatic mode--where rod motion is commanded by the Integrated Control System; and (2) Manual mode--where rod motion is commanded by the operator. Manual control permits operation of a single rod or a group of rods. Alarm lamps on the CRD panel alert the operator to the systems status at all times. The Group 8 control rods can only be controlled manually even when the remainder of the system is in automatic control.

The sequence section of the logic system utilizes rod position signals to generate control interlocks which regulate rod group withdrawal and insertion. Sequence logic applies in both automatic and manual modes of reactor control, and controls the regulating groups only. When operating in the “sequence mode” mode, the PLC controls sequential withdrawal and insertion of numerically adjacent regulating groups. Two adjacent groups are enabled coincidentally within 25% overlap regions, in order to minimize effects of lower rod worth at their upper and lower extremes in travel.

The automatic sequence logic can control only rod Groups 5, 6, and 7. The safety rod groups, Groups 1 through 4, are controlled manually, one group at a time. There is no way in which the automatic sequence logic can affect the operations required to move the safety rods.

In addition to the sequence logic, logic is also provided which prohibits out of sequence conditions. The selection of manual control mode and sequence bypass mode functions permit intentional out-of-sequence conditions. This condition is indicated to the operator. If automatic control is selected, “sequence” operation cannot be bypassed.

“Sequence bypass” operation permits selection of any rod group or any single rod for control. It will not permit selection of more than one rod group at any given time. Motion of more than one group at any given time is also not possible when this operation is selected.

Inputs to the system logic from the Nuclear Instrumentation and the Integrated Control System provide interlock control over rod motion. These interlocks cause rod motion command lines and control mode selection to be inhibited.

Under certain conditions, the nuclear instrumentation generates an “out inhibit” signal. When this signal is received by the Control Rod Drive System, all out command circuits are disabled, thus preventing withdrawal of all rods in either automatic or manual control.

Automatic operation of rods can only be commanded by the ICS when the Control Rod Drive System is in the automatic mode. These commands can only affect rod Groups 5, 6, and 7.

In the Control Rod Drive System, two methods of position indication are provided: an absolute position indicator and a relative position indicator. Either position signal is available to the control board indicator through a selector switch. The absolute position transducer consists of a series of magnetically operated reed switches mounted in a tube parallel to the motor tube extension. Each switch is hermetically sealed. Switch contacts close when a permanent magnet mounted on the upper end of the lead screw extension comes in close proximity.

As the lead screw (and the control rod assembly) moves, the switches operate sequentially, producing an analog voltage proportional to position. Other reed switches included in the same tube with the position indicator matrix provide full-in and full-out limit indications.

The relative position indication is calculated by the TMR processor. Control Rod Drive System trip breakers are provided to interrupt power to the control rod drive mechanisms. When power is removed, the roller nuts disengage from the lead screw allowing a gravity trip of the CRA.

The Group 8 drive mechanisms are modified to prevent rod drop into the core when power is removed from the stators. In this type of mechanism, the roller nuts are mechanically restrained to remain engaged with the lead screw at all times. Thus, the mechanical “trip” action has been removed from these APSR’s, and they remain at the position they occupied immediately before trip was initiated.

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The CRD Trip Breakers are of the three-pole, stored energy type and are equipped with instantaneous undervoltage and shunt trip coils. Each of the four breakers is housed in separate metal-clad enclosures with two vertical breakers housed in the middle two compartments of each of two adjacent and integral seismically-qualified Class 1E breaker cabinets. Two other compartments in each cabinet are utilized for ancillary equipment (Reactor Trip Confirm Signals and Source Interruption Device Signals via the AC Power Interface equipment in top and 15

KVA Control Transformer in bottom). All breakers have motor-driven reset features to provide remote reset capability.

7.6.1.1.8 System Evaluation

Safety Considerations

A reactor trip occurs whenever power has been removed from the rod drive motors. The design provides stored energy breakers which do not require power to interrupt the electrical feeds to control rod drive power supplies.

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The system ensures that power is removed from all of the CRDM's by utilyzing a 1 out of 2 taken twice power design. This design uses 2 qualified breakers located in the "A" power feed into the system and 2 qualified breakers located in the "B" power feed into the system. Therefore a single failure in the distribution system for the control rods does not prevent a plant shutdown.

The minimum voltage required to hold a drive in a withdrawn position is 42 volt DC per coil (2 coil "hold" mode). The probability of an external DC source being applied to the control rod drive mechanisms downstream from the reactor trip points such that the CRA are held in their withdrawn positions after a trip is not considered credible for the following reasons:

1. The trip devices in the Control Rod Drive System remove all DC power from the drives.
2. Control rod drive power cables are terminated at only three points between the Control Rod Drive System cabinets and the drive mechanisms.

   Two of these terminations are made outside and inside the Reactor Building electrical penetrations inside junction boxes containing only control rod drive power cables. The third termination is made in bulkhead connectors (one per drive) in the area of the reactor. The only other cables terminated in this area are the control rod drive instrumentation cables. The instrumentation cables are terminated in bulkhead connectors of a different size and configuration, therefore mismating of connectors could not be accomplished.
3. No cable splices are permitted between termination points described.
4. DC systems from the batteries at Oconee are not grounded and are equipped with ground detecting circuitry.

In summary, series redundant trip devices having adequate rating, testability and a 1 out of 2 taken twice power design arrangement insure safety of reactor trip circuits.

Reactivity Rate Limits

The desired rate of change of CRA reactivity insertion and uniform reactivity distribution over the core are provided for by the control rod drive and power supply design, and the selection of rods in a group. The CRA motor, lead screw, and power supply designs are fixed to provide a uniform rate of speed of 30 in./min. The speed is determined by the CRD PLC, which digitally controls speed. The reactivity change is then controlled by the rod group size. To insure flexibility in this area, rod group assignments are entered off-line at the EWS into password-protected software. This determines desired rod group worth distribution to coordinate with varying core reload design. Any rod may be assigned to any group, with the exception of group 8, so long as the same group pattern exists in each core quadrant. Rod groups may vary from a minimum of four to a maximum of 12, which translates into five possible rod groupings of 4, 5, 8, 9, and 12 – where the odd-numbered group would contain the center rod at core grid H-8. APSR rod assignments are fixed at two near the center of each quadrant.

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Uniform and symmetrical reactivity addition rate is provided by synchronous withdrawal of all rods assigned to that group. All rods in any one group will have the same CRD motor stator windings simultaneously energized. Such synchronous withdrawal is achieved by phase trigger pulses from the Pulse Generator/Monitor (PG/M) modules in response to rod movement command signals generated by the TMR Controller. The TMR architecture employs a highly synchronized triplicated processor set running in parallel. Each processor “slice” executes the application program simultaneously and independently, verifying data, control, clock, and synchronization signals. These signals are partitioned and down-loaded in such a manner as to optimize execution times of the algorithms controlling synchronous motion of the entire group.

Each control rod is provided with rod position indicator logic to sense asymmetric rod patterns by comparing the individual rod position with its group average position. When the rod moves out-of-step from its group by a preset amount, this condition is alarmed to the operator, the plant computer, and the ICS. Depending on the power setting and the control mode, action is initiated by the ICS to insert rods and reduce power.

Startup Considerations

The rod drive controls receive interlock signals from the ICS and nuclear instrumentation (NI). These inputs are used to inhibit automatic mode selection when a large error exists in the ICS reactor control subsystem and to inhibit out motion for high startup rates, respectively.

In addition to the startup considerations, dilution controls, to permit removal of reactor shutdown concentrations of boron in the reactor coolant, are provided. This control bypasses the normal reactor coolant dilution controls, described in Section 7.6.1.1.6, provided all safety rods are withdrawn from the core and the operator initiates a continuous feed and bleed cycle. An additional interlock on rod Group 5 inhibits the use of this circuit when rod Group 5 is more than 80 percent withdrawn.

Operational Considerations

The control rod assembly positioning system provides the ability to move any rod to any position required consistent with reactor safety. As noted in Section 7.6.1.1.8, a uniform speed is provided by the drive system. A fixed rod position when motion is not required is obtained by the power supply ability to energize two adjacent windings of the CRA motor stator. This static energizing of the windings maintain a latched stator and fixed rod position.

Position Indication

As previously described, two separate position indication signals are provided. The absolute position sensing system produces signals proportional to CRD position from the reed switch matrix located on each CRD mechanism. The relative position indication system produces a signal proportional to the number of electrical pulses sent to the CRD motor stator windings, as determined through processing of these signals by a separate programmable logic (TMR) controller whose sole function is the processing of absolute and relative position indication signals.

Position indicating readout devices mounted on the operator's console consist of 69 single rod position meters. The operation of a selector switch permits either relative or absolute position information to be displayed on the single rod meters.

Indicator lights are provided on the position indication panel to indicate when each rod is (1) fully inserted, (2) fully withdrawn, (3) under control, and (4) whether a fault is present. Indicators on the operator control panel show full insertion, full withdrawal, under control, and fault indication for each of the eight control rod groups.

Failures which could result in unplanned control rod withdrawal are continuously monitored by fault detection logic. When failures are detected, indicator lights and alarms alert the operator. Fault indicator lights remain on until the fault condition is cleared by the operator. A list of indicated faults is shown below:

1. Asymmetric rod patterns (indicator and alarm).
2. Sequence faults (indicator and alarm).
3. Trip status (indicator and alarm).
4. Safety rods not withdrawn (indicator only).
5. Rod position sensor faults.

Faults serious enough to warrant immediate action produce automatic correction commands from the fault detection logic, and manual bypass is not possible. Status indicators on the operator's console provide monitoring of control modes.

A description of each fault detector follows:

Asymmetric Rod Monitor

Design Basis - To detect and alarm if any rod deviates from its group reference position by more than a maximum of nine inches true position.

Operation - There are 69 asymmetric rod pattern monitors, one assigned to each control rod. This logic continuously compares the individual rod absolute position signal with the absolute group reference (average) signal. The absolute value of the difference between the two signals is computed, and if this difference is less than the maximum value allowed by the software configuration, no output results. If, however, the difference is greater than the setpoint, the system alarms the asymmetric condition. Two alarm channels are provided which are identical except for the setpoints. One setpoint allows a maximum 7-inch true position separation before initiating an alarm. The other setpoint allows a maximum 9-inch true position separating before initiating the action described below.

Corrective Action - Action taken upon detection of an asymmetric rod fault depends upon the control mode and the power level in effect at the time the fault is detected. Corrective action is the same for any asymmetric condition including “stuck-in,” “stuck-out,” or dropped control rods.

Detection of a 7-inch position separation is defined as an “asymmetric rods alarm.” Actuation of this alarm causes the fault indicator lamp for that rod to be energized and an alarm signal to be sent to the plant computer and annunciator.

If the condition is not corrected and the separation increases to a 9-inch position separation, the following actions occur:

“Asymmetric fault” lamp on the operator's console is energized. If operation is in the manual control mode, operator action is required by administrative control.

If operation is in the automatic mode, a “runback fault” signal is sent to the Integrated Control System. The ICS will impose a maximum reactor power demand of 55 percent of rated power if power is initially less than 55 percent.

When an asymmetric fault occurs, the Control Rod Drive Control System generates an “Out Inhibit” which prevents automatic rod motion that would increase reactor power. Below 60 percent reactor power the ICS generates a bypass signal for the out inhibit, which allows normal automatic rod control.

Reactor power demand remains limited to 55 percent maximum in automatic control until the fault is corrected.

Sequence Monitor

Design Basis - To detect any motion of the regulating rod groups outside of the predetermined automatic sequence patterns, and to prevent further automatic motion when such conditions occur.

Operation - The sequence logic continuously compares the group average (reference) signals for each regulating rod group with the allowable sequence patterns. In addition, the rod group “enable” logic determines if a group is enabled for motion out-of-turn. The safety rod groups' out limit signals serve as a permissive to automatic sequencing: the sequence monitor prevents automatic control until the safety rods are fully withdrawn.

Corrective Action - When an out-of-sequence condition is detected and operation is in the automatic control mode, the automatic mode disengages and an alarm lamp alerts the operator to the malfunction. Control reverts to manual and remains in manual until the fault is corrected and the system is reset by the operator.

Trip Status

Design Basis - To sense the status of trip devices and trip channels.

Operation - The circuit contains elements, which sense the state of each trip device as well as the state of each of the four trip channels. If a trip device or a trip channel is in a trip state, its associated annunciator will alarm. The annunciators are used by operations to detect faults that may affect operation of the trip circuits, such as one trip breaker in the tripped position during normal operation.

Corrective Action - Alarms are provided.

Safety Rods Not Withdrawn

Design Basis - To prevent, on plant startup, withdrawal of the regulating rods until the safety rods are fully withdrawn.

Operation - Continuously monitors the group “out” limit for the four safety rod groups. When the four groups are all fully withdrawn, automatic control is permitted.

Corrective Action - Alarms are provided.

Rod Position Sensor Faults

All rod position sensor faults lead to false asymmetric, stuck, or dropped rod symptoms which are acted upon by the Asymmetric Rod Monitor previously described.

7.6.1.2 Integrated Control System

7.6.1.2.1 Design Basis

The Integrated Control System (ICS) provides the proper coordination of the reactor, feedwater control, and turbine under all operating conditions. Proper coordination consists of producing the best load response to the Core Thermal Power demand while recognizing the capabilities and limitations of the reactor, steam-generator feedwater system, and turbine. When any single portion of the plant is at an operating limit or control selection is on manual, the Integrated Control System design uses the limited or manual section as a load reference.

The Integrated Control System maintains constant average reactor coolant temperature between 15 and 100 percent rated power, and constant steam pressure at all loads. Optimum unit performance is maintained by limiting steam pressure variations; by limiting the unbalance between the steam generator, the turbine, and the reactor; and by limiting the Core Thermal Power demand upon loss of capability of the steam generator feed system, the reactor, or the turbine generator. The control system provides limiting actions to assure proper relationships between the generated load, turbine valves, feedwater flow, and reactor power.

The response of the Reactor Coolant System to increasing and decreasing power transients is limited by the Integrated Control System as indicated in Table 7-6. The Turbine Bypass System permits a load drop of 40 percent or a turbine trip from 40 percent load without safety valve operation.

7.6.1.2.2 Description

The Integrated Control System includes four independent subsystems as shown in Figure 7-14. The four subsystems are: the Core Thermal Power Demand; the Integrated Master; the Feedwater Control; and the Reactor Control. The system philosophy is that control of the plant is achieved through feed-forward control from the Core Thermal Power Demand. The Core Thermal Power Demand produces demands for parallel control of the turbine, reactor, and Steam Generator Feedwater System through respective subsystems.

The Feedwater Control is capable of automatic or manual feedwater control from a startup to full power. The Integrated Master Control is capable of automatic or manual turbine valve control from minimum turbine load to full output, and of manual control below minimum turbine load. The Reactor Control is designed for automatic or manual operation above 2 percent power, and for manual operation below 2 percent power.

The basic function of the Integrated Control System is matching Turbine and Reactor Power to Core Thermal Power demand. The Integrated Control System does this by coordinating the steam flow to the turbine with the rate of steam generation. To accomplish this efficiently, the following basic reactor/steam-generator requirements are satisfied:

The ratios of feedwater flow and BTU input to the steam generator are balanced as required to obtain desired steam conditions.

BTU input and feedwater flow are controlled:

1. To compensate for changes in fluid and energy inventory requirements at each load.
2. To compensate for temporary deviations in feedwater temperature resulting from load change, feedwater heating system upsets or final steam pressure changes.

7.6.1.2.2.1 Unit Load Demand

The Core Thermal Power Demand Subsystem provides the operator with a means of establishing the desired operating power load from the plant. The demand signal produced by this subsystem is called the Core Thermal Power Demand (CTPD), and is the principle independent demand signal in the ICS. Other subsystems receive the CTPD and establish final control element positions in order to meet this demand.

The CTPD subsystem obtains a load demand signal, manually set by the operator, from the Load Control Panel. The Load Control Panel is the primary operator interface to the ICS for Integrated Mode operation. Pushbutton switches, digital meters, a digital thumb switch and status lamps are provided for manipulation of Core Thermal Power Demand Set, the Demand Rate Set, turbine Load and Unload, Maximum Runback function and status for various Load Limit and Tracking conditions. The CTPD substytem initiates load limiting and runback functions to restrict operation within prescribed limits. Figure 7-15 illustrates the functions incorporated in the subsystem.

The CTPD is restrained by a maximum load limiter, a minimum load limiter, a rate limiter and a runback limiter.

Rate limiting is designed as a function of load, so transients are limited as shown in Table 7-6.

The limiter acts to runback and/or limit the CTPD under any of the following conditions:

1. Loss of one or more reactor coolant pumps.
2. CTPD vs reactor coolant flow, variable limit.
3. Low suction pressure (FDW or Condensate)
4. Loss of one feedwater pump.
5. Asymmetric rod patterns exists in reactor.
6. The generator separates from the bus.
7. A reactor trip occurs.

The output of the limiters is a CTPD signal which is applied to the turbine control, feedwater control, and reactor control in parallel.

The controlling subsystems of the ICS (turbine control, feedwater control, and reactor control) normally operate in the automatic mode in response to a demand signal from the CTPD. The subsystems control function is kept within pre-established bounds under other than normal automatic operation by a “load tracking” feature built into the ICS. The ICS will switch to the load tracking mode if either of the following conditions exists:

One or more of the subsystems are in manual.

Errors greater than preset limits develop between the demand and the variable.

In this mode, the CTPD is made to follow the manual or limited control subsystem. Load tracking continues until the limiting condition is brought back to within the pre-established deadband or the subsystem is returned to automatic operation.

7.6.1.2.2.2 The Integrated Master

The Integrated Master has been designed to receive the Core Thermal Power Demand (CTPD) from the Core Thermal Power Demand Subsystem and utilize this signal as a demand for the feedwater, turbine and reactor control. A functional diagram of the Integrated Master Control is shown in Figure 7-16. The Integrated Master subsystem produces demand signals for the reactor control, feedwater control and turbine control (steam valves), to meet the CTPD, while providing coordination between the primary system, feedwater and turbine to maintain heat balance. The subsystem produces demands for total feedwater flow, reactor power and steam valve position to ensure that heat balance indicating parameters are kept within operating limits. The demands are modified during plant limited operation in accordance with the Control Priority. The ICS Control Priority for the four main heat balance variables is as follows:

Tave

Steam Header Pressure

Reactor Power

Cold Leg Temperature Difference (delta - Tc)

Three major control Hand/Automatic (H/A) stations are provided to give the operator a means of manually setting the integrated master demand outputs. The reactor master control station allows the operator to manually establish a demand for reactor NI-Flux and to set the controlling reactor coolant system Tave set point. The steam generator master H/A station allows the operator to manually establish the total feedwater flow demand. The turbine control H/A station allows the operator to establish the EHC load reference signal and to set the controlling turbine header pressure set point.

Turbine Control

Control of the turbine is accomplished by a pressure controller. The turbine header pressure is compared to a set point (set by the operator from the turbine H/A station) and this error drives an analog signal. The resulting analog signal is sent to the load reference logic where it is integrated into a steam valve position demand. The ICS will continue to generate a demand for turbine valve movement until the pressure error is reduced to zero.

The turbine control H/A station gives the operator the option of letting the turbine control pressure or, by transferring the turbine control station to manual, allowing the operator to establish the amount of electrical load generation.

The "LOAD" and "UNLOAD" push buttons on the "Load Control Panel" provide the operator interface with the turbine load and unload system. The turbine load and unload system enables the operator to smoothly introduce and remove the main turbine into/from the plant control process. The system is necessary because the reactor may be operated in automatic at a power level significantly below the normal minimum load of the turbine.

Turbine Bypass

The Turbine Bypass System operates from the turbine header pressure error or individual steam generator pressures as an overpressure relief for the turbine header. The turbine bypass valves receive control inputs from their respective OTSG outlet pressure , unless the main turbine is in automatic. If the main turbine is in automatic, the bypass valves use the turbine header pressure error signal, which is the same signal controlling the main turbine controller.

The turbine bypass valves serve four functions:

1. Provide pressure control at low loads before the turbine can be placed in automatic.
2. Provide a high pressure relief if the turbine header pressure exceeds its set point (normally 885 psig) by 50 psig.
3. Provide an independent high pressure relief that operates proportionally to steam generator pressure above 1035 psig.
4. Provide pressure control after a reactor trip at 125 psi above normal set point to prevent excessive cooling of the reactor coolant fluid.

Once the main turbine is placed in automatic control, and loaded, the turbine bypass valves assume over pressure control at set point plus 50 psi.

7.6.1.2.2.3 Feedwater Control

The Feedwater Control Subsystem has been designed to receive the total feedwater demand signal from the Integrated Master Subsystem and utilize this signal to develop demand signals for control of the feedwater pumps and the feedwater valves for each steam generator. A functional diagram of the Feedwater Control Subsystem is shown in Figure 7-17.

The total feedwater demand signal developed in the Integrated Master Subsystem is corrected for feedwater temperature in the Feedwater Control Subsystem. A proportional correction is also applied to the feedwater demand when RC Pressure is greater than 2250 psig. The feedwater demand signal is limited when Neutron Error exceeds +/- 5%.

The corrected total feedwater demand signal is modified to provide a feedwater demand signal for each steam generator. Under normal conditions, each steam generator will produce one-half of the total load. The steam generator load ratio control (delta Tc control) is provided to balance reactor inlet coolant temperatures during operation with more reactor coolant pumps in one loop than in the other. The steam generator load ratio control (delta Tc control) signal is modified by an anticipatory delta Tc error circuit which is based upon a ratio of the measured RC flow.

A Feedwater Master Hand/Automatic control station for each steam generator enables manual control by the operator or operation in automatic. In the automatic mode of operation, feedwater flow is controlled by either level control or flow control. Each steam generator may independently operate on level or flow control.

Level control ("Low Level Limits", LLL) exists when loop Tave is less than the Tave set point and the steam generator level is equal to or less than the steam generator low level set point. During this mode, steam generator startup level provides a demand signal to the feedwater valves for control of feedwater flow to the steam generator.

Flow control exists when Tave is equal to or greater than the Tave set point and steam generator level is greater than the low level limit.

During the flow control mode, the loop feedwater master demand is compared to steam generator feedwater flow and to a maximum steam generator operate level set point. The resultant feedwater error signal is utilized to develop the position demand signal for the feedwater valves. The feedwater error signal drives the feedwater valves to make feedwater flow match loop feedwater flow demand, or to limit the maximum steam generator level.

Feedwater flow to each steam generator is controlled by two valves, a startup valve and a main valve. The startup feedwater control valve provides feedwater flow control from startup to approximately 15 percent reactor power. The main feedwater control valve provides feedwater flow control from approximately 15 percent to 100 percent power. Each feedwater valve has a Hand/Automatic control station which enables automatic control or the operator to manually establish a valve position demand.

Feedwater flow to both steam generators is provided from two turbine driven main feedwater pumps. The speed of both feedwater pumps is controlled by a single automatic controller to maintain a constant differential pressure across the feedwater valves. Feedwater valve differential pressure is compared to set point and the resultant error is the controller demand signal. The loop A and loop B feedwater master demand signals are input to the controller as a feed forward signal to reduce the amount of feedwater valve differential pressure change during load changes. Each main feedwater pump has a Hand/Automatic control station which enables automatic control or the operator to manually establish a pump speed demand.

Feedwater Control - Reactor Coolant Pumps tripped

Upon loss of all reactor coolant pumps, the ICS positions valves to direct main feedwater flow to the auxiliary feedwater header in each steam generator. The steam generator operate level is used as a demand signal to the startup feedwater valve to establish "natural circulation" cooling of the reactor coolant system.

Steam Generator Overfill Protection

The NRC issued Generic Letter 89-19, "Request for Action Related to the Resolution of Unresolved Issue A-47, 'Safety Implication of Control Systems in LWR Plants' Pursuant to 10CFR 50.54(f)," on September 20, 1989. This generic letter required PWR licensees to provide a description of their steam generator overfill protection (SGOP) systems, which was responded to in the letter from H.B. Tucker to NRC, dated March 19, 1990. As described in that response to the NRC, the Oconee overfill protection system is provided by the Integrated Control System (ICS) and is initiated on high water level in anyone steam generator, based on non-safety grade hardware with a 2-out-of-2 initiating logic. When the high level setpoint is reached, the ICS terminates feedwater by tripping the main feedwater pumps. The Steam Generator Overfill Protection system also added an alternate non-safety grade trip device, SV6, to assure trip of the main feedwater pump turbine in the event of a loss of control power. The NRC SER (see section 10.4.9, Reference II) concluded that this addition minimized the potential for common mode failure such that the overall design of Steam Generator Overfill Protection sufficiently satisfies the single-failure criterion of Generic Letter 89-19.

7.6.1.2.2.4 Reactor Control

The reactor control is designed to maintain a constant average reactor coolant temperature over the load range from 15 to 100 percent of rated power. The steam system operates on constant pressure at all loads. The average reactor coolant temperature decreases over the range from 15 percent to zero load. Figure 7-18 shows the reactor coolant and steam temperatures and the steam pressure over the entire load range.

The Reactor Control Subsystem controls the neutron flux production of the reactor. The subsystem varies the neutron flux such that primary temperature and pressure requirements are maintained, while the heat drawn from the primary system meets the CTPD.

The reactor control subsystem controller receives inputs from core thermal power demand, reactor coolant pressure and reactor coolant average temperature. The output of the controller is an error signal that causes the control rod drives to be positioned until the error signal is within a deadband. A block diagram of the reactor control is shown on Figure 7-19.

A reactor power demand can be established in two ways. The operator can manually establish a reactor power demand using the reactor master hand/automatic control station. The second method of establishing a reactor power demand is with the reactor master control station in automatic. In this mode of operation, the reactor demand becomes a function of CTPD with a modification from Tave, steam pressure and transient RC pressure control.

Cross limits are employed between the reactor control and feedwater control subsystems to help ensure that the basic demand relationships between the reactor and feedwater are preserved during transients. In addition to cross limits, the controller also incorporates a high limit on reactor power level demand.

The reactor power level demand is compared with the reactor power level (neutron flux). The resultant error signal is the reactor power level error (neutron error) signal.

When the reactor power level error signal exceeds the deadband settings, the control rod drive receives a command that withdraws or inserts rods depending upon the polarity of the power error signal.

The reactor controls incorporate automatic or manual rod control above 2 percent of rated power and manual control below 2 percent of rated power.

7.6.1.2.3 System Evaluation

Redundant sensors for major system parameters are available to the Integrated Control System. The list of redundant major system parameters is contained in Section 7.4.2.2.2.

Automatic signal selection between the redundant sensors is provided as described in Section 7.4.2.2.2. The operator can manually select between the redundant sensors which are monitored by SASS; however, if a failure occurs the automatic signal selector (SASS) will transfer the output signal from the failed device to the valid input. The SASS also will not allow the operator to select the failed sensor if the failure occurred on the non-selected sensor. The "Control STAR" uses the median signal selection technique to select between redundant sensors. If a sensor failure occurs the "Control STAR" automatically transfers to the valid redundant sensor. The operator does not have manual selection capability between the redundant sensors which input to "Control STAR"; however, specific sensors can be selected by special maintenance techniques.

Manual reactivity control is available at all power levels. Loss of electrical power to the ICS Automatic control reverts the control system to manual.

Maloperation or failure of any ICS subsystem places no automatic limitations on reactor operation because the ICS reverts to the manual mode. Therefore other ICS subsystems follow the limited subsystem.

The design of the NNI/ICS System in conjunction with procedures and training allow the operator to cope with various loss of power situations. Also, alarm indications provide information to the operator of various instrument and control functions. Emergency procedures provide assurance of positive responses by the operator.

Failure of the ICS does not diminish the safety of the reactor. None of the functions provided by the ICS are required for reactor protection or for actuation of the ESPS. The reactor protection criteria, used in the analysis of accidents presented in Chapter 15 can be met irrespective of ICS action.

7.6.1.2.3.1 Modes of Control

The Integrated Control System is designed to revert to a “Tracking” mode to tie the unit to the subsystem on manual or to the subsystem being limited. In the startup control mode, the reactor is prevented from automatic rod withdrawal below 1.5 percent power.

The controls will limit steam bypass to the condenser when condenser vacuum is inadequate.

7.6.1.2.3.2 Loss-of-Load Considerations

The nuclear unit is designed to accept 10 percent step load rejection without safety valve action or turbine bypass valve action. The combined actions of the control system and the turbine bypass valve permit a load reduction from 40 percent load without safety valve action. The controls will limit steam dump to the condenser when condenser vacuum is inadequate, in which case the steam safety valves may operate. The combined actions of the control system, the turbine bypass valves and the steam safety valves permit separation from the external transmission system without a reactor trip for power levels less than 50 percent.

The features that permit continued operation under load rejection conditions include:

Integrated Control System

During normal operations, the Integrated Control System controls the unit load in response to the core thermal power demand (CTPD) set by the operator. During loss of load, the CTPD is limited to a maximum 20 percent. The ICS will control reactor power, feedwater flow and bypass valve position to maintain the CTPD, Tave and steam pressure. The turbine governor takes control to regulate frequency.

100 Percent Relief Capacity in the Steam System

This provision acts to reduce the effect of large load drops on the Reactor System.

Consider, for example, a sudden load rejection from a power level above 20 percent. When the turbine-generator starts accelerating, the governor valves and the intercept valves close to maintain set frequency. As the governor valves close, steam pressure rises, forcing reduced energy transfer from the primary system and causing reactor coolant average temperature to rise. At the same time, a power demand runback is initiated to 20 percent power by the CTPD, causing reduction in the feedwater and reactor demand signals. The rise in reactor coolant temperature will help initially reduce reactor power along with the reduction in demand. The bypass valves will open in response to the increased steam pressure to reject the excess steam flow to the condenser. In addition, when the load rejection is of sufficient magnitude, the safety valves open to exhaust steam to the atmosphere. If transient conditions warrant, the feedwater system will increase feedwater flow to mitigate the undercooling condition caused by the sudden reduction in steam flow from the loss of load.

As operation continues with the turbine- generator carrying the in-house electrical loads, the turbine control will operate in the frequency control mode, the reactor and feedwater will operate to maintain proper reactor conditions at reduced demand and the bypass system will reject the excess steam flow to the condenser to control steam pressure.

7.6.1.2.3.3 Loss of Power Supply Considerations

The ICS/NNI system power supply is arranged such that it is normally powered from a dedicated static inverter system, which receives a DC input from the Vital I & C batteries, and is backed by an AC input from one of the plants regulated non-load shed buses (Chapter 8). Both automatic and manual transfer switching is provided to select between these supplies.

In addition to the power supply reliability for the ICS, essential plant parameters necessary for shutdown have been arranged with their power supplies independent of the ICS source. Also, a “display group” has been developed and defined on the plant operator aid computer such that upon a loss of ICS power, the operator may quickly have full and complete information on key primary and secondary system parameters. Emergency procedures have also been developed to designate alternate sources of information on key plant parameters if the computer is unavailable, thus assuring the operator can obtain sufficient systems information. The reliable ICS power supply and the development of operator information are consistent with NRC Bulletin 79-27, "Loss of Non-Class IE I&C Power System Bus During Operation," as described in Reference 1.

If a loss of power event occurs, the ICS/NNI is designed to send the plant to a “Known Safe State” (KSS) by initiating a trip of both main feedwater pumps via the failsafe design of the high steam generator level monitoring circuits. These circuits are designed such that upon a loss of both "hand" and "auto" power they will initiate a trip of the main feedwater pumps and main turbine which will also trip the reactor via the Anticipatory Reactor Trip System (ARTS) circuitry. Emergency feedwater is also initiated upon loss of both feedwater pumps as described in Section 7.4.3. Upon loss of either "hand" or "Auto" power, steady state operation is maintained.

7.6.2 Incore Monitoring System

The Incore Monitoring System has been upgraded to meet the requirements of NUREG 0737 Item II.F.2.

7.6.2.1 Description

The Incore Monitoring System provides neutron flux detectors to monitor core performance. Incore self-powered neutron detectors measure the neutron flux in the core to provide a history of power distributions during power operation. Data obtained provides power distribution information and fuel burnup data to assist in fuel management decisions. The plant computer provides normal system readout and a backup readout system is provided for selected detectors.

7.6.2.2 System Design

The Incore Monitoring System consists of assemblies of self-powered neutron detectors and temperature detectors located at preselected positions within the core. Each core can contain up to 52 incore assemblies. The incore monitoring locations are shown on Figure 7-20. In this arrangement, an incore detector assembly consisting of seven local flux detectors, one background detector, one thermocouple and a calibration tube is installed in an instrumentation guide tube. The local detectors are positioned at seven different axial elevations to indicate the axial flux gradient. The outputs of the local flux detectors are referenced to the background detector output so that the differential signal is a true measure of neutron flux. The temperature detectors located just above the top of the active fuel in the fuel assemblies measure core outlet temperature.

Multi-point recorder readouts of selected detectors are provided independent of the computer.

When the reactor is depressurized, the incore detector assemblies can be inserted or withdrawn through guide tubes which originate at a shielded area in the Reactor Building as shown in Figure 7-21. These guide tubes enter the bottom head of the reactor vessel where internal guides extend up to the instrumentation tubes of 52 selected fuel assemblies. The instrumentation tube serves as the guide for the incore detector assembly. During refueling operations, the incore detector assemblies are withdrawn approximately 13 feet to allow free transfer of the fuel assemblies. After the fuel assemblies are placed in their new location, the incore detector assemblies are returned to their fully inserted positions.

7.6.2.3 Calibration Techniques

The nature of the detectors permits the manufacture of nearly identical detectors which produces a high relative accuracy between individual detectors. The detector signals are compensated continuously for burnup of the neutron-sensitive material.

Calibration of detectors is not required. The incore self-powered detectors are controlled to precise levels of initial sensitivity by quality control during the manufacturing stage. The sensitivity of the detector changes over its lifetime due to such factors as detector burnup, control rod position, fuel burnup, etc. The results of experimental programs to determine the magnitude of these factors have been incorporated into calculations and are used to correct the output of the incore detectors for these factors. Operation of these detectors in both power and test reactors has demonstrated that this compensation program, when coupled with the initial sensitivity, provides detector readout accuracies sufficient to eliminate the need for a calibration system.

7.6.2.4 System Evaluation

7.6.2.4.1 Operational Experience

Self-powered incore neutron detectors have been operated since 1962. Such detectors have been assembled and irradiated in a Babcock & Wilcox development program that began in 1964.

The B&W Development Program included these tests:

1. Parametric studies of the self-powered detector.
2. Detector ability to withstand PWR environment.
3. Multiple detector assembly irradiation tests.
4. Background effects.
5. Readout system tests.
6. Mechanical withdrawal-insertion tests.
7. Mechanical high pressure seal tests.
8. Relationship of flux measurement to power distribution experiments.

Conclusions drawn from the results of the test programs are as follows:

1. The detector sensitivity, resistivity, and temperature effects are satisfactory for use.
2. A multiple detector assembly can provide axial flux data in a single channel and can withstand reactor environment.
3. Background effects will not prevent satisfactory operation in a PWR environment.
4. Plant computer systems are successful as read-out system for in-core monitors.

For Incore Monitoring System development program results and conclusions, refer to B&W Topical Report BAW-10001A; “Incore Instrumentation Test Program.”

7.6.2.4.2 Deleted Per 1997 Update

7.6.2.5 Detection and Control of Xenon Oscillations

Under normal operating conditions, the incore detectors supply information to the operator in the control room.

Each individual detector measures the neutron flux at its locality and is used to determine the local power density. The individual power densities are then averaged and a peak-to-average power ratio calculated. This information can be used to indicate possible power oscillations.

7.6.3 References

1. NRC Letter to Duke dated December 7, 1989, Oconee: Audit for Verification of Resolution of IE Bulletin 79-27 concerns

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7.7 Operating Control Stations

Following proven power station design philosophy, all control station, switches, controllers, and indicators necessary to start up, operate, and shut down Oconee I and 2 are located in one control room. Controls for Oconee 3 are located in a separate control room. Control functions necessary to maintain safe conditions after a loss-of-coolant accident are initiated from the centrally located control rooms. Controls for certain auxiliary systems are located at remote control stations when the system controlled does not involve unit control or emergency functions.

7.7.1 General Layout

The control room for Oconee 1 and 2 is designed so that one man can supervise operation of both units during normal steady state conditions. During other than normal operating conditions, other operators are available to assist the control operator. Figure 7-26 shows the control room layout for Oconee I and 2. Oconee 3 has similar accessibility to the various controls. The control boards are subdivided to show the location of control stations and to display information pertaining to various sub-systems.

7.7.2 Information Display and Control Functions

Consideration is given in the control board layout to the fact that certain systems normally require more attention from the operator. The Integrated Control System is therefore located nearest the center line of the boards (Section I on Figure 7-26).

On Section 2 of the control board, one indicator will be provided for each control rod. Fault detectors in the Rod Drive Control System are used to alert the operator should an abnormal condition exist for any individual control rod. Displayed in this same area are limit lights for each control rod group and all nuclear instrumentation information required to start up and operate the reactor. Control rods are manipulated from the Section 2 bench position. Plant computer readout facilities for alarm monitoring and sequence monitoring are located here to aid the operator.

A plant computer is used on each unit to provide fuel management measurements and calculations. These computers also provide for alarm monitoring, performance monitoring, data logging, and sequence monitoring during start-up and shut-down of the turbine-generator. Monitoring and display functions of the plant computer which audit Nuclear Steam Supply System parameters of major interest are duplicated elsewhere in the control rooms. This type of computer application has been successfully applied to units presently in operation on the Duke system.

Variables associated with operation of the secondary side of the station are displayed and controlled from Section 1 and 3 of the control board. These variables include steam pressure and temperature, feedwater flow and temperature, electrical load, and other signals involved in the Integrated Control System. Section 3 of the control board also contains indication and controls of the Reactor Coolant System parameters.

The Engineered Safeguards System is controlled and monitored from Sections 3 and 4 unit boards and Section 8 of the vertical boards. Indicating lights are provided as a means of verifying the proper operation of the Engineered Safeguards System. Control switches located on these panels allow manual operation of equipment that is not controlled elsewhere in the control room or test of individual units.

Control and display equipment for station auxiliary systems are located on Section 6 of the control board.

Reactor coolant pump controls located on Section 5 of the control boards consists of the pump controls and auxiliary instrumentation required for pump operation. Also mounted on this section are the Auxiliary Electrical System controls required for manual switching between the various power sources described in Section 8.2 and Section 8.3.

Controls and indications for all normal ventilation systems are located on Section 7 of the control boards.

In order to maintain the desired accessibility for control of the station, miscellaneous recorders not required for station control are located on the vertical recorder boards where they are visible to the operator. Radiation monitoring information is also indicated there.

Radiation monitoring display and transient monitoring system are combined in the process monitoring computer (PMC). The radiation monitoring display provides supervisory control and display of information from field mounted radiation monitoring equipment. The transient monitoring system automatically records pre-selected plant parameters (temperatures, pressures, flowrates, etc.) for analysis and diagnoses of plant transients or reactor trip. Like the OAC, most of the information provided by the PMC is either duplicated elsewhere in the control room, or deemed not significant enough to have a dedicated display device. The PMC is not QA-1, redundant, or single failure proof. The PMC is independent of the OAC. The PMC is not relied upon to initiate a reactor trip, mitigate an accident, or actuate a safety system, and performs only supervisory control to field mounted radiation monitoring and sampling equipment.

A description and results of the Unit 1, 2, and 3 control room review (per Generic Letter 82-33) were provided in the document "Response to Supplement 1 to NUREG-0737" which was submitted on April 14, 1983 by letter from H. B. Tucker to H. R. Denton.

7.7.3 Summary of Alarms

Visible and audible alarm units are incorporated into the control boards to warn the operator if limiting conditions are approached by any system. Audible Reactor Building evacuation alarms are initiated from the Radiation Monitoring System and from the source range nuclear instrumentation. Audible alarms are sounded in appropriate areas throughout the station if high radiation conditions are present in that area. Alarms for the nuclear systems are indicated in process diagrams in Chapter 6, Chapter 7, and Chapter 9. Alarms are provided to warn security of unauthorized entry into vital areas.

7.7.4 Communications

7.7.4.1 Control Room to Inside Station

The telephones for the site are connected to a Private Automatic Branch Exchange (PABX) located inside the Oconee Office Building. The PABX has capability of up to 10,000 lines and provides access for communications and paging. The equipment provides 4-digit dialing, dial tone, ring-back tone and busy tone. The PABX is powered by 48VDC batteries, which are charged through an inverter/charger combination, fed by a 480VAC supply. Upon loss of normal AC power, the system batteries will provide required power for a minimum of four (4) hours. Alternate power is automatically provided from the emergency diesel generator provided for the building.

The public address system is accessible through plant telephones by dialing a access code. In the event of PABX failure, the PA system is operable through eleven handsets installed at strategic locations within the station.

A radio transmitter/receiver communication system is provided between the control room and the rest of the station. This system is used during normal plant operation and during outage, security or fire situations. Radio transmission is only available in a reactor building when an antenna is activated by the unit 1 & 2 control room. Usage of the radio communication system in the reactor building is limited to times when the unit is open for access.

A sound powered telephone system was supplied during original plant design, but radio utilization allows this system to be an available but nonessential system. This system consists of a network of conductor pairs converted to jacks throughout the plant. Sound powered handsets are plugged into the jacks to form talking paths with separate talking paths available for each unit. The system is completely independent from any other telephone system and involves no external power supply.

7.7.4.2 Control Room to Outside Station

The commercial telephone network and the Duke Power fiber optic network provide communication to outside the station area. An interface is provided between the PABX and the commercial telephone lines and another interface is provided between the PABX and the Duke Power fiber optic network which includes access to the General Office at Charlotte, Transmission Control Center, System Operating Center, and Lee Steam Station. Ringdown phone service (independent of the PABX) is also provided through the fiber optic network to the Transmission Control Center, System Operating Center, and Lee Steam Station.

The control room is also equipped with a transmitter-receiver which operates at 800 megahertz to provide communication between the control room and the System Operating Center, Transmission Control Center, and Bad Creek, Jocassee, and Keowee Hydro Stations.

7.7.4.3 Deleted per 1998 Revision

7.7.5 Occupancy

Safe occupancy of the control room during abnormal conditions is provided for in the design of the Auxiliary Building. Adequate shielding is used to maintain tolerable radiation levels in the control rooms for maximum hypothetical accident conditions. Each Control Room Ventilation System is provided with radiation detectors and appropriate alarms. See Section 9.4.1 for control room ventilation systems description. Emergency lighting is provided.

The potential magnitude of a fire in either control room is limited by the following factors:

1. The control room construction and furnishings are of noncombustible materials.
2. Control cables and switchboard wiring meet the flame test as described in IEEE 383-1974. (Reference IPCEA S-19-81 & ASTMD 2220-68)
3. Qualified trained personnel, adequate extinguishers, and accessibility to all control room areas are provided.

A fire, if started, would be of such a small magnitude that it could be extinguished by the operator using a hand fire extinguisher. The resulting smoke and vapors would be removed by the ventilation system in the case of Unit 3. For Units 1 & 2, the control room would be purged with portable equipment.

Essential auxiliary equipment is controlled by either stored energy, closing-type, air circuit breakers which are accessible and can be manually closed in the event DC control power is lost, or by AC motor starters which have individual control transformers.

7.7.5.1 Emergency (Auxiliary) Shutdown Panel

If temporary evacuation of the control room is required while operating at any power, the operator will trip the control rods and start the Keowee hydro units prior to evacuating the control room. This action can also be accomplished from the cable room located one elevation below the control room. After evacuation, the operator can establish and maintain Mode 3 (with T_{ave} ≥ 525°F) from the emergency shutdown panel located outside the control room. The following instrumentation and controls are available on the emergency shutdown panel:

1. Pressurizer Level Indicator
2. Pressurizer Heater Control
3. RC Pressure Indicator
4. RC Outlet Temperature Indicator
5. Turbine Steam Supply Header Pressure Indicator
6. Turbine Bypass Valve Loop “A” Station
7. Turbine Bypass Valve Loop “B” Station
8. Startup Feedwater Valve Loop “A” Station
9. Startup Feedwater Valve Loop “B” Station
10. Steam Generator “A” Startup Level
11. Steam Generator “B” Startup Level
12. Letdown Storage Tank Level Indicator
13. HP Injection Pump “B” Control Switch
14. Pressurizer Level Control Station

If HP Injection Pump “A” is in operation, it can be tripped from the 4.16 KV switchgear located on elevation 796' + 6". The operator has control of HP Injection Pump “B” at the emergency shutdown panel. Makeup to the letdown storage tank can be obtained, if desired, from one of the following sources:

1. RC Bleed Holdup Tank
2. Concentrated Boric Acid Storage Tank
3. Boric Acid Mix Tank

The necessary pumps can be controlled from the waste disposal control panel.

7.7.5.2 Standby Shutdown Facility

The Standby Shutdown Facility (SSF) provides a secondary alternate and independent means to achieve and maintain a safe shutdown condition for scenarios in which the Control Room is unavailable or equipment it controls is unavailable. The SSF was originally designed for safe shutdown during postulated fire, Turbine Building flooding, and physical security events. In addition to these events, the SSF is also used to address other scenarios. See Section 9.6 for more information on the SSF. The following instrumentation and controls are available on the SSF:

SSF DIESEL GENERATOR AND STATION RELATED CONTROLS AND INSTRUMENTATION

1. Diesel Generator Annunciator Panel
2. Diesel Generator Controls
3. Diesel Generator Metering
4. Diesel Generator Syncroscope
5. SSF Power Systems Breaker Controls and Indicating Lights
6. SSF Power Systems Metering
7. SSF Diesel Engine Service Water Pump Control
8. SSF Diesel Engine Service Water Pump Discharge Flow Meter
9. SSF Auxiliary Service Water Pump Control
10. SSF Auxiliary Service Water Pump Discharge Flow Meter
11. SSF Sump Pump Controls

SSF UNIT RELATED CONTROLS AND INSTRUMENTATION

1. Unit Annunciator
2. Unit Recorder
3. SSF RC Makeup System
    a. Pump Controls
    b. Valve Controls
    c. Pump Suction Pressure and Temperature Indication
    d. Pump Discharge Pressure and Flow Indication
4. Unit Process Indicators
    a. Pressurizer Level
    b. Pressurizer Pressure
    c. RC Loop A and B Hot Leg Temperatures
    d. RC Loop A and B Cold Leg Temperatures
    e. RC Loop A and B Pressure
    f. Steam Generator Level A and B
    g. Steam Generator Auxiliary Service Water Flow
5. Unit Controls
    a. Letdown Cooler A and B Outlet Valve
    b. Pressurizer Water and Steam Space Samples
    c. Steam Generator A and B Feedwater Control Valve
    d. Boron Dilution Block Valve

e. Pressurizer Relief Block Valve

f. Pressurizer Heaters

g. Steam Generator A and B Emergency Feedwater Valves

6. Power Systems Alignment Indicating Lights

Reference Tables 9-15 and 9-16 for additional details on SSF controls and instrumentation.

7.7.6 Auxiliary Control Stations

Auxiliary control stations are provided where their use simplifies control of auxiliary systems equipment such as waste evaporator, sample valve selectors, chemical addition, etc. The control functions initiated from local control stations do not directly involve either the Engineered Safeguards System if actuated or the Reactor Control System. Sufficient indicators and alarms are provided so that the Oconee control room operator is made aware of abnormal conditions involving remote control stations.

7.7.7 Safety Features

Control room layouts provide the necessary controls to start, operate and shut down the units with sufficient information display and alarm monitoring to assure safe and reliable operation under normal and accident conditions. Special emphasis is given to maintaining control during accident conditions. The layout of the engineered safeguards section of the control board is designed to minimize the time required for the operator to evaluate the system performance under accident conditions.

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7.8 Anticipated Transients Without SCRAM (ATWS) Mitigation System

7.8.1 Design Basis

The ATWS system that is installed at the Oconee Nuclear Station is based upon the B&WOG Generic ATWS Design Basis Document 47-1159091-00 dated October 9, 1985, subsequent B&WOG ATWS Committee submittal dated December 1, 1987, the Safety Evaluation Report on B&WOG 47-1159091-00 contained in the NRC letter to DPCo dated July 26, 1988, and the September 7, 1988 letter G. Holohan (NRC) to L. Stalter (B&WOG). The ATWS system was installed as required by the ATWS Rule, 10CFR50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants."

7.8.2 Systems Design

The ATWS Mitigation System is composed of two parts, the ATWS Mitigating Systems Actuation Circuitry (AMSAC) and the Diverse SCRAM System (DSS).

The ATWS Mitigation System Actuation Circuitry (AMSAC) and Diverse Scram System (DSS) consist of two Programmable Logic Controllers (PLC's) for the logic control circuits and two Uninterruptible Power Sources (UPS) connected to offsite power. Inputs from the field sensors are wired to the PLC's and outputs to the final actuation devices are wired using interfacing relays housed with the ATWS equipment cabinets and powered from the UPS. The UPS's are powered from a 120 VAC local panelboard backed by the Oconee Station emergency source (Keowee Hydroelectric Generating Station). The 2 UPS's are isolated from the emergency source by individual fuses coordinated with the panelboard circuit breakers and the upstream distribution network.

The AMSAC/DSS System consists of a two channel energize-to-trip design with the AMSAC portion actuated on low Feedwater Pump Turbine (FDWPT) control oil pressure or low Feedwater Pump (FDWP) discharge pressure while the DSS portion is actuated upon high Reactor Coolant System (RCS) Pressure.

All AMSAC/DSS PLC's and UPS power supplies are located in a stand-alone cabinet located above the Control Room in what is called the Ventilation Room. This location is convenient to the Control Room and allows easy access for testing and maintenance. This location is a Mild Environment.

All AMSAC/DSS process monitoring inputs are provided by existing Oconee instrumentation and control systems. RCS pressure inputs to the DSS which are analog signals are currently displayed on the Main Control Boards. Annunciator alarms are provided in the Control Room to alert the operator that one channel for either AMSAC or DSS has actuated.

7.8.2.1 AMSAC

Each channel of AMSAC uses existing inputs from the Feedwater System which monitor FDWPTA(B) hydraulic control oil pressure and FDWPA(B) discharge pressure signals (one per pump to each channel) from pressure switches which are part of the original Oconee feedwater system design.

These signals are multiplied using relays to provide the contact inputs which will be wired directly to the PLC's. These signals are processed using programmable logic resident in the PLC to provide the outputs to the Main Turbine and the Emergency Feedwater System.

AMSAC interfaces with the following systems and devices:

FROM	TO	ISOLATION
AMSAC PLC Interfacing Relays	Main Turbine Trip Solenoid	NE to NE
AMSAC PLC Interfacing Relays	EFDW Pump Start Circuits	NE to 1E
AMSAC Channels Actuation	Control Room Annunciator	NE to NE
NE = Non-Class 1E	1E = Class 1E	

Feedwater Pump Turbine Oil Pressure is sensed by pressure switches in the Feedwater Pump Turbine Control Console on the turbine standard. These switches are then multiplied using control relays for output to various plant control, monitoring and alarm circuits. AMSAC will be one of the end users of these signals.

Feedwater Pump Discharge Pressure is sensed by pressure switches in the discharge lines of each individual pump. These switches are then multiplied using control relays for output to various plant control, monitoring and alarm circuits. AMSAC will be one of the end users of these signals.

7.8.2.2 DSS

Each channel of DSS uses a Wide Range RCS Pressure signal supplied via an analog isolator from the Westinghouse supplied Reactor Vessel Level Indication System (RVLIS). These signal loops also provide the Regulatory Guide 1.97 wide range RCS pressure indications on the main control board. The DSS utilizes the signal conditioning equipment which is resident in the RVLIS cabinet through an isolation device that separates the Class 1E RVLIS from the Non-Class 1E DSS. DSS trip actuation is initiated at a setpoint of 2450 ± 25 psig using the logic in the PLC. Outputs from both channels of the PLC's are combined to make the required two-out-of-two logic. DSS provides two digital inputs (one per channel) to the CRD system. Upon actuation of both channels of DSS, the CRD system opens a normally-closed solid-state relay contact in each of the 138 Single Rod Power Supply (SRPS) modules. This interrupts power to the CRDM’s causing all control rods (except the captured APSR’s) to fall into the core resulting in a reactor trip. DSS also signals the ICS to raise the Turbine Bypass Valve pressure setpoint to ensure shutdown margin requirements are maintained.

DSS interfaces with the following systems and devices:

FROM	TO	ISOLATION
DSS Interfacing Relays	Single Rod Power Supplies	NE to NE
DSS Interfacing Relays	TBV's Control Setpoint	NE to NE
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FROM	TO	ISOLATION
DSS Channel Actuation	Control Room Annunciator	NE to NE
WR RCS Pressure (RVLIS)	DSS PLC Channels	1E to NE
NE = Non-Class 1E	1E = Class 1E	

The Control Rod Drive (CRD) System also provides an input from the CRD Diamond panel located in the main Control Room into the DSS logic for reset of the CRD SRPS modules.

7.8.2.3 Testing

Inputs are also provided from the ATWS test panel. The panel is resident in the PLC cabinet along with other ATWS equipment.

Periodic testing will use a Bypass/Enable switch located on the test panel for testing each channel of AMSAC and DSS logic in the PLC. Whenever this switch is not in the ENABLE position, a continuous indicator in the Control Room will be illuminated and a computer alarm will be generated for display in the Control Room on a CRT. Status indication of all inputs and outputs are on the test panel.

These systems are designed so that both are two out of two logic actuated systems, and provisions are incorporated which allow disabling of the system output when one of the channels is placed in test. This prevents accidental initiation of the systems during individual channel testing.

7.8.2.4 AMSAC and DSS I/O

Each input to the AMSAC and DSS logic is provided with complete indications and alarms that alert the operator to an off-normal status that might preclude proper response to an ATWS event. Each plant variable that inputs into the AMSAC and DSS is monitored as part of the existing plant indications and provide the operator with information relevant to the status of each variable prior to reaching the AMSAC or DSS set point.

Outputs from the PLC's are provided through interfacing relays located in the ATWS equipment cabinets. These relays provide the outputs to the Main Turbine, Turbine Bypass Valve Set Point, the Emergency Feedwater Pumps, and the Control Rod Drive System for Single Rod Power Supplies via the CRD system PLC. The relays used are powered by the UPS. Each PLC channel output relays will be wired to the above devices in a manner such that both channels of AMSAC/DSS are required for the devices to trip, start, or drop. The relays also provide output status information to the operator.

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7.9 Automatic Feedwater Isolation System (AFIS)

7.9.1 Design Basis

The Automatic Feedwater Isolation System (AFIS) circuitry is designed to address containment over-pressurization concerns, unacceptable thermal stresses to the steam generator tubes, and significant core overcooling by isolating main and emergency feedwater to the faulted steam generator during a Main Steam Line Break event. AFIS is credited in the steam line break containment response analysis (Section 6.2.1.4). AFIS is not credited for the steam line break core response analyses (Sections 15.13 and 15.17) or the steam line break tube stress analysis (Section 5.2.3.4). The design basis of the system includes the items of Section 7.1.2 with the following additions:

7.9.1.1 Loss of Power

1. The loss of vital bus power to an analog channel will cause a loss of signal to that analog channel creating a 1-out-of-4 coincidence without AFIS actuation.
2. The loss of vital bus power to a digital channel will not initiate system actuation.

7.9.1.2 Equipment Removal

1. Removal of an isolation module from the AFIS system will require a bypass on 2 analog channels (for AFIS and Trip Confirm modules) in both digital channels or AFIS system actuation will occur.
2. Removal of a logic module from one protective digital channel does not affect the other protective digital channel and does not initiate system action.

7.9.1.3 Control Logic of AFIS System

AFIS has priority over the automatic actuation/operation of systems affected. All systems receiving the AFIS signal remain controlled by AFIS unless manual control is taken. The affected EFW pumps can be operated manually to override the AFIS actuation. A separate deliberate action is required to place the affected systems in manual prior to performing a reset of the AFIS functions.

7.9.2 System Design

7.9.2.1 System Logic

The AFIS instrumentation is designed to provide automatic termination of feedwater and emergency feedwater flow to the affected steam generator. The AFIS instrumentation automatically terminates Main Feedwater (MFW) by tripping both MFW pumps and closing the affected steam generator's main and startup feedwater control valves (MFCV and SFCV) and block valves. Although the main and startup feedwater block valves are automatically closed, their closure is not credited for mitigation of a MSLB. The AFIS logic automatically terminates emergency feedwater (EFW) by stopping the turbine-driven emergency feedwater pump (TDEFWP) and tripping the motor-driven emergency feedwater pump (MDEFWP) aligned to the affected steam generator. Manual overrides for the TDEFWP and MDEFWPs are provided to allow the operator to subsequently start the EFW pumps if necessary.

In addition, AFIS actuation limits EFW pump runout in the event of a MSLB and certain large break MFW line breaks with the pump in the automatic mode of operation.

Main Steam header pressures are used as input signals to the AFIS circuitry. There are four QA-1 pressure transmitters per header with each feeding a steam pressure signal to a signal isolator. The output of the signal isolator provides an analog signal to a processor module that actuates isolation functions at desired setpoints. One pressure transmitter per header and associated cabling and resistors constitute an AFIS detection analog channel.

The four AFIS analog channels per header feed two redundant AFIS digital channels. Each digital channel provides independent circuit functions to isolate each steam generator. If the logic is satisfied, a trip output is energized. The use of an energized-to-trip processor module ensures that a loss of power to the digital channel will not result in inadvertent feedwater isolation. If either digital channel is actuated, feedwater is isolated to the affected steam generator. Energizing the trip outputs results in the actuation of contacts in various control circuits for systems and components used for the MSLB and feedwater line break mitigation. Therefore, when the trip outputs are actuated, the systems and components perform their isolation functions. Other features of the digital channels include header specific manual initiation pushbuttons, a header specific ENABLE/OFF switch, and redundant “trip confirm” modules for each digital channel. The AFIS digital channel is defined as the analog isolation modules, the (4) digital 2-out-of-4 logic modules (Framatome STAR), the ENABLE/OFF pushbutton, the manual initiation pushbutton, the associated trip relays, the trip relay outputs to the feedwater pumps, the switchgear trips for the MDEFWP, the solenoid valves for the MFCV and SFCV, the trip solenoid valves for the feedwater pumps, and the TDEFWP trip function. While AFIS provides isolation of the feedwater block valves, this is not a credited function and is not a requirement for digital channel operability.

The AFIS digital channels are enabled and disabled administratively rather than automatically. Appropriate operating procedures contain provisions to enable/disable the digital channels.

7.9.2.2 Trip Setpoints

Trip setpoints are the nominal values that are user defined in AFIS software. An AFIS analog channel is considered to be properly adjusted when the AS LEFT value is within the band for channel calibration accuracy.

The trip setpoints used in the AFIS software are selected such that adequate protection is provided when all sensor and processing time delays are taken into account. The trip setpoints are set for low main steam pressure and a high rate of depressurization associated with a specific steam generator. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, the allowable values specified are conservatively adjusted with respect to the analytical limits. The actual nominal trip setpoint entered into the software is controlled procedurally.

7.9.2.3 Availability of Information

All system analog signals are indicated within the system cabinets and are monitored by the plant computer. All BWNT STAR module outputs are indicated within the cabinets and their state monitored by the plant computer. Plant annunciators provide the operator with immediate indication of changes in the status of the processor module inputs and outputs. The following conditions are annunciated for the AFIS system:

1. Digital Channel 1 Test/Disable
2. Digital Channel 2 Test/Disable

3. AFIS Initiate Header A
4. AFIS Initiate Header B
5. AFIS Analog Channel Trip

Initiation of Header A (3) or Header B (4) requires simultaneous detection by both the “primary” and “trip confirm” modules of either of the Digital Channels for the Low Pressure Trip. Inadvertent actuation of the “primary” low pressure trip without confirmation from the “trip confirm” function or actuation of the “trip confirm” by itself will not result in an AFIS system actuation but will be annunciate on the appropriate “trouble” annunciator (1 or 2). The STAR modules indicate when any "one out of four" analog channel trip occurs, which the annunciator (5) will be illuminated.

7.9.2.4 Summary of Protective Action

The AFIS circuitry is designed to address containment over-pressurization concerns and thermal stresses on steam generator tubes by isolating feedwater to the faulted steam generator during a Main Steam Line Break event. Two conditions apply for AFIS actuation:

1. Low main steam pressure
2. Low main steam pressure and a high rate of depressurization

In response to the first condition of low main steam pressure, the AFIS circuitry trips the main feedwater pumps and trips or prevents the turbine driven emergency feedwater pump from automatically starting by redundantly and independently closing valves, MS-93 and MS-95. The AFIS circuitry also closes the main and startup feedwater control and block valves on the affected header.

In response to the second condition, AFIS circuitry performs the same actions as in the first condition with the addition of redundant trip signals to the motor driven emergency feedwater pump associated with the faulted steam generator.

7.9.3 System Evaluation

The four AFIS analog channels per steam generator feed two redundant feedwater digital channels. Each digital channel provides independent circuit functions to isolate each steam generator. If the logic is satisfied, a trip output is energized. The use of an energized-to-trip processor module ensures that a loss of power to the digital channels will not result in inadvertent feedwater isolation. If either digital channel is actuated, feedwater to the affected steam generator is isolated. Energizing the trip outputs results in actuation of contacts in various control circuits for systems and components used for the MSLB and feedwater line break mitigation. Therefore, when the trip outputs are actuated, the systems and components perform their isolation functions. While AFIS provides isolation of the feedwater block valves, this is not a credited function and is not a requirement for digital channel operability.

There is redundancy of sensors, logic, and equipment, excluding the main feedwater equipment. The redundancy is preserved and kept effective by independence of sensors, instrument strings, logic, and control elements in the final actuator. These characteristics enable the system to tolerate single failures at all levels.

To prevent a single-failure from causing loss of feedwater flow to one or both headers inadvertently, a redundant trip confirm function is provided that must also detect the low pressure trip condition in order to create an AFIS low pressure trip.

The system protective devices require electrical power in order to operate and perform their functions. The power for the STAR modules is taken from the plant's system of battery-backed vital buses since loss of power at this level could affect the performance capability of the system. The system will tolerate the loss of one vital bus without loss of protective capability.

7.9.3.1 Redundancy and Diversity

The system as evaluated above is shown to have sufficient diversity and redundancy to withstand single failures at every level, excluding the main feedwater components associated with AFIS. The Startup and Main Feedwater Control Valves are supplied with backup compressed air from accumulators to allow their closure for their mission time after a Loss of Offsite Power. See UFSAR Section 9.5.2.2.

7.9.3.2 Electrical Isolation

The use of analog isolation will effectively prevent adverse affects of faults (shorts, grounds, or cross connection of signals) on any analog signal leaving the system from being reflected into or propagating through the system. The isolation amplifier circuits have been qualified to isolate the output signal from input circuit faults. The STAR module employs diverse software to mitigate common mode failures.

Separation of redundant AFIS functions is accomplished by maintaining isolation for the power, control, equipment location, and cable routing between channels.

AC power for AFIS channels is supplied from independent vital power panels. Analog channel 1 is supplied from Vital Power Panelboard KVIA. Analog channel 2 is supplied from Vital Power Panelboard KVIB. Analog channel 3 is supplied from Vital Power Panelboard KVIC. Analog channel 4 is supplied from Vital Power Panelboard KVID. The digital channels, 1 and 2, are supplied from AC panelboards, KVIC and KVID, respectively. The devices controlled by the digital channels are supplied by redundant and independent QA-1 sources of power. These are described in Section 8.3.

7.9.3.3 Physical Separation

The arrangement of modules within the system cabinets is designed to reduce the chance of physical events impairing system operation. Channel specific control wiring between the STAR modules and the final actuating devices is physically separated and protected against damage, which could impair system operation. The equipment is separated to limit the possibility of spurious actuation.

Separation between redundant channels of equipment, control cables, and power cables provides defense of redundant AFIS functions. Power and control cables for redundant elements of AFIS equipment are routed in separate cable trays.

7.9.4 Periodic Testing and Reliability

The redundancy of the logic and the division of protective devices between channels form a system having two parallel protective channels either of which is capable of performing the required functions. These characteristics are basic to an inherently reliable system.

The built-in test facilities permit an electrical actuation test of each analog instrument string by the substitution of signals at the STAR module inputs. The AFIS STAR module provides both manual and automated test capability, and self-diagnostic tests performed during start-up and operation. The front panel of each of the STAR module has LED indicators, which indicate module status.

When testing, chance of an inadvertent initiation of an AFIS low pressure trip is minimized by the trip confirm function which requires actuation by both the primary and trip confirm modules.

When an analog instrument string is placed in test or bypass, the logic assigned to the digital control module changes the actuation logic to a 2-in-3 coincidence. This assures that placing an analog channel in test cannot defeat the protective action.

On-line checks of the system will confirm the normal state of the system, principally by comparative readings of similar analog indications between redundant measurements and by the status lamps on the logic modules.

7.9.5 Manual Initiation

A manual initiation switch is provided in each Automatic Feedwater Isolation System digital channel. The manual initiation switches are capable of actuating trip outputs without relying on the STAR outputs. There are two control switches on the control room board for the disabling of each digital channel and two control switches for manually initiating the respective header circuitry.

7.9.6 Bypassing

Bypassing must be initiated manually within a fixed pressure band above the protective system actuation point. The removal setpoints are above the actuation setpoints in order to obtain a pressure band in which the system actuation may be bypassed during a normal cooldown and startup. The bypasses do not prevent automatic actuation of the emergency feedwater pumps. Bypassing is under administrative control. Once a bypass has been initiated, the plant annunciator indicates the condition on Unit 1 only and by the OAC for all units.

After actuation of AFIS, the turbine driven and motor driven emergency feedwater pumps can be manually actuated or restarted from their respective control switches.

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7.10 Diverse Low Pressure Injection Actuation System (DLPIAS)

7.10.1 Design Basis

A Defense-in Depth and Diversity (D^3) Analysis was performed per the guidelines of BTP HICB - 19. This analysis resulted in the inclusion of a Diverse Low Pressure Injection Actuation System (DLPIAS). The system is designed as diverse backup for ESPS during the unlikely event of a Large Break Loss of Coolant Accident (LBLOCA) concurrent with a Software Common Mode Failure (SWCMF) of the ESPS digital equipment.

7.10.2 System Design

The DLPIAS is a combination of both safety-related and non-safety-related components. The DLPIAS design does not require the use of any software. All DLPIAS process monitoring inputs are provided by existing Oconee instrumentation and control systems. The DLPIAS utilizes analog pressure input signals from the Reactor Coolant System (RCS), which are displayed on the Main Control Boards. RCS input pressure signals are isolated from the safety-related signals by the ESPS signal isolators. The signal is split on the front end of the ESPS and is not affected by the software of the ESPS computers. The analog RCS pressure signals provide input to the DLPIAS bistable trip units which output to a 2- out-of-3 relay logic circuit to actuate the ESPS Channel 3 and 4 devices. Power for the bistables and relay logic is non-safety-related.

The DLPIAS is actuated on low RCS Pressure. The system is designed as a diverse backup for ESPS during the unlikely event of a LBLOCA concurrent with a SWCMF of the ESPS digital equipment. A low RCS pressure condition is the most appropriate indication that a LBLOCA has occurred. Because the DLPIAS is a backup system for LBLOCA, the setpoint for actuation of the DLPIAS is chosen such that the ESPS actuation of the LPI components will occur prior to DLPIAS actuation.

Physical separation is maintained between safety-related and non-safety-related components per IEEE Std 384-1992 separation criteria. The bistables and relays are rail mounted components. Electrical separation between safety-related and non-safety-related components is maintained by the use of signal isolators for the analog signals and relays. All equipment associated with the DLPIAS, with the exception of the RCS pressure transmitters and associated cabling, is located in the Control Room and is qualified for a mild environment.

The DLPIAS 2-out-of-3 relay logic minimizes an inadvertent actuation of the LPI components. The circuit relays are energized to actuate, therefore loss of power will not result in actuation of the trip circuit. The design includes a DLPIAS Bypass Switch located on the Unit Control Board. The switch is used to bypass the DLPIAS system for both maintenance and operations.

Procedures require that the DLPIAS be bypassed on controlled shutdowns at the same time the LPI Bypass is initiated for the ESPS. The interface with the LPI actuation circuit is safety- related. The design includes indications in the Control Room for a DLPIAS trip, DLPIAS Bypass, and DLPIAS Bistable Tripped. The indication circuits are non-safety-related.

A DLPIAS Override switch is located on the unit board which allows operators to override the DLPIAS in case of an inadvertent actuation. Once the override is initiated, operators are able to manually position ESPS components.

Manual initiation of LPI is accomplished with the existing ESPS Trip/Reset buttons located on the main control board. The logic for this manual trip bypasses the ESPS logic and allows the Operator to initiate actuation on a per channel basis.

7.10.3 Testing

Periodic testing of DLPIAS will use the Bypass Switch located on the Control Board for testing each output channel of DLPIAS. Whenever this switch is in the Bypass position, an indicator in the Control Room will be illuminated continuously.

These systems are designed so that a 2-out-of-3 relay logic actuates the system, and provisions are incorporated which allow disabling of the system output when the protective channels are placed in test. This prevents accidental initiation of the system during protective channel testing.

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7.11 Diverse High Pressure Injection Actuation System (DHPIAS)

7.11.1 Design Basis

Duke committed to install a Diverse High Pressure Injection Actuation System (DHPIAS). This system is designed as a diverse backup for ESPS during the unlikely event of a Small Break Loss of Coolant Accident (SBLOCA) concurrent with a Software Common Mode Failure (SWCMF).

7.11.2 System Design

The DHPIAS is a combination of both safety-related and non-safety-related components. The DHPIAS design does not require the use of any software. All DHPIAS process monitoring inputs are provided by existing Oconee instrumentation and control systems. The DHPIAS utilizes analog pressure input signals from the Reactor Coolant System (RCS), which are displayed on the Main Control Boards. RCS input pressure signals are isolated from the safety- related signals by the ESPS signal isolators. The signal is split on the front end of the ESPS and is not affected by the software of the ESPS computers. The analog RCS pressure signals provide input to the DHPIAS bistable trip units which output to a 2-out-of-3 relay logic circuit to actuate ESPS Channel 1 and 2 devices. Power for the bistables and relay logic is non- safety-related.

The DHPIAS is actuated on low RCS Pressure. This system is designed as a diverse backup for ESPS during the unlikely event of a SBLOCA concurrent with a SWCMF of ESPS digital equipment. A low RCS pressure condition is the most appropriate indication that a SBLOCA has occurred. Because the DHPIAS is a backup system, the setpoint for actuation of the DHPIAS is chosen such that the ESPS actuation of the HPI components will occur prior to DHPIAS actuation.

Physical separation is maintained between safety-related and non-safety-related components per IEEE Std 384-1992 separation criteria. The bistables and relays are rail mounted components. Electrical separation between safety-related and non-safety-related components is maintained by the use of signal isolators for the analog signals and relays. All equipment associated with DHPIAS, with the exception of the RCS pressure transmitters and associated cabling, is located in the Control Room and is qualified for a mild environment.

The DHPIAS 2-out-of-3 relay logic minimizes an inadvertent actuation of the HPI components. The circuit relays are energized to actuate, therefore loss of power will not result in actuation of the trip circuit. The design includes a DHPIAS Bypass Switch located on the Unit Control Board. The switch is used to bypass the DHPIAS system for both maintenance and operations.

Procedures require that the DHPIAS be bypassed on controlled shutdowns at the same time the HPI Bypass is initiated for the ESPS. The interface with the HPI actuation circuit is safety-related. The design includes indications in the Control Room for a DHPIAS trip, DHPIAS Bypass, and DHPIAS Bistable Tripped. The indication circuits are non-safety-related.

A DHPIAS Override switch is located on the unit board which allows operators to override the DHPIAS in case of an inadvertent actuation. Once the override is initiated, operators are able to manually position ESPS components.

Manual initiation of HPI is accomplished with the existing ESPS Trip/Reset buttons located on the main control board. The logic for this manual trip bypasses the ESPS logic and allows the Operator to initiate actuation on a per channel basis.

7.11.3 Testing

Periodic testing of DHPIAS will use the Bypass Switch located on the Control Board for testing each protective channel of DHPIAS. Whenever this switch is in the Bypass position, an indicator in the Control Room will be illuminated continuously.

These systems are designed so that a 2-out-of-3 relay logic actuates the system, and provisions are incorporated which allow disabling of the system output when the protective channels are placed in test. This prevents accidental initiation of the system during protective channel testing.

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Appendix 7A. Tables

Table 7-1. Reactor Trip Summary

Trip Variable	No. of Sensors	Steady-State Normal Range	Trip Value or Condition for Trip
Over Power[4]	4 Flux Sensors	0-100%	105.5 percent of rated thermal power[4] (RTP) with four RC pumps operating 80.5 percent of RTP when reset for three RC pumps operating
Nuclear Over Power Based on Flow and Imbalance[2]	4 Two-Section Flux Sensors 8 ΔP Flow	NA	109.4 percent RTP times flow minus reduction due to imbalance
Power/RC Pumps[2]	4 Pump Monitors	3 to 4 Pumps	
			Loss of any two operating reactor coolant pumps with the reactor at power operation
Reactor Outlet Temperature	4 Temperature Sensors	532-604 F	618 F
Pressure/ Temperature[2]	4 Pressure Sensors 4 Temperature Sensors	NA	$(11.14T_{hot}-4706) \geq P$
Reactor Coolant Pressure	4 Pressure Sensors	2,090-2,220 psig	2,355 psig (high)[3] 1,800 psig (low)[2]
Reactor Building Pressure	4 Pressure Sensors	0 psig	4 psig
Main Turbine Trip	4 Pressure Sensors	NA	Turbine Trip
Loss of Main Feedwater Trip	4 Pressure Sensors /pump (8 total)	NA	Loss of both Main Feedwater Pump Turbines

Note:

1. Trip condition bypassed at predetermined low power setpoints.
2. Bypassed by shutdown bypass.
3. Reset to 1720 psig by shutdown bypass.
4. Administratively reset to 5 percent during reactor shutdown.

Table 7-2. Engineered Safeguards Actuation Conditions

Channel No.	Action	Trip Condition	Steady State Normal Value	Trip Point[1]
1,2[2]	High Pressure Injection and Reactor Building Non-Essential Isolation	Low Reactor Coolant Pressure or	2,120-2,250 psig	1,600 psig[4]
		High Reactor Building Pressure	Atmospheric	3 psig[5]
3,4[3]	Low-Pressure Injection	Very Low Reactor Coolant Pressure or	2,120-2,250 psig	550 psig
		High Reactor Building Pressure	Atmospheric	3 psig[5]
5,6	Reactor Building Cooling & Reactor Building Essential Isolation	High Reactor Building Pressure	Atmospheric	3 psig
7,8	Reactor Building Spray	Very High Reactor Building Pressure	Atmospheric	10 psig[5]

Note:

1. Typical values and conditions. Refer to Technical specifications for current allowable value requirements.
2. May be bypassed below 1750 psig and is automatically reinstated above the removal setpoint value.
3. May be bypassed below 900 psig and is automatically reinstated above the removal setpoint value.
4. Based on the analyses presented in BAW-1976, "SBLOCA Analyses for B&W 177-FA Lowered-Loop Plants in Response to NUREG-0737, Item II.K.3.31", and the measurement uncertainty associated with wide range RCS pressure, 1600 psig is the minimum allowable setpoint for low RCS pressure.
5. During non-design basis events mitigated by the Standby Shutdown Facility (SSF) (e.g., Fire Event and Turbine Building Flood Event), the HPI, LPI, and BS pumps of the affected ONS unit(s) may be manually removed from service in order to 1) Prevent HPI pump operation from interfering with the function of the SSF Reactor Coolant Makeup Pump, 2) Prevent extended and potentially damaging operation of an LPI pump in a deadheaded configuration, and 3) Prevent inadvertent building spray that could impact operation of the SSF Reactor Coolant Makeup Pump.

Table 7-3. Engineered Safeguards Actuated Devices

Channel 1	Channel 2	Channels 1 & 2	Channel 3	Channel 4	Channels 3 & 4
HP-P1A HP-24 HP-26 HP-3 HP-4 HP-20 KEOWEE START (Channel A) LOAD SHED & STBY. BKR. 1 Standby BUS FEED BKR. 1 RC-5 RC-6 FDW-105 FDW-107 GWD-12 LWD-1 CS-5 PR-1(7) PR-6(7) PR-7 PR-9	HP-P1C HP-25 HP-27 HP-5 HP-21 KEOWEE START (Channel B) LOAD SHED & STBY. BRK. 2 Standby BUS FEED BKR. 2 RC-7 FDW-106 FDW-108 GWD-13 LWD-2 CS-6 PR-2(7) PR-3(7) PR-4(7) PR-5(7) PR-8 PR-10 FDW-103 FDW-104	HP-P1B	LP-P1A LP-17 LPSW-PIA(1)	LP-P1B LP-18 LPSW-PIB(2)	LPSW-P1C (3)

Channel 5	Channel 6	Channels 5 & 6	Channel 7	Channel 8
CC-7 LPSW-18 RBCU-F1A PR-E1A LPSW-1055 LPSW-1061	CC-8 LPSW-24 RBCU-F1C PR-E1B LPSW-1054 LPSW-1062	LPSW-15 LPSW-6 LPSW-21 RBCU-F1B	BS-1 BS-P1A	BS-2 BS-P1B

NOTES:

1. LPSW-P1C for Unit 2 LPSW-P3A for Unit 3
2. LPSW-P1B for Unit 2 LPSW-P3B for Unit 3
3. LPSW-P1A for Unit 2
4. Deleted per 2012 update
5. Deleted per 2012 update
6. Deleted per 2006 update
7. Maintained in ES position (closed) in accordance with the requirements of NUREG 0737, Item II.E.4.2.6 in any mode where ES is required operable.

Table 7-4. Characteristics of Out-of-Core Neutron Detector Assemblies

Characteristic		Source/Wide	Power
Type Tube Sensitivity		FC Gamma - Metrics 900217-101	UCIC[1]
Thermal Neutron Flux	20 CPS/nv		Note 2
Gamma Flux	NA		$1.5x10^{-10}$ A/R/hr
Maximum Ratings			
External Pressure		70 psig (QTR 010)	150 psig
Temperature		420 F (DBE QTR 010)	212 F
Thermal Neutron Flux			
Operating		$1x10^{10}$ nv	$1.5x10^{10}$ nv
Non-Operating		$1x10^{10}$ nv	$2.5x10^{11}$ nv
Gamma Flux		$1x10^{6}$ R/hr	$5x10^{5}$ R/hr
Integrated Exposure Before 10% Reduction in Sensitivity			
Neutron		10^{20} nvt	10^{19} nvt
Gamma		N/A	$3x10^{9}$ R

Note:

1. WL23636, WL23636A, and WL23636B Type Detectors are installed in various locations in Oconee Units (For Safety Related RPS Inputs); WL23675 is only installed in unit 1, a non-safety application (Unit 1 NI-9 abandoned in place per EC100792). Unit 2 NI-9 was abandoned in place per EC100793 and Unit 3 NI-9 was abandoned in place per EC100794. The original Qualification Test Report is for a WL23675 detector. All applicable data is the same for the WL23636 series except for Thermal Neutron Sensitivity. WL23636B is available replacement for all applications.
2. Approximate Thermal Neutron Sensitivity for Each Section

   WL-23675 3.75 x 10^{-13} A/nv

   WL-23636 3.75 x 10^{-13} A/nv

   WL-23636A 3.75 x 10^{-13} A/nv

   WL-23636B 2.15 x 10^{-13} A/nv (spec. for new detector)

Table 7-5. NNI Inputs to Engineered Safeguards

Characteristics	Reactor Outlet Pressure (WR)[1]	Reactor Building Pressure (WR)	Reactor Building Pressure (NR)
Component Item Number	RC3A-PT3 RC3A-PT4 RC3B-PT3	BS4-PS1 & 2 BS4-PS3 & 4 BS4-PS5 & 6	BS4-PT1 BS4-PT2 BS4-PT3
ESPS Channel	A,B,C	A,B,C	A,B,C
Sensor Type	Pressure Transmitter	Pressure Switch	Pressure Transmitter
Type Readout	all indicating	NA	all indicating
Power Required	external	none	external
Sensors Connected to Common Taps	Note (3)	BS4-PS2 & BS4-PT1 BS4-PS4 & BS4-PT2 BS4-PS6 & BS4-PT3	All separate building penetrations

NNI Inputs to RPS

Characteristics	Reactor Outlet Pressure (NR)[1]	Reactor Outlet Temperature (NR)	Reactor Coolant Flow	Reactor Building Pressure (NR)
Component Item Number	RC3A-PT1 RC3A-PT2 RC3B-PT1 RC3B-PT2	RC4A-TE1 RC4A-TE4 RC4B-TE1 RC4B-TE4	RC14A-dPT1 RC14A-dPT2 RC14A-dPT3 RC14A-dPT4 RC14B-dPT1 RC14B-dPT2 RC14B-dPT3 RC14B-dPT4	BS4-PS7 BS4-PS8 BS4-PS9 BS4-PS10
Reactor Protective Channel	A,B,C,D	A,B,C,D	A,B,C,D[2]	A,B,C,D
Sensor Type	Press. Transmitter	RTD	Differential Pressure Transmitter	Pressure Switch
Type Readout	all indicating	all indicating	all indicating	NA
Power Required	external	external	external	none

NNI Inputs to RPS				
Characteristics	**Reactor Outlet Pressure (NR)[1]**	**Reactor Outlet Temperature (NR)**	**Reactor Coolant Flow**	**Reactor Building Pressure (NR)**
Sensors Connected to Common Taps	RC3A-PT1 [3] & RC3A-PT3 RC3A-PT2 & RC3A-PT4 RC3B-PT1 & RC3B-PT3	All sensors have separate taps.	All sensors for same loop are connected to common taps.	All sensors have separate taps.

Note:

1. NR = Narrow Range, WR = Wide Range
2. Each channel has an input from each loop.
3. Pressure taps for each RPS channel are independent. A RPS channel and an ESPS channel may have common pressure sensing taps.
4. Deleted per 2006 Update.

Table 7-6. ICS Transient Limits

Transient	Ramp Range (% Full Power)	Ramp Input Limit (% Power/min)
Power Increase	2-15	1
	15-20	5
	20-95	9.9
	95-100	5
Power Decrease	100-95	9.9
	95-20	9.9
	20-15	5
	15-2	1
Runback	**High Limit (% Full Power)**	**Ramp Input Limit (% Power/min)**
RC Flow		20
RCP	74	25
Feedwater Pump Limit	65	25
Asymmetric Rod	55	1
Generator Breakers	20	20
Maximum Runback	15	20
Condensate/Feedwater Pump Low Suction Pressure	15	20
Reactor Trip	0	600

Appendix 7B. Figures

Figure 7-1. Reactor Protection System

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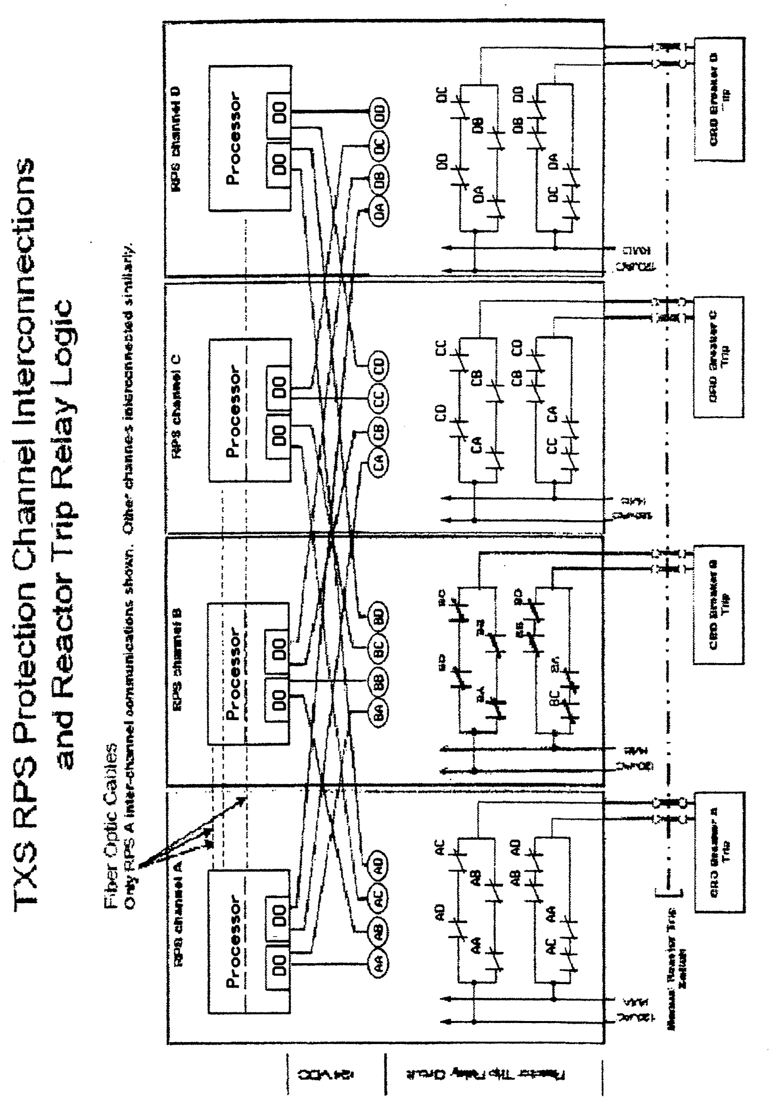
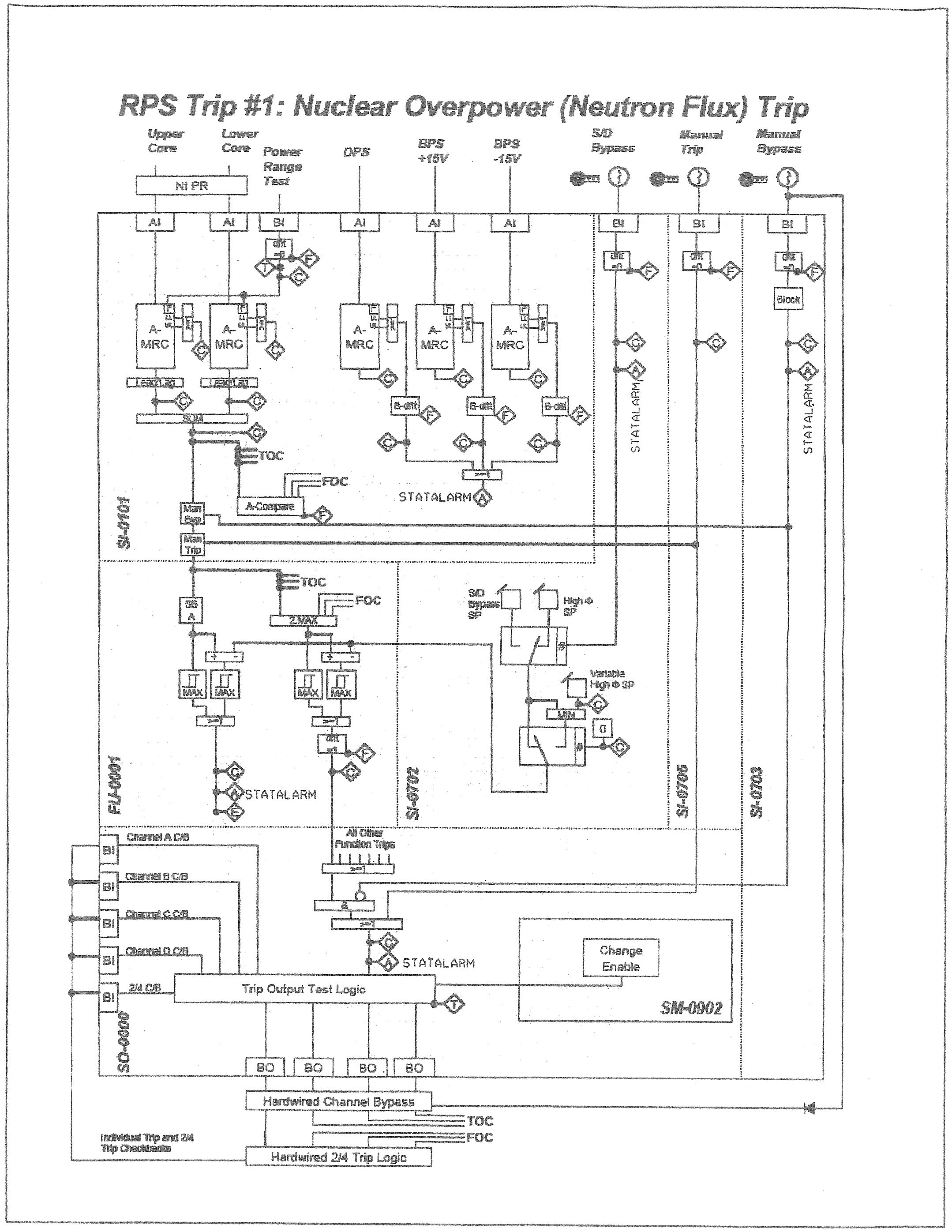
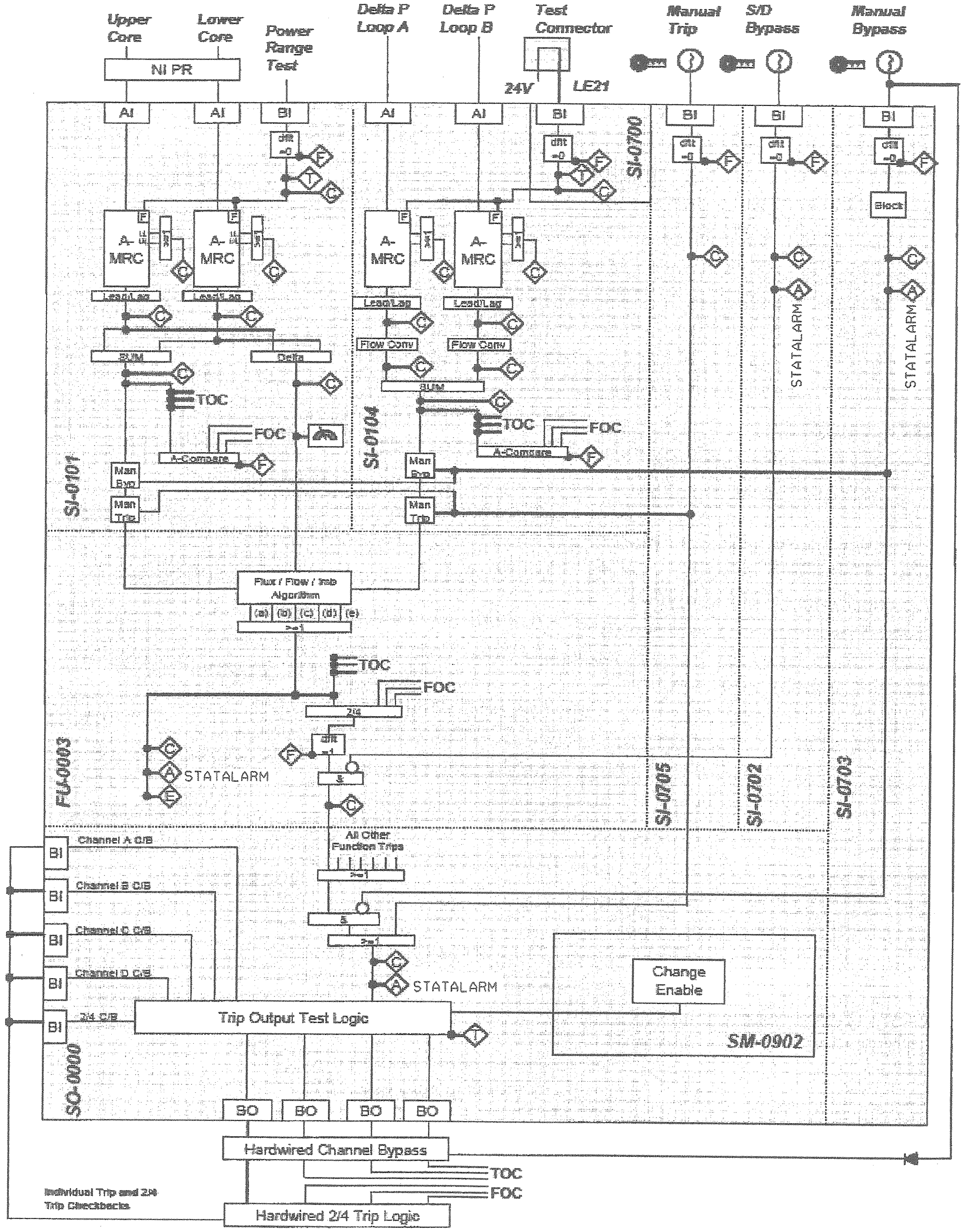

TXS RPS Protection Channel Interconnections
and Reactor Trip Relay Logic
Fiber Optic Cables
Only RPS A inter-channel communications shown. Other channels interconnected similarly.
RPS channel A
RPS channel B
RPS channel C
RPS channel D
Processor
DO
AA
AB
AC
AD
BA
BB
BC
BD
CA
CB
CC
CD
DA
DB
DC
DD
CRD Breaker A Trip
CRD Breaker B Trip
CRD Breaker C Trip
CRD Breaker D Trip
24 VDC
Reactor Trip Relay Circuit

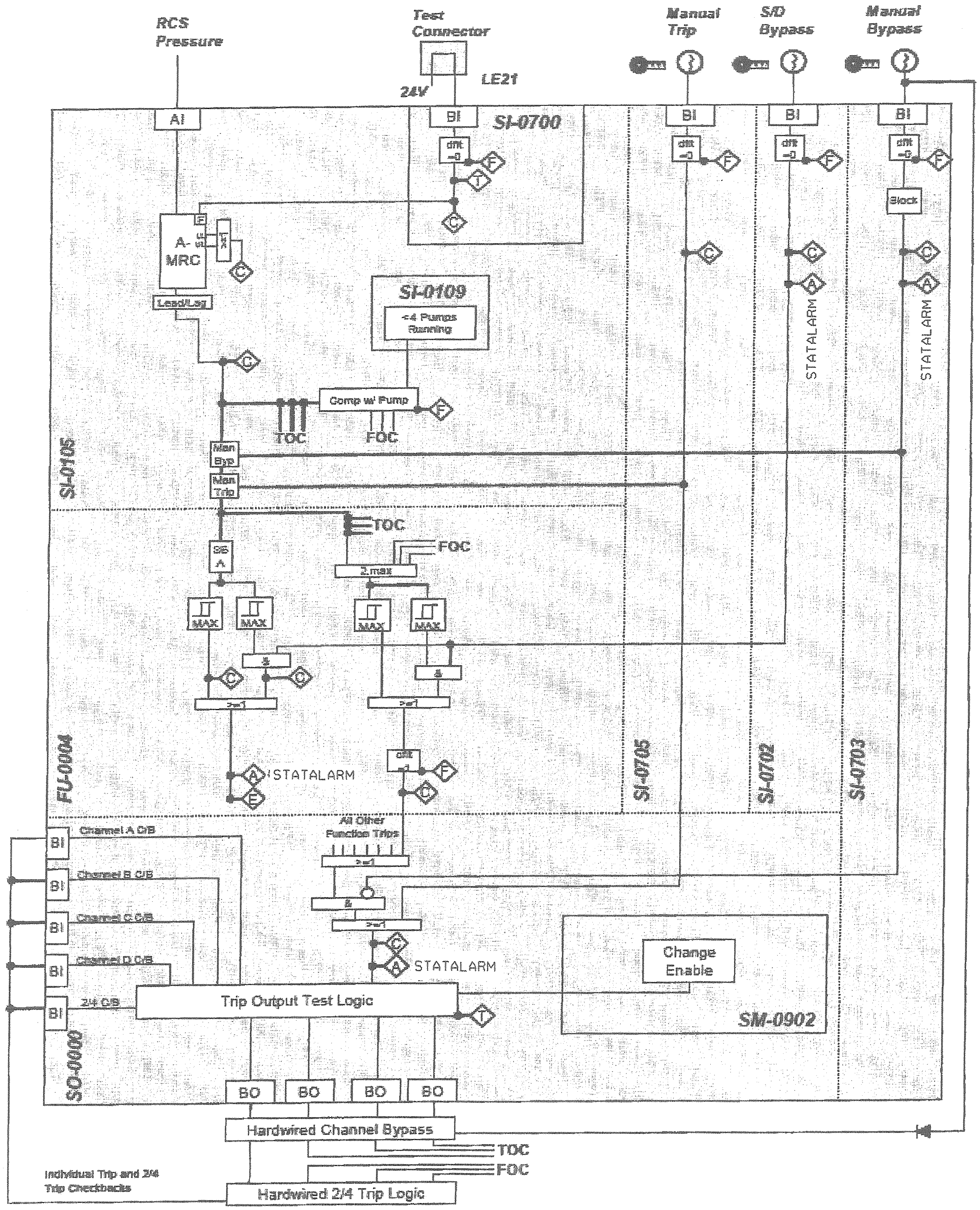

RPS Trip #1: Nuclear Overpower (Neutron Flux) Trip
Upper Core
Lower Core
Power Range Test
DPS
BPS +15V
BPS -15V
S/D Bypass
Manual Trip
Manual Bypass
NI PR
AI
BI
Block
A-MRC
Lead/Lag
SUM
B-diff
TOC
FOC
A-Compare
STATALARM
Man Byp
Man Trip
SB A
2 MAX
MAX
S/D Bypass SP
High Φ SP
Variable High Φ SP
MIN
SI-0101
FU-0001
SI-0702
SI-0705
SI-0703
Channel A C/B
Channel B C/B
Channel C C/B
Channel D C/B
2/4 C/B
All Other Function Trips
Trip Output Test Logic
Change Enable
SM-0902
SO-0000
BO
Hardwired Channel Bypass
Individual Trip and 2/4 Trip Checkbacks
Hardwired 2/4 Trip Logic

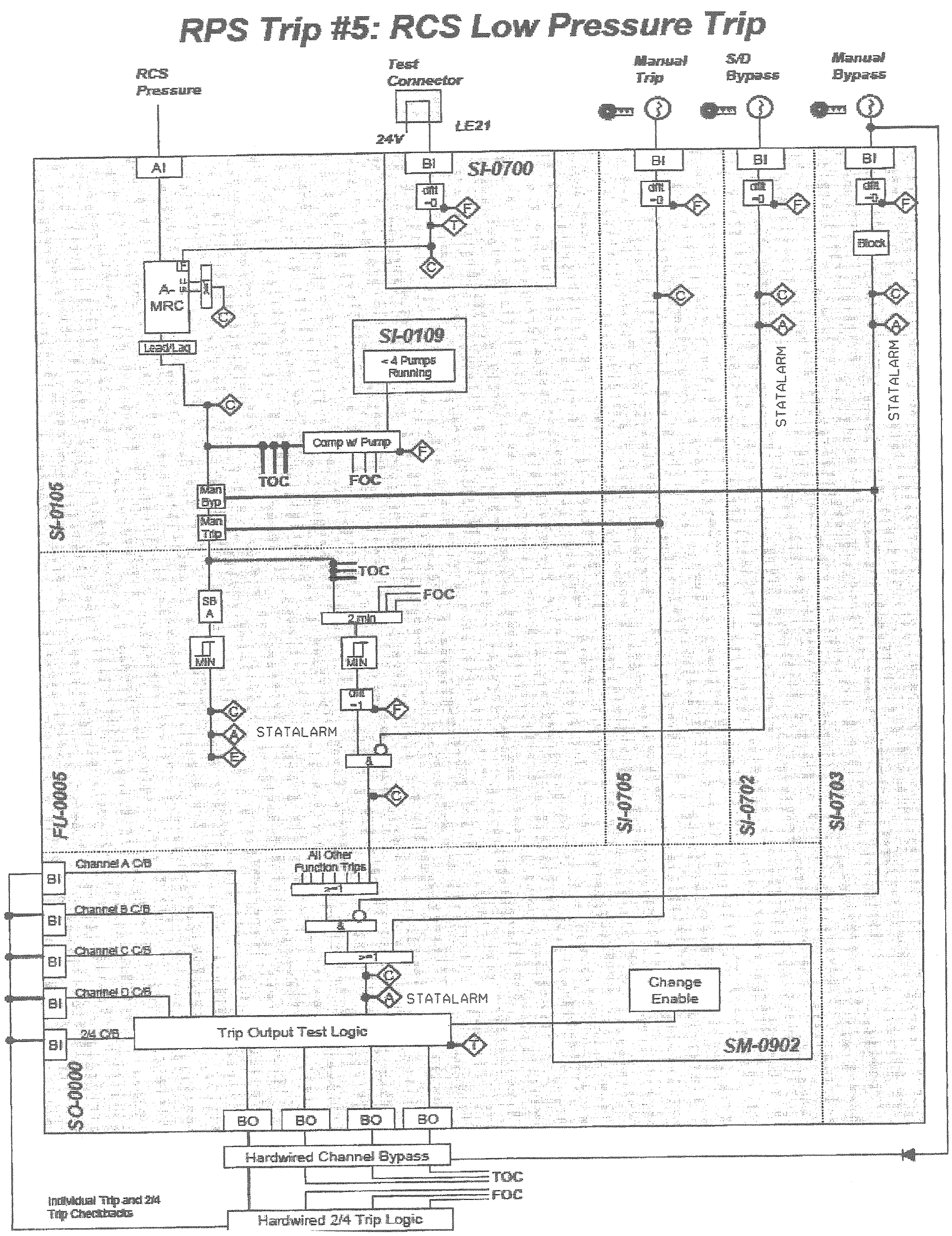
RPS #2 Trip Not Used

RPS Trip #3: Nuclear Overpower Flux/Flow/Imbalance Trip



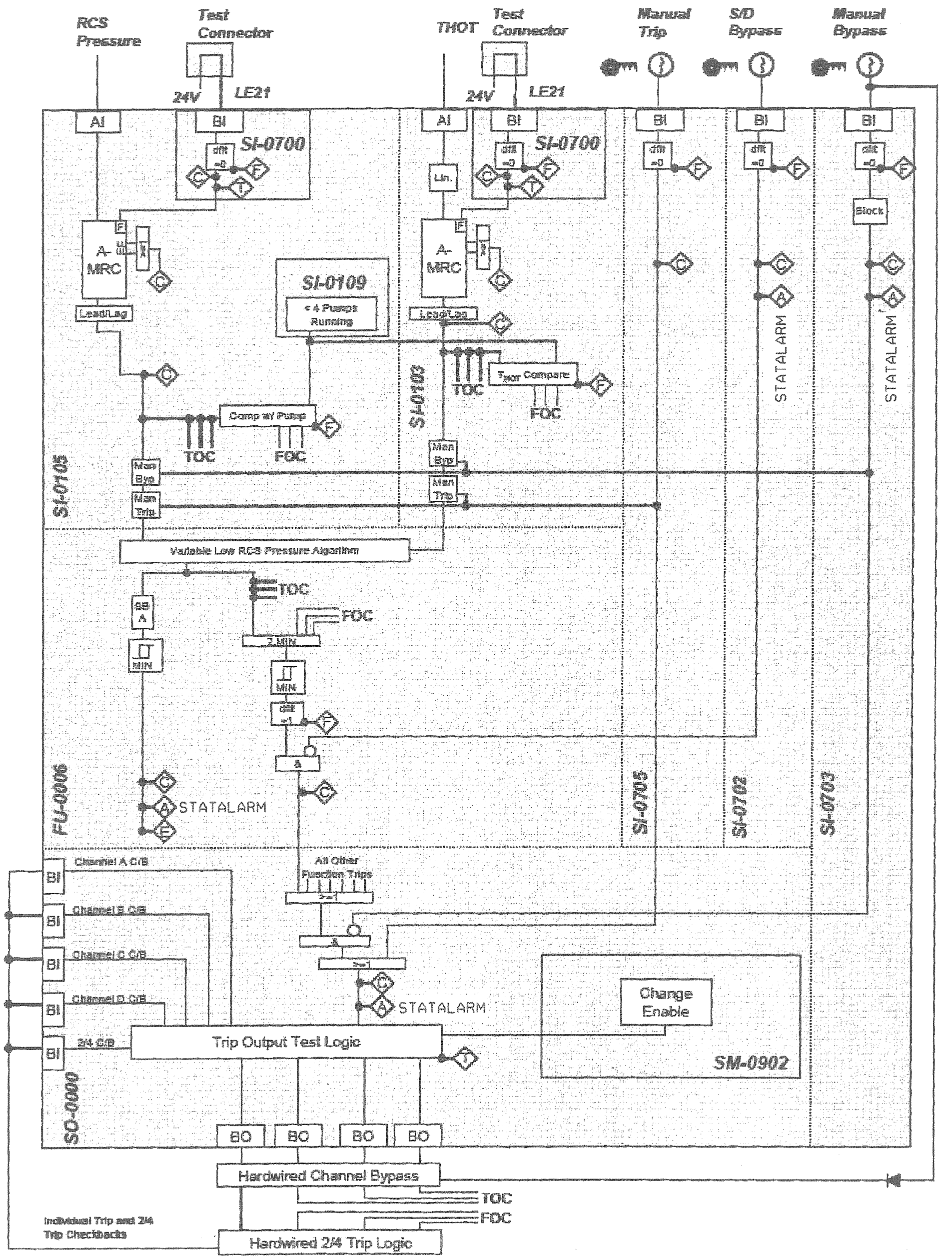
RPS Trip #4: RCS High Pressure Trip




RPS Trip #5: RCS Low Pressure Trip
RCS Pressure
Test Connector
24V
LE21
Manual Trip
S/D Bypass
Manual Bypass
AI
BI
SI-0700
A-MRC
Lead/Lag
SI-0109
< 4 Pumps Running
Comp w/ Pump
TOC
FOC
Man Byp
Man Trip
SI-0105
Block
STATALARM
SB A
2 min
MIN
FU-0005
SI-0705
SI-0702
SI-0703
Channel A C/B
Channel B C/B
Channel C C/B
Channel D C/B
2/4 C/B
All Other Function Trips
>=1
&
Change Enable
Trip Output Test Logic
SM-0902
SO-0000
BO
Hardwired Channel Bypass
Individual Trip and 2/4 Trip Checkbacks
Hardwired 2/4 Trip Logic

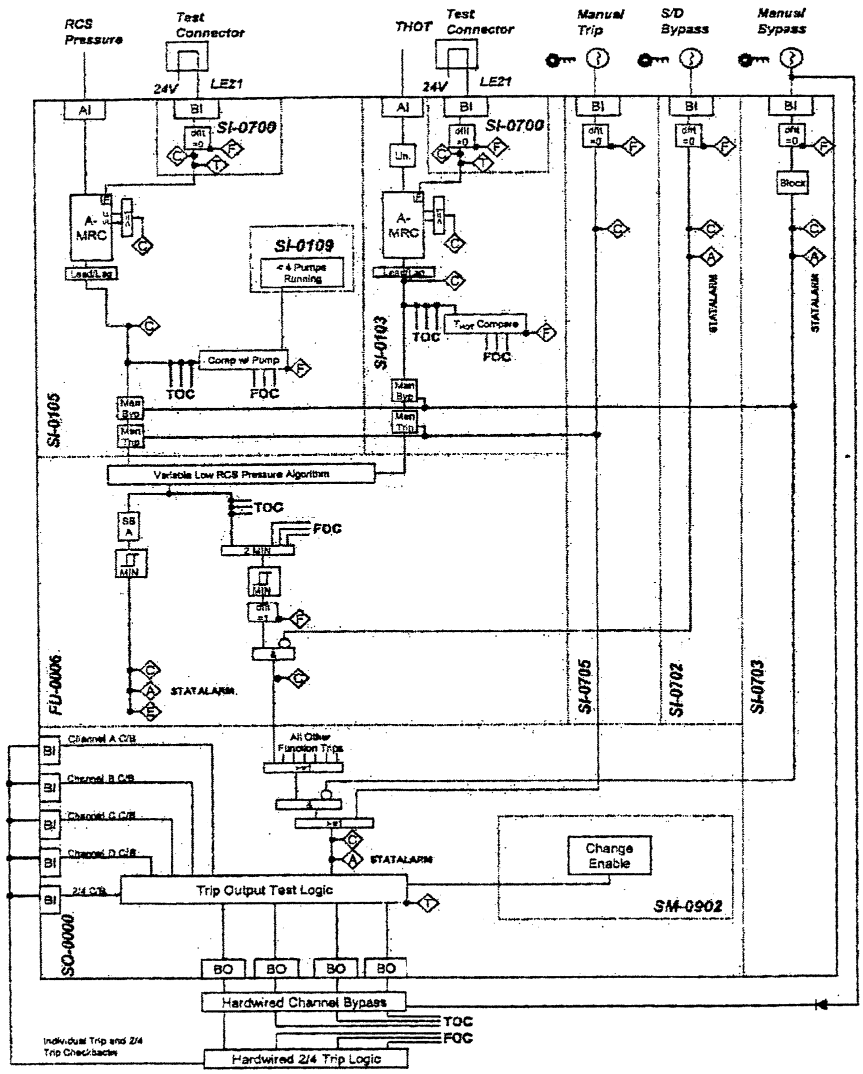
UNIT 1 ONLY

RPS Trip #6: RCS Variable Low Pressure Trip

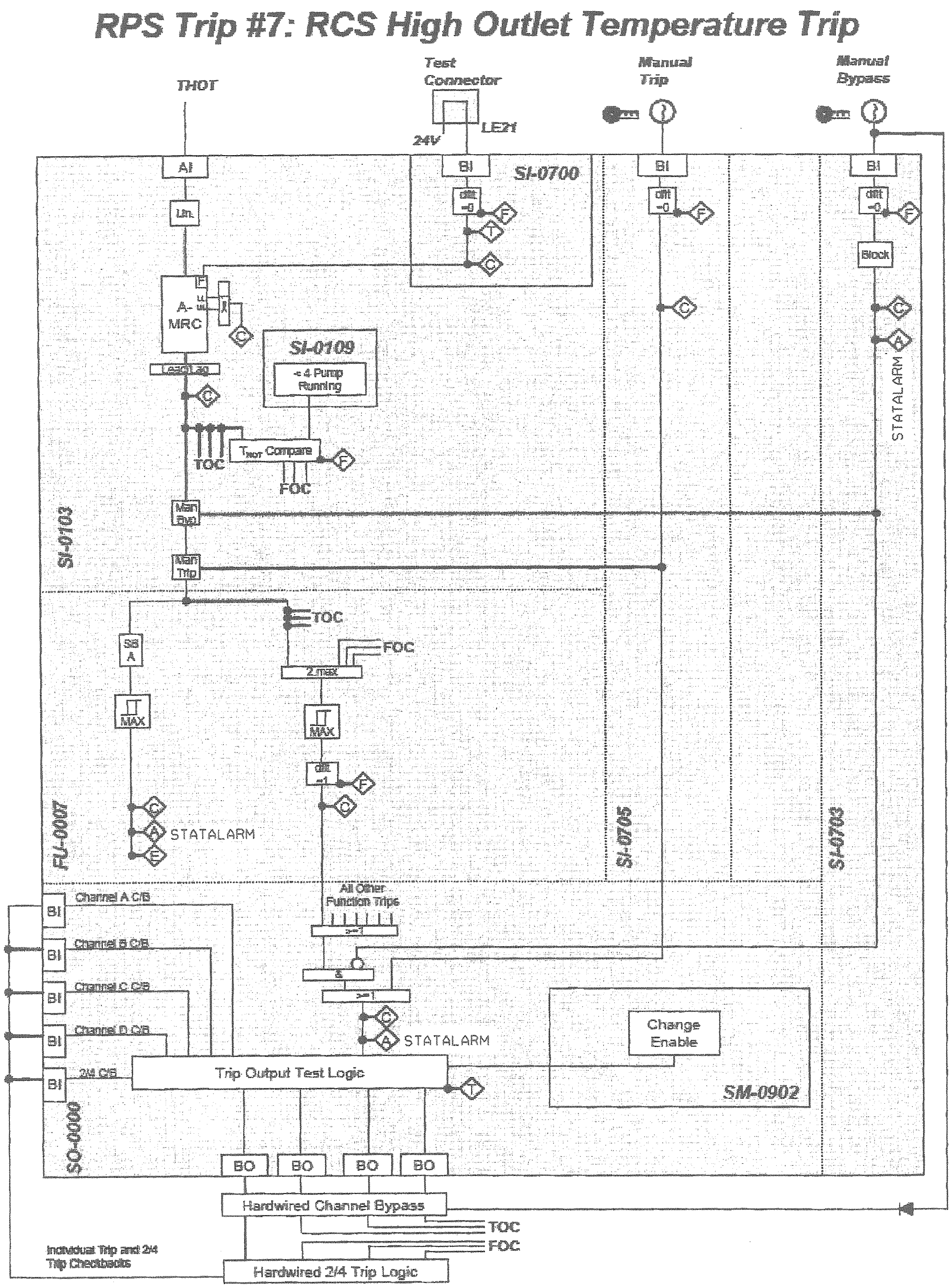


UNITS 2 & 3 ONLY

RPS Trip #6: RCS Variable Low Pressure Trip

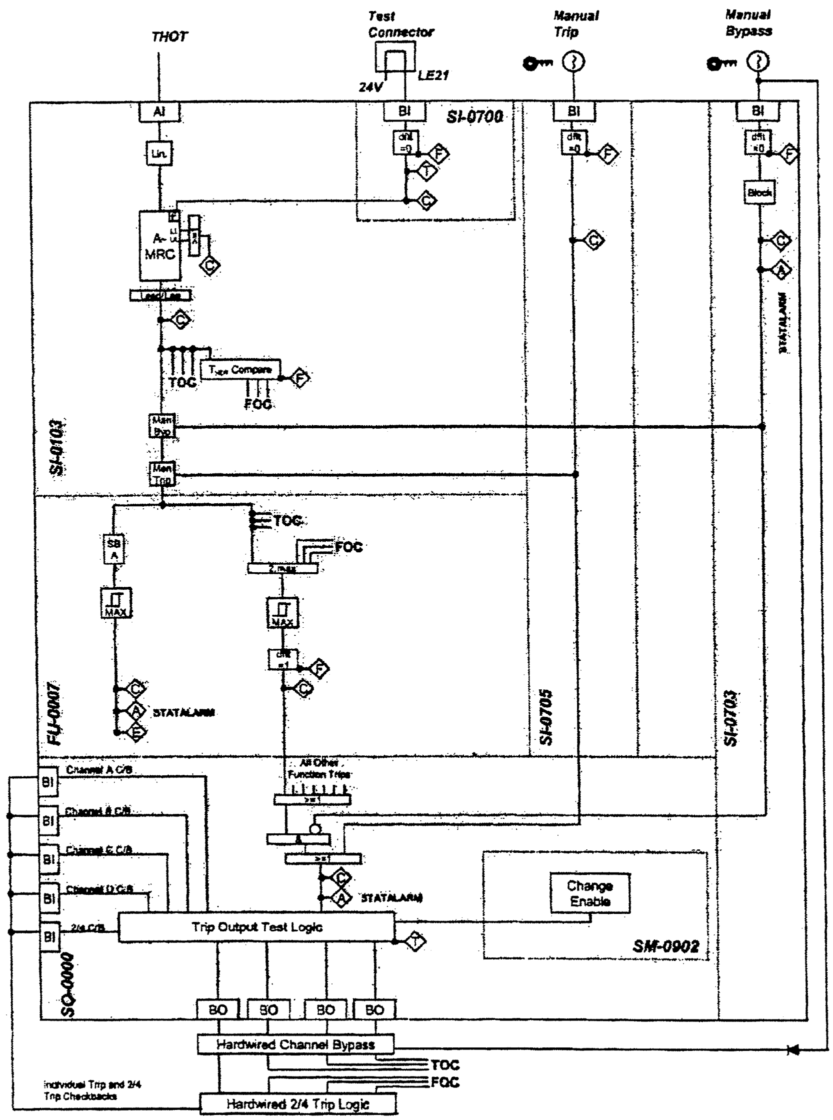


UNIT 1 ONLY

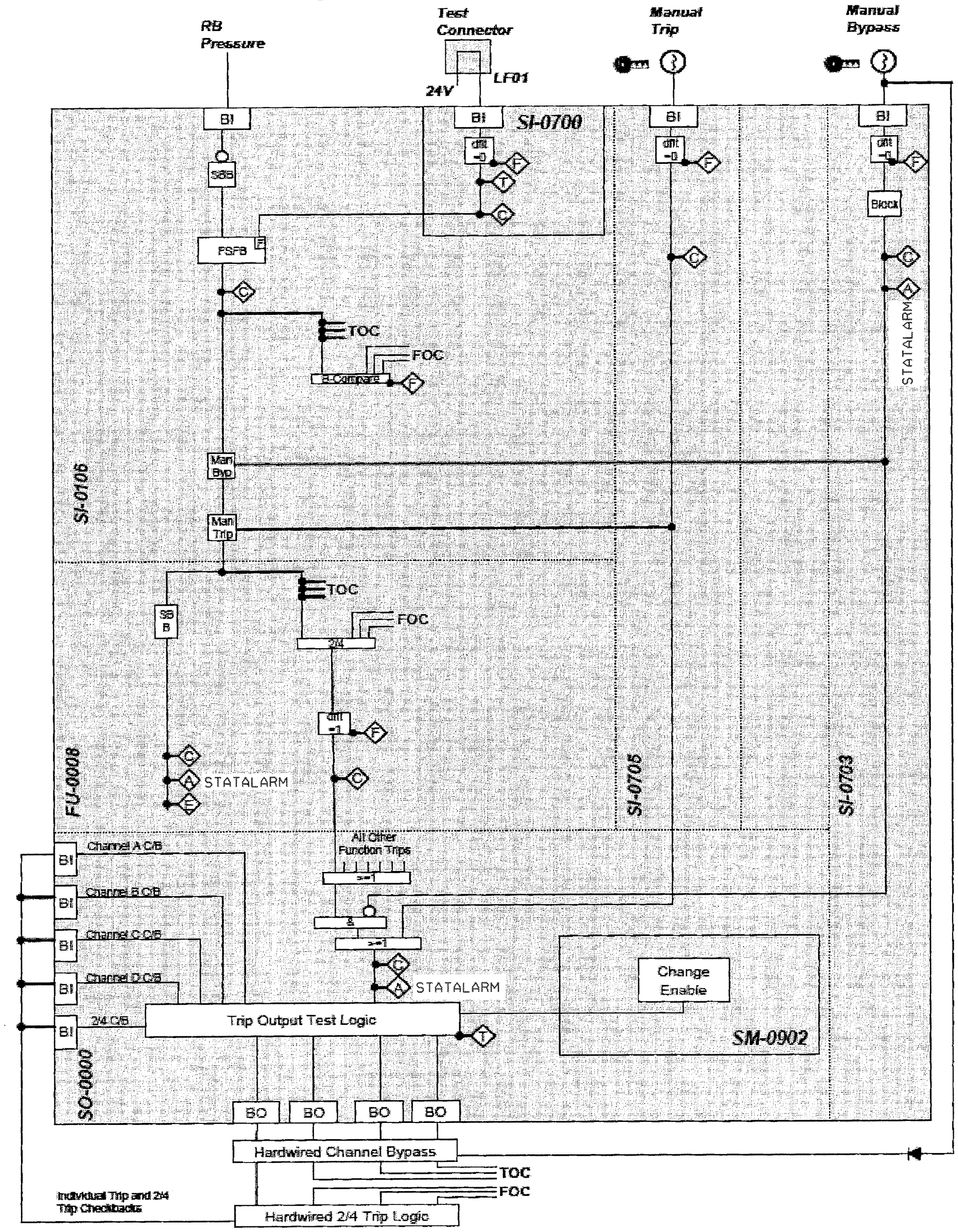

RPS Trip #7: RCS High Outlet Temperature Trip
THOT
Test Connector
24V
LE21
Manual Trip
Manual Bypass
AI
BI
SI-0700
Lim.
A-MRC
Lead Lag
SI-0109
< 4 Pump Running
TOC
FOC
Man Byp
Man Trip
SI-0103
SB A
MAX
2.max
STATALARM
FU-0007
SI-0705
SI-0703
Block
All Other Function Trips
Channel A C/B
Channel B C/B
Channel C C/B
Channel D C/B
2/4 C/B
Trip Output Test Logic
Change Enable
SM-0902
SO-0000
BO
Hardwired Channel Bypass
Individual Trip and 2/4 Trip Checkbacks
Hardwired 2/4 Trip Logic

UNITS 2 & 3 ONLY

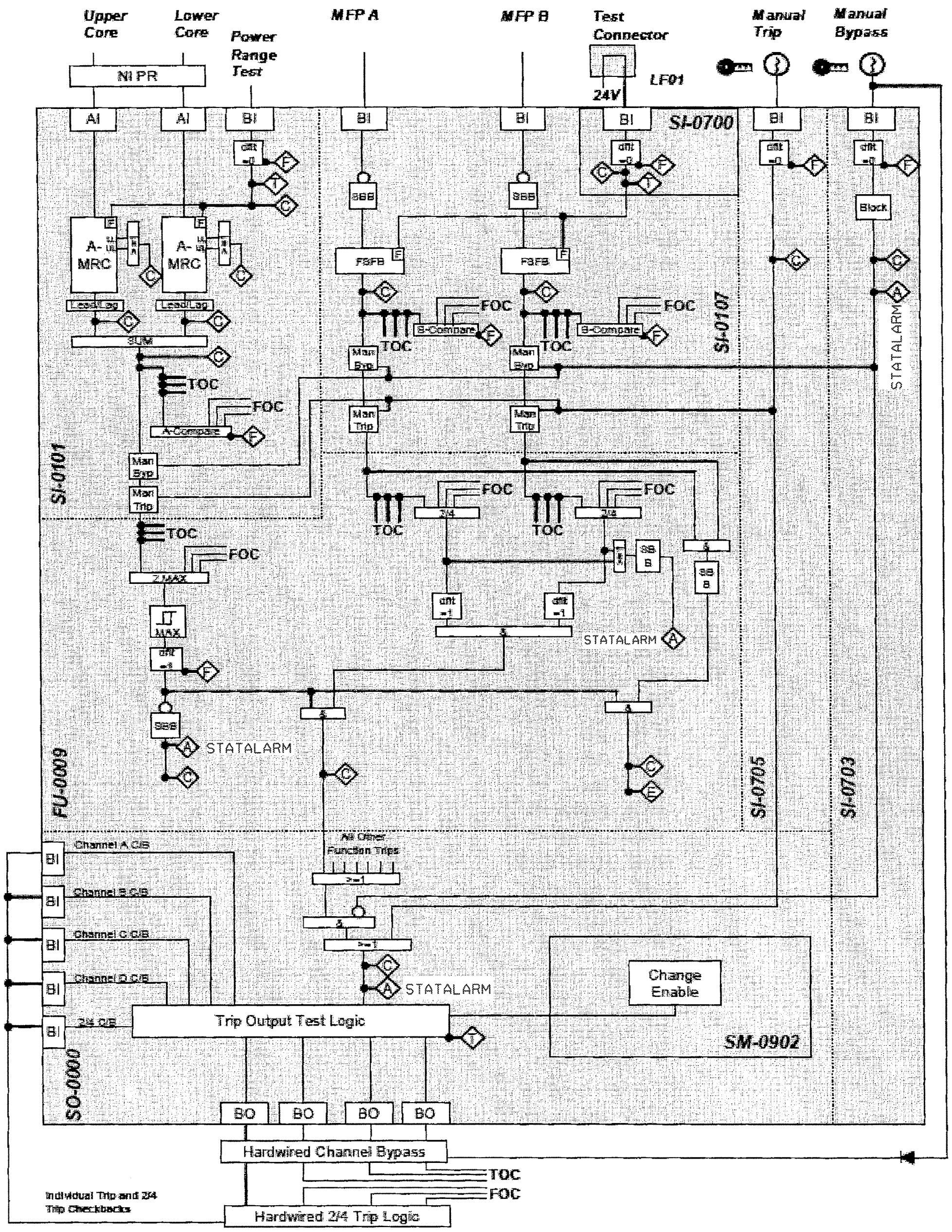
RPS Trip #7: RCS High Outlet Temperature Trip



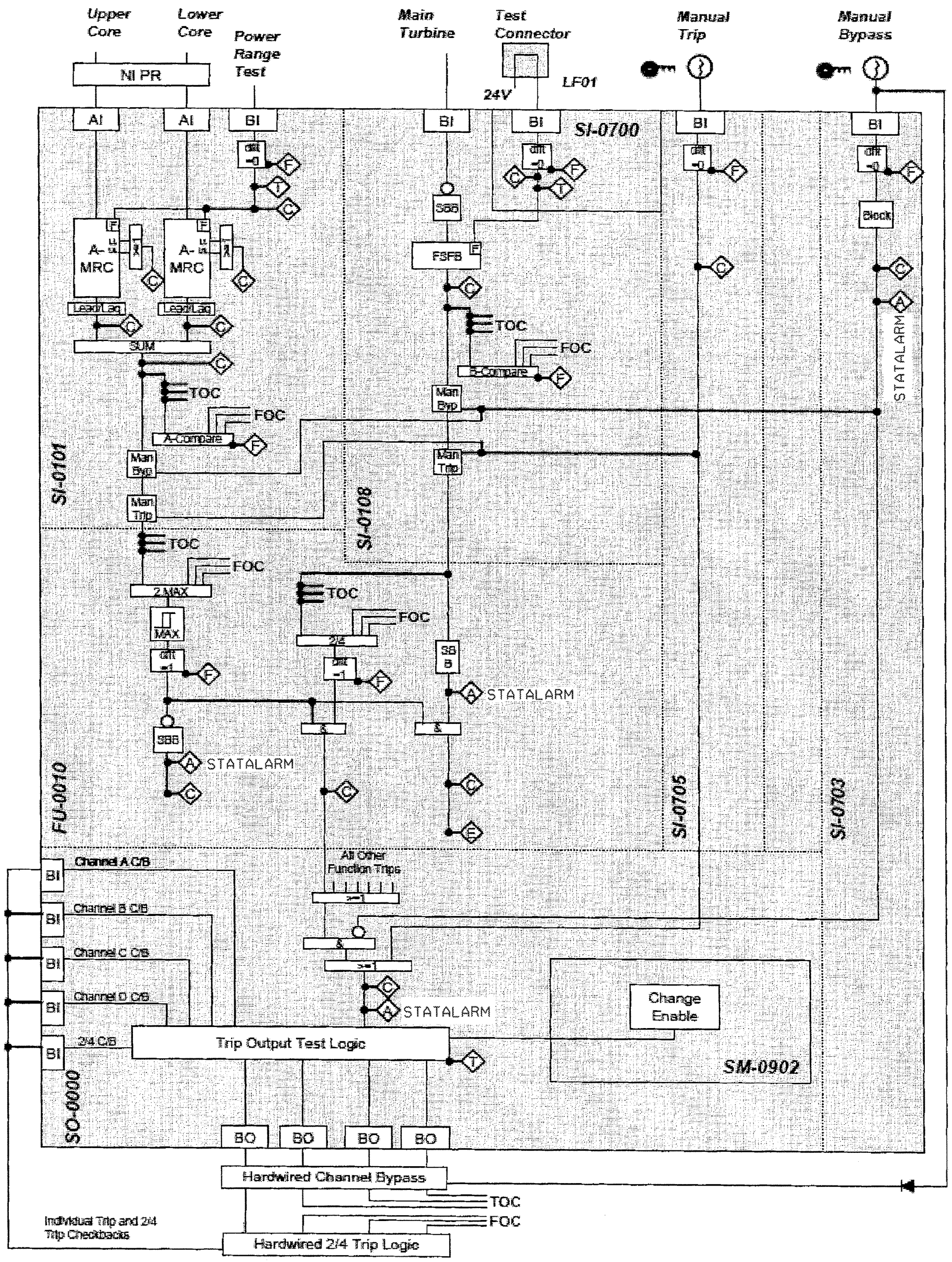
RPS Trip #8: RB High Pressure Trip



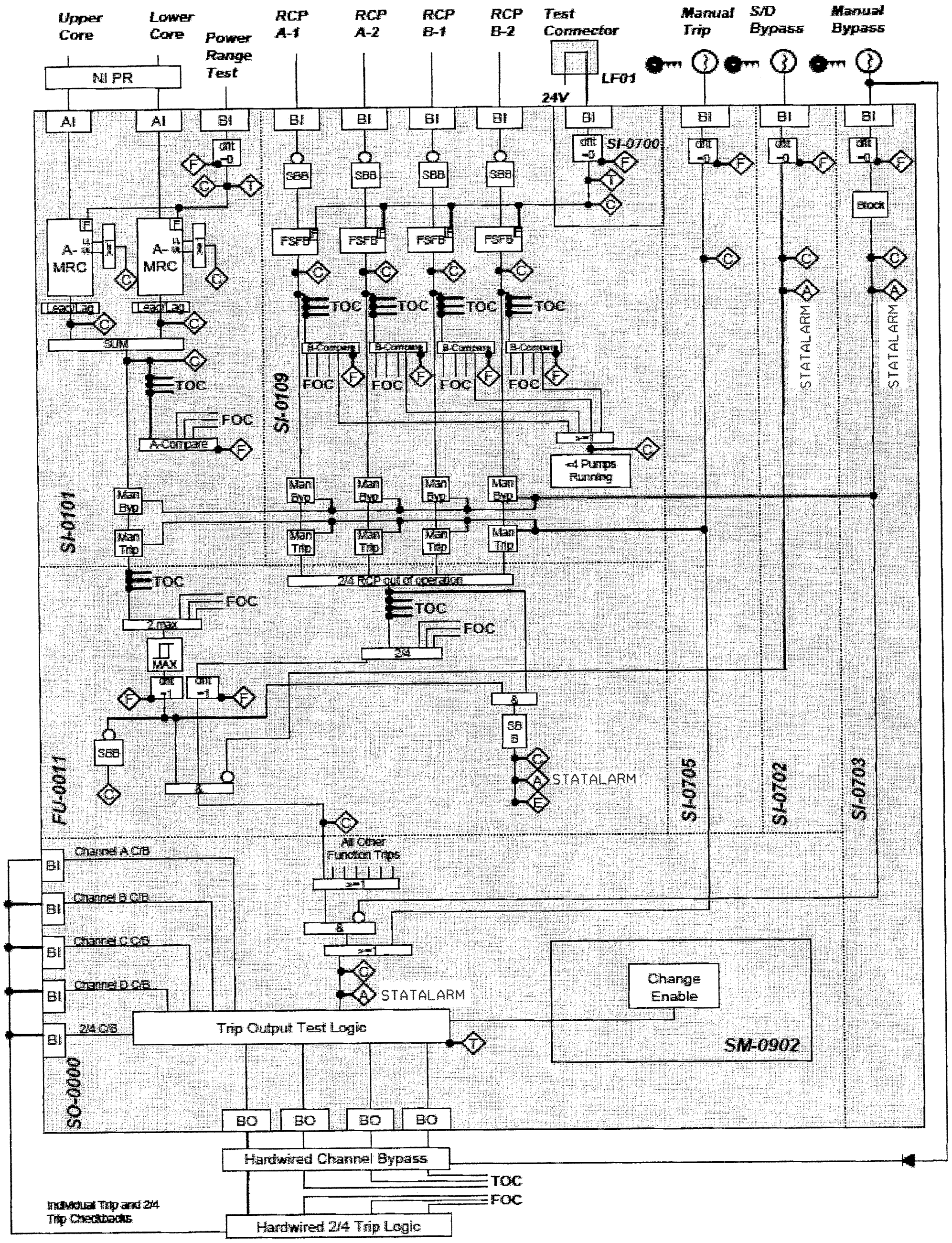
RPS Trip #9: Loss of Both Main Feedwater Pumps Trip



RPS Trip #10: Main Turbine Trip



RPS Trip #11: Reactor Coolant Pump Power/Flux Trip



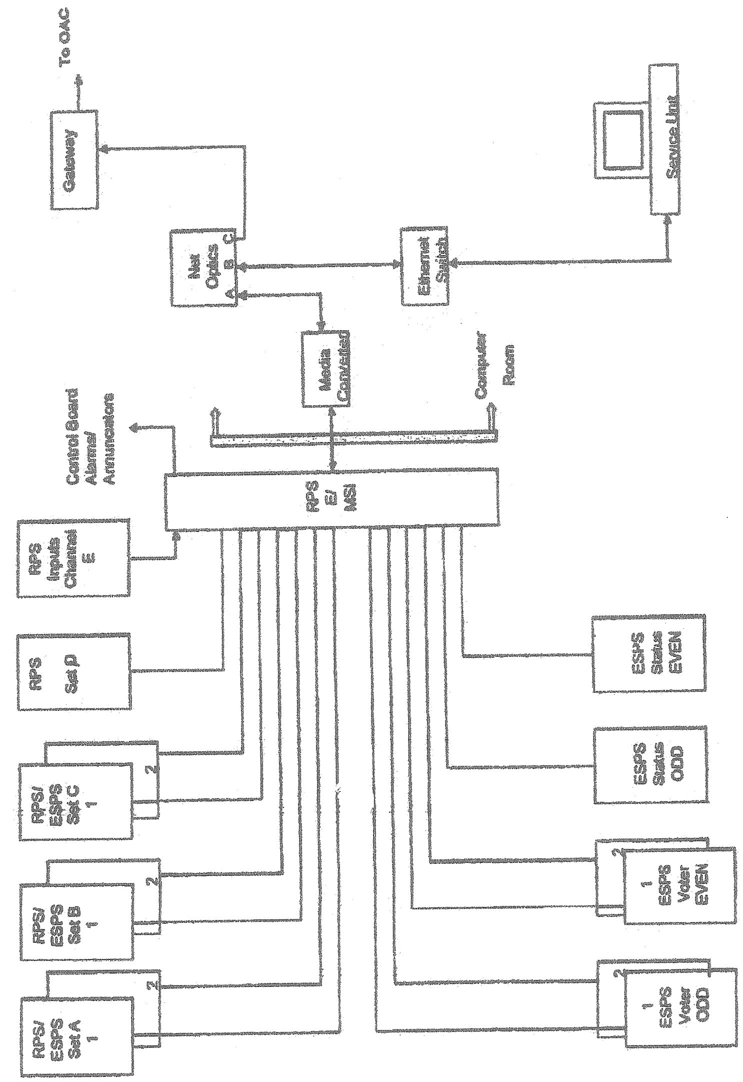

To OAC
Gateway
Net Optics
A B C
Ethernet Switch
Service Unit
Media Converter
Computer Room
Control Board Alarms/ Annunciators
RPS E/ MSI
RPS Inputs Channel E
RPS Set D
RPS/ ESPS Set C 1
2
RPS/ ESPS Set B 1
2
RPS/ ESPS Set A 1
2
ESPS Status EVEN
ESPS Status ODD
1 ESPS Voter EVEN
2
1 ESPS Voter ODD
2

Figure 7-2. Typical Pressure Temperature Boundaries

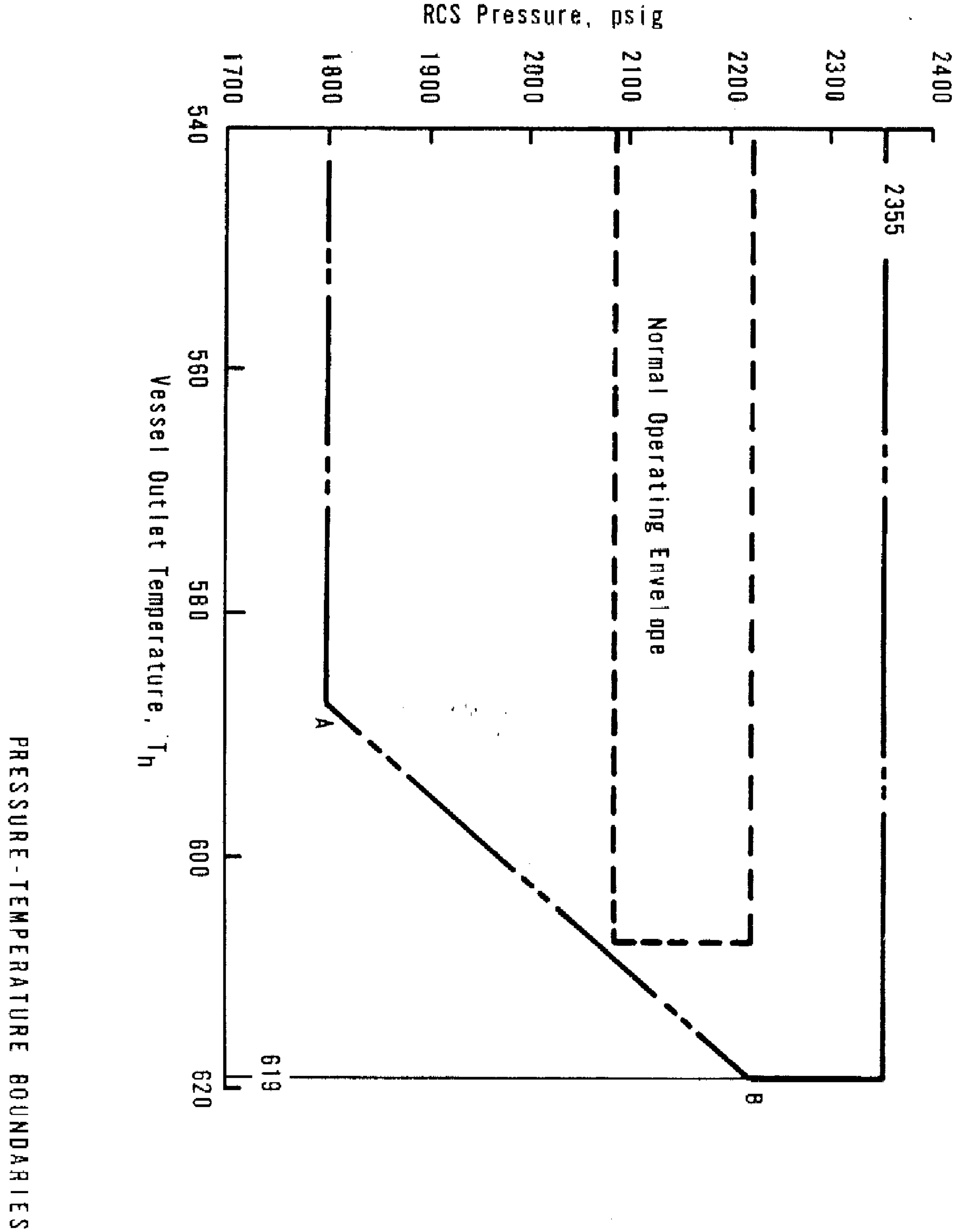


Figure 7-3. Typical Power Imbalance Boundaries

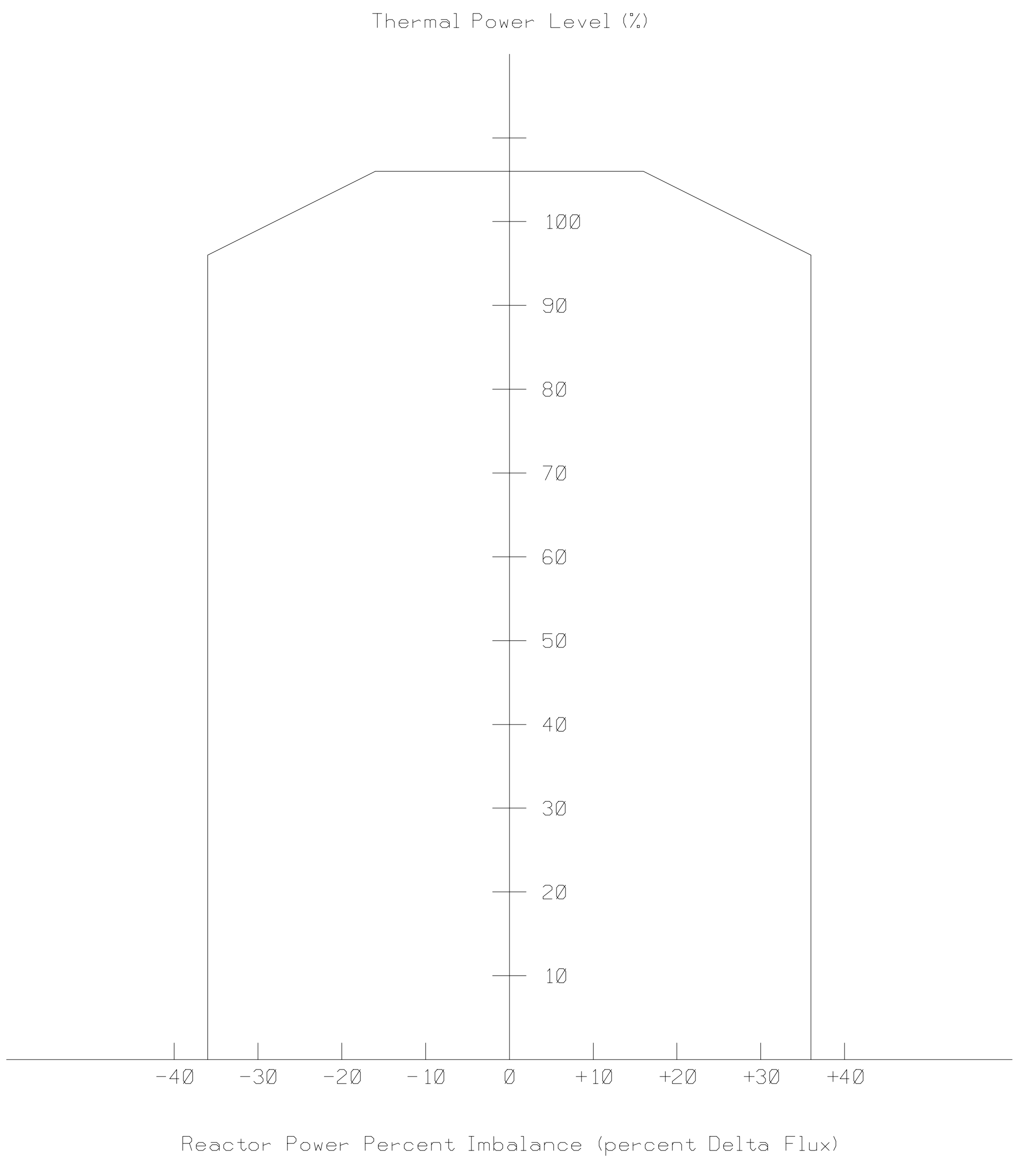


Figure 7-4. Rod Control Drive Controls

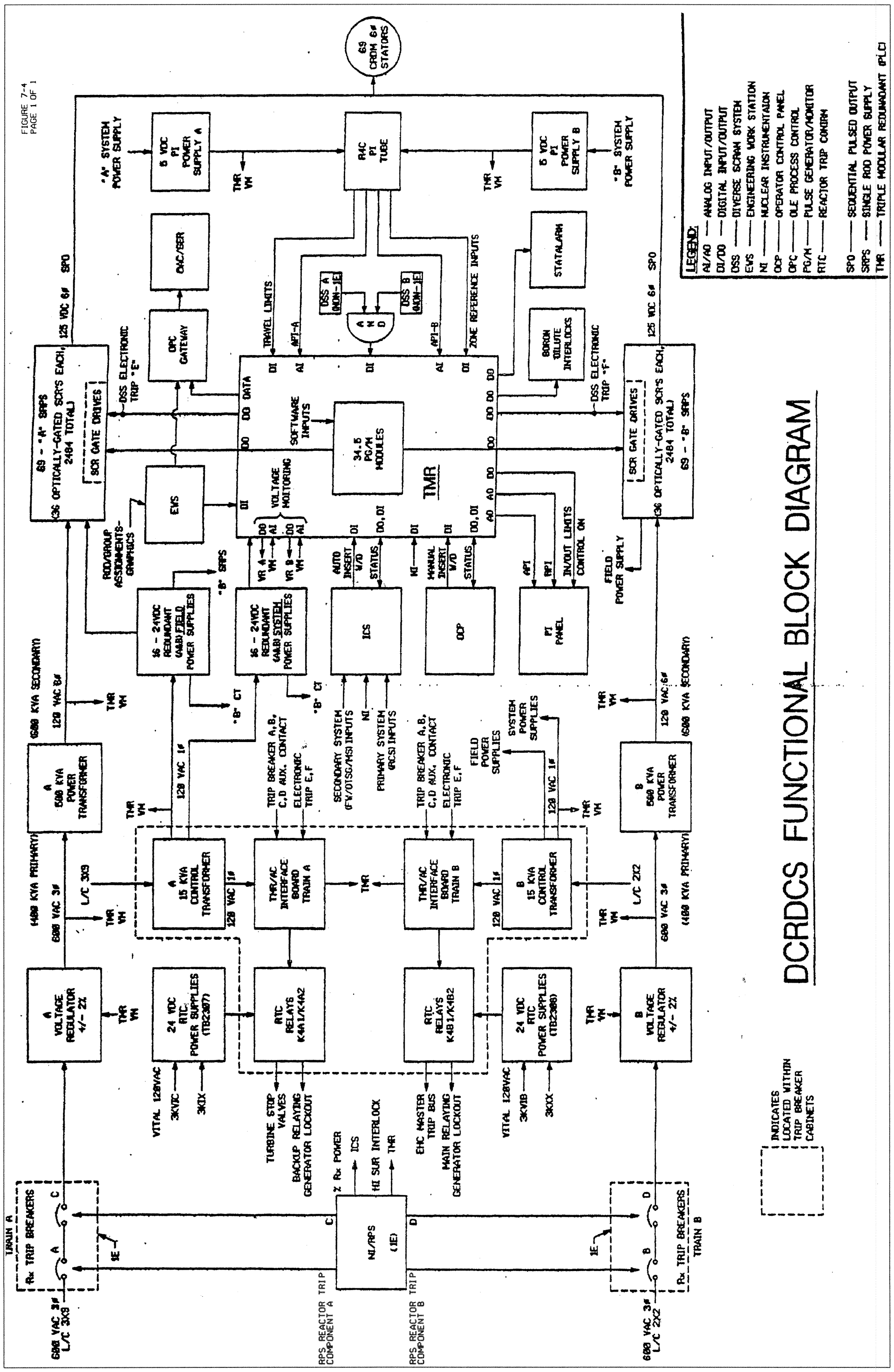


Figure 7-5. Engineered Safeguards Protection System

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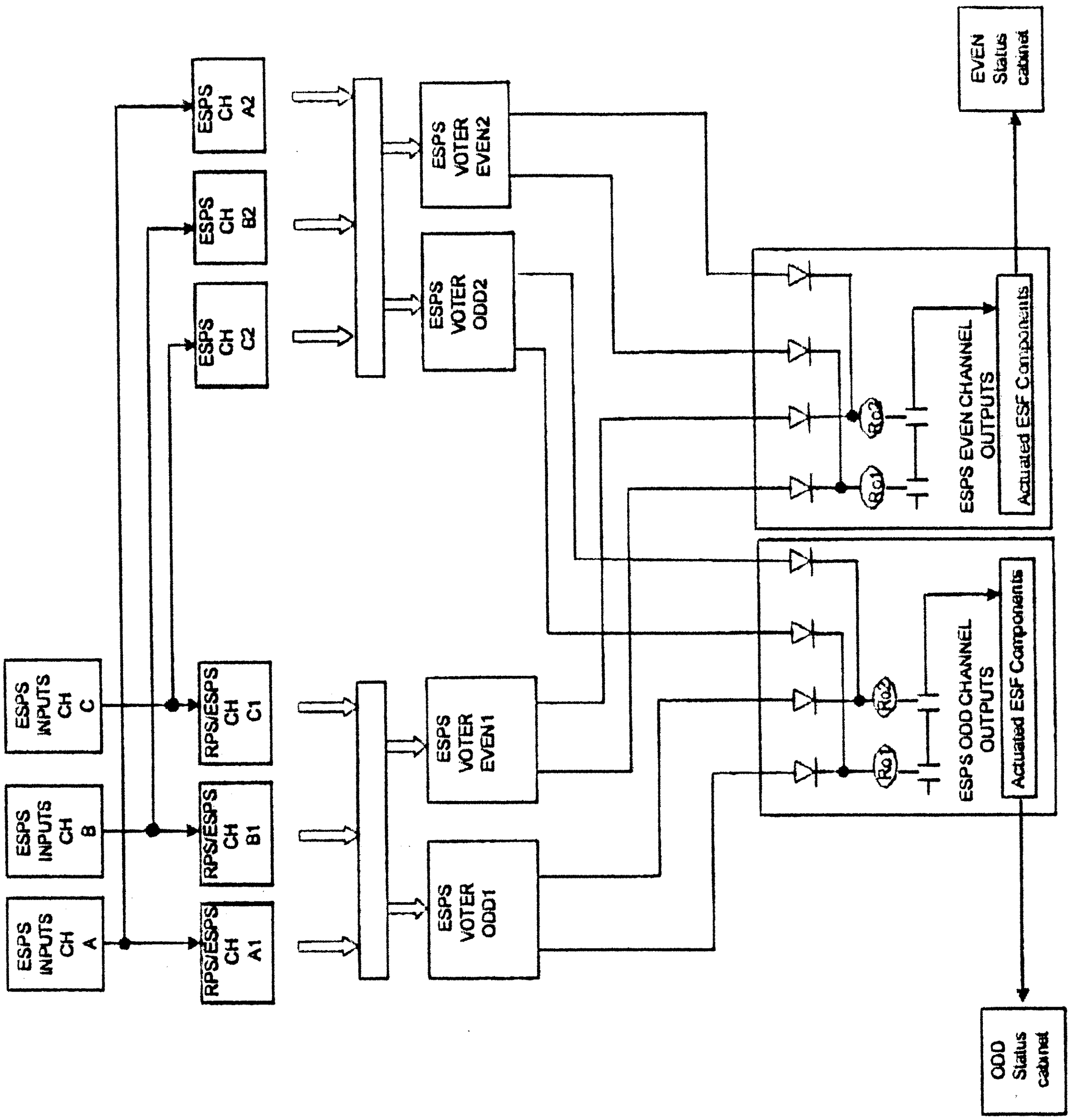
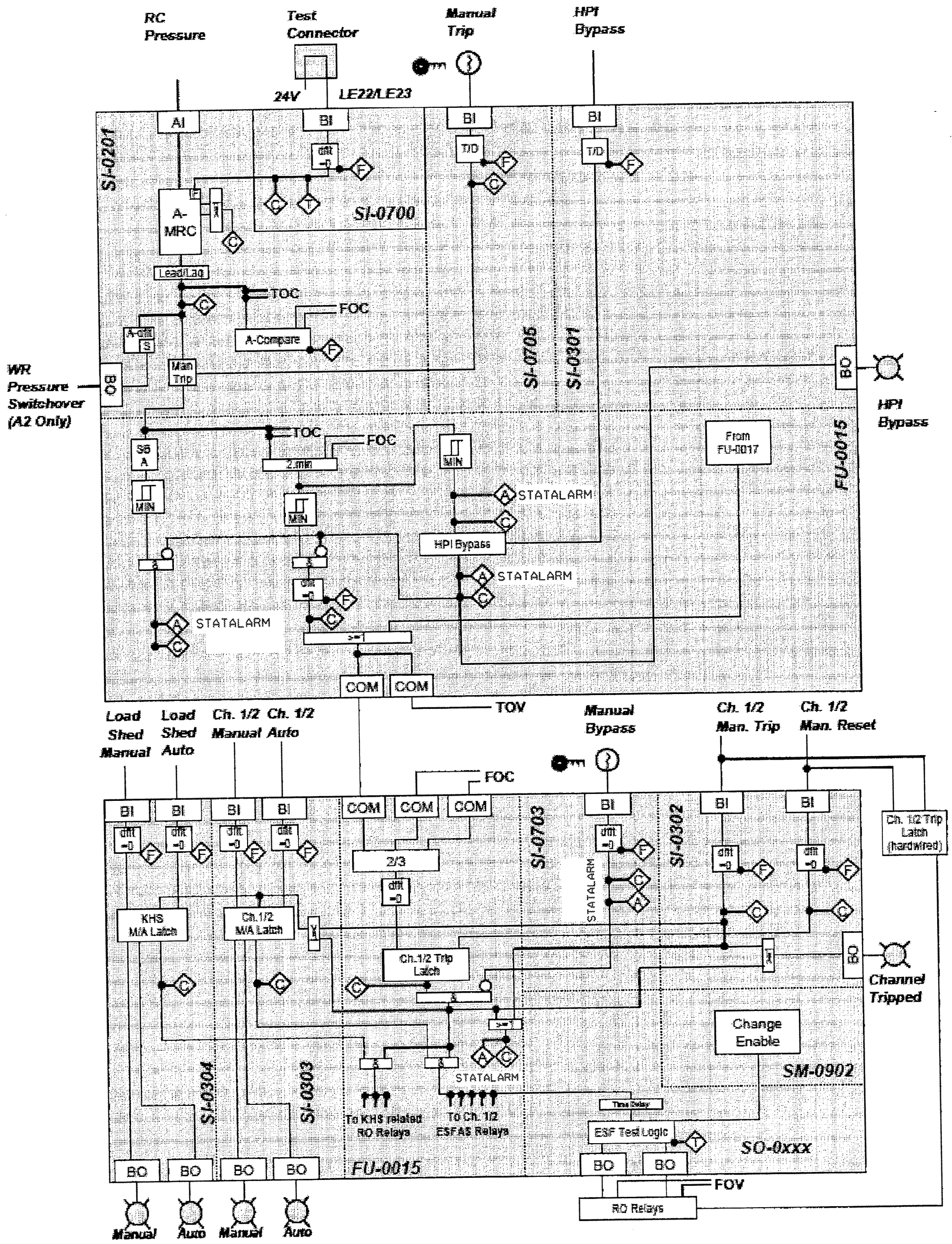

ESPS INPUTS CH A
ESPS INPUTS CH B
ESPS INPUTS CH C
RPS/ESPS CH A1
RPS/ESPS CH B1
RPS/ESPS CH C1
ESPS CH C2
ESPS CH B2
ESPS CH A2
ESPS VOTER ODD1
ESPS VOTER EVEN1
ESPS VOTER ODD2
ESPS VOTER EVEN2
ESPS ODD CHANNEL OUTPUTS
ESPS EVEN CHANNEL OUTPUTS
Actuated ESF Components
Actuated ESF Components
ODD Status cabinet
EVEN Status cabinet

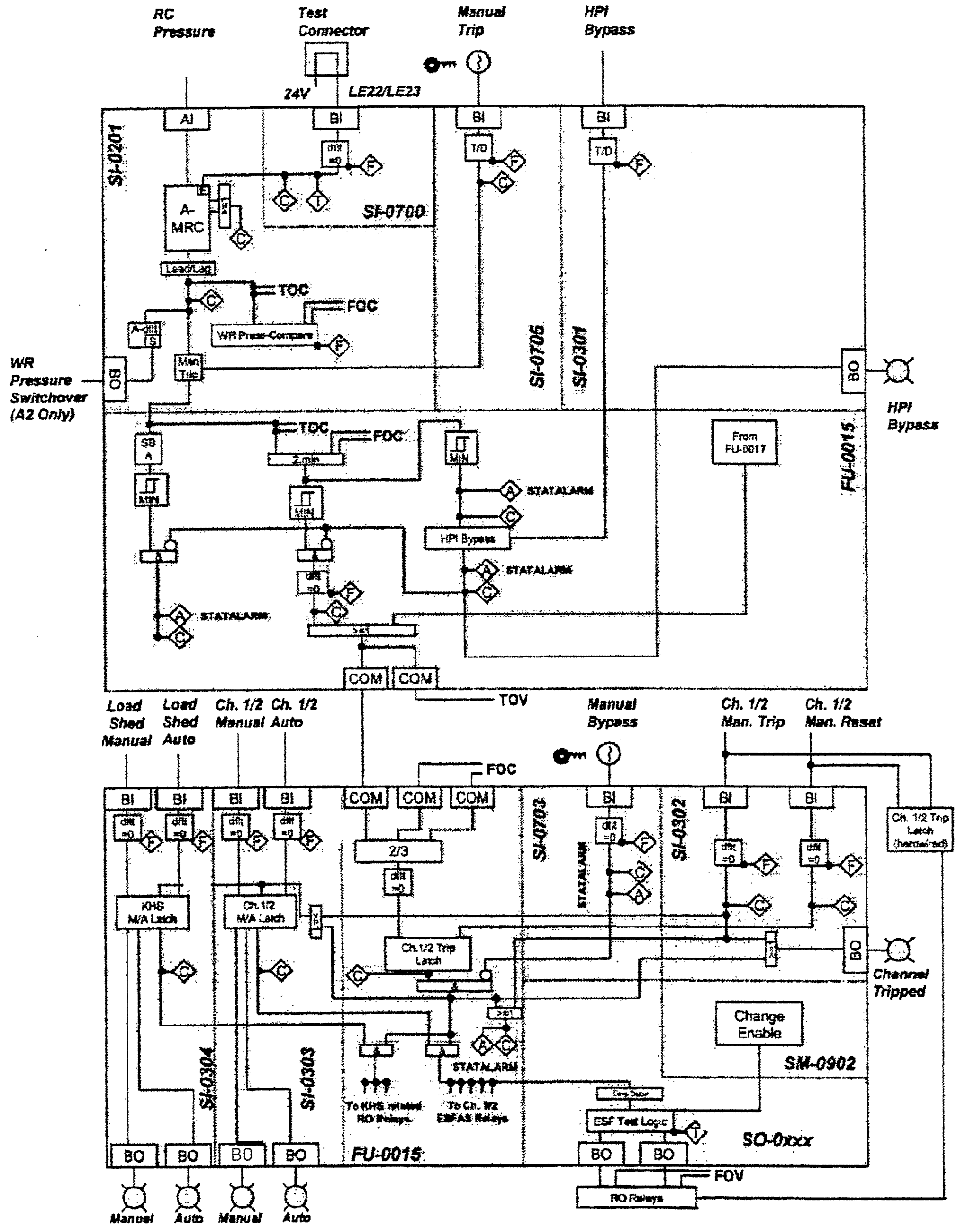
UNIT 1 ONLY

ESFAS Trip #1: RCS Pressure Low Trip

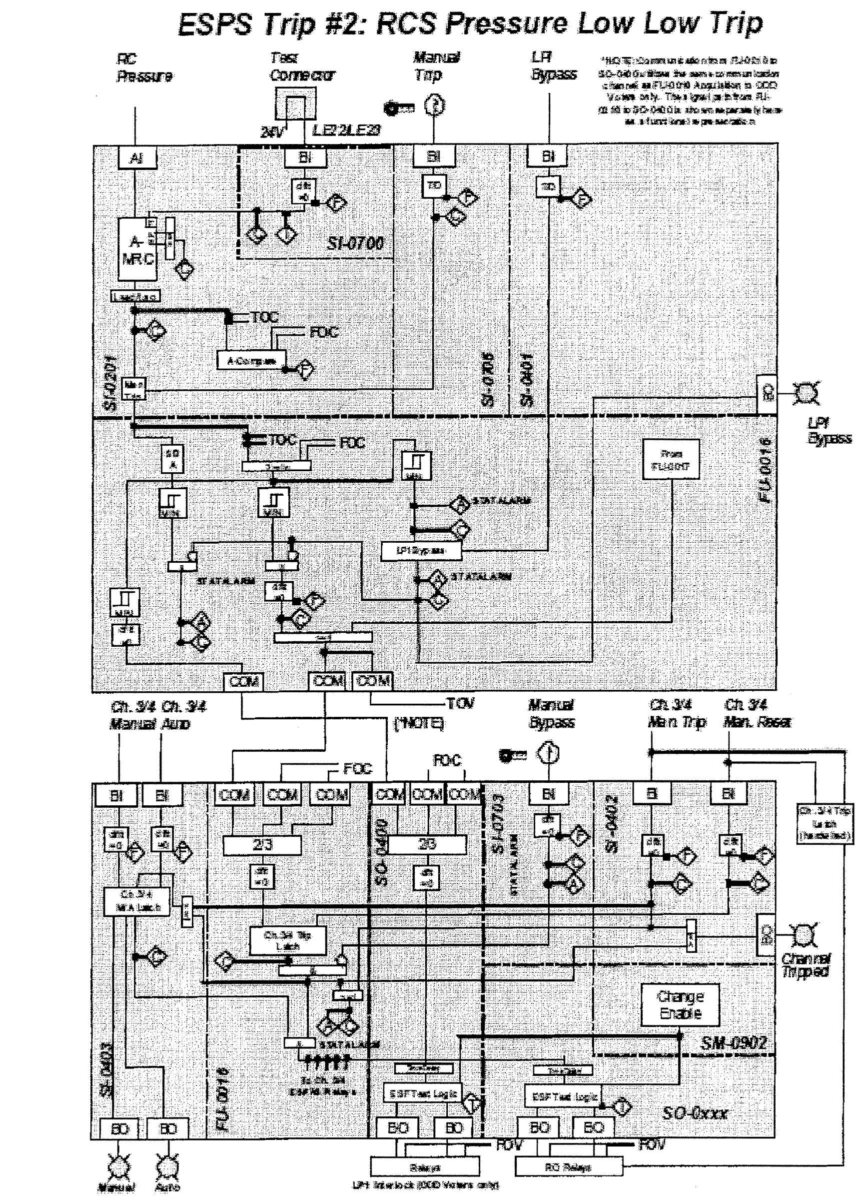


UNITS 2 & 3 ONLY

ESPS *Trip #1: RCS Pressure Low Trip*

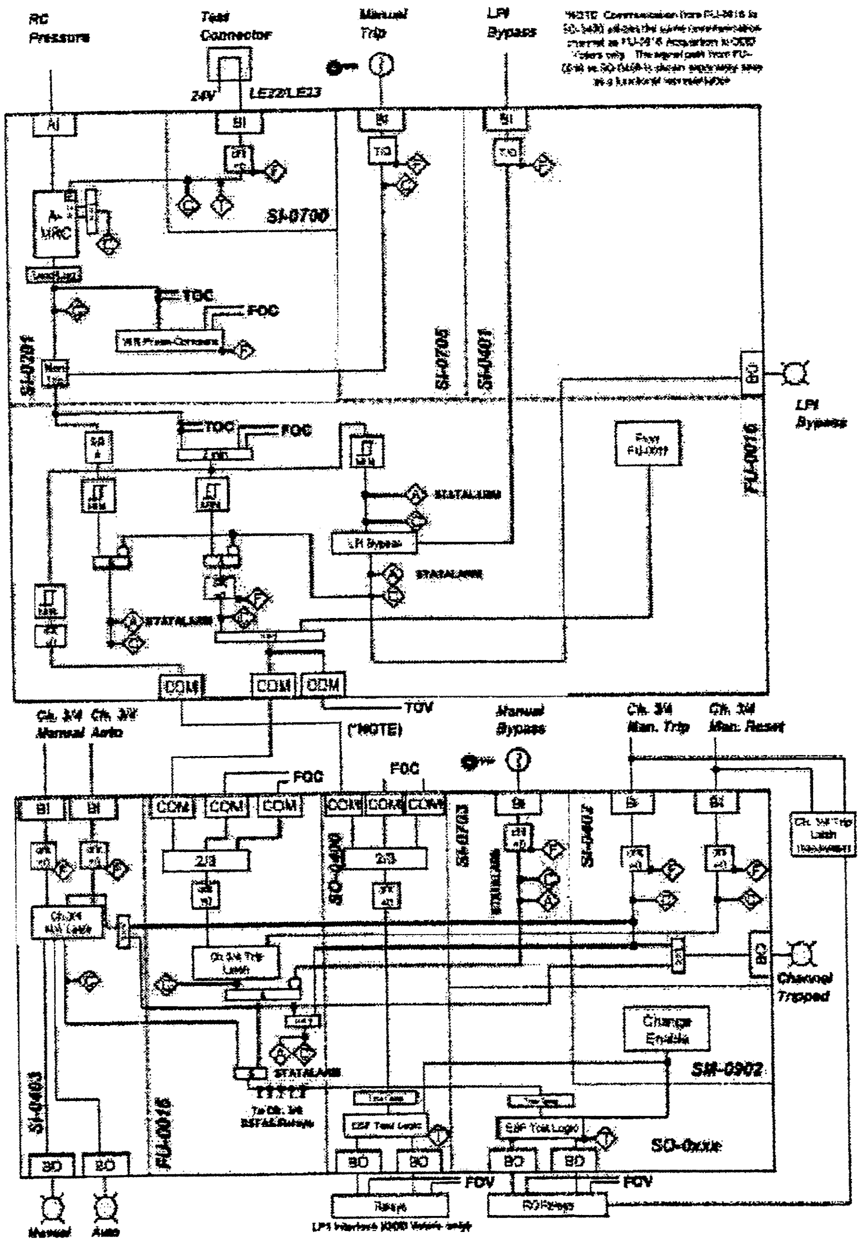


UNIT 1 ONLY

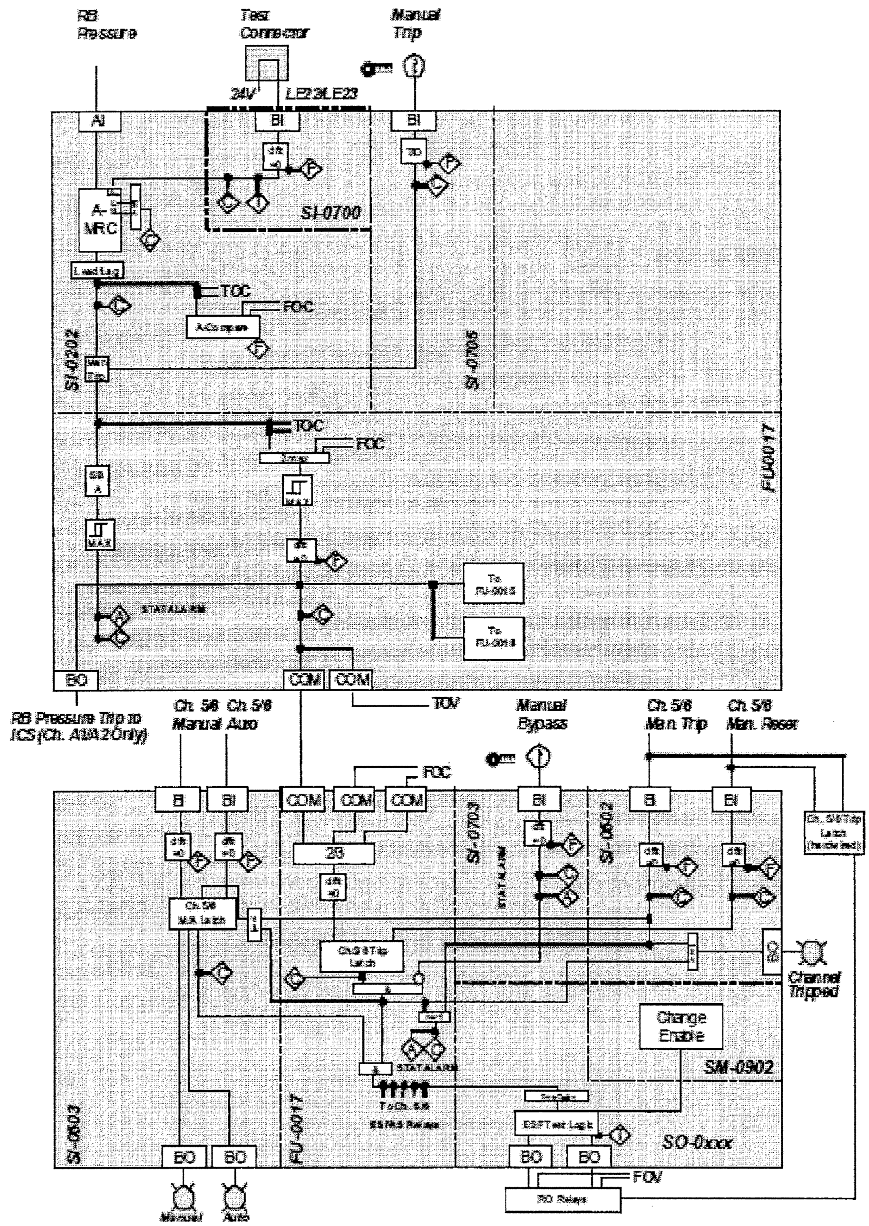

ESPS Trip #2: RCS Pressure Low Low Trip
RC Pressure
Test Connector
Manual Trip
LPI Bypass
24V
LE22LE23
AI
BI
SI-0700
A-MRC
TOC
FOC
A-Compare
SI-0201
SI-0706
SI-0401
BO
LPI Bypass
FU-0016
STAT ALARM
COM
TOV
(*NOTE)
Ch. 3/4 Manual
Ch. 3/4 Auto
Manual Bypass
Ch. 3/4 Man. Trip
Ch. 3/4 Man. Reset
2/3
SO-0400
SI-0703
SI-0402
Channel Tripped
Change Enable
SM-0902
SI-0403
ESF Test Logic
SO-0xxx
FOV
Manual
Auto

UNITS 2 & 3 ONLY

ESPS *Trip #2: RCS Pressure Low Low Trip*



ESPS Trip #3: Reactor Building Pressure High Trip



ESPS Trip #4: Reactor Building Pressure High High Trip

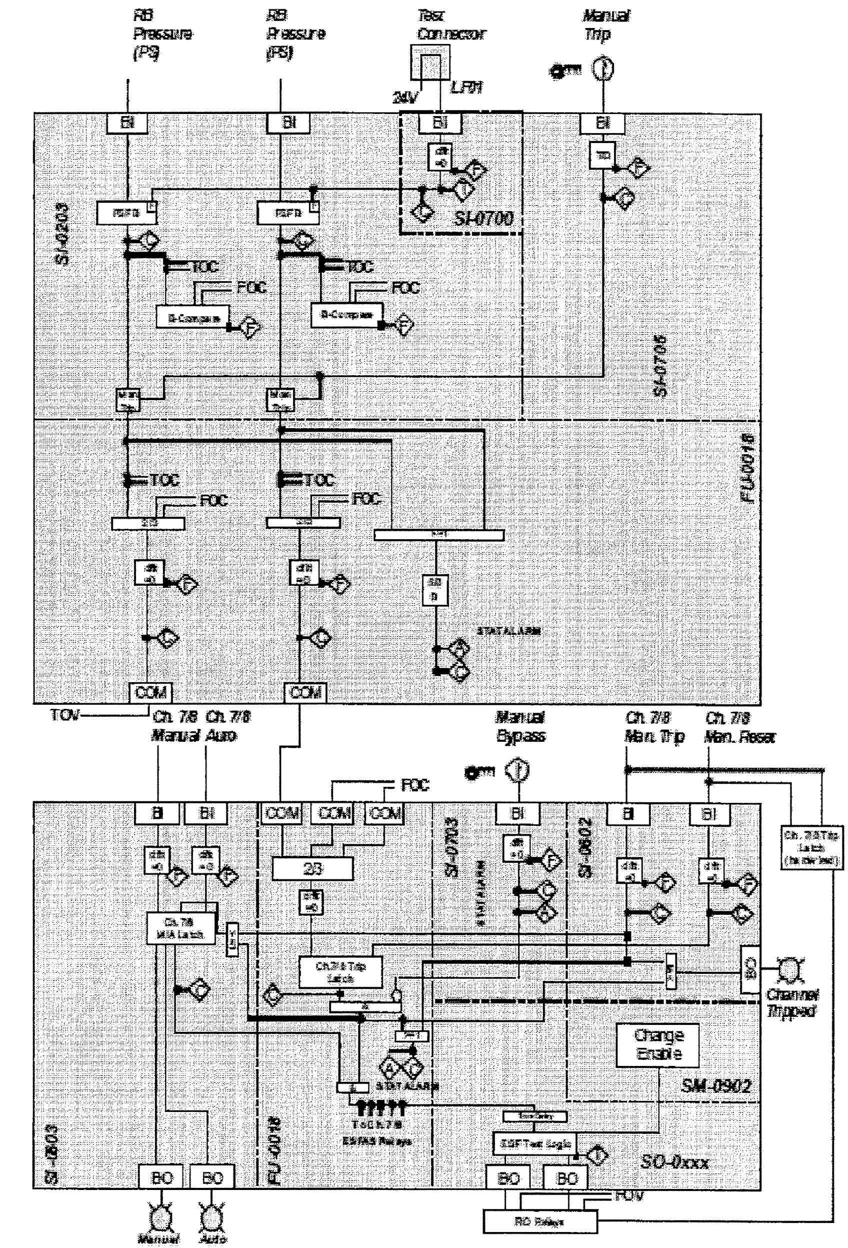


Figure 7-6. Nuclear Instrumentation System

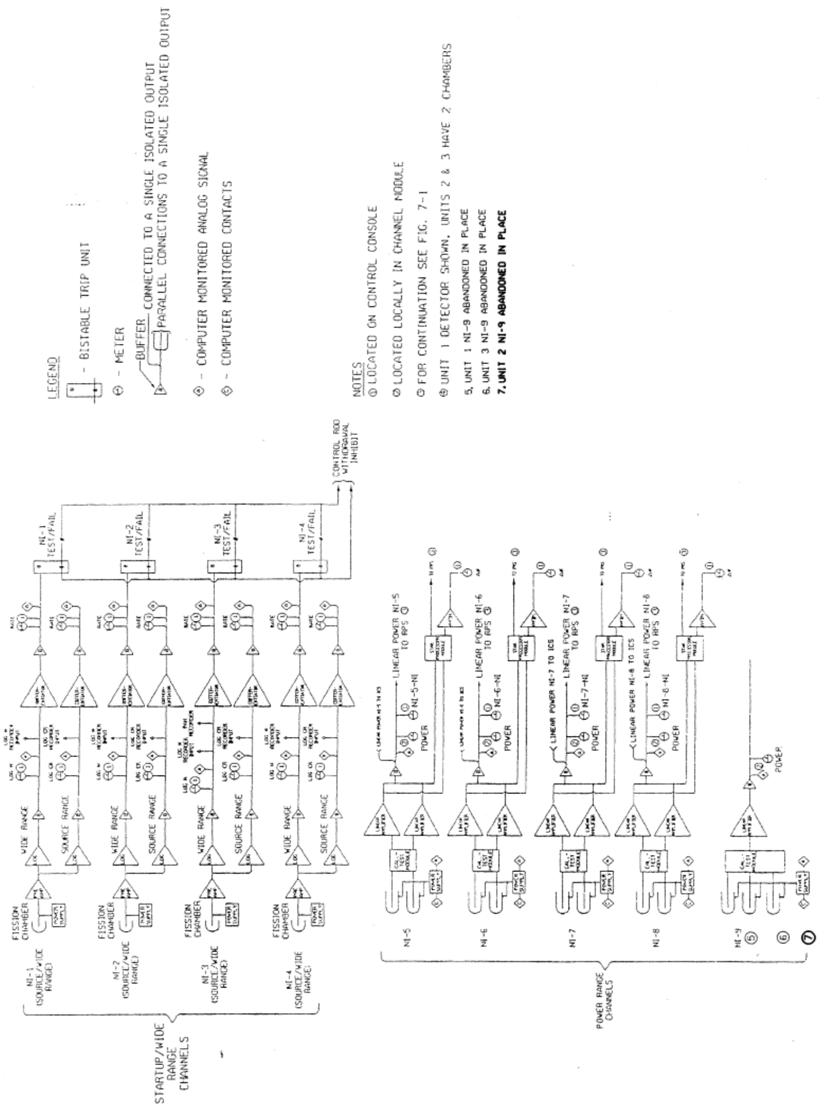


Figure 7-7. Nuclear Instrumentation Flux Range

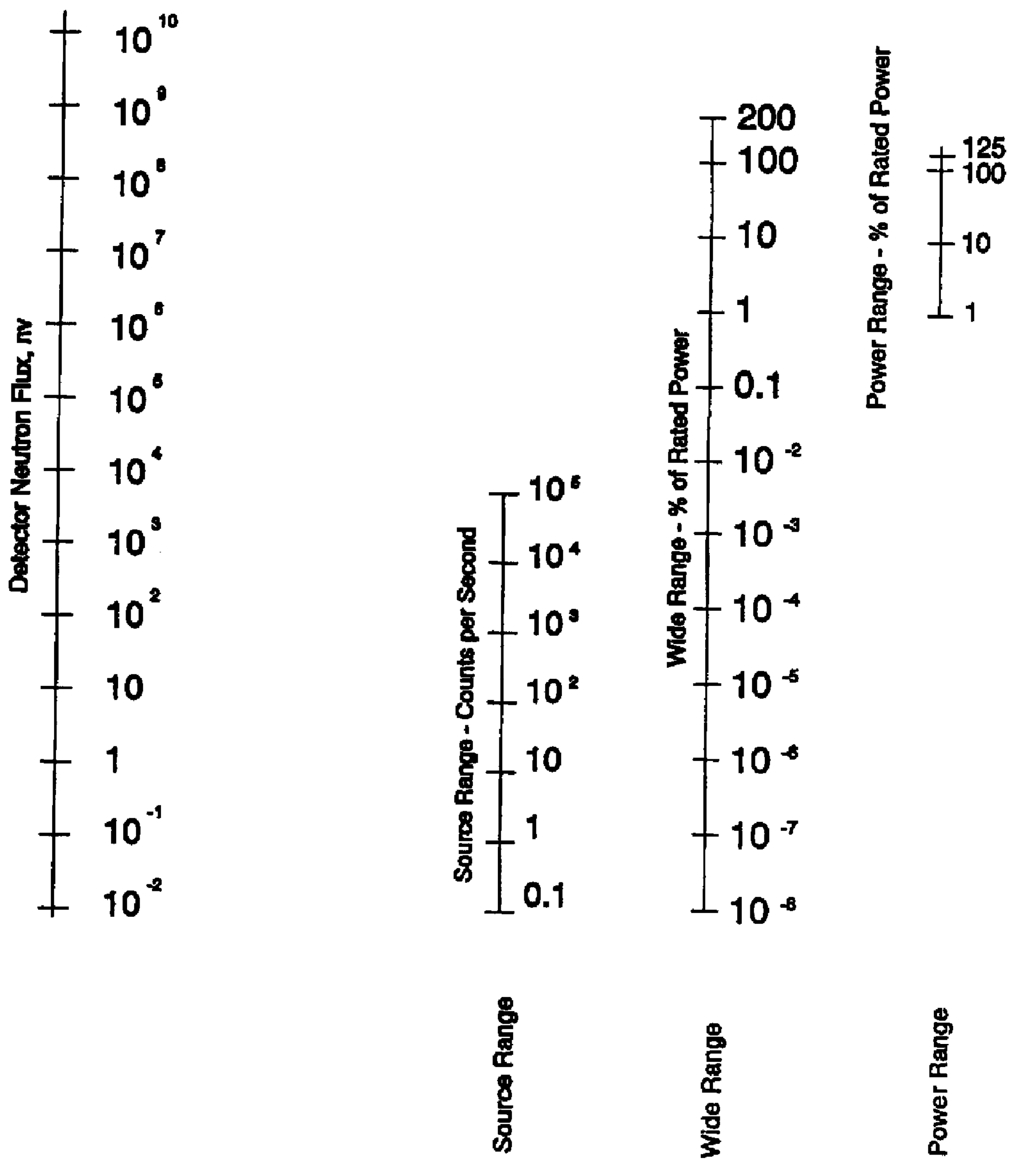


Figure 7-8. Nuclear Instrumentation Detector Locations

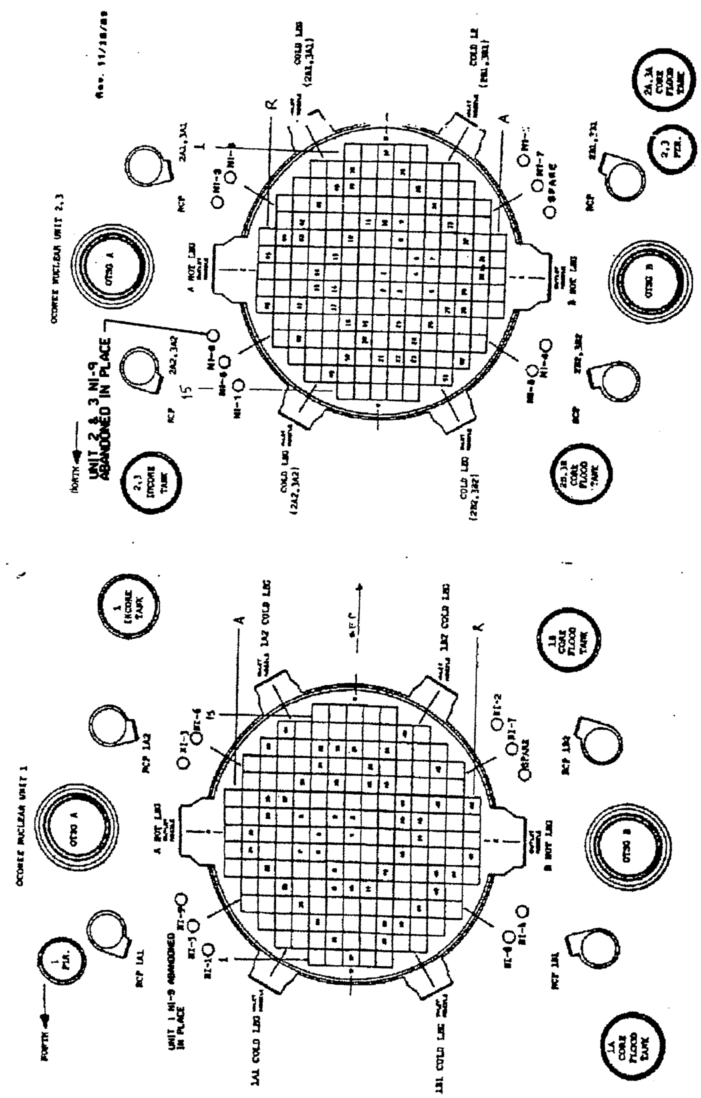
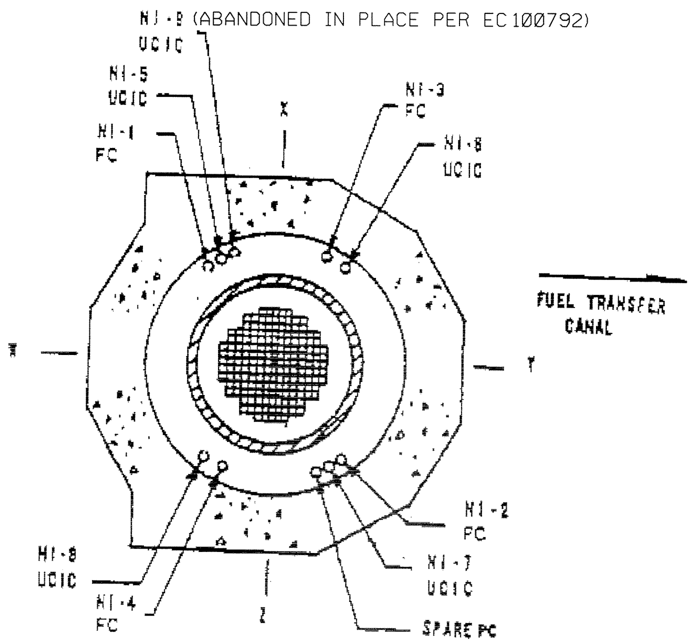


Figure 7-9. Nuclear Instrumentation Detector Locations - (Unit 1)

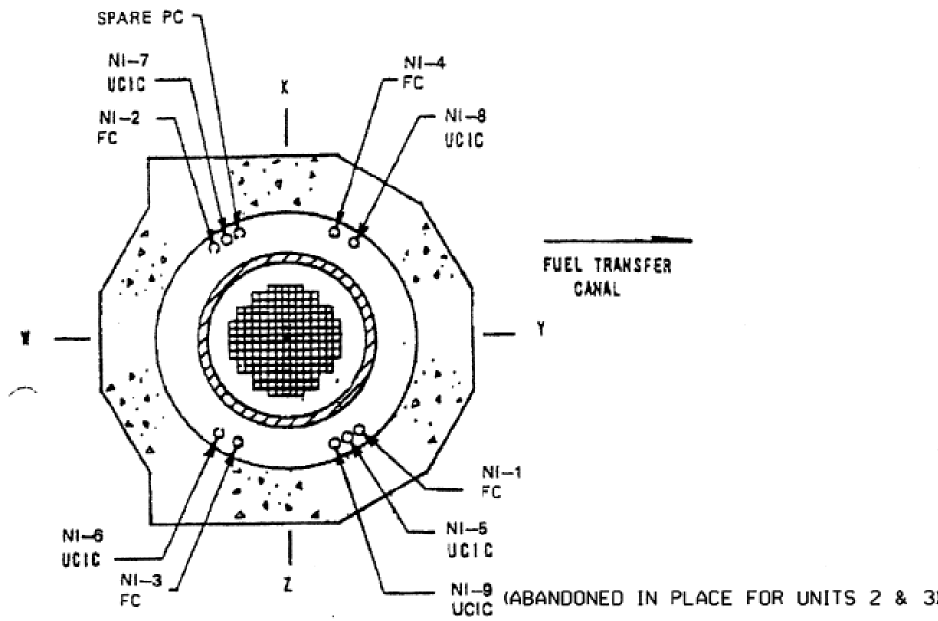


LEGEND

FC - FISSION CHAMBER - SOURCE RANGE/WIDE RANGE DETECTOR

UCIC - UNCOMPENSATED ION CHAMBER - POWER RANGE DETECTOR

Figure 7-10. Nuclear Instrumentation Detector Locations - (Unit 2 & 3)



LEGEND

FC - FISSION CHAMBER - SOURCE RANGE/WIDE RANGE DETECTOR

UCIC - UNCOMPENSATED ION CHAMBER - POWER RANGE DETECTOR

Figure 7-11. Automatic Control Rod Groups - Typical Worth Value Versus Distance Withdrawn

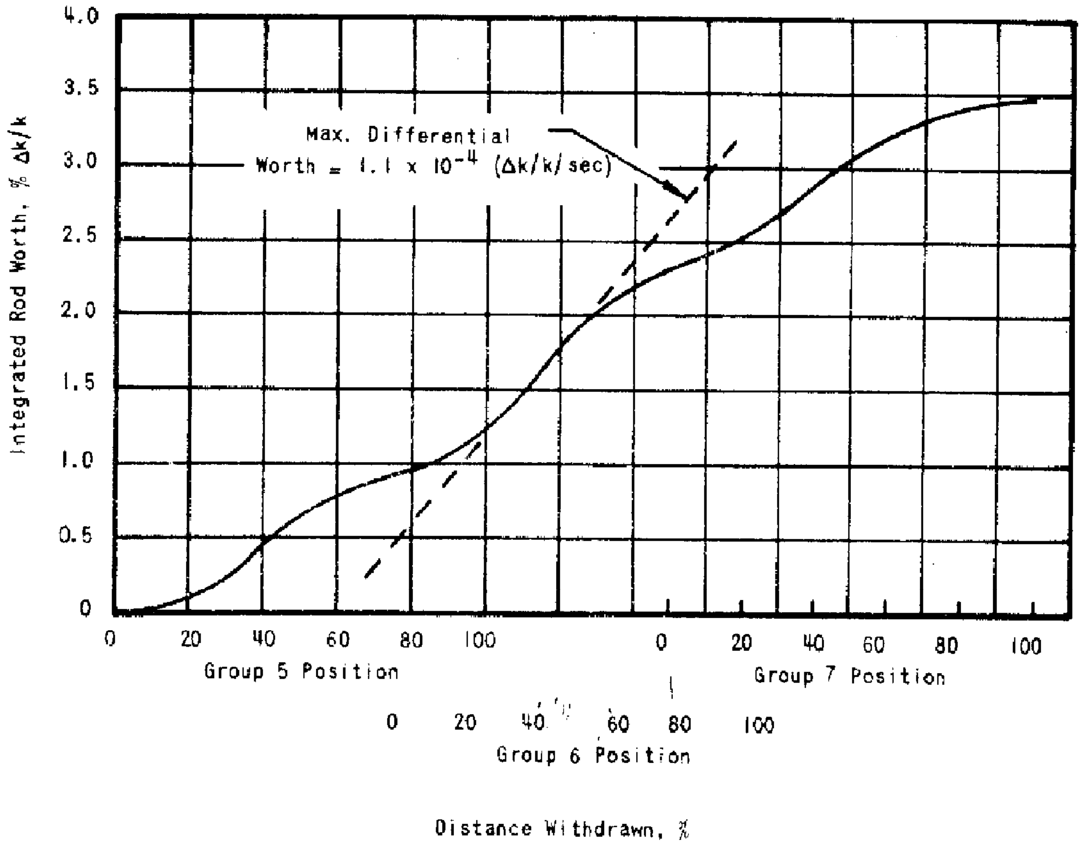


Figure 7-12. Control Rod Drive Logic Diagram

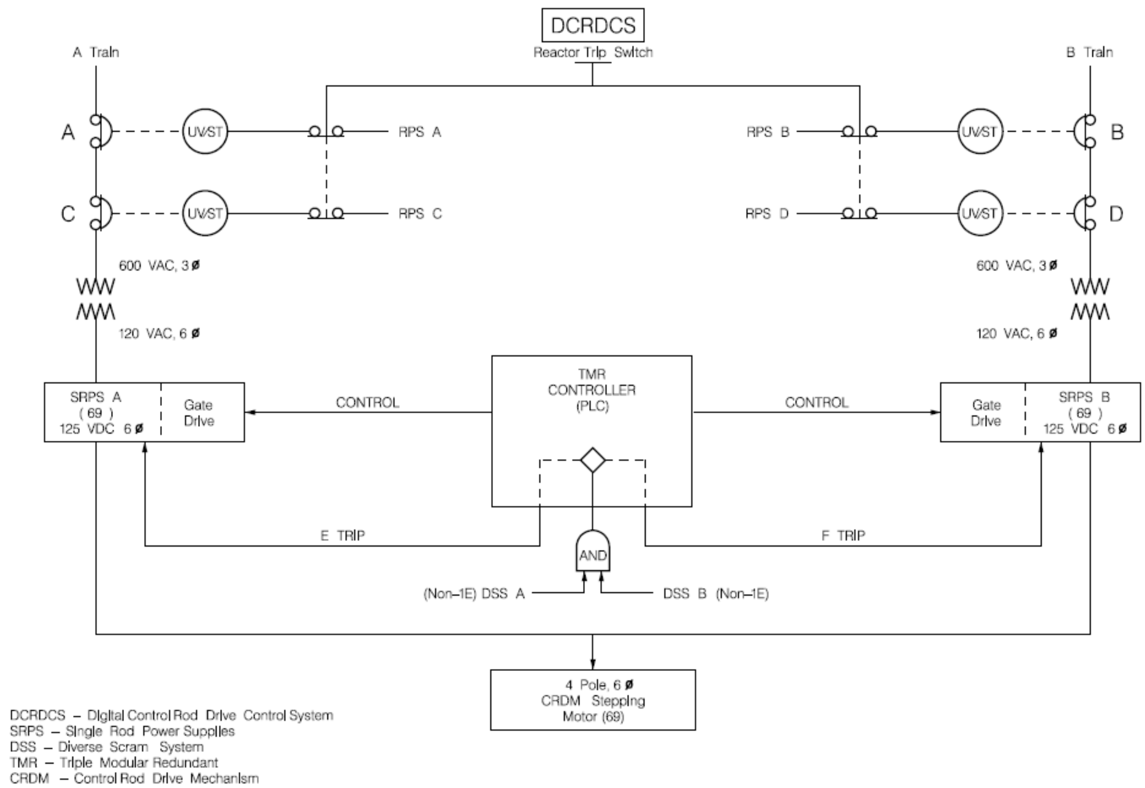


Figure 7-13. Control Rod Electrical Block Diagram

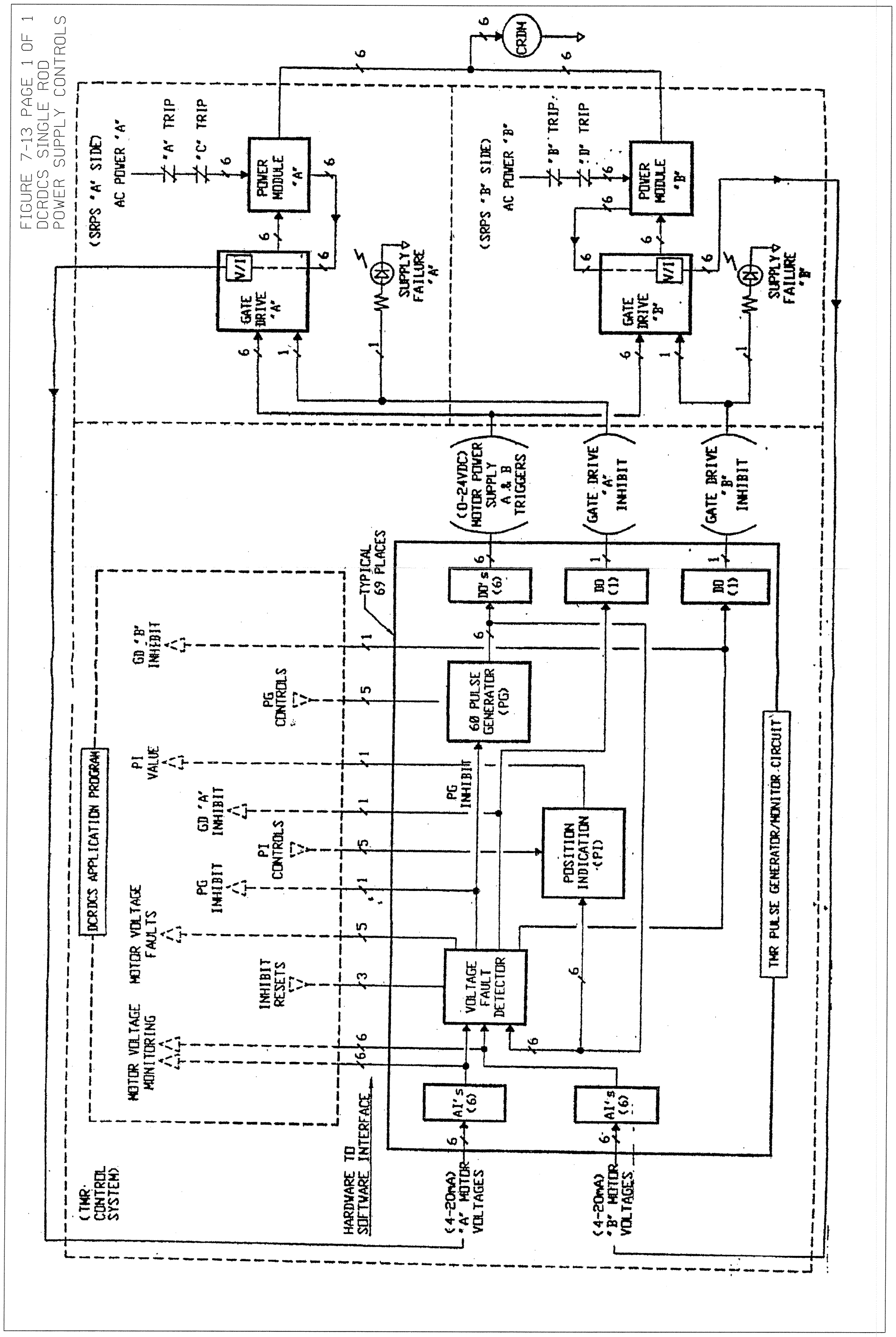
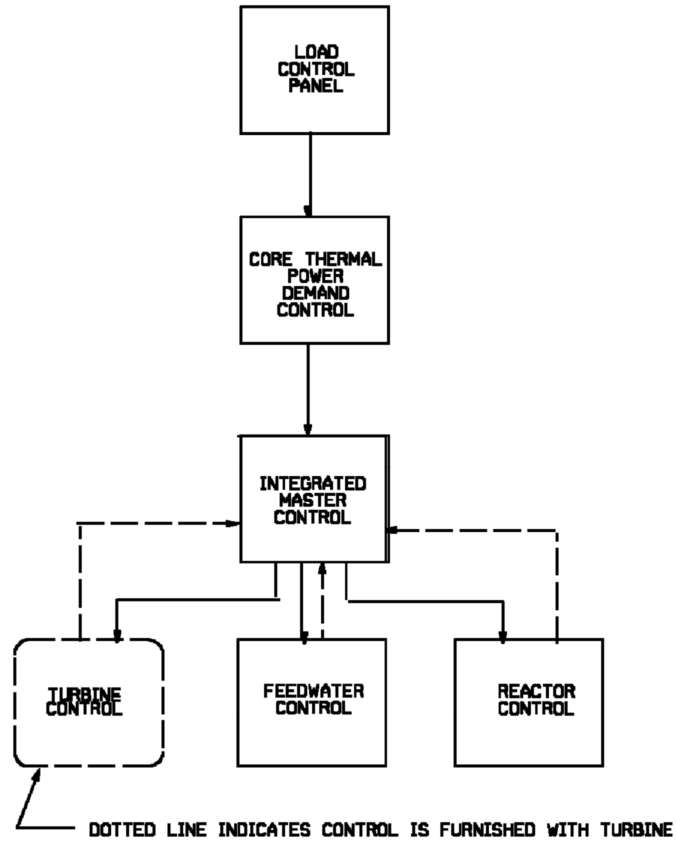


Figure 7-14. Integrated Control System



NOTES:
1. TURBINE CONTROL IS FROM THE INTEGRATED MASTER.

Figure 7-15. Core Thermal Power Demand - Integrated Control System

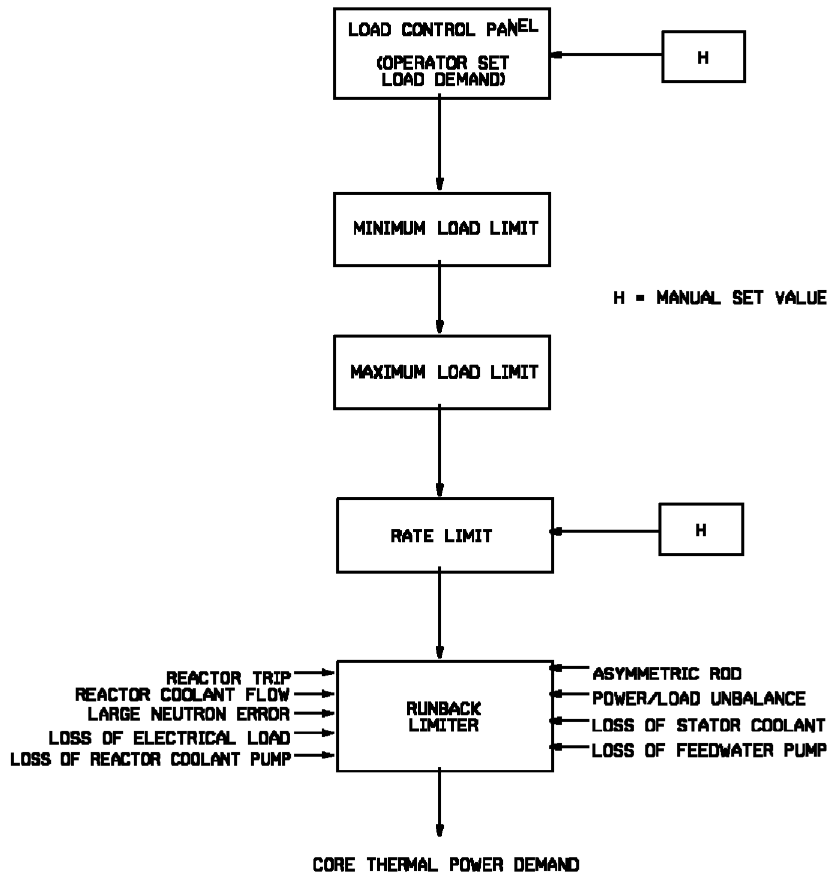


Figure 7-16. Integrated Master - Integrated Control System

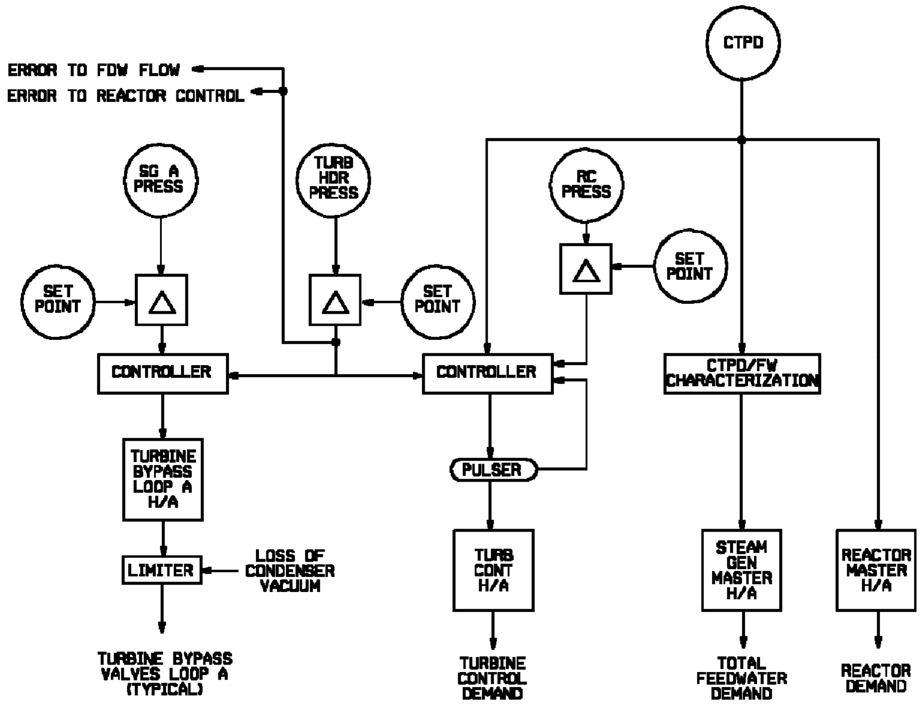


Figure 7-17. Feedwater Control - Integrated Control System

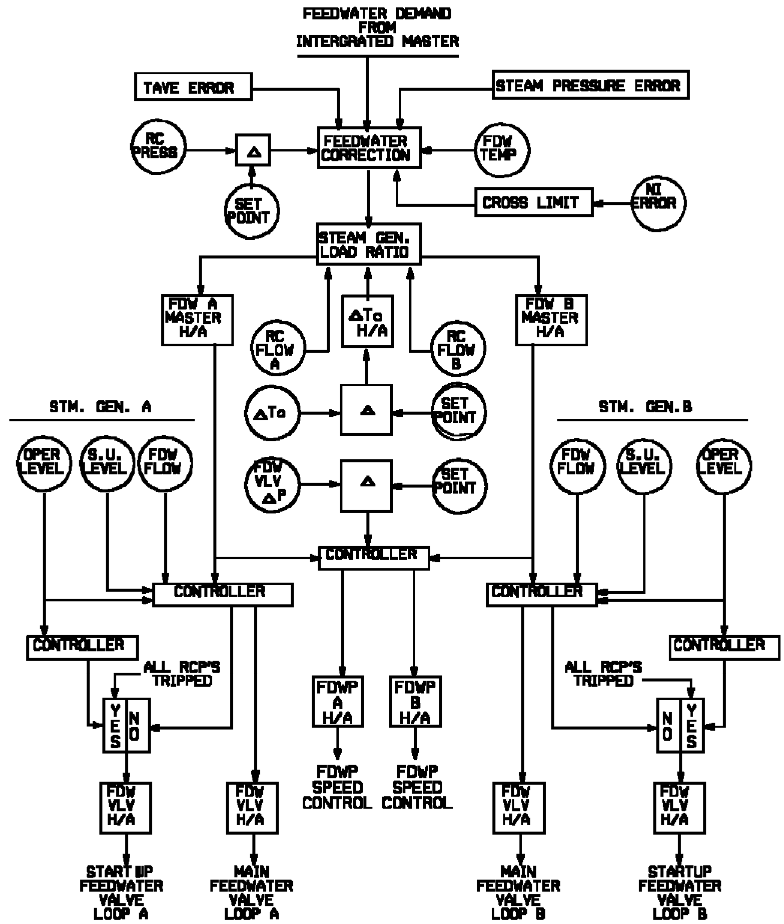


Figure 7-18. Reactor and Steam Temperatures Versus Reactor Power.(Replacement Steam Generator)

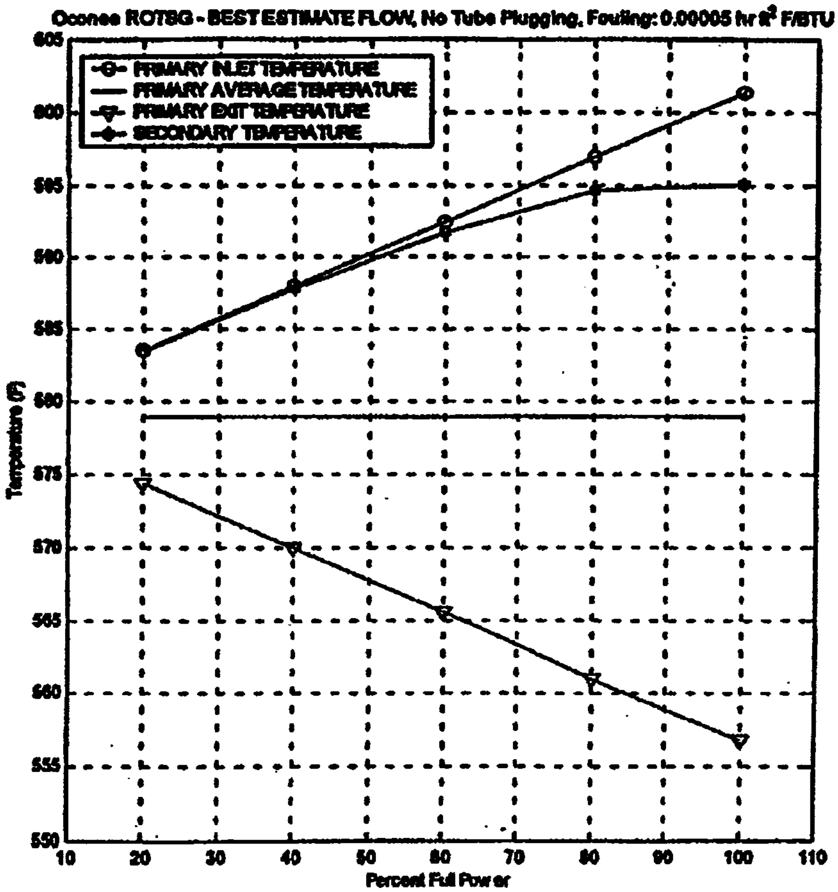


Figure 7-19. Reactor Control - Integrated Control System

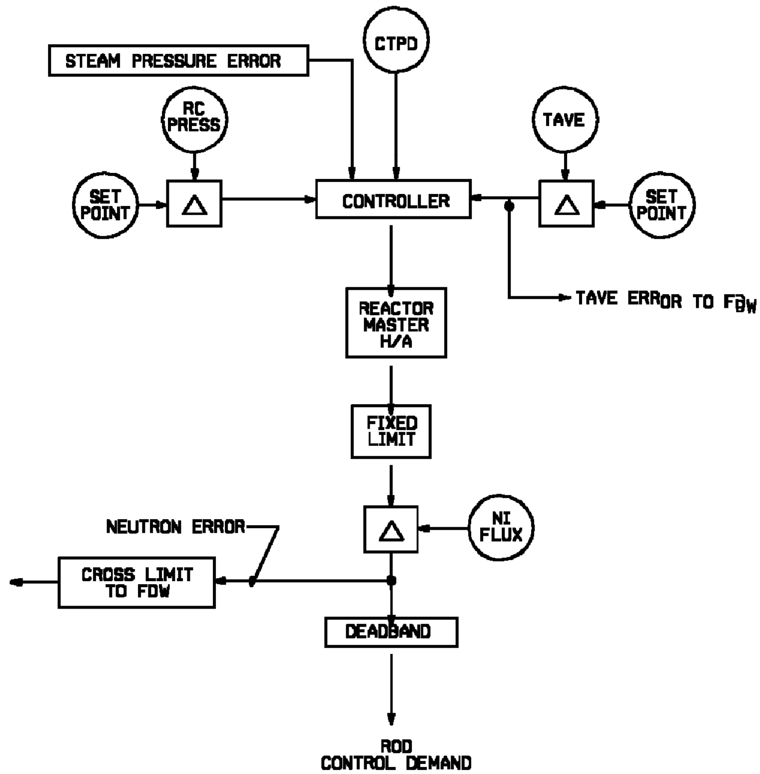


Figure 7-20. Incore Detector Locations

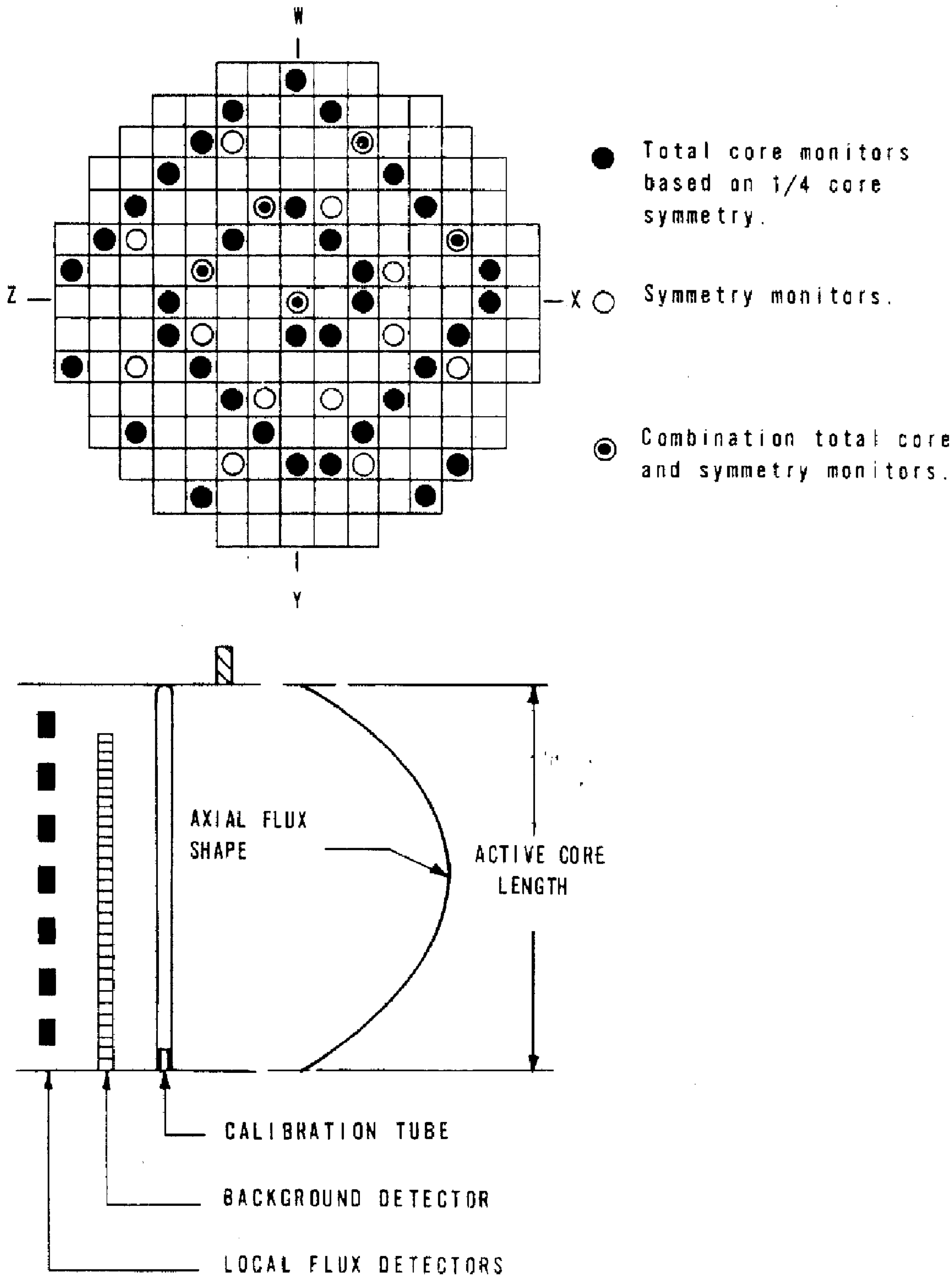


Figure 7-21. Incore Monitoring Channel

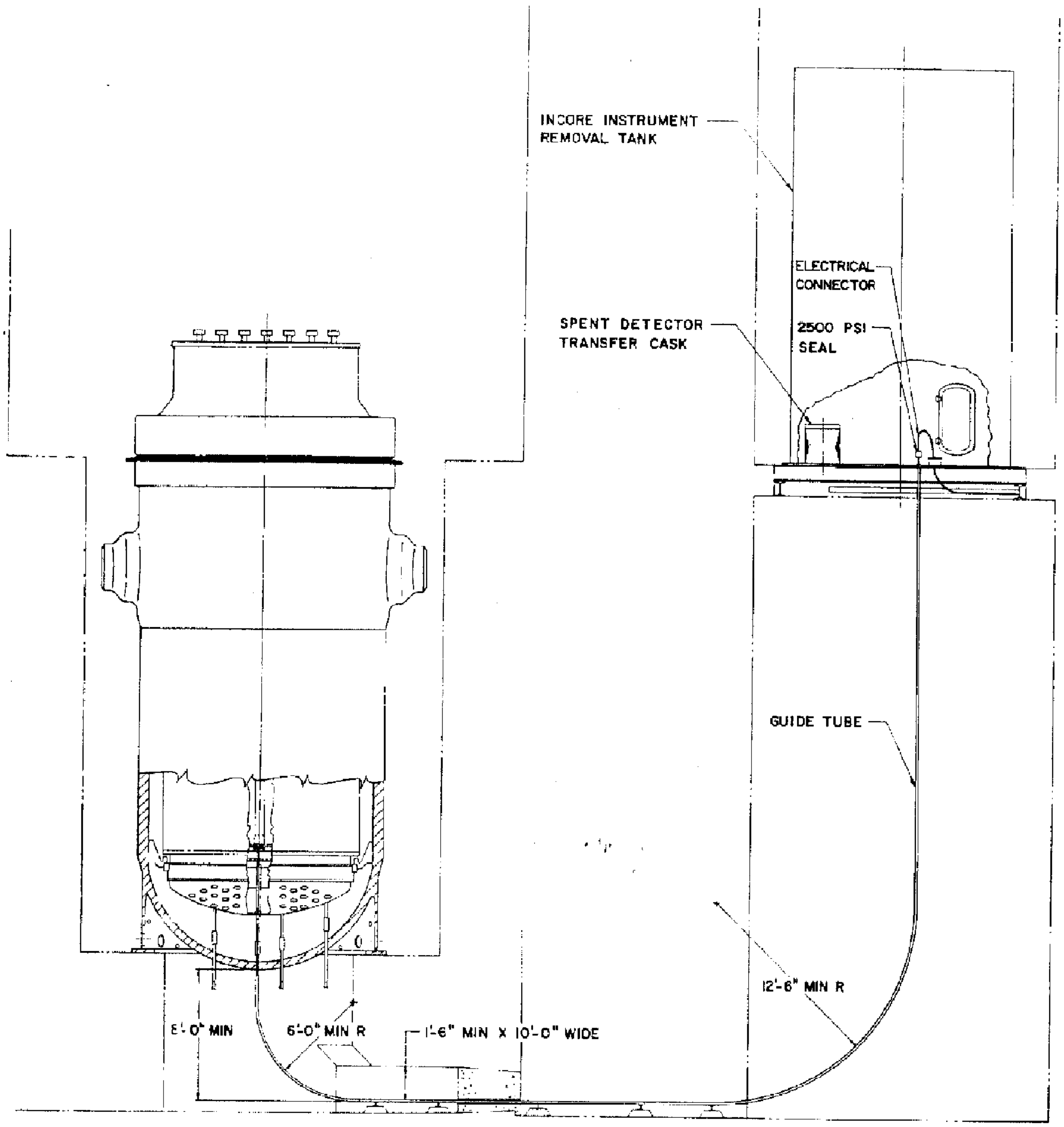


Figure 7-22. Deleted Per 1997 Update

Figure 7-23. Deleted Per 1997 Update

Figure 7-24. Deleted Per 1997 Update

Figure 7-25. Deleted Per 1997 Update

Figure 7-26. Control Room Layout

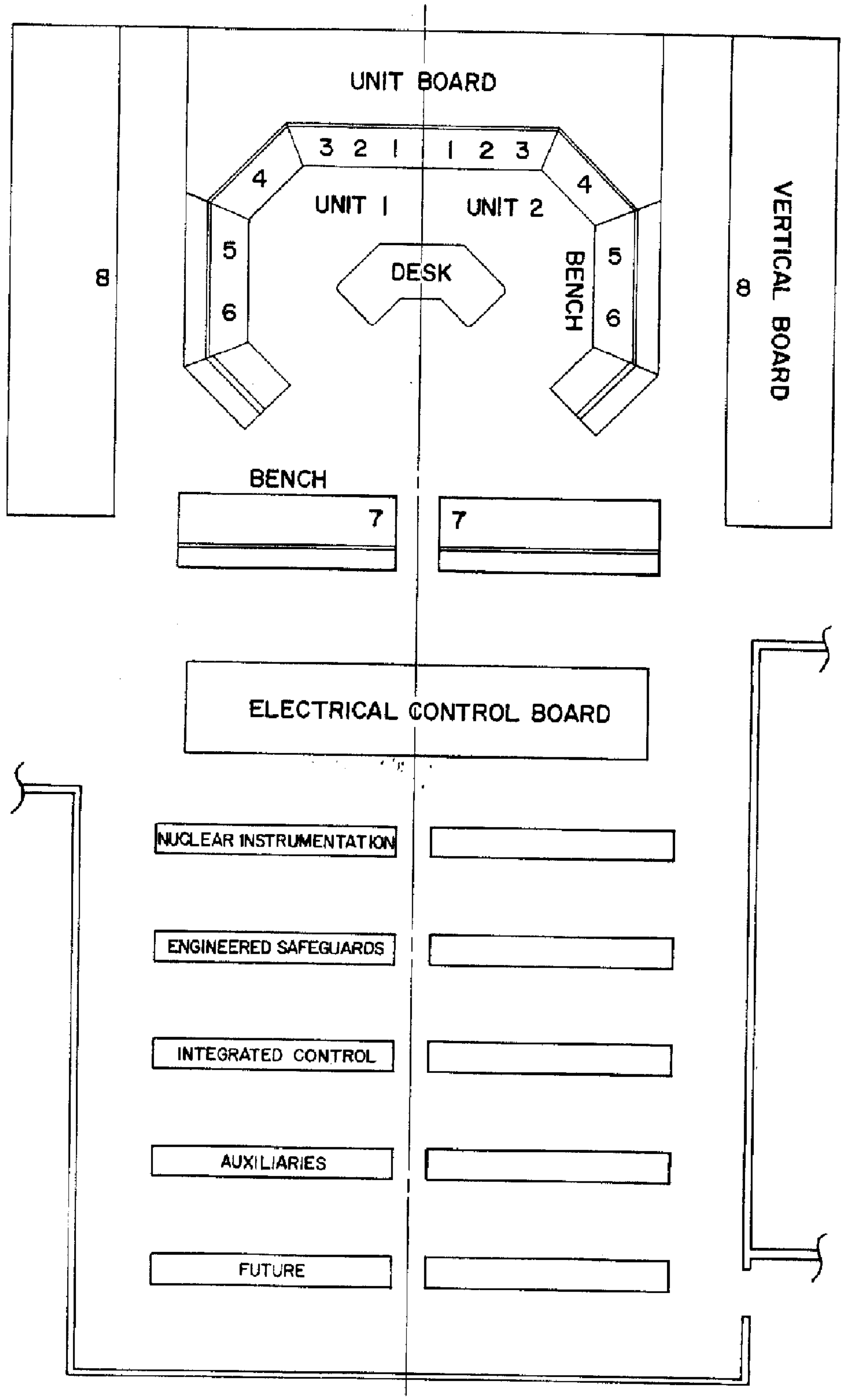


Table of Contents

List of Tables

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List of Figures

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8.0 Electric Power

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8.1 Introduction

An off-site power system and an onsite power system are provided for each unit at the Oconee Nuclear Station to supply the unit auxiliaries during normal operation and the Reactor Protection System and Engineered Safeguards Protection Systems during abnormal and accident conditions.

Each Oconee unit has five available sources of power to the Engineered Safeguards Systems as shown in Figure 8-1. These are:

1. The 230 kV transmission system and/or the 525 kV transmission system
2. Two Keowee hydro units
3. The 100 kV transmission system
4. Deleted Row(s) per 2011 Update

The normal arrangement is for three of these to serve any or all units and to be switched in the preferential order as follows: (1) the 230 kV transmission network through the unit startup transformers, (2) one Keowee hydro unit through an overhead 230 kV circuit, and (3) the other Keowee hydro unit through an underground circuit.

Whenever the underground circuit from Keowee is unavailable, a circuit from the 100 kV transmission network can be connected to the Standby Buses and serve as an emergency power source.

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8.1.1 Utility Grid System and Interconnections

Duke Power Company is an investor-owned utility serving the Piedmont region of North Carolina and South Carolina. The Duke transmission system consists of interconnected hydro plants, fossil-fueled plants, combustion turbine units, and nuclear plants supplying energy to the service area at various voltages up to 525 kV. Duke is a member of the Virginia-Carolina (VACAR) Subregion of the Southeastern Electric Reliability Council (SERC). All the companies in the region are interconnected such that the combined networks operate as a single, integrated system.

Protocols between Oconee and the transmission system operator (TSO) have been established to ensure grid voltage is monitored and maintained in accordance with the guidance of Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Off-site Power." Transmission load flow analysis tools (analysis tools) are used by the TSO to assist Oconee in monitoring grid conditions to determine the operability off-site power systems under plant technical specifications (TSs). In addition, off-site power restoration procedures are in accordance with Section 2 of NRC Regulatory Guide (RG) 1.155, "Station Blackout."

A detailed description of the off-site power system is provided in Section 8.2.

8.1.2 On-site Power Systems

The on-site power system for each unit consists of the main generator, the unit auxiliary transformer, the startup transformer, the Keowee Hydro Station, the Standby Shutdown Facility (SSF), the batteries, CT4 transformer, and the auxiliary power system. Under normal operating conditions, the main generator supplies power through the isolated phase bus to the unit auxiliary transformers. The unit auxiliary transformers are connected to the bus between the generator disconnect link and the associated unit step-up transformer for all three Units. During normal operation, station auxiliary power is supplied from the main generator through the unit auxiliary transformer or start up transformers. During startup, during shutdown, and after shutdown station auxiliary power is supplied from the 230 kV system through the startup transformer or auxiliary transformer via back charge (Reference Section 8.2.1.3 Second Paragraph).

The on-site power systems and their interconnection with the off-site power system are shown in Figure 8-1.

The on-site power systems are described in detail in Section 8.3.

8.1.3 Safety-Related Loads

The loads that require electric power to perform their safety function are identified in Table 8-1.

8.1.4 Design Bases

The design of the electrical systems for this three unit nuclear station is based on providing the required electrical equipment and power sources to assure continuous operation of the essential station equipment under all applicable conditions.

A safety related valve with electric motor actuation will be assigned a safety related power source if the valve is required to respond immediately in an accident scenario in order to assure safe shutdown of the plant or to mitigate the consequences of the accident. Valves (with electric motor actuators) which are not required to respond immediately for accident mitigation or safe shutdown may be powered from safety related sources when readily available, or from non-safety related, non-loadshed sources when the following conditions exist: a) the valve actuator is equipped with manual override to allow manual actuation, b) the environment in the immediate vicinity of the valve will allow operator access, c) adequate time exists for operator intervention to be effective, and d) operator training is such that there is reasonable expectation that operator intervention will occur when required.

THIS IS THE LAST PAGE OF THE TEXT SECTION 8.1.

8.2 Off-site Power System

8.2.1 System Description

8.2.1.1 Utility Grid System

The primary transmission system of Duke consists of a highly integrated 525 kV and 230 kV loop network. Underlying the primary transmission system is an extensive 100 kV sub-transmission network integrated into the primary system by means of 230/100 kV tie stations.

8.2.1.2 525 kV Switching Station

Unit 3 generates electric power at 19 kV that is fed through an isolated phase bus to a unit step-up transformer where it is stepped up to the transmission voltage of 525 kV. From the step-up transformer an overhead transmission line feeds power to the 525 kV switching station through two circuit breakers connecting the unit to the 525 kV transmission network.

Three transmission lines connect to the Oconee 525 kV Switching Station; one circuit goes east-northeast to Jocassee, one east to the Newport Station and one southeast to the Georgia Power Co. In addition, a 230/525kV autotransformer connects the 525 kV switching station to the 230 kV switching station. The 525 kV buses, disconnect switches, and circuit breakers are arranged into a breaker-and-a-half configuration.

8.2.1.3 230 kV Switching Station

Unit 1 and Unit 2 also generate electric power at 19 kV that is fed through an isolated phase bus on each unit to its own step-up transformer, where it is stepped up to the transmission voltage of 230 kV. From each step-up transformer, an overhead transmission line feeds power to the 230 kV switching station through two circuit breakers connecting each unit to the 230 kV transmission network. Eight transmission lines connect to the Oconee 230 kV Switching Station; two circuits are installed east-northeast to North Greenville, four east-southeast to Central, and two north-northwest to Jocassee. See Figure 8-1 and Figure 8-2 for arrangement of lines in the Oconee Station and on the site.

The 230 kV buses, disconnect switches, and circuit breakers are arranged into a breaker-and-a-half configuration.

Each unit is provided with two physically independent circuits from the switching station. One is the circuit from the 230 kV switching station through the startup transformer, which is designed to be available within a few seconds following a loss of coolant accident. The second circuit is the path from the switchyard through the main step-up transformer, the main generator bus and the unit's auxiliary transformer with the generator disconnected from the main bus. This second circuit was originally required to be available following a hypothetical loss of all station power and the resulting LOCA in time to prevent fuel and reactor coolant pressure boundary degradation. This ceased to be a requirement following the 1993 UFSAR update in which the safety analysis of the hypothetical loss of all station power was replaced with a station blackout analysis for Oconee. The station blackout analysis outlines the use of the Standby Shutdown Facility to mitigate a station blackout while preventing a loss of coolant accident. The second circuit is currently used during refueling as an additional power feed for the shutdown unit(s) from the 230 kV switchyard. Both the Unit 1 and Unit 2 auxiliary transformers and the Unit 1, Unit 2, and Unit 3 startup transformers are rated at 45/60MVA and have two isolated secondary windings rated 6900 volts and 4160 volts each. The Unit 3 auxiliary transformer is rated at 42/56/70MVA and has two isolated secondary windings rated 6900 volts and 4160 volts each.

The normal power supply to a unit's auxiliary load can be provided through the unit auxiliary transformer connected to the generator bus. This source of power is available except when:

1. The generating unit is in a normal shutdown condition, or
2. There is a malfunction or failure preventing continued operation of the reactor-turbine-generator-auxiliary transformer combination.

If power is not available from the unit's generator through the unit's auxiliary transformer or operating preference is to use the start-up transformer, power is supplied to the unit through its startup transformer fed from either or both of the buses in the 230 kV switching station. Power to the startup transformer can flow through the 230 kV switching station from any one of thirteen supplies. These include eight 230 kV transmission circuits, two nuclear generating units if operating, two hydroelectric units and the 525 kV switching station. Each unit's auxiliary startup transformer is sized to carry full load auxiliaries for one nuclear generating unit plus the engineered safeguards equipment of another unit. In addition, each unit's startup transformer can backup another unit's startup transformer through emergency startup buses and dual isolating disconnect switches. Refer to Section 8.4.2 for limitations and effects on system voltage adequacy.

This source of power is available except when:

1. Both of the 230 kV buses in the switching station are unavailable, or
2. There is a 230 kV system blackout, no nuclear generating unit is running, and neither hydro unit is capable of supplying power through the 230 kV connection; or
3. The startup transformer fails or their connection to the 230 kV switching station fails and the unit's auxiliary transformers or their backfeeding circuitry are not available.

8.2.1.3.1 230 kV Switching Station Degraded Grid Protection

Two channels of Degraded grid protection (DGP) are provided to assure that the degradation of the voltage from off-site sources does not adversely impact the safety function of safety-related systems and components. Each channel of this system, upon indication of inadequate voltage, will provide an alarm to alert control room personnel of the existence of inadequate voltage in the 230 kV switchyard. If an ES signal is sensed by the DGPS, while the voltage is sustained below acceptable levels, the DGPS will initiate an isolation of the 230 kV switchyard (yellow bus) and start Keowee so that the on-site emergency overhead power path is available. The non-ES operating units will not be affected by this action. The other units will continue to operate since their generators remain connected to the red bus. It is anticipated that any degradation of the voltage in the 230 kV switchyard will not last for an extended period of time. It is recognized that the voltage in the yard needs to be maintained above acceptable levels, and corrective measures would be taken to assure that timely actions are taken to restore the voltage.

There are three single-phase undervoltage relays installed to monitor the switchyard voltage on X, Y, and Z Phase of the 230 kV yellow bus. Each of the undervoltage relays is connected to one of three single- phase coupling capacitor voltage transformers. The setpoint of the undervoltage relays considers the minimum analyzed switchyard voltage and the accumulative tolerances of the undervoltage relays and the voltage sensing devices. A time delay is provided to override transients in the off-site system and prevent unnecessary actuation of this protection system.

Voltage analyses indicate that several 208V and 600V MOV and continuous-duty motor terminal voltages are below the acceptance criteria during the worst-case accident with degraded grid conditions. The analyses conclude that (a) several MOV's could stall due to the low supply voltage and (b) 4160V bus undervoltage relays could trip, thereby disconnecting the EDS from the transmission grid and repowering it from the standby on-site emergency power source (i.e. a Keowee Hydro Unit). As an operating option, by load shedding several large non-safety related 4160V loads, safety related equipment performance can be improved during an accident with degraded grid conditions.

Normally, the Oconee 230 kV switchyard operates at satisfactory rated voltage when one or more Oconee Units are on-line. If all three units are off-line (including a single on-line Unit that trips), a minimum switchyard voltage is not guaranteed.

In the event of a design basis accident, the accident Unit trips off-line. This reduces switchyard voltage due to the lost generation. As an operating preference, by tripping several large non-safety related loads, the available margin can be maintained above an acceptable level. If the load shed circuitry is unavailable or fails to operate, the Keowee Units will start and re-power the safety related EDS as designed.

8.2.1.4 100 kV Switching Station

Whenever there is inadequate power from the generating units, the 230 kV switching station and the hydro units, power is available to the standby power buses either directly from the 100 kV Central Tie Substation or from Lee Steam Station via a 100 kV transmission line connected to 12/16/20 MVA Transformer CT5 located on the opposite side of the station from the 230 kV facilities. This single 100 kV circuit is connected to the 100 kV transmission system through the substation at Central located eight miles from Oconee. Central Substation is connected to Lee Steam Station twenty-two miles away through a similar 100 kV line. If an emergency occurs that would require the use of the 100 kV transmission system, this line can either be isolated from the balance of the transmission system to supply emergency power to Oconee from Lee Steam Station, or emergency power can be supplied directly from the 100 kV system from the Central Tie Substation.

The 100kV transmission system also provides power to the 100kV/13.8kV Protected Service Water (PSW) Substation. The PSW Substation is controlled by Transmission Control Center (TCC), has automatic voltage regulators, and supplies the normal of two 13.8kV power feeds to the PSW 13.8kV electrical system.

Degraded voltage protection is provided to protect the essential plant auxiliaries from low voltage on the 100 kV system grid. Logic and relaying is installed to alert the operator via an annunciator any time the secondary voltage of transformer CT-5 decreases to such a low value that, if it was the power supply to the main feeder buses and a LOCA/LOOP occurred, proper equipment operation could not be assured. This logic and relaying also "arms" the supply breakers from transformer CT-5 to 4160V Standby Buses #1 & 2 after a time delay. Logic and relaying is also provided which automatically trips the supply breakers from transformer CT-5 to 4160V Standby Buses #1 & 2 if the breakers have previously been armed and the voltage decreases to the trip setpoint.

Located at Lee Steam Station are two 41 MVA combustion turbines. One of these combustion turbines can be started in one hour and connected to the 100 kV line. Transformer CT5 is sized to carry all the engineered safeguards auxiliaries of one unit plus the shutdown loads of the other two units. This source of power is available except:

1. When the 100 kV line or transformer is out of service, or

2. Temporarily after a complete system blackout of all transmission facilities.

8.2.1.5 Switching Station 125 Volt DC Power Systems

The 230 kV switchyard and 525 kV switchyard are served by independent 125V DC power systems. Each switching station DC system consists of two 125 volt DC, two conductor, metalclad distribution center assemblies; three battery chargers; and two 125 volt DC batteries. The 230 kV switchyard 125V DC system is typical of this arrangement and is shown in Figure 8-7. A bus tie with breakers is provided between the switchgear bus sections to "backup" a battery when it is removed for servicing. One standby 125 volt dc battery charger is also provided between the two 125 volt dc batteries for servicing. One battery supplies power through panelboards for primary control and protective relaying, and the second battery supplies power through panelboards for backup control and protective relaying. Dual feeds from the redundant panelboards are provided to each Power Circuit Breaker (PCB) for closing and tripping control. Separate dual trip coils are provided for each PCB. For the 230 kV switching station PCBs isolating diodes are provided for the redundant power feeds to the common closing coil circuit.

8.2.2 Analysis

Reliability considerations to minimize the probability of power failure due to faults in the network interconnections and the associated switching are as follows:

1. Redundancy is designed into the network interconnections by installing two full capacity transmission circuits for each connection to the 230 kV grid.
2. The two single 230 kV transmission circuits are installed on the same line of double circuit towers. Each line of double circuit towers is separated a safe distance from the others and in most cases installed over a different route.
3. One of the circuits on a line of 230 kV transmission towers is insulated at a higher insulation level than the other, thus minimizing the probability of double outages due to flashovers.
4. Each circuit is protected from lightning and switching surges by an overhead electrostatic shield wire and in addition, lightning arresters are installed at both terminals.
5. The breaker-and-a-half switching arrangement in the 230 kV and 525 kV switching stations includes two full capacity main buses which feed each circuit through a circuit breaker connected to each bus. Completely redundant primary and backup relaying is provided for each circuit along with circuit breaker failure backup protection. These provisions permit the following:
    a. Any circuit can be switched under normal or fault switching without affecting another circuit.
    b. Any single circuit breaker can be isolated for maintenance without affecting any circuit.
    c. Short circuits of a single main bus will be isolated without interrupting service to any circuit.
    d. Short circuit failure of the tie breaker will result in the loss of its two adjacent circuits until it is isolated by disconnect switches.
    e. Short circuit failure of a bus side breaker will result in the loss of the associated bus until it is isolated.
    f. Failure of either the primary protective relaying or the backup protective relaying will not result in the loss of circuit protection.

With the above protection features, the probability of loss of more than one source of 230 kV or 525 kV power from credible faults is low; however, in the event of an occurrence causing loss of all the 230 kV and 525 kV connections, the station is supplied from one or more of three sources of power, i.e., the two hydro units or the 100 kV line supplied by either the Lee combustion turbines or the Central Tie Substation.

6. The 100 kV transmission line is located above the level of any flood that is postulated on the Keowee River. On the Duke system, wind and ice loadings are more severe than seismic loadings and govern the structural design of transmission lines, including this 100 kV line.
7. As shown in Table 8-2, the 125 volt DC switching station power systems are arranged such that a single fault within a system does not preclude the protective relaying and control in the affected switching station from performing its intended functions.

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8.3 Onsite Power Systems

8.3.1 AC Power Systems

8.3.1.1 System Descriptions

The station distribution system consists of various electrical systems designed to provide reliable electrical power during all modes of station operation and shutdown conditions. The systems are designed with sufficient power sources, redundant buses, and required switching to accomplish this. Engineered safeguard equipment for each unit is arranged onto three load group buses such that the loss of a single bus section for any reason results in only the loss of equipment fed from that bus leaving redundant equipment to perform the same function. In general, the equipment related to unit operation is connected to its respective unit auxiliary electrical buses, whereas equipment common to and serving all units is distributed between the three unit auxiliary electrical buses. The control of power sources and switching for Oconee 1 and 2 is accomplished from the Oconee 1 and 2 control room while control of power sources and switching for Oconee 3 is from the Oconee 3 control room.

8.3.1.1.1 Keowee Hydro Station

The Keowee Hydro Station contains two units rated 87,500 kVA each, which generate at 13.8 kV. Upon loss of power from the Oconee generating unit and 230 kV switchyard, power is supplied from both Keowee units through two separate and independent routes. Each Keowee Hydroelectric Generating unit is also capable of providing an electrical power source to the Protected Service Water (PSW) building.

One route is a 4000 ft. underground 13.8 kV cable feeder to 12/16/20 MVA Transformer CT4 which supplies the redundant 4160 volt standby power buses. The underground emergency power feeder is arranged with double air circuit breakers (equipped with low air pressure monitoring switches) so that it can be connected to either Keowee generator bus. The connection to the generator bus is made with metal-enclosed bus. This under ground feeder is selected at all times to one hydroelectric generator on a predetermined basis and is automatically energized along with Transformer CT4 whenever that generator is in service in either emergency or normal mode. The underground feeder and associated transformer are sized to carry full engineered safeguards auxiliaries of one unit plus auxiliaries for safe shutdown of the other two units.

The second route is a 230 kV transmission line to the 230 kV switching station at Oconee which supplies each unit's startup transformer. Each Keowee generator is connected to a common 230 kV stepup transformer through a 13.8 kV metal-enclosed bus and synchronizing air circuit breaker equipped with low air pressure monitoring switches.

A third route consists of an underground 13.8 kV power cable feeder to the transformers CT6 and CT7 located in the Protected Service Water (PSW) building providing additional defense in depth protection by serving as a backup for existing safety systems. The Keowee switchgear circuit breaker and bus arrangement provides the capability of aligning either the Unit 1 or Unit 2 generators to the CT6 and/or CT7 transformers. The power cables from each Keowee Unit to the PSW building, routed underground for protection, are individually sized to carry the full PSW system load.

Each Keowee unit is provided with its own automatic startup equipment located in separate cubicles within the Keowee control room. The initiation of emergency startup is accomplished by control signals from either Oconee control area. Normal startup of either unit is by operator action while emergency startup is automatic. Both units are started automatically and simultaneously and run on standby on either of three conditions: 1) external grid trouble protection system actuation, 2) engineered safeguards actuation or 3) main feeder bus monitor undervoltage actuation. If the units are already operating when any of the above conditions occur, they are separated from the network (and momentarily from the underground path) and continue to run on standby until needed. Each unit's voltage regulator is equipped with a volts-per-cycle limiting feature which permits it to accept full emergency power load as it accelerates from zero to full speed within 23 seconds from receipt of the emergency startup initiation signal.

The auxiliaries for the unit aligned to the underground feeder receive power from Transformer CX. The auxiliaries for the unit aligned to the overhead feeder receive power from Auxiliary Transformer 1X or 2X. The power source for each alignment is referred to as the normal source.

On normal automatic startup, each unit is automatically connected and supplies power to the Oconee 230 kV switching station through the stepup transformer by its respective generator air circuit breaker. This is accomplished by the automatic synchronizing equipment of each unit. On emergency automatic startup, both units are started; the unit with the underground feeder selected to it supplies that feeder and the other unit is available to supply the Oconee 230 kV switching station. If there is a system disturbance, this unit is connected automatically to the Oconee 230 kV Yellow Bus only after the Oconee 230 kV Yellow Bus is isolated automatically from the system and the preset time delay has elapsed. Redundant External Grid Trouble Protective Systems are provided to isolate the 230 kV switching station on failure of the external transmission network. Therefore, on loss of the external transmission network, both of the Keowee hydro units can provide emergency power to any of the Oconee units through either the 230 kV switching station to the unit's respective startup transformer or the underground feeder and Transformer CT4 at Oconee.

Power from the hydro units is available except when:

1. Both units are out of service, or
2. There is a coincident failure of the underground feeder circuit and a complete outage of the 230 kV feeder circuit through the switching station.

   The Standby Shutdown Facility (SSF) consists of standby systems for use in extreme emergency conditions. Following the loss of all normal and emergency power, on-site and off-site, the SSF diesel electric generating unit will be manually started by initiating the start signal from the SSF Control Panel in the SSF. The SSF Electrical Power System supplies power necessary to maintain the reactors of each unit in a safe shutdown condition, in the event of loss of power from all other power systems.

The SSF is described in detail in Section 9.6. The SSF's role in SBO coping is discussed in Section 8.3.2.2.4.

8.3.1.1.2 6900 Volt Auxiliary System

The 6900 volt auxiliary system for each unit is designed to supply electric power to the 9000 horsepower reactor coolant pump motors. This system is arranged into two bus sections. Both bus sections feed into two switchgear bus sections, each feeding two motors. Each switchgear bus supplies one motor for each of the two reactor coolant piping loops. Either the unit auxiliary or the startup transformer is capable of feeding both switchgear buses. During startup, shutdown and after shutdown, the switchgear buses are supplied from the startup transformer. During normal operation, the switchgear buses are supplied from the unit auxiliary transformer.

Normal bus transfers between the two sources are initiated at the discretion of the operator from the control room, while emergency transfer from the unit auxiliary to the startup transformer is initiated automatically by protective relay action. Normal bus transfers used on startup or shutdown of a unit are “live bus” transfers, i.e., the incoming source feeder circuit breaker is closed onto the energized bus section and its interlocks will trip the outgoing source feeder circuit breaker which results in transfers without power interruption. Emergency bus transfers used on the loss of the normal unit source are rapid bus transfers, i.e., the outgoing source feeder circuit breaker is tripped and its interlocks close the incoming source feeder circuit breaker which results in a transfer within a maximum of nine cycles. An exception to this occurs when the main generator has been supplying in-plant loads source while separated from the switching station. In this instance, there is a transfer delay when the normal unit is lost.

The 6900 volt auxiliary system as shown in Figure 8-1 and Figure 8-3 is similar in arrangement for each of Oconee 1, 2, and 3.

8.3.1.1.3 4160 Volt Auxiliary System

The 4160 volt auxiliary system for each unit is arranged into a double bus - double circuit breaker switching arrangement. The three power sources, (1) the unit's auxiliary transformer, (2) the startup transformer and (3) the standby power buses, feed each of the main feeder buses by this double circuit breaker arrangement. Each of the two redundant main feeder buses provide power to each of the three redundant engineered safeguards switchgear bus sections that serve the engineered safeguards auxiliaries. The engineered safeguards auxiliaries are arranged so that a failure of any single bus section does not prevent the respective systems from fulfilling their protective functions.

The 4160 volt auxiliary system as shown in Figure 8-1 and Figure 8-3 is similar in arrangement for all three units.

On loss of their normal sources of power the 4160 volt main feeder buses are transferred as described for the 6900 volt system to alternate sources of power in the following preferential sequence:

1. Transfer to startup transformer where:
   a. Power is supplied from the 230 kV transmission system, or
   b. Power is supplied from one of the two Keowee hydro units via the 230 kV switchyard.
2. Transfer to 4160 volt standby power buses where:
   a. Standby power is supplied from one Keowee hydro unit via the 13.8 kV underground feeder, or
   b. Standby power is supplied from the 100 kV transmission line.

The control system is designed to prevent the paralleling of two sources during the switching operation and is similar to the transfer systems Duke has used for many years in their fossil-fired plants.

Upon loss of the unit auxiliary transformer source and startup transformer source, and in the absence of an engineered safeguards (ESG) signal, the following occurs:

> The turbine-generator and reactor are tripped and the main feeder buses become deenergized. Control power is still available from the dc and vital power systems.

Both of the Keowee hydro units are started and the selected unit will be automatically connected to the standby power buses from which power can be supplied to the shutdown auxiliaries.

The non-essential loads are shed.

The equipment required to bring the reactor to a hot shutdown is energized.

Logic and control circuits will be fed without interruption from dc sources and vital power buses.

In the event of a loss of coolant accident requiring engineered safeguards action, the following action takes place:

Both Keowee hydro units are started immediately. The unit not selected to the underground feeder is run on standby and connected to the 230 kV Yellow Bus when the bus is isolated.

The underground circuit from Keowee becomes automatically energized as the hydro unit to which it is selected is started and breaker control interlocks are satisfied.

The 4160 volt redundant main feeder buses of the unit with the accident are switched to the emergency power sources in the preferential order as described in Section 8.3.1.1.3 (1) and (2).

The engineered safeguards of the unit with the accident are started and the non-essential loads are shed when power is unavailable from the normal or startup sources.

In the event the external transmission network is lost, the following action takes place:

Both Keowee hydro units are started immediately and the unit not selected to the 13.8 kV underground feeder is connected automatically to the 230 kV Yellow Bus by closing its respective generator circuit breaker and the 230 kV Power Circuit Breaker (PCB)-9 when the 230 kV Yellow Bus is isolated from the system network.

The 230 kV Switchyard Yellow Bus is isolated automatically from the system grid by energizing the dual trip coils of the 230 kV PCBs 8, 12, 15, 17, 21, 24, 26, 28, and 33.

The startup transformers No. CT1, CT2, and CT3 remain connected to the 230 kV switching station.

The 13.8 kV underground circuit from Keowee becomes energized as the hydro unit to which it is connected is started.

In the event of an accident and the simultaneous loss of the external transmission network, the engineered safeguard switchgear buses are supplied emergency power through both 4160 volt main feeder buses from either the 4160 volt startup transformers through their respective feeder breakers or from both of the redundant standby power buses. The standby power buses receive emergency power from either the Keowee Hydro Station or the 100 kV transmission line described in Section 8.3.1.1.3 (2). In the event of a Loss of Coolant Accident (LOCA) any breakers supplying the engineered safeguards loads are closed automatically. In the event of a LOCA and the simultaneous loss of both the normal auxiliary source and the startup source, the non-essential load breakers are tripped. Redundant engineered safeguards load-shedding logic equipment assures positive shedding of non-essential equipment by energizing separate trip coils provided in their circuit breakers. Redundant engineered safeguards actuation channels initiate closing of the essential equipment feeder breakers.

In the event of a Unit reactor trip and a simultaneous engineered safeguards channel 1 or channel 2 actuation, the load shed circuit can be activated to trip several large non-safety related loads.

Each Oconee Unit has a LOCA Load Shed Logic Scheme that, in the event of LOCA when the main turbine trips and offsite power is available, trips the following non-essential 4160 volt load breakers.

1. Three (3) of four (4) Condenser Circulating Water Pumps
2. Two (2) of three (3) Condensate Booster Pumps
3. Two (2) of three (3) Hotwell Pumps
4. All four (4) Heater Drain Pumps

LOCA Load Shed ensures adequate 4kV (and below) system voltages for safety-related equipment during a LOCA or inside-containment main steam line break with offsite power available via the startup transformer.

8.3.1.1.4 600 Volt Auxiliary System

Each unit's 600 volt auxiliary system is similar and arranged into multiple bus sections. Each bus section is fed from a separate load center transformer which is connected to one of the three 4160 volt switchgear bus sections. Various 600 volt non-engineered safeguard motor control centers are located throughout the station to supply power to equipment within the related area. The three engineered safeguards load centers and associated motor control centers as shown in Figure 8-4 are redundant and are supplied independently from the three 4160 volt engineered safeguards load buses. Load center X8 and X9 have an alternate feeder with manual transfer to be used when the normal source of power is not available. Each engineered safeguard motor control center has an alternate feeder with manual transfer to be utilized only for maintenance. No common failure mode exists for this system.

8.3.1.1.5 208 Volt Auxiliary System

For each unit, a system is provided to supply instrumentation, control, and power loads requiring unregulated 208Y/120 volt ac power. It consists of motor control centers, distribution panels, and transformers fed from 600 volt motor control centers.

The redundant engineered safeguards 208 volt motor control centers for a unit are shown in Figure 8-4. Each of these motor control centers have redundant supply feeders from separate transformers and redundant 600 volt motor control centers. The feeder breakers have mechanical interlocks and manual transfers.

The 208 volt auxiliary system is similar in arrangement for each of the three units.

8.3.1.1.6 Tests and Inspections

Remote startup of the Keowee generators is provided in each of the control rooms of the nuclear station. Provisions are made in the control rooms to manually initiate an emergency start of both of the two hydroelectric generators connecting the generator to the nuclear station's 4160 volt buses. Testing of this system may be scheduled any time the Keowee hydro units are not running.

The 100 kV, 230 kV and 525 kV circuit breakers are inspected, maintained and tested as follows:

1. 100 kV transmission line circuit breakers are tested on a routine basis.
2. 230 kV and 525 kV transmission line circuit breakers are tested on a routine basis. This is accomplished without removing the transmission line from service.

3. 230 kV and 525 kV switchyard generator circuit breakers may be tested with the generator in service.

Transmission line protective relaying is tested on a routine basis.

Generator protective relaying may be tested when the generator is in service.

The 4160 volt circuit breakers and associated equipment are tested in service by opening and closing the circuit breakers in a manner that does not interfere with the operation of the station. The circuit breakers may be “jacked out” to a test position and operated without energizing the circuits, if necessary.

The 600 volt circuit breakers, motor contactors, and associated equipment are tested in service by opening and closing the circuit breakers or contactors so as not to interfere with operation of the station.

Emergency transfers to the various emergency power sources are tested on a routine basis to prove the operational ability of these systems. The 4160 volt Main Feed Bus can be transferred between power sources or associated normal, startup, and standby circuit breakers on one bus can be “jacked out” into test position and initiated manually for an emergency transfer test.

8.3.1.2 Analysis

The emergency electric power system provided for each nuclear generating unit possesses certain inherent design features which improve its reliability over limited capacity split-bus arrangements usually provided in nuclear power plants.

The basic design criterion for the electrical portion of the emergency electric power system of a nuclear unit, including the generating sources, distribution system, and controls is that a single failure of any component, passive or active, will not preclude the system from supplying emergency power when required. Special provisions have been employed to accomplish this which include a double bus - double breaker distribution system, redundant circuit breaker trip coils and circuits, diverse protective relaying for each circuit breaker, redundant load shedding and transfer logic equipment, physical separation and other features.

The reliability afforded by the split bus concept is included in the design of the double bus - double breaker system employed here. Consideration has been given to the capacity of the emergency power sources, the method of switching, redundancy utilized and the protective features. For example, the electrical system together with the sources of electric power which are installed to supply emergency power to a nuclear unit possesses the following design features:

1. Each electric power source is extremely large for the requirements. For example, each of the redundant on-site Keowee hydroelectric units is rated 87,500 kVA while the maximum combined load demand on one nuclear unit with a LOCA and the other two nuclear units with a LOOP is 16,721 kVA as shown in Table 8-1. The Keowee underground and Lee emergency power sources are the smallest due to the power limitations of Transformers CT-4 and CT-5 which have a maximum continuous rating of 22,400 kVA. The significant effect of these large sources of emergency power is that a greater number of plant auxiliaries may be run and used to help cope with an incident as well as shutdown and maintain the other nuclear units in safe shutdown conditions.
2. The Keowee hydroelectric units are inherently reliable sources of power as proven by years of operating experience with similar generating units. Since they are stored energy type machines, their ability to start is very reliable.

Except for the penstock, and cooling water supply pipe to the first valve, shared air supply, static inverter and regulation, standby battery charger, 4160V and 600V underground power supply to Keowee through CX, 230 kV main transformer, fire protection system, ACB air system, each unit is entirely independent of the other, consisting of its own turbine, governor system, generator, exciter, voltage regulator, generator circuit breaker, synchronizing equipment, protective relaying, automatic startup control equipment, manual controls, unit dc control battery, etc.

If one hydro unit is out for maintenance, the other unit is available for service. The two units are served by a common tunnel-penstock, and unwatering for tunnel or scroll case maintenance will make both units unavailable. Based upon Duke's experience since 1919 with a hydro station similarly arranged, it is expected that unwatering frequency will be about one day per year plus four days every tenth year.

During all periods when the Keowee units are available for emergency power service, the Keowee Hydro Headgate will be rigidly fastened to assure that failure of the hoist system will not permit the gate to move into the closed position.

The independent Keowee units, along with the alternate circuits, provide the required redundancy to assure reliable emergency power. The Keowee reservoir and naturally occurring streamflow provide the water for the Keowee units so they can provide emergency power following an accident. Selected Licensee Commitment 16.9.7 contains lake level information associated with the Lake Keowee water supply for the Keowee Hydro Station. Selected Licensee Commitment 16.8.4 specifies operating restrictions during commercial power generation by one or both Keowee Hydro Units. These restrictions ensure that the units are able to perform their emergency power function from an initial condition of commercial power generation.

Zone Overlap Protection Circuitry provides single failure protection for the Keowee Hydro Units when the unit assigned to the underground path is commercially generating to the grid. Single failures in the Zoner Overlap Region result in automatically realigning the unit assigned to the overhead path to the underground path. For single failures mitigated by the Zone Overlap Protection Circuitry, Auxiliary Power Transfer Circuitry automatically realigns the power source for the auxiliaries from the normal source to the alternate source to ensure continued operation of the units.

The failure analysis covering the Keowee Hydro Station is outlined in Table 8-3.

3. Each electric power distribution system is designed with redundant full capacity buses to match the capacity of the large emergency power source. This thereby provides two continuous sources of supply from the two full capacity main feeder buses to each of the three engineered safeguards switchgear buses.

4. Reliability of the engineered safeguards switchgear buses is assured by the following protective features:

   a. 4160 V engineered safeguards (ESG) switchgear bus overload and bus fault conditions are protected for by both ground fault overcurrent relays and phase overcurrent relays. These relays are provided on each ESG switchgear bus breaker and function to open the associated breaker to isolate the ESG switchgear bus from the main feeder buses, thereby maintaining the integrity of the main feeder buses.

   b. Each ESG switchgear feeder breaker is also included in the zone of protection afforded by the main feeder bus differential current relays which would function to isolate a faulted breaker from any source of supply.

c. Each ESG switchgear feeder breaker is provided with breaker failure protective relaying. This feature will initiate action to isolate the breaker from any source of supply if the breaker fails to open upon a protective relay trip. The maximum equipment this would remove from service is one ESG switchgear bus and one main feeder bus, leaving two ESG switchgear buses and the other main feeder bus to supply the required loads which are sufficient to perform the intended safety functions.

d. Each ESG switchgear feeder breaker is provided with redundant trip coils, supplied from separate dc supplies, assuring positive trip action.

With the above protective features plus their metalclad construction and the physical separation maintained, failure of any one of the three redundant ESG switchgear buses or components will not affect the ability of the other two ESG switchgear buses to supply their engineered safeguards loads.

5. Reliability of the main feeder buses and the standby buses is assured by the following protective features:

   a. Each main feeder bus and each standby bus is protected independently by differential current relays. These relays will sense any fault condition in the zone between the source side of the incoming bus feeder breakers to the load side of the outgoing feeder breakers. The outgoing feeder breakers on the standby bus are the breakers connecting to the main feeder buses and they have overlapping differential protection from both buses. The outgoing feeder breakers of the main feeder buses are the feeder breakers to the engineered safeguards switchgear buses. If a fault condition occurs, the relays will function to isolate the affected bus from all sources of supply by opening all circuit breakers associated with that bus. The other redundant bus still provides the required power to all three engineered safeguards switchgear buses.

   b. Each feeder breaker to each of the buses is protected with phase overcurrent and ground fault overcurrent protective relaying. These relays function to open the breaker and isolate the main feeder bus from the power source upon the occurrence of these overcurrent conditions. This thereby maintains the integrity of the power source and allows the continued supply of power to the other bus and all three engineered safeguards switchgear buses. The comparable condition on a split bus concept would cause the loss of one engineered safeguards bus.

   c. Each feeder breaker is also provided with breaker failure protective relaying. This feature will initiate action to isolate the breaker from any source of supply if the breaker fails to open on a protective relay trip. The maximum loss on this condition would be the connected source of supply and the associated bus. The other bus would transfer by the redundant transfer logic to the alternate source of supply and continue supplying power to all three engineered safeguards switchgear buses. The maximum loss under the split bus concept would not only be the source of supply, but also the associated engineered safeguards switchgear bus.

   d. Each feeder breaker is provided with redundant trip coils supplied from separate dc supplies, assuring positive trip action.

   With the above protective features, their metal-enclosed construction and their physical separation, failure of any one of the redundant bus sections or components will not affect the ability of the other buses to supply the engineered safeguards loads.

6. The emergency power sources are independent of each other and switched on to the main feeder buses such that this independency is maintained. Paralleling of emergency power sources is prevented by redundancy in transfer logic equipment and interlocking.

   Redundant systems of emergency power switching equipment are provided to switch the emergency power to the unit's 4160 volt redundant main feeder buses. The redundant transfer logic will seek the most available source of power and when it becomes available close into it. If this source is then subsequently lost, the switching logic and equipment will transfer to the other source automatically if power is available.

7. The seismic and environmental qualification of Class 1E AC Power system equipment is discussed in Section 3.11.2, Qualification Test and Analysis. The NRC issued IE Bulletin 88-10, "Nonconforming Molded-Case Circuit Breakers," on November 22, 1988 and Supplement 1 on August 3, 1989. The purpose of this bulletin and supplement was to alert licensees to the possibility of existence of molded-case circuit breakers which were nontraceable and unqualified for safety-related duties at their nuclear facilities. Accordingly, in responses submitted in letters from H. B. Tucker to the NRC, dated April 3, 1989, April 24, 1989, July 17, 1989, and November 9, 1989, Duke Power Company reported its efforts to identify and locate any suspect circuit breakers, to administratively remove applicable breakers from service/perform appropriate testing and equipment operability evaluations, and to describe programmatic controls to prevent future reoccurrence of this supplier problem. Of the group of suspect breakers, some were eventually designated following qualification inspection for use in non-safety applications. Final removal from service of all suspect breakers used in safety related applications was confirmed in the letter from H.B. Tucker to the NRC, dated August 13, 1990. Closure of DPC actions to satisfy IE Bulletin 88-10 was confirmed in the letter from the NRC to M.S. Tuckman on June 7, 1991.

The failure analysis covering the emergency electrical systems is outlined in Table 8-4.

8.3.1.3 Physical Identification of Safety-Related Equipment

Detailed cable lists are developed for all cables. These cable lists identify each cable by cable type, specific cable routing by tray section number, and termination points. Protective system cables are identified as such on the cable lists. These lists are issued and are used by the field for cable installation. Each cable tray section, excluding cable trays inside the Reactor Building is identified by tags bearing the tray section number assigned to it. Cables required for protective systems are identified as follows:

1. Power and control cables are color coded to identify their use and/or channel association. The color code is as follows:

Gray	Swgr 1TC, 2TC, 3TC Ld Ctr 1X8, 2X8, 3X8 MCC 1XS1, 2XS1, 3XS1, 1XSF, 1XS4, 2XSF, 3XSF, 2XS4, 3XS4 ESG channel 1, 3, 5, & 7 DC Pnlbd 1DIA, 2DIA, 3DIA Vital Pwr Pnlbd 1KVIA, 2KVIA, 3KVIA RPS Ch A AFIS Analog Channel 1

Yellow	Swgr 1TD, 2TD, 3TD Ld Ctr 1X9, 2X9, 3X9 MCC 1XS2, 1XS5, 2XS2, 3XS2, 2XS5, 3XS5 ESG channel 2, 4, 6, & 8 DC Pnlbd 1DIB, 2DIB, 3DIB Vital Pwr Pnlbd 1KVIB, 2KVIB, 3KVIB RPS Ch B AFIS Analog Channel 2
Blue	Swgr 1TE, 2TE, 3TE Ld Ctr 1X10, 2X10, 3X10 MCC 1XS3,1XS6, 2XS3, 3XS3, 2XS6, 3XS6 ESG channel Even-Odd DC Pnlbd 1DIC, 2DIC, 3DIC Vital Pwr Pnlbd 1KVIC, 2KVIC, 3KVIC RPS Channel C AFIS Analog Channel 3 AFIS Digital Channel 1
Orange	DC Pnlbd 1DID, 2DID, 3DID Vital Pwr Pnlbd 1KVID, 2KVID, 3KVID RPS Ch D AFIS Analog Channel 4 AFIS Digital Channel 2
Red	RPS and ESPS Fiber optic communication* Swgr B6T, B7T Load Center PX13 MCC XPSW, 1XPSW, 2XPSWA, 2XPSWB, 3XPSW 600 V Pwr Pnlbd PSWPLEC01, PSWPLEC02 208/120 Pwr Pnlbd 1KPSW, 2KPSW, 3KPSW DC Load Center LXDC01 DC Pwr Pnlbd 1PSWPL2DC, 2PSWPL2DC, 3PSWPL2DC, PSWPL1DC, PSWPL2DC

*See Section 8.3.1.4.6.2

2. All cables have their identifying number permanently affixed to both ends.

8.3.1.4 Independence of Redundant Systems

The physical locations of electrical distribution system equipment shown in Figure 8-1, Figure 8-3 and Figure 8-4 are arranged to minimize vulnerability of vital circuits to physical damage as a result of accidents.

8.3.1.4.1 Auxiliary Transformers

Auxiliary transformers, startup transformers, and the 100 kV transformer are located out of doors and physically separated from each other. Transformer CT4, fed from the on-site Keowee Hydro Station is physically separated from the other transformers and located in a Class I enclosure. Reference Section 3.2.1. Surge arresters are used where applicable for lightning protection. All transformers are covered by automatic water spray systems. Transformers are well spaced to minimize their exposure to fire, water, and mechanical damage. As part of a long term compensatory action (References 4 and 5) associated with the

Keowee Underground Path, evaporative cooling for the CT-4 Blockhouse area is supplied by the HPSW system.

8.3.1.4.2 Switchgear and Load Centers

The 6900 volt switchgear, 4160 volt switchgear, and 600 volt load centers are located in areas to minimize exposure to mechanical, fire, and water damage. This equipment is coordinated electrically to permit safe operation of the equipment under normal and short circuit conditions. Metalclad construction is used throughout for personnel and equipment protection.

The 4160 volt main feeder bus switchgear sections and standby power bus switchgear sections are located in a Class I enclosure. The 4160 volt main feeder busses provide power from the switchgear sections in the Class I structure to the redundant engineered safeguards 4160 volt switchgear and their associated 600 volt load centers and motor control centers, etc., located within the turbine building and auxiliary building below the operating floor level. The engineered safeguards switchgear and load centers are located in areas with separation and protection to minimize exposure to mechanical, fire and water damage. This equipment is coordinated electrically to permit safe operation under normal and short circuit conditions. The engineered safeguards system is of Class I seismic design.

8.3.1.4.3 Motor Control Centers

The 600 volt motor control centers are located in the areas of electrical load concentration. Those associated with the turbine-generator auxiliary system in general are located below the turbine-generator operating floor level. Those associated with the nuclear steam supply system are located in the auxiliary building and mezzanine floor of the turbine building. Motor control centers are located in areas with separation and protection to minimize their exposure to mechanical, fire and water damage. The safety related motor control centers located in the turbine building are qualified for the postulated environment.

8.3.1.4.4 Batteries, Chargers, Inverters, and Panelboards

The 125 volt dc instrumentation and control power system batteries of a unit are physically separated in separate enclosures from batteries of another unit to minimize their exposure to any damage. The battery chargers and associated dc bus sections and switchgear of a unit are located in separate rooms from battery chargers and associated dc bus sections of another unit in the auxiliary building and physical separation is maintained between redundant equipment.

8.3.1.4.5 Metal-Enclosed Bus

Metal-enclosed buses are used for all major bus runs where large blocks of current are to be carried. They are also routed to minimize exposure to mechanical, fire, and water damage.

8.3.1.4.6 Cable Installation and Separation

8.3.1.4.6.1 Cable Installation

Hanger type HC-18, which is one of the most heavily laden hangers, was checked. This Hanger was inspected during the resolution of Generic Letter (GL) 87-02 and found to be seismically adequate per the Generic Implementation Procedure (GIP-2) for Seismic Verification of Nuclear Plant Equipment, Rev 2, developed by the Seismic Qualification Utility Group (SQUG).

Paragraph(s) Deleted Per 2000 Update.

Overfilled trays were examined and it was determined that section 1ME8 contains 120.4 pounds of cable per linear foot. The tray manufacturers' safe load chart (Reference 2) states that 24 inch tray with 9 inch rung spacing will support a load of 215 pounds per foot with a 2.2 safety factor. The tray used has an ultimate strength of 473 pounds (2.2 x 215). With an existing load of 120.4 pounds the minimum safety factor is 3.8. Therefore, the present tray system is capable of supporting the weight of the cable even with the existing overfilled conditions and the additional fire retardant barriers.

8.3.1.4.6.2 Cable Separation

Control, instrumentation, and power cables are applied and routed to minimize their vulnerability to damage from any source.

Our criteria for routing cables requires that mutually redundant safety related cables be run in separate trays. Trays are spaced vertically in the cable room a minimum of 10 inches apart and in some cases redundant cables are in vertically adjacent trays. It should be pointed out that the cable armors used provide excellent mechanical and fire protection which would not be provided with conventional, unarmored cable systems. An early warning fire detection system has also been provided in this area.

Wire and cables related to engineered safeguards and reactor protective systems are routed and installed to maintain the integrity of their respective redundant channels and protect them from physical damage. Fiber optic wiring (red cable) for the RPS and ESPS, while designated as nuclear safety related, is not required to be separated as a mutually redundant safety channel. This is due to the physical separation provided by its inherent optical design. (Reference SER for RPS/ES.) Power and control cables for redundant auxiliaries or services are run by different routes to reduce any probability of an accident disabling more than one piece of redundant equipment. Floor sleeves are filled with a fire retardant material.

It is our intent wherever physically possible to utilize metallically armored and protected cable systems. By this we mean the use of rigid and thin wall metal conduit, metal sheathed cables (aluminum and other metals), bronze armored control cables, steel interlocked armor power and control cables, and either interlocked armor, served wire or braided armored instrumentation cables.

New power, control, or instrumentation cable installed is constructed similar to or superior to the original cable and meets the requirements of IEEE-383-1974 "IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations."

Where overfill situations exist in Oconee Units 1, 2, and 3 between vertically adjacent cable trays to the extent that the top cable in the lower tray is within three inches of the bottom cable in the tray immediately above, a one-eighth of an inch fire retardant fiberglass reinforced polyester barrier will be placed between the trays. The fire retardant fiberglass reinforced polyester is used as an insulator and protection mechanism to prevent an electrical short from contacting a nearby tray. This product was used due to its good electric insulating characteristics and its low additional combustible load contribution. These barriers will be attached to the bottom of the upper tray and fitted around cables which may pass through the barrier.

Five inches of cable tray rail to rail separation is provided on installation of cable tray. In Oconee 1, 2, and 3 Cable Rooms where available space will not allow a minimum of five inches rail to rail separation between vertical trays a one-eighth of an inch fire retardant fiberglass reinforced polyester barrier will be attached to the bottom of the top tray as an insulator and protection mechanism.

As documented in the NRC Safety Evaluation Report (SER) dated February 28, 2018, an alternative means of cable separation is provided in select areas by implementing the requirements of IEEE Std 384-1992 "Criteria for Independence of Class 1E Equipment and Circuits" Section 6.1.4 'Limited Hazard Areas.' The IEEE 384-1992 Section 6.1.4 requirements include separation distances of three feet horizontally and five feet vertically between openly routed medium voltage and low voltage control cables. Where these open separation distances cannot be met fully enclosed metallic raceways are provided to separate the medium voltage and low voltage cables to meet the enclosed configuration separation distances of 1 inch horizontally and 1 inch vertically. These requirements are specifically applied only to the areas and equipment listed below:

1. Keowee Hydro Station (KHS) Mechanical Equipment Gallery
    a. 4.16 kV power feed to Transformer CX,
    b. 13.8 kV power feed to Transformer CT-4,
    c. 13.8 kV PSW Keowee Power Feeder (KPF) Switchgear line side cable bus,
    d. And any control cables adjacent to the three medium voltage feeds listed above.

2. Protected Service Water (PSW) Cable Spreading Area
    a. 13.8 kV Off-site power feed to the PSW Building,
    b. 4.16 kV power feed from PSW Switchgear B6T to Transformer PX13,
    c. And any KHS control cables adjacent to the two medium voltage feeds listed above.

Specific separation criteria have also been applied to the single conductor medium voltage power cables that constitute the 13.8 kV power feed from KHS to the PSW Building. Review of the construction and configuration of the power cables involved along with the normally de-energized state of the power path has deemed these medium voltage cables acceptable as-is within the KHS Mechanical Equipment Gallery, the PSW Ductbank including Manholes 1 through 6, and the PSW Cable Spreading Area.

8.3.1.5 Cable Derating and Cable Tray Fill

8.3.1.5.1 Cable Derating

All cables are selected using conservative margins with respect to their current carrying capacities, insulation properties, and mechanical construction. Cable insulations in the Reactor Building are selected to minimize the effects of radiation, heat, and humidity. Appropriate instrumentation cables are shielded to minimize induced voltage and magnetic interference.

Power cables are derated based on IEEE S-135, ICEA (Insulated Cable Engineers Association), Publication No. P-46-426, recommendations for interlocked armor power cables when installed in cable support systems.

Studies of heating due to I^2R loss in the cables were made. It was determined that the worst case was tray section 1ME8 which contained 322 cables. Cables were classed in three groups: control, control power and instrumentation. Losses were determined by conservative means and were found to be a total of 1.3 watts per lineal foot of tray. Assuming that one cable dissipates 36% of the total heat and that this cable is in the center of a nine inch pile of cable, its maximum temperature would be only 14°C above the ambient cable spreading room temperature, even though the insulation qualities of the cable pile were assumed to be almost perfect. No air flow was assumed through the cables; therefore, the addition of barriers does not alter the heating calculations. Due to the small amount of heat generated and since all cable used in this area is rated 90°C, these temperatures will have no detrimental affect on adjacent cables or on cables in other trays.

Temperature measurements have been made periodically at ten selected locations for the first-year of operation. These locations are where the tray over-fill is the most severe.

Overload protection for cables is very closely related to the basic power and control systems designs. The 4 kV power systems are protected by electro-mechanical overcurrent relays and solid state type ground relays. The relays are selected for the loads protected and the cables are sized based on the maximum currents which these relays should allow without tripping for the loads they are protecting. The 600 volt load centers are used to feed individual motor control centers. The feeder breakers used are furnished with long-time and instantaneous electromechanical or short-time trip elements. Cables to each breaker are sized in coordination with the trip elements selected for that particular breaker. Small motor loads at the 600 volt and 208 volt levels are generally handled through combination motor starters located in motor control centers. Short circuit protection for the load is provided by molded case circuit breakers with magnetic trip devices while overcurrent protection is provided by standard starter overload elements sized for the application. On small engineered safeguard motor loads two of the three overload elements are oversized for cable protection rather than motor protection and are wired in the contactor trip circuit. The third element is sized for motor protection but is wired to alarm only. This is based on the premise that the motor should operate even if motor damage does occur. Cable sizing is based on maximum service factor loading of the motor.

8.3.1.5.2 Cable Tray Fill

Early cable tray requirements were based on types of cable which had been used in the past which were primarily not armored. Armored cable was used at Oconee to achieve better mechanical protection and fire retardance. This caused the trays to fill faster than anticipated and in several locations the fill became excessive. Steps have also been taken to insure that no additional cables are routed through trays which are already overfilled.

The cable tray spacing criterion for those trays containing power cables is based on ICEA, Publication No. P-46-426 recommendations for interlocked armor power cables when installed in cable support systems.

8.3.2 DC Power Systems

8.3.2.1 System Descriptions

For each nuclear unit, two separate dc power systems are provided; namely, a 125 volt dc system provides a source of reliable continuous power for control and instrumentation for normal operation and orderly shutdown for each unit, and a separate 125/250 volt dc system is provided to supply large power loads for each unit. These systems are shown in Figure 8-5 and Figure 8-9. For each Keowee hydro unit, separate and independent dc power systems are provided to assure a source of reliable continuous power for normal and emergency operation. These systems are shown in Figure 8-6.

The adequacy of safety-related dc power was assessed in the Duke response (letter form M.S. Tuckman to USNRC, dated October 9, 1991) to NRC Generic Letter (GL) 91-06, "Adequacy of DC Safey-related Power Supplies," which identified specific alarms/annunciators and indications to monitor dc power and specific procedures for maintenance and surveillance activities. The NRC approved the response in a letter from David B. Matthews to H. B. Tucker, dated June 5, 1992.

8.3.2.1.1 125 Volt DC Instrumentation and Control Power System

For each unit, two independent and physically separated 125 volt dc batteries and dc buses are provided for the vital instrumentation and control power system. The dc buses are two conductor metalclad distribution center assemblies. Three battery chargers are also supplied, with two serving as normal supplies to the bus sections with the associated 125 volt dc battery floating on the bus. The batteries supply the load without interruption should the battery chargers or the ac source fail. Each of the three battery chargers are supplied from the redundant 600 volt ac engineered safeguards motor control centers of each unit. One of these three battery chargers serves as a standby battery charger and is provided for servicing and to backup the normal power supply chargers. A bus tie with normally open breakers is provided between each pair of dc bus sections to “backup” a battery when it is removed for servicing.

Four separate 125 volt dc instrumentation and control panelboards are also provided for each unit. Each panelboard receives its dc power through an auctioneering network of two isolating diode assemblies. One assembly is connected to the unit's 125 volt distribution system and the other assembly is connected to another unit's 125 volt distribution system. The functions of the diode assemblies are to discriminate between the voltage level of the two dc distribution systems, to pass current from the dc system of higher potential to the instrumentation and control panelboard connected on the output of the diode assemblies, and to block the flow of current from one dc distribution system to the other.

Each isolating diode assembly is composed of a series-parallel network of four diodes in each polarity leg of the dc supply to the panelboard it serves. With this series-parallel arrangement of diodes, either an open circuited or short circuited diode can be tolerated without affecting the operability of the diode assembly. The individual diodes are sized for a minimum continuous current of 500 amperes with the maximum panelboard load current is less than 500 amperes. Each diode is also rated for continuous operation with a peak inverse voltage of 800 volts.

Continuous monitoring of each diode is provided in the design of the isolating diode assemblies to allow detection of a shorted or open circuited diode.

An alarm relay, connected to an individual control room annunciator point, is provided for each isolating diode assembly to advise the operator of diode trouble.

Test provisions are included in each isolating diode assembly to allow the in-service checking of the operability of individual diode monitors, and, in addition, to allow the out of service periodic checking of the peak inverse voltage capability of each individual diode. The latter test can be conducted on one isolating diode assembly with the other diode assembly in the network in operation. Breakers on the input and output of each isolating diode assembly are provided for complete isolation during maintenance and testing of an assembly.

8.3.2.1.2 125/250 Volt DC Station Power System

For each unit a separate 125/250 volt dc power system is supplied. Each system consists of three 125/250 volt dc power supply battery chargers, a three conductor, metalclad distribution center assembly, and two 125 volt dc batteries. This arrangement provides 125 volts dc from “P” bus to “PN” bus, 125 volts dc from “PN” bus to “N” bus, and 250 volts dc from “P” bus to “N” bus. Loads on this system are basically the 250 volt dc power loads of units. Each 125 volt dc half of a bus section normally is supplied from one of the 125 volt dc power supply battery chargers with the associated 125 volt dc battery floating on the bus. The batteries supply the load without interruption should the battery charger or the ac source fail. A bus tie with normally open double breakers is provided between the three units' distribution center bus sections to backup a battery when it is removed for servicing. One standby 125 volt dc power supply battery charger is provided between each pair of the 125 volt dc batteries for servicing and to “backup” the normal power supply battery chargers.

8.3.2.1.3 125 Volt DC Keowee Station Power System

For each Keowee hydro unit a separate 125 volt dc power system is supplied. Each system consists of one 125 volt dc power supply battery charger, one 125 volt dc, two conductor, metalclad distribution center assembly and one 125 volt dc battery. A bus tie with normally open double circuit breakers is provided between the two distribution center bus sections to “backup” a battery when it is removed for servicing. One standby 125 volt dc battery charger is also provided between the two 125 volt dc batteries for servicing. The batteries, battery charger and distribution center associated with one unit are located in the same room as those associated with the other unit, but are physically separated from those associated with the other unit by different enclosures. Loss of power to any Keowee instrument and control power supply bus is indicated in the Keowee control room on "statalarm" panels that are powered from an uninterruptible power supply (battery backed inverter). Loss of power to the inverter will be alarmed in the Keowee control room but will not prevent either Keowee unit from performing its safety function.

8.3.2.1.4 120 Volt AC Vital Power Buses

Figure 8-5 shows the arrangement of the 120 volt ac vital power buses. For each unit, four redundant 120 volt ac vital instrument power buses are provided to supply power in a predetermined arrangement to vital power, instrumentation, and control loads under all operating conditions. Each bus is supplied separately from a static inverter connected to one of the four 125 volt dc control power panelboards described in Section 8.3.2.1.1. Upon loss of power from 125 volt dc bus DCA or DCB, the affected inverter is supplied power from a 125 volt dc bus of another unit through dc control power panelboards and transfer diodes of the affected 125 volt dc panelboard. A tie with breakers is provided to each of the 120 volt vital ac buses from the alternate 120 volt ac regulated bus to provide backup for each vital bus and to permit servicing of the inverters. Each inverter has the synchronizing capability to permit synchronization with the regulated buses.

For each unit, each of the four redundant channels of the nuclear instrumentation and reactor protective system equipment is supplied from a separate bus of the four redundant buses. Also for each unit, each of the three redundant channels of the engineered safeguards protective system is supplied from a separate bus of the four redundant buses. The two engineered safeguards actuation power buses are supplied from separate vital power buses.

8.3.2.1.5 240/120 Volt AC Uninterruptible Power System

For each unit, four uninterruptible power systems are provided to supply power.

They are:

1. The unit's Integrated Control System (ICS) power system, which is 120 volt ac, single phase.
2. The unit's Auxiliary Power System (APS) which is 120 volt ac, single phase.

3. The unit's original design Computer Power System (CPS), which is 240/120 volt ac, single phase.
4. The units' new Computer Power System (KOAC), which is 240/120 volt ac, single phase.

Each of these first three systems consist of a static inverter, with redundant 125 volt dc supplies from separate 125 volt dc buses, circuit breakers and distribution panelboards. The fourth system consists of a static inverter with a 250 volt dc supply from a single 250 volt dc bus, circuit breaker, and distribution panelboard. Also, a static transfer switch is provided in each system as a means for automatic transfer of system loads to the alternate ac regulated power system should the inverter become unavailable. The output of each inverter is synchronized with the ac regulated power system through the static switch in order to minimize transfer time from inverter to the regulated supply.

In addition, an automatic transfer switch is provided in the ICS, APS, and CPS power systems as a means for automatic transfer of system loads to the alternate ac regulated power system should the static transfer switch become unavailable.

8.3.2.1.6 240/125 Volt AC Regulated Power System

For each unit, a system is provided to supply instrumentation, control, and power loads requiring regulated ac power. It also serves as an alternate power source to both the vital power panelboards and to the uninterruptible power panel boards. The system consists of two distribution panels, two regulators, and two transformers fed from separate motor control centers. These systems are shown in Figure 8-5.

8.3.2.1.7 Emergency Lighting System

For each unit, two separate emergency lighting systems are provided; namely, an Emergency 250 Volt DC Lighting System and a separate Engineered Safeguards 208Y/120 Volt AC Lighting System. These two systems are separate and distinct.

8.3.2.1.7.1 Emergency 250 Volt DC Lighting System

The 250 Volt DC Lighting System, which is normally de-energized, provides operating level lighting in the control room and lighting at selected areas in the Auxiliary, Turbine, Reactor, Administrative and Service Buildings. The emergency lighting is energized automatically by an undervoltage sensing relay mounted on the individual panelboards located in their associated areas. Control power for the undervoltage transfer circuit is provided from the 250 volt dc station batteries. A test button is also provided at each panelboard to test the operability of the system without affecting normal lighting.

8.3.2.1.7.2 Engineered Safeguards AC Lighting System

The Engineered Safeguards AC Lighting System, which is normally de-energized, provides lighting in the following parts of the Auxiliary Building: control room, cable room, equipment room, stairs, exits, corridors, hot machine shop, spent fuel pool room, fuel unloading area, decontamination rooms, pump and tank room areas, fan and ventilation rooms of roof elevation, penetration rooms, and purge rooms. The stairs and platforms in the Reactor Building are also provided lighting to enable personnel to leave or enter the entire building. Power is provided from two engineered safeguards 600 volt ac control centers through two 600/208Y/120 volt ac dry type transformers which in turn feed each of two panelboards located in the equipment room area. The engineered safeguard lighting is energized automatically by undervoltage sensing relays monitoring the normal 600 volt ac feeder voltage.

Upon loss of power, the undervoltage relay for the Engineered Safeguards Lighting (ESL) system drops out and aligns the engineered safeguards lighting system to the safety-related bus. When Keowee starts and supplies power to the station, the under voltage relay is picked up by the recovery of power to Units 1, 2, 3 load centers X5, X6, and X7 and therefore the ESL lights never illuminate. The ESL emergency lighting system is still functional, but is not expected to illuminate and thus not tested.

8.3.2.1.8 DC and AC Vital Power System Monitoring

Failure and/or misoperation of all dc and ac vital power system equipment is being monitored on two local alarm annunciators located in the equipment room near most of the vital equipment. Several variables within each piece or redundant group of equipment are being monitored on one of the local panels, with any alarm from each group being retransferred to a common group alarm in the control room. Although not considered a failure or misoperation, ground conditions on the vital dc system are provided an alarm in the control room. The control room alarms alert the operator if an alarm condition occurs on any piece or group of equipment, or if power is lost to the local alarm monitoring equipment.

The DC bus tie breakers, battery breakers and standby charger breaker position indication contacts; the standby charger trouble contact; and the computer, ICS and auxiliary inverter isolating diode trouble contacts are monitored directly in the control room.

The other vital alarms are divided into two separate and independent monitoring systems. Alarms for equipment which have battery 1CA for their primary source of power are maintained physically and electrically separate from battery 1CB powered equipment. For example, the distribution center, isolating diodes, breakers, panelboards, inverters and transfer switches associated with battery 1CA are alarmed on local and remote annunciators which are physically and electrically separated from the annunciators being used for monitoring battery 1CB associated systems.

Specifically, the variables being monitored locally with a composite alarm from each of the 17 groups being taken to the control room are as follows:

Group 1 and 11 for each of the two dc buses

Charger trouble

Charger output breaker tripped

Bus voltage low

Group 2, 3, 4, 5, 12, 13, 14, 15 for each of eight isolating diodes

Fuse blown

Diode failure

Input breaker open

Output breaker open

Feeder breaker open

Group 6, 7, 16, 17 for each of four vital inverters and panelboards

Inverter input voltage low

Inverter output voltage low

Bypass voltage low

Inverter bypassed

Panelboard voltage low (60%)

Group 8, 18, 19 for computer, ICS and auxiliary inverters and panelboards

Inverter input voltage low

Inverter output voltage low

Bypass voltage low

Inverter bypassed

Panelboard voltage low (60%)

8.3.2.2 Analysis

The 125 Volt DC Instrumentation and Control Power System and the 125 Volt AC Vital Power System are designed such that upon loss of power supplies no interactions exist between Reactor Protection Systems, Engineered Safeguards Protection Systems, and control systems that would preclude these systems from performing their respective functions. Also, any interactions between units as a result of the loss of power supplies does not preclude the safety and control systems of any unit from fulfilling their function. This is verified by safety analyses and is shown in Table 8-5, Table 8-6, and Table 8-7.

The ungrounded dc system has a ground detector with a manually switched backup to indicate when there is a ground existing on any leg of the system. A ground on one leg of the dc system will not cause any equipment to malfunction. Simultaneous grounds on two legs of the system may cause all energized equipment to drop out if the grounds are of sufficiently low resistance. This may be momentary if the grounded circuit is cleared by its circuit breaker or sustained if the grounded circuit is not cleared by its circuit breaker.

Each battery is sized to carry the continuous emergency load for a period of one hour in addition to supplying power for the operation of momentary loads during the one hour period. The Station Blackout (Section 8.3.2.2.4) coping strategy which manually strips non-essential loads from the 125 Volt I&C Power System within 30 minutes into the event allows for the operation of the equipment required during the scenario for four hours.

In normal operation the batteries are floated on the buses, and assume load without interruption on loss of a battery charger or ac power source.

The lead-acid batteries are tested to prove their ampere-hour capacity. The surveillance frequencies for this test are in accordance with the Battery Discharge Testing Program and are consistent with the recommendations in IEEE-450-1987 (Reference 3). Inservice periodic checks of the status of each cell is made through battery hydrometer log readings and cell voltage. Temperature readings are used to adjust hydrometer readings.

The seismic and environmental qualification of Class 1E dc power system equipment is discussed in Section 3.11.2, Qualification Test and Analysis. The NRC issued IE Bulletin 88-10, "Nonconforming Molded-Case Circuit Breakers," on November 22, 1988 and Supplement 1 on August 3, 1989. The purpose of this bulletin and supplement was to alert licensees to the possibility of existence of molded-case circuit breakers which were nontraceable and unqualified for safety-related duties at their nuclear facilities. Accordingly, in responses submitted in letters from H.B. Tucker to the NRC, dated April 3, 1989, April 24, 1989, July 17, 1989, and November 9, 1989, Duke Power Company reported its efforts to identify and locate any suspect circuit breakers, to administratively remove applicable breakers from service/perform appropriate testing and equipment operability evaluations, and to describe programmatic controls to prevent future reoccurrence of this supplier problem. Of the group of suspect breakers, some were eventually designated following qualification inspection for use in non-safety applications. Final removal from service of all suspect breakers used in safety related applications was confirmed in the letter from H.B Tucker to the NRC, dated August 13, 1990. Closure of DPC actions to satisfy IE Bulletin 88-10 was confirmed in the letter from the NRC to M.S. Tuckman on June 7, 1991.

8.3.2.2.1 Single Failure Analysis of the 125 Volt DC Instrumentation and Control Power System

As shown in Table 8-5, the 125 Volt DC Instrumentation and Control Power System is arranged such that a single fault within either system does not preclude the Reactor Protective System, Engineered Safeguards Protective System, and the engineered safeguards equipment from performing their safety functions.

8.3.2.2.2 Single Failure Analyses of the 125 Volt DC Keowee Station Power System

The 125 Volt DC Keowee Station Power System is arranged such that a single fault within either unit's system does not preclude the other unit from performing its intended function of supplying emergency power.

8.3.2.2.3 Single Failure Analysis of the 120 Volt Vital Power Buses

The 120 Volt Vital Power System is arranged such that any type of single failure or fault will not preclude the Reactor Protective System, Engineered Safeguards Protective System, and engineered safeguards equipment from performing their safety functions. There are four independent buses available to each unit, and single failure within the system can involve only one bus. A single failure analysis is presented in Table 8-6.

8.3.2.2.4 Station Blackout Analysis

Station Blackout (SBO) is the hypothetical case where all off-site power and both Keowee hydro-electric units are lost. Electrical power is available immediately from the battery systems and within 10 minutes from the SSF diesel generator. This event was originally included in FSAR section 15.8.3. As documented in the NRC Safety Evaluation Report (SER) dated March 10, 1992 and the NRC Supplemental SER dated December 3, 1992, Oconee Nuclear Station is in compliance with 10 CFR 50.63 and conforms to the guidance of NUMARC Report 8700 and Regulatory Guide 1.155. This regulation requires that a licensed nuclear power plant demonstrate the ability to achieve safe shutdown from 100% reactor power by ensuring containment integrity and adequate decay heat removal for a calculated duration. The licensee must also demonstrate that the required equipment be able to withstand the resulting operating environment. The temperature of the control room and other areas where extensive manual operations occur, shall not exceed habitability requirements of 120°F. Station blackout is not a design basis event. Therefore, the SBO scenario is not concurrent with any design basis event or single failures.

Oconee is capable of coping with a SBO by the following means:

1. The SBO duration is 4 hours by application of NUMARC 8700 guidance.
2. The SSF diesel generator is the alternate AC (AAC) source and is available within 10 minutes. The SSF diesel generator must be manually started from the SSF control room, and the capability of plant operators to access the SSF control room, manually start the

diesel generator, and supply electric power within 10 minutes of recognition of an SBO event has been demonstrated by testing.

3. The SSF Auxiliary Service Water system is the design basis source of decay heat removal. Actuation of the Emergency CCW System is not required since the inventory in the CCW piping is sufficient for 4 hour operation of the SSF/ASW system.
4. The non-essential inverters (KI, KU, and KX) are manually stripped from the Vital 125VDC System within 30 minutes to ensure that the Class 1E batteries have sufficient capacity for the 4-hour SBO coping duration and recovery actions, and to reduce the electrical heat loads of the unit control complex. Refer to FSAR Selected Licensee Commitment 16.8.1. The resulting temperature in the unit control room does not exceed the habitability requirement of 120°F. Therefore, command and control remain in the unit control room to allow completion of restoration procedures as required in the Supplemental SER dated December 3, 1992.
5. Containment isolation valves fail closed on loss of air or power, can be manually closed, or have diverse closure ability from the SSF as required in NUMARC 8700.
6. Restoration of power is accomplished by manual closure of switchgear breakers at Switchgear control panel.

Stripping the non-essential inverters from the 125VDC system will make power available to the TDEFWP and its associated controls in the unit control room for 4 hours. Although its operability is limited to 2 hours due to the volume of the associated nitrogen supply. Notably, the TDEFWP is not required for the 4 hour coping period since the SSF ASW system is the licensing and design basis commitment for decay heat removal during the SBO event.

The 4 hour coping duration is derived from NUMARC 8700 based on meteorological data, grid stability, switchyard features, and availability/reliability of emergency power sources. A program to control SSF availability/reliability has been implemented to ensure at least a value of 95% as stated in the Supplemental SER. The program is based on the largest single contributor of SSF unavailability, which is unwatering of Unit 2 CCW intake piping. This is based on the fact that Unit 2 CCW intake piping supplies suction to the SSF Auxiliary Service Water pump, the diesel engine cooling and the SSF HVAC. SSF availability is also dependent on the reliability of Keowee, the SSF batteries, the SSF diesel generator and supporting systems. Additionally, controls are implemented so that planned maintenance on the SSF and Keowee does not occur simultaneously.

8.3.3 References

1. Unistrut Corporation General Engineering Catalog No. 6, 1966, Page 11.
2. Unistrut Corporation Catalog KUR4P-2, Page 16.
3. Issuance of Amendments – Oconee Nuclear Station, Units 1, 2, and 3, letter dated December 16, 1998 (TAC NOS. M99912, M99913, and M99914), Docket Nos. 50-269, -270, and -287.
4. EC110081, Install Class F Spray Cooling Piping/Tubing in U1/2 Blockhouse and Electrical Temperature Control Circuitry in the CT-4 Blockhouse.
5. EC110082, Connect U1/2 Blockhouse Evap Cooling Piping to HPSW.

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8.4 Adequacy of Station Electric Distribution System Voltages

8.4.1 Analysis

Each offsite power source was analyzed to the onsite distribution system under maximum and minimum load conditions with the offsite power sources at maximum and minimum anticipated voltages. The analysis included the transient effects on the Class 1E equipment from starting a large Class 1E and non-Class 1E load. The maximum voltage expected at the 4kV bus is slightly higher than the equipment rating. However, this voltage does not have detrimental effects on plant loads or motor feeder circuits. When voltage drops are accounted for, the maximum equipment terminal voltage is within the equipment rating. In anticipation of future growth, changes have been incorporated to maintain bus and terminal voltages within acceptable limits specifically, relocating loads to various buses, delaying the start time of certain large motors, and shedding non-safety related loads in anticipation of unique conditions. The minimum analyzed bus voltages shown in the most current analysis are high enough to account for feeder voltage drops that exist between the bus and the loads. The minimum equipment terminal voltage is within the equipment rating. It has been established that the 4160 volt, 600 volt and 208 volt emergency loads will operate within allowable voltage limits when supplied from the offsite power system.

Tests were performed in accordance with NRC guidelines for verification of voltages and currents for the Unit 3 distribution system while the unit auxiliary transformer of that unit supplied 100% of the normal full power operating loads. The measured voltage values were compared with calculated voltage values, and in all cases, the measured values were acceptably close to the analyzed voltage values (0.21-0.28% for the 4 kV buses; within 0.33% for 600 volt buses; and within 1.05 to 1.73% for the 208 volt buses). This test verifies the accuracy of the analysis for the steady-state condition. The verification tests on Unit 3 are applicable to Units l and 2 also, since they employ identical equipment and distribution systems. Therefore, no separate tests are required on Units 1 and 2.

8.4.2 Conclusions

1. The voltages are within the operating limits of Class IE equipment for projected combinations of plant load and offsite power grid conditions provided one startup transformer is used for one unit.
2. Spurious separation from the offsite power system due to the operation of voltage protective relays will not occur (with the offsite grid voltage within its expected limits) as a result of starting safety loads.
3. It has been determined (by analysis) that no potential for either a simultaneous or consequential loss of both offsite power sources exists.

8.4.3 References

1. J. F. Stolz (NRC) to H. B. Tucker, Letter, Review of Adequacy of Station Electric Distribution System Voltages for Oconee Nuclear Station, Units Nos. 1, 2, and 3 (enclosing NRC SER and EG&G TER) Washington, D.C., March 1983.

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Appendix 8A. Tables

Table 8-1. Loads to be Supplied from the Emergency Power Source

This table will provide a list of Oconee loads which automatically start after a LOOP or LOCA, and the Oconee loads which are required to mitigate the event. This table demonstrates that the transformers have adequate capacity to supply the required Oconee loads. Loads may be added at the option of the operator to help mitigate the event. The additional loads are not listed in this table.

I. Equipment automatically loaded after load shed (KVA).

	Unit 1		Unit 2		Unit 3	
Equipment	**LOCA**	**LOOP**	**LOCA**	**LOOP**	**LOCA**	**LOOP**
H.P. Injection Pump	1800 hp	1200 hp	1800 hp	1200 hp	1800 hp	1200 hp
L.P. Injection Pump	800 hp	0	800 hp	0	800 hp	0
L.P. Service Pump (1)	1200 hp	600 hp	600 hp	600 hp	1200 hp	600 hp
R.B. Spray Pump	500 hp	0	500 hp	0	500 hp	0
Emerg. Fdw Pump	1000 hp	1000 hp	1200 hp	1200 hp	1200 hp	1200 hp
R.B. Cooling Fans	225 hp	225 hp	225 hp	225 hp	225 hp	225 hp
ESV Pump (2)	50 hp	50 hp	50 hp	50 hp	50 hp	50 hp
Pene Rm. Vent Fans	10 hp	0	10 hp	0	10 hp	0
MOVs (3)	100 kva	0	100 kva	0	100 kva	0
Safety MCCs	375 kva	375 kva	375 kva	375 kva	375 kva	375 kva
Auto Load LCs (4)	1290 kva	1290 kva	1290 kva	1290 kva	1290 kva	1290 kva
Keowee Aux. Power	750 kva	750 kva	0	0	0	0
Total (5)	7743 kva	5130 kva	6274 kva	4489 kva	6803 kva	4489 kva
II. Equipment required to run for event mitigation (KVA)						
H.P. Injection Pump	600 hp	600 hp	600 hp	600 hp	600 hp	600 hp
L.P. Injection Pump	400 hp	0	400 hp	0	400 hp	0
L.P. Service Pump	600 hp	600 hp	600 hp	600 hp	600 hp	600 hp
R.B. Spray Pump	250 hp	0	250 hp	0	250 hp	0
Emerg. Fdw Pump	0	1000 hp	0	1200 hp	0	1200 hp
R.B. Cooling Fans	225 hp	225 hp	225 hp	225 hp	225 hp	225 hp
HPSW Pumps	1000 hp	1000 hp	0	0	0	0
Pene Rm. Vent Fans	10 hp	0	10 hp	0	10 hp	0
ESV Pump	25 hp	25 hp	25 hp	25 hp	25 hp	25 hp
Safety MCCs	375 kva	375 kva	375 kva	375 kva	375 kva	375 kva
Auto Load LCs	1290 kva	1290 kva	1290 kva	1290 kva	1290 kva	1290 kva

Keowee Aux. Power	750 kva	750 kva	0	0	0	0
Chiller Comp (6)	350 hp	350 hp	350 hp	350 hp	825 hp	825 hp
Chill. SW Pumps (6)	25 hp	25 hp	25 hp	25 hp	0	0
Chill. Wtr Pm (6)	30 hp	30 hp	30 hp	30 hp	0	0
AC Sys. Fan (6)	20 hp	20 hp	20 hp	20 hp	0	0
Total (5)	5534 kva	5834 kva	3902 kva	4378 kva	4255 kva	4731 kva

III. Combined Load Demand for Station

	Starting	Running
LOCA KVA	7743	5534
LOOP KVA (7)	4489	4003
LOOP KVA (7)	4489	4003
Total KVA	16,721	13,540

IV. Source Size

Two Keowee Units 2@87.5 MVA = 175 MVA

Startup Transformers (CT1, CT2, CT3) = 45/60 MVA each

Standby Transformers (CT4, CT5) = 12/16/20/22.4 MVA each

V. Summary

Transformers CT1, CT2, CT3, CT4, CT5 and Keowee hydro generators are sized adequately to provide power for Oconee loads required to start and/or run during a LOCA/LOOP event. There is sufficient margin in the transformer and generator sizing to allow the operator to start additional loads as desired to assist in event mitigation. There is sufficient guidance given to the operator so that transformer ratings will not be exceeded.

Note:

1. LPSW-B pump is shown fed from Unit 1.
2. The ESV Pumps will automatically start 2 minutes after power becomes available.
3. Loading for MOVs is an approximate value.
4. Auto loading non-safety load centers will delay loading for 30 seconds when the Standby Bus is supplied from a Lee Combustion Turbine.
5. KVA was calculated using a combined power factor-efficiency of .85 for all loads shown in horsepower.
6. Only 1 unit would be supplying a chiller. Unit 3 would supply a temporary chiller if the other 2 were out of service.
7. LOOP loads are loaded approximately 20 seconds after the LOCA loads.

Table 8-2. Single Failure Analysis for 125 Volt DC Switching Station Power Systems

	Component	Malfunction		Comments & Consequences
1.	480V AC Power Supply to Charger	Loss of power to one		No consequence - power from battery is available to supply power without interruption.
2.	Battery Charger	Loss of power from one	(a)	The 125 volt dc bus would continue to receive power from its respective battery without interruption except as in (c) below.
			(b)	Standby battery charger may be manually aligned.
			(c)	Battery Charger internal faults may cause high short circuit currents to flow resulting in voltage reduction on the 125 volt dc bus until the fault is cleared by the isolating circuit breakers. Complete loss of voltage on the 125 volt dc bus may result if the battery circuit breakers open. However, redundant protective relaying and panelboards are provided and are supplied from the other redundant 125 volt dc bus.
3.	125V DC Battery	Loss of power from one		Only those 125 volt dc control panelboards supplied from the affected bus will be lost. The redundant panelboards supplied from the other 125 volt dc bus would be unaffected and continue to provide power for protection and control.
4.	DC Distribution Center Buses P-N	Bus shorted		Same comment as 3.
5.	125V DC Bus SY-1, SY-2, SY-3, SY-4	Grounding a single bus (P or N)		The 125 volt dc system is an ungrounded electrical system. Ground detector equipment monitors and alarms upon a ground anywhere on the 125 volt dc system. A single ground will not cause any malfunction or prevent operation of any safety feature.
6.	125V DC Bus SY-1, SY-2, SY-3, SY-4	Gradual decay of voltage on one bus		Each 125 volt bus is monitored to detect the voltage decay on the bus and initiate an alarm at a setting above a voltage where the battery can deliver power for safe and orderly shutdown of the station. Upon detection power will be restored by correcting the deficiency.

	Component	Malfunction		Comments & Consequences
7.	DC Distribution Center Load Feeder Cables	Cables shorted		Same comments as 3.
8.	125V DC Primary or Backup Panelboards	Bus shorted in one panelboard	(a)	Voltage on associated 125 volt dc bus will decay until isolated by isolating circuit breakers.
			(b)	Protective relaying connected to the affected panelboards may be lost; however, redundant protective relaying supplied from the other 125 volt dc bus would provide protection.
			(c)	One source of control power may be lost to the switching station power circuit breakers; however, a redundant source of control power is provided from the other 125 volt dc bus.

Table 8-3. Single Failure Analysis for the Keowee Hydro Station

	Component	Malfunction		Comments & Consequences
1.	Keowee Hydro Units	Loss of one	(a)	One emergency power source would be lost; however, the other unit would supply 100% of emergency power load.
			(b)	If the 13.8 kV underground feeder were selected to the unit which was lost, it would also be lost; however, the other unit would supply power through the stepup transformer and the 230 kV switching station to the startup transformers and the underground feeder could be transferred by the Oconee operator to the running unit.
2.	Generator Circuit Breakers and Buses	Loss of one		Same as 1 above.
3.	Stepup Transformer, Low Side Buses, 230 kV Overhead Line and PCB-9	Loss of one		Both hydro units would be separated from the 230 kV switching station; however, one hydro unit would supply emergency power through the 13.8 kV underground circuit.
4.	13.8 kV Underground Feeder Circuit Breaker, Cables, or Transformer	Loss of one		One circuit of emergency power would be lost; however, both units could supply emergency power over the 230 kV overhead line. Although a ground fault would cause the underground unit to lockout, the lockout could be reset allowing the Keowee Unit to restart so that it could supply emergency power over the 230 kV overhead line.
5.	Keowee Hydro Unit Automatic Startup and Unit Control Systems	Loss of one unit's system		Same as 1 above.
6.	Keowee Hydro Unit 125V DC Control Battery, Panelboard, Feeders, etc.	Loss of one		Same as 1(a) above.
7.	Keowee Hydro Unit Emergency Startup and Switching Logic	Loss of one		Same as 1(a) above.

	Component	Malfunction	Comments & Consequences
8.	Keowee Hydro Unit Emergency Startup and Switching Circuits from Oconee	Loss of one	No Consequence, since independent and redundant underground signal cables are provided.
9.	Underground assigned Keowee Hydro Unit generating to the grid during commercial generation or testing	Loss of underground assigned Keowee Hydro Unit and overhead path	Overhead assigned Keowee Hydro Unit would be automatically realigned to provide power to underground path. Auxiliary loads for overhead assigned Keowee Hydro Unit would be automatically realigned to receive power from Transformer CX.

Table 8-4. Single Failure Analysis for the Emergency Electrical Power Systems

	Component		Malfunction	Comments & Consequences
1.	Any 230 kV Bus, PCB-18, 27 and PCB-30, 230 kV Circuit to Startup Transformers, CT1, CT2, CT3, and Associated Buses		Loss of one	On loss of the yellow bus, the 230 kV emergency power circuit would be lost until the Oconee operator could reroute this supply in the switching station. However, emergency power would be available through the 13.8 kV underground circuit from one of the Keowee units. Other singular losses would have no consequence.
2.	230 kV Power Circuit Breaker Trip Coils or 125V DC Trip Coil Power Supply		Loss of one	No consequence as two trip coils are provided for each circuit breaker and each trip coil is provided with a separate 125 volt dc control circuit.
3.	13.8 kV Underground Circuit from Keowee Hydro or Transformer No. CT4		Loss of one	One circuit of emergency power would be lost; however, both hydro units could supply emergency power over the 230 kV overhead line. Although a ground fault would cause the underground unit to lockout, the lockout could be reset allowing the Keowee Unit to restart so that it could supply emergency power over the 230 kV overhead line.
4.	4160V Main Feeder Buses, 4160V Stand-by Power Buses and Feeder Circuit Breakers	(a)	One circuit breaker fails to close when required to supply emergency power.	No consequence, as sufficient redundant circuit breakers and buses are provided with redundant switching logic.
		(b)	One bus section faults	No consequence as sufficient redundant circuit breakers and buses are provided with redundant switching logic.
5.	4160 V Auxiliary Switchgear Bus Section		Loss of one	Same as 4(a) above.
6.	600V Auxiliary Switchgear Bus Sections		Loss of one	One 600 volt bus section containing engineered safeguards would fail to receive emergency power; however, sufficient redundant engineered safeguards will be supplied from the remaining redundant buses to perform the engineered safeguards function.

	Component	Malfunction	Comments & Consequences
7.	125V DC System	Single failures	See Section 8.3.2.2.1 and Table 8-5 for single failure analysis.
8.	120V AC Vital Power Buses	Single failures	See Section 8.3.2.2.3 and Table 8-6 for single failure analysis.

Table 8-5. Single Failure Analysis for 125 Volt DC Instrumentation and Control Power System

	Component	Malfunction		Comments & Consequences
1.	600V AC Power Supply to charger	Loss of power to one		Power from battery is available to supply power without interruption until standby charger is switched in.
2.	Battery Charger	Loss of power from one	(a)	The 125 volt dc bus would continue to receive power from its respective battery without interruption except as in (2c) below.
			(b)	Standby battery charger may be manually aligned.
			(c)	Battery Charger internal faults may cause high short circuit currents to flow resulting in voltage reduction on the 125 volt dc bus until the fault is cleared by the isolating circuit breakers. Complete loss of voltage on the 125 volt dc distribution center may result if the battery circuit breakers open. However, power to reactor protection systems and engineered safeguards instrumentation and control would be unaffected since they are supplied from redundant feeders.
3.	125V DC Battery	Loss of power from one	(a)	Those 125 volt dc control panelboards supplied from the affected bus will continue to receive uninterrupted power from their alternate power supplies through isolating diodes.
			(b)	All power could be lost to the other loads supplied from the faulted bus; however, they are not associated with reactor instrumentation, protective systems, or engineered safeguards.
4.	125V DC Distribution Center Buses P-N	Bus shorted		Same comment as 3a and 3b .

	Component	Malfunction		Comments & Consequences
5.	125V DC Distribution Center DCA, DCB	Grounding a single bus (P or N)	(a)	The 125 volt dc system is an ungrounded electrical system. Ground detector equipment monitors and alarms a ground anywhere on the 125 volt dc system. A single ground will not cause any malfunction or prevent operation of any safety feature.
6.	125V DC Distribution Center DCA, DCB	Gradual decay of voltage on one bus	(a)	Each 125 volt bus is monitored to detect the voltage decay on the bus and initiate an alarm at a setting above a voltage where the battery can deliver power for safe and orderly shutdown of the station. Upon detection, power will be restored either by correcting the deficiency by switching to a redundant source or by employing one of the redundant circuits.
7.	DC Distribution Center Load Feeder Cables	Cables shorted	(a)	Same comments as 3a 3b.
8.	Isolating Diodes	Failure of one	(a)	If the diode fails "shorted" then the other series diodes will still provide adequate isolation and power will be uninterrupted.
			(b)	If the diode fails "open" then the other redundant supply through its isolating diodes will continue to supply power without interruption.
9.	125V DC Control Power Panelboard 1DIA, 1DIB, 1DIC, 1DID, 2DIA, 2DIB, 2DIC, 2DID, 3DIA, 3DIB, 3DIC or 3DID	Bus shorted	(a)	Voltage on two of the 125 volt dc bus systems will decay until isolated by the isolating circuit breakers causing consequences same as comments 3a and 3b. At most, one panelboard in a single unit could be lost.

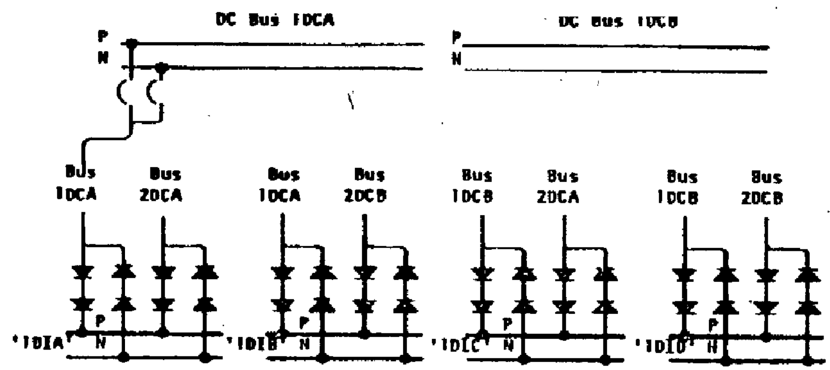
Component	Malfunction		Comments & Consequences
		(b)	For one unit, one-half of control and instrumentation power not associated with reactor instrumentation and protective systems or engineered safeguards will be degraded until the shorted panel board isolates, after which one-fourth of the loads would be lost. Control and instrumentation power associated with reactor instrumentation and protective systems or engineered safeguards is covered in 9(g).
		(c)	For one unit, one-half of 6900 volt switchgear closing control power could be lost but dual trip coils and redundant tripping power supplies are provided.
		(d)	For one unit, one-third of the 4160 volt switchgear closing control power could be lost. Dual trip coils and redundant tripping control power are provided. The remaining redundant switchgear is adequate and is supplied control power from the other dc panels.
		(e)	For one unit, the 4160 volt main feeder bus circuit breakers on only one of the two buses could lose closing control. All 4160 volt circuit breakers have redundant trip coils and power supplies. The remaining main feeder bus and circuit breakers are supplied control power from the other dc panels, permitting the switching of 4160 volt emergency power to any unit.
		(f)	For one unit, the 600 volt load center(s) associated with the affected panel will lose dc control power; however, each load connected to the load center(s) has an alternate feed from a redundant load center.

Component	Malfunction		Comments & Consequences
		(g)	One static inverter would be lost and power to one instrument bus would be lost temporarily until a manual transfer could be made to a regulated instrument bus. The temporary loss of one vital instrument bus would result in the temporary loss of one channel of reactor protection and instrument systems and engineered safeguards systems. Other remaining channels will receive vital instrument control power from the other panelboards.

Table 8-6. Single Failure Analysis for the 120 Volt AC Vital Power System

	Component	Malfunction	Comments & Consequences
1.	125V DC Control Power Panelboard 1DIA, 1DIB, 1DIC, 1DID, 2DIA, 2DIB, 2DIC, 2DID, 3DIA, 3DIB, 3DIC or 3DID	Bus shorted	One static inverter would be lost and power to one instrument bus would be lost temporarily until a manual transfer could be made to a regulated instrument bus. The temporary loss of one vital instrument bus would result in the temporary loss of one channel of reactor protection and instrument systems and engineered safeguards systems. Other remaining channels will receive vital instrument control power from the other panelboards.
2.	Static Inverter Feeder Cable	Failure	Same as comment 1.
3.	Static Inverter	Failure	Same as comment 1.
4.	Vital Instrument Power Panelboard 1KVIA, 1KVIB, 1KVIC, 1KVID, 2KVIA, 2KVIB, 2KVIC, 2KVID, 3KVIA, 3KVIB, 3KVIC or 3KVID	Failure of one	For any one bus failure only one channel of any system associated with reactor instrumentation and protective systems or engineered safeguards would be lost. Sufficient redundant channels supplied from other vital instrument buses would provide adequate protection.

Table 8-7. 125 Volt DC Panelboard Fault Analysis



FAULT	EQUIPMENT LOSS	PNLB'S AFFECTED	COMMENTS
Pnlbd 1DIA BUS	Pnlbd 1DIA & (No. 1DCA D.C.Bus) (No. 2DCA D.C.Bus)	1DIB, 3DIA, 3DIB 1DIC, 2DIA, 2DIB	All would receive power from redundant DC buses in Oconee 1, 2, or 3 (See Below)
Pnlbd 1DIB Bus	Pnlbd 1DIB & (No. 1DCA D.C.Bus) (No. 2DCB D.C.Bus)	1DIA, 3DIA, 3DIB 1DID, 2DIC, 2DID	All would receive power from redundant DC buses in Oconee 1, 2, or 3 (See Below)
Pnlbd 1DIC Bus	Pnlbd 1DIC & (No. 1DCB D.C.Bus) (No. 2DCA D.C.Bus)	1DID, 3DIC, 3DID 1DIA, 2DIA, 2DIB	All would receive power from redundant DC buses in Oconee 1, 2, or 3 (See Below)
Pnlbd 1DID Bus	Pnlbd 1DID & (No. 1DCB D.C.Bus) (No. 2DCB D.C.Bus)	1DIC, 3DIC, 3DID 1DIB, 2DIC, 2DID	All would receive power from redundant DC buses in

Panelboard No.	OCONEE 1				OCONEE 2				OCONEE 3			
	1DIA	1DIB	1DIC	1DID	2DIA	2DIB	2DIC	2DID	3DIA	3DIB	3DIC	3DID
Supplied From bus	1DCA 2DCA	1DCA 2DCB	1DCB 2DCA	1DCB 2DCB	2DCA 3DCA	2DCA 3DCB	2DCB 3DCA	2DCB 3DCB	3DCA 1DCA	3DCA 1DCB	3DCB 1DCA	3DCB 1DCB

Appendix 8B. Figures

Figure 8-1. Single Line Diagram

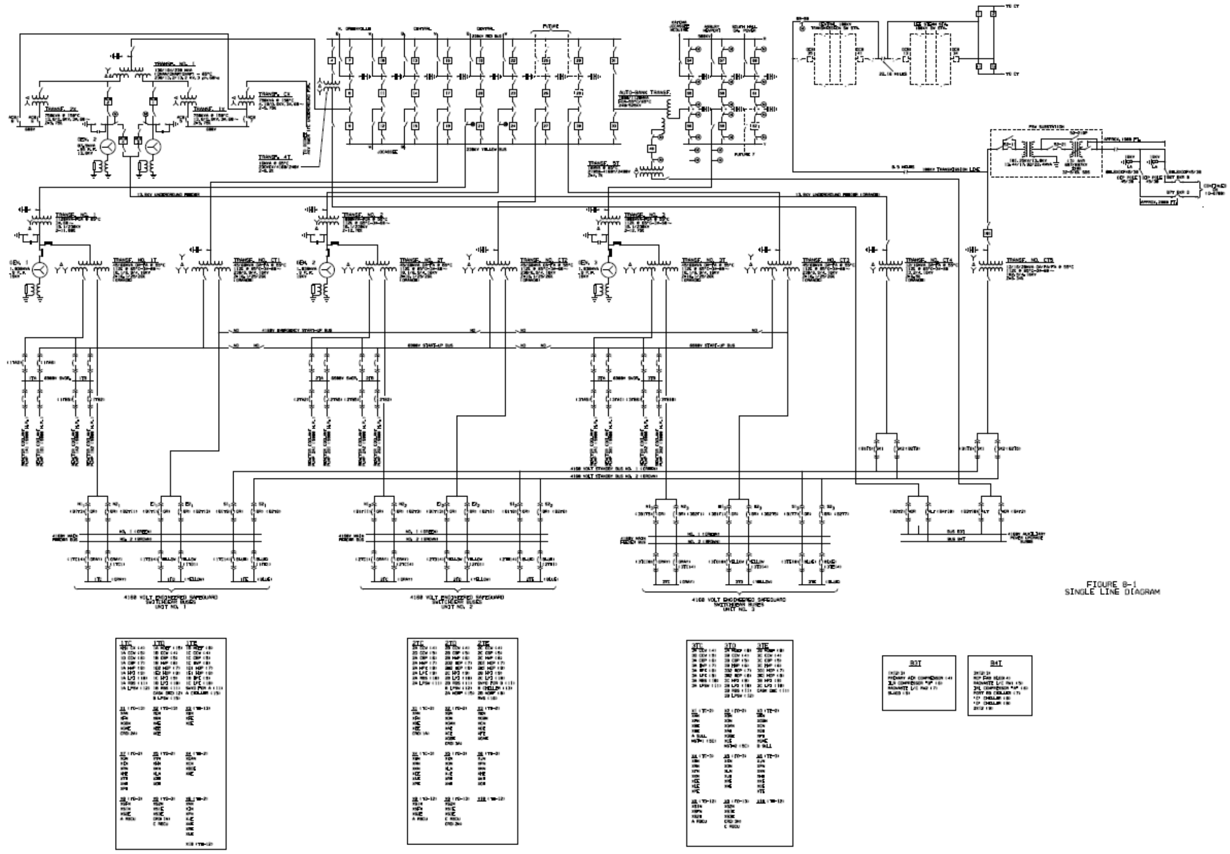


Figure 8-2. Site Transmission Map

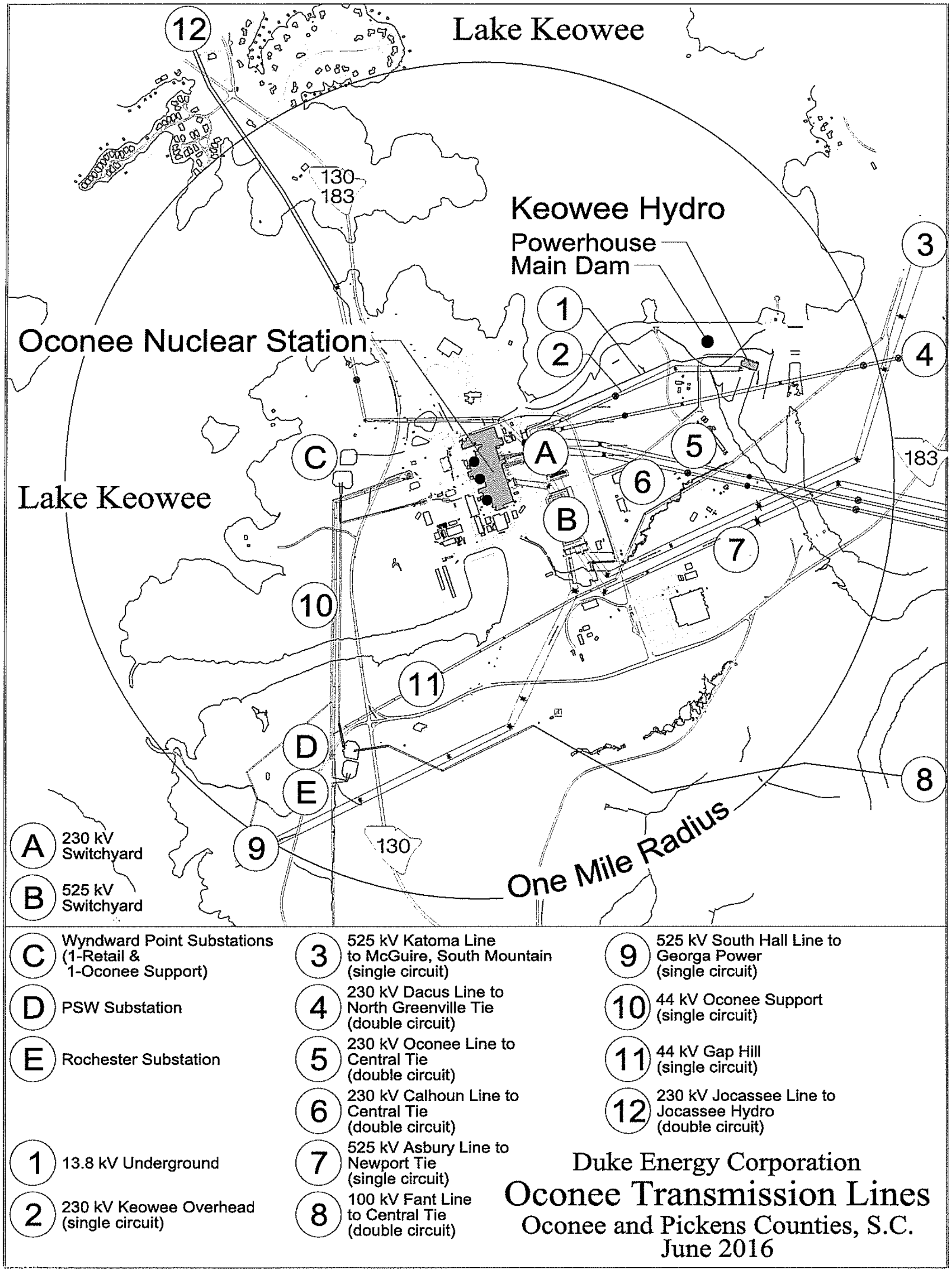
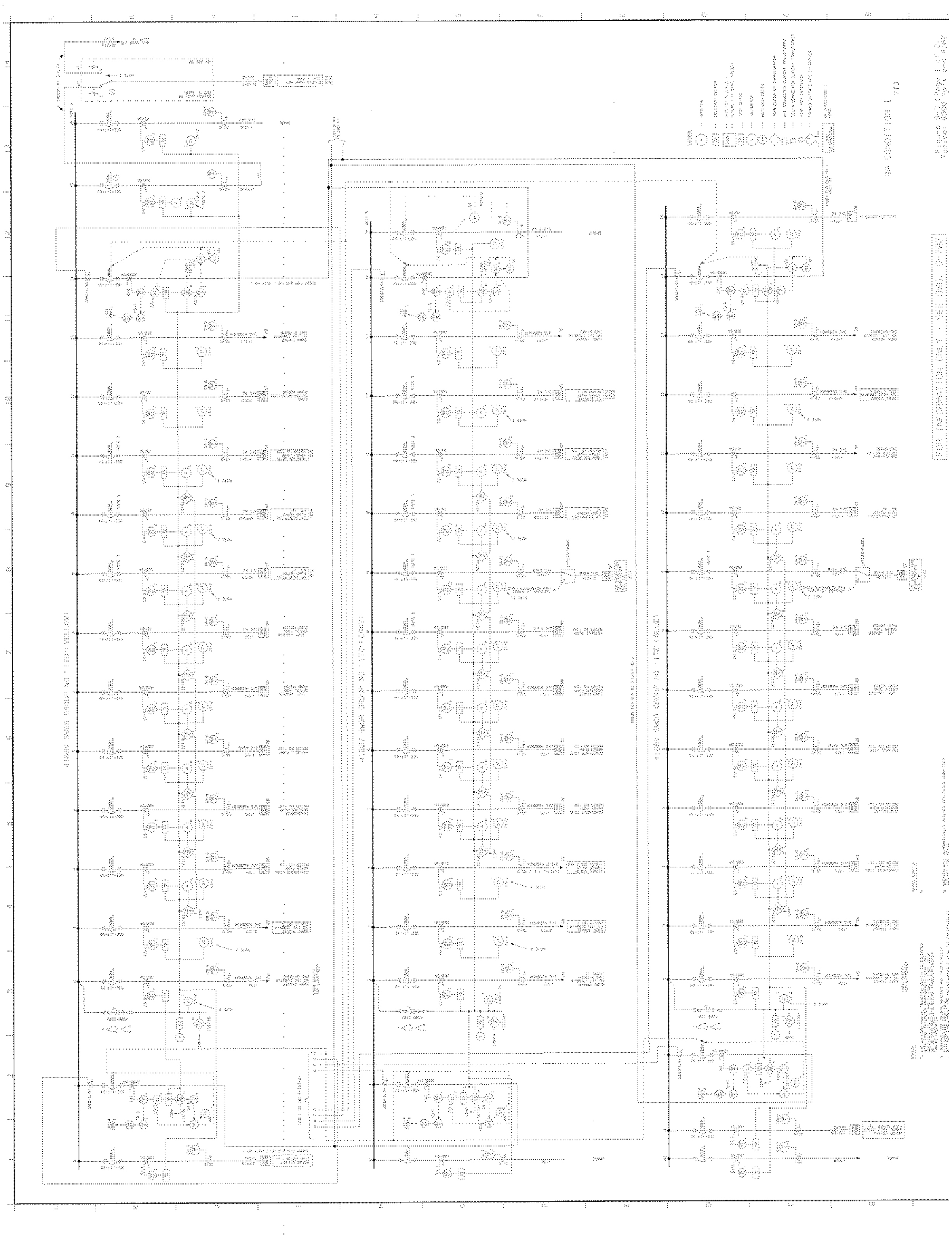


Figure 8-3. Typical 6900 Volt and 4160 Volt Unit Auxiliary - Single Line Diagram



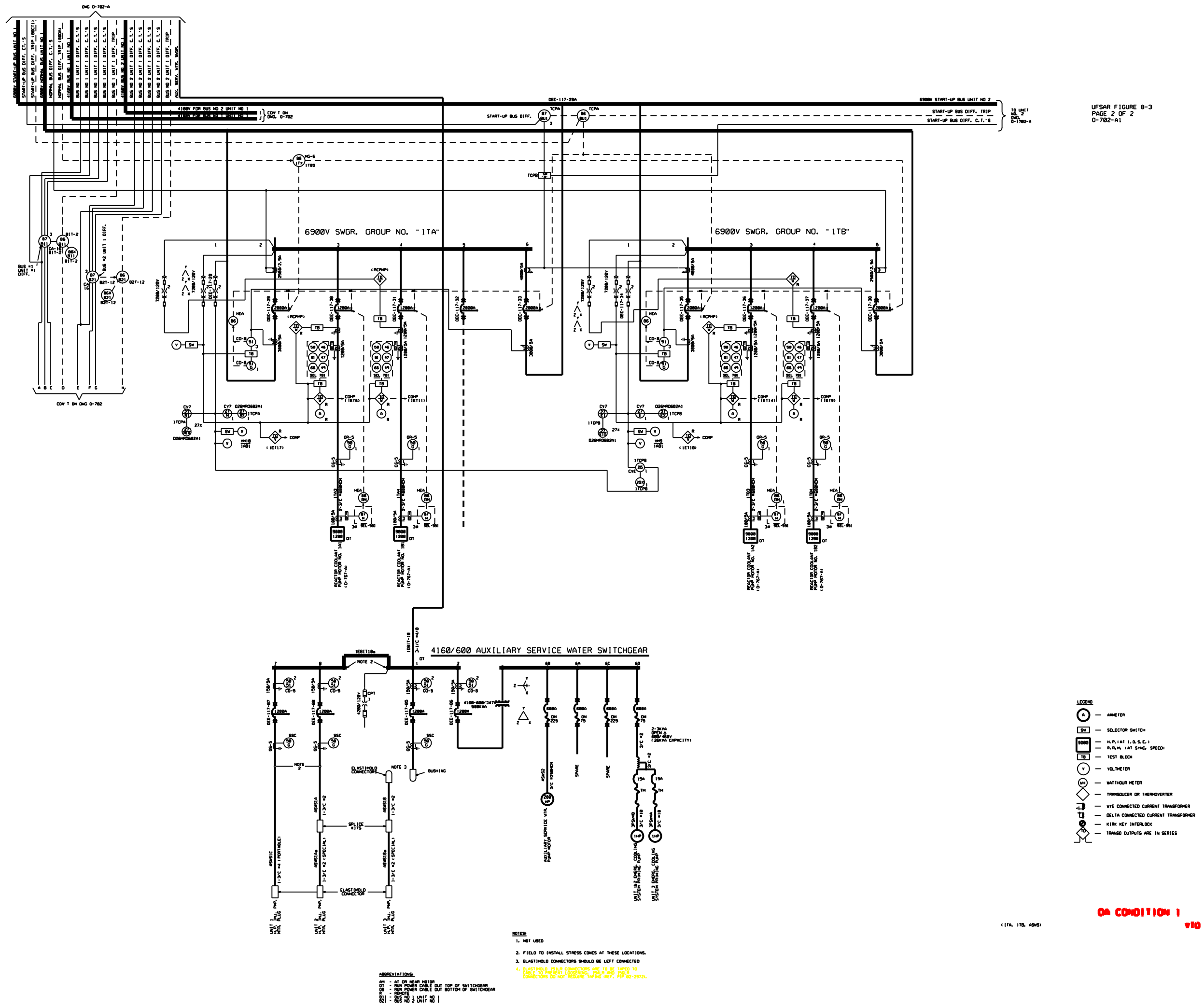
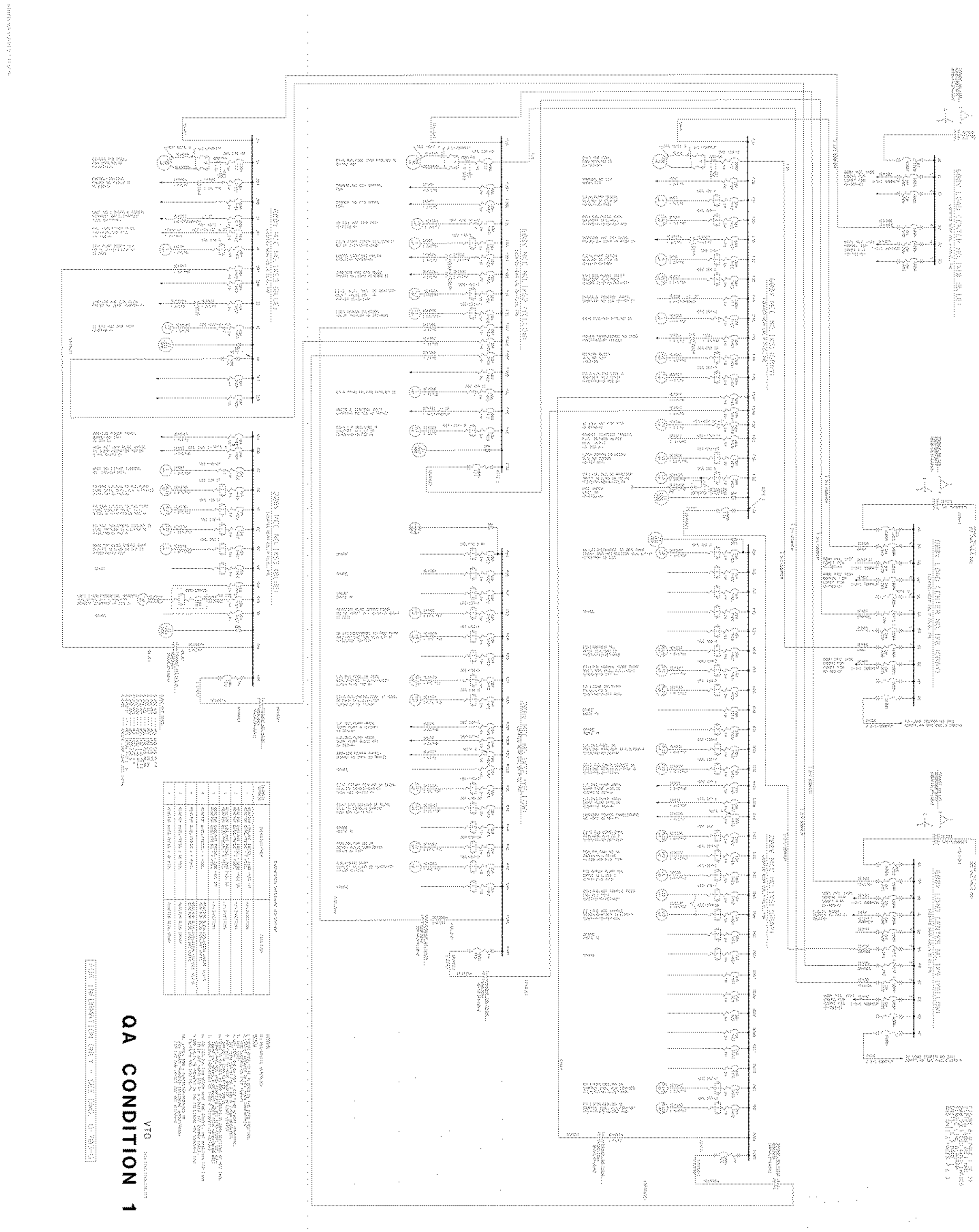
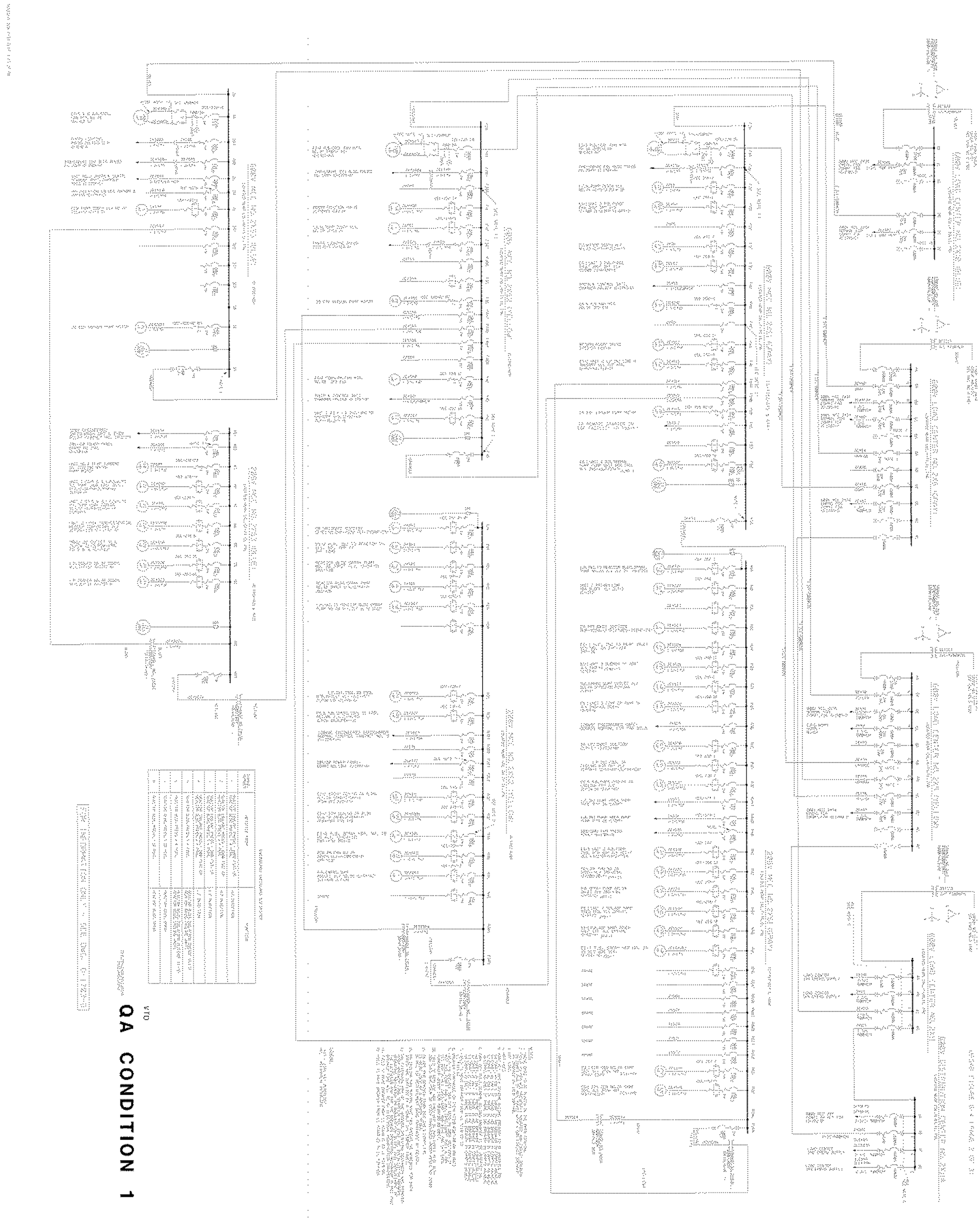

6900V SWGR. GROUP NO. "1TA"
6900V SWGR. GROUP NO. "1TB"
4160/600 AUXILIARY SERVICE WATER SWITCHGEAR
UFSAR FIGURE 8-3
PAGE 2 OF 2
O-702-A1
OA CONDITION 1

Figure 8-4. Typical 600 Volt and 208 Volt ESG Auxiliaries - Single Line Diagram




QA CONDITION 1

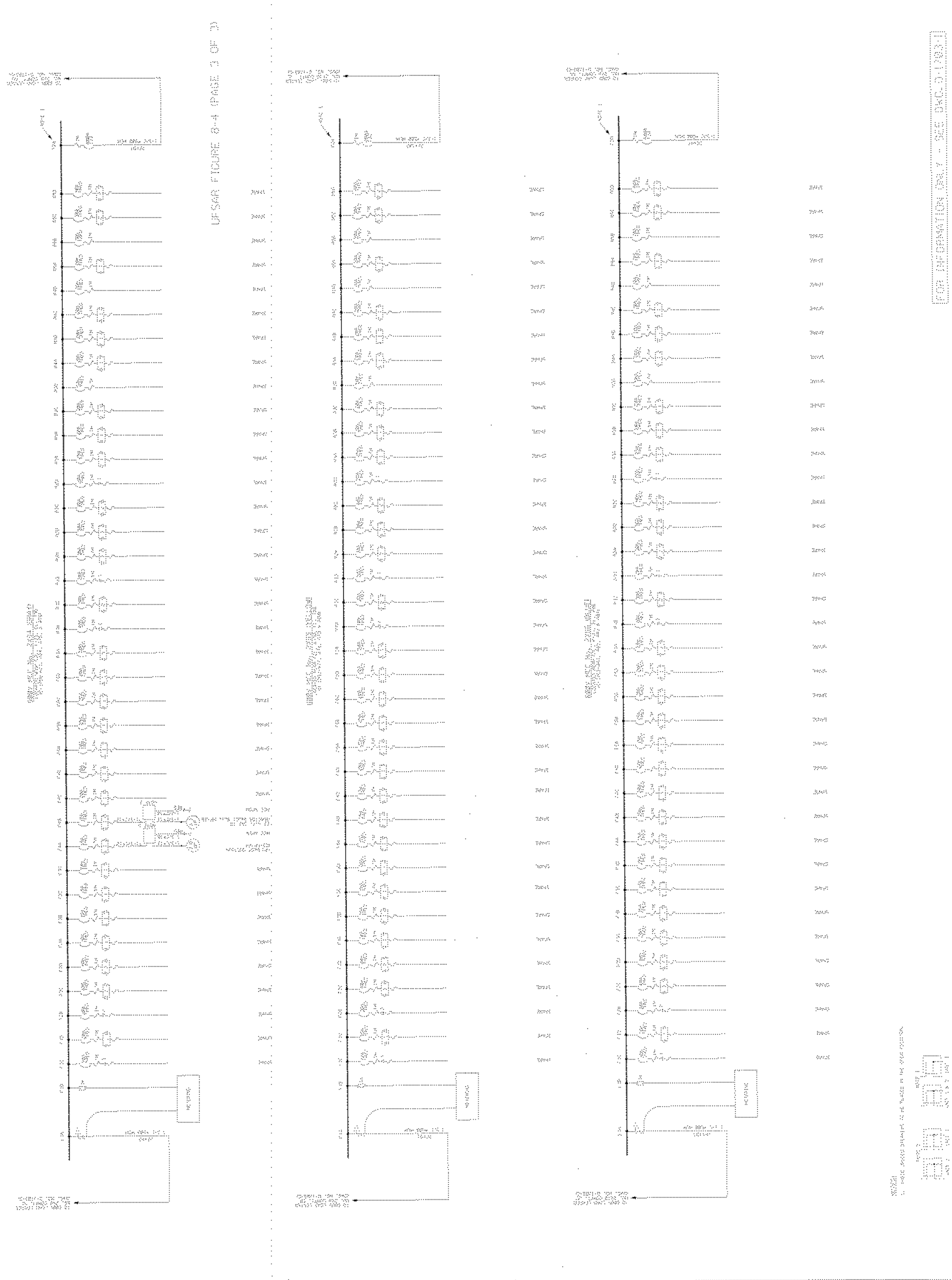


Figure 8-5. Typical DC and AC Vital Power System - Single Line Diagram

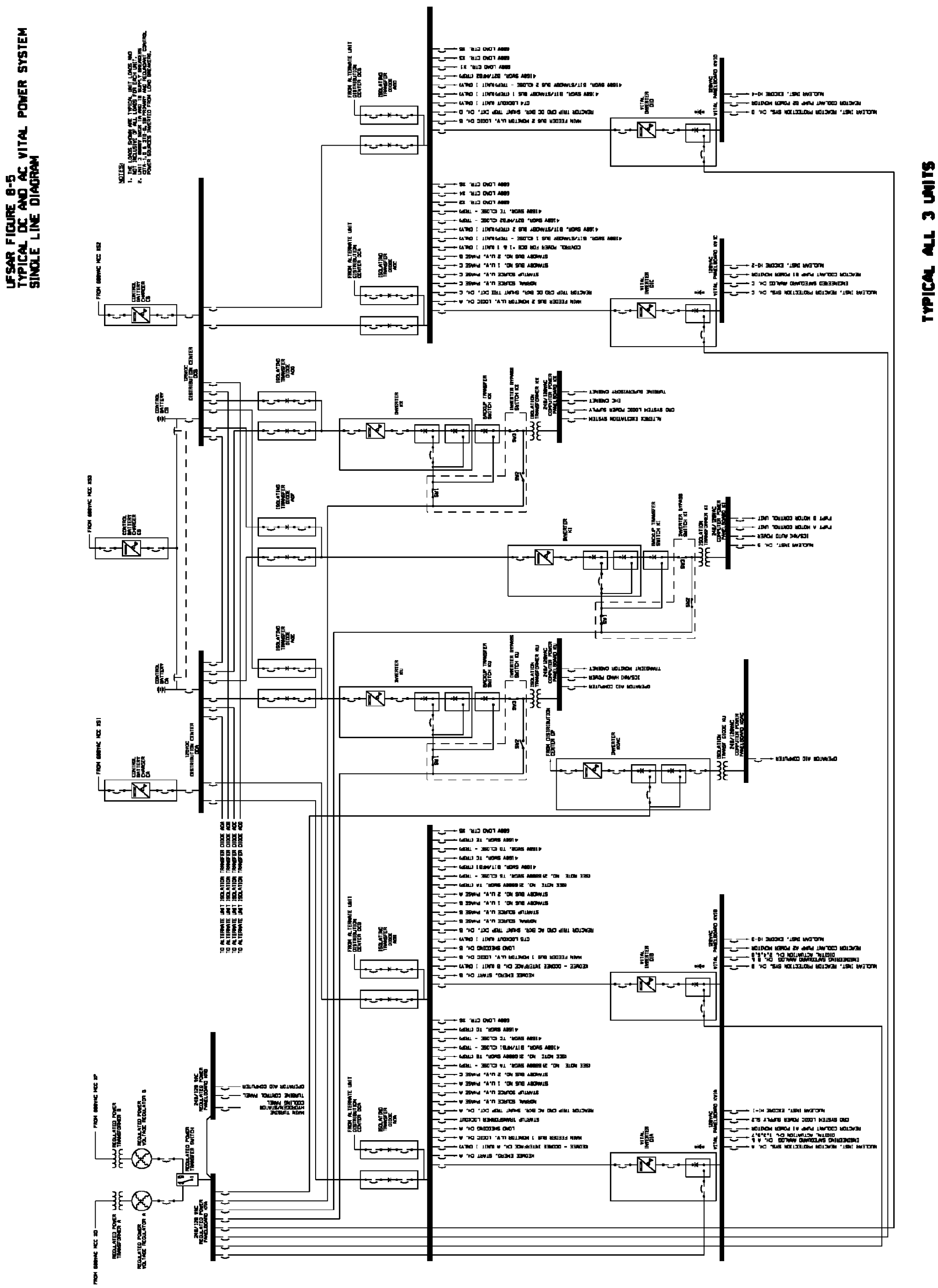


fig. 8-5 .DGN 5/10/2018 5:04:31 PM

Figure 8-6. Keowee DC Power System - Single Line Diagram

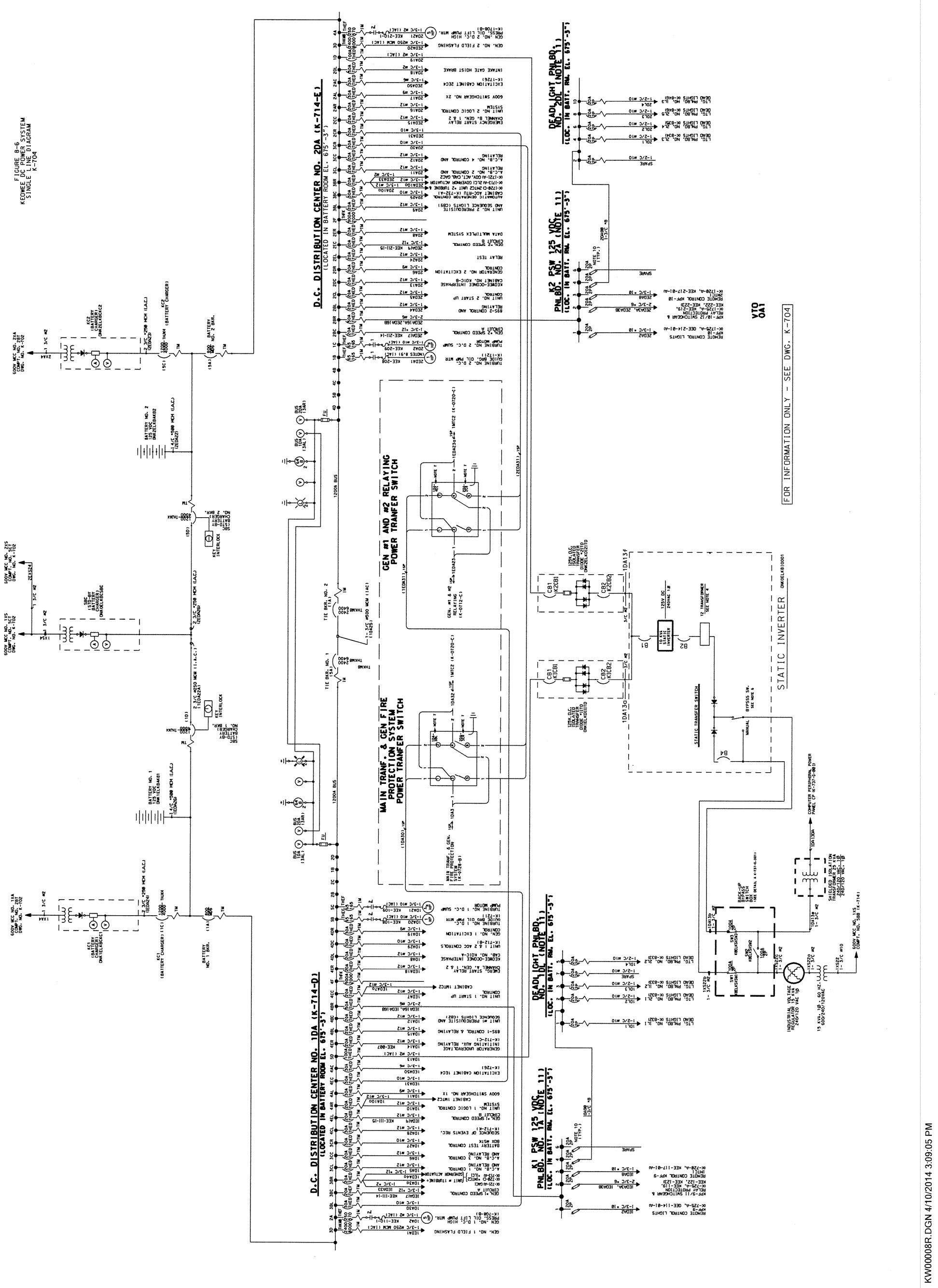


Figure 8-7. 230 KV SWYD One Line 125V DC

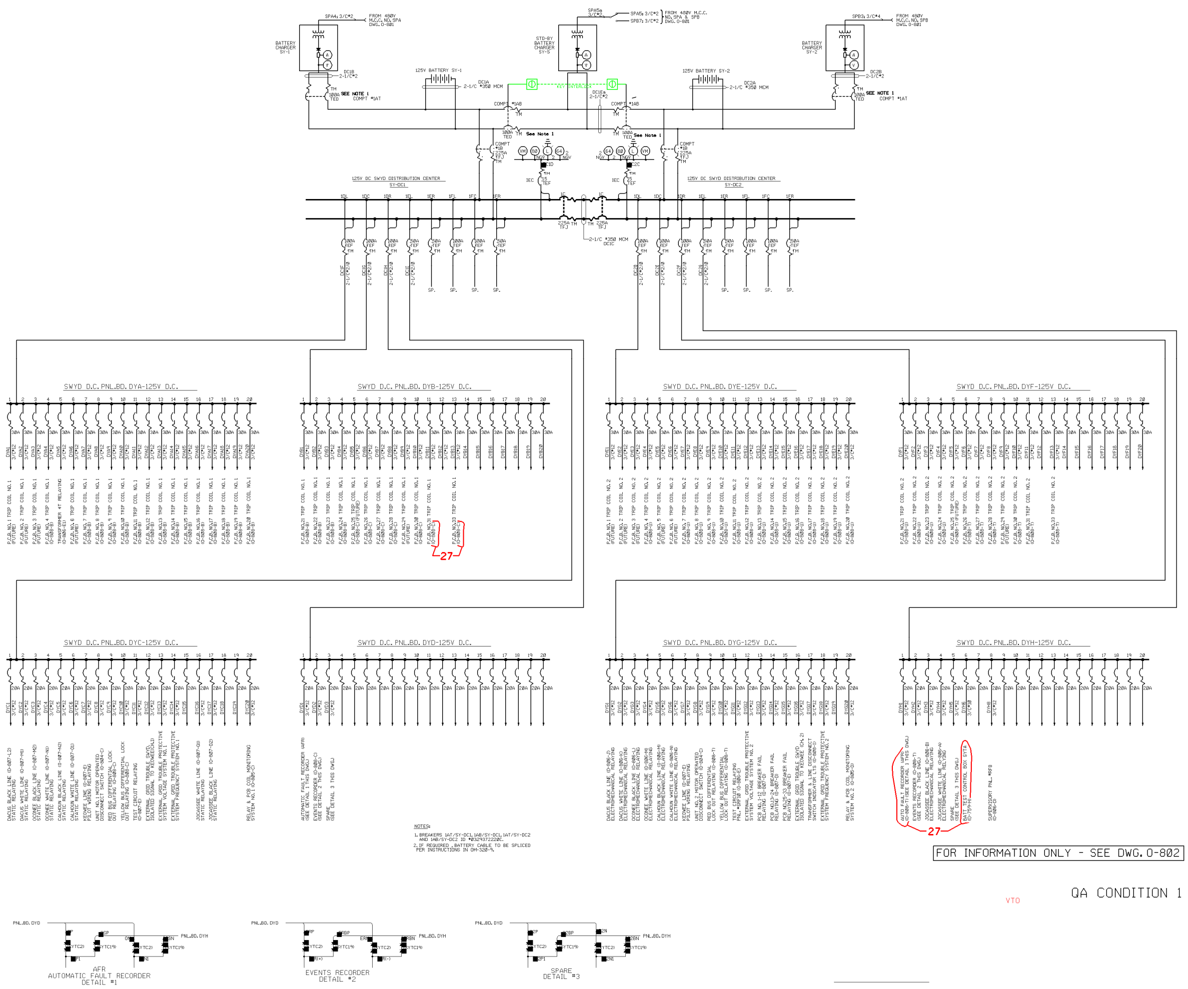


Figure 8-8. Deleted Per 1997 Update

Figure 8-9. 125/250 VDC Station Aux. Circuits

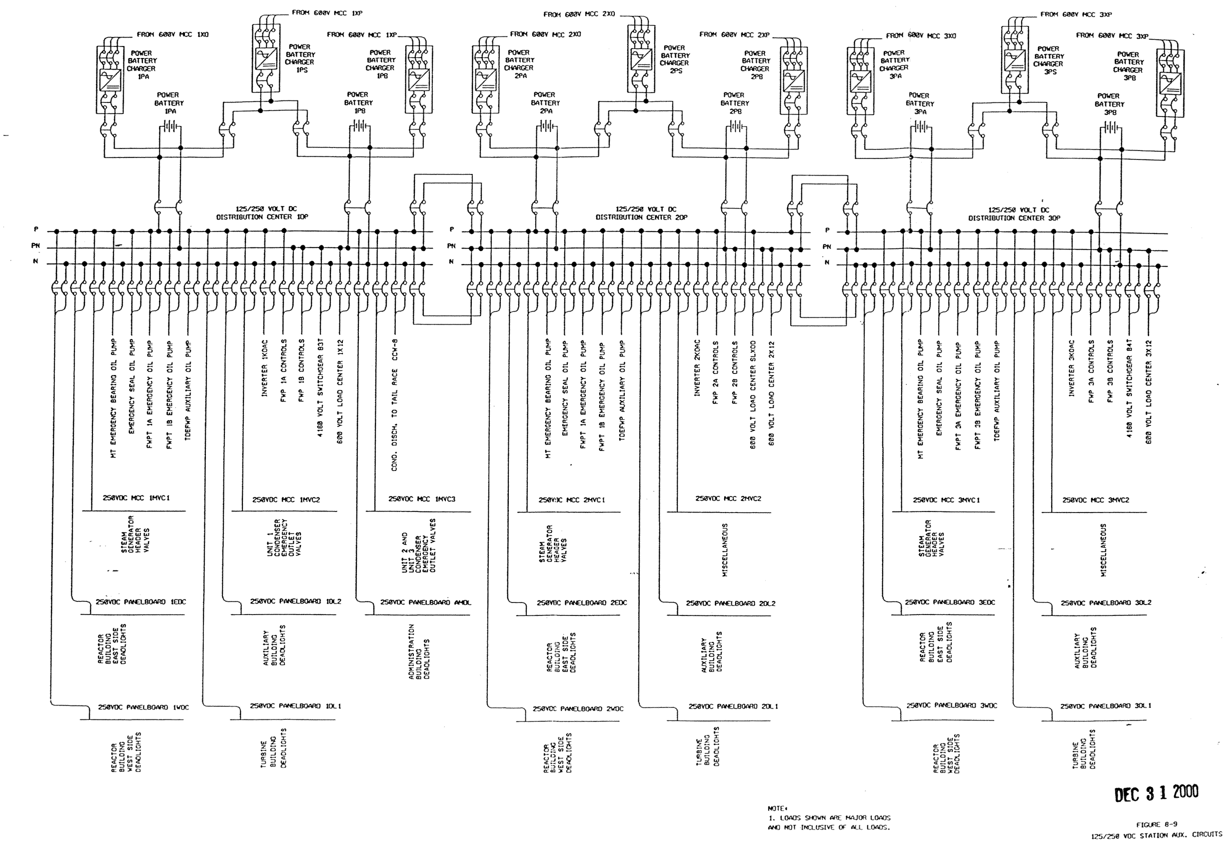


Table of Contents

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List of Tables

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List of Figures

9.0 Auxiliary Systems

The Auxiliary Systems required to support the reactor during normal operations and servicing of the Oconee Nuclear Station are described in this section. Some of these systems have also been described and discussed in Chapter 6, since they serve as engineered safeguards. The information in this section deals primarily with the functions served by these systems during normal operation.

The design of the Auxiliary Systems has included consideration of system sharing, where feasible, between the three Oconee Nuclear Station units. This section describes the equipment for each unit and states where equipment is shared.

The majority of the components in these systems are located within the Auxiliary Building. Those systems connected by piping between the Reactor Building and the Auxiliary Building are equipped with Reactor Building isolation valves as described in Chapter 6.

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9.1 Fuel Storage and Handling

9.1.1 New Fuel Storage

New fuel will normally be stored in the spent fuel pool serving the respective unit. New or irradiated fuel assemblies with initial nominal enrichments up to 5.00 weight percent U-235 which do not meet the requirements for unrestricted storage must be placed in a restricted loading pattern.

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Reactivity analyses for these assemblies, stored in a checkerboard type configuration in the spent fuel pool, were performed using the methods discussed in Section 9.1.2.3.2.

New fuel may also be stored in the fuel transfer canal. The fuel assemblies are stored in five racks in a row having a nominal center-to-center distance of 2 ft 1-3/4 inches. One rack is oversized to receive a failed fuel assembly container. The other four racks are normal size and are capable of receiving new fuel assemblies.

New fuel may also be stored in shipping containers.

9.1.2 Spent Fuel Storage

9.1.2.1 Spent Fuel Storage - Oconee 1, 2

The Spent Fuel Pool common to Oconee Units l and 2 has been re-racked to increase the spent fuel storage capacity to 1312 fuel assemblies. This modification is pursuant to License Amendment Nos. 90, 90 and 87 for License Nos. DPR-38, DPR-47 and DPR-55 for the Oconee Nuclear Station.

9.1.2.1.1 Design Bases

The Spent Fuel Pool designed for Oconee 1 and 2 is an integral part of the Oconee 1 and 2 Auxiliary Buildings and conforms to Safety Guide 13, “Fuel Storage Design Basis.” The fuel pools were designed for tornado wind and missiles, turbine generator missile, and seismic conditions as listed in Table 3-23. The Spent Fuel Pools were analyzed for the postulated cask drop accident as described in Section 3.8.4.4.

The spent fuel pool is constructed of reinforced concrete lined with stainless steel plate. The fuel pool concrete, reinforcing steel, liner plate and welds connecting the liner plate to the fuel pool floor concrete embedments are analyzed based on consideration of the new racks and additional fuel. Design criteria including loading combinations and allowable stresses are in compliance with Oconee FSAR Section 3.8.4 for Class I structures. The determination of Ta (abnormal thermal load condition to be used in combination with E') is based on the failure of one pump or cooler during normal operating conditions.

The function of the spent fuel storage racks is to provide for storage of spent fuel assemblies in a flooded pool, while maintaining a coolable geometry, preventing criticality, and protecting the fuel assemblies from excess mechanical or thermal loadings.

A list of design criteria is given below:

1. The racks are designed in accordance with the “NRC Position for Review and Acceptance of Spent Fuel Storage and Handling Applications,” dated April 14, 1978 and revised January 18, 1979.

2. The racks are designed to meet the nuclear requirements of ANSI/ANS-57.2-1983. Oconee complies with the criticality accident requirements of 10CFR50.68(b) (Reference 27). The effective multiplication factor, K_{eff}, in the spent fuel pool is less than or equal to 0.95, including all uncertainties and under all credible conditions with partial credit for soluble boron.
3. The racks are designed to allow coolant flow such that boiling in the water channels between fuel assemblies does not occur.
4. The racks are designed to Seismic Category 1 requirements, and are classified as ANS Safety Class 3 and ASME Code Class 3 Component Support structures.
5. The racks are designed to withstand loads which may result from fuel handling accidents and from the maximum uplift force of the fuel handling crane.
6. Each storage position in the racks is designed to support and guide the fuel assembly in a manner that will minimize the possibility of application of excessive lateral, axial and bending loads to fuel assemblies during fuel assembly handling and storage.
7. The racks are designed to preclude the insertion of a fuel assembly in other than design locations.
8. The materials used in construction of the racks are compatible with the storage pool environment and do not contaminate the fuel assemblies

9.1.2.1.2 Design Description

The Oconee fuel storage racks are composed of individual storage cells made of stainless steel interconnected by grid assemblies to form integral module structures as shown in Figure 9-1. Each cell has a lead-in opening which is symmetrical and is blended smooth to facilitate fuel insertion. The cells are open at the top and bottom to provide a flow path for convective cooling of spent fuel assemblies through natural circulation. The fuel assembly storage cells are structurally connected to form modules through the use of plates and box beams which limit structural deformations and maintain a nominal center-to-center spacing between adjacent storage cavities during design conditions including the Safe Shutdown Earthquake. The racks utilize a neutron absorber, Boraflex, which is attached to each cell. However, due to degradation of the absorber material, no reactivity holddown credit is taken for any remaining Boraflex in the storage cells. The modules are neither anchored to the floor nor braced by the pool walls. The following information applies to the Oconee 1 and 2 fuel storage pool.

Number of Cells	1312
Number of Modules	4 – 8 x 11 10 – 8 x 12
Deleted row(s) per 2002 Update.	
Center-to-Center Spacing	10.65 in.
Deleted row(s) per 2004 Update.	
Approximate Rack Assembly Dimensions and Maximum Weights	8 x 10 – 85.5 x 107 x 172 – 18, 060 lbs. 8 x 12 – 85.5 x 128 x 172 – 21,800 lbs.

The pool outline and rack arrangements are shown in Figure 9-3 and Figure 9-4.

9.1.2.2 Spent Fuel Storage - Oconee 3

The Spent Fuel Pool serving Oconee Unit 3 has been re-racked to increase the spent fuel storage capacity to 822 fuel assemblies, plus 3 additional storage spaces for failed fuel containers. This modification is pursuant to License Amendment Nos. 123, 123, and 120 for License Nos. DPR-38, DPR-47 and DPR-55 for the Oconee Nuclear Station.

9.1.2.2.1 Design Bases

The Oconee 3 Spent Fuel Pool has the same Design Bases as the Oconee 1 and 2 pool described in Section 9.1.2.1.1.

9.1.2.2.2 Design Description

The Oconee 3 Spent Fuel Pool storage racks are similar to the Oconee 1 and 2 racks described in Section 9.1.2.1.2. The following information applies to Oconee Unit 3 spent fuel storage racks.

Number of Cells	822 plus storage locations for 3 failed fuel containers
Number Rack Arrays	7 – 8 x 11 2 – 8 x 12 1 – 8 x 10 x/3 container locations
Deleted row(s) per 2002 Update.	
Center-to-Center Spacing	10.60 in.
Deleted row(s) per 2004 Update.	
Approximate Rack Assembly Dimensions and Maximum Weights	8 x 10 – 85.5 x 107 x 172 – 18, 060 lbs. 8 x 12 – 85.5 x 128 x 172 – 21,800 lbs.

The pool outline and rack arrangements are shown in Figure 9-3 and Figure 9-4.

9.1.2.3 System Evaluation

9.1.2.3.1 Structural and Seismic Analysis

Fuel assembly storage rack and associated structures are designed to withstand the maximum forces generated during normal operation combined with the Safe Shutdown Earthquake according to the requirements of a Seismic Class I structure. For these conditions, the storage rack design is such that all stresses fall within the allowable stress limits specified in the AISC Specifications for Design, Fabrication and Erection of Structural Steel.

Normal operating loads include dead weight (in air) and thermal expansion loads. Lateral and vertical seismic loads along with the fluid forces generated by seismically generated pool water sloshing are considered to be acting simultaneously.

The seismic input spectra conform to the requirements of Regulatory Guide 1.60, “Design Response Spectra for Seismic Design of Nuclear Power Plants.”

Reference is made to Project 81 PSAR, Docket Nos. STN50-488 through -493, Section 3.7. The smoothed response spectra shown on Figure 2E-2A were normalized to 10 percent g for Safe Shutdown Earthquake (SSE). An earthquake acceleration-time history compatible with these spectra, as shown in Figures 2E-2B through 2E-2E, was used as a base motion on the model of the Auxiliary Building.

The seismic response of the Auxiliary Building to the base excitation is determined by a dynamic analysis. The dynamic analysis is made by idealizing the structure as a series of lumped masses with weightless elastic columns acting as spring restraints. The base of the structure is considered fixed. The choice of the location of the mass-joints depends on the distribution of masses in the real structure.

The seismic analysis of the racks was performed in two phases:

First a seismic time history analysis of a simplified non-linear 2-dimensional model was conducted. The model consisted of spring, mass, damping, friction, and gap elements to simulate a fuel bundle in a simplified model of a rack. The fuel assembly-to-cell impact loads, support pad lift-off values, rack sliding, and overall rack response were determined from the non-linear analysis. Coefficients of friction were varied between minimum and maximum possible values in order to determine worst case conditions of sliding and tipping respectively. Rack-to-rack impacts were precluded by spacing the racks beyond maximum possible excursion. The gap spaces are large enough to accomodate lateral module motion due to earthquake forces. In order to account for 3-dimensional effects, the results of independent orthogonal loadings were combined by the SRSS method.

Next, a seismic response spectrum analysis of a 3-dimensional finite element model of the racks, using inputs from the results of the non-linear analysis, and superimposed with other applicable loads, was conducted. Design stresses and safety margins for appropriate components in the racks were tabulated and found to be acceptable.

The structural damping values used are 4 percent for an SSE and 2 percent for an OBE.

The maximum uplift load available from the fuel handling crane on the storage rack is limited to 3000 lbs or less by the hoist interlock. A separate fuel assembly drop analysis was performed. A 3000 pound object was postulated to impact the top of the rack from a height of 6 feet. Calculations show that the resulting stresses are within acceptable stress limits.

Structural design precludes placing a fuel assembly between cells, and the rack will withstand the loadings imposed by a postulated dropped fuel assembly.

9.1.2.3.2 Criticality Analysis

The design methodology which ensures the criticality safety of the fuel assemblies in the spent fuel storage rack is discussed in Section 9.1.2.3.2.3 and in Reference 8.

9.1.2.3.2.1 Neutron Multiplication Factor

Criticality of fuel assemblies in the spent fuel storage rack is prevented by the design of the rack which limits fuel assembly interaction. This is done by fixing the minimum separation between assemblies and inserting neutron poisons between assemblies.

The design basis for preventing criticality outside the reactor is that, including uncertainties, there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (k_{eff}) of the fuel assembly array will be less than 1.0 in unborated spent fuel pool water, and less than 0.95 with partial credit for soluble boron, in accordance with Reference 26. Oconee complies with the criticality accident requirements of 10CFR50.68(b) (Reference 27). The acceptance criteria for criticality is further discussed in Section 9.1.2.3.2.5.

9.1.2.3.2.2 Normal Storage

Under normal storage conditions, the following assumptions were used in the criticality analysis.

1. Credit is taken for the decrease in reactivity associated with the fuel assembly burnup.
2. The fuel assembly is the most reactive fuel assembly to be stored based on a minimum burnup. The fuel designs analyzed include the fuel assembly designs described in Chapter 4, and earlier designs. Additionally, a small number of alternate fuel configurations are analyzed (e.g. lead test asssemblies, failed rod canisters, and rod consolidation canisters).
3. The moderator is at the temperature within the design limits of the pool which yields the largest reactivity, and contains at least 430 ppm boron (pursvant to License Amendment Nos. 323, 323, 324 for License Nos. DPR-38, DPR-47, and DPR-55), to maintain $K_{eff} \leq 0.95$ for normal storage conditions. Full credit for soluble boron is taken for postulated accident conditions and during fuel movement. For accident conditions the double contingency principle of ANSI N16.1-1975 is applied. This principle states that it shall require at least two unlikely, independent, and concurrent events to produce a criticality accident. During fuel movement the presence of dissolved boron in the spent fuel pool water is assumed since this is only a temporary condition and only a single assembly is handled at a time.
4. The array is either infinite in the lateral extent or is surrounded by a conservatively chosen reflector, whichever is appropriate for the design. The nominal case calculation is infinite in the lateral extent. However, poison plates are not necessary on the periphery of the modular array and between widely spaced modules because calculations show that this finite array is less reactive than the nominal case infinite array. The assemblies are also infinite in the axial extent. A reactivity bias is included in all burned-fuel criticality calculations to conservatively account for reactivity differences between a detailed 3-D axial burnup model and the 2-D average burnup model employed for nominal calculations.
5. Mechanical uncertainties and biases due to mechanical tolerances during construction are treated by either using "worst case" conditions or by performing sensitivity studies and obtaining appropriate values. The items included in the analysis are:
   a. Deleted row per 2002 Update.
   b. Deleted row per 2002 Update.
   c. Can ID
   d. Stainless steel thickness
   e. Center-to-center spacing
   f. Fuel enrichment
   g. Fuel pellet density
   h. Fuel pellet OD

   Other applicable uncertainties and biases are discussed in Section 9.1.2.3.2.3.
6. No credit is taken for the assembly spacer grids.
7. No credit is taken for fuel assembly control components which can be removed (e.g. burnable poisons and control rods).
8. Credit is taken for the inherent neutron absorbing effect of some of the rack structure materials in accordance with ANSI/ANS-57.2-1983 and Reference 26.

9.1.2.3.2.3 Criticality Analysis Methodology

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer, shipping and storage facilities and by administrative control procedures. The two principal methods of preventing criticality are limiting the fuel assembly array size and limiting assembly interaction by fixing the minimum separation between assemblies and/or inserting neutron poisons between assemblies.

The design basis for preventing criticality outside the reactor is that, considering possible variations, there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (k_{eff}) of the fuel assembly array will be less than or equal to 0.95, with partial credit for soluble boron. Oconee complies with the criticality accident requirements of 10CFR50.68(b) (Reference 27). The conditions that are assumed in meeting this design basis are outlined in Section 9.1.2.3.2.2.

In order to justify storage of fuel up to 5.0 w/o, the burnup credit approach was utilized in the spent fuel pools. The burnup credit approach to fuel rack criticality analysis requires calculation and comparison of reactivity values over a range of burnup and initial enrichment conditions. In order to accurately model characteristics of irradiated fuel which impact reactivity, a criticality analysis method capable of evaluating arrays of these irradiated assemblies is needed. The advanced nodal methodology combining CASMO-3/TABLES-3/SIMULATE-3 is used for this purpose. CASMO-3 (Reference 4) is an integral transport theory code, SIMULATE-3 (Reference 6) is a nodal diffusion theory code, and TABLES-3 (Reference 5) is a linking code which reformats CASMO-3 data for use in SIMULATE-3. This methodology permits direct coupling of incore depletion calculations and resulting fuel isotopics with out-of-core storage array criticality analyses. The variable effects of fission product poisoning, fissile material production and utilization and other related effects are accurately modeled with the CASMO-3/TABLES-3/SIMULATE-3 methodology. Applicable biases and uncertainties are developed and become inputs to the methodology.

The results for the criticality methodology are validated by comparison to measured results of fuel storage critical experiments. The criticality experiments used to benchmark the methodology were the Babcock and Wilcox close proximity storage critical experiments performed at the CX-10 facility (Reference 7). The B&W critical experiments used are specifically designed for benchmarking reactivity calculation techniques. The experiments are analyzed, and the statistical accuracy of the calculated reactivity results are assessed.

The bias associated with the benchmarks is -0.00142 Δk with a standard deviation of 0.00412 Δk. The 95/95 one-sided tolerance limit factor for 10 values is 2.911. Therefore, there is a 95 percent probability at a 95 percent confidence level that the uncertainty in reactivity due to the method is not greater than 0.01199 Δk.

For burned fuel, the maximum reactivity occurs approximately 100 hours after shutdown due to the decay of Xe^{135}. Therefore, all fuel assemblies in the spent fuel pool are modeled at no xenon conditions.

An additional bias and uncertainty are required to quantify the reactivity of burned nuclear fuel assemblies. Two burnup uncertainties associated with this methodology are accounted for in the criticality analysis. The first penalty accounts for uncertainties in the reactivity due to uncertainties in the burnup of the assembly, while the second penalty accounts for the reactivity holddown effect of lumped burnable absorbers.

The exposure reactivity uncertainty accounts for the uncertainty on the assembly burnup. Since the final burnup qualification curves are based on a code calculated burnup, the uncertainty in that calculated burnup must be considered. Rather than determining the uncertainty on the actual burnup, the uncertainty on reactivity due to burnup was applied to account for the burnup uncertainty. A 95/95 one-sided tolerance was determined to account for the maximum reactivity error associated with the burnup of the fuel.

As required by the standards, no removable poisons are accounted for in the criticality analyses. Thus, all assemblies are modeled with no burnable poisons (BPs). However, this can be slightly non-conservative due to the increase in reactivity associated with the removal of the BP. Thus a burnable poison removal (BP-Pull) penalty is developed to account for this effect. BPs are used in the core design to hold down reactivity, and hence peaking of fresh assemblies. Thus, the reactivity of the BPd assembly is less than the non-BPd assembly. However, once the BP is removed (from the previously BPd assembly), a reactivity increase is seen due to the shadowing effect the BPs had on the assembly. This difference in reactivity is applied as an additional bias on reactivity.

The basic approach in the burnup credit methodology is to use reactivity equivalencing techniques to construct burnup versus enrichment curves which represent equivalent and acceptable reactivity conditions over an applicable range of burnups and initial enrichments. These burnup versus enrichment curves are established for each type of storage, e.g. unrestricted and restricted storage.

Generation of the applicable burnup credit curves requires a two part calculation process. The first part is to create two types of reactivity versus burnup curves. The first type of curve defines the maximum reactivity for the spent fuel pool such that the appropriate design criteria are met including allowances for both calculational uncertainties and manufacturing tolerances. The second type of curve represents the reactivity versus burnup for a particular enrichment, and is generated for the range of enrichments. The intersection of the maximum design reactivity curve with the multiple enrichment curves provides data points for the second part of the process.

The second part of the process generates the burnup versus initial enrichment curves by plotting the burnup where the maximum design reactivity equals the reactivity of a particular enrichment for each enrichment. Two curves are generated which represent the qualification criteria for a particular storage configuration. Each burnup versus enrichment curve shows the minimum amount of burnup required to qualify fuel for storage in the applicable loading pattern as a function of the fuel's initial enrichment. Additional details of the methods used can be found in Reference 8.

The SCALE-4 system of computer codes (Reference 10) was used to analyze the boundary restrictions between Checkerboard, Restricted, and Unrestricted storage configurations to assure that the storage configurations at the boundary do not cause an increase in the nominal k_{eff} for the individual regions. This analysis is performed to determine if there is a need for new administrative restrictions at the boundaries.

This methodology utilizes two dimensional Monte Carlo theory. Specifically, this analysis method used the CSAS25 sequence contained in Criticality Analysis Sequence No. 4 (CSAS4). CSAS4 is a control module contained in the SCALE-4.2 system of codes. The CSAS25 sequence utilizes two cross section processing codes (NITAWL and BONAMI) and a 3-D Monte Carlo code (KENO Va) for calculating the effective multiplication factor for the system. The 27 Group NDF4 cross section library was used exclusively for this analysis.

Acceptable interface boundary conditions between storage configurations were determined by varying the boundaries between various storage regions to determine the worst case configurations for coupling between assemblies in different regions. The boundaries were then reflected to simulate an infinite array. The k_{eff} of these infinite boundary arrays were compared to the base k_{eff} of infinite arrays of either fuel storage region creating the boundary. If the infinite boundary array k_{eff} did not represent an increase in the k_{eff} of the regions making the boundary, then no storage restrictions were imposed at the interface. When the worst case did represent an increase, conservative storage restrictions were applied.

These methods conform with ANSI N18.2-1973, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," Section 5.7, Fuel Handling System; ANSI/ANS-57.2-1983, "Design Requirements for LWR Spent Fuel Storage Facilities at Nuclear Power Stations," Section 6.4.2.2; ANSI N16.9-1975, "NRC Standard Review Plan," Section 9.1.2 and the NRC guidance contained in Reference 26.

9.1.2.3.2.4 Postulated Accidents

As part of the criticality analysis for the Oconee spent fuel pools, abnormal and accident conditions are considered to verify that acceptable criticality margin is maintained for all conditions. Most accident conditions will not result in an increase in k_{eff} of the rack. For an assembly dropped on top of the storage rack, the section of the rack structure which is essential for preventing criticality is not excessively deformed. Furthermore, the dropped assembly has more than eight inches of water separating it from the active fuel height of stored assemblies which precludes any interaction between the dropped assembly and the stored assemblies. Although the dropped assembly is more reactive outside of the storage cell rather than inside, the assembly is no more reactive dropped on top of the storage rack than located anywhere else in the pool outside the storage rack.

However, accidents can be postulated which would increase reactivity. Misloading of an assembly would increase reactivity; in particular, misloading the highest reactive assembly in place of the lowest reactive assembly. This is either the misplacement of a fresh assembly in an empty cell in the checkerboard pattern or in a filler cell in the restricted pattern.

For loss of spent fuel pool cooling scenarios, the reactivity increases with decreasing water density for the Oconee fuel storage racks and the current analyzed fuel designs. Two accident scenarios are postulated: heat load due to the loss of one cooling train and cold water emergency makeup. The emergency makeup event encompasses a dilution event, since one source of makeup is Lake Keowee.

For accident conditions, the double contingency principle is employed. The double contingency principle of ANSI/ANS-57.2-1983 states that it is not required to assume two unlikely, independent concurrent events to ensure protection against a criticality accident. Thus, for accident conditions, the presence of soluble boron in the storage pool water can be assumed as a realistic initial condition, since not assuming its presence would be a second unlikely event.

The acceptance criteria for criticality are further discussed in 9.1.2.3.2.5.

9.1.2.3.2.5 Acceptance Criteria for Criticality

The acceptance criteria for the spent fuel pools will be $k_{eff} \leq 0.95$. This assumes full credit may be taken for soluble boron under accident conditions as allowed by the double contingency principle in ANSI/ANS-57.2-1983, and that only partial credit is taken for soluble boron under normal conditions, per Reference 26. Oconee complies with the criticality accident requirements of 10CFR50.68(b) (Reference 27).

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9.1.2.3.2.6 Cask Drop Accident

Cask drop accidents are analyzed for criticality consequences in Section 15.11.2.5.1.

9.1.2.3.2.7 Criticality Analyses for Loading NUHOMS Dry Storage Canisters (DSC)

The criticality analysis of the NUHOMS®-24P/24PHB DSC, for loading and unloading operations in the Oconee spent fuel pools, has been performed in accordance with the requirements of 10CFR50.68(b). The evaluation takes partial credit for soluble boron in the spent fuel pools. Minimum burnup requirements were developed for fuel to be placed without location restrictions in the NUHOMS®-24P/24PHB DSC. These burnup requirements, applicable for eligible fuel assemblies with a minimum 5 years post-irradiation cooling time, are a function of initial U-235 enrichment.

The criticality analysis demonstrated that the current minimum boron concentration required in the Oconee spent fuel pools is adequate to maintain the maximum 95/95 K_{eff} below 0.95 for all normal conditions and credible accident scenarios associated with loading fuel assemblies into the NUHOMS®-24P/24PHB DSCs.

Consistency was maintained between the spent fuel pool rack and DSC normal and accident analyses. Accidents analyzed included assembly dropped on top of the storage rack, misloading of an assembly, and loss of spent fuel pool cooling scenarios.

9.1.2.3.3 Material, Construction, and Quality Control

The entire fuel assembly storage rack is constructed of type 304 stainless steel, with Boraflex panels attached to each cell. All welded construction is used in the fabrication of the fuel assembly storage rack. The all-welded construction ensures the structural integrity of the storage modules and provides assurance of smooth, snag-free passage in the storage cavities so that it is highly improbable that a fuel assembly could become stuck in the rack.

The material, construction and quality control procedures are in accordance with the quality assurance requirements of Duke Power Company, as described in Duke Power Company Topical Report, DUKE-1.

9.1.2.3.4 Interface of High Capacity Fuel Storage Rack and Spent Fuel Storage Pool

The pool floor will support the high capacity storage rack as a free-standing structure during all design conditions. During installation, no racks are moved over spent fuel assemblies in the pool. All spent fuel assemblies in Unit 3 are removed prior to removing existing racks.

For the free-standing rack structure, conservative analysis shows that under simultaneous forces from vertical and lateral seismic excitation, the residual displacement of the rack relative to the pool floor is less than 1 inch for full-loaded condition (i.e., much less than minimum clearance of 2.75 inches to pool walls and installed equipment.)

The maximum sliding distance of the Westinghouse free-standing fuel rack is obtained by equating the kinetic energy developed in the fuel rack, in response to the SSE seismic event, to the energy dissipated by friction between the fuel rack supports and the pool floor, during sliding. The maximum kinetic energy in the fuel rack, produced by the SSE seismic event, is calculated from the spectral response to the SSE response spectrum. The horizontal displacement of the rack is 1.414 times the sum of the deflecton of the top of the rack (0.245 in) and the maximum sliding distance (0.432). The coefficient of friction is assumed to be 0.20.

The rack/pool floor normal force on which the lateral friction forces used in the analysis are based includes the effect of vertical seismic acceleration.

The maximum lateral seismic force exerted by any rack module on pool floor is 189000 pounds and results in a stress of 2440 psi in the floor liner and 3296 psi in the weld connecting the floor liner to embedments in the concrete. The maximum combined seismic and thermal stress in the floor liner is 21640 psi and 30610 psi in the weld between liner and embedments. The maximum stresses are below the design allowable stress of 27,000 psi in the liner and 32000 psi in the welds.

9.1.2.4 Safety Evaluation

The storage rack is designed and constructed to retain the integrity of the structure under all anticipated loads, including the Safe Shutdown Earthquake, with the maximum number of fuel assemblies occupying the storage locations.

The rack design provides protection against damage to the fuel and precludes the possibility of a fuel assembly being placed between cells. Although not required for safe storage of spent fuel assemblies, the spent fuel pool water is normally borated to a concentration of at least 2220 ppm, or higher as specified by the Core Operating Limits Report (COLR). The rack design also assures a K_{eff} of less than 1.0 even when the entire array of fuel assemblies, assumed to be in their most reactive condition and within the limits specified in the Technical Specifications, are immersed in unborated water at room temperature. Furthermore, if the pools were filled with the most reactive fuel allowed, which is clearly in violation of the Technical Specifications, K_{eff} would be $\underset{\sim}{ }$ 0.85 with full credit for soluble boron. Under these conditions a criticality accident during refueling or storage is not considered credible.

9.1.2.5 Boraflex

The spent fuel storage racks contain Boraflex, which is the trade name for a silicon polymer that contains a specified amount of Boron 10 that was originally used as the neutron absorber to assure that the design basis for criticality control was met through the service life of the racks. The Boraflex is affixed to each of the four exterior sides of the fuel storage cell by means of stainless steel wrappers. Boraflex was originally used in spent fuel storage racks for the nonproductive absorption of neutrons such that the NRC established acceptance criterion of k_{eff} no greater than 0.95 was maintained. However, due to degradation of the absorber material, no reactivity holddown credit is taken any longer for the remaining Boraflex in the storage cells.

Since reactivity hold-down credit is no longer being taken for Boraflex in the Spent Fuel Pool storage cells, the License Renewal commitment to inspect the Boraflex panels is no longer required, and the inspection program has been discontinued.

Deleted paragraph(s) per 2002 update.

9.1.3 Spent Fuel Cooling System

9.1.3.1 Design Bases

9.1.3.1.1 Units 1 and 2 Spent Fuel Pool Cooling System

The primary function of Spent Fuel Pool Cooling System for Units 1 and 2 is to provide decay heat removal for the spent fuel stored in the Units 1 and 2 spent fuel pool. The cooling system design requirements are the criteria imposed by the 1980 re-racking (References 11, 12). Other system functions are to maintain the pool inventory, clarity and chemistry at acceptable levels.

Revised criteria have been imposed during the 1980 re-racking modification, pursuant to Amendments 90, 90, and 87 for License Nos. DPR-38, DPR-47 and DPR-55 for the Oconee Nuclear Station. The thermal-hydraulic analyses associated with the spent fuel pool racks assumes that the bulk spent fuel pool temperature remain at or below 150°F, for normal heat loads (Reference 11). The Units 1 and 2 Spent Fuel Cooling System is designed to keep the pool bulk water temperature:

1. Below 150°F for normal heat loads and two or three pump-cooler configurations in operation (Reference 11)
2. Below 150°F for abnormal heat loads and three pump-cooler configurations in operation (Reference 11)
3. Below 205°F for abnormal heat loads and any two pump-cooler configurations in operation (Reference 11).

For the Units 1 and 2 spent fuel cooling system, the design basis normal heat load assumes that Units 1 and 2 are refueled consecutively, and the rack positions are filled with previous discharges, except for 118 spaces reserved for a full core discharge (Reference 11). The design basis abnormal heat load assumes that Units 1 and 2 are refueled consecutively, followed by a full core discharge after a short period of operation. In this case, all rack positions contain spent fuel (References 11 and 12). Because the current refueling practice is to offload the entire core (as discussed in 9.1.3.3.1), core offloads are controlled such that the design basis maximum abnormal heat load of 34.0 x 10^6 Btu/hr for the Units 1 and 2 Spent Fuel Pool (Reference 58) is not exceeded. The licensing basis decay heat predictions were performed with the methodology outlined in Reference 13. Various operational evolutions may utilize decay heat predictions based on the ORIGEN methodology (e.g., ORIGEN-ARP or SAS2H/ORIGEN-S) presented in References 24 and 25.

It should be noted that, while all temperature conditions above represent design criteria associated with specific analytical assumptions, only the higher temperature of 205°F represents an actual operating limit. Analyses have been performed to ensure that seismic and structural integrity of the pool liner, supporting concrete, and fuel racks are not compromised at this temperature limit. Thermal - hydraulic analysis of the racks has also shown that boiling within the fuel cells does not occur with pool temperatures maintained at or below this limit, provided normal operating pool level is maintained.

In addition to the primary function of decay heat removal, the system provides for purification of the spent fuel pool water, the fuel transfer canal water, and the contents of the borated water storage tank, in order to remove fission and corrosion products and to maintain water clarity for fuel handling operations. The system also provides inventory makeup for the fuel transfer canal and the incore instrument handling tank.

The system is designed to withstand the effects of a seismic event and meet the requirements of Duke piping Class C for Oconee.

Portions of the Spent Fuel Cooling system are credited to meet the Extensive Damage Mitigation Strategies (B.5.b) commitments, which have been incorporated into the Oconee Nuclear Station operating license Section H - Mitigation Strategy License Condition.

The above discussion of Spent Fuel Cooling is for the permanently installed systems and not for the temporary Supplemental SFP Cooling System (Section 9.1.3.1.3) used to improve the SFP area environment.

9.1.3.1.2 Unit 3 Spent Fuel Pool Cooling System

The Unit 3 Spent Fuel Pool Cooling System duplicates the equipment used for the Units 1 and 2 system. The Unit 3 system is designed to remove the decay heat from the stored fuel in the Unit 3 spent fuel pool. The cooling system heat removal requirements are as set forth in NRC Standard Review Plan Section SRP-9.1.3 (References 14, 15). Other system functions are to maintain the pool inventory, clarity and chemistry at acceptable levels.

The Unit 3 system heat removal design requirements, as stipulated by Standard Review Plan 9.1.3, are:

1. For the maximum normal heat load with the normal cooling systems in operation, and assuming a single active failure, the temperature of the pool water shall be maintained at or below 140°F and the liquid level in the pool should be maintained.
2. For the abnormal maximum heat load with the normal cooling systems in operation, the pool water temperature should be kept below boiling and the liquid level in the pool should be maintained. A single active failure need not be considered.

The design basis maximum normal and abnormal decay heat loads are as defined in SRP 9.1.3 (Reference 15), for fuel racks with greater than 1 1/3 core storage capacity. Because the current refueling practice is to offload the entire core (as discussed in 9.1.3.3.1), core offloads are controlled such that the design basis maximum abnormal heat load of 30.8 x 10^6 Btu/hr for the Units 1 and 2 Spent Fuel Pool (Reference 59) is not exceeded.The licensing basis decay heat predictions were performed with the methodology outlined in Reference 13. Various operational evolutions may utilize decay heat predictions based on the ORIGEN methodology (e.g., ORIGEN-ARP or SAS2H/ORIGEN-S) presented in References 24 and 25.

It should be noted that, while both temperature conditions above represent design criteria associated with specific analytical assumptions, only the boiling criterion represents an actual design limit. An operating limit of 205°F is imposed for conservatism. Analyses have been performed to ensure that seismic and structural integrity of the pool liner, supporting concrete, and fuel racks are not compromised at this temperature limit. Thermal - hydraulic analysis of the racks also has shown that boiling within the fuel cells does not occur with pool temperatures maintained at or below this limit, provided normal operating pool level is maintained.

In addition to the primary function of decay heat removal, the system provides for purification of the spent fuel pool water, the fuel transfer canal water, and the contents of the borated water storage tank, in order to remove fission and corrosion products and to maintain water clarity for fuel handling operations. The system also provides inventory makeup for the fuel transfer canal and the incore instrument handling tank.

The system is designed to withstand the effects of a seismic event and meet the requirements of Duke piping Class C for Oconee.

Portions of the Spent Fuel Cooling system are credited to meet the Extensive Damage Mitigation Strategies (B.5.b) commitments, which have been incorporated into the Oconee Nuclear Station operating license Section H – “Mitigation Strategy License Condition”.

9.1.3.1.3 Units 1 and 2 Supplemental Spent Fuel Pool Cooling System

A Supplemental Spent Fuel Pool Cooling System (SSFPC) is provided as a temporary means of reducing the Unit 1 and Unit 2 SFP temperature following a full core off-load. The SSFPC provides supplemental cooling to the Unit 1 / 2 Spent Fuel Pool to reduce the post-full core offload pool temperature for the duration of fall outages to improve working conditions in the SFP area environment. The system is not credited to ensure the limits in 9.1.3.1.1 are met.

The permanent SFP Cooling System is credited to ensure those limits are met. The system consists of the following equipment:

- Primary Skid – The primary skid is comprised of two (2) components (pump and plate-frame heat exchanger) and the interfacing piping. The Primary pump skid is for recirculation of SFP water with one (1) backup pump. Each primary pump will be sized to provide 100% of the flow required at the design maximum heat load. The plate-frame heat exchanger is sized to remove 100% of the design maximum heat load.
- Secondary Skids – The secondary skid consists of our (4) skid mounted cooling tower units sized to remove 100% of the design maximum heat load at the specified wet bulb temperature. Each cooling tower unit will have an integral 650 gpm centrifugal pump with isolation valves. The cooling towers and secondary pumps will be located approximately 100 feet due west of the Truck Bay roll-up door.
- Electrical distribution system suitable for routing Power to SSFPC System components.
- Piping, valves and flexible hoses to interconnect system components and control flow paths and volume, including suction and discharge piping and supports for temporary installation into the SFP. Some of the piping and valves will remain when the equipment is not in service. Hoses will only be installed when the equipment is in service. Instrument Air is required and available to support control of the Westinghouse supplied Air Operated Valves (AOVs).
- Threshold for Unit 1 / 2 SFP Truck Bay Door (a Vital Area door) to provide a secure way to permit the secondary hoses and cables to pass under the door.

9.1.3.2 System Description

The Spent Fuel Cooling System (Figure 9-5, Units 1, 2 and 3) provides cooling for the spent fuel pool to remove fission product decay heat energy. System performance data are shown in Table 9-1 (Units 1 and 2) and Table 9-2 (Unit 3). Major components of the system are briefly described below.

Spent Fuel Coolers

The spent fuel coolers are designed to maintain the temperature of the spent fuel pool as noted in Section 9.1.3.1. There are three coolers for Oconee 1 and 2, and three coolers for Unit 3, arranged in parallel.

Spent Fuel Coolant Pumps

The spent fuel coolant pumps take suction from the spent fuel pool and recirculate the fluid back to the pool after passing through the coolers. A portion of the flow is demineralized and filtered depending on conditions. There are three pumps for Oconee Units I and 2, and three pumps for Oconee 3. The spent fuel coolant pumps are also used for filling the fuel transfer canal or incore instrumentation handling tank with borated water from the borated water storage tank.

Spent Fuel Coolant Demineralizers

One spent fuel coolant demineralizer will process approximately one-half of the spent fuel pool volume in 24 hours. There is one demineralizer for Units 1 and 2, and one for Unit 3.

Spent Fuel Coolant Filters

The spent fuel coolant filters are designed to remove particulate matter from the spent fuel pool water. They are sized for the same flow rate as the demineralizers (180 gpm). There are two filters for Units I and 2, and two for Unit 3.

Borated Water Recirculation Pump

This pump removes water from the borated water storage tank for demineralization and filtering. The pump may also be used while demineralizing and filtering the water in the fuel transfer canal during a transfer of fuel. It may also be used for emptying the fuel transfer canal if spent fuel coolant pumps are unavailable for use. There is one pump for Units 1 and 2, and one for Unit 3.

Reverse Osmosis Unit

This is a packaged unit that removes dissolved silica which typically originates from the Boraflex neutron absorber in the spent fuel pools. The reverse osmosis unit is permanently installed and interconntected, as part of the Reverse Osmosis System, with the Unit 1 and U 2 borated water storage tanks and the Unit 1 & 2 spent fuel pool. The Reverse Osmosis System is operated periodically to maintain low silica concentrations in these reservoirs sufficient to satisfy warranty requirements for the reactor fuel. The water in these reservoirs is mingled to a greater or lesser extent with that in the Reactor Coolant Systems of Unit 1 or 2 during refueling operations. The Reverse Osmosis System is operated on one source at a time. There is a direct suction connection to the spent fuel pool, but the borated water storage tanks are connected to the Reverse Osmosis System at the purification loop piping shared between Units 1 and 2. The Reverse Osmosis System discharges to the purification loop piping downstream of the last filter. Boron and water are removed along with the silica during operation of the reverse osmosis unit and discharged to the miscellaneous waste holdup tank.

Borated Water Recirculation Automatic Isolation Valves

Two air operated valves installed upstream of the Unit 1 & 2 and Unit 3 Borated Water Recirculation Pumps will isolate the Unit 1 & 2 or Unit 3 Borated Water Storage Tank (BWST) recirculation pump suction line, respectively. This also isolates the Reverse Osmosis suction line that branches off the BWST recirculation line. The valves are automatically isolated upon receipt of a low BWST level actuation signal prior to ECCS suction swapover to the reactor building sump. The isolation occurs prior to alignment of the core cooling suction from the BWST to Reactor Building Emergency Sump (RBES). Automatic closure of these valves prevents radioactive RBES fluid from entering the Spent Fuel Purification and Reverse Osmosis systems. The valves fail closed on loss of air or power.

9.1.3.3 System Evaluation

9.1.3.3.1 Normal Operation

The normal operation of the Spent Fuel Cooling System provides several functions. The most safety significant of these functions is to maintain pool inventory so that stored fuel is always covered with water. In order to protect against loss of inventory by boil-off, the system maintains the pool temperature below the design bases limits specified in Section 9.1.3.1. The system also maintains the pool clarity and chemistry at acceptable levels.

Spent fuel pool heat removal is accomplished by recirculating spent fuel coolant water through heat exchangers and then back to the pool. The spent fuel pumps take suction from the spent fuel pool and transport the flow through the coolers, which are arranged in parallel. The waste heat is removed from the shell side of the coolers by the Recirculated Cooling Water System. The cooled spent fuel pool water is then directed back to the spent fuel pool.

The spent fuel pool water temperature is a direct function of the decay heat load produced by the fuel in the racks, in conjunction with the heat removal capability of the spent fuel cooling system. The total heat removal capacities are the same for the Units 1 and 2 and the Unit 3 spent fuel pool coolant systems. Both systems use the same numbers of pumps and coolers, with the same design specifications and overall equipment configurations. The expected decay heat loads vary with the number of fuel assemblies present in the pool, the burnups of the various fuel assemblies, and the post-irradiation decay times.

At the time that the Units 1 and 2 spent fuel pool was re-racked, its spent fuel cooling system was upgraded to handle the higher total heat load expected from the increased number of stored fuel assemblies. The heat removal capability of the upgraded spent fuel cooling system has been sized to meet the design limits specified in Section 9.1.3.1. A specific analysis of expected maximum normal and abnormal heat loads was performed, as described in Reference 58. The Spent Fuel Cooling System was analyzed to predict the pool temperatures which would result from these heat loads. Temperatures meet the design requirements as specified in Section 9.1.3.1. Core offloads are controlled such that the ultimate heat load from these analyses are not exceeded.

At the time that the Unit 3 spent fuel pool was re-racked, its spent fuel cooling system was upgraded to handle the higher total heat load expected from the increased number of stored fuel assemblies. The heat removal capability of the upgraded spent fuel cooling system has been sized to meet the design limits specified in Section 9.1.3.1. A specific analysis of expected maximum normal and abnormal heat loads was performed, as described in Reference 59. Again, the Spent Fuel Cooling System was analyzed to predict the pool temperatures resulting from these heat loads. These temperatures meet the design requirements as specified in Section 9.1.3.1. Core offloads are controlled such that the ultimate heat load from these analyses are not exceeded.

During an actual refueling outage for any unit at ONS, it is now common practice to offload a full core (177 fuel assemblies) into the pool. The resulting heat load under this condition will not exceed the abnormal heat load cases evaluated in Sections 9.1.3.1.1 and 9.1.3.1.2 for the Units 1 and 2 fuel pool and Unit 3 fuel pool respectively. In addition, the resulting temperature will be less than 205°F in the fuel pools in the abnormal heat load case, assuming a single active failure. Normal practice at Oconee during the abnormal heat load case is to limit the maximum pool temperature to 150°F. This is accomplished via plant procedures. The seismic structural integrity of the storage racks, pools, and supporting structures has been evaluated at or above this temperature, and found to be adequate. Also, the thermal-hydraulic analysis of the storage racks indicates that localized boiling will not occur if water entering the storage cells reaches this temperature, as long as normal pool level is maintained.

A bypass purification loop is provided to maintain the purity of the water in the spent fuel pool. This loop is also utilized to purify the water in the borated water storage tank following refueling, and to maintain clarity in the fuel transfer canal during refueling. Water from the borated water storage tank or fuel transfer canal can be purified by using the borated water recirculation pump.

The reverse osmosis unit may also be operated to remove silica from the Unit 1 & 2 spent fuel pool and the Unit 1 and Unit 2 borated water storage tank, which is typically generated by the decomposition of the Boraflex coating on the spent fuel storage racks.

9.1.3.3.2 Failure Analysis

An analysis of the maximum fuel cladding temperature has been performed for the postulated case of complete loss of coolant circulation to the pool. The analysis assumes maximum anticipated heat load in the pool, with the hottest assembly located in the least cooled storage area. The maximum cladding temperature will occur at the location of maximum heat flux. For a fuel assembly having the maximum value for decay heat power of 80 kw, and for an axial peak to average power density ratio of 1.2, the maximum local fuel rod heat flux is 1200 BTU/hr-ft^2. Natural circulation flow rates within the storage tubes have been calculated which give confidence that convection film coefficients in excess of 50 BTU/hr-ft^2 °F can be expected. Assuming this low value for conservatism, the clad surface temperature is 24°F above the coolant temperature. Because the heat flux is small, very large uncertainties in the film coefficient are acceptable without causing prohibitively high clad temperatures. For example, a reduction by a factor of five in the film coefficient would result in a clad surface temperature of 120°F above the coolant temperature. A reduction by a factor of ten, from 50 BTU/hr-ft^2 °F to 5 BTU/hr-ft^2 °F would result in a clad surface temperature of 240°F above the coolant temperature. These temperatures are below 650°F, which is the normal operating temperature of the fuel clad in the core.

The reverse osmosis unit adds heat to the Unit 2 Pipe Trench Area Room (Room 349) when it is operating, and some residual heat while cooling down after it is shut down. Equipment exists in Room 349 that is used for accident mitigation. This equipment is protected from excessive ambient room temperatures due to operation of the reverse osmosis unit by an automatic shutdown circuit. The automatic shutdown circuit provides a safety-related means to ensure that power is removed from the reverse osmosis unit in the event that the ambient temperature of Room 349 exceeds a setpoint value. This setpoint value is sufficiently low so that the reverse osmosis unit is shut down before it can result in exceeding ambient temperature limits of any components in the room which provide 10CFR50.59 design functions.

9.1.3.4 Safety Evaluation

The Spent Fuel Cooling System provides adequate capacity and component redundancy to assure the cooling of stored spent fuel, even when large quantities of fuel are in storage. Multiple component failures or complete cooling failures permit ample time to assure that protective actions are taken. The system is arranged so that loss of fuel pool water by piping or component failure is highly improbable. The system performs no emergency functions. Alarms are provided to alert operator of abnormal pool level and temperature.

The Spent Fuel Cooling System has one process line connecting to the Reactor Coolant System through the SSF RC Makeup line. Its major penetration to the Reactor Building is through the fuel transfer tube. The fuel transfer tube is isolated inside the Reactor Building by a blind flange connection in the fuel transfer canal.

The reverse osmosis unit is operated on the Units 1 and 2 SFP or the Unit 1 or Unit 2 borated water storage tank in accordance with maximum time limits and/or minimum water levels per batch that vary with the initial silica concentration. This ensures that the water level of the source remains at or above the minimum required levels and that the boron concentration is not reduced below the minimum required concentration. Other restrictions are necessary to ensure that operation of the RO Unit does not impact accident scenarios or degrade other plant equipment, as further detailed in Reference 60.

Two air operated valves installed upstream of the Unit 1 & 2 and Unit 3 Borated Water Recirculation Pumps will isolate the Unit 1 & 2 or Unit 3 Borated Water Storage Tank (BWST) recirculation pump suction line, respectively. This also isolates the Reverse Osmosis suction line that branches off the BWST recirculation line. The valves are automatically isolated upon receipt of a low BWST level actuation signal prior to ECCS suction swapover to the reactor building sump. The isolation occurs prior to alignment of the core cooling suction from the BWST to Reactor Building Emergency Sump (RBES). Automatic closure of these valves prevents radioactive RBES fluid from entering the Spent Fuel Purification and Reverse Osmosis systems. The valves fail closed on loff of air or power.

9.1.4 Fuel Handling System

9.1.4.1 Design Bases

9.1.4.1.1 General System Function

The fuel handling system shown on Figure 9-7 (sheets 1 & 2) is designed to provide a safe, effective means of transporting and handling fuel from the time it reaches the station in an unirradiated condition until it leaves the station after postirradiation cooling. The system is designed to minimize the possibility of mishandling or maloperations that could cause fuel assembly damage and/or potential fission product release.

Separate fuel handling equipment is provided for each reactor. A common fuel storage area serves Oconee 1 and 2, while a separate fuel storage area is provided for Oconee 3.

The reactors are refueled with equipment designed to handle the spent fuel assemblies underwater from the time they leave the reactor vessels until they are placed in a cask for shipment from the spent fuel pools. Underwater transfer of spent fuel assemblies provides an effective, economic, and transparent radiation shield, as well as a reliable cooling medium for removal of decay heat. Use of borated water assures reactor subcriticality during refueling.

9.1.4.1.2 New Fuel Storage

New Fuel Storage is described in Section 9.1.1.

9.1.4.1.3 Spent Fuel Pool

Each spent fuel pool is a reinforced concrete pool located in its respective Auxiliary Building. The Oconee 1, 2 pool is lined with stainless clad plate. The Oconee 3 pool is lined with stainless steel plate. The unit 1 and 2 spent fuel pool will hold 1312 fuel assemblies. The unit 3 spent fuel pool will hold 822 assemblies plus 3 spaces for failed fuel canisters. Fuel components (such as control rods, BP's, or APSR's) requiring removal from the reactors are stored in the spent fuel assemblies or in brackets suspended from the top of the fuel racks.

9.1.4.1.4 Fuel Transfer Tubes

Two horizontal tubes are provided to convey fuel between each Reactor Building and the respective Auxiliary Building. These tubes contain tracks for the fuel transfer carriages, gate valves on the spent fuel pool side, and a means for flanged closure on the Reactor Building side. The fuel transfer tubes penetrate the spent fuel pool and the fuel transfer canal at their lower depth, where space is provided for the rotation of the fuel transfer carriage baskets.

9.1.4.1.5 Fuel Transfer Canal

The fuel transfer canal is a passageway in the Reactor Building extending from the reactor vessel to the Reactor Building wall. It is formed by an upward extension of the primary shield walls. The enclosure is a reinforced concrete structure lined with stainless clad plate to form a canal above the reactor vessel which is filled with borated water for refueling.

Space is available in the deeper portion of the fuel transfer canal for underwater storage of the reactor vessel internals upper plenum assembly. This portion of the fuel transfer canal can also be used for storage of the reactor vessel internals core barrel and thermal shield assembly by storing the upper plenum assembly in the upper end of the fuel transfer canal.

9.1.4.1.6 Fuel Handling Equipment

This equipment consists of fuel handling bridges, fuel handling mechanisms, fuel storage racks, fuel transfer mechanisms, and shipping casks. In addition to the equipment directly associated with the handling of fuel, equipment is provided for handling the reactor vessel closure head and the upper plenum assembly to expose the core for refueling.

9.1.4.2 System Description and Evaluation

9.1.4.2.1 Receiving and Storing Fuel

New fuel assemblies are received in shipping containers, unloaded and stored in the appropriate spent fuel pool. After reactor shutdown, new fuel assemblies can be transferred from the spent fuel pool to the Reactor Building with the use of the fuel transfer mechanisms and the fuel transfer tubes.

9.1.4.2.2 Loading and Removing Fuel

Following the reactor shutdown and Reactor Building entry, the refueling procedure is begun by removal of the reactor closure head. Prior to this it is necessary to uncouple the control rods from the drive mechanisms. An auxiliary hoist (the CRDM crane, located over the fuel transfer canal) is used for this and any other special purposes that may be required during refueling. The electrical and water connections to the head assembly are disconnected.

To close the annular space between the reactor vessel flange and fuel transfer canal floor, a seal plate is lowered into position and bolted to the canal shield flange with appropriate gaskets. The isolation valves on the spent fuel pool end of the fuel transfer tubes are closed and the tubes drained. The blind flanges on the reactor building end of the transfer tubes are also removed.

Head removal and replacement time is minimized by the use of multiple tensioners. The stud tensioners are hydraulically operated to permit preloading and unloading of the reactor vessel closure studs at cold shutdown conditions. The studs are tensioned to their operational load in discrete steps in a predetermined sequence. When the alternate HydraNut tensioning system is utilized, the studs are tensioned simultaneously. Required stud elongation after tensioning is verified by an elongation gauge.

Following removal of the studs from the reactor vessel tapped holes, the studs and nuts are supported in the closure head bolt holes with specially designed spacers. The studs and nuts are then removed from the reactor closure head for inspection and cleaning using special stud and nut handling fixtures. Two special alignment studs are installed in stud location Nos. 15 and 45. The lift of the head and replacement after refueling is guided by these studs. These studs are also used to locate the index fixture used for aligning the plenum assembly during removal and replacement. Storage racks are provided for the closure head studs and the alignment studs.

The reactor closure head is lifted out of the canal onto a head storage stand on the operating floor by a head and internals handling fixture attached to the polar crane. The stand is designed to protect the gasket surface of the closure head.

The upper plenum assembly is removed from the reactor, using the head and internals handling fixture and adaptors attached to the polar crane with an internals handling extension, and stored in the deeper portion of the fuel transfer canal on a stand on the canal floor. The reactor vessel stud holes except for locations Nos. 15 and 45 are closed with special plugs that prevent water and/or other foreign substances from entering the holes. The fuel transfer canal is then filled with borated water.

The original plant design provided provisions for optimizing refueling operations by using two fuel handling bridges in each Reactor Building, a Main Bridge and an Auxiliary Bridge, which spanned the fuel transfer canal. The Main Bridge was used to shuttle spent fuel assemblies from the core to the transfer station and new fuel assemblies from the transfer station to the core, while the Auxiliary Bridge was used to relocate partially spent fuel assemblies within the core as specified by the fuel management program. The full core off-load refueling practice is now normally used. Fuel shuffling is performed by completely unloading the core using the Main Bridge, shuffling the control components in the spent fuel pool using manual tools suspended from an overhead hoist mounted on the Spent Fuel Bridge, and then reloading the core. Since the Auxiliary Bridges were no longer needed for their original design purpose (Main Bridge could be used if 'in-core' shuffling *of fuel assemblies* became necessary) and they were an interference for fuel handling activities, the Auxiliary Bridges were physically removed from the Reactor Buildings (ref. NSM X2914).

In the original plant design, each unit's Main Bridge was equipped with two trolley-mounted hoists. One hoist (fuel handling mechanism) was equipped with a fuel grapple and the second hoist (control rod handling mechanism) housed the control rod grapple. (The Unit 3 Main Bridge was later upgraded to one trolley mounted multiple purpose hoist equipped with both fuel and component grapples). The Main Bridges now have one trolley mounted hoist equipped with a fuel grapple only. (ref. NSM-X2914) The Auxiliary Bridges (which consisted of one trolley-mounted hoist with fuel grapple only) for each unit has been removed. Each fuel handling bridge uses a pneumatic system for grapple operation. (ref. NSM X2914)

The Main Bridge moves a spent fuel assembly from the core underwater to the transfer station where the fuel assembly is lowered into the fuel transfer carriage fuel basket. The Main Bridges have a fuel mast only and are not capable of handling components (ref. NSM-X2914). Components are shuffled in the spent fuel pool (after complete core off load) using manual tools suspended from an overhead hoist mounted on the Spent Fuel Bridge, and then reloaded the core

Spent fuel assemblies removed from the reactors are transported to the spent fuel pool from the Reactor Building via fuel transfer tubes by means of the fuel transfer mechanism. The fuel transfer mechanisms are carriages that run on tracks extending from each spent fuel pool through the transfer tubes and into the respective Reactor Building. Each of the two independently operated fuel transfer mechanisms which serve Oconee 1 and 2 is designed to operate in two directions so that either of the two Reactor Buildings can be serviced by one or two mechanisms as required. A rotating fuel basket is provided on each end of each fuel transfer carriage to receive fuel assemblies in a vertical position. The hydraulically operated fuel basket is rotated to a horizontal position for passage through the transfer tube, and then rotated back to a vertical position in the spent fuel pool or Reactor Building for vertical removal or insertion of the fuel assembly.

The spent fuel assemblies are removed from the fuel transfer carriage fuel basket using a fuel handling bridge equipped with a fuel handling mechanism and fuel grapple. This bridge spans the spent fuel pool and permits the refueling crew to store or remove new and spent fuel assemblies in any one of the storage rack positions. Spent fuel assemblies may be moved within the spent fuel pools by use of the fuel handling bridge auxiliary hoist and appropriate remote handling tools.

Once refueling is completed, the fuel transfer canal is drained through a pipe located in the deep transfer station area. The canal water is pumped to the borated water storage tank to be available for the next refueling.

During operation of the reactors, the fuel transfer carriages are stored in the respective spent fuel pools, thus permitting a blind flange to be installed on the Reactor Building side of each tube.

Space is provided in each spent fuel pool to receive a spent fuel shipping cask as well as provide for required fuel storage. The layout of the fuel pool is shown on Figure 1-4 through Figure 1-8. The cask area is located at the north end of the fuel pools and adjacent to the fuel racks. Following a decay period, the spent fuel assemblies are removed from storage and loaded into the spent fuel shipping cask under water for removal from the site. The spent fuel shipping cask does not pass over fuel storage racks, or any systems or equipment important to safety when being moved to or from the spent fuel pool.

The spent fuel cask handling facility consists of a 100-ton capacity overhead bridge crane with a 13 foot 6 inch span. The hoist controls are five step magnetic, contactor reversing, secondary resistor type with time delay acceleration and a maximum speed of 9 feet per minute. The hoist is equipped with AC solenoid-operated brake system and an eddy-current brake. The bridge controls are the same as the hoist controls and are equipped with AC solenoid operated brake system and has a maximum speed of 50 feet per minute. The trolley is a single speed, four feet/minute, magnetic contactor reversing type controller with AC solenoid-operated brake system. The cranes were designed in accordance with Electric Overhead Crane Institute's Specification No. 61, Class A.

The cranes were tested in the shop by performing a running test, and load tested at the Oconee site to 98 percent of capacity. The running and load test results were satisfactory. Maintenance of the cranes is in accordance with ANSI B30.2. The structural and mechanical components of the crane are designed to have a minimum factor of safety of 2.5 based on yield strength and rated capacity. The hoist brake system consists of the dynamic AB 707 eddy-current control brake and a 13-inch solenoid-operated shoe brake (Whiting SESA). The bridge is equipped with a solenoid-operated shoe brake for operating the crane by pendant control from the floor. The trolley is equipped with a solenoid-operated shoe brake. The hoist system is equipped with a 75 horsepower motor that produces 328 foot-pounds of torque at full load, 1200 rpm. The starting and instantaneous stalling torque is 902 foot-pounds. The hoist is equipped with a geared lower limit switch for block travel and a paddle-type upper limit switch to prevent a two-blocking situation from occurring.

The cranes are equipped with a sister type hook with safety latch. The hook was load tested and non-destructive tested in the shop. Bethanized wire rope with a safety factor of 6 was used. A lifting adapter to be used between the yoke and the crane hook is also designed to support three times the load. The lifting adapter is a stainless steel member approximately 24 feet long, used to lift the cask from the platform to the bottom of the spent fuel pool.

A decontamination area is located in the building adjacent to each spent fuel pool where the outside surfaces of the casks can be decontaminated prior to shipment by using water, detergent solutions and manual scrubbing to the extent required.

9.1.4.2.3 Safety Provisions

Safety provisions are designed into the fuel handling system to prevent the development of hazardous conditions in the event of component malfunctions, accidental damage or operational and administrative failures during refueling or transfer operations.

All fuel assembly storage facilities employ neutron poison material and/or maintain an eversafe geometric spacing between assemblies to assure fuel storage arrays remain subcritical under all credible storage conditions. The fuel storage racks are designed so that it is impossible to insert fuel assemblies in other than the prescribed locations, thereby assuring the necessary spacing between assemblies. Fuel handling and transfer containers are also designed to maintain an eversafe geometric array. Under these conditions, a criticality accident during refueling or storage is not considered credible.

Fuel handling equipment is designed to minimize the possibility of mechanical damage to the fuel assemblies during transfer operations. If fuel damage should occur, the amount of radioactivity reaching the environment will present no hazard. The fuel handling accident is analyzed in Chapter 15.

All spent fuel assembly transfer operations are conducted underwater. The water level in the fuel transfer canal provides a nominal water level of 9 feet over the active fuel line of the spent fuel assemblies during movement from the core into storage to limit radiation at the surface of the water. The fuel storage racks provide a nominal 23.5 feet of water shielding over the stored assemblies. The minimum water depth over the stored fuel assemblies is equal to, or greater than 21.34 feet. The minimum depth of water over the fuel assemblies and the thickness of the concrete walls of the storage pool are sufficient to limit radiation levels in the working area.

Water in the reactor vessel is cooled during shutdown and refueling as described in Section 9.3.3. Adequate redundant electrical power supply assures continuity of heat removal. The spent fuel pool water is cooled as described in Section 9.1.3. A power failure during the refueling cycle will create no immediate hazardous condition due to the large water volume in both the transfer canal and spent fuel pool. With a normal quantity of spent fuel assemblies in the storage pool and no cooling available, the water temperature in the spent fuel pool would increase very slowly (Section 9.1.3).

During reactor operations, bolted and gasketed closure plates, located on the reactor building flanges of the fuel transfer tubes, isolate the fuel transfer canal from the spent fuel pool. Both the spent fuel pool and the fuel transfer canals are completely lined with stainless clad steel plate for leak tightness and for ease of decontamination. The fuel transfer tubes will be appropriately attached to these liners to maintain leak integrity. The spent fuel pool cannot be accidentally drained by gravity since water must be pumped out.

During the refueling period the water level in both the fuel transfer canal and the spent fuel pool is the same, and the fuel transfer tube valves are open. This eliminates the necessity for interlocks between the fuel transfer carriages and transfer tube valve operations except to verify full-open valve position.

The fuel transfer canal and spent fuel pool water will have a boron concentration as specified by the Core Operating Limits Report. Although this concentration is sufficient to maintain core shutdown if all of the control rod assemblies were removed from the core, only a few control rods will be removed at any one time during the fuel shuffling and replacement. Although not required for safe storage of spent fuel assemblies, the spent fuel pool water will also be borated so that the transfer canal water will not be diluted during fuel transfer operations.

The fuel transfer mechanisms permit initiation of the fuel basket rotation from the building in which the fuel basket is being loaded or unloaded. Carriage travel and fuel basket rotation are interlocked to prevent inadvertent carriage movement when the fuel basket is in the vertical position. Rotation of the fuel baskets is possible only when the carriages are in the rotating frame at the end of travel.

Interlocks are provided to prevent operation of the bridges or trolleys with a fuel assembly until the assemblies have been hoisted to the upper limit in the mast tube. Mandatory slow zones are provided for the hoisting mechanisms as the grapples approach the core and fuel baskets during insertion of fuel assemblies. The slow zones will be in effect during entry into the reactor core or fuel storage rack and just before and during bottoming out of the fuel assemblies. The controls are appropriately interlocked to prevent simultaneous movement of the bridge, trolley or hoists. The grapple mechanisms are interlocked with the hoists to prevent vertical movement unless the grapples are either fully opened or fully closed. The fuel grapple is so designed that when loaded with the fuel assembly, the fuel grapple cannot be opened as a result of operator error, electrical, or pneumatic failure.

All operating mechanisms of the system are located in the fuel handling and storage area for ease of maintenance and accessibility for inspection prior to start of refueling operations. All electrical equipment, with the exception of some limit switches, is located above water for greater integrity and ease of maintenance. The hydraulic systems which actuate the fuel basket rotating frame use demineralized water for operation.

Deleted paragraph(s) per 2005 update

The Main fuel handling bridges have a fuel mast only and are not capable of handling components. The original design of the Main fuel bridges included separate hoists, which allowed control components to be exchanged between fuel assemblies within the Reactor building. This capability has been removed. (ref NSM-X2914) All lifts for handling of reactor closure heads and reactor internal assemblies will be made using the Reactor Building Polar crane.

Travel speeds for the fuel handling bridges, hoists and fuel transfer carriages will be controlled to assure safe handling conditions.

Since 1990, Oconee has been involved in transferring spent fuel from the Unit 1 and 2 and the Unit 3 Spent Fuel Pools to an on-site Independent Spent Fuel Storage Installation. A specially designed transfer cask and associated handling equipment is used for this operation. Cask handling accidents are addressed in Chapter 15. More detailed information on cask loading and handling activities can be found in the ONS Site Specific and General License System ISFSI UFSARs.

9.1.5 Overhead Heavy - Load Handling Systems

9.1.5.1 Introduction and Licensing Background

As a result of Generic Task A-36, “Control of Heavy Loads Near Spent Fuel," NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” (Reference 28) was developed. Following the issuance of NUREG-0612, Generic Letter 80-113, dated December 22, 1980 (Reference 29), as supplemented on February 3, 1981, by Generic Letter 81-07 (Reference 30), was sent to all operating plants, applicants for operating licenses and holders of construction permits requesting that responses be prepared to indicate the degree of compliance with the guidelines of NUREG-0612. Phase 1 responded to Section 5.1.1 of NUREG-0612 and addressed applicable codes and standards for the subject cranes and special lifting devices, crane operator training and qualification and procedures for heavy load handling. Phase II responded to Sections 5.1.2, 5.1.3, 5.1.5, and 5.1.6 (5.1.4 was specific to BWRs) of NUREG-0612 and addressed the need for mechanical stops or electrical interlocks, the need for single- failure-proof handling systems and load drop consequence analyses. By correspondence dated June 26, July 30, August 31, October 1, 1981, and February 1, October 8, November 5, and

December 22, 1982, (References 31, 32, 33, 34, 35, 36, 37, and 38) Duke provided the Oconee responses.

On April 20, 1983, the NRC issued its Safety Evaluation Report (SER) (Reference 39) for Oconee Nuclear Station (ONS), concluding that "... the guidelines of NUREG-0612, Section 5.1.1, have been satisfied." The SER further states that "... Phase 1 actions taken for the Oconee units are acceptable."

On June 28, 1985, the NRC issued Generic Letter 85-11 (Reference 40). This generic letter concluded that Phase 1 had provided improvements in heavy load handling and that Phase II was no longer required. By correspondence dated October 2, 1987 (Reference 41), Duke concluded that implementation of any actions identified in Phase II are not a requirement. NRC responded with a letter dated November 2, 1987 (Reference 42), stating NRC has no objections with the statement that Duke will implement only those Phase II commitments which Duke considers appropriate. On October 31, 2005, the NRC issued Regulatory Issue Summary (RIS) 2005-25, "Clarification of NRC Guidelines for Control of Heavy Loads" (Reference 45), as a result of recommendations developed through Generic Issue (GI) 186, "Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants." (Reference 44) The RIS reemphasized the guidelines of NUREG-0612 and identified relevant operating experience and inspection information related to the movement of heavy loads. On May 29, 2007, the NRC issued Supplement 1 of RIS 2005-25 (Reference 46) addressing remaining recommendations associated with GI 186 and communicated regulatory expectations related to safe load handling.

On September 14, 2007, an "Industry Initiative on Heavy Load Lifts" (Reference 55) was initiated by the Nuclear Energy Institute (NEI) to specify those actions to be taken by each plant to ensure that heavy lifts continue to be conducted safely and that each plant's licensing bases accurately reflected those plant practices.

9.1.5.2 Design Basis

The design bases of the overhead heavy load systems are to:

1. Assure that the potential for a load drop is extremely small,
2. Assure that in the event of a postulated reactor vessel head drop, the core remains covered and cooled, and,
3. Assure the consequences of a load drop in the spent fuel pool meet the acceptance criteria of NUREG-0612.

9.1.5.3 Scope of Heavy Load Handling Systems

All cranes and hoists lifting heavy loads over spent fuel or safe shutdown equipment comply with the guidelines of NUREG-0612 and are consistent with Duke's responses and commitments related to the handling of heavy loads.

9.1.5.4 Control of Heavy Lifts Program

The control of heavy lifts consists of the following:

1. Duke's commitments in response to NUREG-0612, Phase 1 elements
2. Duke's response to the NEI Initiative on Heavy Load Lifts

3. Reactor pressure vessel head lift load drop analysis assumptions (lift height and medium present) are incorporated into plant procedures

4. Load drop analyses have been performed for loads over the spent fuel pool.

Duke maintains a Lifting Program to minimize the potential for adverse interaction between overhead load handling operations and: 1) nuclear fuel assemblies to ensure a sub-critical configuration and preclude radiological consequences and; 2) structures, systems and components (SSCs) selected to ensure safe shutdown of the plant following a postulated heavy load drop event. A "heavy load" has been defined as one weighing 1500 lbs. or more. No suspended loads of more than 3000 lbs shall be transported over fuel stored in the spent fuel pool. The bases of the NRC acceptance of Duke's program is summarized in the April 20, 1983 SER. The objective of the program is to ensure that all load handling systems are designed, operated, and maintained such that their probability of failure is uniformly small and their use appropriate for the critical tasks in which they are employed.

9.1.5.4.1 Oconee Commitments in Response to NUREG-0612, Phase 1 Elements

The Duke Lifting Program is based on the NEI "Industry Initiative on Heavy Load Lifts" and the following general guideline areas of NUREG-0612, Section 5.1.1:

Guideline 1 - Safe Load Paths

Guideline 2 - Load Handling Procedures

Guideline 3 - Crane Operator Training

Guideline 4 - Special Lifting Devices

Guideline 5 - Lifting Devices (not specifically designed)

Guideline 6 - Cranes (inspection, testing and maintenance)

Guideline 7 - Crane Design

The following sections summarize the commitments made by Duke in compliance with Section 5.1.1 of NUREG-0612:

<u>Safe Load Paths</u>

NUREG-0612, Section 5.1.1 defines a "Safe Load Path" as one which minimizes the potential for heavy loads, if dropped, to impact irradiated fuel in the reactor vessel and in the spent fuel pool, or to impact safe shutdown equipment.

Oconee has established safe load paths for all load handling systems identified as "handling heavy loads in the vicinity of vital equipment." Heavy loads are considered to be those weighing 1500 lb or more. Vital equipment includes those systems necessary for safe shutdown and decay heat removal and those involved with spent fuel handling.

The safe load paths for cranes follow beams and avoid vital systems where possible. The safe load paths for monorails are the vertical projections of the beams onto the floor.

Safe load paths are indicated on general arrangement drawings. Guidance for following safe load paths is contained in site procedures and directives.

<u>Load Handling Procedures</u>

Load handling requirements are specified in site procedures and directives which describe; safe load paths, instructions for special lifts, appropriate procedures, and any restrictions placed on the crane or hoist.

Crane Operator Training

Crane operators are qualified, trained and conduct themselves in accordance with ANSI B30.2-1976.

Special Lifting Devices

Special lifting devices at Oconee comply with applicable ANSI standards and NUREG-0612 guidelines. Acoustic emissions testing has been justified as an alternative NDE testing method for the reactor vessel head and reactor internals lifting rigs. Many special lift devices at Oconee were designed and procured prior to the publication of ANSI N14.6-1978 and therefore were not designed in specific accordance with that standard. As a result, the NRC identified exceptions and “approaches consistent with this guideline” in "Synopsis of Issues Associated with NUREG 0612 dated May 4, 1983" (Reference 57). This provided information to better determine which ONS special lift devices require specific inspections.

Lifting Devices (not specifically designed)

All lifts are made by qualified personnel who, by experience and/or training, are cognizant in the movement of loads.

The use of lifting devices at Oconee Nuclear Station complies with the applicable ANSI standards and NUREG-0612 guidelines. Lifting devices used consist of the appropriate size and number of rigging hardware, such as chain-falls, chokers, and slings as determined by the rigger. In making a selection, the rigger draws on experience and training. Choker and sling sizing is determined by a conservative estimated weight of the load.

Slings are required to be inspected before each use.

Dynamic loads on slings are properly accounted. Typically, these dynamic loads can be neglected due to being a reasonably small percentage of the overall static load. (Based on hoisting speed less than 30 fpm) (Reference 39)

Inspection, Testing and Maintenance

The Oconee Crane Inspection Program is discussed in Section 18.3.5 of the Oconee UFSAR (Reference 50).

Oconee Nuclear Station crane inspection, testing, and maintenance programs comply with the requirements of ANSI B30.2-1976, Chapter 2-2.

Crane Design

Oconee Nuclear Station evaluated its overhead heavy load handling systems for design compliance with CMAA-70 and ANSI B30.2-1976. The generator room crane in the standby shutdown facility (SSF) is exempt from CMAA-70 and ANSI B30.2-1976 design requirements because it is a manually operated, single girder overhead traveling crane. With the exception of the SSF generator room crane, the cranes listed in Section 2.1.1(a) of the Oconee SER, dated April 20, 1983, were designed in accordance with Duke Power Company specifications, Electric Overhead Crane Institute (EOCI) Specification 61, and USAS B30.2.0-1976. A comparative study of CMAA-70 versus EOCI-61 identified 13 items of difference between the two specifications. The 13 items of difference are enumerated within the April 20, 1983, SER.

Oconee Nuclear Station cranes substantially meet the intent of this guideline on the basis that the cranes were originally built to EOCI-61. In addition, for those criteria in CMAA-70 noted to be more restrictive than the requirements of EOCI-61, Oconee demonstrated compliance with CMAA-70 or provided reasonable assurance that the existing design meets the intent of the CMAA criteria.

9.1.5.4.2 Oconee Response to NEI Initiative on Heavy Load Lifts

9.1.5.4.2.1 Reactor Vessel Head Lifting Procedures

In response to the September 14, 2007 NEI "Industry Initiative on Heavy Load Lifts," and in accordance with NEI 08-05 "Industry Initiative on Control of Heavy Loads," Oconee procedures used to control the lift and replacement of the reactor vessel head contain limits of load height above the reactor vessel flange. These load height limits are based on the Oconee load drop analysis of record. These load height limits provide additional assurance that the core will remain covered and cooled in the event of a postulated reactor vessel head drop.

The Oconee reactor vessel head load drop analysis meets the guidance and acceptance criteria developed by NEI as part of its initiative.

9.1.5.4.2.2 Load Drops in the Spent Fuel Pool Building

The Spent Fuel Pool (SFP) slab was designed for the postulated cask drop accident. Fill concrete was placed from sound rock to the bottom of the fuel pool slab in the area covered by the cask crane to prevent the shearing of a large plug from the pool slab in the event the cask was accidentally dropped.

The SFP concrete floor slab is designed to withstand a 100 ton cask drop. However, localized concrete could be crushed and the steel liner plate punctured in the area of the dry storage cask impact. For the purpose of analyzing the event, a gap of 1/64 inch for a perimeter of 308 inches in the liner plate was assumed. The calculated leakage of pool water through the gap is 21.3 gallons per day. This amount of water loss is within the capability of the SFP makeup sources.

The evaluation and consequence of fuel shipping cask drops is discussed in Section 15.11.2.4 of the UFSAR (Reference 48). The evaluation and consequence of dry storage transfer cask drops is discussed in Section 15.11.2.5 of the UFSAR (Reference 49).

The radiological consequence of either a fuel shipping cask drop or a dry storage transfer cask drop is within Regulatory Guide 1.183 (Reference 56) limits.

9.1.5.5 Safety Evaluation

The Duke Lifting Program provides a defense-in-depth approach which ensures that all load handling systems are designed, operated, and maintained such that the probability of their failure is very small and the use of said handling systems appropriate for the tasks in which they are employed. In addition, procedures to lift and replace the reactor vessel head ensure the core remains covered and cooled when a reactor vessel head drop is postulated.

9.1.6 References

1. Calculation OSC-1870, "Oconee Nuclear Station Unit 3 Poison Spent Fuel Storage Racks"

2. Calculation OSC-6574, "Oconee Nuclear Station Unit 1 and 2 Poison Spent Fuel Storage Racks"
3. Calculation OSC-1875, "Slashing Effect of Water in Spent Fuel Pools"
4. Studsvik, "CASMO-3 A Fuel Assembly Burnup Program," STUDSVIK/NFA-89/3, Revision 4.4, January, 1991.
5. Studsvik, "TABLES-3 Library Preparation Code for SIMULATE-3", STUDSVIK/SOA-92/03, Revision 0, April, 1992.
6. Studsvik, "SIMULATE-3 Advanced Three-Dimensional Two-Group Reactor Analysis Code", STUDSVIK/SOA-92/01, Revision 0, April, 1992.
7. M.N. Baldwin, et. al., "Critical Experiments Supporting Close Proximity Water Storage of Power Reactor Fuel", The Babcock and Wilcox Company, BAW-1484-7, July, 1979.
8. Duke Power Company, Letter to U.S. Nuclear Regulatory Commission Document Control Desk, from J.W. Hampton, November 22,1994, "Oconee Nuclear Station Docket Nos. 50-269,-270,-287 Unit 3 Cycle 16 Reload Technical Specifications".
9. U.S. Nuclear Regulatory Commission letter to All Power Reactor Licensees, from B.K. Grimes, April 14, 1978, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications".
10. Oak Ridge National Laboratory, "SCALE 4.2, A Modular Code System for Performing Standardized Computer Analyses for Licensing Evaluation", Volumes I-IV, NUREG/CR-200, Revision 4, April 1995.
11. Letter from W. O. Parker, Jr. (DPC) to H. R. Denton (USNRC), dated July 1, 1980.
12. Letter from W. O. Parker, Jr. (DPC) to H. R. Denton (USNRC), dated July 25, 1980.
13. USNRC Branch Technical Position (BTP) APCSB 9-2, "Residual Decay Energy for Light Water Reactors for Long Term Cooling".
14. Letter from H. B. Tucker (DPC) to H. R. Denton (USNRC), dated March 10, 1983.
15. NUREG-0800, Standard Review Plan Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System".
16. Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment No. 209 to Facility Operating License DPR-38, Amendment No. 209 to Facility Operating License DPR-47, Amendment No. 206 to Facility Operating License DPR-55, Duke Power Company, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.
17. Letter from J. W. Hampton to USNRC, dated November 22, 1994, Oconee Nuclear Station Docket Nos. 50-269, -270, -287 Unit 3 Cycle 16 Reload Technical Specifications, May 3, 1995.
18. License amendment 123, 123, and 120 for Units 1, 2 and 3 respectively, September 29, 1983.
19. License amendment 90, 90, and 87 for Units 1, 2 and 3 respectively, December 24, 1980.
20. Calculations OSC-1870, Rev D3, "Oconee Nuclear Station Unit 3 Poison Spent Fuel Storage Racks".
21. Calculations OSC-6574, Rev 0, "Oconee Nuclear Station Unit 1 and 2 Poison Spent Fuel Storage Racks".

22. Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.
23. NUREG-1723, Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.
24. NUREG/CR-0200, Section S2, "SAS2H: A Coupled One-Dimensional Depletion and Shielding Analysis Module."
25. NUREG/CR-0200, Section D1, "ORIGEN-ARP: Automatic Rapid Process for Spent Fuel Depletion, Decay, and Source Term Analysis."
26. "Guidance on the Regulatory Requirements for Criticality Analysis of Fuel Storage at Light-Water Reactor Power Plants," L. Kopp, U.S. NRC, August 19, 1998.
27. Letter from Bruce H. Hamilton to USNRC dated March 1, 2006, "License Amendment to Reconcile 10CFR50 and 10CFR72 Criticality Requirements for Loading and Unloading Dry Spent Fuel Storage Canisters in the Spent Fuel Pool," LAR No. 2005-009.
28. NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" Resolution of Generic Technical Activity A-36, July 1, 1980.
29. Letter from D. G. Eisenhut (NRC) to all licensees dated December 22, 1980. Subject: Control of Heavy Loads (Generic Letter 80-113).
30. Letter from D. G. Eisenhut (NRC) to all licensees dated February 3, 1981. Subject: Control of Heavy Loads (Generic Letter 81-07).
31. Letter from W. O. Parker, Jr. (Duke) to H. R. Denton (NRC) dated June 26, 1981. Subject: Response to the Dec 22, 1980 Generic Letter 80-113.
32. Letter from W. O. Parker, Jr. (Duke) to H. R. Denton (NRC) dated July 30, 1981. Subject: Control of Heavy Loads, NUREG-0612.
33. Letter from W. O. Parker, Jr. (Duke) to H. R. Denton NRC) dated August 31, 1981. Subject: Control of Heavy Loads, NUREG-0612.
34. Letter from W. O. Parker, Jr. (Duke) to H. R. Denton (NRC) dated October 1, 1981. Subject: Control of Heavy Loads, NUREG-0612.
35. Letter from W. O. Parker, Jr. (Duke) to H. R. Denton (NRC) dated February 1, 1982. Subject: Control of Heavy Loads, NUREG-0612.
36. Letter from H. B. Tucker (Duke) to H. R. Denton (NRC) dated October 8, 1982. Subject: Control of Heavy Loads, NUREG-0612.
37. Letter from H. B. Tucker (Duke) to H. R. Denton (NRC) dated November 5, 1982. Subject: Control of Heavy Loads, NUREG-0612.
38. Telephone Conversation of S. Roberts (FRC) and P. Wagner (NRC) dated December 22, 1982. Subject: Control of Heavy Loads, NUREG-0612. (No transcripts available; this is listed as Ref. 11 in Oconee SER dated April 20, 1983).
39. Letter from J. F. Stolz (NRC) to H. B. Tucker (Duke) dated April 20, 1983. Subject: Control of Heavy Loads [Safety Evaluation Report].
40. Letter from H. L. Thompson, Jr. (NRC) to All Licensees for Operating Reactors dated June 28, 1985. Subject: Completion of Phase II of "Control of Heavy Loads at Nuclear Power Plants", NUREG-0612 (Generic Letter 85-11).

41. Letter from H. B. Tucker (Duke) to Document Control Desk (NRC) dated October 2, 1987. Subject: Control of Heavy Loads.
42. Letter from Lawrence P. Crocker (NRC) to H. B. Tucker (Duke) dated November 2, 1987. Subject: Control of Heavy Loads, Phase II.
43. Letter from M. S. Tuckman (Duke) to Document Control Desk (NRC) dated May 13, 1996. Subject: Response to NRC Bulletin 96-02: Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, or Over Safety-Related Equipment.
44. Generic Issue 0186, "Potential Risk and Consequences of Heavy Load Drops in Nuclear Power, dated April 1, 1999.
45. NRC Regulatory Issue Summary 2005-25, "Clarification of NRC Guidelines for Control of Heavy Loads" dated October 31, 2005.
46. NRC Regulatory Issue Summary 2005-25, Supplement 1, "Clarification of NRC Guidelines for Control of Heavy Loads" dated May 29, 2007.
47. Oconee UFSAR Section 3.8.4.4, "Design and Analysis Procedures".
48. Oconee UFSAR Section 15.11.2.4, "Fuel Shipping Cask Drop Accidents".
49. Oconee UFSAR Section 15.11.2.5, "Dry Storage Transfer Cask Drop Accident in Spent Fuel Pool Building".
50. Oconee UFSAR, Section 18.3.5, "Crane Inspection Program".
51. Selected Licensee Commitment (SLC) 16.9.16, Reactor Building Polar Crane and Auxiliary Hoist (RCS System Open).
52. Selected Licensee Commitment (SLC) 16.12.5, Loads Suspended Over Spent Fuel in Spent Fuel Pool.
53. Duke Energy Nuclear Lifting Program.
54. NRC Enforcement Guidance Memorandum 07-006, "Enforcement Discretion for Heavy Load Handling Activities," dated September 28, 2007.
55. NEI "Industry Initiatives on Heavy Load Lifts," dated September 14, 2007.
56. Regulatory Guide 1.183, "Alternative Radiological Source Term for Evaluating Design Basis Accidents at Nuclear Power Reactors".
57. NRC "Synopsis of Issues Associated with NUREG 0612" dated May 4, 1983.
58. Safety Evaluation Report dated June 19, 1979 relating to the modification of the Oconee Units 1/2 common Spent Fuel Pool.
59. Safety Evaluation Report dated September 29, 1983 relating to the modification of the Oconee Unit 3 Spent Fuel Pool.
60. License Amendments 385, 387 and 386, dated April 30, 2014, by the Office of Nuclear Reactor Regulation for operation of the Reverse Osmosis System.
61. License Amendment Request (LAR) # 2012-05 dated Oct. 30, 2012 regarding use of RO System.
62. License Amendment Request (LAR) # 2012-05 Supplement 3 dated September 3, 2013 addressing RO System.

63. License Amendment Request (LAR) # 2012-05 Supplement 4 dated October 21, 2013 addressing RO System.

64. License Amendment Request (LAR) # 2012-05 Supplement 5 dated December 2, 2013 addressing RO System.

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9.2 Water Systems

9.2.1 Component Cooling System

9.2.1.1 Design Bases

The Component Cooling System is designed to provide cooling water for various components in the Reactor Building as follows: letdown coolers, reactor coolant pump cooling jacket and seal coolers, quench tank cooler, and control rod drive cooling coils. The design cooling requirement for the system is based on the maximum heat loads from these sources. The system also provides an additional barrier between high pressure reactor coolant and service water to prevent an inadvertent release of activity.

9.2.1.2 System Description and Evaluation

The Component Cooling System is shown schematically on Figure 9-8, and the performance requirements of the system are tabulated in Table 9-3. The following is a brief functional description of the major components of the system and their sharing between nuclear units of the station:

Component Cooler

Each component cooler is designed for the total Component Cooling System heat load for a reactor unit. Oconee 1 and 2 each have a single component cooler with a shared common spare. Oconee 3 has two coolers. The coolers reject the heat load to the Low Pressure Service Water System.

Component Cooling Pumps

Each component cooling pump is designed to deliver the necessary flows to the letdown coolers, reactor coolant pump cooling jackets and seal coolers, quench tank cooler, and control rod drive cooling coils. Each unit has one operating pump and one spare.

Component Cooling Surge Tank

This tank allows for thermal expansion and contraction of the water in this closed-loop system. It also provides the required NPSH for the component cooling pumps.

Control Rod Drive Filters

Two filters are provided in the cooling water circuit to the control rod drives to prevent particulates from entering the drive cooling coils. Only one filter is used at a time, with the second as a spare. A bypass is also provided.

9.2.1.3 Mode of Operation

During operation, one component cooling pump and one component cooler recirculate and cool water to accommodate the system heat loads for each reactor unit. The component cooling surge tank accommodates expansion, contraction, and leakage of coolant into or out of the system. The surge tank provides a reservoir of component cooling water until a leaking cooling line can be isolated. Makeup water is added to the system in the surge tank. Corrosion inhibiting chemicals are added to the system in the surge tank or the chemical addition feeder (pot).

9.2.1.4 Reliability Considerations

The Component Cooling System performs no emergency functions. Redundancy in active components is provided to improve system reliability. The pumps, coolers, surge tank, and most of the instrumentation are located in the Auxiliary Building and are accessible for inspection and maintenance.

9.2.1.5 Codes and Standards

The components of the system are designed to the codes and standards given in Table 9-13.

9.2.1.6 System Isolation

Since the Component Cooling System is not an engineered safeguards system, Reactor Building isolation valves are automatically closed on a high Reactor Building pressure signal to provide building isolation. The Reactor Building inlet lines are isolated by two check valves, one on the outside and one on the inside of the Reactor Building. The Reactor Building outlet line is isolated by an electric motor-operated valve on the inside and by a pneumatic valve on the outside of the Reactor Building.

9.2.1.7 Leakage Considerations

Water leakage from piping, valves, and other equipment in the system is not considered to be detrimental since the cooling water is normally nonradioactive. Welded construction is used throughout the system to minimize the possibility of leakage except where flanged connections are required for servicing.

In-leakage of reactor coolant to the system is detected by a radiation monitor (RIA-50) located in the pump recirculation line and is also indicated by an increase in surge tank level. A defective coil or thermal barrier tube of a reactor coolant pump can be remotely isolated by an electric motor-operated valve on the outlet cooling line and a stop-check valve on the inlet line. On Unit 1 the RCS leak can be isolated. On Units 2 and 3 the RCS leak will be vented to containment through CC System relief valves. A letdown cooler leak can be remotely isolated with motor-operated valves on the reactor coolant side of the cooler. The cooling water side can be completely isolated by closing a remotely operated, motor-actuated valve on the inlet of the cooler and the manual valves on the outlet cooling lines. Leakage from the quench tank cooler can be isolated by manual valves on the reactor coolant side. The cooling water side can be completely isolated by two manual valves. Access to the manual valves is not available at power operations.

9.2.1.8 Failure Considerations

Since the system serves no engineered safeguards function, the only consideration following a loss-of-coolant accident is the operation of the containment isolation valves. Redundant isolation valves are provided as described in Chapter 6. Failures and malfunction of components during normal operation were evaluated. Operation of the Component Cooling System is essential to normal reactor operation. In the event of loss of a component cooling pump, the standby pump will automatically start and maintain cooling water flow. The complete loss of cooling water flow does not require immediate reactor shutdown. However, procedures will require the operator to shutdown the reactor to protect the control rod drive coils. The reactor coolant pumps can be operated without component cooling water if seal injection flow is available.

9.2.2 Cooling Water Systems

9.2.2.1 Design Bases

The cooling water systems for the station are designed to provide redundant cooling water supplies to insure continuous heat removal capability both during normal and accident conditions.

The Low Pressure Service Water (LPSW) and portions of the Condenser Circulating Water (CCW) systems are designed so no single component failure will impair emergency safeguards operation. Redundant pumping capability is provided, heat exchangers and pumps can be isolated and pressure reducing valves are provided with bypasses.

All cooling systems are designed to be operated and monitored from the control room. Component design parameters are given in Table 9-4.

The design purpose of each of the cooling water systems is outlined below:

Condenser Circulating Water (CCW) System - This system provides for cooling of the condensers during normal operation of the plant. The system generally uses lake water as the ultimate heat sink for decay heat removal during cooldown of the plant. In some events, such as the loss of Lake Keowee, the water trapped in the CCW piping is used as the ultimate heat sink. The CCW System is the suction source for other service water systems, including HPSW, LPSW, PSW, and SSF ASW. In addition, CCW provides a heat sink for the RCW system. Following a design basis event involving loss of the CCW pumps, the Emergency Condenser Circulating Water (ECCW) System supplies suction to the LPSW pumps.

High Pressure Service Water (HPSW) System - This system provides a source of water for fire protection throughout the station. In the event of a loss of the normal LPSW supply, HPSW automatically supplies cooling water to the HPI pump motor coolers. For loss of A.C. power, HPSW via the Elevated Water Storage Tank automatically supplies cooling water to the Turbine Driven Emergency Feedwater Pump Oil Cooler and the LPSW Leakage Accumulator for all Units. As part of a long term compensatory action (References 14 and 15) associated with the Keowee Underground Path, the HPSW system supplies cooling water to the evaporative cooling system for the CT-4 Blockhouse area.

Low Pressure Service Water (LPSW) System - This system provide cooling water for normal and emergency services throughout the station. Safety related functions served by this system are:

1. Reactor Building cooling units.
2. Decay heat removal coolers.
3. High pressure injection pump motor bearing coolers.
4. Motor-Driven Emergency Feedwater Pump motor air coolers.
5. Deleted Per 2006 Update.
6. Siphon Seal Water.

Recirculated Cooling Water (RCW) System - This is a closed loop system to supply corrosion inhibited cooling water to various components. This system has no direct safety related functions.

Essential Siphon Vacuum (ESV) System - This system supports the Condenser Circulating Water (CCW) system by removing air from the CCW Intake header during normal and siphon modes of operation. The nuclear safety-related functions are:

1. Remove air from the CCW Intake Headers during normal operation to ensure that the operable Intake Headers are primed at the start of an event requiring the siphon mode of operation.
2. Remove air from the CCW Intake Headers during the siphon mode of operation to ensure that the siphon does not fail due to air accumulation during a Design Basis Accident involving loss of power to the CCW pumps.

Paragraph(s) Deleted Per 2000 Update.

Siphon Seal Water (SSW) System - This system's nuclear safety-related function is to support the ESV system by providing operating liquid to the ESV pumps. The ESV pumps are liquid ring vacuum pumps which require a continuous supply of water in order to create a vacuum. Additionally, it has a non-nuclear safety-related function of providing sealing and cooling water to the CCW pumps and motors.

On July 18, 1989 the NRC Issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," requesting holders of operating licenses to supply information about their respective service water systems to assure the NRC of compliance with the recommended actions of Generic Letter 89-13, and to confirm that the safety functions of their respective service water systems are being met. Oconee's responses to Generic Letter 89-13 are contained in references 7, 8, 9, 10, 12. In order to assure the adequacy of the Oconee service water systems and safety related heat exchangers to perform their functions as designed, a Service Water System Program has been established in accordance with NSD-312. The Service Water System Program consists of all those activities related to the service water systems and components, including periodic inspections, repairs, replacements, monitoring and testing.

9.2.2.2 System Description and Evaluation

9.2.2.2.1 Condenser Circulating Water System (CCW)

The Little River arm of Lake Keowee is the source of water for the CCW systems. Figure 2-4 shows the arrangement of the systems with respect to the two branches of Lake Keowee. Each unit has four condenser circulating water pumps supplying water via two 11 ft. conduits into a common condenser intake header under the turbine building floor. The discharge from the condenser is returned to the Keowee River arm of Lake Keowee.

The suction of the condenser circulating water pumps extends below the maximum drawdown of the lake. The intake structure is provided with screens which can be manually removed for periodic cleaning.

The CCW system is designed to take advantage of the siphon effect so the pumps are required only to overcome pipe and condenser friction loss.

The CCW system has an emergency discharge line to the Keowee hydro tailrace. This discharge line is connected to each of the three condensers of each unit. Under a loss-of-power situation, the emergency discharge line will automatically open and the CCW system will continue to operate as an unassisted siphon system supplying sufficient water to the condenser for decay heat removal and emergency cooling requirements. This siphon system is the Emergency Condenser Circulating Water (ECCW) System and can be divided into two distinct parts. The "first siphon" takes suction from the CCW intake canal and supplies flow to the CCW crossover header in the Turbine Building basement, where the LPSW System takes its suction. The "second siphon" takes suction from the condenser inlet piping, supplies flow through the condenser, and discharges to the Keowee Hydro tailrace. A loss of function of the second siphon would not affect the capability of the first siphon to perform its function.

In a loss of off-site power (LOOP) situation, the CCW pumps will be tripped by a load shed command. The ECCW System first siphon is required to supply suction to the LPSW System until a CCW pump can be manually restarted by the control room operator. Restart of a CCW pump is not required since the ESV system can maintain the first siphon for the duration of the event. Gravity flow (without relying on the siphon) to the suction of the LPSW pumps is possible if the lake level is sufficiently above the bottom of the CCW intake piping to maintain the required NPSH and flow demand. Refer to Section 16.9.7, Selected Licensee Commitments Manual, for additional requirements regarding the CCW Supply to the LPSW System.

During a loss of all AC power situation (Station Blackout), the CCW System is not required to supply suction to the LPSW System since power to the LPSW pumps would not be available. The second siphon is not required. Decay heat removal can be accomplished by venting steam to the atmosphere using the main steam safety valves or the manual atmospheric dump valves. The CCW piping has sufficient inventory to cope with a four-hour Station Blackout by supplying suction to the SSF Auxiliary Service Water System. (Reference 8.3.2.2.4.)

During normal operation, the continuous vacuum priming system removes noncondensible gases from portions of the CCW System. An emergency steam air ejector (ESAE) is available to enhance operation of the second siphon if the vacuum priming pumps are lost due to a loss of power. The essential siphon vacuum (ESV) system is connected to the CCW inlet header to remove non-condensible gases during normal and siphon operations.

Pursuant to the recommendations of the Oconee Probabilistic Risk Assessment study a pushbutton has been installed in the control room for sending a close signal to the CCW pump discharge valves. The capability to close the CCW valves is needed to protect against the possibility of CCW siphoning into the turbine building basement, causing flooding.

The intake canal that supplies water from Lake Keowee to the suction of the CCW pumps contains a submerged weir. The purpose of this weir is to provide an emergency pond of cooling water if the water supply from Lake Keowee were lost. This emergency pond could be recirculated through the condensers and back to the intake canal for decay heat removal as long as the intake canal level remains sufficient. The Protected Service Water (PSW) System is capable of using the inventory trapped in the CCW piping for decay heat removal (Reference 9.7). Therefore, the licensing basis does not rely on the weir nor recirculation of the intake canal for decay heat removal after a loss of Lake Keowee event (Reference 2).

9.2.2.2.2 High Pressure Service Water System (HPSW)

The schematic arrangement of the HPSW system is shown on Figure 9-10. This system is used primarily for fire protection throughout the Oconee station. In the event of a loss of the normal LPSW supply, HPSW automatically supplies cooling water to the HPI pump motor coolers. For loss of AC power, HPSW via the elevated water storage tank automatically supplies cooling water to the turbine driven emergency feedwater pump oil cooler for all units. HPSW is also used as a backup supply to the SSW system. Refer to Sections 16.9.7 and 16.9.8 for specific requirements to support the LPSW System.

Two full size (6000 gal/min at 117 psig) and one reduced size (500 gal/min at 117 psig) high pressure service water pumps supply the high pressure system. A 100,000 gallon elevated water storage tank provides inventory for a backup supply of water.

The 500 gal/min pump will normally operate to keep pressure on the fire headers. In the event of a fire, one full size pump provides adequate capacity for automatically maintaining the elevated water storage tank inventory. The second full size pump is an installed spare. The HPSW pumps take suction from the CCW system. The HPSW and LPSW pump suctions are connected to the 42 inch cross-connection between the Condenser Circulating Water inlet headers for the three units. Manual isolation valves are provided so that service water may be supplied from any or all of the inlet headers.

Portions of the High Pressure Service Water system are credited to meet the Extensive Damage Mitigation Strategies (B.5.b) commitments, which have been incorporated into the Oconee Nuclear Station operating license Section H - Mitigation Strategy License Condition.

9.2.2.2.3 Low Pressure Service Water System (LPSW)

The schematic arrangement of the LPSW system is shown on Figure 9-11 and Figure 9-12. Oconee 1 and 2 share three 15,000 gal/min LPSW pumps. The LPSW pumps and the HPSW pumps take suction from the 42 inch crossover line between the condenser inlet headers; two LPSW pumps are supplied by one suction line and the other pump is supplied by the other suction line. The HPSW system is connected to LPSW at the LPSW pump discharge, but the interconnections are not used. The alignment of HPSW to LPSW is not credited to mitigate any design basis accident or design event.

Suction is provided to the LPSW pumps via gravity flow or siphon flow from the CCW System (ECCW mode) following a design basis accident where the CCW pumps are not running. Lake level is administratively controlled to maintain sufficient NPSH for the LPSW pumps under these conditions.

The LPSW pumps have a minimum continuous flow rate of 4250 gpm based on manufacturer's recommendation. On Oconee Units 1 & 2, two LPSW pumps are normally operating with the third pump in standby. Therefore, on Oconee Units 1 & 2, the potential for interaction between running LPSW pumps is possible whenever the total demand from system loads is minimized. The potential exists where the stronger pump may close the weaker pump's discharge valve and keep it closed. The weaker pump would then be exposed to extended dead-head conditions. To minimize the potential for deadheading, procedural guidance has been provided to ensure LPSW flow will be maintained greater than 4,000 gpm on the shutdown unit whenever either Unit 1 or Unit 2 is shutdown in refueling. If this flow rate cannot be maintained on the shutdown unit, the LPSW system must be reduced to one pump operation. (References 3, 4)

On an engineered safeguards signal, the standby LPSW pump(s) starts resulting in three Unit 1 & 2 LPSW pumps operating or two Unit 3 LPSW pumps operating. Under this condition the potential exists for the LPSW pumps to be operated below the recommended minimum continuous flow rate of 4250 gpm per pump, or for a stronger pump to deadhead a weaker pump during low flow conditions. To avoid pump damage due to low flow conditions, a minimum flow line is provided for each LPSW pump. (Reference 5)

The Standby LPSW pump auto-start circuit actuates the Standby LPSW pump automatically for the Units 1&2 and Unit 3 LPSW system. The circuit actuates following a Loss of Offsite Power (LOOP) event when a running LPSW pump fails to restart and LPSW header pressure fails to return to normal operating values. The auto-start circuit will also start the Standby LPSW pump during normal operation when LPSW header pressure falls below an acceptable value.

The LPSW system provides cooling for components in the Turbine Building, the Auxiliary Building, and in the Reactor Building. Two separate 24 inch lines provide LPSW to the components in the Auxiliary and Reactor Buildings. These two supply lines are further divided into four separate supply headers, two supplying the components in Oconee I and two supplying the components in Oconee 2. The decay heat removal coolers and the Reactor Building cooling units are supplied by separate LPSW supply lines. The return lines from the decay heat removal coolers and the Reactor Building coolers maintain separation to a point beyond a remote-operated isolation valve.

For Oconee 3, each of the two 15,000 gal/min LPSW pumps take their suction from the CCW crossover. These pumps provide cooling water via separate supply lines to engineered safeguards equipment in the Reactor Building and the Auxiliary Building similar to Oconee 1 and 2. The return lines from the Oconee 3 engineered safeguards maintain separation to a point beyond a remote-operated isolation valve.

The Turbine Building requirements for LPSW are supplied from other separate headers. The three pumps associated with Oconee 1 and 2 have a Turbine Building header serving the Turbine Building requirements for Oconee I and 2. The two pumps associated with Oconee 3 also have a Turbine Building header to supply the Oconee 3 requirements.

The separate flow paths serving the emergency safeguards equipment can be isolated by remote-operated isolation valves.

The LPSW system is monitored and operated from the control room. Isolation valves are incorporated in all LPSW lines penetrating the Reactor Building.

The three (per unit) Reactor Building coolers (RBCUs) ("A", "B", and "C") are supplied by individual lines from the separate LPSW supply headers. Each inlet line is provided with a motor operated shutoff valve located outside the Reactor Building. Similarly, each discharge line from the coolers is provided with a motor operated valve located outside the Reactor Building. This allows each cooler to be isolated individually.

LPSW flow is provided to the Reactor Building Auxiliary Cooling Units (RBACs) through a separate piping loop that is independent of the RBCUs. RBAC flow can be throttled to supplement RBCU cooling. During normal plant operation, the three RBCUs "A", "B", and "C" can be throttled to provide cooling of the Reactor Building. During times when LPSW temperature is high and greater cooling is desired inside the Reactor Building, chilled water can be provided to the Auxiliary Coolers in lieu of LPSW by a temporary chilled water system during modes 1-4 and to the Auxiliary Coolers and/or the "B" RBCU during modes 5, 6, and no mode. LPSW flow path to and from RB auxiliary cooling units is automatically isolated by air-operated containment isolation valves on engineered safeguard signals. The Containment Isolation Valves (CIVs) are also automatically closed upon low LPSW supply header pressure to prevent column closure waterhammers upon LPSW pressure restoration.

On an engineered safeguards signal the outlet valves on the three RBCUs fully open to assure emergency flow through coolers.

The LPSW System provides sufficient flow to the Low Pressure Injection (LPI) coolers and Reactor Building Cooling Units (RBCUs) to ensure sufficient heat transfer capability following a design basis accident and a single active failure. The worst case design basis accident involves a LOCA/loss of offsite power with a loss of instrument air. The worst case single failures for achieving desired flows to the RBCUs and LPI coolers are 1) failure of a single LPSW pump, and 2) failure of a 4160 volt bus which fails an LPSW pump, an RBCU fan, and an LPI cooler isolation valve. Analysis and testing have been performed to demonstrate system performance under worst case conditions.

The LPSW System can provide sufficient flow to the required loads following a seismic event. Valves 1LPSW-139, 2LPSW-139, and 3LPSW-139 are remotely-operated, seismically-qualified valves which can isolate the non-seismic, non-essential header from the safety-related portions of the system. Non-seismic connections to the system exist which cannot be remotely isolated. Analysis has demonstrated that a seismically-induced single pipe break of a non-seismic connection that cannot be remotely isolated will not cause loss of system safety function.

LPSW flow to the LPI coolers is normally throttled using air-operated valves LPSW-251 and LPSW-252. During a design basis accident involving a loss of instrument air, these valves fail open to their travel stops. Motor-operated valves LPSW-4 and LPSW-5 will be used to throttle LPSW flow to the LPI coolers under these conditions. Travel stops are in place on LPSW-251 and LPSW-252 to ensure LPSW flow through an LPI cooler does not exceed the design limit of 7500 gpm under worst case conditions.

The LPSW flow to and from each Reactor Building cooler is measured. Provisions are available to indicate cooler leakage.

LPSW is a non-radioactive cooling water system that is monitored for radioactivity. Monitoring is required per Section 11.5.1 since LPSW provides cooling to normally radioactive systems. Components from these normally radioactive systems could potentially leak radioactivity into LPSW. Upon any indication of radioactivity, the component suspected of leaking may be individually isolated.

The LPSW pumps are connected to the 4160 volt buses which supply power to engineered safeguards equipment. The emergency power supply is adequate to operate all LPSW pumps upon a loss of off-site power.

During normal operation, the cooling requirements are supplied by operating one LPSW pump per unit. The LPSW requirement following a loss of coolant accident can also be supplied by one pump per unit. The spare pump is started by the engineered safeguards actuation signal to provide redundancy for single failure criteria.

LPSW supplies water to the SSW system.

Generic Letter 96-06 required consideration of effects inside containment due to the change in environment during a Loss of Coolant Accident (LOCA). This consideration identified the potential for waterhammers in cooling water systems serving containment following a Loss of Offsite Power (LOOP) concurrent with a LOCA or Main Steam Line Break (MSLB). Analysis and system testing in response to GL 96-06 concluded that waterhammers could occur in the Low Pressure Service Water (LPSW) system during all LOOP events (e.g., LOCA/LOOP, MSLB/LOOP). The LPSW piping supplies the Reactor Building Cooling Units (RBCU), the Reactor Building Auxiliary Coolers (RBAC), and the Reactor Coolant Pump Motor Coolers (RCPMC). During Loss of Offsite Power (LOOP) events or Loss of Coolant Accident (LOCA) events coupled with a LOOP it was possible to create a column Closure Waterhammer (CCWH) or Condensation Induced Waterhammer (CIWH) in the LPSW piping and components inside containment. CCWH could have occurred when the LPSW pumps restart following a LOOP and rapidly close vapor voids within the system. CIWH could have occurred when heated steam voids interact with sub-cooled water in long horizontal piping sections.

The LPSW RB Waterhammer Prevention system (WPS) was designed to maintain the LPSW piping inside containment water solid during events which cause a loss of LPSW such a LOOP, LOCA/LOOP, or MSLB/LOOP. The system's major components consist of check valves in the supply headers (LPSW-1111, 1116), pneumatic discharge isolation valves (LPSW-1121, 1122, 1123, and 1124), pneumatic vent valves (a.k.a., controllable vacuum breakers) (LPSW-1150, 1151), and associated actuation circuitry. The discharge header from containment is a common header. The header splits into two parallel headers each of which contain two of the pneumatic discharge isolation valves. The controllable vacuum breakers are located on the common header downstream of the pneumatic discharge isolation valves. See Figure 9-12. The actuation circuitry consists of four pressure measurement loops along with necessary components to cause the pneumatic discharge isolation valves to close and the controllable vacuum breakers to open on low LPSW supply header pressure. The circuitry resets and causes a) the pneumatic discharge isolation valves to reopen and b) the controllable vacuum breakers to reclose on increasing LPSW supply header pressure. The circuitry is designed to be single failure proof to open and close the valves. Failure of the pneumatic discharge isolation valves to reopen following system actuation will prevent flow through the Reactor Building Cooling Units as well as other containment loads such as the Reactor Building Auxiliary Coolers and the Reactor Coolant Pump coolers. Provisions to manually fail open the valves are provided. The failure of the controllable vacuum breakers to reclose is inconsequential (i.e., containment heat removal can be accomplished with the valves in the open position). Each pneumatic valve is provided with an air accumulator to provide a source of air to move the valve and maintain the desired end state for a short period of time. Only for the case of a Station Blackout (SBO) could the air in the accumulator be insufficient to maintain closure of the pneumatic discharge isolation valves for the duration of the SBO. In this case, reliance on the Supplemental Diesel Air Compressors is needed to provide air to make-up any leakage to maintain closure.

The system includes a “leakage accumulator” to allow a reasonable amount of boundary valve leakage while the piping inside containment is being maintained water solid. The leakage accumulator consists of a quantity of water with an air overpressure. The air overpressure will force water into the isolated portion of LPSW should the pressure decrease due to leakage in order to prevent voiding. The leakage accumulator is a passive device and is normally kept charged by LPSW. During an SBO, a HPSW connection to the accumulator provides extended make-up for leakage. During times when the WPS is out of service, piping code allowable stresses may be exceeded, but pipe rupture is not expected, if an event occurs that produces a waterhammer.

9.2.2.2.4 Recirculated Cooling Water System (RCW)

The RCW system for the Oconee station is shown schematically in Figure 9-13. This system provides inhibited closed cycle cooling water to various components outside the Reactor Building including:

1. RC pump seal return coolers
2. Spent fuel cooling
3. Sample coolers
4. Evaporator systems
5. Various pumps and coolers in the Turbine Building

The RCW system consists of two parallel loops which are normally isolated from each other. One loop supplies cooling for shared station loads, Unit 1 and 2 loads and secondary loads on Unit 3. It consists of four motor-driven pumps and four RCW heat exchangers. A 25,000 gallon surge tank provides a surge volume to accommodate temperature changes and leakage. Condenser circulating water is used to cool the RCW heat exchangers. The other loop supplies cooling for Unit 3 primary loads. It consists of two motor-driven pumps and two RCW heat exchangers. It contains a 7,700 gallon surge tank and also utilizes condenser circulating water to cool the RCW heat exchangers. RCW effluent from the Auxiliary Building is monitored for radioactivity. Leakage of radioactive fluids from any of the coolers in the Auxiliary Building will be indicated by these monitors. Separate monitors are provided on the return lines from the Oconee I and 2 Auxiliary Building and the Oconee 3 Auxiliary Building.

The number of RCW pumps and RCW heat exchangers in operation varies depending on the spent fuel heat load and lake water temperature. The isolation valves, which normally separate the two parallel loops, can be opened, however; it is not a necessary configuration.

The RCW provides no engineered safeguards functions and does not penetrate the Reactor Building.

9.2.2.2.5 Essential Siphon Vacuum and Siphon Seal Water Systems

The Essential Siphon Vacuum (ESV) and the Siphon Seal Water (SSW) systems are discussed together due to their inherit relatedness. Simplified schematic diagrams of the systems are shown in Figure 9-42 and Figure 9-43.

The ESV system consists of three (3) liquid ring vacuum pumps per unit. These pumps, one of which is an installed spare, are connected to two (2) tanks. These tanks are connected to the CCW Intake headers (one tank per header). A float valve is used to minimize CCW water passage into the ESV system. A minimum flow line for the ESV pumps is provided on the tanks to ensure that a minimum amount of air is passing through the ESV pumps. Without this minimum amount of air, the vacuum created in the ESV pumps will cause cavitation, which, over a long period of time, can cause pump degradation. Short periods of time (e.g., over a month) without minimum flow operation will not degrade the pumps.

During normal operations, an ESV pump and tank are aligned to a given CCW Intake header. Air accumulation in the CCW Intake Header is removed by the ESV system in order to maintain the CCW Intake Header primed during normal operations. During emergency operations, the ESV pump minimum flow line is isolated and the ESV pumps remove any air accumulation that occurs in the CCW Intake Header. This allows full ESV pump capacity to be directed toward the siphon until the event is mitigated.

The ESV pumps are controlled from the Control Room. Vacuum Tank pressure indication and pump operating status are located in the control room. Float valve heat trace current and valve temperature indications are also available in order to allow monitoring of float valve condition during sub-freezing weather. During emergency operations, the ESV pump restart is delayed for a short period of time in order to allow for other, more time-critical loads to load onto the emergency power system. A variety of non-nuclear safety-related data points associated with the ESV/SSW/ECCW systems are sent to the plant computer.

The SSW System consists of two headers that are supplied water from the Low Pressure Service Water (LPSW) system. Only one header is needed to supply all loads. However, both SSW headers are normally in service so that a single failure in the LPSW system cannot cause a loss of safety function. The SSW supply water routes from the Turbine Building to the ESV Building, where it is strained. Once strained, SSW routes to the ESV pumps and to the CCW pumps. SSW provides an operating liquid for the ESV pumps and provides sealing and cooling water the CCW pump shaft seal and motor bearing cooler. The nuclear safety-related function of the SSW System is to provide the operating liquid to the ESV pumps. The ESV pumps are liquid ring vacuum pumps which require a continuous supply of water in order to create a vacuum. As the header branches to the ESV pumps and then branches to each ESV pump individually, a solenoid valve is contained at each pump. This solenoid valve is interlocked with the ESV pump control circuitry. The valve opens when the pump starts and closes when it stops. A failure of one of these solenoids would cause a single ESV pump to be inoperable.

The SSW system function would not be affected, since it could successfully deliver water to the remaining ESV pumps.

The SSW system contains provisions for connection of a submersible pump to supply sealing/cooling water to the CCW pumps. Both the ESV and SSW systems are designated as QA Condition I systems. They are seismically designed and designed to continue functioning with a single, active failure. However, they are not designed for tornado loads. Interfacing structures existing prior to the installation of these systems are designated QA Condition 4. The ESV Building shell is also a QA Condition 4 structure.

9.2.3 Auxiliary Service Water System (Deleted Per 2014 Update - Refer to UFSAR Section 9.7, Protected Service Water System)

9.2.3.1 Deleted Per 2014 Update

9.2.3.2 Deleted Per 2014 Update

9.2.4 Ultimate Heat Sink

Lake Keowee supplies the Condenser Circulating Water (CCW) System and the lake water generally serves as the ultimate heat sink for Oconee Nuclear Station. In some events, such as loss of Lake Keowee, the water trapped in the CCW piping serves as the ultimate heat sink The CCW system is described in Section 9.2.2.2.1.

9.2.5 Control Room Ventilation Chilled Water System (WC)

The WC System is shown schematically on Figure 9-24.

9.2.5.1 Design Basis

The WC System provides chilled water for the Control Room Ventilation System for all three units. The major equipment of the chilled water system is arranged in two parallel redundant trains with one supply and return line and each train capable of supplying the required cooling capacity. A temporary cooling train and piping may be installed in parallel with the permanent chilled water system equipment. The temporary cooling train and piping will connect to the system supply and return piping and be capable of supplying the required cooling capacity. The bases to one of the Technical Specification 3.7.16 addresses the use a temporarily installed full capacity control area cooling train as one of the Tchnical Specification 3.7.16 required WC trains.

9.2.5.2 System Description and Evaluation

The WC permanently installed chillers are each made up of a compressor, an evaporator and a refrigerant condenser. The single stage compressor is driven by an open drip proof motor. Both the evaporator and condenser are horizontal shell and finned tube design with individually replaceable tubes. Two chillers are provided for this system, each with 100% capacity.

For the permanently installed WC cooling trains condenser water temperature is measured by a thermistor located upstream of the condenser. This sensor is used to generate a signal that modulates a three-way bypass valve located downstream of the condenser, to maintain proper condenser water temperature. (i.e. as the temperature increases, the bypass port on the three-way valve is modulated towards closed, to maintain proper entering condenser water temperature for operating the chiller.)

A temporary cooling train with piping connected to the WC system chilled water return and supply piping may be used, providing 100% cooling capacity.

Cooling of a specific area is controlled by a chilled water control valve located downstream of the corresponding AHU. Temperatures throughout the Control Room Area are monitored by individual room thermostats. On a rise in room temperature, the AHU controls will modulate open the corresponding chilled water valve. On a decrease in room temperature, the chilled water valve will be gradually closed.

9.2.5.3 Alternate Chilled Water System (AWC)

An Alternate Chilled Water System (AWC) is provided to supply, via manual alignment, ventilation cooling water to air handling units (AHUs) located in Control Area (Control Room, Cable Room, Equipment Room), Penetration Rooms, and portions of the Auxiliary Buildings. The purpose of AWC is to maintain the temperature environment in these plant areas acceptable for the operation of equipment necessary to respond to non-Design Basis Accidents (non-DBAs), specifically, when certain power disturbances, equipment failures or adverse interactions in the Turbine Building (fires, internal flooding, etc.) have rendered the normally functioning ventilation cooling water (Low Pressure Service Water (LPSW), Auxiliary Building Chilled Water (CW), and Control Room Ventilation Chilled Water (WC)) unavailable. Two (2) skid-mounted air-cooled chillers located at grade elevation at the southeast corner of the Turbine Building produce chilled water that is then routed through dedicated header piping to the air handling units (AHUs) of identified plant areas.

9.2.6 References

1. Safety Evaluation Report for Oconee Units 2 and 3, dated July 6, 1973.
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3. Letter from H. B. Tucker (Duke) to USNRC Document Control Desk, dated December 5, 1989, NRC Bulletin No. 88-04 Potential Safety-Related Pump Loss Action 4 Report Status Update.
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13. PIP 0-098-3629 Operability Evaluation
14. EC110081, Install Class F Spray Cooling Piping/Tubing in U1/2 Blockhouse and Electrical Temperature Control Circuitry in the CT-4 Blockhouse.
15. EC110082, Connect U1/2 Blockhouse Evap Cooling Piping to HPSW.

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9.3 Process Auxiliaries

9.3.1 Chemical Addition and Sampling System

9.3.1.1 Design Bases

Chemical addition and sampling operations are required to change and monitor the concentration of various chemicals in the Reactor Coolant System and Auxiliary Systems. The Chemical Addition and Sampling System is designed to add boric acid to the Reactor Coolant System for reactivity control, lithium hydroxide for pH control, and hydrazine and/or carbohydrazide for oxygen control. The Chemical Addition and Sampling System can also be used for hydrogen peroxide additions to induce 'crud' bursts during unit shutdowns to enhance corrosion product removal and, therefore, reduce equipment/system/component dose rates. Following a LOCA, a passive design system is used to modify the pH of the reactor coolant system.

9.3.1.2 System Description and Evaluation

The Mechanical Chemical Addition and Sampling System is shown schematically on Figure 9-15 and Figure 9-16. The Passive TSP Baskets are described below. The Sampling System has separate sampling stations for reactor coolant and steam generator sampling for each of the three units. Two auxiliary systems sampling stations are provided, one for Oconee I and 2 and one for Oconee 3.

Two chemical addition systems are also provided, one for Oconee I and 2 and one for Oconee 3. These systems permit chemical addition to and sampling of the Reactor Coolant System and other Reactor Auxiliary Systems during normal reactor operation.

The Chemical Addition and Sampling System performs no emergency functions (Refer to Section 9.3.6 for information on Post-Accident Sampling System). Guidelines for maintaining feedwater and reactor coolant quality are derived from vendor recommendations and the current revisions of the EPRI PWR Secondary and Primary Water Chemistry Guidelines, respectively. Detailed operating specifications for the chemistry of these systems are addressed in site specific or fleet documents. A brief functional description of the major system components follows.

Boric Acid Mix Tank

Two Boric Acid Mix Tanks, one shared between units 1 and 2, and one for unit 3, are provided as a source of concentrated boric acid solution. Tank heaters and electrically heat traced transfer lines maintain the fluid temperature above that required to assure solubility of the boric acid.

Boric Acid Pumps

Six boric acid pumps, three shared between units I and 2, and three for Unit 3, are provided to transfer the concentrated boric acid solution from the boric acid tank to the borated water storage tank, letdown storage tanks, spent fuel storage pool, or the core flood tanks. Two pumps, each with a I gal/min capacity, supply boric acid to the core flood tanks. The other four pumps, which each have 10 gal/min capacities, supply boric acid to other tanks, systems, and locations (Figure 9-15 and Figure 9-16).

Reactor Building TSP Baskets

Granulated Tri-Sodium Phosphate (TSP) is stored in screen-sided baskets at the lowest elevation of the Reactor Building. During events that flood the Reactor Building, the TSP dissolves and maintains the pH of the water in the Reactor Building Emergency Sump at a level that minimizes gaseous iodine production and H_2 production from zinc-boric acid reactions during Reactor Building Spray operation. This Post LOCA pH Adjustment System was installed to replace the Caustic Addition System.

Caustic Mix Tank

The caustic addition portion of the system is no longer used during emergency conditions. Previously the Caustic Addition System was used to add sodium hydroxide to the LPI system following a LOCA. The addition of the TSP baskets described above replaced this function. Previously, this system was used to control the pH in the RC bleed and miscellaneous waste evaporators and to regenerate the resins in the deborating demineralizers, but it is no longer used in this capacity. A single caustic mix tank is provided for Units 1 and 2, and one tank is provided for Unit 3. This system can be used to add chemicals (as needed) to the RCS and Auxiliary Systems.

Caustic Pump

The caustic pump provides the capability to transfer sodium hydroxide from caustic bulk storage containers or the caustic mix tank to the LPI system. It is no longer used for this purpose since installation of the Reactor building TSP Baskets. A single pump is provided for Units 1 and 2 and one is provided for Unit 3. These pumps can be used to add other chemicals (as needed) to the RCS and Auxiliary Systems.

Lithium Hydroxide Tank

Lithium hydroxide is mixed and added to the Reactor Coolant System for pH control from the lithium hydroxide tank. A single tank is provided for Units I and 2, and one tank is provided for Unit 3.

Lithium Hydroxide Pump

The lithium hydroxide pump transfers lithium hydroxide from the LiOH tank to the letdown line upstream of the letdown filters. A single pump is provided for Units I and 2, and one pump is provided for Unit 3.

Hydrazine Pump

The hydrazine pump transfers hydrazine to the letdown line upstream of the letdown filters. The hydrazine pump, after sufficient demineralized water flushes, is also used to transfer hydrogen peroxide. A single pump is provided for units 1&2, and one pump is provided for unit 3. These pumps can also be used as a backup to the Lithium Hydroxide pump or to add other chemicals (as needed) to the RCS.

Pressurizer Chemical Addition Pump

A Pressurizer Chemical Addition pump transfers an oxygen scavenger from a small container backwards through the pressurizer water space sample line to the pressurizer. Each unit has its own separate pump.

Pressurizer Sample Cooler

This cooler cools the effluent sample taken from the pressurizer steam or water space. One cooler is provided per unit.

Steam Generator Sample Cooler

This cooler cools the effluent sample taken from the secondary side of the steam generator. Two coolers are provided per unit.

9.3.1.2.1 Mode of Operation

The chemical addition portion of this system delivers the necessary chemicals to other systems as required. Boric acid is provided to the spent fuel pool, borated water storage tank, letdown storage tank, and core flooding tanks as makeup for leakage or to change the concentration of boric acid in the associated systems. Following a LOCA, tri-sodium phosphate (TSP) is mixed with the LPI system to maintain the pH of the water via use of screen-sided baskets that contain granulated TSP. The TSP dissolves during Reactor Building flooding. The sampling portion of this system is used to take samples to assure that water qualities and boric acid concentrations are maintained. Sampling locations and the samples taken at each location are as follows:

Liquids

Primary Sample Basin

Steam Generator Sample Sink

Secondary Side of Steam Generator

Reactor Coolant Sample Sink

Pressurizer Water Space

Pressurizer Steam Space

Low Pressurizer Injection Cooler Outlet

Core Flooding Tanks

Total Gas Sample

Reactor Coolant

Waste Disposal Sample Basin

Auxiliary Systems Sample Sink

Purification Demineralizer Inlet and Outlet

Deborating Demineralizer Outlet

Letdown Storage Tank Water Space

RC Bleed Evaporator Feed Pump Discharge (out of service)

Deborating Demineralizer Outlet (Regeneration)

Waste Evaporator Feed Pump Discharge (out of service)

RC Bleed Evaporator (Concentrate) (out of service)

Concentrated Boric Acid Storage Tank Pump Discharge

RC Bleed Evaporator (Distillate) (out of service)

Waste Evaporator (Concentrate) (out of service)

RC Bleed Transfer Pump Discharge

Waste Transfer Pump Discharge

High Activity Waste Transfer Pump Discharge

Low Activity Waste Transfer Pump Discharge

Condensate Test Tank Pump Discharge (out of service)

RC Bleed Evaporator Demineralizer Outlet (out of service)

Reactor Building Normal Sump

Waste Evaporator (distillate) (out of service)

Gaseous

Hydrogen Analyzer

Containment

Gas Analyzer (Unit 1 and 3) (out of serice)

Waste Holdup Tank

High Activity Waste Tank

RC Bleed Holdup Tanks

Waste Gas Vent Header

RC Bleed Evaporator (Unit 1 only)

Waste Evaporator (Unit 1 only)

Waste Gas Decay Tanks

H_2 Purge Station

Sample Containers (to be analyzed for a variety of substances)

Letdown Storage Tank Gas Space

Pressurizer Steam and Water Space

Gas Analyzer Sample (out of service)

9.3.1.2.2 Reliability Considerations

The Chemical Addition and Sampling System is not required to function during an emergency condition. Redundant boric acid pumps and flow paths are provided to guard against a single component failure rendering the system inadequate for boron addition. In addition to the boric acid mix tank, boric acid is also available for boration in 5-percent by weight solution from the concentrated boric acid storage tank. To prevent precipitation, heating/heat tracing is installed on components and lines used to transfer concentrated boric acid. The pumps, tanks, coolers, and instrumentation are located in the Auxiliary Building and are accessible for inspection and maintenance.

9.3.1.2.3 Codes and Standards

The components of the Chemical Addition and Sampling System are designed to the codes and standards noted in Table 9-5.

9.3.1.2.4 System Isolation

The pressurizer sample line, core flood sample line, and both steam generator sample lines are the only system lines that penetrate the Reactor Building. All these lines contain electric motor-operated isolation valves inside the Reactor Building and pneumatic valves outside, which are automatically closed by an engineered safeguards signal (except for the core flood sample line which has a manual isolation valve).

9.3.1.2.5 Leakage Considerations

Leakage of radioactive reactor coolant from this system within the Reactor Building will be collected in the Reactor Building normal sump. Leakage of radioactive gases from this system outside the Reactor Building is collected by placing the sampling stations under hoods exhausting to the unit vent.

9.3.1.2.6 Failure Considerations

Since the system serves no engineered safeguards function, the only consideration immediately following a loss-of-coolant accident is the operation of the isolation valves. Redundant isolation valves are provided to assure isolation of the Reactor Building as described in Section 9.3.1.2.4.

9.3.1.2.7 Deleted Per 2001 Update

9.3.2 High Pressure Injection System

9.3.2.1 Design Bases

The High Pressure Injection System is designed to accommodate the following function during normal reactor operation:

Supply the Reactor Coolant System with fill and operational makeup water.

Provide seal injection water for the reactor coolant pumps.

Provide for purification of the reactor coolant to remove corrosion and fission products.

Control the boric acid concentration in the reactor coolant.

In conjunction with the pressurizer, the system will accommodate temporary changes in reactor coolant volume due to small temperature changes.

Maintain the proper concentration of hydrogen and corrosion inhibiting chemicals in the Reactor Coolant System.

Provides continuous flow for cooling the normal HPI nozzles (see FSAR Section 5.4.7.2) to minimize thermal shock.

Provides auxiliary pressurizer spray control for cooldown when normal pressurizer spray is unavailable.

The specific design bases for various parts of the system are as follows:

Letdown Capability

The system will accommodate letdown required as a result of coolant volume expansion when heating the reactor coolant to operating temperature at a rate of 100°F/h while maintaining constant pressurizer level. The letdown is cooled before leaving the Reactor Building.

Purification

Filters and demineralizers are provided to remove reactor coolant impurities. The letdown filters and purification demineralizers are sized for full flow through the letdown orifice.

Makeup

The system will accommodate makeup requirements during design reactor coolant system transients and for Reactor Coolant System cooldown at the design rate.

9.3.2.2 System Description and Evaluation

The High Pressure Injection System is shown schematically on Figure 9-17 and Figure 9-18. Table 9-6 and Table 9-7 list the system Performance requirements and data for individual components. The following is a brief functional description of system components:

Letdown Cooler

The letdown cooler reduces the temperature of the letdown flow from the Reactor Coolant System to a temperature suitable for demineralization and injection to the reactor coolant pump seals. Heat in the letdown coolers is rejected to the Component Cooling System.

Letdown Flow Control

The letdown flow is controlled by using a flow path with a fixed block orifice as well as the use of parallel flow paths as needed. The flow path with the block orifice as well as one of the parallel paths each contain a remotely operated valve that can be opened to maintain the desired flow rate. A second parallel path contains a manual valve which may also be positioned for flow control.

Purification Demineralizer

The letdown flow is passed through the purification demineralizer to remove reactor coolant impurities other than boron. The design purification letdown flow is equal to one Reactor Coolant System volume in 24 hours. One demineralizer is provided for each unit. In addition, a spare demineralizer is shared between Oconee 1 and 2, and another spare is installed for Oconee 3. The spare demineralizer may be used to remove lithium from the reactor coolant system to maintain system chemistry and/or used to remove cesium from the reactor coolant system in the event of fuel defects. Chapter 11 describes coolant activities, coolant handling and storage, and expected limits on activity discharge.

Letdown Filters

Two letdown filters in parallel are provided to prevent particulates from entering the Reactor Coolant System and subsequently the pump seal filters. One filter is normally in use.

High Pressure Injection Pumps

The high pressure injection pumps are designed to return coolant which is letdown for purification to the Reactor Coolant System, and to supply the seal water to the reactor coolant pumps. The pumps are sized to permit one pump to provide normal operating makeup and seal water flow.

Reactor Coolant Pump Seal Injection Filters

Two reactor coolant pump seal filters are provided to prevent particulates from entering the pump seals. One is normally in use.

Seal Return filter

A single filter is installed in the seal return line upstream of the seal return coolers to remove particulate matter. A bypass is installed to permit servicing during operation.

Reactor Coolant Pump Seal Return Coolers

The seal return coolers are sized to remove the heat added by the high pressure injection pumps and the heat picked up in passage through the reactor coolant pump seals. Heat from these coolers is rejected to the Recirculated Cooling Water System. Two coolers are provided and one is normally in operation.

Letdown Storage Tank

The letdown storage tank serves as a receiver for letdown, seal return, chemical addition, and system makeup. The tank also accommodates temporary changes in system coolant volume.

9.3.2.2.1 Mode of Operation

During normal operation of the Reactor Coolant System, one high pressure injection pump continuously supplies high pressure water from the letdown storage tank to the seals of each of the reactor coolant pumps and to makeup line connections on two of the reactor inlet lines. Makeup flow to the Reactor Coolant System is regulated by a flow control valve, which operates on signals from the pressurizer level controller.

A control valve in the common injection line to the pump seals automatically maintains the desired total injection flow to the seals. Manual Throttle valves in each pump seal injection line provide a capability to balance the seal injection flow rates. A portion of the water supplied to the seals enters the Reactor Coolant System. The remainder returns to the letdown storage tank after passing through one of the two reactor coolant pump seal return coolers. A small amount which leaks through the final seal is also collected and routed to the quench tank.

Paragraph(s) Deleted Per 2000 Update.

Seal water inleakage to the Reactor Coolant system requires a continuous letdown of reactor coolant to maintain the desired pressurizer level. Letdown is also required for removal of impurities and boric acid from the reactor coolant. The letdown is cooled by one or both of the letdown coolers, reduced in pressure by the letdown orifice and parallel flow path's associated valves, and then passed through the purification demineralizer to a three-way valve which directs the coolant to the letdown storage tank or to the Coolant Storage System.

Normally, the three-way valve is positioned to direct the letdown flow to the letdown storage tank. If the boric acid concentration in the reactor coolant is to be reduced, the three-way valve is positioned to divert the letdown flow to the Coolant Storage System. Boric acid is removed by directing the letdown flow through a deborating demineralizer with the effluent returned directly to the letdown storage tank, or by the feed and bleed method. Feed and bleed is the process of directing the letdown flow to a coolant bleed holdup tank and maintaining the level in the letdown storage tank with demineralized water pumped from a supply of unborated water. The flow of demineralized water is measured and totaled by inline flow instrumentation. The flow of demineralized or borated water returning to the letdown storage tank is controlled remotely by the makeup control valve. During normal operation the inline instrumentation or the control rod drive interlock will terminate makeup flow.

The letdown storage tank also receives chemicals for addition to the reactor coolant. A hydrogen overpressure is maintained in the tank to assure a slight amount of excess hydrogen in the circulating reactor coolant. Other chemicals are injected in solution into the tank.

System control is accomplished remotely from the control room with the exception of the reactor coolant pump seal return cooling. The letdown flow rate is set by positioning valves in three parallel flowpaths as needed to pass the desired flow. The valves in two paths are able to be positioned remotely and the third valve is a manual valve that can also be positioned as needed. The spare purification demineralizer can be placed in service by remote positioning of the demineralizer isolation valves. The letdown flow to the Coolant Storage System is diverted by remote positioning of the three-way valve and the valves in the Coolant Storage System. The reactor coolant volume control valve is automatically controlled by the pressurizer level controller.

A continuous cooling flow is maintained through the HPI nozzle warming lines. Flow is monitored via the Operator Aid Computer with signals from a flow transmitter on each warming line.

Auxiliary pressurizer spray is remote manually controlled from the control room. No means exists for directly monitoring auxiliary pressurizer spray flow. Instead, pressurizer level is utilized for process monitoring of auxiliary pressurizer spray.

For emergency operation as a High Pressure Injection System, the normal letdown coolant flow line and the normal pump seal return line are closed, and additional makeup flow is supplied through the high pressure injection emergency lines. The pumps and pump motors are designed to be able to operate at the higher flow rates and lower discharge pressures associated with emergency high pressure injection requirements. Emergency operation of this system is described in Chapter 6.

9.3.2.2.2 Reliability Considerations

This system provides essential functions for the normal operation of the unit. Redundant components and alternate flow paths have been provided to improve system reliability.

Each unit has three high-pressure injection pumps, each capable of supplying the required reactor coolant pump seal and makeup flow. One is normally in operation while another is in standby status to be used as needed. The third pump is used only for emergency injection. There are two letdown coolers and two seal return coolers. One cooler in each group will perform the required duty although two coolers may be utilized as desired.

One of the two letdown filters or reactor coolant pump seal filters is normally in use while the other is a spare.

9.3.2.2.3 Codes and Standards

Each component of this system will be designed to the code or standard, as applicable, noted in Table 9-7.

9.3.2.2.4 System Isolation

The letdown line and reactor coolant pump seal return line are outflow lines which penetrate the Reactor Building. Both lines contain electric motor-operated isolation valves inside the Reactor Building and pneumatic valves outside which are automatically closed by an engineered safeguards signal. The injection lines to the reactor coolant pump seals are inflow lines penetrating the Reactor Building. These lines contain a check valve on the inside and on the outside of the Reactor Building. Check valves in the discharge of each high pressure injection pump provide further backup for Reactor Building isolation. The two emergency coolant injection lines are used for injecting coolant to the reactor vessel after a loss-of-coolant accident.

After use of the lines for emergency injection is discontinued the electric motor-operated isolation valves in each line outside the Reactor Building may be closed for isolation. The HPI nozzle warming line and auxiliary pressurizer spray line are inflow lines penetrating the Reactor Building. These lines each contain a check valve on the inside and on the outside for Reactor Building isolation.

9.3.2.2.5 Leakage Considerations

Design and installation of the components and piping in the High Pressure Injection System considers the radioactive service of this system. Except where flanged connections have been installed for ease of maintenance, the system is an all-welded system.

9.3.2.2.6 Failure Considerations

The effects of failure and malfunctions in the High Pressure Injection System concurrent with a loss-of-coolant accident are presented in Chapter 6. These analyses show that redundant safety features are provided where required.

For pipe failures in the High Pressure Injection System, the consequences depend upon the location of the rupture. If the rupture were to occur between the reactor coolant loop and the first isolation valve or check valve, it would lead to an uncontrolled loss-of-coolant from the Reactor Coolant System. The analysis of this loss-of-coolant Accident is included in Chapter 15. If the rupture were to occur beyond the first isolation valve or outside the Reactor Building, the release of radioactivity would be limited by the small line sizes and by closing of the isolation or check valve.

A single failure will not prevent boration when desired for reactivity control, since several alternate paths are available for adding boron to the Reactor Coolant System. These are: (a) through the normal makeup lines, (b) through the reactor coolant pump seals, and (c) through the emergency injection lines. If pump suction is unavailable from the letdown storage tank, a source of borated water is available from the borated water storage tank during normal operation.

9.3.2.2.7 Operational Limits

Alarms or interlocks are provided to limit variables or conditions of operation that could cause system upsets. The variables or conditions of operation that are limited are as follows:

Letdown Storage Tank Level

Low water level in the letdown storage tank is alarmed and interlocked to the three-way bleed valve. Low water level will switch the three way valve from the bleed position to the normal position.

Letdown Line Temperature

A high letdown temperature in the letdown line downstream of the letdown coolers is alarmed and interlocked to close the pneumatic letdown isolation valve, thus protecting the purification demineralizer resins.

Dilution Control

The dilution cycle is initiated by the operator. Several safeguards are incorporated into the design to prevent inadvertent excessive dilution of the reactor coolant.

The dilution valves have an automatic feature such that the operator may preset the desired quantity of dilution volume before initiating the dilution cycle. The dilution cycle will terminate when flow has integrated to the desired batch size. This interlock may be manually bypassed. Operation in the automatic mode is the preferred method of dilution.

Interlocks on the regulating control rod bank automatically terminate the dilution cycle regardless of the mode of operation the controller is in, automatic or manual, if the regulating rod group (Group 6) is inserted into the core beyond 25 percent.

The operator may manually terminate the dilution cycle at any time.

9.3.3 Low Pressure Injection System

9.3.3.1 Design Bases

The Low Pressure Injection System removes decay heat from the core and sensible heat from the Reactor Coolant System during the latter stages of cooldown. It provides the means for filling and draining the fuel transfer canal. The system maintains the reactor coolant temperature during refueling and reduced inventory operation. The LPI and support system(s), selected components of the RCS and HPI are dedicated to prevention and mitigation of loss of Decay Heat Removal events. (See Section 16.5.3 in the Selected Licensee Commitments Manual.)

In the event of a loss-of-coolant accident, the system injects borated water into the reactor vessel for longterm emergency cooling. The emergency functions of this system are described in Chapter 6. Performance data is listed in Table 9-8.

9.3.3.2 System Description and Evaluation

The Low Pressure Injection System is shown schematically in Figure 9-19. An independent system is provided for each unit. The Low Pressure Injection System normally takes suction from the reactor coolant outlet line and delivers the water back to the reactor through the core flooding nozzles after passing through the low pressure injection pumps and coolers. The Low Pressure Injection System may be lined up when the reactor pressure is below the system suction piping design pressure for cooldown of the system to refueling temperatures. The decay heat is transferred to the Low Pressure Service Water System by the decay heat removal coolers. Component data are shown in Table 9-9.

The major system components are described as follows:

Decay Heat Removal Pumps

Three decay heat removal pumps are arranged in parallel with electric motor operated valves in the suction line to each pump. Each pump has a separate minimum flow recirculation line with an orifice between pump discharge and pump suction. The bore of each orifice was increased to address considerations detailed in IEB 88-04, Safety Related Pump Loss. The two outboard pumps are normally available for emergency operation, and the center pump is valved off on both the suction and discharge sides of the pump. During decay heat removal, any two of the three pumps are lined up to the decay heat removal coolers.

The design flow is that required to cool the Reactor Coolant System from 250°F to 140°F in 14 hours. The steam generators are used to reduce the Reactor Coolant System from operating temperature to the 250°F temperature.

Decay Heat Removal Coolers

The decay heat removal coolers, during a routine shutdown, remove the decay heat from the circulated reactor coolant. Both coolers are designed to cool the circulated reactor coolant from 250°F to 140°F in 14 hours.

Borated Water Storage Tank

The borated water storage tank is located outside the Reactor Building and the Auxiliary Building. It contains borated water with boron concentration maintained in accordance with the Core Operating Limits Report. It is used for filling the fuel transfer canal during refueling and for filling the incore instrumentation handling tank. The borated water storage tank also provides borated water for emergency core cooling and the Reactor Building Spray System. Liquid level in the borated water storage tank is monitored by redundant level instrumentation.

9.3.3.2.1 Mode of Operation

Two pumps and two coolers normally perform the decay heat removal function for each unit. The steam generators reduce the reactor coolant temperature to approximately 250°F and pressure to approximately 300 psig. These conditions represent upper limits for starting an LPI pump so as to avoid exceeding system design limits. For Oconee Units 1 and 2, when these temperatures and pressures are reached, decay heat removal will be initiated by aligning the system in one of three possible configurations. The first path aligns A and C pumps to RCS through high pressure piping. With either the A or C pump operating, fluid is returned to the RCS through the "A" train of LPI. The second path aligns the B cooler to the RCS and the outlet of the cooler is routed to the suction of the A and C pumps. In this alignment, the pump in service will return fluid to the RCS through the "B" train of LPI. The third path aligns the B cooler to the RCS and the outlet of the cooler is routed to the suction of the A and C pumps. In this alignment, the pump in service will return fluid to the RCS through the “A” train of LPI (including the A cooler). After the RCS pressure has been reduced to approximately 125 psig, the system is aligned so that two pumps take suction from the reactor outlet line and discharge through two coolers.

For Oconee 3 decay heat cooling is initiated at 290 psig/250°F by aligning pumps to take suction from the reactor outlet line and discharge through the coolers into the reactor vessel. The equipment utilized for decay heat cooling is also used for low pressure injection during accident conditions.

During refueling, the decay heat from the reactor core is rejected to the low pressure injection coolers in the same manner as it is during cooldown to 140°F. At the beginning of the refueling period, both coolers and both pumps are required to maintain 140°F in the core and fuel transfer canal. Later, as core decay heat decreases, one cooler and pump can maintain the required 140°F.

The fuel transfer canal may be filled by switching the suction of the decay heat removal pumps from the reactor outlet to the borated water storage tank. When the transfer canal is filled, suction to the pumps is switched back to the reactor outlet pipe. (Normally filled with the spent fuel cooling pumps as described in Section 9.1.3.)

After refueling, the transfer canal is drained by switching the discharge of one of the pumps from the reactor injection nozzle to the borated water storage tank. The other pump will continue the recirculation mode of decay heat removal.

9.3.3.2.2 Reliability Considerations

Since the equipment is designed to perform both normal and emergency functions, separate and redundant flow paths and equipment are provided to prevent a single component failure from reducing the system performance below a safe level. All rotating equipment and most valves are located in the Auxiliary Building to facilitate maintenance and periodic operational testing and inspection. See also Section 6.3.4.3 for additional considerations related to DHR system operability.

9.3.3.2.3 Codes and Standards

Each component of this system will be designed to the code or standard, as applicable, as noted in Table 9-9.

9.3.3.2.4 System Isolation

The Low Pressure Injection System is connected to the reactor outlet line on the suction side and to the reactor vessel on the discharge side. The system is isolated from the Reactor Building on the suction side by two electric motor-operated valves located inside the Reactor Building and one electric motor-operated valve located outside the Reactor Building. The discharge side is isolated from the Reactor Building by a check valve inside and an electric motor-operated valve outside the Reactor Building. All of these valves are normally closed whenever the reactor is in the operating condition. In the event of a loss-of-coolant accident, the valve on the discharge side opens, but the valves between the reactor vessel and the suction side of the pumps remain closed throughout the accident.

9.3.3.2.5 Leakage Considerations

During reactor power operation, all equipment of the Low Pressure Injection System is idle, and all isolation valves are closed. Under loss-of-coolant accident conditions, fission products may be recirculated in the coolant through the exterior piping system. Potential leaks have been evaluated to obtain the total radiation dose to the public due to leakage from this system. The evaluation is discussed in Chapter 12.

9.3.3.2.6 Operational Limits

Alarms or interlocks are provided to limit variables or conditions of operation that might affect system or station safety. These variables or conditions of operation are as follows:

Decay Heat Removal Flow Rate

Low flow from the pumps during the decay heat removal mode of operation is alarmed to signify a reduction or stoppage of flow and cooling to the core.

Reactor Coolant Pressure Interlock

The first valve from the Reactor Coolant System in the suction line to the low pressure injection pumps is interlocked with the Reactor Coolant System pressure instrumentation to prevent inadvertent overpressurization of the Low Pressure Injection System piping while the Reactor Coolant System is still above Low Pressure Injection System design pressure.

Reactor Coolant Leaving Decay Heat Removal Coolers

High temperature of the reactor coolant discharging from the decay heat removal coolers is alarmed to signal a loss of cooling capability in the respective cooler.

9.3.3.2.7 Failure Considerations

The effects of failure and malfunctions in the Low Pressure Injection System concurrent with a loss-of-coolant accident are presented in Section 6.3.3.4. Redundant safety features are provided where required.

For pipe failures in the Low Pressure Injection System, the consequences depend upon the location of the rupture. If the rupture were to occur between the first check valve upstream of the core flood nozzle and the vessel, this would lead to a loss-of-coolant accident. The analysis of this loss-of-coolant accident is included in Chapter 15. Section 15.14.4.3 addressed this failure as one of the limiting small break. Reference ECCS Analysis of B&W 177 FA LOWERED-LOOP NSS Rev. 3 (BAW-10103A, Rev. 3 Topical Report July 1977).

9.3.4 Coolant Storage System

9.3.4.1 Design Bases

The Coolant Storage System for each unit is designed to accommodate the accumulated coolant bleed over a core cycle, including startup expansion and coolant letdown to storage for boric acid reduction.

Two coolant bleed holdup tanks, each with a capacity of 11,000 ft^3, are provided for each unit. One tank provides storage for the reactor coolant bleed prior to treatment by the Radwaste Facility or makeup to the Reactor Coolant System. The other tank provides additional storage and is used to store clean water for use as feed to the Reactor Coolant System. An additional tank is provided for storage of the concentrated boric acid from the boric acid mix tank. The RC Bleed Evaporator and associated equipment is not used for coolant processing. Coolant processing is performed by the Radwaste Facility.

The storage of reactor coolant bleed requires approximately 55 percent of the volume of the bleed holdup tanks for each unit. The tanks for all three units are arranged so that they can be utilized to store liquid from the other units if so desired.

The design volume of coolant removed from one unit during heatup and dilution from MODE 5 is approximately 9600 ft^3. This occurs near the end of the core cycle when boric acid concentrations are reduced. Earlier in core life, coolant is removed in smaller quantities to reduce boric acid concentrations.

An additional requirement for coolant storage is the partial drain which occurs during refueling. The coolant is removed in a batch of approximately 6100 ft^3. per unit and returned to the Reactor Coolant System upon completion of refueling. Thus, it occupies storage capacity only during the period of refueling. The required storage volume for refueling operations of 6100 ft^3. is less than 10 percent of the total available capacity.

A quench tank, located inside the Reactor Building, condenses and contains any effluent from the pressurizer safety valves. The quench tank is sized to condense one normal pressurizer steam volume without relieving to the Reactor Building atmosphere. A quench tank drain pump is provided for pumping the quench tank contents into the letdown storage tank. The reactor coolant which has leaked into the quench tank can be pumped directly back into the coolant system to avoid routing this leakage through the waste disposal system.

9.3.4.2 System Description and Evaluation

The Coolant Storage System is used for the collection and storage of reactor coolant liquid. The liquid is received from the High Pressure Injection System both as a result of reactor coolant expansion during startup and for boric acid concentration reduction during startup and normal operation. It is either conveyed to coolant bleed holdup tanks for storage or passed through deborating demineralizers for boric acid removal and returned as unborated makeup to the High Pressure Injection System. A spray nozzle in the coolant bleed tanks on the inlet line allow some of the gases to be released. Recirculating the tank allows further stripping action to occur. Liquid from the coolant bleed holdup tanks can be pumped to the Radwaste Facility for processing. This is schematically shown in Figure 9-21 and Figure 9-18. Component data is shown in Table 9-10.

The quench tank, located inside the Reactor Building, condenses and contains effluent from the pressurizer safety valves and various vents. The quench tank can also serve as a reservoir for the discharge of the Standby Shutdown Facility (SSF) Letdown Line. Liquid in the quench tank can be circulated through a cooler for temperature control, sampled and the excess liquid pumped to the Letdown Storage Tank, coolant bleed holdup tanks or the Liquid Waste Disposal System. This portion of the Coolant Storage System is shown schematically on Figure 9-20.

The deborating demineralizers may also be loaded with mixed bed resin and used as purification demineralizers to support normal purification and boron/lithium coordination programs.

The coolant bleed holdup tanks and the concentrated boric acid storage tanks are vented to the gaseous waste vent header to provide for filling and emptying without overpressurization or causing a vacuum to exist. In addition, each tank is equipped with a relief valve and a vacuum breaker. Pressurized nitrogen can be supplied to each tank to allow purging.

Instruments and controls for operation of this system are located in the control rooms. Instruments and controls for the coolant bleed holdup tanks and pumps and for the concentrated boric acid storage tanks and pumps are duplicated on the auxiliary control boards.

9.3.5 Coolant Treatment System

The Coolant Treatment System was originally designed and installed to both store reactor coolant bleed and to treat RC bleed for recycling. Since the boron recycling portion of the original Coolant Treatment System never functioned properly, the coolant storage portion is the only part of the system still in use at Oconee. The Coolant Storage System is described in Section 9.3.4. Radwaste processing is described in Section 11.6.3.

9.3.6 Post-Accident Sampling System

9.3.6.1 Post-Accident Liquid Sampling System

9.3.6.1.1 Design Bases

The system is no longer required to be used to obtain and analyze a liquid Reactor Coolant System sample under accident conditions. The system may be used for sampling to determine boron concentration during certain plant conditions, but is not required to be used. Even though the system is no longer required to be used, Figure 9-22 schematically illustrates the system. (Reference 32, 33)

9.3.6.1.2 Deleted Per 2013 Update

Deleted paragraph(s) per 2005 update.

9.3.6.1.3 Deleted Per 2005 Update

9.3.6.2 Post-Accident Containment Air Sampling System

9.3.6.2.1 Design Bases

The system is no longer used to obtain and analyze a containment air sample under accident conditions. Even though the system is no longer used, Figure 9-23 schematically illustrates the system.

9.3.6.2.2 Deleted Per 2005 Update

9.3.6.2.3 Deleted Per 2005 Update

9.3.7 Containment Hydrogen Monitoring System

9.3.7.1 Design Bases

The containment Hydrogen Monitoring System provides continuous indication of hydrogen concentration in the containment atmosphere. The measurement capability is provided over the range of 0% to 10% hydrogen concentration under both positive and negative ambient pressures. A continuous indication of the hydrogen concentration is not required in the control room at all times during normal operation. If continuous indication of the hydrogen concentration is not available at all times, continuous indication and recording shall be functioning within 90 minutes of the initiation of the safety injection.

9.3.7.2 System Description

The Containment Hydrogen Monitor System withdraws a sample from the containment under normal, LOCA or Post LOCA conditions. The sample is analysed and returned to the containment. The monitoring system is designed to monitor containment gas for percentage volume of hydrogen.

A system of sample taking tubing is installed in the containment to draw air samples from 5 different levels or areas. Each of the sample intake lines has a solenoid valve which is remotely operated from a control panel in the ventilation room. At the control panel a selector solenoid valve is used to provide air flow to the Hydrogen Analyser from the selected intake port. The Hydrogen Analyser panels and associated remote control panels are located in the ventilation room. Remote alarm and indication is provided in the control room. There are two trains of equipment for each unit.

Ten Hydrogen Analyzer intake ports are installed, (two each) in the following locations:

The top of the Containment Building Dome, Elevation 983' ± 5"

The operational level as close to the vessel as practical, Elevation 844 + 0' ± 10'

The basement area, Elevation 788' + 0" ± 10'

The radiation monitor/hydrogen recombiner inlet header, Elevation 827' + 4"

The radiation monitor/hydrogen recombiner outlet header, Elevation 824' + 0"

Hydrogen Measurement

Analysis is accomplished by using the well established principle of thermal conductivity measurements of gases. This technique utilizes a self-heating filament fixed in the center of a temperature-controlled metal cavity. The filament temperature is determined by the amount of heat conducted by the presence of gas from the filament of the cavity walls. Thermal conductivity varies with gas species, thereby causing the filament temperature to change as the gas in the cavity changes. Filament resistance changes with temperature therefore, by using two filaments in separate cavities and connecting them in an electrical bridge, the difference in thermal conductivity of gases in the separate cavities may be determined electrically.

Electrical zero is set by first introducing the same gas to both cavities, then adjusting the electrical bridge to balance, resulting in a zero output. As different gases are introduced to the two individual cavities, the bridge will become unbalanced, and the electrical output will amplify with increasing differences in thermal conductivity of the gases used.

The measurement of hydrogen in the presence of nitrogen, oxygen and water vapor is possible because the thermal conductivity of hydrogen is approximately seven times higher than nitrogen, oxygen or water vapor, which have nearly the same thermal conductivities (at the filament operational temperature of approximately 550°K). The measurement is accomplished by using a thermal conductivity measurement cell and a catalytic reactor. The sample first flows through the reference section of the cell, then passes through the sample section of the measuring cell that includes the catalyst. The catalyst is chosen so that post-LOCA iodine will not poison the catalyst bed. The change in sample composition, due to the catalytic reaction is therefore indicated by the difference in thermal conductivity of the sample hydrogen content, as measured in the sample and reference sides of the cell.

If an excess amount of oxygen does not exist in the sample for recombining all the hydrogen, oxygen can be provided ahead of the hydrogen analyzer. The amount of oxygen added is determined by the highest range of the analyzer.

Alarms

Alarms are provided for high hydrogen concentration, cell failure and loss of power. These alarms are available on the analyzer itself and as signals to the control room annunciator. Additional alarms on the analyzer itself include low instrument temperature, low sample flow, low gas pressure and common failure.

9.3.7.3 Safety Evaluation

The Containment Hydrogen Monitor System (CHMS) meets the requirements of NUREG-0737, Item II.F.1.6. The CHMS has both indicator and recorder readouts in the control room on one of the two redundant channels and a indicator readout on the second channel. The CHMS has a range of 0% to 10% of Hydrogen. The CHMS indicator loop has a system accuracy of 3.0% of the full scale. The CHMS hardwired recorder loop and all the CHMS plant process computer loops have a system accuracy of 2.6% of the full scale. These values will provide information over the intended range of the CHMS that is sufficiently accurate and useful to allow the plant operator to adequately assess the hydrogen concentration within containment. There are five ports to draw samples for each of the redundant hydrogen monitors. The system provides capability to rapidly detect Hydrogen from the reactor and determine its concentration throughout the containment.

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9.4 Air Conditioning, Heating, Cooling and Ventilation Systems

9.4.1 Control Room Ventilation

9.4.1.1 Design Bases

The Control Room Ventilation and Air Conditioning Systems are designed to maintain the environment in the control area within acceptable limits for equipment and personnel. The control area is comprised of the Control Room, Cable Room and Electrical Equipment Rooms as indicated on Figure 9-24. Redundant air conditioning and ventilation equipment is provided, as summarized below.

1. Two 100 percent capacity supply fans with filter banks and chilled water coils for cooling the control rooms and the Unit 3 cable & electrical equipment rooms.
2. Two 100 percent capacity chillers.
3. Two 100 percent capactiy chilled water pumps.
4. Two 100 percent capacity chiller condenser service water pumps.
5. Two 100 percent capacity outside air booster fans. (see Note below)
6. Four supply fans with filter banks and chilled water coils serving the Units 1&2 cable & electrical equipment rooms.
7. Four motorized control dampers in the cable shafts between the Units 1 and 2 Cable and Electrical Equipment Rooms.

NOTE: The two outside air booster fans were originally designed to combine to positively pressurizer their respective control room (i.e., two 50 percent capacity fans per control room). It was thought that verifying ability to positively pressurize the Control Rooms was enough to confirm there was no unfiltered infiltration. The industry recognized that measuring pressure in the Control Rooms was not an adequate test method to ensure operators were protected following an accident (Generic Letter 2003-01). Thus, new requirements were proposed to perform tracer gas testing, which provides a means to measure and quantify infiltration. After a resealing effort on the Control Room boundaries and adoption of the alternate source term, dose calculations were revised to credit only one fan. Oconee has demonstrated with various tracer gas tests that each booster fan independently has enough capacity to maintain unfiltered infiltration to the Control Room below the limits established by the dose calculations.

To ensure that no single failure of an active component within these systems will prevent proper control area environmental control, manual action may be required to realign systems, restart load shed equipment, or return the systems to service for other reasons.

Acceptable limits for equipment in the cable rooms and for the electrical equipment rooms is 120°F and 100°F for the Control Room.

Design conditions for the Control Room are 74°F and 50 percent maximum relative humidity. The Equipment Room is designed for 86°F and all other areas, i.e., the Control Room Zone and Cable Room are designed for 74°F. Outdoor design conditions are 95°F dry bulb and 76°F wet bulb. The ventilation and air conditioning systems are designed for continuous operation.

The radiation monitor, RIA-39, has a continuous sample of control room air pumped through the detector. High radiation level and loss of sample flow are annunciated separately. If high radiation level is detected, the operator starts the outside air filter trains if not already started by

Emergency Procedures or Abnormal Procedures. Emergency Procedures and Abnormal Procedures direct operators to start the outside air filter trains regardless of radiation levels inside the Control Rooms. If loss of sample flow occurs, backup sampling or other alternate operator actions are performed, as required, until RIA-39 is restored. The outside air filter trains act to filter particulate matter from the outside air to minimize uncontrolled infiltration into the Control Room.

Control area temperatures related to Station Blackout are addressed by Selected Licensee Commitment 16.8.1. The pressurization and filtration of the control room envelope is discussed further in Section 6.4.

In the event of unavailability of Control Room Ventilation Chilled Water (WC) during non-Design Basis Accident (non-DBA) conditions, Alternate Chilled Water (AWC) described in Section 9.2.5.3 can be manually aligned to supply alternate ventilation cooling water to control area air handling units (AHUs) and activate supplemental AHUs in order to maintain ambient temperatures acceptable to operate control area-located equipment whose function is necessary during non-DBA scenarios. Alternate power sources are also provided to ensure that control room area AHUs can operate during non-DBA scenarios.

9.4.1.2 System Description

9.4.1.2.1 Control Room Oconee 1 and 2

The Control Room for Oconee 1 and 2 is shared for the operation of both units. The Control Room is primarily served by two large air handling units. The units are 100 percent capacity and only one unit is required to operate at a time. Cooling is provided to the Unit 1 Cable Room, Unit 2 Cable Room, Unit 1 Equipment Room, and Unit 2 Equipment Room by a total of four air handling units. An automated damper control system will operate to maintain acceptable temperatures in the cable and electrical equipment rooms if one of the cable rooms AHUs is out of service.

All of the air handling units described above consist of roughing filters, chilled water cooling coils, and centrifugal fans. Chilled water is supplied to the units from the plant WC chilled water system. Electric duct heaters are installed in the ductwork to provide heat to the different areas when necessary.

Outside air is supplied to the Control Room for pressurization purposes, from dual intakes on the Turbine Building roof. Air passes through filter trains which consist of pre-filters, 99.5 percent efficient HEPA filters, 97.5 percent efficient charcoal filter beds, and a centrifugal fan. There are two filter trains and the system is capable of operating with one train or both trains. Each train has 100 percent capacity to maintain unfiltered infiltration to its respective control room within acceptable limits. During normal plant operations, the filter trains are not energized and require operator action to start. The outside air is supplied to the return air intake of the large air handling units which serve the Control Room. A radiation monitor is provided in the return air intake of the air handling units to alert the operators in the Control Room on a high radiation reading at which time the operators start the outside air filter trains if not already started by Emergency Procedures or Abnormal Procedures. The filter trains are designed for a flow of 1350 +/- 135 cfm each. The pressurization system was not designed or licensed to maintain a positive pressure in the Control Room assuming a single failure.

A chlorine monitor is provided in the Outside Air Intake Duct to each Control Room Outside Air Booster fan. Detection of high chlorine by either monitor will actuate an alarm in the Control Room, de-energize the Booster Fans, and close the Control Room Ventilation Dampers.

Cooling is provided to the Cable Rooms and Electrical Equipment Rooms by four air handling units located in the vicinity of the rooms.

Table 9-11 is a list of the air handling units and operation requirement for the Control Room and Control Room Zone air conditioning system. Figure 9-24 is a schematic description of the ventilation and air conditioning systems for the Control Room and Control Room Zone.

9.4.1.2.2 Control Room Oconee 3

The Oconee 3 Control area is comprised of the Control Room, the Cable Room, and the Electrical Equipment Room. These areas are served by six air handling units. Two 100 percent air handling units serve the Control Room, two 100 percent air handling units serve the Cable Room, and two 100 percent air handling units serve the Electrical Equipment Room. The air handling units consist of roughing filters, chilled water cooling coils, and centrifugal fans. Chilled water is supplied to the air handling units by the Plant WC Chilled Water System.

Outside air is supplied to the Control Room for pressurization purposes, from dual intakes on the Turbine Building roof. Air passes through filter trains which consist of pre-filters, 99.5 percent efficient HEPA filters, 97.5 percent efficient charcoal filter beds, and a centrifugal fan. There are two filter trains and the system is capable of operating with one train or both trains. Each train has 100 percent capacity to maintain unfiltered infiltration to its respective control room within acceptable limits. During normal plant operations, the filter trains are not energized and require operator action to start. The outside air is supplied to the return air intake of the large air handling units which serve the Control Room. A radiation monitor is provided in the return air intake of the air handling units to alert the operators in the Control Room on a high radiation reading at which time the operators start the outside air filter trains if not already started by Emergency Procedures or Abnormal Procedures. The filter trains are designed for a flow of 1350 +/- 135 cfm each. The pressurization system was not designed or licensed to maintain a positive pressure in the Control Room assuming a single failure.

A chlorine monitor is provided in the Outside Air Intake Duct to each Control Room Outside Air Booster Fan. Detection of high chlorine by either monitor will actuate an alarm in the Control Room, de-energize the Booster Fans, and close the Control Room Ventilation Dampers.

A radiation monitor is provided to sample the return air entering the Control Room and Control Room Zone air handling units. The monitor alarms on a high radiation signal and alerts the operators to energize the outside air filter system if not already started by Emergency Procedures or Abnormal Procedures to minimize the infiltration of unfiltered air into the Control Room.

Table 9-11 lists the air handling unit and operation requirements. Figure 9-24 is a schematic representation of the air conditioning system.

9.4.1.3 Safety Evaluation

The Control Room is served by redundant air handling units. The chilled water for the air handling units is supplied from the Plant WC Chilled Water System which is capable of supplying sufficient chilled water for all necessary systems with one of two chillers in service or a temporarily cooling train.

Return air from the Control Room is continuously monitored by a radiation monitor before recirculating back to the Control Room. A high radiation level will alert the operators to energize the outside air filter trains if not already started by Emergency Procedures or Abnormal Procedures. The filter trains are 100 percent, each train consisting of a prefilter, HEPA filter, 97.5 percent efficient charcoal filter bed and centrifugal fan. The filters act to filter particulate matter from the outside air supplied to minimize uncontrolled infiltration into the Control Room.

9.4.1.4 Inspection and Testing Requirements

The Control Room Ventilation System is in continuous operation and is accessible for periodic inspection. The Control Room pressurization portion of the system is tested periodically to demonstrate its readiness and operability as required by the Technical Specifications. Temperatures in the Control Rooms, Cable Rooms, and the Electrical Equipment Rooms are periodically monitored, as required by SLC's to ensure proper system operation.

9.4.2 Spent Fuel Pool Area Ventilation System

9.4.2.1 Design Bases

The Spent Fuel Pool Area Ventilation System is designed to maintain a suitable environment for the operation, maintenance and testing of equipment and also for personnel access. The ventilation system is designed to maintain the Spent Fuel Pool Area at a maximum inside temperature of 113°F and a minimum temperature of 60°F.

The path of ventilating air in the Spent Fuel Pool Area is from areas of low activity toward areas of progressively higher activity for discharge to the unit vent.

An air handling unit consisting of roughing filters, steam heating coil, cooling coil supplied by low pressure service water, and a centrifugal fan supply 100 percent outside air to the Spent Fuel Pool Area. During periods of increased work in Spent Fuel Pool areas, Air Handling Units normal LPSW supply may be replaced temporarily by chilled water by station procedures to increase capacity and protect workers from heat stress. Two methods of exhausting air from the Fuel Pool Area are provided, a filtered exhaust system and an unfiltered exhaust system. Normal operation is with the unfiltered system in operation. In the filter mode, the Fuel Pool Area ventilation air passes through a filter train consisting of prefilters, high efficiency particulate (HEPA) filters, charcoal filter and two 100 percent vane axial fans. The filtered exhaust system is operable whenever fuel handling operations involving recently irradiated fuel assemblies in the fuel pool are in progress.

The Spent Fuel Pool Area air is continuously monitored by radiation monitor, RIA-41.

9.4.2.2 System Description

Ventilation air for the Spent Fuel Pool Area is supplied by an air handling unit which consists of roughing filters, steam heating coil, cooling coil supplied by low pressure service water, and a centrifugal fan. Temperature is maintained in the Spent Fuel Pool Area by throttling steam to the heating coil or low pressure service water to the cooling coil. During periods of increased work in Spent Fuel Pool areas, Air Handling Units normal LPSW supply may be replaced temporarily by chilled water by station procedures to increase capacity and protect workers from heat stress.

In the normal mode of operation, the air from the Spent Fuel Pool Area is exhausted directly to the unit vents by the general Auxiliary Building exhaust fans. When fuel handling operations involving recently irradiated fuel assemblies are in progress, the filtered exhaust system must be operable so in the event of an emergency the air leaving the Fuel Pool Area can be filtered.

The filtered exhaust system consists of a single filter train and two 100 percent capacity vane axial fans. The filter train utilized is the Reactor Building Purge Filter Train. The filter train is comprised of prefilters, HEPA filters, and charcoal filters. An attempt to start the main Reactor Building purge fan will stop the Spent Fuel Pool filtered ventilation.

To control the direction of air flow, i.e., to direct the air from the Fuel Pool Area to the Reactor Building Purge Filter Train, a series of pneumatic motor operated dampers are provided along with a crossover duct from the Fuel Pool to the filter train.

Figure 9-25 and Figure 9-26 are detailed diagramatics of the Spent Fuel Pool Area Ventilation System. The flow paths as well as air quantities are given in the diagram. With the adoption of the alternate source term and installation of various modifications, the Spent Fuel Pool Ventilation System is not credited in dose analysis calculations.

9.4.2.3 Safety Evaluation

Deleted paragraph per Rev. 29 update.

There are two 100 percent capacity vane axial fans which direct the Spent Fuel Pool air through the Reactor Building Purge Filter Train prior to being released to the unit vent. Only one fan is required for operation. The fans are manually energized by the operators should it become necessary to filter the exhaust air from the Fuel Pool Area. The automatic control sequence is such that the damper alignment, to redirect air flow through the Reactor Building Purge Filters, is automatically done when one of the fans is energized.

An alarm is provided when the fuel pool filtered flow drops below 70 percent of design flow.

A radiation monitor is provided to continuously monitor the fuel pool air and will alarm on a high radiation level.

The analysis of the limiting fuel handling accident, the cask drop accident, assumes that a certain number of fuel assemblies are damaged. The DBA analysis for the cask drop accident does not assume operation of the SFPVS in order to meet requirements of 10CFR50.67. The assumptions and analysis are consistent with guidance provided in Regulatory Guide 1.183.

9.4.2.4 Inspection and Test Requirements

The normal mode of the Spent Fuel Pool Area Ventilation System is in continuous operation and is accessible for periodic inspection. The filtering mode of the Spent Fuel Pool Area Ventilation system is tested prior to movement of recently irradiated fuel assemblies to demonstrate its readiness and operability as required by the Technical Specifications.

9.4.3 Auxiliary Building Ventilation System

9.4.3.1 Design Bases

The Auxiliary Building Ventilation System is designed to provide a suitable environment for the operation, maintenance and testing of equipment and also for personnel access.

The Auxiliary Building Ventilation System serves all areas of the Auxiliary Building with the exception of the Control Room Area and the Penetration Rooms. The ventilation system indoor design conditions are 104°F and 60°F during summer and winter respectively. During normal operation, the system maintains temperatures within limits for equipment operation.

Ventilation air is supplied to both clean and potentially contaminated areas within the Auxiliary Building. The flow path of the ventilation air in the Auxiliary Building is from clean or low activity areas towards areas of progressively higher activity.

All potentially contaminated air from the Auxiliary Building is directed to the unit vent stacks at which point it is exhausted and continuously monitored by a radiation monitor which alarms on high radiation levels. In addition, a radiation monitor samples air throughout the Auxiliary Building Ventilation System. The detector output is logged on a recorder in the Control Room. All air from the Hot Machine Shop is exhausted to the atmosphere after being measured by an air flow monitor. Periodically, radiation levels are checked in the air flow using an air flow totalizer and particulate sampler.

The exhaust fans and supply fans are manually balanced such that the exhaust flow exceeds the supply air flow to minimize outleakage.

9.4.3.2 System Description

The Auxiliary Building Ventilation System is comprised of the Auxiliary Building Ventilation System proper and the Hot Machine Shop as shown in Figure 9-27 and Figure 9-28. Air is supplied to the Auxiliary Building by a low pressure fan duct system. Air is taken in through outside air intake louvers by supply units consisting of roughing filters, steam coil, and cooling coil supplied by low pressure service water. There are six main supply fans, each required for normal plant operation. Auxiliary Building air is exhausted from the building, via exhaust duct and exhaust fans, through three unit vent stacks.

The Hot Machine Shop air is supplied by two recirculating local cooling units. Each unit consists of roughing filters, a compressor, evaporator and condenser coils, and centrifugal fan. These units supply recirculated air with a small amount of make-up air throughout the Hot Machine Shop via a low pressure duct system. Air is exhausted from the Hot Machine Shop via exhaust duct and filter train and is discharged to the atmosphere through an independent vent stack.

Table 9-11 is a list of the primary equipment which comprises the Auxiliary Building Ventilation System and the Hot Machine Shop Ventilation System. The list includes number of installed components and normal operation requirements.

Temperatures are maintained in the Auxiliary Building by throttling steam to the steam coils or low pressure service water to the cooling coils as required. Temperatures are maintained in the Hot Machine Shop by electric unit heaters in the supply ductwork. The Hot Machine Shop uses direct expansion (DX) cooling.

Remote recirculating fan-coil type units provide standby spot cooling in the pump rooms and other high heat load areas. The fan coil units are also served by the Low Pressure Service Water System (LPSW). In the event of LPSW unavailable or other reasons during non-Design Basis Accident (non-DBA) conditions, certain air handling units (AHUs) which ventilate Auxiliary Building areas containing equipment that is required to remain functional during non-DBA scenarios can also be supplied with ventilation cooling water by manual alignment to the AWC System chilled water that is described in Section 9.2.5.3. Alternate power sources are also provided to these AHUs to ensure that they can operate during non-DBA scenarios.

9.4.3.3 Safety Evaluation

Under normal operating conditions, the Auxiliary Building Ventilation System supply fans and exhaust fans are balanced such that the exhaust air flow exceeds the supply air flow in order to minimize outleakage.

All exhaust air from potentially contaminated areas of the Auxiliary Building is directed to the unit vents where it is monitored prior to being released to the atmosphere. All exhaust air from the Hot Machine Shop is monitored prior to being released to the atmosphere through an independent vent stack.

HPI and LPI/RBS pump room temperatures are maintained within pump temperature limits by natural convection if the Auxiliary Building Ventilation System is unavailable. The natural convection flow path is for air to enter the pump rooms through duct openings and escape through stairwell and piping openings.

9.4.3.4 Inspection and Testing Requirements

The Auxiliary Building Ventilation System and the Hot Machine Shop Ventilation System are in continuous operation and are readily accessible for periodic inspection and maintenance.

9.4.4 Turbine Building Ventilation System

9.4.4.1 Design Bases

The Turbine Building Ventilation System is designed to provide a suitable environment for the operation of equipment and personnel access as required for inspection, testing and maintenance.

9.4.4.2 System Description

The Turbine Building is ventilated using 100 percent outside air. Air is supplied through wall openings along the east wall and is exhausted by fans mounted in the roof and along the west wall.

There are twelve roof mounted exhaust fans. Eighteen additional exhaust fans are located along the west wall. Each of the thirty fans are independently operated so that all or a portion of the fans can run as needed to maintain conditions within the Turbine Building.

Table 9-11 is a list of the primary equipment which includes the Turbine Building Ventilation System Exhaust Fans. The list includes number installed and normal operation requirements.

9.4.4.3 Safety Evaluation

The Turbine Building Ventilation System operates to maintain suitable environmental conditions in the Turbine Building during normal plant operation.

9.4.4.4 Inspection and Testing Requirements

The Turbine Building Ventilation System is in continuous operation during normal plant operation and is readily accessible for periodic inspection and maintenance.

9.4.5 Reactor Building Purge System

9.4.5.1 Design Bases

The Reactor Building Purge System purges the Reactor Building with fresh air during unit outages.

During operation, outside air is introduced into the Reactor Building through a supply system which has dual isolation valves at the containment wall. Outside air is circulated throughout the Reactor Building by the normal Reactor Building Ventilation System. Air is then exhausted from the Reactor Building by the Reactor Building purge exhaust filter train.

The filter train consists of prefilters, HEPA filters, and charcoal filters. A centrifugal fan is positioned downstream of the filter train. There are double isolation valves in the piping running from the Reactor Building to the filter train.

The isolation valves are automatic, are normally closed, and are opened only for the purging operation. The valves are arranged so the purge supply piping and the purge exhaust piping each have a electrically actuated valve inside the Reactor Building and a pneumatically actuated valve outside the Reactor Building.

There are two modes of operation possible for the Reactor Building Purge System; normal purge, and mini-purge. The system also has a recirculation mode, however it is not used because of duct leakage concerns. The purge filter train can also be used to provide filtered exhaust as discussed in Section 9.4.2.

9.4.5.2 System Description

The "Reactor Building Purge System" (Figure 6-4) purges the Reactor Building with fresh air to reduce airborne contaminant levels inside the Reactor Building.

The supply portion of this system consists of an outside air intake louver, roughing filters, a steam heating coil, associated ductwork and dual isolation valves at the reactor building wall. The exhaust portion of this system consists of a filter train, fans, associated ductwork, and dual isolation valves at the Reactor Building wall. The filter train consists of prefilter, HEPA filter, and charcoal filter. The isolation valves are automatic, normally closed in accordance with the requirements of NUREG 0737, Item II.E.4.2.6, and are opened only for the purging operation. The valves are so arranged that the supply portion and exhaust portion of the system each have an electrically actuated isolation valve inside the Reactor Building and two (2) pneumatically operated valves outside the Reactor Building (one is an isolation valve). A bleed valve between the two (2) outer valves vents any leakage from the Reactor Building into the penetration room.

There are two modes of operation possible for the "Reactor Building Purge System": 1) the normal purge, and 2) the mini-purge.

The normal purge mode purges the Reactor Building with 35,000 cfm of fresh air which enters by way of the supply portion and leaves by way of the exhaust portion described above. The filtered exhaust air is all released to the atmosphere via the unit vent.

The mini-purge mode of operation provides a means to purge the Reactor Building at a reduced flow rate when activity levels are higher than desired for full purging. A 10,000 cfm vane-axial fan is provided to by-pass the normal purge exhaust fan. A series of pneumatically operated dampers provide isolation and control. During mini-purge, flow from the Reactor Building is through the purge filter train and can be modulated up to a maximum of 10,000 cfm. The vane-axial mini-purge fan is constant volume and to maintain 10,000 cfm flow, Reactor Building air is mixed with outside air, i.e., the more air being purged from the Reactor Building, the less air drawn from the outside air make-up intake. The mini-purge fan and normal purge fan cannot operate simultaneously.

9.4.5.3 Safety Evaluation

Each Reactor Building Purge System supply and exhaust penetration of the Reactor Building wall is equipped with dual isolation valves. The valves inside the Reactor Building are electrically operated and the valves outside the Reactor Building have pneumatic actuators. The valves operate independently of one another and are in the closed position unless the purge is in operation.

The Purge System discharge to the unit vent is monitored and alarmed to prevent the release from exceeding acceptable limits.

9.4.5.4 Inspection and Testing Requirements

The Reactor Building Purge System is normally not in operation. The equipment and component are accessible for periodic maintenance. Parts of the system are maintained and tested in accordance with the Technical Specifications.

9.4.6 Reactor Building Cooling System

9.4.6.1 Design Bases

The Reactor Building Cooling Systems are designed to remove the heat in the containment atmosphere during normal plant operation and post accident operation.

A portion of the Reactor Building Cooling System is described in Section 6.2.2 as an Engineered Safety Feature.

The Reactor Building Cooling System is composed of two subsystems: Reactor Building Coolers and Reactor Building Auxiliary Coolers.

All components of the Reactor Building Cooling System are inside the Reactor Building. The only penetrations into and out of the Reactor Building that are related to the cooling system are the low pressure service water supply and return lines and isolation valves are provided on these lines at the penetrations.

9.4.6.2 System Description

The Reactor Building Cooling System shown in Figure 6-3 consists of the following subsystems and components:

1. Three Reactor Building Cooling Units (RBCUs), each consisting of a 2-speed vane axial fan, four cooling coils and distribution ductwork. These three cooling units are Engineered Safety Systems.
2. Four Reactor Building Auxiliary Cooling Units, each consisting of a 2-speed vane axial fan, four cooling coils, and distribution ductwork.

Deleted paragraph(s) per 2006 update.

The LPSW flow is provided to four Reactor Building Auxiliary Cooling Units (RBACs) through a separate piping loop that is independent of the RBCUs. During normal plant operation, any combination of the three RB cooling units (“A”, “B”, and “C”) may operate in the high or low speed mode to provide normal cooling of the Reactor Building.

The RB cooling units circulate Reactor Building air over low pressure service water supplied cooling coils and distribute the cool air throughout the lower portion of the Reactor Building. The Auxiliary Cooling Units distribute the cool air via a duct system to the upper portion of the Reactor Building. The temperature in the Reactor Building can be controlled by varying the number of Auxiliary Cooling Units or RBCUs running, changing their speed, or by supplying chilled water from a temporary chiller to the Auxiliary Coolers in lieu of LPSW in modes 1-4 and to the Auxiliary Coolers and/or the “B” RBCU in modes 5, 6, and no mode.

During an emergency, the Reactor Building Cooling System mode of operation changes automatically. Upon receipt of the signal from the Engineered Safeguards Actuation System, the operating Reactor Building Cooling Units change to low speed operation and any idle unit(s) is energized at low speed. This change occurs after a three (3) minute delay. Upon an ES signal, the Reactor Building Cooling Units operating in high or low speed automatically stop, and then restart in low speed operation after a three (3) minute time delay, and any idle unit(s) is also energized at low speed after a three (3) minute time delay. The fans are run at the slower speed because of the changed horsepower requirements generated by the denser building atmosphere. The LPSW flow path to RBACs is automatically isolated by the closure of air-operated containment isolation valves (LPSW-1054, 1055, 1061, and 1062) on ES signals. Additionally, all Low Pressure Service Water valves at the discharge of the three RBCUs go to the full open position.

The accident may impose severe stresses on the lower portion of the duct work, causing possible collapse or deformation. Fusible dropout plates have been completely removed from all units on “A” "B", and “C” RBCU ductwork, assuring that a positive path for recirculation of the Reactor Building atmosphere is available.. This prevents the fans from operating in stalled conditions. On all units, the “B” RBCU ductwork has a fusible dropout plate. See Figure 6-3.

9.4.6.3 Safety Evaluation

The three Reactor Building Cooling Units (RBCUs) are an engineered safety feature. These units alone can provide the design heat removal capacity to keep containment pressure below the design limit following a loss-of-coolant accident with all three coolers operating by continuously circulating the steam-air mixture past the cooling tubes to transfer heat from the containment atmosphere to the low pressure service water.

Inside the Reactor Building, the cooling units are located outside the secondary shield at an elevation above the water level in the bottom of the Reactor Building during post-accident conditions. In this location, the units are protected from being flooded.

The major equipment of the Reactor Building Cooling Units is arranged in three independent strings with three duplicate service water supply lines. In the unlikely event of a failure in one of the three cooling units, half of the Reactor Building Spray System capacity combined with the remaining two cooling units, is capable of keeping the containment temperature and pressure within environmental qualification (EQ) limits and is capable of keeping containment pressure below the design limit after a loss-of-coolant or steam line break accident. Acceptable fan-motor operation is verified by testing each refueling outage or every 24 months.

A failure analysis of the cooling units is presented in Table 6-6.

The NRC issued Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Conditions," on September 30, 1996, requesting that licensees determine if containment air cooler cooling water systems are susceptible to either water hammer or two-phase flow conditions during postulated accident conditions and to determine if piping systems that penetrate containment are susceptible to thermal expansion of fluid so that overpressurization of piping could occur. Evaluations of affected Oconee Nuclear Station systems and components were completed with response to the NRC submitted in the letter from M. S. Tuckman to the NRC, dated January 28, 1997. The evaluations determined that the Oconee Nuclear Station containment air cooler cooling water systems were not susceptible to significant two-phase flow conditions, but that some types of water hammer could occur during accident conditions. Commitments were provided in a letter from W. R. McCollum to the NRC, dated 9/30/02 to implement two modifications to mininmize water hammer potential: (1) changes to the LPSW piping in containment to prevent drainage from the system, and (2) modifications to the containment ventilation system to separate the RBACU from the RBCU trains. Regarding the thermal overpressure concern, further evaluations performed concluded that certain piping systems that penetrate the containment were susceptible to thermal expansion of fluid so that overpressurization of piping could occur. Commitments provided in a letter from W. R. McCollum to the NRC, dated 12/17/98, identified a list of containment penetrations and associated piping that warranted modifications to provide overpressure protection. The NRC approved the Oconee responses and closed the Generic Letter 96-06 in a letter to B. H. Hamilton, dated 12/06/07. The referenced modifications for containment ventilation system train separation and containment penetration overpressure protection were completed. The NRC-approved LPSW piping drainage modifications are pending future Oconee refueling outages.

9.4.6.4 Inspection and Testing Requirements

See "Tests and Inspections" under Section 6.2.2.

9.4.7 Reactor Building Penetration Room Ventilation System

9.4.7.1 Design Bases

Prior to the adoption of the alternate source term, Reference 2, the Penetration Room Ventilation system was required to collect and process post-accident Reactor Building leakage by establishing a vacuum in the Penetration Rooms and processing the leakage through a prefilter, an absolute filter, and a carbon filter prior to release by way of the unit vent. This system is still available but no longer required to serve an accident mitigation function. Reference Figure 6-4 for a schematic of the system.

This system is designed to collect and process potential Reactor Building penetration leakage to minimize environmental activity levels resulting from post-accident Reactor Building leaks. Experience has shown that Reactor Building leakage is more likely at penetrations than through the liner plates or weld joints.

The main function of the system is to control and minimize the release of radioactive materials from the Reactor Building to the environment in post-accident conditions.

Leakage into each of the penetration rooms is discharged to the unit vent through a pair of filter assemblies each consisting of a prefilter, an absolute filter, and a charcoal filter in series. The entire system is designed to operate under negative pressure up to the fan discharge.

The Penetration Room Ventilation System is not vulnerable to control malfunctions since it is controlled manually. Instrumentation is used only to monitor system performance and has no control function other than to guide the operator in adjusting the final control elements.

More detailed information concerning radiation levels and leakage requirements are discussed in Section 6.5.1.

9.4.7.2 System Description

The Penetration Room Ventilation System is provided with two fans and two filter assemblies. Both fans discharge through a single line to the unit vent. A schematic of the system is shown in Figure 6-4.

During normal operation, this system is held on standby with each fan aligned with a filter assembly. The engineered safeguards signal from the Reactor Building pressure will actuate the fans. The Control room, as well as remote instrumentation, monitors operation.

The design flow rate from the penetration room far exceeds the maximum anticipated Reactor Building leakage. The design leak rate of 0.1 volume percent per day from the Reactor Building to the penetration room (this is one-half of the total design leak rate out of the Reactor Building referenced in Section 6.2.1) amounts to approximately 6.2 scfm compared to a design evacuation rate of 1000 scfm for each half of the system. The three valves in each purge line penetration will be closed by Reactor Building isolation signal. The Reactor Building Purge Equipment, if running, will be shut down from an interlock on the Reactor Building Purge isolation valves. After closing of the external valves, a small normally open valve vents the leakage, if any, from the two outermost valves into the penetration room. The Reactor Building Purge Equipment is not activated when the reactor is above cold shutdown conditions.

Following a loss-of-coolant accident, a Reactor Building isolation signal will place the system in operation by starting both full-size fans. Two power-operated butterfly valves which open when the fans start are provided at the discharge of each fan. This valve will be closed to prevent recirculation if one fan fails. A check damper is also provided at the discharge of each fan to prevent recirculation on failure of a fan. In the event of a fan failure, the normally closed tie valve (PR-20) can be opened from its remote manual station to maintain cooling air through the idle filter train. Even if air flow is lost through a filter train, Reference 2 has shown that the charcoal ignition temperature will not be reached and operation of PR-20 is not required.

The system utilizes remote manual control valves PR-13 and PR-17 in conjunction with constant speed fans. Locations of penetrations and openings in the penetration room are shown on Figure 6-23 and Figure 6-24.

The remote manual control valve is also used to compensate for filter loading. Initially, it will be partially closed; and as the filter loads up causing a decrease in flow and negative penetration room pressure, the valve will gradually be opened so that the pressure drop across the filter-valve combination remains constant. By periodically adjusting the remote manual control valve to offset the effect of increased leakage and filter loading, the system characteristic remains constant.

The communicative paths between various parts of the penetration room are very large in comparison with the minute leakage that might exist due to imperfect seals. It therefore can be assumed that no pressure differentials exist in the room so that an instrument string sensing pressure at a single point can be used. Penetration room pressure is displayed in the control room and excessive and insufficient vacuum are annunciated.

Fan status and radiation level of filter effluent are displayed in the control room and excessive radiation is annunciated. Filter ΔP is displayed locally. Filter flow is displayed remotely adjacent to the remote manual control valves PR-13 and PR-17 remote control stations.

The system may be actuated by an operator during normal operation for testing. It may also operate intermittently during normal conditions as required to maintain satisfactory temperature in the penetrations rooms.

Particulate filtration is achieved by a medium efficiency pre-filter and a high efficiency (HEPA) filter.

The pre-filter consists of multiple horizontal tubular bags attached to a vertical metal plate header. The bags are made of ultra fine glass fibers and are supported so that adjacent bags do not touch and reduce the flow area. At the filter train design flow of 1000 cfm, the pre-filter is operating at one-half its rated flow.

The HEPA filter will intercept any particulates that pass through the pre-filter. The filter consists of a single cell of fiber glass media mounted in a metal frame. The cell has face dimensions of 24 inches x 24 inches and a depth of 11½ inches and is rated at 1150 scfm.

Adsorption filtration is accomplished by an activated charcoal filter. The filter consists of three horizontal removable type double tray carbon cells. Flow through the trays is essentially vertical. Each tray has a face area of 4.2 sq ft and a bed depth of 2 inches. At rated flow (167 cfm), the average face velocity is 40 ft/min and the residence time is 0.25 seconds. Each tray contains 40 lbs of carbon. The carbon is impregnated so that it will adsorb methyl iodide as well as elemental iodine.

9.4.7.3 Safety Evaluation

The Penetration Room Ventilation system is no longer required due to the adoption of the alternate source term, Reference 2.

9.4.7.4 Inspection and Test Requirements

The Penetration Room Ventilation System is not normally in operation, but the equipment is accessible for periodic inspection. The entire system can be tested during normal operation.

9.4.8 Ventilation Systems in the Station Battery Rooms

Ventilation systems in the station battery rooms are designed to maintain the hydrogen concentration below two percent volume concentration.

9.4.9 References

1. Deleted per 2005 update.
2. License Amendment No. 338, 339, and 339 (date of issuance – June 1, 2004); Adoption of Alternate Source Term.
3. Deleted per 2016 update.
4. Deleted per 2016 update.
5. Deleted per 2016 update.

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9.5 Other Auxiliary Systems

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9.5.1 Fire Protection

The fire protection program is based on the NRC requirements and guidelines. With regard to NRC criteria, the fire protection program meets the requirements of 10 CFR 50.48(c), which endorses, with exceptions, the National Fire Protection Association's (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants" – 2001 Edition. Oconee Nuclear Station has further used the guidance of NEI 04-02, "Guidance for Implementing a Risk-Informed, Performance-Based Fire Protection Program under 10 CFR 50.48(c)" as endorsed by Regulatory Guide 1.205, "Risk-Informed, Performance Fire Protection for Existing Light-Water Nuclear Power Plants."

A Safety Evaluation was issued on December 29, 2010 by the NRC, that transitioned the existing fire protection program to a risk-informed, performance-based program based on NFPA 805, in accordance with 10 CFR 50.48(c).

Adoption of NFPA 805, 2001 Edition in accordance with 10 CFR 50.48(c) serves as the method of satisfying 10 CFR 50.48(a) and UFSAR Section 3.1.3. This is further explained in the Fire Protection Design Basis Specification (OSS-0254.00-00-4008).

(Clarifying Note: Throughout this UFSAR section on Fire Protection, general reference is made to the Fire Protection Design Basis Specification (DBD) in accordance with FAQ 12-0062, Revision 1, UFSAR Content (ADAMS ML121430035) and NEI 98-03, Revision 1, Guidelines for Updating Final Safety Analysis Reports. General reference of this DBD is only intended to reduce unnecessary detail in the UFSAR and direct the reader for additional information and is in no way to be construed as "incorporation by reference" as defined in NEI 98-03, Revision 1.)

9.5.1.1 Design Basis Summary

9.5.1.1.1 Defense-in-Depth

The fire protection program is focused on protecting the safety of the public, the environment, and plant personnel from a plant fire and its potential effect on safe reactor operations. The fire protection program is based on the concept of defense-in-depth. Defense-in-depth shall be achieved when an adequate balance of each of the following elements is provided:

1) Preventing fires from starting,
2) Rapidly detecting fires and controlling and extinguishing promptly those fires that do occur, thereby limiting fire damage,
3) Providing an adequate level of fire protection for structures, systems, and components important to safety, so that a fire that is not promptly extinguished will not prevent essential plant safety functions from being performed.

9.5.1.1.2 NFPA 805 Performance Criteria

The design basis for the fire protection program is based on the following nuclear safety and radiological release performance criteria contained in Section 1.5 of NFPA 805:

- Nuclear Safety Performance Criteria. Fire protection features shall be capable of providing reasonable assurance that, in the event of a fire, the plant is not placed in an unrecoverable condition. To demonstrate this, the following performance criteria shall be met.

(a) Reactivity Control. Reactivity control shall be capable of inserting negative reactivity to achieve and maintain subcritical conditions. Negative reactivity inserting shall occur rapidly enough such that fuel design limits are not exceeded.

(b) Inventory and Pressure Control. With fuel in the reactor vessel, head on and tensioned, inventory and pressure control shall be capable of controlling coolant level such that subcooling is maintained such that fuel clad damage as a result of a fire is prevented for a PWR.

(c) Decay Heat Removal. Decay heat removal shall be capable of removing sufficient heat from the reactor core or spent fuel such that fuel is maintained in a safe and stable condition.

(d) Vital Auxiliaries. Vital auxiliaries shall be capable of providing the necessary auxiliary support equipment and systems to assure that the systems required under (a), (b), (c), and (e) are capable of performing their required nuclear safety function.

(e) Process Monitoring. Process monitoring shall be capable of providing the necessary indication to assure the criteria addressed in (a) through (d) have been achieved and are being maintained.

- Radioactive Release Performance Criteria. Radiation release to any unrestricted area due to the direct effects of fire suppression activities (but not involving fuel damage) shall be as low as reasonably achievable and shall not exceed applicable 10 CFR, Part 20, Limits. Oconee's prior licensed performance criteria for liquid effluent release was approved as 10 times that of 10 CFR Part 20, Appendix B, Table 2, Column 2 (by NRC Safety Evaluation dated January 6, 1993). This criteria was accepted as equivalent to the NFPA 805 performance criteria.

Chapter 2 of NFPA 805 establishes the process for demonstrating compliance with NFPA 805.

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features.

Chapter 4 of NFPA 805 establishes the methodology to determine the fire protection systems and features required to achieve the nuclear safety performance criteria outlined above. The methodology shall be permitted to be either deterministic or performance-based. Deterministic requirements shall be "deemed to satisfy" the performance criteria, defense-in-depth, and safety margin and require no further engineering analysis. Once a determination has been made that a fire protection system or feature is required to achieve the nuclear safety performance criteria of Section 1.5, its design and qualification shall meet the applicable requirement of Chapter 3.

9.5.1.1.3 Codes of Record

The fundamental code of record for Oconee's fire protection program is NFPA 805, 2001 Edition, as approved by the NRC in the 12/29/2010 Safety Evaluation. The codes, standards and guidelines used for the design and installation of plant fire protection systems are listed in the Fire Protection Design Basis Specification (OSS-0254.00-00-4008).

9.5.1.2 System Description

9.5.1.2.1 Required Systems

Nuclear Safety Capability Systems, Equipment, and Cables

Section 2.4.2 of NFPA 805 defines the methodology for performing the nuclear safety capability assessment. The systems, equipment, and cables required for the nuclear safety capability assessment are referenced in OSS-0254.00-00-4008, Fire Protection Design Basis Specification.

Fire Protection Systems and Features

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features. Compliance with Chapter 3 is documented in the Fire Protection Design Basis Specification (OSS-0254.00-00-4008).

Chapter 4 of NFPA 805 establishes the methodology and criteria to determine the fire protection systems and features required to achieve the nuclear safety performance criteria of Section 1.5 of NFPA 805. These fire protection systems and features shall meet the applicable requirements of NFPA 805 Chapter 3. These fire protection systems and features are documented in the Fire Protection Design Basis Specification (OSS-0254.00-00-4008).

Radioactive Release

Structures, systems, and components relied upon to meet the radioactive release criteria are documented in the Fire Protection Design Basis Specification (OSS-0254.00-00-4008).

9.5.1.2.2 Definition of "Power Block" Structures

Where used in NFPA 805 Chapter 3 the terms "Power Block" and "Plant" refer to structures that have equipment required for nuclear plant operations. For the purposes of establishing the structures included in the fire protection program in accordance with 10 CFR 50.48(c) and NFPA 805, the plant structures listed in Fire Protection Design Basis Specification (OSS-0254.00-00-4008) are considered to be part of the 'power block'.

9.5.1.3 Safety Evaluation

The Fire Protection Design Basis Specification (OSS-0254.00-00-4008) documents the achievement of the nuclear safety and radioactive release performance criteria of NFPA 805 as required by 10 CFR 50.48(c). This document fulfills the requirements of Section 2.7.1.2 "Fire Protection Program Design Basis Document" of NFPA 805. The document contains the following:

- Identification of significant fire hazards in the fire area. This is based on NFPA 805 approach to analyze the plant from an ignition source and fuel package perspective.
- Summary of the Nuclear Safety Capability Assessment (at power and non-power) compliance strategies.
    - Deterministic compliance strategies
    - Performance-based compliance strategies (including defense-in-depth and safety margin)
- Summary of the Non-Power Operations Modes compliance strategies.

- Summary of the Radioactive Release compliance strategies.
- Summary of the Fire Probabilistic Risk Assessments.
- Summary of the NFPA 805 monitoring program.

9.5.1.4 Fire Protection Program Documentation, Configuration Control and Quality Assurance

In accordance with Chapter 3 of NFPA 805 a fire protection plan documented in the Fleet Fire Protection Program Manual (PD-EG-ALL-1500) and the Fire Protection Design Basis Specification defines the management policy and program direction and defines the responsibilities of those individuals responsible for the plan's implementation. The Fleet Fire Protection Program Manual and/or the Fire Protection Design Basis Specification:

- Designates the senior management position with immediate authority and responsibility for the fire protection program.
- Designates a position responsible for the daily administration and coordination of the fire protection program and its implementation.
- Defines the fire protection interfaces with other organizations and assigns responsibilities for the coordination of activities. In addition, the Fleet Fire Protection Program Manual identifies the various plant positions having the authority for implementing the various areas of the fire protection program.
- Identifies the appropriate authority having jurisdiction for the various areas of the fire protection program.
- Identifies the procedures established for the implementation of the fire protection program, including the post-transition change process and the fire protection monitoring program.
- Identifies the qualifications required for various fire protection program personnel.
- Identifies the quality requirements of Chapter 2 of NFPA 805.

9.5.2 Instrument and Breathing Air Systems

9.5.2.1 Design Basis

The Instrument and Breathing Air Systems are designed to provide clean, dry, oil free instrument air to all air operated instrumentation and valves. Instrument air is supplied to ANSI/ISA-7.0.01-1996 standards, and breathing air is supplied at ANSI Z86.1 Grade D standards to minimize personnel exposure in areas of airborne contamination.

9.5.2.2 System Description

The Instrument Air (IA) System consists of a) one primary IA compressor with two filter/dryer trains, b) three backup IA compressors with two filter/dryer trains, c) distribution headers, d) receiver tanks and e) components supply lines. The IA System is shared by all three Oconee Units and the Radwaste Facility; therefore, the IA System is required to operate continuously.

Normal operation for the IA System is for the primary IA compressor to supply all IA demands. Should the primary IA compressor trip, be required to be removed from service for maintenance, or the IA System demand exceed the primary IA compressor capacity, the backup IA compressors and any available Service Air System compressor capacity reserves are used in supplying IA System demands.

An Auxiliary Instrument Air (AIA) System provides a backup auxiliary source of instrument air to key plant components in order to minimize operator burden during a normal loss of IA event while reaching and maintaining a safe shutdown. This system is composed of three (one per unit) compressors, combination filters, and desiccant dryers. Separate distribution headers and supply lines are provided to these key components to ensure AIA availability. The AIA System is designed such that a failure will not fail Instrument Air or affect operating equipment.

Although the AIA System may be available, it is not required for performing or supporting any operation. Each of the key plant components supplied backup AIA fails in a safe condition and has an alternate procedurally controlled method to control the process.

The Unit 1 and 2 Breathing Air System and the Unit 3 Breathing Air System each consist of one primary and one backup compressor package. These packages consist of one a) two stage inlet air filter, b) compressor, c) air/oil separator, d) and oil cooler/aftercooler. After the compressor the air is passed through a) an air/water separator, b) a filter package, c) two purification packages in parallel (Unit 3 'A' train has only one purifier package), d) into two parallel receiver tanks, and e) finally into the breathing air manifolds. Breathing air is supplied to all areas and elevations by headers and individual supply stations where the pressure is regulated for personnel use. Units 1 & 2 have one primary and one backup compressor total for both Units, and Unit 3 has one primary and one backup for its use. The breathing air systems are cross connected in such a way that any of the compressors can supply either of the Units' breathing air needs.

The startup and main feedwater control valves (FDW-32, FDW-35, FDW-41 and FDW-44) are supplied with backup compressed air from an accumulator tank. This source of compressed air is sufficient for their 2 hour mission time in the event they must be closed and stay closed in response to an AFIS signal for a steam line break, concurrent with a Loss of Offsite Power (LOOP). This 2 hour mission time is consistent with that approved for other equipment mitigating the same accident per Reference 1 in Section 9.5.3. These accumulators are supplied for the Instrument Air System. Therefore, none of the feedwater control valves require operation of Service Air Diesel Air Compressor(s).

9.5.2.3 Instrument Air (IA) System Tests and Inspections

The Instrument Air System is always in service, supporting the continued operation of three nuclear units, and therefore continually demonstrates it is capable of performing its intended function. The Primary IA components are normally in service, the backup IA components are placed in service when PM's are performed on the Primary IA Components. The air supplied by the Instrument Air System is periodically tested to verify that the quality of the air is acceptable (e.g., acceptable dew point, oil content, and particulate contamination). Safety related air-operated valves are periodically tested to ensure that they fail in their safe position during a loss of Instrument Air event. The Instrument Air Preventive Maintenance Program and ongoing monitoring of the system operation also help ensure adequate system performance. All of these tests, inspections and programs ensure that the Instrument Air System is capable of performing its intended function and will not adversely affect safety-related demand equipment in accordance with Generic Letter 88-14, "Instrument Air Supply System Problems affecting Safety-Related Equipment."

9.5.3 References

1. Oconee Nuclear Station, Units 1, 2 & 3, Issuance of Amendments (TAC NOS. MA9596, MA9597, AND MA9598), September 26, 2001.

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9.6 Standby Shutdown Facility

9.6.1 General Description

The Standby Shutdown Facility (SSF) houses stand-alone systems that are designed to maintain the plant in a safe and stable condition following postulated emergency events that are distinct from the design basis accidents and design basis events for which the plant systems were originally designed. The system provides additional "defense in-depth" protection for the health and safety of the public by serving as a backup to existing safety systems. The original licensing basis of the SSF provided an alternate means to achieve and maintain mode 3 with an average Reactor Coolant temperature ≥ 525°F (RCS cold leg temperature ≤ 555°F and RCS pressure ~ 2155 psig) following postulated fire, security-related, or turbine building flood events, and is designed in accordance with criteria associated with these events.

TB Flood does not occur with any other concurrent event. The loss of all other non-SSF power is a design criteria applied to the SSF design to ensure that the SSF can independently mitigate the event over the long term. A loss of offsite power (LOOP) is not postulated to occur at event initiation, however it could occur as a consequence of the flooding event. (References 36 and 37)

In the time since the SSF was licensed and build, various new licensing issues have broadened and re-defined the SSF licensing requirements. In the early 1980's soon after the TMI event, NRC took steps to ensure the Emergency Feedwater System was adequately designed, GL 81-14 was issued to ensure the EFW System was designed seismically. When EFW vulnerabilities were identified, the SSF was credited as an acceptable alternate heat removal system with the required seismic design (Reference 34). Similarly, the ability of the EFW System to withstand tornado missiles was questioned by NRC. The SSF was credited as an acceptable heat removal system with adequate tornado missile protection (Reference 4). When the Station Blackout Rule was issued, the SSF was credited as the alternate AC (AAC) power source and the source of decay heat removal required to demonstrate safe shutdown during the required station blackout coping duration (References 2 and 3). A June 11, 2002, license amendment credited the SSF as one of multiple, alternate paths that can be used to mitigate certain EFW single failure vulnerabilities (Reference 35). Adoption of the NFPA 805 changed the SSF licensing basis from what was originally committed for Fire to a new set of rules. Key differences are the elimination of the "ten minute rule" and the elimination of 72 hours as a required time to be at cold shutdown (See Section 9.5.1.3.2). For units with the HELB Mitigation Strategy (Reference 43) implemented, a high energy line break (HELB) licensing basis reconstitution effort that began in the early 2000s resulted in the SSF being credited as an alternate means to achieve and maintain safe shutdown following HELBs in the turbine building and auxiliary building.

The SSF had certain design criteria and rules that were applied to it as part of the original licensing action that apply to those events for which the SSF was originally licensed. As the scope of issues for which SSF was credited broadened, it is important to realize that original SSF design criteria may or may not apply to these new scenarios. It is necessary to review the specific licensing correspondence for the specific issue to determine the applicable design criteria and other requirements.

Per the licensing correspondence which documented the SSF design criteria, SSF-designated events are not postulated to simultaneously occur with standard design basis events such as an earthquake or LOCA; therefore, the single failure criterion is not applicable or required. However, SSF systems are required to be designed such that a failure of an SSF component would not result in failures or inadvertent operation of existing plant systems that would prevent existing plant systems from performing their intended function. SSF ties to the existing plant are such that no SSF failure will result in consequences more severe than those analyzed in the UFSAR. The SSF requires manual activation that would occur under adverse fire, flooding, HELB (for units with the HELB Mitigation Strategy (Reference 43) implemented), or sabotage events when normal plant systems may have been damaged or have become unavailable.

Per the original SSF licensing correspondence as documented in the April 28, 1983 SER and corresponding Duke Energy submittals (fire and TB flood) the SSF is designed to:

1. Maintain a minimum water level above the reactor core, with an intact Reactor Coolant System, and maintain Reactor Coolant Pump Seal cooling.
2. Assure natural circulation and core cooling by maintaining the primary coolant system filled to a sufficient level in the pressurizer while maintaining sufficient secondary side cooling water.
3. Transfer decay heat from the fuel to an ultimate heat sink.
4. Maintain the reactor 1% shutdown with the most reactive rod stuck fully withdrawn, after all normal sources of RCS makeup have become unavailable, by providing makeup via the Reactor Coolant Makeup Pump System which always supplies makeup of a sufficient boron concentration. (The stuck rod requirement was eliminated for fire events when NFPA 805 was adopted. See Section 9.6.2)

The SSF consists of the following:

1. SSF Structure
2. SSF Reactor Coolant Makeup (RCM) System
3. SSF Auxiliary Service Water (ASW) System
4. SSF Electrical Power
5. SSF Support Systems

System Main Components are listed in Table 9-14. SSF Primary Valves are listed in Table 9-15. SSF Instrumentation is listed in Table 9-16.

Based on subsequent SSF licensing correspondence, different design criteria may have been applied for new SSF events. Refer to the event specific design bases below for details.

9.6.2 Design Bases

FIRE EVENT (NFPA 805 Fire which supersedes the original SSF Fire Design Requirements)

Oconee transitioned to NFPA 805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition, in accordance with 10CFR50.48(c). NFPA 805 establishes a nuclear safety goal that requires reasonable assurance that a fire during any operational mode or plant configuration will not prevent the plant from being maintained in a safe and stable condition. Safe and stable is defined as maintaining $K_{eff}<0.99$ with the RCS at or below the requirements for hot standby.

To accomplish this goal, fire protection systems and features must be capable of ensuring at least one success path of equipment remains free of fire damage following a fire in a single fire area. For one fire area of Oconee, the SSF provides the single success path necessary to achieve the NFPA 805 nuclear safety goal.

The nuclear safety goal of NFPA 805 does not prescribe a transition to cold shutdown within 72 hours following a fire; rather, only that the plant be maintained safe and stable in hot standby (K_{eff} <0.99 and RCS temperature >/= 250°F for up to a 72 hour coping duration while repairs are made to achieve a licensed end state of hot shutdown (K_{eff} <0.99 and RCS temperature below 250°F but above 200°F) (Reference 9.5.1.3.2). For the most limiting fire scenarios, it is anticipated that the end state of the cooldown would be an RCS temperature of approximately 250°F with a long term strategy for reactivity, decay heat removal and inventory/pressure control. Long-term subcooled natural circulation decay heat removal is provided by supplying lake water to the steam generators and steaming to atmosphere. The extended coping period at these conditions is based on the significant volume of water available for decay heat removal and reduced need for primary makeup to only match nominal system losses. A stuck rod is not required to be postulated for this event. Initial conditions are 100% power with sufficient decay heat such that natural circulation can be achieved. The hypothesized fire is to be considered an "event", and thus need not be postulated concurrent with non-fire-related failures in safety systems, other plant accidents, or the most severe natural phenomena (Reference 31).

Deleted Paragraph(s) per 2015 update.

Deleted Paragraph(s) per 2012 update.

TURBINE BUILDING FLOOD EVENT

The Turbine Building Flood was one of the events that was identified in the original SSF licensing requirements. The SSF is designed to maintain the reactor in a safe shutdown condition for a period of 72 hours following a TB Flood. No other concurrent event is assumed to occur. To verify SSF performance criteria, thermal-hydraulic (T/H) analysis was performed to demonstrate that the SSF can achieve and maintain safe shutdown following postulated turbine building floods. The analysis evaluates RCS subcooling margin using inputs that are representative of nominal full power end of cycle plant conditions. The analysis uses an initial core thermal power of 2619 MWth (102% of 2568 MWth) and accounts for 24-month fuel cycles. The consequences of the postulated loss of main and emergency feedwater were analyzed as a RCS overheating scenario. For the examined overheating scenario, an important core input is decay heat. High decay heat conditions were modeled that were reflective of maximum, end of cycle conditions. The high decay heat assumption was confirmed to be bounding with respect to the RCS subcooling response. The results of the nominal case analysis demonstrate that the SSF is capable of meeting the success criteria for this event: 1) maintain a minimum water level above the reactor core, 2) assure natural circulation and core cooling by maintaining the primary coolant system filled to a sufficient level in the pressurizer while maintaining sufficient secondary side cooling, 3) transfer decay heat to an ultimate heat sink, and 4) maintain the reactor at least 1% $\Delta k/k$ shutdown with the most reactive rod fully withdrawn. (Reference 1, 10)

<u>Off-nominal success criteria are only applicable to unit(s) with the SSF letdown line and SSF RC makeup pump pulsation dampener modifications complete.</u>

In addition to the nominal case analysis described above, off-nominal cases with low decay heat, low initial power and low initial temperature were analyzed. In each of these off-nominal cases, the results demonstrate that the SSF continues to meet the following success criteria for this event: 1) maintain a minimum water level above the reactor core, 2) transfer decay heat to an ultimate heat sink, and 3) maintain the reactor at least 1% $\Delta k/k$ shutdown with the most reactive rod fully withdrawn.

During periods of very low decay heat the SSF will be used to establish conditions that support the formation of subcooled natural circulation between the core and the SGs; however, natural circulation involving the SGs may not occur if the amount of decay heat available is less than or equal to the amount of heat removed by ambient losses to containment and/or by other means, e.g., letdown of SSF reactor coolant makeup. When these heat removal mechanisms are sufficient to remove core decay heat, they are considered adequate to meet the core cooling function and systems supporting SG decay heat removal, although available, are not necessary for core cooling.

A nominal full power condition is defined as a unit at 100% power for approximately 4 days of operation which provides the decay heat required to meet the nominal SSF success criteria. Regarding operation in MODES 1, 2, and 3 at other than nominal full power, T-H analyses demonstrate that the SSF maintains conditions that support the formation of subcooled natural circulation between the core and SGs such that there is no water relief through the pressurizer safety valves.

Regarding operation at low initial temperature, T-H analyses demonstrate that in some cases pressurizer level was not maintained on scale; however, conditions that support the formation of subcooled natural circulation between the core and the SGs were maintained. In cases where the pressurizer did go water-solid, there was no liquid relief through the pressurizer safety valves.

SECURITY-RELATED EVENT

A Security Related Event was one of the events that was identified in the original SSF licensing requirements. The SSF is designed to achieve and maintain a safe shutdown condition for this event. No other concurrent event is assumed to occur. (Reference 1) The success criteria for this event is to assure the core will not return to criticality, the active fuel will not be uncovered, and long-term natural circulation will not be halted. (Reference 41)

STATION BLACKOUT EVENT

This event was licensed after the design of the SSF was completed and approved by NRC. The SSF was credited as the method the plant would employ to mitigate a SBO event. (References 38 and 39) The success criteria is to maintain the core covered for 4 hours. No stuck rod is assumed for this event. Initial conditions are 100% power and 100 days of operation. (Reference 40)

SSF TORNADO DESIGN CRITERIA

For Units where the revised tornado mitigation strategies as described in Section 3.2.2 have not been implemented:

This is a design criterion for the SSF that was committed to as part of the original SSF licensing correspondence. All parts of the SSF itself that are required for mitigation of the SSF events are required to be designed against tornado winds and associated tornado missiles. This requirement is satisfied through appropriate design of the SSF structure. This requirement does not extend to SSCs that were already part of the plant which SSF relies upon and interfaces with for event mitigation. It is important to note that the SSF was not licensed to mitigate a tornado event or a tornado missile event (Reference 1). Tornado design requirements for the plant itself are addressed in Section 3.2.2. A subsequent issue related to crediting SSF ASW as an alternative for EFW tornado missile protection vulnerabilities is discussed below (see EFW Tornado Missile Design Criteria).

For Units where the revised tornado mitigation strategies as described in Section 3.2.2 have been implemented:

This is a design criterion for the SSF structure that was committed to as part of the original SSF licensing correspondence and remains valid. All parts of the SSF structure that are required for mitigation of the SSF events are required to be designed against tornado winds and associated tornado missiles. This requirements is satisfied through appropriate design of the SSF structure. Originally, the design criterion did not extend to SSCs that were already part of the plant which the SSF relies upon and interfaces with for event mitigation. The design criterion is now extended to SSCs that are a part of the plant which the SSF relies upon and interfaces with for tornado mitigation. This is satisfied either through physical protection or evaluated by TORMIS. It is important to note that the overall tornado mitigation strategy utilizes the SSF to mitigate a tornado (Reference 42). Tornado design requirements for the plant itself are addressed in Section 3.2.2.

Successful mitigation of a tornado condition at Oconee shall be defined as meeting the following criteria to ensure that the integrity of the core and RCS remains unchallenged:

- The core must remain intact and in a coolable geometry during the credited strategy period.
- Minimum Departure from Nucleate Boiling Ratio (DNBR) meets specified acceptable fuel design limits.
- RCS must not exceed 2750 psig (110% of design).

In addition to the criteria specified above, the following criteria are validated for the overcooling analysis to demonstrate acceptable results:

- Steam Generator tubes remain intact.
- RCS remains within acceptable pressure and temperature limits.

The tornado initial conditions are defined for the unit(s) as MODE 1, 102% rated thermal power at end of core life (690 effective full-power days). The tornado is assumed to leave one unit significantly damaged and a loss of all AC power to all three units. Two bounding analyses were performed, overheating and overcooling. For an overheating event, the significantly damaged unit is supplied by SSF ASW. The other two units will be initially supplied by the TDEFWP and subsequently supplied by SSF ASW. For an overcooling event, the TDEFWP is conservatively assumed to run until the contents of the Upper Surge Tank are depleted (to maximize the overcooling). SSF ASW flow is subsequently established to all three units as needed.

Following a tornado induced overcooling event the unit may experience a minor return to power of short duration. There are no consequences associated with the return to power due to the very low power level generated. The SSF is not required to meet the single failure criterion or the postulation of the most reactive rod fully stuck withdrawn. Failures in the SSF system will not cause failures or inadvertent operations in other plant systems. The SSF requires manual activation and can be activated if emergency systems are not available. A subsequent issue related to crediting SSF ASW as an alternative for EFW tornado missile protection vulnerabilities is discussed below (see EFW Tornado Missile Design Criteria).

HELB DESIGN CRITERIA

Note: This section applies to units with the HELB Mitigation Strategy (Reference 43) implemented.

As a result of a HELB licensing basis reconstitution that began in the early 2000s, the SSF is credited for meeting the design requirements of certain HELB locations. The SSF provides an alternate means to achieve and maintain safe shutdown following HELBs in the turbine building and auxiliary building. See Section 3.6 for more details on the design criteria of HELBs outside containment.

EFW SEISMIC DESIGN CRITERIA (GL 81-14)

During the seismic qualification review of the Oconee EFW system in the 1980s, the NRC postulated that a seismic event could break a pipe and potentially cause a flood of the turbine building thereby submerging and failing the EFW pumps. The NRC wanted to ensure that the EFW System was seismically designed and could withstand a single failure, as well. As an alternative to upgrading the EFW System, NRC credited the use of the SSF ASW System and HPI Feed & Bleed (Reference 34). These two decay heat removal systems are seismically designed and independent from each other. The event postulated by GL 81-14 (a seismic break) was a special condition imposed on ONS to evaluate the EFW design. It was not intended to re-define the SSF mitigated TB Flood (which does not concurrently consider a seismic event, nor does it impose a single failure). Although both "events" are TB Floods, they are two separate licensing actions with different scopes, different acceptance criteria, and different purposes. The GL 81-14 flood does not have specified initial conditions, other mitigation assumptions, or success criteria to be considered because it is not an event, only an EFW design criterion (Reference 34).

EFW TORNADO MISSILE DESIGN CRITERIA

An additional issue that arose after TMI was the capability of the EFW System to withstand the effects of tornado missiles. The design of the EFW System did not include this capability, therefore, Duke Energy requested and NRC approved crediting the SSF Auxiliary Service Water (SSF ASW) System as an acceptable alternative (even though it was recognized that SSF ASW System itself is not completely protected from all tornado missiles). It is important to note that this licensing action did not specify a tornado missile event or define a tornado missile mitigation strategy. Using a probabilistic approach, it solely focused on ensuring that a secondary side heat removal path is adequately designed to withstand the effects of tornado missiles (Reference 4).

EFW SINGLE FAILURE VULNERABILITIES

During the 1990's and early 2000's, the NRC again focused on the design capabilities of the EFW System. Certain single failure vulnerabilities were identified after reviews by both Duke Energy and NRC. NRC accepted these vulnerabilities by crediting the existence of multiple alternate paths that could also provide secondary side heat removal. SSF Auxiliary Service Water (SSF ASW) was one of the paths credited for this function (Reference 35).

Deleted Per 2014 Update.

The reactor building spray pumps are described with respect to the waterproofing of the walls between the auxiliary building and the turbine building. However, Duke did not credit the reactor building spray pumps in the mitigation of the turbine building flood. In addition, the NRC did not credit the reactor building spray pumps for the mitigation of the turbine building flood event in the licensing basis or backfit analysis.

ELECTRICAL SEPARATION CRITERIA

Selected motor operated valves and selected pressurizer heaters are capable of being powered and controlled from either the normal station electrical systems or the SSF electrical system. Suitable electrical separation is provided in the following manner. Electrical distribution of the SSF is identified in Figure 9-40 and Figure 9-41 is provided by the SSF motor control centers (MCC's). Loads fed from MCC's 1XSF, 2XSF, 3XSF, and XSF are capable of being powered from either an existing plant load center or the SSF load center through key interlocked breakers at the MCC's. These breakers provide separation of the power supplies to the SSF loads.

Loads fed from MCC PXSF are capable of being powered from either Unit 2 B2T or the SSF Diesel or the alternate PSW B7T via switchgear OTS1. Breakers feeding OTS1 are electrically interlocked and provide separation of the power supplies to the SSF loads.

During normal operation, these loads are powered from a normal (non-SSF) load center via the SSF MCC's 1XSF, 2XSF, 3XSF (Group B) or switchgear OTS1 via SSF MCC PXSF (Group C).

During operation of the SSF, these loads are powered from the SSF diesel generator via the SSF load center/switchgear and SSF MCC's.

9.6.3 System Descriptions

9.6.3.1 Structure

The Standby Shutdown Facility (SSF) is a reinforced concrete structure consisting of a diesel generator room, electrical equipment room, mechanical pump room, control room, central alarm station (CAS), and ventilation equipment room. The general arrangement of major equipment and structures is shown in Figure 9-30, Figure 9-31, Figure 9-32, Figure 9-33 and Figure 9-34.

The SSF has a seismic classification of Category 1. The following load conditions are considered in the analysis and design:

1. Structure Dead Loads
2. Equipment Loads
3. Live Loads
4. Normal Wind Loads
5. Seismic Loads
6. Tornado Wind Loads
7. Tornado Missile Loads
8. High Pressure Pipe Break Loads
9. Turbine Building Flooding Potential

WIND AND TORNADO LOADS

The design wind velocity for the SSF is 95 mph, at 30 ft. above the nominal ground elevation. This velocity is the fastest wind with a recurrence interval of 100 years. A gust factor of unity is used for determining wind forces. The design tornado used in calculating tornado loadings is in conformance with Regulatory Guide 1.76, Revision 0, with the following exceptions:

1. Rotational wind speed is 300 mph.
2. Translational speed of tornado is 60 mph.
3. Radius of maximum rotational speed is 240 ft.
4. Tornado induced negative pressure differential is 3 psi, occurring in three seconds.

The spectrum and characteristics of tornado-generated missiles are covered later in this section.

Revision 1 to Regulatory Guide 1.76, “Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants,” was released in March 2007. Revision 1 to Regulatory Guide 1.76 was incorporated into the SSF licensing basis in the 4th quarter of 2007. The design of all future changes to and/or analysis of SSF-related systems, structures, and components subject to tornado loadings will conform to the tornado wind, differential pressure, and missile criteria specified in Regulatory Guide 1.76, Revision 1 or be evaluated by TORMIS for Units with the revised tornado mitigation strategies described in Section 3.2.2 implemented. Adoption of Regulatory Guide 1.76, Revision 1 tornado design criteria for application to future design changes of SSF-related SSCs and to new plant systems and structures does not impact the design of existing SSCs. Wind and tornado loadings considered and applied to the design of existing Class 1 structures remain as is and Regulatory Guide 1.76, Revision 1 is not retroactively applied to existing SSCs.

FLOOD DESIGN

Flood studies show that Lake Keowee and Jocassee are designed with adequate margins to contain and control floods. The first is a general flooding of the rivers and reservoirs in the area due to a rainfall in excess of the Probable Maximum Precipitation (PMP). The FSAR addresses Oconee's location as on a ridgeline 100' above maximum known floods. Therefore, external flooding due to rainfall affecting rivers and reservoirs is not a problem. The SSF is within the site boundary and, therefore, is not subject to flooding from lake waters.

The grade level entrance of the SSF is 797.0 feet above mean sea level (msl). In the event of flooding due to a break in the non-seismic condenser circulating water (CCW) system piping located in the Turbine Building, the maximum expected water level within the site boundary is 796.5 ft. Since the maximum expected water level is below the elevation of the grade level entrance to the SSF, the structure will not be flooded by such an incident.

The SSF is provided with external flood walls that protect both the north and south entrances. The flood wall near the south entrance is equipped with a water tight door. Stairways over the walls provides access to both the north and south entrances. The yard elevation at both the north and the south entrance to the SSF is 796.0 feet above mean sea level (msl). Flooding due to the potential failure of the Jocassee Dam is considered in the PRA, but is not considered part of the Oconee licensing basis.

MISSILE PROTECTION

The only postulated missiles generated by natural phenomena are tornado generated missiles. The SSF is designed to resist the effects of tornado generated missiles in combination with other loadings. Table 9-17 lists the postulated tornado generated missiles.

Penetration depths are calculated using the modified NDRC formula and the modified Petry formula.

Modified N.D.R.C Formula:

$$\text{Penetration depth}, (x) = \sqrt{4KNWd\left(\frac{v_o}{1{,}000d}\right)^{1.80}} \text{ for } x/d \le 2.0$$

$$= \sqrt{KNWd\left(\frac{v_o}{1{,}000d}\right)^{1.80}} + d \text{ for } x/d > 2.0$$

Where:

N = missile shape factor = 0.72 for flat nosed bodies, 1.14 for sharp nosed bodies

K = concrete penetrability factor = $\frac{180}{\sqrt{f_c}}$

W = Weight in pounds

v_o = striking velocity

D = effective projectile diameter = $\sqrt{4Ac/\pi}$

A_c = projectile contact Area in in^2

Modified Petry Formula:

Penetration depth,(x) $= 12K_pA_p \log_{10}(1+V^2/215{,}000)$

Where:

K_p = a coefficient depending on the nature of the concrete

= 0.00426 for normal reinforced concrete

A_p = weight of missile per unit of impact area

= W/A_c

A_c = Impact Area

V = striking velocity of projectile

Table 9-18 lists the calculated penetration depths and the minimum barrier thicknesses to preclude perforation and scabbing, hence eliminating secondary missiles.

Revision 1 to Regulatory Guide 1.76, “Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants,” was released in March 2007. Revision 1 to Regulatory Guide 1.76 was incorporated into the SSF licensing basis in the 4th quarter of 2007. The design of all future changes to and/or analysis of SSF-related systems, structures, and components subject to tornado loadings will conform to the tornado wind, differential pressure, and missile criteria specified in Regulatory Guide 1.76, Revision 1 or be evaluated by TORMIS for Units with the revised tornado mitigation strategies described in Section 3.2.2 implemented. Adoption of Regulatory Guide 1.76, Revision 1 tornado design criteria for application to future design changes of SSF-related SSCs and to new plant systems and structures does not impact the design of existing SSCs. Wind and tornado loadings considered and applied to the design of existing Class 1 structures remain as is and Regulatory Guide 1.76, Revision 1 is not retroactively applied to existing SSCs.

SEISMIC DESIGN

The design response spectra correspond to the expected maximum bedrock acceleration of 0.1 g. The design response spectra were developed in accordance with the procedures of Reg. Guide 1.60. The seismic loads as a result of a base excitation are determined by a dynamic analysis. The dynamic analysis is made utilizing the STRUDL-DYNAL computer program. The base of the structure is considered fixed.

With the geometry and properties of the model defined, the model's influence coefficients (the flexibility matrix) are determined. The contributions of flexure as well as shearing deformations are considered. The resulting matrix is inverted to obtain the stiffness matrix, which is used together with the mass matrix to obtain the eigenvalues and associated eigenvectors.

Having obtained the frequencies and mode shapes and employing the appropriate damping factors, the spectral acceleration for each mode can be obtained from Design Ground Motion response spectra curves. The standard response spectrum technique is used to determine inertial forces, shears, moments, and displacements for each mode. The structural response is obtained by combining the modal contributions of all the modes considered. The combined effect is represented by the square root of the sum of the squares.

The analytical technique used to generate the response spectra at specified elevations is the time history method. The acceleration time history of each elevation is retained for the generation of response spectra reflecting the maximum acceleration of a single degree of freedom system for a range of frequencies at the respective elevation. The structure will withstand the specified design conditions without impairment of structural integrity or safety function.

9.6.3.2 Reactor Coolant Makeup (RCM) System

The SSF RCM System is designed to supply borated makeup to the Reactor Coolant System (RCS) to provide Reactor Coolant Pump Seal cooling and RCS inventory. An SSF RCM Pump located in the Reactor Building of each unit will supply makeup to the RCS should the normal makeup system and the reactor coolant pumps become inoperative because of a station blackout condition caused by the loss of all other on-site and off-site power. The system is designed to ensure that sufficient borated water is available from the spent fuel pools to allow the SSF to maintain mode 3 with an average Reactor Coolant temperature ≥ 525°F (the initiating event may cause average RCS temperature to drop below 525°F) for all three units for approximately 72 hours. This time period is based on drawing the water level in the spent fuel pool down to a minimum of one foot above the top of the spent fuel racks. The SSF RCM System is operated and/or tested from the Standby Shutdown Facility. The SSF RCM System is shown on Figure 9-35. The SSF RCM Pump is capable of delivering borated water from the Spent Fuel Pool to the RC pump seal injection lines. A portion of this seal injection flow is used to makeup for RC pump seal leakage while the remainder flows into the RCS to makeup for other RCS leakage. The SSF Letdown Line is used in coordination with the SSF RCM Pump for RCS inventory control.

The SSF RCM Pump is a positive displacement pump driven by an induction motor, powered from the SSF Power System. The pump is located in the Reactor Building basement sufficiently below the spent fuel pool water level to assure that adequate net positive suction head is available.

A SSF RCM Filter is supplied downstream of the SSF RCM Pump to collect particulate matter larger than five microns that could be harmful to the seal faces. The filter is sized to accept three times the flow output of the SSF RCM Pump. Fouling of this filter is not considered to be a problem since the filter has been conservatively sized.

SSF controlled pressurizer heaters support achieving and maintaining RCS natural circulation flow by offsetting pressurizer heat loss due to ambient heat loss from the pressurizer and pressurizer steam space leakage. Pressurizer heater Group B, Bank 2 that is normally controlled from the main unit's control room may be controlled from the SSF Control Panel during SSF events. Pressurizer heater Group C, Bank 2 can only be controlled from the SSF Control Panel. Pressurizer level control can be accomplished from proper control of ASW flow to the steam generators, and proper control of the SSF RC letdown line flow. Additional RCS inventory control can be accomplished using the RV head vent. SSF D/G power can be connected to the RV head vent valves. Control of the RV head vent valves will be accomplished using a portable control panel.

During an accident that requires operation of the SSF, the following RCS isolation valves are closed to preserve RCS inventory once control of these valves is transferred to the SSF (Reference Table 9-15):

1,2,3HP-3
1,2,3HP-4
1,2,3HP-20
1,2,3RC-4
1,2,3RC-5
1,2,3RC-6

9.6.3.3 Auxiliary Service Water (ASW) System

The SSF ASW System is designed to cool the RCS during a station blackout and in conjunction with the loss of the normal and Emergency Feedwater System by providing steam generator cooling.

The SSF ASW pump is the major component of the system. One motor driven SSF ASW pump, powered from OTS1 Switchgear, serves all three units and is located in the SSF. The suction supply for the SSF ASW pump, the SSF HVAC service water pumps, and the SSF DSW pump is lake water from the embedded Unit 2 condenser circulating water piping. A portable submersible pump that can be installed in the intake canal and powered from the SSF is available to replenish the water supply in the embedded CCW pipe if both forced CCW and siphon flow through the CCW pipe are lost.

The SSF ASW flow rate provided to each unit's steam generators is controlled using the motor operated valves on each unit's SSF ASW supply header. Manually operated bypass valves, installed in parallel with the motor-operated valves, are also available to:

1. Provide SSF ASW Flow control at low SSF ASW Flow rates.
2. Provide more precise SSF ASW Flow control when used in parallel with the motor-operated valves.

The SSF ASW pump is sized to provide enough flow to all 3 Oconee units to adequately remove decay heat from the RCS and maintain natural circulation in the RCS. An SSF ASW pump minimum flow line is provided to ensure that the pump minimum flow requirements are met. The SSF ASW system, pump and valves are operated and tested from the SSF only. The SSF ASW system is shown on Figure 9-36.

Auxiliary service water enters the steam generators via the normal emergency feedwater ring headers. Main Steam pressure is controlled automatically by the main steam relief valves or manually by the atmospheric dump valves (ADVs). When the ADVs are operated in this manner, communication with the SSF Control Room is in place to coordinate main steam pressure control with RCS pressure/temperature parameters. Local main steam pressure indication is also available at the ADVs.

The SSF ASW System provides the motive force for the SSF ASW suction pipe air ejector. The air ejector is needed to maintain siphon flow to the SSF HVAC service water pump, the SSF DSW pump, and the SSF ASW pump when the water level in the U2 CCW supply pipe becomes too low.

The SSF ASW System provides adequate SG cooling to reduce and maintain RCS pressure below the pressure where the SSF RC makeup pump discharge relief valve, HP-404, begins to pass flow. Therefore, full SSF RC Makeup System seal injection flow will be provided to the RC pump seals in time to prevent seal degradation or failure.

Though not a requirement for operability, the SSF diesel generator should be aligned to carry SSF loads and the SSF ASW pump should be operated to provide a large enough load so that diesel souping concerns are not a problem when the Emergency Start pushbutton is used to start the SSF diesel engines and continued operation of the SSF diesel engines is desired. While continued operation of the SSF diesel engines when they are lightly loaded is possible (i.e. one, two or three SSF RC makeup pumps operating without operating the SSF ASW pump), lightly loading the engines in this manner is not preferred due to the potential for a fire in the diesel exhaust if a large load is added after souping of the engine occurs.

Portions of the SSF ASW system are credited to meet the Extensive Damage Mitigation Strategies commitments per NEI 06-12 (B.5.b) and NEI 12-06 (FLEX). Some of these commitments have been incorporated into the Oconee Nuclear Station operating license Section H - Mitigation Strategy License Condition.

9.6.3.4 Electrical Power

9.6.3.4.1 General Description

The Standby Shutdown Facility (SSF) Electrical Power System includes 4160VAC, 600VAC, 208VAC, 120VAC, and 125VDC power. This system supplies power necessary to maintain mode 3 with an average Reactor Coolant temperature ≥ 525°F for the reactors of each unit, in the event of loss of power from all other power systems. It consists of switchgear, load center, motor control centers, panelboards, batteries, battery chargers, inverters, a diesel-electric generator unit, relays, control devices, and interconnecting cable supplying the appropriate loads.

The 120VAC power system in conjunction with the 125VDC instrumentation and control power system supplies continuous control power to all loads that are required for achieving mode 3 with an average Reactor Coolant temperature ≥ 525°F of each reactor.

Following the loss of all normal and emergency power, on-site and off-site, the diesel-electric generating unit will be manually started by initiating its start signal from the SSF Control Panel in the SSF. SSF Systems cannot operate without receiving power from the diesel for SSF scenarios when power from the Unit 2 Main Feeder Bus or the PSW (B7T-4) are not available. The diesel generator and its associated auxiliaries are housed in a Class 1 structure and are protected against seismic events.

The 4160VAC SSF Power System bus will then be connected to its diesel-electric, backup source of power by manually closing the appropriate 4160VAC generator breaker.

Schematics of the SSF electrical system are shown on Figure 9-40 and Figure 9-41.

9.6.3.4.2 Diesel Generator

The SSF Power System is provided with standby power from a dedicated diesel generator. This SSF diesel generator is rated for continuous operation at 3500 kW, 0.8 pf, and 4160 VAC. The SSF electrical design load does not exceed the continuous rating of the diesel generator. The auxiliaries required to assure proper operation of the SSF diesel generator are supplied entirely from the SSF Power System. The SSF diesel generator is provided with manual start capability from the SSF only. It uses a compressed air starting system with four air storage tanks. Each set of two tanks will provide sufficient air to start the diesel unit three successive times. An independent fuel system, complete with a separate underground storage tank, duplex filter arrangement, a fuel oil transfer pump, and one-hour day tank, is supplied for the diesel-electric generating unit.

The diesel generator protection system initiates automatic and immediate protective action to prevent or limit damage to the SSF diesel generator. The following protective trips are provided to protect the diesel generator at all times and are not bypassed when the diesel generator is in the emergency mode:

1. Engine Overspeed
2. Generator Differential Protection
3. Low-low Lube Oil Pressure
4. Generator Overcurrent

9.6.3.5 Instrumentation

9.6.3.5.1 SSF Reactor Coolant Makeup System Instrumentation

Each unit is provided with instrumentation to monitor RCM System flow, pressure and temperature; RC Loop A and B pressure and temperature; pressurizer level and pressure; and reactor incore temperature. Five (5) Incore Thermocouples per unit may be used to monitor the incore temperature. Six (6) RTD's per unit will be used to monitor Loop A and B RC System Hot & Cold Leg temperature. Readout is displayed on the SSF control panel. Table 9-16 provides a listing of instrumentation.

9.6.3.5.2 SSF Auxiliary Service Water Instrumentation

Each unit is provided with Steam Generator A & B level instrumentation labeled as listed in Table 9-16. Readout is displayed on the SSF control panel. Each unit's SSF ASW piping is also provided with instruments to monitor SSF ASW System flow and pressure. Each unit's flow is displayed on the SSF control panel. The SSF ASW pump recirculation piping is provided with instrumentation to monitor SSF ASW System recirculation flow and pressure. The recirculation flow is displayed on the SSF control panel.

9.6.3.6 Support Systems

The Standby Shutdown Facility (SSF) Support Systems are designed to provide for the SSF:

1. Lighting
2. Fire Protection
3. Fire Detection
4. Service Water
5. Heating Ventilation and Air Conditioning (HVAC)
6. Sump Drainage
7. Potable Water

The diesel engine service water and the HVAC service water piping are designed in accordance with ASME Section III, Class 3, which includes seismic design. The fire protection water, carbon dioxide, potable water, and sewage piping systems are seismically restrained in areas above seismically designed equipment. Portions of the SSF Sump System are seismically restrained to prevent flooding of the SSF Pump Room. The lighting system and the fire detection system are not seismically designed. The water and carbon dioxide fire protection systems and the fire detection system are designed and constructed to meet or exceed National Fire Codes.

9.6.3.6.1 SSF Lighting System Description

Normal lighting for the SSF is provided by various lighting unit types. These lighting units are located to provide adequate levels of light with good distribution throughout the structure.

Emergency AC lighting for the SSF is provided. These units are located to provide adequate levels of lighting in all areas of the structure.

Emergency DC lighting for the SSF is provided by self-contained 12VDC battery pack lighting units. These units are located to provide adequate levels of lighting for control panel operation and for entering and leaving the structure. These battery pack lights are energized automatically upon an undervoltage in the normal lighting system power supply.

9.6.3.6.2 SSF Fire Protection and Detection

The SSF contains two fire protection systems, a water system and a carbon dioxide system.

The water system is provided with manually valved hose reels in the stairwell at each floor elevation and inside the entrance to the diesel room. From these locations the hose lengths are such that the entire SSF can be served by the primary fire protection system.

The low pressure carbon dioxide system provided is actuated by thermal detectors to automatically flood the diesel area. Carbon dioxide is stored in a refrigerated storage tank in sufficient quantity to provide twice the required coverage for the area.

Portable carbon dioxide extinguishers are also provided.

Detection devices are located throughout the SSF and will annunciate with a single alarm to the Unit Control Rooms, SSF Control Room and Security. Specific alarms annunciate on the Fire Alarm Control Unit located in the SSF vestibule.

9.6.3.6.3 SSF Service Water

The SSF Service Water System consists of two subsystems: The HVAC Service Water System and the Diesel Engine Service Water System.

The HVAC Service Water System, which operates continuously, contains two pumps and supplies cooling water to the HVAC condensers. Only one pump will operate at any given time with the other idle pump acting as a backup.

The Diesel Engine Service Water System, which normally operates only when the diesel is operating or when system components are being tested, contains one pump and provides service water to the diesel engine jacket water heat exchangers.

This flow is monitored during periodic operational test or emergency operation. All three pumps take their suction from the embedded CCW piping and return the flow to the CCW piping after passing through their respective system. SSF Diesel Engine Service Water is diverted to the yard drain during an SSF event to avoid overheating the water contained in the SSF ASW supply piping.

The SSF Diesel Engine Service Water System is shown on Figure 9-37.

9.6.3.6.4 Heating Ventilation and Air Conditioning

The SSF HVAC system consists of two subsystems, a ventilation system and an air conditioning system. Both systems are powered by the SSF Power System. Sections of each system are shut down in event of fire in the area served. The SSF HVAC System supports operation of systems and equipment located in the SSF by maintaining temperature in the SSF within design limits.

VENTILATION SYSTEM

The diesel generator room, switchgear room, pump room, and HVAC room do not require close control of temperature, and the relatively high heat loads are dissipated with a variable volume ventilation system. The purpose of the ventilation system is to provide filtered outside air which is tempered if necessary to maintain a minimum temperature of 60°F and a maximum temperature as follows:

1. HVAC Room 120°F
2. Switchgear Room 120°F
3. Pump Room 120°F
4. Diesel Generator Room 125°F

AIR CONDITIONING SYSTEM

Certain rooms in the SSF require close control of temperature and have year-round heat loads of such magnitude to necessitate mechanical refrigeration. Normal operating conditions for these rooms are 72°F and 50 percent RH with a minimum of outside air for ventilation. During an SSF event, air conditioned rooms are maintained within the following design temperature limits:

1. SSF Control Room 100°F
2. SSF Battery Rooms 113°F
3. Computer Room (no limit for SSF power system operability)

The air conditioning system supplies each area with a constant volume of air. A heating coil located in each area with a local control tempers the air as required to maintain the desired temperature.

9.6.3.6.5 SSF Sump System

The SSF Sump System provides a collection and discharge function for normal equipment drainage within the SSF. The main components of the system are the sump and two sump pumps which handle the flow routed to the sump via the floor drain system located throughout the SSF.

9.6.4 System Evaluations

9.6.4.1 General

The design of the SSF was reviewed to meet the requirements of Appendix R of 10CFR 50, Sections III.G.3 and III.L, and those requirements applicable for flooding and seismic events. Since the transition to NFPA 805, some original SSF design criteria for fire events only no longer align with Appendix R.

The SSF, the associated mechanical and electrical systems and power supplies meet or exceed the applicable criteria contained in the Oconee FSAR Chapter 3. Additionally, ASME and IEEE codes are utilized as appropriate, in the design of various subsystems and components. The SSF and systems/components needed for safe shutdown are designed to withstand the Safe Shutdown Earthquake (SSE). The SSF systems required for safe shutdown are designed with adequate capacity to achieve and maintain mode 3 conditions with an average Reactor Coolant temperature ≥ 525°F (the initiating event may cause average RCS temperature to drop below 525°F) of all three Oconee units.

The SSF power system is designed with adequate capacity and capability to supply the necessary loads, and is physically and electrically independent from the station electrical distribution system power supply. Additionally, the AC and DC power systems and equipment required for the SSF essential functions have been designed and installed consistent with the Oconee QA program for Class 1E equipment.

These systems are not designed to meet the single failure criterion, but are designed such that failures in the systems do not cause failures or inadvertent operations of existing plant systems. The electrical systems in the SSF are manually initiated, that is, multiple actions must be performed to provide flow to existing plant safety systems.

9.6.4.2 Structure Design

The SSF is statically and dynamically analyzed and designed as a three-dimensional space frame subjected to the applicable loads summarized in Section 9.6.3.1. The Structural Design Language (STRUDL) computer program is used to perform the analyses. The design is in accordance with the codes and criteria listed in Table 9-19. Design loads and loading combinations are in accordance with the NRC Standard Review Plan, Section 3.8.4.

The SSF is designed to withstand the effects of wind and tornado loadings, without loss of capability of the systems to perform their safety functions. The basis for the selected wind velocity is reference 1 of Section 3.3. Buildings and structures with a height to minimum horizontal dimension ratio exceeding five should be dynamically analyzed to determine the effect of gust factors (ref. American National Standard, "Building Code Requirements for Minimum Design Loads in Buildings and Other Structures," ANSI A58.1-1972, New York, New York). The SSF has a height/width ratio of less than five, and therefore, the gust factor of unity is used for determining wind forces. The design tornado used in calculating tornado loadings is in conformance with Regulatory Guide 1.76 except as noted in Section 9.6.3.1.

The relatively small surface area of the structure and its location result in an extremely low probability that a turbine missile would strike the facility. Turbine missile impact is not considered a viable load condition due to the location of the SSF with respect to the turbine. All postulated missiles are per the NRC Standard Review Plan Section 3.5.1.4 Rev. 1 and Regulatory Guide 1.76, Revision 0. The barrier thicknesses for the structure are such that they preclude any perforation and/or scabbing from the postulated tornado generated missiles.

Minimum barrier thickness is three times the postulated missiles calculated depths of penetrations (see Table 9-18).

See Section 9.6.3.1 for information regarding Regulatory Guide 1.76, Revision 1, and future changes to and/or analysis of SSF-related systems, structures, and components subject to tornado loadings.

The dynamic analysis is made utilizing the STRUDL-DYNAL computer program. The design response spectra were developed in accordance with the procedures of Regulatory Guide 1.60. It corresponds to the expected maximum bedrock acceleration of 0.1g. Damping values are per Regulatory Guide 1.61.

The structure will withstand the specified design conditions without impairment of structural integrity or safety function.

9.6.4.3 Seismic Subsystem Analysis

The seismic analysis of Category I pipe is performed using dynamic modal analysis techniques. No static seismic analysis is used for SSF ASME Code piping. Modal response spectrum methods are used. Response of individual modes is combined by the Grouping Method of Regulatory Guide 1.92. An adequate number of masses or degrees of freedom are included in the model to determine the response of significant modes. The response due to each of three components of earthquake motion is combined by the square-root-of-the-sum-of-the-square rule as described in Regulatory Guide 1.92. Pipe supported from multiple levels or structure is designed for an envelope of the response spectra for all supporting structures.

Constant vertical static factors are not used. Vertical response is obtained from a dynamic modal analysis. Modal damping ratios are consistent with Regulatory Guide 1.61.

The location of the SSF non-Category I piping has been reviewed to determine those areas of proximity to Category I piping or safety related equipment. Where Category I piping or safety related equipment is in the proximity area, the non-Category I piping has been seismically qualified and supported or rerouted out of the problem area.

The SSF auxiliary service water buried piping is seismically designed for stresses resulting from SSE and OBE events. The design and analysis were based on the current state-of-the-art for initial effects and the effects of static resistance of the surrounding soil.

9.6.4.4 Dynamic Testing and Analysis of Mechanical Components

Procedures were established for the startup testing of the Class B and C piping in the SSF to verify the following information under different operating modes:

1. Physical Compliance with Piping Design: An "as built" verification procedure is utilized to verify that piping, components and support-/restraints have been erected with design tolerance.
2. Vibration Monitoring for Equipment: The purpose of this monitoring program is to verify that vibration levels for system components are within acceptance criteria. Pump vibration is monitored during testing in accordance with IWP-3210 to verify vibrations are less than or equal to the maximum allowable per the specific vendor's requirements.

9.6.4.5 ASME Code Class 1, 2, and 3 Components, Component Supports and Core Support Structures

Piping systems for the SSF are designed in accordance with the appropriate ASME Code based on the Quality Group classifications outlined in Regulatory Guide 1.26. Where part of an existing QA 1 piping system was used by an SSF subsystem to perform its function, the existing piping system was not "upgraded" to the pipe class and code used for piping when the SSF was constructed. The load combinations and stress limits contained in the requirements of SRP 3.9.3.II and referenced in Regulatory Guide 1.48 are met, except Code Case 1606 is used for the faulted load combination.

The SSF RC Makeup System is designed per the requirements stated in ASME Section III Class 2 (1974 Edition, Summer 1975 Addendum) to Oconee Class B. Portions of the HPI seal injection piping used by the SSF RC Makeup System to deliver flow to the RC pump seals are designed to Duke Class C. Also, the piping from the SSF letdown line high flow control valve (RC-219) to the pressurizer relief valve discharge line is designed as Duke Class C.

The SSF ASW System has a portion (crossover between emergency feedwater lines) in each Reactor Building that was designed per the requirements stated in ASME Section III, Class 2 (1974 Edition, Summer 1975 Addendum) to Oconee Class B. The remainder of the SSF ASW System was designed per the requirements stated in ASME Section III Class 3 (1974 Edition, Summer 1975 Addendum) to Oconee Class C. Portions of the EFW System piping used by the SSF ASW System to deliver flow to the steam generators are designed to Duke Class F.

The loads from pressure relief valves with an open discharge are evaluated in accordance with Code 1569, "Design of Piping for Pressure Relief Valve Station", assuming multiple valves on the same pipe open in the most conservative sequence. A dynamic load factor of two is used to determine the transient loads unless a lower value is justified by analysis.

Relief valves discharging into a closed system or a system with long discharge piping are reviewed to identify any significant transient loadings. Any significant loading is analyzed using dynamic analyses to include the effects of changes in momentum due to fluid flow changes of direction and any potential water slugs. The piping will be adequately supported such that piping stresses associated with the defined transient loads satisfy applicable Code requirements.

The loading combinations and stress limits contained in the requirements of SRP 3.9.3.II.4 and referenced in Regulatory Guide 1.48 are met. However, ASME Code Section III Subsection NF did not provide faulted condition allowable stress limits for Class 2 and 3 component supports until the 1977 edition. The allowables for Class 1 components in the 1974 edition of Subsection NF and subsequent applicable addenda for its Class 2 and 3 component supports faulted stress allowables were utilized.

9.6.4.6 Fire Protection

Resulting from the Nuclear Safety Capability Assessment conducted as required by NFPA 805, the SSF is credited for achieving and maintaining safe and stable plant conditions following a fire in specific locations within the Auxiliary Building, including the main control rooms.

9.6.4.6.1 Safe Shutdown Systems

Safe shutdown of the reactor is initially performed by the insertion of control rods from the control room. Insertion can also be accomplished by removing power to the control rod drive mechanisms. When normal and emergency systems are not available, reactor coolant inventory and reactor shutdown margin are maintained, from the SSF Control Panel by the SSF RC makeup pump taking suction from the spent fuel pool. Primary system pressure can be maintained by the pressurizer heaters or by use of charging combined with letdown.

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9.6.4.6.2 Performance Goals

The performance goals for post-fire safe and stable conditions (as defined in NFPA 805) can be met using the SSF for those specific fire events that require SSF control.

The process monitoring instruments to be used for a post fire shutdown include reactor coolant hot leg and cold leg temperatures, reactor coolant pressure, pressurizer level and pressure, steam generator level, SSF RC makeup pump flow, and SSF ASW system flow to each unit.

STEAM GENERATOR PRESSURE

Reactor coolant system (RCS) heat removal for achieving mode 3 with an average Reactor Coolant temperature $\geq$ 525°F can be directly monitored by RCS parameters and controlled by SG level without SG pressure indication, provided that SG pressure is regulated.

SG pressure should be regulated by the main steam code safety valves, which will relieve at their setpoints. Secondary side depressurization is limited by isolating selected main steam branch line boundary valves. RCS conditions can be monitored by primary coolant temperature and pressure, pressurizer level and SG level. Should RCS overcooling occur, corrective actions can be taken from the SSF to reinstate proper cooling by controlling the SSF ASW flow rate provided to a unit's SGs, and by restoring steam generator level for applicable events, in order to restore T-cold.

The SSF is designed to achieve and maintain mode 3 with an average Reactor Coolant temperature $\geq$ 525°F (RCS cold leg temperature $\leq$ 555°F and RCS pressure $\simeq$ 2155 psig) for one or more of the three Oconee units. The SSF is not designed to independently bring the reactor from mode 3 with an average Reactor Coolant temperature $\geq$ 525°F (RCS cold leg temperature $\leq$ 555°F and RCS pressure $\simeq$ 2155 psig) to shutdown. Shutdown will be achieved and maintained through the use of normal plant systems and equipment.

SOURCE RANGE FLUX MONITOR

The SSF is designed to achieve and maintain mode 3 with an average Reactor Coolant temperature $\geq$ 525°F (RCS cold leg temperature $\leq$ 555°F and RCS pressure $\simeq$ 2155 psig) for any or all of the Oconee units. Prior to leaving the Unit 1/2 or Unit 3 control room, all control rods for the unit under consideration are required to be inserted. No non-borated sources tie into the SSF makeup/boration flow path. RCS makeup and boration following transfer of control to the SSF RCM is from the spent fuel pool. Thus, boron dilution events are highly unlikely.

Oconee Units 1, 2, and 3 can achieve and maintain controlled cooling to mode 3 with an average Reactor Coolant temperature $\geq$ 525°F (RCS cold leg temperature $\leq$ 555°F and RCS pressure $\simeq$ 2155 psig) safely from the SSF without the need for remote SG pressure instrumentation or a remote source range monitor.

The need for source range instrumentation is not necessary since boron sampling can be utilized to ensure shutdown margin.

9.6.4.6.3 Instrumentation Guidelines

NFPA 805 states that shutdown systems installed for ensuring post-fire shutdown capability need not be designed to meet seismic Category I criteria, single failure criteria, or other design basis accident criteria, except where required for other reasons, e.g., because of interface with or impact on existing safety systems, or because of adverse valve actions due to fire damage. Since the monitors for the above listed parameters, in Section 9.6.4.6.2, will not interface with or impact existing safety systems, the monitors need not be "safety grade".

9.6.4.6.4 Repairs for Hot Shutdown

NFPA 805 requires that the plant achieve safe and stable conditions after any single fire. For scenarios requiring the use of the SSF, safe and stable conditions can be maintained in mode 3 (hot standby) with an average Reactor Coolant temperature ≥ 525°F for up to a 72 hour coping duration to allow for the repair of any damaged equipment necessary to reach hot shutdown. Repairs might include replacement of power cabling, pump motors and switchgear associated with the HPI system required for hot shutdown. Stored on-site are all components necessary to achieve all repairs. Guidelines are available to implement the required repairs and replacements.

9.6.4.6.5 Fire Protection Conclusion

While many fire areas have credited success paths for achieving safe and stable plant conditions from the Control Room, a select number of fire scenarios only credit the SSF for providing the requisite one train of systems necessary to achieve and maintain safe and stable conditions.

9.6.4.7 Flooding Review

The SSF will not be affected by the following postulated flood events:

1. Turbine Building Flood caused by a break in the non-seismic condenser circulating water (CCW) piping system.
2. Infiltration of normal groundwater.

The structure meets the requirements of GDC 2, and the guidelines of Regulatory Guide 1.102 with respect to protection against flooding.

9.6.5 Operation and Testing

The SSF will be placed into operation to mitigate the consequences of the following events/criterion:

Note that tornado is a design criterion per Section 3.2.2, but is treated similar to an event in that planned, formalized actions are taken as the result of a reported tornado.

1. Flooding
2. Fire
3. Sabotage
4. Station Blackout
5. Tornado (for Units where revised tornado mitigation strategies as described in Section 3.2.2 have been implemented)
6. High Energy Line Break for units with the HELB Mitigation Strategy (Reference 43) implemented

For fire events that require activation of the SSF for the unit affected, following local confirmation of the fire, the operator will staff the SSF and perform the electrical isolation/control transfer of the 600VAC Motor Control Center in the SSF as promptly as possible after confirmation of the fire. Following the control transfer, the operator will establish continuous communications with the Control Room of the unit affected awaiting instructions regarding the need to start and utilize the available SSF Diesel Generator, RCMU system and establish SSF Auxiliary Service Water flow to the steam generators as needed and close all of the Reactor Coolant System isolation valves that are controlled from the SSF.

Additionally, for fire and flooding events where SSF activation is required, designated main steam and feedwater boundary valves must also be promptly closed to maintain proper control of RCS parameters while the SSF is made operational.

For flooding, sabotage, station blackout, tornado (for Units where revised tornado mitigation strategies as described in Section 3.2.2 have been implemented), high energy line break for units with the HELB Mitigation Strategy (Reference 43) implemented, and those fire events where the SSF is credited for safe shutdown, operators will be sent to the SSF. When directed by the shift supervisor or procedure, the operator will start the RCM system and establish SSF Auxiliary Service Water flow to the steam generators as needed, as well as close SSF controlled Reactor Coolant System pressure boundary valves.

Deleted Paragraph(s) per 2012 update.

In-service testing of pumps and valves will be done in accordance with the provision of ASME OM Code except for the Submersible Pump which is used to supply makeup water to the Unit 2 embedded condenser circulating piping. This pump should be tested every other year to verify flow capability. A recirculation flow path with flow and pressure instrumentation is available for SSF ASW pump testing.

The electrical power system components will be tested consistent with Duke Power's Testing Philosophy as described in the nuclear station directives.

9.6.6 References

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2. Safety Evaluation for Station Blackout (10 CFR 50.63) - Oconee Nuclear Station, Units 1, 2, and 3 (TACS M68574/M68575/M68576), Docket Nos. 50-269, 50-270, 50-287, March 10, 1992
3. Safety Evaluation for Station Blackout (10 CFR 50.63) - Oconee Nuclear Staton, Units 1, 2, and 3 (TACS M68574/M68575/M68576), Docket Nos. 50-269, 50-270, 50-287, December 3, 1992
4. Safety Evaluation Report on Effect of Tornado Missiles on Oconee Emergency Feedwater System (TACS 48225, 48226, and 48227), July 28, 1989
5. Safety Evaluation Report for Implementation of Recommendation for Auxiliary Feedwater Systems, August 25, 1981
6. Evaluation of the Oconee, Units 1,2,&3 Generic Safety Issues (GSI-23 & GSI-105) Resolution, March 24, 1995
7. Letter from WO Parker (Duke) to EG Case (NRC), dated 1/25/78, Response to NRC Questions

8. Letter from WO Parker (Duke) to EG Case (NRC), dated 2/1/78, SSF System Description
9. Letter from WO Parker (Duke) to EG Case (NRC), dated 6/19/78, Response to Staff Questions Concerning Oconee Nuclear Station Safe Shutdown System
10. Letter from WO Parker (Duke) to HR Denton (NRC), dated 3/28/80
11. Letter from WO Parker (Duke) to HR Denton (NRC), dated 2/16/81, Response to NRC Request for Information
12. Letter from WO Parker (Duke) to HR Denton (NRC), dated 3/18/81, Modifications Needed to Meet Appendix R Requirements
13. Letter from WO Parker (Duke) to HR Denton (NRC), dated 3/31/81, Response to NRC Request for Information
14. Letter from WO Parker (Duke) to HR Denton (NRC), dated 4/30/81, Cable Routing and Separation
15. Letter from WO Parker (Duke) to HR Denton (NRC), dated 1/25/82, Response to NRC Concerns for Source Range Instrumentation and Steam Generator Pressure
16. Letter from HB Tucker (Duke) to HR Denton (NRC), dated 9/20/82, Response to NRC Request for Information
17. Letter from HB Tucker (Duke) to HR Denton (NRC), dated 12/23/82, Requested Supplemental Information
18. Letter from HB Tucker (Duke) to HR Denton (NRC), dated 7/15/83, Request for Exemption from 10CFR50 Appendix R, Section III.L.2
19. Letter from JF Stolz (NRC) to HB Tucker (Duke), dated 8/31/83, Exemption from Source Range Flux and Steam Generator Pressure Instrumentation for the SSF
20. Deleted per 2012 update.
21. Deleted per 2012 update.
22. Deleted per 2012 update.
23. Regulatory Guide 1.76, “Design-Basis Tornado and Tornado Missiles for Nuclear Power Plants,” Revision 1
24. OSC-9086, Calculation for the USQ Review of Regulatory Guide 1.76, Revision 1
25. Letter from CA Julian (NRC) to HB Tucker (Duke), dated 10/4/89, NRC Inspection Report
26. O-320Z-3 SSF External Barrier Walls Concrete
27. 10CFR Part 50 Appendix R Section III.L Alternative and Dedicated Shutdown Capability
28. NFPA 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants”, 2001 Edition
29. 10CFR50.48 (c), “Fire Protection”
30. ONS NFPA 805 License Amendment Request 2008-01 (April 14, 2010)
31. NRC Issuance of ONS NFPA 805 Amendments and Safety Evaluation (December 29, 2010)
32. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 346 Amendment No. 348 to Renewed Facility Operating License DPR-38 to Renewed Facility Operating License DPR-47 And Amendment No. 347 to Renewed Facility Operating

License DPR-55 Duke Energy Corporation Oconee Nuclear Station, Units 1, 2, and 3 Docket Nos. 50-269, 50-270, and 50-287, July 12, 2005.

33. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 362 to Renewed Facility Operating License No. DPR-38 Amendment No. 364 to Renewed Facility Operating License No. DPR 47 and Amendment No. 363 to Renewed Facility Operating License No. DPR-55 Duke Energy Carolinas, LLC Oconee Nuclear Station, Units 1, 2, and 3 Docket Nos. 50-269, 50-270, and 50-287, October 29, 2008.
34. Safety Evaluation issued by NRC, "Seismic Qualification of the Emergency Feedwater System," dated January 14, 1987.
35. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 325 to Renewed Facility Operating License No. DPR-38 Amendment No. 325 to Renewed Facility Operating License No. DPR 47 and Amendment No. 326 to Renewed Facility Operating License No. DPR-55 Duke Energy Carolinas, LLC Oconee Nuclear Station, Units 1, 2, and 3 Docket Nos. 50-269, 50-270, and 50-287, June 11, 2002.
36. Duke Energy letter to NRC, "Seismic Licensing Basis," May 25, 1994.
37. Duke Energy letter to NRC, "Seismic Licensing Basis," August 18, 1994.
38. Safety Evaluation issued by NRC, "SER for Station Blackout - Oconee Nuclear Station," March 10, 1992.
39. Supplemental Safety Evaluation "Supplemental SER for Station Blackout - Oconee Nuclear Station," December 3, 1992.
40. NUMARC 87-00, Rev 1, "Guidelines and Technical Bases for NUMARC Initatives Addressing Station Blackout at Light Water Reactors," August 1991.
41. OSC-11214, Rev 1, "SSF Licensing Summary Documents."
42. License Amendments Nos. 415, 417, and 416 (date of issuance – October 31, 2019); Tornado Mitigation.
43. License Amendment No. 421, 423, and 422 (date of issuance – March 15, 2021); HELB Mitigation.

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9.7 Protected Service Water System

Section 9.7, Protected Service Water System is added in its entirety. Please note that information associated with powering the pressurizer heaters and vital I&C battery chargers will not be effective until completion of Milestone 5.

9.7.1 General Description

The Protected Service Water (PSW) System is designed as a standby system for use under emergency conditions. The PSW System provides added "defense-in-depth" protection by serving as a backup to existing safety systems and as such, the system is not required to comply with single failure criteria. The PSW System is provided as an alternate means to achieve and maintain safe shutdown conditions for one, two or three units following certain postulated scenarios. The PSW System reduces fire risk by providing a diverse power supply to power safe shutdown equipment in accordance with the National Fire Protection Association (NFPA) 805 safe shutdown analyses. The PSW System requires manual activation and can be activated if normal emergency systems are unavailable.

The function of the PSW System is to provide a diverse means to achieve and maintain safe shutdown by providing secondary side decay heat removal, RCS pump seal cooling, RCS primary inventory control, and RCS boration for reactivity management following plant scenarios that disable the 4160V essential electrical power distribution system. Following achieving safe shutdown, a plant cooldown is initiated within 72 hours of event initiation. The PSW System is not an Engineered Safety Feature Actuation System (ESFAS) and is not credited to mitigate design basis events as analyzed in UFSAR Chapters 6 and 15. No credit is taken in the safety analyses for PSW System operation following design basis events. Based on its contribution to the reduction of overall plant risk, the PSW System satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii) and is therefore included in the Station Technical Specifications.

Core decay heat removal is provided by feeding the steam generators from the PSW pumps (booster and high head pumps) via PSW flow control valves. Core reactivity is controlled in a safe manner by injecting borated water from the borated water storage tank (BWST) into the RCS to maintain adequate shutdown margin. RCS inventory control is provided by existing plant equipment that can be selectively powered from the PSW Electrical Distribution System. Specifically, one High Pressure Injection (HPI) pump (either "A" or "B"), the associated suction valve from the BWST (HP-24), the RCP seal injection flow control valves (HP-139 and HP-140), and the "A" HPI injection valve (HP-26) can be powered from PSW to provide RCS makeup. RCS letdown can be provided by repowering the Reactor Vessel (RV) Head Vents (RC-159 and RC-160) and the RCS Loop High Point Vent Valves (RC-155, -156, -157, -158) and repositioning the valves as needed to control RCS inventory. These valves are capable of being supplied with electrical power from the PSW switchgear. Manual power transfer control switches for these components are located in each respective unit’s control room.

The PSW Electrical Distribution System can be used to repower a number of pressurizer heaters to establish and maintain a steam bubble in the pressurizer to aid in RCS pressure control. Selected pressurizer heaters with a nominal combined capacity of ≥ 400 kW are capable of being supplied with electrical power from the PSW switchgear. Manual power transfer switches for these components are located in each respective unit’s East Penetration Room.

The PSW Electrical Distribution System also supplies power to the Vital Instrumentation and Control (I&C) Battery Chargers to maintain electrical power on the vital I&C buses. The PSW Electrical Distribution System can also be aligned to supply power to the Standby Shutdown

Facility (SSF) Electrical Distribution System should the normal and emergency power sources to the SSF be lost.

The PSW System does not provide the primary success path for core decay heat removal following design basis events and transients. The Emergency Feedwater (EFW) System serves as the primary success path for design basis events and transients in which the normally operating main feedwater system is lost and the steam generators are relied upon for core decay heat removal. The PSW System serves as a backup to the EFW System and adds a layer of defense-in-depth to the SSF Auxiliary Service Water (ASW) System, which also serves as a backup to the EFW System.

The PSW System reduces fire risk by providing a diverse QA-1 power supply to power safe shutdown equipment thus enabling the use of plant equipment for mitigation of certain fires as defined by the Oconee Fire Protection Program. For certain scenarios inside the Turbine Building (TB) resulting in loss of 4160V essential power, either the SSF or PSW System is used for reaching safe shutdown. (For HELBs, see UFSAR Section 3.6.) The PSW System can achieve and maintain safe shutdown conditions for all three units for an extended period of operation during which time other plant systems required to cool down to MODE 5 conditions will be restored and brought into service as required. Similar to the SSF, the PSW System is equipped with a portable pumping system that may be utilized as necessary to replenish water to the Unit 2 embedded Condenser Circulating Water (CCW) piping. The water in the Unit 2 embedded CCW piping is used as a suction source for the PSW System. Electrical power is supplied from the PSW electrical system. The PSW portable pump is located in an onsite storage location. The portable pumping system is not expected to be necessary unless there is a prolonged use of the PSW System to feed the steam generators. Should there be a prolonged use of the PSW System, the portable pumping system would be used to replenish the water in the CCW piping since the PSW System takes suction off the CCW pipe at its low point in the Unit 2 Auxiliary Building.

The PSW System consists of the following:

1. PSW Building and associated support systems.
2. Conduit duct bank from the Keowee Hydroelectric Station underground cable trench to the PSW Building.
3. Conduit duct bank and raceway from PSW Building to Unit 3 Auxiliary Building (AB).
4. Conduit duct bank from PSW Building to SSF trench and from SSF trench to SSF.
5. Electrical power distribution system from breakers at Keowee Hydro Units (KHUs) and from breakers connecting the PSW Building to the Central Tie Switchyard, and from there to the AB and SSF.
6. PSW booster pump, PSW primary pump, and mechanical piping taking suction from Unit 2 embedded CCW System to the EFW headers supplying cooling water to the respective unit's SGs and HPI pump motor bearing coolers.
7. PSW portable pumping system.
8. PSW pump room exhaust fan (in AB).

Portions of the PSW System are credited to meet the Extensive Damage Mitigation Strategies (B.5.b) commitments, which have been incorporated into the Oconee Nuclear Station operating license Section H - Mitigation Strategy License Condition.

The PSW mechanical system is shown on Figure 9-44. The interface of the PSW System and the EFW System is shown on Figure 10-8. The PSW AC electrical distribution system is shown on Figure 9-45. The PSW DC electrical distribution system is shown on Figure 9-46.

In order to ensure PSW/HPI mitigating component design temperature limits will not be exceeded during PSW/HPI System operation, alternate cooling water and power to the existing ventilation systems is provided to recover from the potential loss of ventilation to the AB and RB (refer to Section 9.7.3.4.5).

9.7.2 Design Bases

The design criteria for the PSW System are as follows:

1. Major PSW components are Duke Energy Quality Assurance Condition 1 (QA-1). Components that receive backup power from PSW or systems that connect to PSW retain their existing seismic and quality classifications.
2. Maintain a minimum water level above the reactor core and maintain Reactor Coolant Pump Seal cooling. In addition, maintains Reactor Coolant System subcooling for fire scenarios.
3. Provide steam generator secondary side cooling water from Lake Keowee to promote natural circulation core cooling.
4. Transfer decay heat from the RCS by steaming the steam generator(s) (SGs) to atmosphere.
5. Maintain K_{eff} < 0.99 after all normal sources of RCS makeup have become unavailable, by providing makeup via the HPI system which supplies makeup of a sufficient boron concentration from the BWSTs.
6. Control of PSW primary and booster pumps, motor operated valves and solenoid valves, required to bring the system into service are controlled from the Main Control Rooms (MCRs).

9.7.3 System Description

9.7.3.1 Mechanical

The mechanical portion of the PSW System is designed to provide decay heat removal by feeding Lake Keowee water to the secondary side of the steam generators. The system, consisting of one booster pump and one primary (high-head) pump, is designed to provide 375 gpm per unit at 1082 psig with SG pressure at the lowest relief valve lift set point. In addition, the system is designed to supply Lake Keowee water at 10 gpm per unit to the HPI pump motor bearing coolers. Refer to Figure 9-44 and Figure 10-8 for more information.

The PSW System utilizes the inventory of lake water contained in the plant Unit 2 CCW embedded piping. The PSW pumps are located in the AB at Elevation 771'. The PSW booster pump takes suction from the Unit 2 CCW embedded piping and with the aid of the PSW primary pump, discharges into the SG(s) of each unit via separate lines into the emergency feedwater headers. The raw water is vaporized in the SG(s) removing residual heat and discharged to the atmosphere. For extended operation, a portable pump can be utilized via recovery actions to pump water directly from Lake Keowee to the Unit 2 CCW embedded piping.

During periods of very low decay heat the PSW System will be used to establish conditions that support the formation of subcooled natural circulation between the core and the SGs; however, natural circulation may not occur if the amount of decay heat available is less than or equal to the amount of heat removed by ambient losses to containment and/or by other means, e.g., letdown of required minimum HPI flow through the RCS vent valves. When these heat removal mechanisms are sufficient to remove core decay heat, they are considered adequate to meet the core cooling function and systems supporting SG decay heat removal, although available, are not necessary for core cooling.

The piping system has pump minimum flow lines that discharge back into the Unit 2 CCW embedded piping. For flow testing to the steam generators, the system is connected to a condensate water source located in the TB that is normally isolated using valves in the AB.

The PSW pumps are controlled from the Unit 2 main control room. Electrically operated valves, used to control flow to the SGs, are controlled from each unit's control room. PSW transfer switches for the HPI motor and motor operated valves, required to operate the system, are located in each unit's respective control room. Check valves and manual handwheel operated valves are used to prevent back-flow, accommodate testing, or are used for system isolation during system maintenance. Pumps and valves in the system are ASME Section III Class 3. Piping is designed to the 1967 Edition of USAS B31.1 (Reference 11). The PSW System piping is classified as Oconee Class F.

Inservice testing of pumps and valves is accomplished in accordance with the provisions of ASME Section XI and Oconee's In-Service Test (IST) program, except for the portable pump. The portable pump is tested periodically to verify flow capability. A recirculation flow path and instrumentation is available for testing of the PSW Booster and PSW Primary Pumps. Active motor operated valves are included in the ONS Generic Letter (GL) 89-10 monitoring program.

9.7.3.2 Electrical

The PSW electrical system is designed to provide power to PSW mechanical and electrical components as well as other system components needed to establish and maintain a safe shutdown condition. The system is designed with adequate capacity and capability to supply the necessary loads and is electrically independent from the station electrical distribution system.

A separate PSW electrical equipment structure (PSW Building) is provided for major PSW electrical equipment. Normal power is provided from the Central Tie Switchyard via a 100 kV transmission line to a 100/13.8 kV substation located adjacent to Oconee Nuclear Station and then via an overhead 13.8 kV feeder that transitions to a direct-buried and underground conduit route leading to the PSW Building. This power path from the Central Tie Switchyard to the PSW Switchgear is non QA-1. Alternate QA-1 power is provided from the KHUs via a tornado protected underground path. These external power sources provide power to transformers, switchgear, breakers, load centers, batteries, and battery chargers located in the PSW electrical equipment structure (PSW Building). The PSW DC system consists of two (2) batteries, two (2) battery chargers, a distribution center and panelboards. Either battery can be aligned to either battery charger. Refer to Figure 9-45 and Figure 9-46 for additional information.

The power system provides primary or backup power to the following:

1. PSW booster pump
2. PSW primary pump
3. Required 125 VDC Vital I&C Normal Battery Chargers (CA & CB)

4. One HPI pump (either "A" or "B") motor per unit
5. HPI valves needed to align the HPI pumps to the BWSTs
6. HPI valves and instruments that support RCP seal injection and RCS makeup
7. RCS and Reactor Vessel Head high point vent valves
8. Portable pump (if not self-powered)
9. Select groups of pressurizer heaters (nominal capacity in excess of 400 KW)
10. Standby Shutdown Facility (SSF)
11. Control Battery Room Ventilation System

The PSW Electrical Distribution System does not provide the primary success path for supplying electrical power to systems and components used to mitigate design basis events and transients. The two main feeder buses and the three Engineered Safeguards (ES) power strings are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ES systems so that the fuel, RCS, and containment design limits are not exceeded. The main feeder buses and the ES power strings are the primary success path, consistent with the initial assumptions of the accident analyses, and are credited to meet the design basis of the unit. The PSW Electrical Distribution System serves as a backup source of power for certain components normally powered from the three ES power strings.

9.7.3.2.1 Electrical Separation Criteria

The PSW electrical power distribution system has only one train; however, the PSW Primary and Booster Pump circuits, and the associated valve circuits in the PSW System are separate to the SSF ASW pump and valve circuits with one exception. The PSW 4.16 kV switchgear has a circuit that can repower the SSF 4.16 kV switchgear in the event the SSF normal and emergency power sources are not available. This circuit is normally electrically isolated from the SSF switchgear. Whenever the PSW 4.16 kV switchgear is providing power to the SSF, there will no longer be electrical separation between the PSW and SSF electrical systems.

The KHU generator output breakers to the PSW circuits (KPF-9 and KPF-10) are electrically interlocked such that both breakers cannot be closed simultaneously. This feature prevents inadvertent connection of the outputs of KHU-1 and KHU-2, maintaining train separation and preventing potential damage to the generators.

9.7.3.2.2 Electrical Testing Requirements

The electrical power system components are tested consistent with Oconee's testing philosophy as described in fleet procedures.

9.7.3.3 Instrumentation and Control (I&C)

The PSW System has dedicated instrumentation and controls located in each main control room (MCR) as follows:

1. Two (2) high flow controllers (one per SG)
2. Two (2) low flow controllers (one per SG)
3. Two (2) flow indicators (one per SG)
4. One (1) SG header isolation valve

5. Two (2) HPI pump power transfer switches
6. Power transfer control switches to HPI valves needed to align the HPI System
7. Power transfer control switches for the Reactor Vessel Head and RCS High Point vent valves

SG parameters and critical reactor coolant system parameters are monitored in the MCRs. The critical reactor parameters needed to support PSW operation are:

1. Two (2) Hot Leg Temperature
2. Two (2) Cold Leg Temperature
3. Twelve (12) Core Exit Thermocouples
4. RCS Pressure (Trains A & B)
5. RCP Seal Injection Flow
6. HPI Injection Flow (Train A)
7. Pressurizer Level (Train A & B)
8. PSW Flow

9.7.3.4 Support Systems

The PSW Building support systems are designed to provide:

1. Emergency Lighting
2. Fire Protection and Detection
3. Heating, Ventilation, and Air Conditioning
4. Duct Bank and Building Drainage
5. Battery power backup.

9.7.3.4.1 PSW Building Lighting System

The PSW Building lighting system consists of exit/emergency signs, security lighting fixtures, indoor and exterior building lighting.

Emergency DC lighting for the PSW Building is provided by self-contained 12VDC battery pack lighting units. These units are located to provide adequate levels of lighting for control panel operation and for entering and leaving the structure.

9.7.3.4.2 PSW Building Fire Protection and Detection System

Fire protection for the PSW Building is provided by two hose reel stations inside the building and adjacent fire hydrants outside of the building. The hose reels are located such that hose spray can reach any interior portion of the building. The High Pressure Service Water (HPSW) System at the north and south ends of the PSW Building supplies the fire protection water. The HPSW System is maintained filled to meet NFPA 805 requirements.

The PSW Building fire detection system consists of a local fire alarm control panel (FACP), a remote fire alarm annunciator panel, photoelectric smoke detectors, heat detectors, an outdoor horn/strobe, indoor horn/strobes and multiple manual pull stations. The system is connected to the Unit 3 FACP via two monitor modules, alarm and trouble. The Unit 3 FACP will alert operators when either module actuates.

9.7.3.4.3 PSW Building Heating Ventilation and Air Conditioning System

The PSW Building Heating, Ventilation, and Air Conditioning (HVAC) system consists of two subsystems, a ventilation system and an air conditioning system. The PSW HVAC System supports operation of systems and equipment located in the PSW Building by maintaining temperature within design limits. The air conditioning system is normally operating while the ventilation system is in standby. The ventilation system will actuate in the event the air conditioning is lost. Both systems are shut down in event of fire in the building.

The PSW Building HVAC is designed to maintain transformer and battery rooms within their design temperature range. The HVAC System consists of two (2) systems; a non QA-1/non credited system designed to maintain the PSW Transformer and Battery Rooms environmental profile and a QA-1/ credited system designed to actuate whenever the non QA-1 system is not able to meet its design function.

VENTILATION SYSTEM

The PSW Building Transformer Room and Battery Rooms have independent ventilation systems. These two systems contain exhaust fans, duct heaters, tornado dampers, backdraft dampers, motor-operated dampers, air inlet dampers, and associated ductwork. Ventilation for the Battery Rooms is designed to provide adequate air flow to prevent buildup of hydrogen emitted from charging batteries in accordance with IEEE-484 (Reference 21). Both ventilation systems are located within the PSW Building and protected from tornado loads. The purpose of the ventilation systems is to maintain the PSW Building at temperatures between 60°F and 130°F.

AIR CONDITIONING SYSTEM

The PSW Building Transformer Room and Battery Rooms have independent air conditioning systems. Both systems are similar in that the condensing units are located on concrete pads outside the PSW Building. The transformer space air handling units are mounted on platforms inside the PSW Building east wall. Cooling coils and fans for the Battery Rooms are integral with the Battery Room ventilation system. The purpose of the air conditioning systems is to maintain the PSW Building at approximately 75°F. The air conditioning systems are designed in accordance with ASME AG-1-2003 (Reference 17).

9.7.3.4.4 PSW Building Underground Duct Bank Drainage System

The underground duct banks and manholes associated with the PSW Building are designed and installed to preclude water entry. In the event of water entry, duct bank conduits are sloped to manholes to prevent standing water accumulation. Manholes and duct banks are provided with gravity drains that exit the duct bank or lead to existing yard drains, or in the case of Manhole 7 and the Technical Support Building cable vault, to the Radwaste and Interim Radwaste Trenches.

Manhole inspection ports are provided to ensure that the manholes drains are working properly and there is no standing water in the manholes. The inspection ports are located such that the bottom of the manhole is visible and inspection of the manhole interior may be accomplished by video camera without removing the manhole cover. Manhole drain exit points are provided with animal screens. Underground drain fields or dry wells are not used.

9.7.3.4.5 Alternate Cooling for the Reactor and Auxiliary Buildings

Alternate cooling water and power to the existing ventilation systems is provided to recover from the potential loss of normal AB and RB ventilation and to support extended PSW System operation to meet NFPA 805 requirements.

The alternate cooling equipment is included in the QA-5 program in accordance with the Duke Quality Assurance Topical Report as discussed in UFSAR Chapter 17. Existing repowered equipment retains its current quality classification. Cooling water to the RB equipment is supplied from Lake Keowee. Cooling water to the AB is supplied by portable chillers. The equipment is not protected from tornado or external flood damage and is not single failure proof. The equipment is not seismically designed; however, it is designed to preclude interactions with other seismically-designed SSCs during a seismic event.

9.7.3.5 Civil/Structural

9.7.3.5.1 Building Structures

The PSW System is housed in four new QA-1 structures, as follows:

1. PSW Building.
2. Conduit duct banks and manholes connecting the Keowee Underground to the PSW Building.
3. Conduit duct banks, Technical Support Building (TSB) cable vault, Elevated Raceway, and Manhole 7 connecting the PSW Building with the Unit 3 Auxiliary Building (AB).
4. Conduit duct banks connecting Manhole 7 to the SSF cable trench and the SSF trench to the SSF.

The PSW Building houses the major electrical equipment. The building is a reinforced concrete structure consisting of a transformer room, a mezzanine, a cable spreading area, and two battery rooms. The building is seismically qualified to the Maximum Hypothetical Earthquake (MHE) and designed to withstand tornado missiles, wind and differential pressure in accordance with Regulatory Guide 1.76, Revision 1 (Reference 7). The following load conditions were considered in the analysis and design:

1. Structure Dead Load
2. Equipment Loads
3. Live Loads
4. Normal Wind Loads
5. Seismic Loads
6. Tornado Wind Loads
7. Tornado Missile Loads
8. Tornado Differential Pressure Loads

A reinforced concrete conduit duct bank connects the Keowee Underground power path to the PSW Building. From the PSW Building, a second reinforced concrete conduit duct bank/elevated raceway connects to the Unit 3 AB. A third conduit duct bank connects the PSW Building to the existing SSF cable trench. These structures were seismically qualified to the Maximum Hypothetical Earthquake (MHE) and designed to withstand tornado missiles, wind and differential pressure in accordance with Regulatory Guide 1.76, Revision 1 (Reference 7).

The PSW Building and the three duct banks were designed in accordance with the following codes and standards:

1. ACI 349-97 (Reference 3).
2. AISC Manual of Steel Construction, 13th edition, 2006 (Reference 4).
3. ANSI / AISC, N690-1984 (Reference 5).
4. ASCE 4-98 (Reference 19)
5. NUREG-0800, Chapter 3, Revision 3, March 2007 (Reference 20).
6. Regulatory Guide 1.122, Revision 1, February 1978 (Reference 15).
7. Regulatory Guide 1.142, Revision 2, November 2001 (Reference 6).
8. Regulatory Guide 1.76, Revision 1, March 2007 (Reference 7).
9. Topical Report BC-TOP-9A, Revision 2, Bechtel Power Corporation, 1974 (Reference 8).

The existing sections of the Interim Radwaste Trench, which the conduit duct bank/elevated raceway from the PSW Building to the Unit 3 AB connects to, were designed in accordance with ACI 318-63 (Reference 9). The existing sections of the SSF trench, which the conduit duct bank from the PSW Building to the SSF connects to, were designed in accordance with ACI 318-71, "Building Code Requirements for Reinforced Concrete" (Reference 10).

The PSW Building is founded on structural fill (overburden). The Maximum Hypothetical Earthquake (MHE) response spectra used for the design of the PSW Building was Figure 2-55 of the ONS UFSAR in accordance with ONS current licensing basis (UFSAR Section 3.7.1.1 "Design Response Spectra"). The design MHE in-structure response spectra for the PSW Building was generated from the time history record of the North-South, May 1940 El Centro earthquake normalized to a peak ground acceleration of 0.15g for both the vertical and horizontal excitations in accordance with the ONS current licensing basis (UFSAR Section 3.7.1.2 "Design Time History"). The building design in-structure response spectra were developed in accordance with the intent and guidance of Regulatory Guide 1.122 (Reference 15). The dynamic analysis of the PSW Building is made using the STAAD-PRO computer program with amplified response spectra generated at elevations of significant nodal mass.

9.7.3.5.2 Subsystem Seismic Analysis

The PSW mechanical piping system was seismically designed using dynamic modal analysis techniques. The system was modeled using the lumped mass piping analysis program SUPERPIPE. An adequate number of lumped masses or degrees of freedom are included in the model to determine the response of significant modes. Rigid range acceleration effects are included in the modal analysis. The Oconee Nuclear Station earthquake motion is two directional in accordance with UFSAR Section 3.7.2.5. Therefore, the PSW structures, systems and components (SSCs) have been analyzed for maximum horizontal component (either X or Z) and the vertical component (Y) for seismic loads applied simultaneously. Pipe supported from multiple levels or structure is designed for an envelope of the response spectra for all supporting structures. Resulting analysis stresses were evaluated using the ASME USAS B31.1.0, 1967 edition (Reference 11).

The PSW mechanical piping was evaluated for potential effects from non-seismic piping and components that may be proximate to the system.

The PSW HVAC system was designed in accordance with ASME AG-1-2003 (Reference 17).

PSW piping supports were designed in accordance with the AISC Manual of Steel Construction, 6th edition, 1963 (Reference 12) per UFSAR Section 3.9.3.4.2. Tube steel shapes were designed using AISC 7th Edition (Reference 18) with the equations used reconciled with the 6th Edition.

Cable trays located in the PSW Building, the ONS AB, and the Keowee Hydro Station, installed to support the PSW electrical distribution system, were evaluated by the Seismic Qualification Utility Group Generic Implementation Procedure (SQUG GIP) for Seismic Verification of Nuclear Plant Equipment, Revision 3A (Reference 13).

The structural attachment of equipment within the PSW Building was designed in accordance with the following codes and standards:

1. AISC Manual of Steel Construction for Member Properties, 13th edition, 2006 (Reference 4).
2. Regulatory Guide 1.142, Revision 2, November 2001 (Reference 6).
3. AISI North American Specification for the Design of Cold-Formed Steel Structural Members, 2001 Edition (Reference 14).
4. ANSI / AISC N690-1984 (Reference 5).
5. Regulatory Guide 1.122, Revision 1, February 1978 (Reference 15).
6. Regulatory Guide 1.199, November 2003 (Reference 16).
7. OSS-0020.00-00-0006, Specification for the Design, Installation and Inspection of Hilti Concrete Expansion Anchors (Reference 24).

The anchorage of PSW related equipment in the ONS AB was designed in accordance with the following codes, standards, and specifications:

1. For concrete expansion anchors: OSS-0020.00-00-0006, Specification for the Design, Installation and Inspection of Hilti Concrete Expansion Anchors (Reference 24).
2. For grouted anchor bolts: ACI 349-01 (Reference 22), ACI 349-06 (Reference 23), and Regulatory Guide 1.199 (Reference 16).
3. For steel support frames: AISC Manual of Steel Construction, 6th edition (Reference 12).
4. Member properties for steel support frames: AISC Manual of Steel Construction, 13th edition, 2006 (Reference 4) and AISC Manual of Steel Construction, 14th edition (Reference 25).
5. Evaluation of anchorage loads on ONS AB structural members: ACI 318-63 (Reference 9).

9.7.3.5.3 Dynamic Testing and Analysis of Mechanical Components

As part of the PSW System implementation process, procedures were established for the startup testing of the PSW mechanical system to verify the following information:

1. An "as-built" verification process is used to verify that the piping, components, and piping support/restraints have been erected within the design tolerance.
2. Vibration monitoring was completed to verify that vibration levels for system components during PSW Booster and PSW Primary Pump operations are within acceptable limits.

9.7.4 Safety Evaluation

To verify PSW System performance criteria, thermal-hydraulic (T/H) analysis was performed to demonstrate that the PSW System could achieve and maintain safe shutdown following postulated fires that disable the 4160V essential power distribution system, without reliance on equipment located in the turbine building. The analysis evaluates RCS subcooling margin using inputs that are representative of plant conditions as defined by Oconee’s NFPA 805 Fire Protection Program. The analysis uses an initial core thermal power of 2619 MWth (102% of 2568 MWth) and accounts for 24 month fuel cycles. The consequences of the postulated loss of main and emergency feedwater and 4160 VAC power were analyzed as a RCS overheating scenario. For the examined overheating scenario, an important core input is decay heat. High decay heat conditions were modeled that were reflective of maximum, end of cycle conditions. The high decay heat assumption was confirmed to be bounding with respect to the RCS subcooling response. The results of the analysis demonstrate that the PSW System is capable of meeting the relevant NFPA 805 nuclear safety performance criteria.

During periods of very low decay heat the PSW System will be used to establish conditions that support the formation of subcooled natural circulation between the core and the SGs; however, natural circulation may not occur if the amount of decay heat available is less than or equal to the amount of heat removed by ambient losses to containment and/or by other means, e.g., letdown of required minimum HPI flow through the Reactor Coolant vent valves. When these heat removal mechanisms are sufficient to remove core decay heat, they are considered adequate to meet the core cooling function and systems supporting SG decay heat removal, although available, are not necessary for core cooling.

Regarding operation in MODES 1 and 2 other than operation at nominal full power, the duration of operation in these conditions is insufficient to result in an appreciable contribution to overall plant risk. As a result, T/H analysis was performed assuming full power initial conditions, as described above and in the Oconee Fire Protection Program, Nuclear Safety Capability Assessment (Reference 2). The plant configuration examined in the T/H analysis is representative of risk significant operating conditions and provides reasonable assurance that a fire mitigated by PSW during these MODES will not prevent the plant from achieving and maintaining fuel in a safe and stable condition.

9.7.5 References

1. Not used (reserved for Nuclear Station Report ONDS-351, "Analysis of Postulated High Energy Line Breaks (HELBs) Outside of Containment," (Rev. 2)).
2. NRC Issuance of ONS NFPA 805 Amendments and Safety Evaluation dated December 29, 2010.
3. ACI 349-97, "Code Requirements for Nuclear Safety Related Concrete Structures" (and its supplements, except Appendix B), American Concrete Institute.
4. AISC, Manual of Steel Construction, 13th edition, 2006, American Institute of Steel Construction.
5. ANSI/AISC, N690-1984, "Specification for the Design, Fabrication, and Erection of Steel Safety Related Structures for Nuclear Facilities."
6. Regulatory Guide 1.142, "Safety Related Concrete Structures for Nuclear Power Plants," Revision 2, November 2001.
7. Regulatory Guide 1.76, "Design Basis Tornado and Tornado Missiles for Nuclear Power Plants," Revision 1, March 2007.

8. Topical Report BC-TOP-9A, "Design of Structures for Missile Impact," Revision 2, Bechtel Power Corporation, 1974.
9. ACI 318-63, "Building Code Requirements for Reinforced Concrete," American Concrete Institute.
10. ACI 318-71, "Building Code Requirements for Reinforced Concrete," American Concrete Institute.
11. ASME, USAS B31.1.0-1967, "Power Piping," American Society of Mechanical Engineers.
12. AISC, Manual of Steel Construction, 6th edition, 1963, American Institute of Steel Construction
13. Seismic Qualification Utility Group (SQUG), Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment, Revision 3A.
14. AISI, North American Specification for the Design of Cold-Formed Steel Structural Members, 2001 Edition, American Iron and Steel Institute.
15. Regulatory Guide 1.122, "Development of Floor Design Response Spectra for Seismic Design of Floor Supported Equipment or Components," Revision 1, February 1978.
16. Regulatory Guide 1.199, "Anchoring Components and Structural Supports in Concrete," November 2003.
17. ASME AG-1-2003, "Code on Nuclear Air and Gas Treatment," American Society of Mechanical Engineers.
18. AISC, Manual of Steel Construction, 7th Edition, American Institute of Steel Construction
19. ASCE 4-98, "Seismic Analysis of Safety-Related Nuclear Structures and Commentary," American Society of Civil Engineers.
20. NUREG-0800, Chapter 3, USNRC Standard Review Plan 3.7.2, Seismic System Analysis, Revision 3, March 2007.
21. IEEE-484-2002, "IEEE Recommended Practice for Installation design and installation of large lead storage batteries for generating stations and substations."
22. ACI 349-01, "Code Requirements for Nuclear Safety Related Concrete Structures," American Concrete Institute.
23. ACI 349-06, "Code Requirements for Nuclear Safety Related Concrete Structures," American Concrete Institute.
24. OSS-0020.00-00-0006, Specification for the Design, Installation and Inspection of Hilti Concrete Expansion Anchors.
25. AISC, Manual of Steel Construction, 14th edition, 2011, American Institute of Steel Construction.

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Appendix 9A. Tables

Table 9-1. Spent Fuel Cooling System Data, Units 1, 2

System Design Pressure, psig		125
System Design Temperature, °F		215
Spent Fuel Coolers A&B		
	Type	Shell and tube
	Material Shell/Tube	SS/SS
	Capacity, Btu/hr/cooler	27.2×10^6
	Cooling Water Flow, lb/hr/cooler	5×10^5
	Code	ASME VIII, III-C
Spent Fuel Cooler C		
	Type	Plate
	Material	SS
	Capacity, Btu/hr	27.2×10^6
	Cooling Water Flow, lb/hr	5×10^5
	Code	ASME III-3
Spent Fuel Pumps		
	Type	Horizontal, centrifugal
	Material	SS
	Design Flow, gal/min	1,000
	Design Head, ft H_2O	100 (Pumps A&B) 110 (Pump C)
	Motor Horsepower, hp	40
Spent Fuel Pool Volume, ft^3		73,000
Spent Fuel Filters		
	Design Flow, gal/min	180
	Material	SS
	Design Pressure, psig	150
	Design Temperature, °F	200
	Code	ASME III-C
Borated Water Recirculation Pump		
	Type	Vertical, inline, centrifugal
	Material	SS
	Design Flow, gal/min	180
	Design Head, ft H_2O	140

	Motor Horsepower, hp	15
	Design Pressure, psig	125
	Design Temperature, °F	250
Spent Fuel Demineralizer		
	Type	Mixed bed
	Material	SS
	Resin Volume, ft^3	21
	Design Flow, gal/min	180
	Design Pressure, psig	125
	Design Temperature, °F	250
	Code	ASME III-C

Table 9-2. Spent Fuel Cooling System Data, Oconee 3

System Design Pressure, psig	125
System Design Temperature, °F	215
Spent Fuel Coolers A and B	
Type	Tube and shell
Material Tube/Shell	SS/SS
Design Heat Rate, BTU/hr/cooler	27.2×10^6
Cooling Water Flow, lb/h/cooler	5×10^5
Design Inlet Temp., °F	205
Design Outlet Temp., °F	150.6
Code	ASME VIII/III-C
Spent Fuel Cooler C	
Type	Plate
Material	SS
Capacity, Btu/hr	27.2×10^6
Cooling Water Flow, lb/hr	5.0×10^5
Code	ASME III-3
Spent Fuel Pumps	
Type	Horizontal, centrifugal
Material	SS
Flow, gal/min	1,000
Design Head, ft H_2O	100
Motor Horsepower, hp	40
Spent Fuel Pool Volume, ft^3	50,000
Spent Fuel Filters	
Design Flow Rate, gal/min	180
Material	SS
Design Temperature, °F	200
Design Pressure, psig	125

Code	ASME III-C
Borated Water Recirculation Pump	
Type	Vertical, inline, centrifugal
Material	SS
Flow, gal/min	180
Head, ft H_2O	140
Motor Horsepower, hp	15
Design Temperature, °F	250
Design Pressure, psig	125
Spent Fuel Demineralizer	
Type	Mixed bed
Material	SS
Resin Volume, ft^3	21
Flow, gal/min	180
Design Temperature, °F	250
Design Pressure, psig	125
Code	ASME III-C

Table 9-3. Component Cooling System Performance Data (For Normal Operation on a Per Oconee Basis)

Number of Component Cooling Pumps	2
Number of Pumps Normally Operating	1
Design Flow, gpm	766
Number of Component Coolers	
Oconee 1 and 2	1 + 1 Shared Spare
Oconee 3	2
Number of Coolers Normally Operating	1
Design Heat Removal Requirements, Btu/h per cooler	19×10^6

Table 9-4. Cooling Water Systems Component Data (Component Data on a Per Unit Basis)

Parameter	Value
Note: This table contains the original selected nominal design points for few key components. It is not intended to convey design limits or nominal operating conditions. It is not a comprehensive list of components.	
Condenser Circulating Water Pumps	4 per unit
Flow (per pump), gal/min	177,000
Design temperature, °F	90
Total Developed Head at Rated Flow, psig	12.4, at rated flow
High Pressure Service Water Pumps	2 for all units
Flow (per pump), gal/min	6,000
Design temperature, °F	75
Design pressure, psig	117
High Pressure Service Water Jockey Pump	1 for all units
Flow (per pump), gal/min	500
Design temperature, °F	75
Design pressure, psig	117
Low Pressure Service Water Pumps	5 for all units
Flow (per pump), gal/min	15,000
Design temperature, °F	75
Design pressure, psig	65
Recirculated Cooling Water Pumps (Units 1 & 2)	4 shared
Flow (per pump), gal/min	2,400
Design temperature, °F	105
Design pressure, psig	100
Recirculated Cooling Water Pumps (Unit 3)	2
Flow (per pump), gal/min	2,050
Design temperature, °F	150
Design pressure, psig	100
Recirculated Cooling Water Heat Exchangers (Units 1 & 2)	4 shared
Type	Shell and tube
Recirculating cooling water flow, each (shellside), gal/min	1,800

Parameter	**Value**
Recirculating cooling water inlet temperature, °F	105
Recirculating cooling water outlet temperature, °F	90
Condenser circulating water inlet temperature, °F	80°F
Design pressure, shell/tube, psig	100/50
Design temperature, shell/tube, °F	200/200
Tube material	Admiralty metal (SB-111)
Recirculated Cooling Water Heat Exchangers (Unit 3)	2
Type	Flat plate
Recirculating cooling water flow, each, gal/min	1,800
Recirculating cooling water inlet temperature, °F	109
Recirculating cooling water outlet temperature, °F	89
Condenser circulating water inlet temperature, °F	80
Design pressure, psig	150
Design temperature, °F	150
Plate material	SA-240
Shell material	SA515-70
Essential Siphon Vacuum Pumps	3 per Unit
Type	Liquid ring
Design flow	300 ACFM @ 2l" Hg. Vacuum

Table 9-5. Chemical Addition and Sampling System Component Data

Tanks	
Boric Acid Mix Tank	
Type	Vertical cylindrical
Volume, ft^3	500
Design Pressure, psig	Atmospheric
Design Temperature, °F	250
Material	Al
Code	USAS B96.1
Lithium Hydroxide Mix Tank	
Type	Vertical cylindrical
Volume, gal.	50
Design Pressure, psig	Atmospheric
Design Temperature, °F	140
Material	SS
Caustic Mix Tank	
Type	Vertical cylindrical
Volume, gal.	150
Design Pressure, psig	Atmosphere
Design Temperature, °F	200
Material	SS
Reactor Building TSP Baskets	
Number per unit	7
Mass of TSP per unit	16,000 lbs
Material	SS
Pumps	
Boric Acid Pump	
Type	Reciprocating, variable stroke
Capacity, gal/min	10
Maximum Discharge Pressure, psig	75
Design Pressure, psig	100
Design Temperature, °F	200
Pump Material	SS

Boric Acid Pump (Core Flood Tanks)		
	Type	Reciprocating, variable stroke
	Capacity, gal/min	1
	Maximum Discharge Pressure, psig	630
	Design Pressure, psig	700
	Design Temperature, °F	300
	Pump Material	SS
Lithium Hydroxide Pump		
	Type	Reciprocating, variable stroke
	Capacity, gal/hr	10
	Maximum Discharge Pressure, psig	75
	Design Pressure, psig	250
	Pump Material	SS
Hydrazine Pump		
	Type	Reciprocating, variable stroke
	Capacity, gal/hr	10
	Maximum Discharge Pressure, psig	100
	Design Pressure, psig	100
	Design Temperature, °F	200
	Pump Material	SS
Caustic Pump		
	Type	Reciprocating, variable stroke
	Capability, gal/min	2
	Maximum Discharge Pressure, psig	50
	Design Pressure, psig	100
	Design Temperature, °F	200
	Pump Material	SS
Pressurizer Sample Cooler		
	Type	Shell and spiral tube
	Rated Capacity, Btu/h	2.1×10^5
	Sample Flow Rate, lb/h	200
	Maximum Sample Inlet Temperature, °F	650
	Sample Outlet Temperature, °F	120

Cooling Water Flow, lb/h	5,000
Design Temperature Shell/Tube, °F	250/670
Design Pressure Shell/Tube, psig	150/2,500
Code	ASME Sec. III-C & VIII
Steam Generator Sample Cooler	
Type	Shell and spiral tube
Rated Capacity, Btu/h	2.3×10^5
Sample Flow Rate, lb/h	500
Sample Inlet/Outlet Temperature, °F	535/100
Cooling Water Flow, lb/h	5,000
Design Temperature Shell/Tube, °F	300/600
Design pressure Shell/Tube, psig	150/1,050
Code	ASME Sec. VIII

Table 9-6. High Pressure Injection System Performance Data

Letdown Orifice Design Flow, Cold, gal/min	45
Letdown Flow Maximum, Cold, gal/min	140
Seal Flow to Each Reactor Coolant Pump (excluding makeup), gal/min (Oconee 1)	8
Seal Inleakage to Reactor Coolant System per Reactor Coolant Pump, gal/min (Oconee 1)	5.8 (1A1, 1B2), 6.0 (1A2, 1B1)
Total Seal Flow to Each Reactor Coolant Pump, gal/min (Oconee 2, 3)	10
Seal Inleakage to Reactor Coolant System per Reactor Coolant Pump, gal/min (Oconee 2, 3)	8.5
Injection Pressure to Reactor Coolant Pump Seals, psig	2,190
Temperature to Seals, normal/maximum, °F	120/150
Purification Letdown Fluid Temperature, normal/maximum, °F	120/135
Letdown Storage Tank Normal Operating Pressure, psig	6.3-50
Letdown Storage Tank Volume Between Minimum and Maximum Operating Levels, ft^3	250

Table 9-7. High Pressure Injection System Component Data

High Pressure Injection Pump	
Type	Vertical, multistage, centrifugal, mechanical seal
Capacity, gal/min	(See Figure 6-16)
Head, ft H_2O (at sp. gr. = 1)	(See Figure 6-16)
Motor Horsepower, nameplate hp	600
Pump Material	SS wetted parts
Design Pressure, psig	3,040/3,120
Design Temperature, °F	200/150
Letdown Cooler	
Type	Shell and spiral tube
Heat Transferred, Btu/h	16.0×10^6
Letdown Flow, lb/h	3.5×10^4
Letdown Cooler Inlet/Outlet Temperature, °F	555/120
Material, shell/tube	CS/SS
Design Pressure, psig	2,500
Design Temperature, °F	600
Component Cooling Water Flow (ea.), lb/h	2×10^5
Code	ASME Sec. 111-C & VIII
Reactor Coolant Pump Seal Return Cooler	
Type	Shell and tube
Heat Transferred, Btu/h	2.2×10^6
Seal Return Flow, lb/hr	1.25×10^5
Seal Flow Inlet/Outlet Temperature, °F	145/127
Material, shell/tube	SS/SS
Design Pressure, psig	150
Design Temperature, °F	286 (Unit 1), 200 (Units 2&3)
Recirculated Cooling Water Flow (ea.), lb/h	1.25×10^5
Code	ASME Sec. III-C & VIII
Letdown Storage Tank	
Volume, ft^3	600
Design Pressure, psig	100
Design Temperature, °F	200

Material	SS
Code	ASME Sec. III-C
Purification Demineralizer	
Type	Mixed bed, boric acid saturated
Material	SS
Resin Volume, ft^3	50
Flow, gal/min	70
Vessel Design Pressure, psig	150
Vessel Design Temperature, °F	200
Code	ASME Sec. III-C
Letdown Filter	
Design Flow Rate, gal/min	80
Material	SS
Design Temperature	200
Design Pressure	150
Code	ASME Sec. III-C
Reactor Coolant Pump Seal Injection Filter	
Design Flow Rate, gal/min	50
Material	SS
Design Temperature, °F	200
Design Pressure, psig	3,050 @ 200°F / 3350 @ 150°F
Code	USAS B 31.7, class II
Reactor Coolant Pump Seal Return Filter	
Design Flow Rate, gal/min	50
Material	SS
Design Temperature, °F	286 (Unit 1), 200 (Units 2&3)
Design Pressure, psig	150
Code	ASME Sec. III-C

Table 9-8. Low Pressure Injection System Performance Data

Reactor Coolant Temperature at Startup of Decay Heat Removal, °F	250
Time to Cool Reactor Coolant System From 250°F to 140°F, hr	14
Refueling Temperature, °F	140
Fuel Transfer Canal Fill Time, hr	Not Used
Fuel Transfer Canal Drain Time, hr	8 (nominal)
Boron Concentration in Borated Water Storage Tanks, ppm	Per Core Operating Limits Report

Table 9-9. Low Pressure Injection System Component Data

Pump (3 per unit)	
Type centrifugal	Single stage,
Capacity, gal/min	3,000
Head at Rated Capacity, ft H_2O	350
Motor Horsepower, hp	400
Material	SS (wetted parts)
Design Pressure, psig	560/580
Design Temperature, °F	300/250
Cooler (each) (Oconee 1, 2) (2 per unit)	
Type	Shell and tube
Capacity (at 140°F), Btu/hr	60×10^6
Reactor Coolant Flow, gal/min	6,000
Low Pressure Service Water Flow, gal/min	6,000
Low Pressure Service Water Inlet Temp, °F	75
Material, Shell/Tube	CS/SS
Design Pressure, Shell/Tube	150/515 (1) 150/370 (2)
Design Temperature, °F	250 (1) 300 (2)
Code, Shell/Tube	ASME Section III-C, III, and VIII
Cooler (each) (Oconee 3)	
Type	Shell and Tube
Capacity (at 140°F), Btu/h	60×10^6
Reactor Coolant Flow, gpm	6,000
Low Pressure Service Water Flow, gpm	6,000
Low Pressure Service Water Inlet Temp. °F	75°
Material, Shell/Tube	CS/SS
Shell Design Pressure, psig	150
Tube Design Pressure, psig	470/505
Shell Design Temperature, °F	300
Tube Design Temperature, °F	300/250
Code Shell/Tube	ASME Section III-C, III, and VIII
Borated Water Storage Tank (each)	
Capacity, gal	388,000

Material	CS/Coated inside [3]
Design Pressure	Vessel Full plus 10 ft Hydro Head
Design Temperature, °F	150
Code	AWWA D-100

Note:

1. A Cooler Units 1&2
2. B Cooler Units 1&2
3. Manhole covers are uncoated stainless steel.

Table 9-10. Coolant Storage System Component Data (Component Quantities for Three Units)

Reactor Coolant Bleed Holdup Tank	
Number	6
Volume each, cu. ft.	11,000
Material	Stainless Steel
Design Pressure	Vessel Full Plus 10 ft. Hydro Head
Deborating Demineralizer[1]	
Number	5
Resin Volume, cu. ft	62.8
Flow, gal/min	70
Design Pressure, psig	150
Concentrated Boric Acid Storage Tank	
Number	3
Volume each, cu. ft	3,000
Material	Aluminum
Design	Vessel Full Plus 10 ft. Hydro Head
Quench Tank	
Number	3
Volume each, cu. ft.	780
Material	Stainless Steel
Design Pressure, psig	55
Reactor Coolant Bleed Transfer Pump	
Number	6
Capacity each, gal/min	150
Diff. Head, ft.	220
Concentrated Boric Acid Storage Tank Pump	
Number	3
Capacity each, gal/min	50
Type	Centrifugal
Component Drain Pump	
Number	3
Capacity each, gal/min	100
Diff. Head, ft.	100

Coolant Bleed Evaporator Demineralizer	
Number	2
Resin Volume, cu. ft.	11
Flow, gal/min	20
Design Pressure, psig	150
Condensate Demineralizer	
Number	2
Resin Volume, cu. ft.	2
Flow, gal/min	20
Design Pressure, psig	50
Coolant Bleed Evaporate Recirculating Pump	
Number	1
Capacity, gal/min	160
Diff. Head, ft.	53
Distillate Pump	
Number	1
Capacity, gal/min	7-12
Diff. Head, ft.	60
Coolant Bleed Evaporate Feed Pump	
Number	1
Capacity, gal/min	7½
Diff. Head, ft.	60

Note:

1. These demineralizers may be loaded with mixed bed and used as purification demineralizers to support normal purification and boron/lithium coordination programs.

Table 9-11. Ventilation System Major Component Data

System	Equipment	Number Installed	Number Required Normal Operation
Control Room Zone Units 1 & 2	Air Handling Unit (1)	2	1
	Air Handling Unit	1	1
	Air Handling Unit	1	1
	Air Handling Unit	2	2
	Air Handling Unit	2	2
	Booster Fan	2	0
	Outside Air Filter Train	2	0
	Cable Shaft Motorized Dampers	4	4
Control Room Zone Unit 3	Air Handling Unit (1)	2	1
	Air Handling Unit	2	1
	Air Handling Unit	2	1
	Booster Fans	2	0
	Outside Air Filter Train	2	0
Auxiliary Building Units 1 & 2	Ventilation Unit (2) (Spent Fuel Pool)	1	1
	Exhaust Fan (Spent Fuel Pool)	2	1
	Ventilation Unit	1	1
	Ventilation Unit	1	1
	Ventilation Unit	1	1
	Exhaust Fan	2	1
	Exhaust Fan	2	1
	Exhaust Fan	3	2
Auxiliary Building Unit 3	Ventilation Unit (2) (Spent Fuel Pool)	1	1
	Exhaust Fan (Spent Fuel Pool)	2	1
	Ventilation Unit	2	1
	Ventilation Unit	1	1
	Exhaust Fans	3	2
Hot Machine Shop	Exhaust Fans	3	2

System	Equipment	Number Installed	Number Required Normal Operation
	Air Handling Unit [3]	1	1
	Air Handling Unit	1	1
	Booster Fan	2	2
	Outside Air Filter Train	2	2
Turbine Building	Roof Exhaust Fans	12	12
	Exhaust Fans	18	18

Note:

1. Air Handling Units consist of a fan, roughing filters, and chilled water coil.
2. Ventilation Units consist of a fan, service water coil, and steam heating coil.
3. Air Handling Units consist of a fan, roughing filters and direct expansion (DX) coil.

Table 9-12. Deleted Per 2002 Update.

Table 9-13. Component Cooling System Component Data (Component Data on a Per Unit Basis)

Parameter	Value
Component Cooling Pumps	
Type	Centrifugal
Rated Capacity, gpm	766
Rated Head, ft, H_2O	220
Motor Nameplate Horsepower, hp	60
Casing Material	CS
Design Pressure, psig	150
Design Temperature, °F	225
Component Coolers (Oconee 1)	
Type	Shell and Tube
Capacity, Btu/h	19×10^6
Component Cooling Water Inlet Temp, °F	150
Component Cooling Water Outlet Temp, °F	100
Code	ASME Section VIII
Component Coolers (Oconee 2, 3)	
Type	Shell and Tube
Capacity, Btu/h	19×10^6
Component Cooling Water Inlet Temp, °F	150
Component Cooling Water Outlet Temp, °F	100
Code	ASME Section VIII
Surge Tank	
Volume, ft^3	50
Material	CS
Design Pressure, psig	Atmospheric
Design Temperature, F	200
Code	AWWA D-100

Parameter	Value
Control Rod Drive Filter	
Design Flow Rate, gal/min	140
Code	ASME Section VIII

Table 9-14. SSF System Main Components

SSF RC Makeup Pump	
Quantity	1/Unit
Design Pressure (psig)	2790
Design Temperature (°F)	220
Design Flow Rate (gpm)	29 design
Design Head (psig)	2250 normal/ 2790 max.
Type	Pos. Disp.
Material of Construction	S. S.
Fluid	Borated Water
SSF RC Makeup Filter	
Quantity	1/Unit
Design Pressure (psig)	2790
Design Temperature (°F)	220
Design Flow Rate (gpm)	78
Normal Flow Rate (gpm)	29
Retention for 5-Micron Particles (%)	98
Material of Construction	S. S.
Fluid	Borated Water
SSF Auxiliary Service Water Pump	
Quantity	1/Station
Nameplate Design Pressure (psig)	1440
Nameplate Design Temperature (°F)	150
Design Flow Rate (gpm)	1975
Design Head (ft)	2730
Type	
Material of Construction	C. S.
Type	Centrifugal
Fluid	River Water
HVAC Service Water Pump	
Quantity	2/Station
Nameplate Design Pressure (psig)	210
Nameplate Design Temperature (°F)	150

Design Flow Rate (gpm)	55
Nameplate Design Head (ft)	365 @55 gpm, pump #1 365 @55 gpm, pump #2
Type	Centrifugal
Material of Construction	C. S.
Fluid	Strained River Water
Diesel Engine Service Water Pump	
Quantity	1/Station
Design Pressure (psig)	100
Design Temperature (°F)	110
Design Flow Rate (gpm)	500
Design Head (ft)	90
Type	Centrifugal
Material of Construction	C. S.
Fluid	Strained River Water
SSF Service Water Strainer	
Quantity	1/Station
Design Pressure (psig)	60
Design Temperature (°F)	110
Design Flow Rate (gpm)	600
Mesh Size (inch)	0.1
Deleted row(s) per 2010 Update	
Type	Duplex
Material of Construction	C. S.
SSF Sump Pump	
Quantity	2/Station
Nameplate Design Pressure (psig)	75
Design Temperature (°F)	100
Design Flow Rate (gpm)	100
Design Head from Pump Head Curve (ft)	44
Type	Centrifugal, Vertical Cantilever
Material of Construction	C. S.
Fluid	Floor Drain Liquid

Diesel Engine Fuel Oil Storage Tank	
Quantity	1/Station
Capacity (gal)	50,000
Material of Construction	C. S.
Location	Yard, Underground
Fuel Oil Day Tank	
Quantity	1/Station
Capacity (gal)	550
Material of Construction	C. S.
Location	SSF, Generator Room
Diesel Engine Fuel Oil Transfer Pump	
Quantity	1/Station
Nameplate Design Pressure (psig)	150
Nameplate Design Temperature (°F)	125
Design Flow Rate (gpm)	13.6
Differential Pressure (psid)	30
Type	Rotary
Material of Construction	C. S.
Fluid	No. 2 Diesel Fuel Oil
SSF Fuel Oil Transfer Filter	
Quantity	2/Station
Design Pressure (psig)	150
Design Temperature (°F)	125
Design Flow Rate (gpm)	20
Retention for 25-Micron Particles (%)	99
Maximum Pressure Drop @ 65% Plugged (ft)	32
Type	Duplex Arrangement
Material of Construction	S. S.
Fuel Oil Recirculation Pump	
Quantity	1/Station
Design Pressure (psig)	30
Design Temperature (°F)	90
Design Flow Rate (gpm)	30

Design Head (ft)	32
Type	Rotary
Material of Construction	C. I.
Fluid	No. 2 Diesel Fuel Oil
Fuel Oil Recirculation Filter	
Quantity	1/Station
Design Pressure (psig)	30
Design Temperature (°F)	90
Design Flow Rate (gpm)	30
Retention for 25-Micron Particles (%)	100
Maximum Pressure Drop @ 65% Plugged (ft)	13.5
Type	Simplex
Material of Construction	S. S.
Unloading Oil Spill Sump Pump	
Quantity	1/Station
Design Pressure (psig)	35
Design Temperature (°F)	100
Design Flow Rate (gpm)	32
Type	Centrifugal, Submersible
Material of Construction	C. I.
Fluid	Groundwater and No. 2 Fuel Oil Spillage

Table 9-15. SSF Primary Valves

Valve No.	Control Room Control	SSF Control	SSF D/G Powered	New Valve	Description
FDW-347	No	Yes	Yes	Yes	EFW to "B" OTSG
CCW-269	No	Yes	Yes	Yes	EFW Crossover
CCW-268	No	Yes	Yes	Yes	SSF ASW Throttle Valve
CCW-287	No	Yes	Yes	Yes	SSF ASW Block Valve
HP-3	Yes	Yes	Yes	No	Letdown
HP-4	Yes	Yes	Yes	No	Letdown
HP-20	Yes	Yes	Yes	No	RCP Seal Return
HP-398	No	Yes	Yes	Yes	RCS Makeup Pump Discharge
HP-405	No	Yes	Yes	Yes	RCS Makeup Test
HP-417[3]	No	No	No	Yes	RCS Makeup Recirculation
Deleted per Rev. 29 Update					
HP-428	No	Yes	Yes	Yes	Fuel Transfer Tube RCMU Return Iso.
SF-82	No	Yes	Yes	Yes	RCS Makeup Pump Suction
SF-97	No	Yes	Yes	Yes	Fuel Transfer Tube RCMU Supply Isol.
LP2 [(1)]	Yes	No	No	No	Decay Heat Line
LP103	No	Yes	Yes	No	Alt. Decay Heat Line
RC-4	Yes	Yes	Yes	No	PORV Block
RC-5	Yes	Yes	Yes	No	Press. Stm. Sample Isol.
RC-6	Yes	Yes	Yes	No	Press. Wtr. Sample Isol.
RC-159	Yes	No[(2)]	Yes[(2)]	No	
RC-160	Yes	No[(2)]	Yes[(2)]	No	
RC-223	No	Yes	Yes	Yes	Letdown Isol. Vlv.
RC-218	No	Yes	Yes	Yes	Letdown Normal Ctrl.
RC-219	No	Yes	Yes	Yes	Letdown High Flow Ctrl.
RC-238	No	No	No	Yes	Letdown Check Vlv.
SF-244	No	No	No	Yes	Letdown Check Vlv.

Valve No.	Control Room Control	SSF Control	SSF D/G Powered	New Valve	Description

Note:

1. This valve is closed, power is removed from the feeder breaker that supplies power to the motor operator, and the feeder breaker is locked during the MODES of Applicability for the SSF with respect to the applicable unit(s). Therefore, no power is required from the SSF power system to operate this valve. In addition to the above table, certain RCS vent lines should be isolated during an SSF event. Each line has two solenoid operated (control room control only) valves in series, a vent valve and a vent block valve. Closure of either the vent or the vent block valve is necessary. These valves are:

a. RC-155 "A" OTSG Hot Leg Vent

b. RC-156 "A" OTSG Hot Leg Vent Block

c. RC-157 "B" OTSG Hot Leg Vent

d. RC-158 "B" OTSG Hot Leg Vent Block

e. RC-159 Reactor Vessel Head Vent

f. RC-160 Reactor Vessel Head Vent Block

2. Control of the RV head vent valves will be accomplished using a portable control panel.
3. 1HP-417, 2HP-417, 3HP-417 no longer have SSF Control and are not powered from the SSF D/G – ECs 112474, 403752, and 112872 removed the Electric Motor Operator and installed a manual operator for respective Units 1, 2, and 3.

Table 9-16. SSF Instrumentation

PARAMETER MONITORED	INSTRUMENT NO.
RCS Loop A Pressure	PT 225
RCS Loop B Pressure	PT 226
SSF RC Makeup Pump	
Suction Pressure	PT 223
Discharge Pressure	PT 227
Suction Temperature	RD 174
Discharge Flow	FT 157
RC System Temperature	RD-85A,-84A,-8A,-7B,-6A,-5B
Pressurizer Water Level	LT 72
Unit 1 Pressurizer Pressure	1RC PT0224, 1RC P0236
Unit 2 Pressurizer Pressure	2RC PT0224, 2RC P0236
Unit 3 Pressurizer Pressure	3RC PT0224, 3RC P0236
SSF Auxiliary Service Water Water Pump	
Suction Pressure	PG 435
Discharge Pressure	PG 430, PG 431
Unit 1 Discharge Pressure	1 PG 434
Unit 2 Discharge Pressure	2 PG 434
Unit 3 Discharge Pressure	3 PG 434
Discharge Test Flow	FT 71
Suction Temperature	TH 102
Unit 1 Flow	1 FT 225 (1 FE 226, 1P 353)
Unit 2 Flow	2 FT 225 (2 FE 226, 2P 353)
Unit 3 Flow	3 FT 225 (3 FE 226, 3P 353)
Minimum Flow Line Flow	FE 230 (PG 867)
Unit 1 Steam Generator Levels A, B	LT 66, LT 67
Unit 2 Steam Generator Levels A, B	LT 66, LT 67
Unit 3 Steam Generator Levels A, B	LT 66, LT 67
Underground Fuel Oil Storage Tank Level	LT 50
Incore Thermocouples	
D/G Service Water Pump Discharge Flow	FT 73
HVAC Service Water Pump Discharge Flow	FT 72

Table 9-17. Design Basis Tornado Missiles And Their Impact Velocities

				Design Impact Velocity (Ft/Sec)	
No.	Missile Descriptions	Weight (lbs.)	Impact Area (sq. in.)	Horizontal	Vertical
1	WOOD PLANK, 3.62 in. x 11.37 in. x 12 ft.	115	41.2	272	190
2	STEEL PIPE, 6 in. diam. 15 ft. long, Schedule 40	287	34.5	171	120
3	STEEL ROD, 1 in. diam., 3 ft. long	8.8	0.79	167	117
4	UTILITY POLE, 13.5 in. diam., 35 ft. long	1124	143.1	180	126
5	STEEL PIPE, 12 in. diam., 15 ft. long, Schedule 40	750	127.68	154	108
6	AUTOMOBILE, 28 sq. ft. frontal area	3990	4032.0	194	136

Table 9-18. Design Basis Tornado Missiles Minimum Barrier Thicknesses

	Modified Petry Formula				Modified N.D.R.C. Formula			
Missile	**Penetration Depth Horiz Strike (D)**	**Min. Thickness (3D)**	**Penetration Depth Vert. Strike (D)**	**Min. Thickness (3D)**	**Penetration Depth Horiz. Strike (D)**	**Min. Thickness (D)**	**Penetration Depth Vert. Strike (D)**	**Min. Thickness (D)**
1	2.64	7.92	1.39	4.17	4.07	12.21	2.95	8.85
2	3.39	10.17	1.72	5.16	4.39	13.17	3.19	9.57
3	4.77	14.31	2.41	7.23	2.02	6.06	1.46	4.38
4	3.54	10.62	1.79	5.37	6.85	20.55	4.97	14.91
5	1.96	5.88	0.99	2.97	4.97	14.91	3.61	10.83
6	0.51	1.53	0.26	0.78	7.08	21.24	5.14	15.42

Note:

1. All Penetration Depths are calculated based on a concrete strength f'c of 5000 PSI.
2. All Penetration Depths and Minimum Barrier Thicknesses are in inches.

Table 9-19. Codes and Specifications For Design of Category I Structures

Structural Component	Design Codes and Specifications
Concrete	ACI 318-71
Concrete Reinforcement	ASTM A615-72, Grades 40 and 60
Cadwelds	Regulatory Guide No. 1.10, Rev. 1 (1)
Structural Steel and Plates	ASTM A-36 AISC, Seventh Edition

Note:

1. Valid test results are used. A valid test is a test whose failure is in the Cadwell Splice and not in the bar or near testing machine grips. Test samples for B Series Splices will be sister Splices only.

Abbreviations:

ACI American Concrete Institute

AISC American Institute of Steel Construction

ASTM American Society for Testing and Materials

Table 9-20. Reverse Osmosis System Data, Common to Units 1 & 2

Reverse Osmosis Feed Booster Pump	
Type	Two Stages
Horsepowerof Motor	2
Material	SS
Process Flow, Gal/min	65 (design)
Design Head, feet H_2O	75
Reverse Osmosis Feed Pump	
Type	Horizontal, Single Stage, gear-driven
Horsepowerof Motor	SS
Material	40
Process Flow, Gal/min	65 (design)
Design Head, feet H_2O	1025
Reverse Osmosis Membrane Filter Housings	
Quantity	6
Material	SS
Process Flow, Gal/min	Varies (<65)
Design Pressure, psig	600
Code	Inspection and Testing: ASME B31.1
	Materials: ASME B&PV II

Appendix 9B. Figures

Figure 9-1. Fuel Storage Rack (Module)

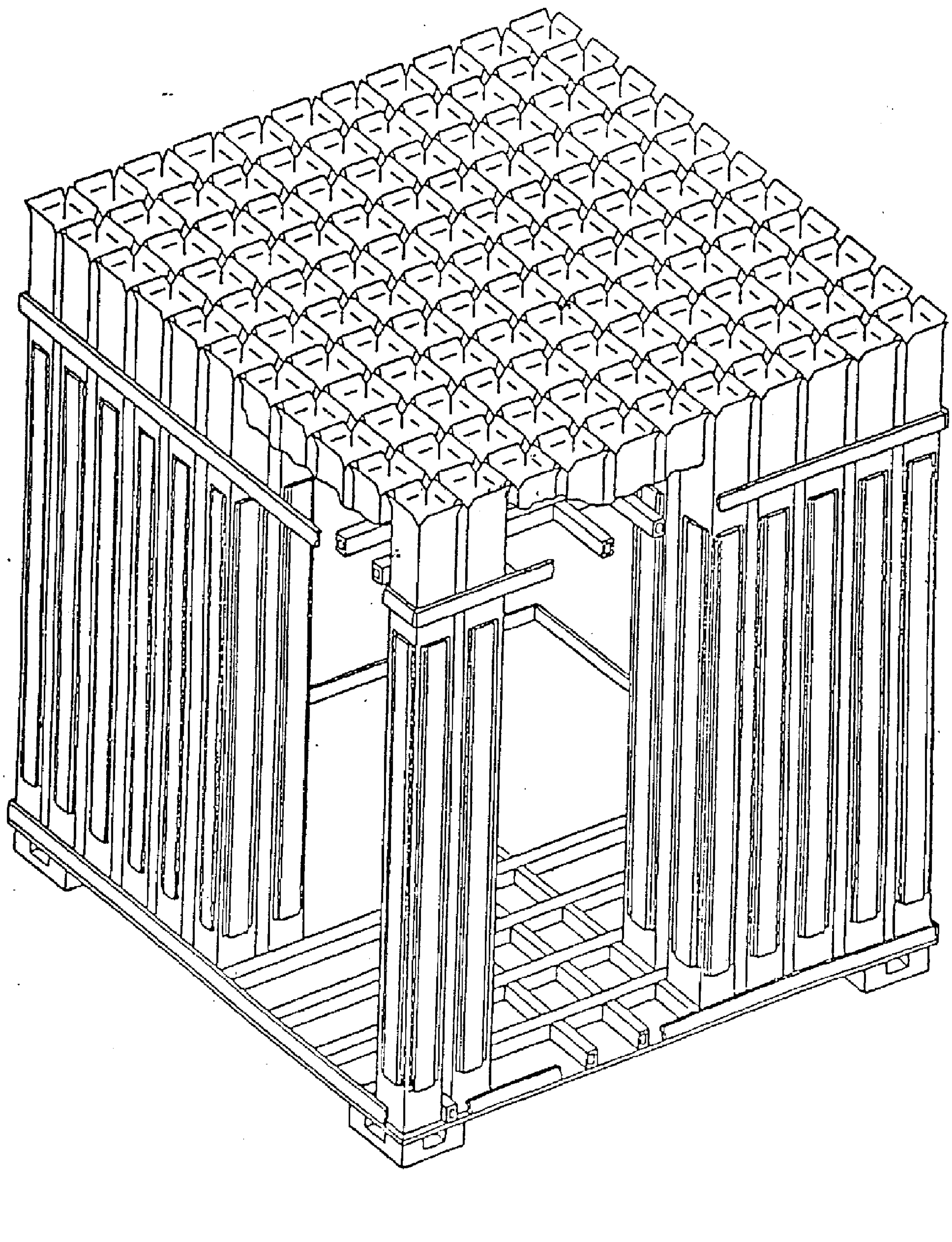


Figure 9-2. Fuel Storage Rack (Assembly)

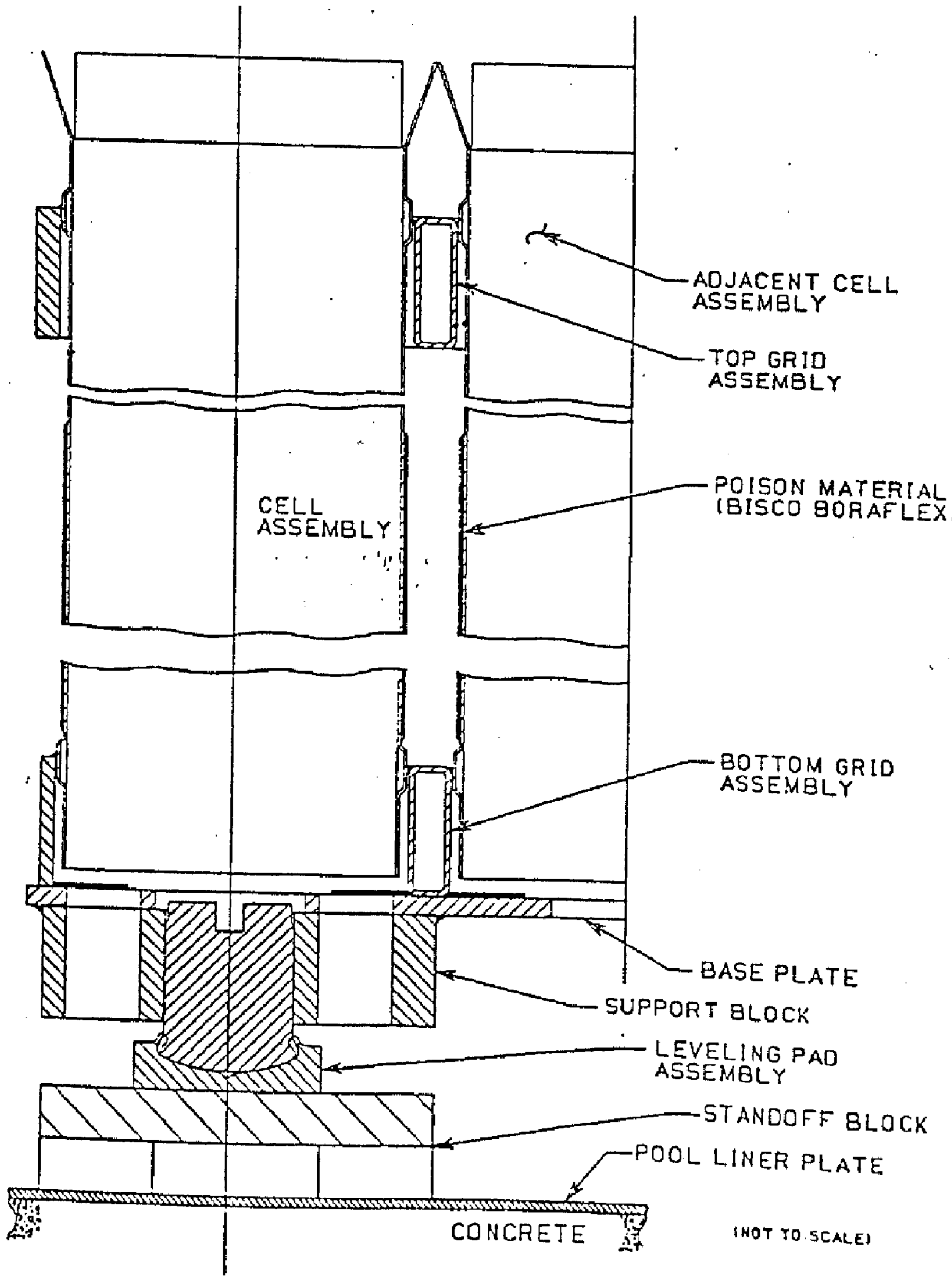


Figure 9-3. Spent Fuel Pool Outline Oconee 1, 2

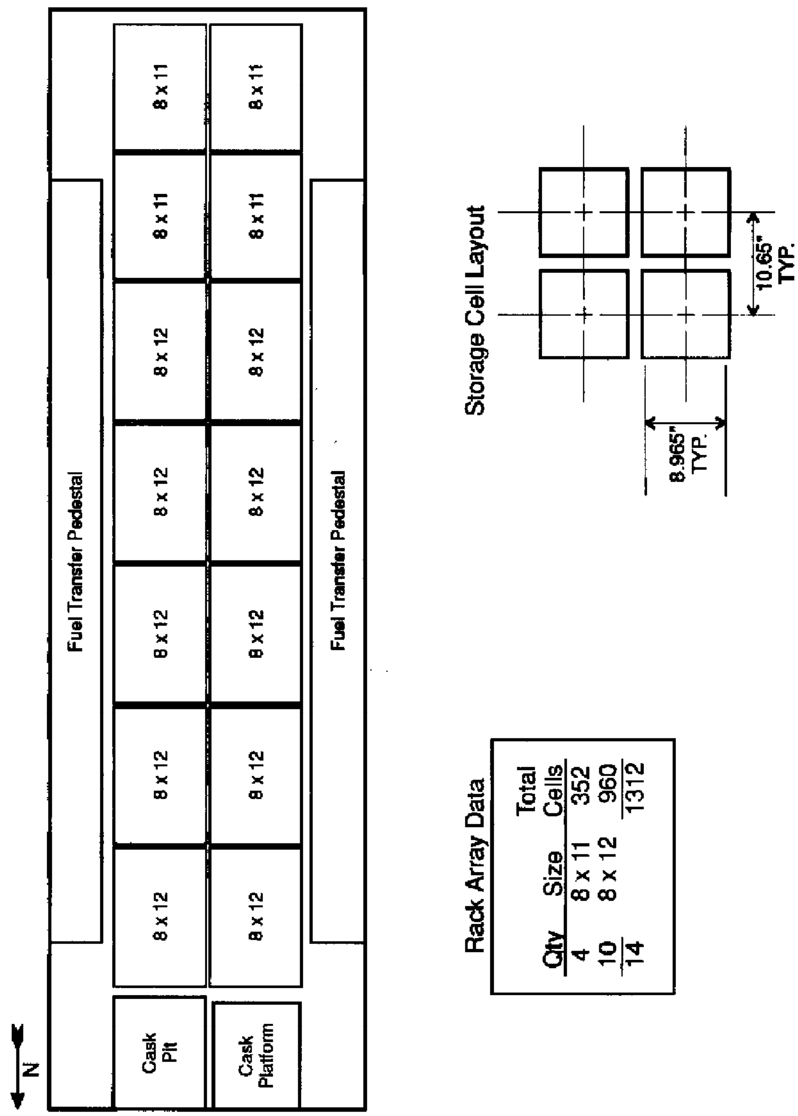


Figure 9-4. Spent Fuel Pool Outline Oconee 3

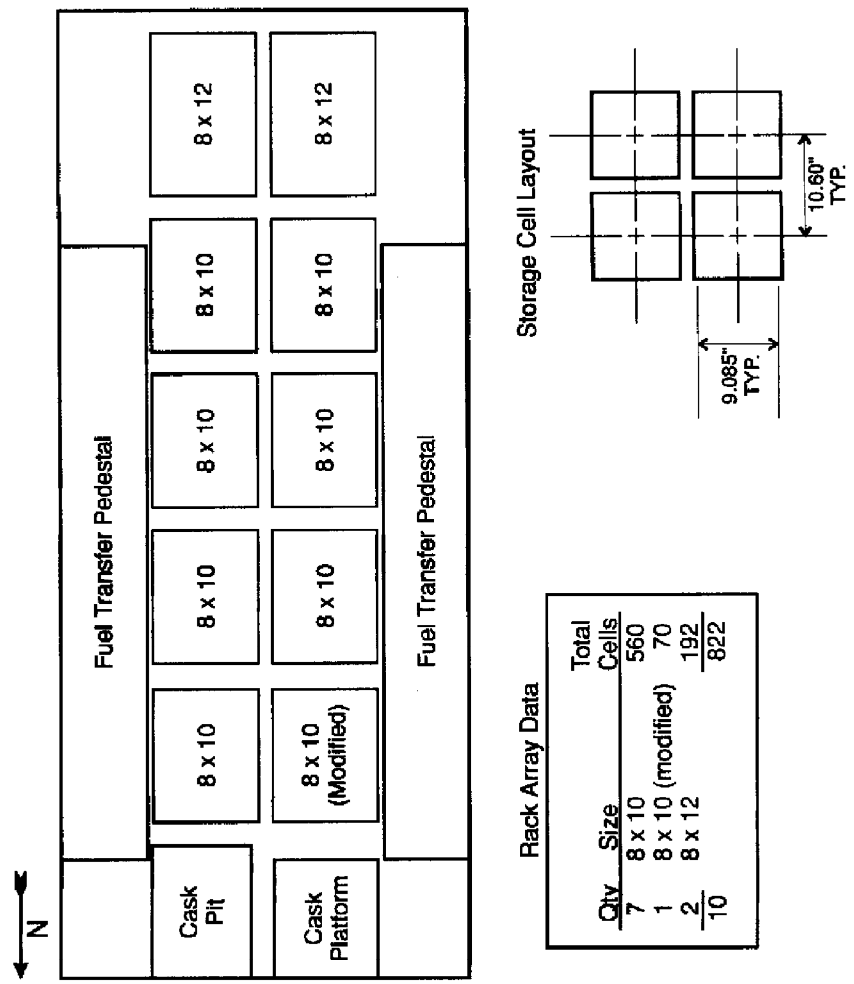


Figure 9-5. Spent Fuel Cooling System

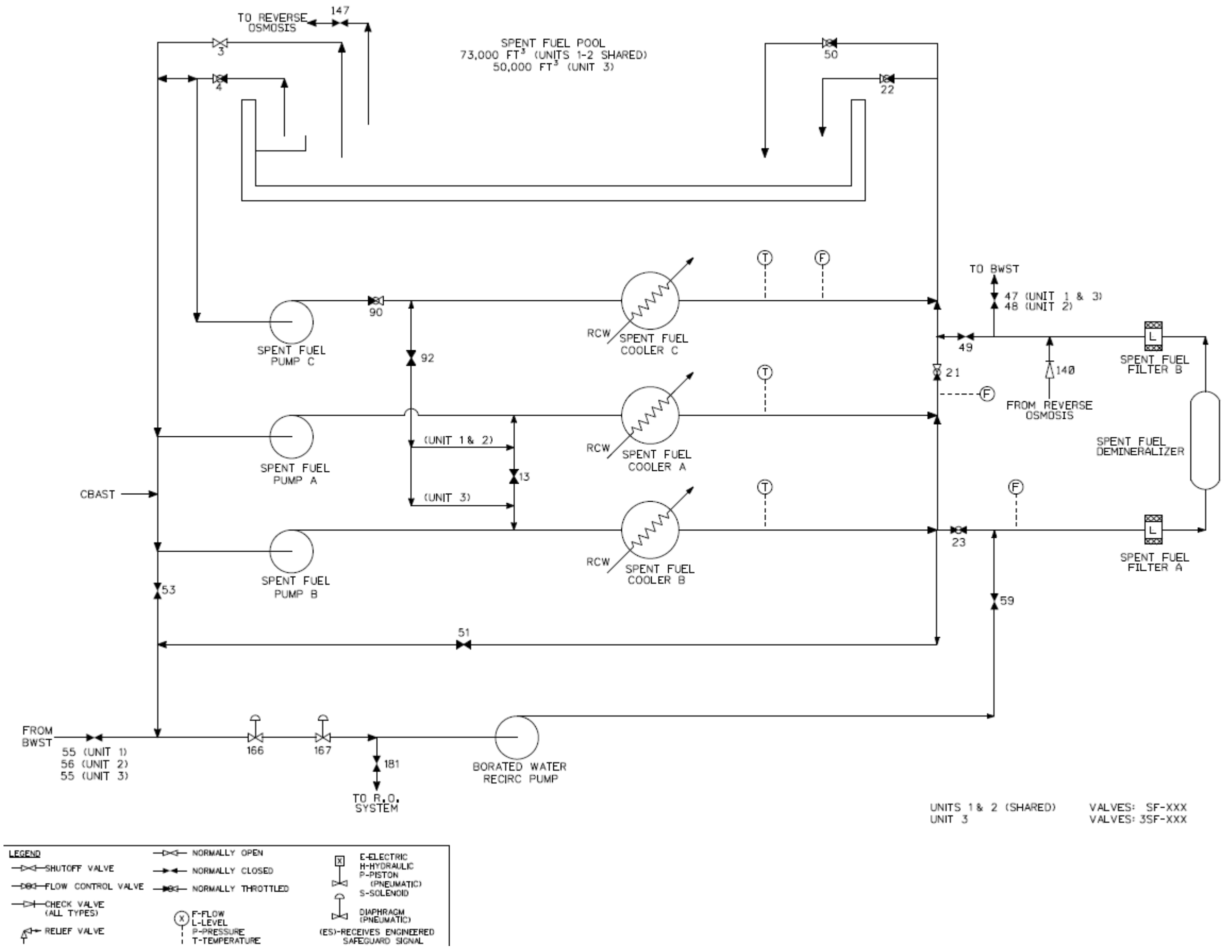


Figure 9-6. Deleted per 1990 Update

Figure 9-7. Fuel Handling System (Units 1&2 Page 1 and Unit 3 Page 2)

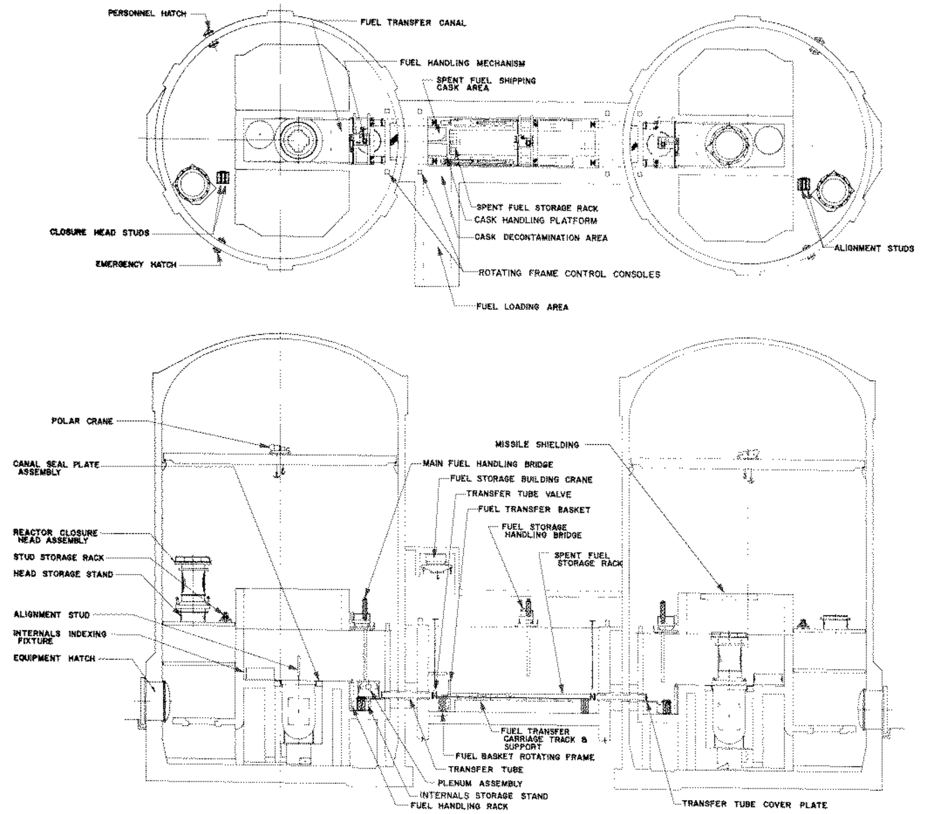


FIG. 9-7 (SHEET 1 OF 2)
FUEL HANDLING SYSTEM
UNITS 1 AND 2

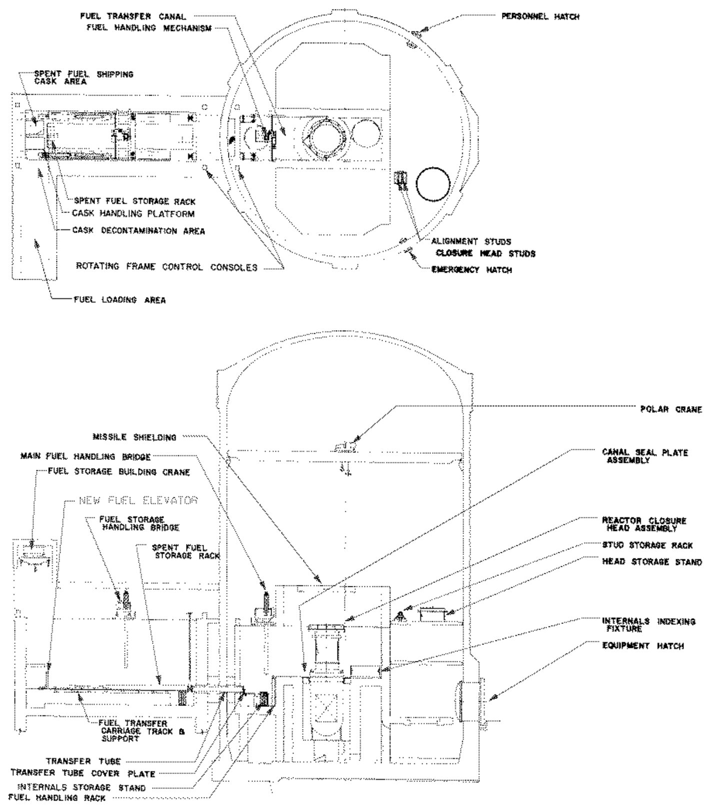


FIG. 9-7 (SHEET 2 OF 2)
FUEL HANDLING SYSTEM
UNIT 3

Figure 9-8. Component Cooling System

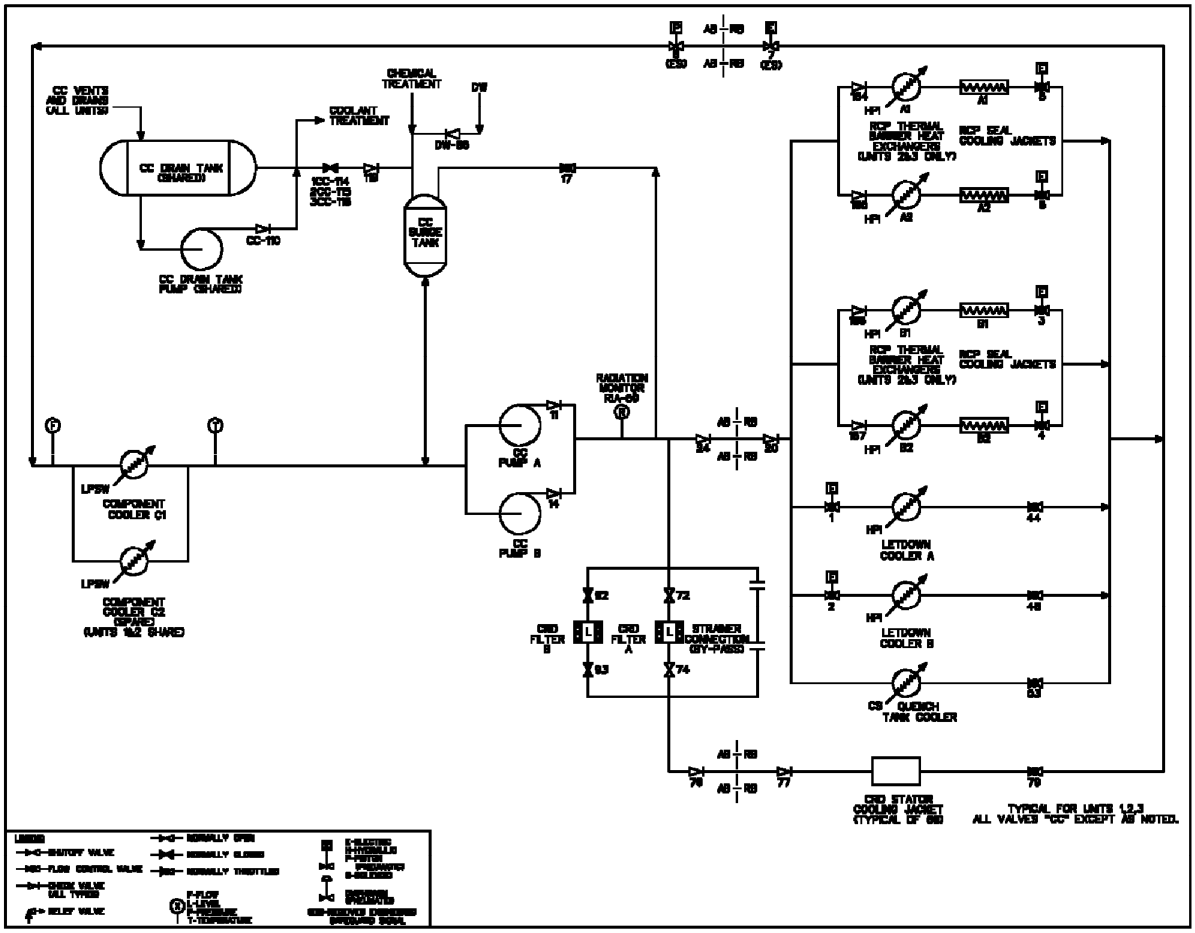


Figure 9-9. Condenser Circulating Water System

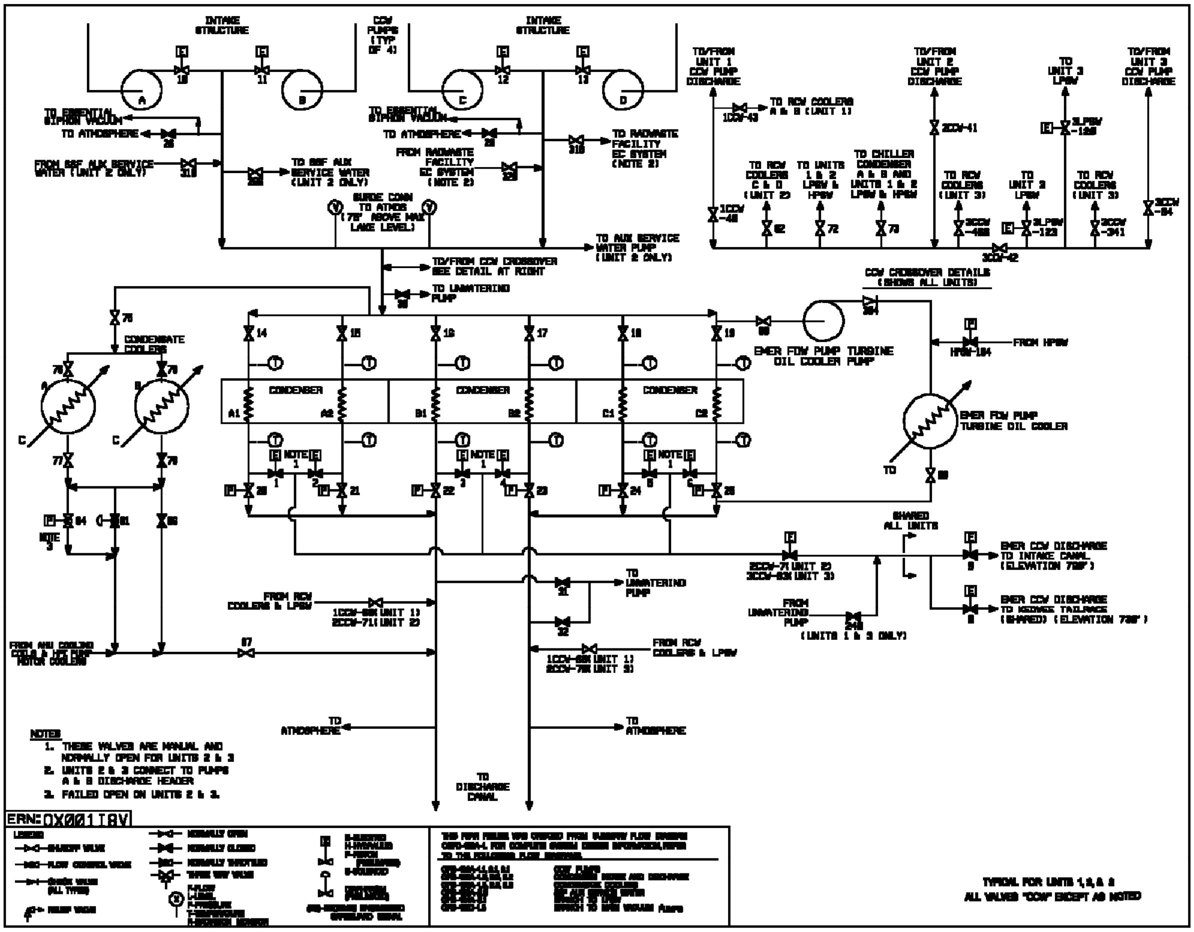


Figure 9-10. High Pressure Service Water System

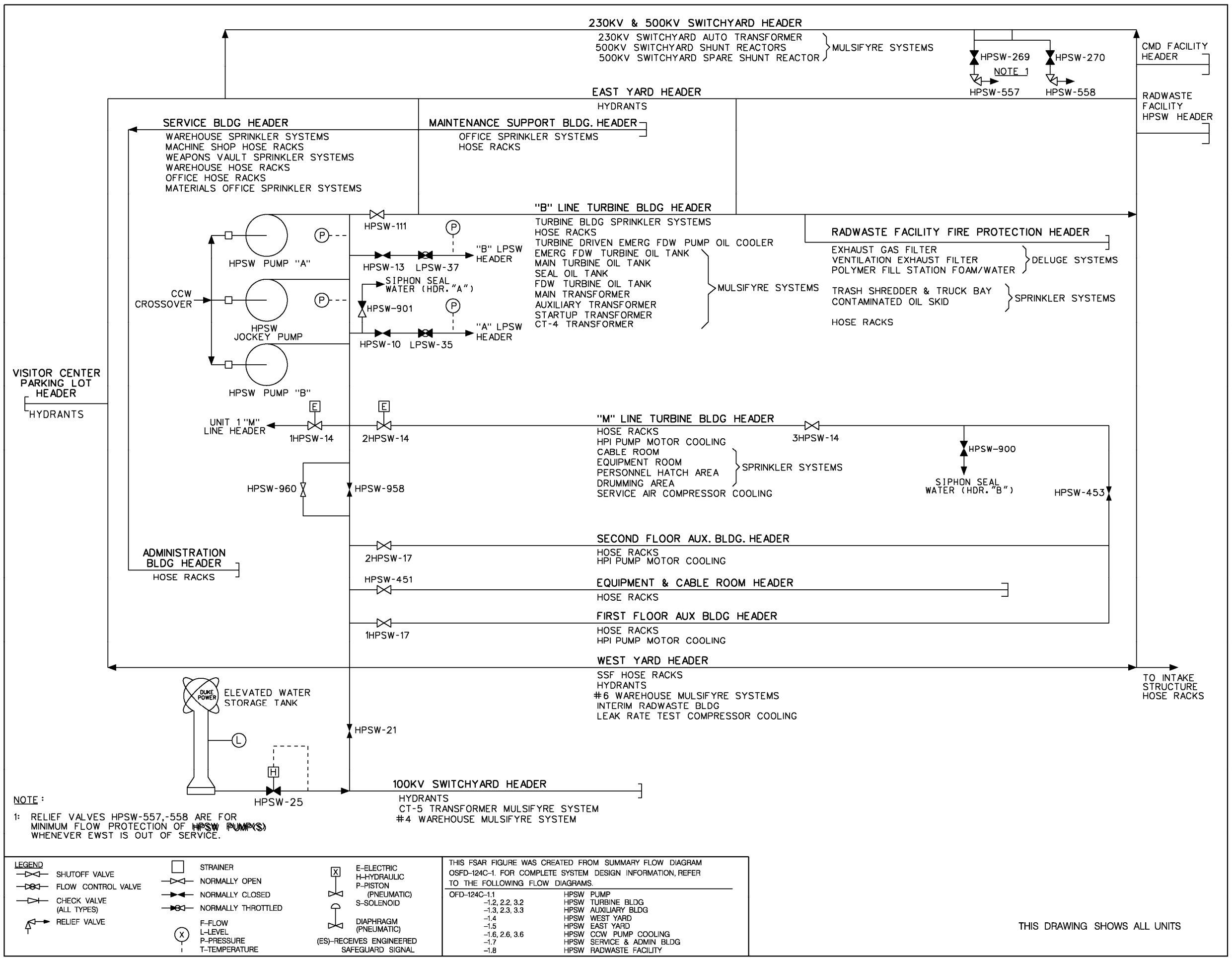


Figure 9-11. Low Pressure Service Water System

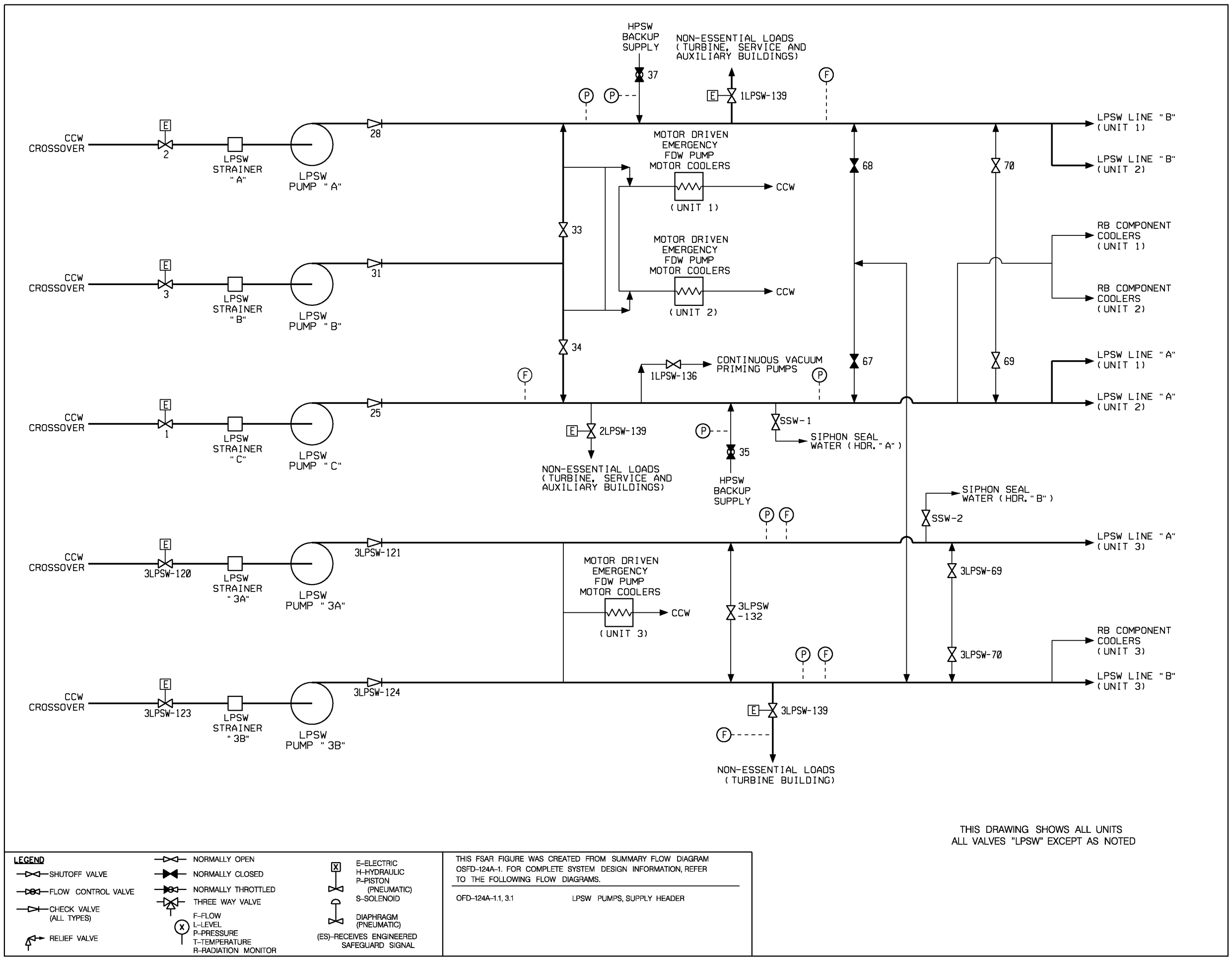


Figure 9-12. Low Pressure Service Water System

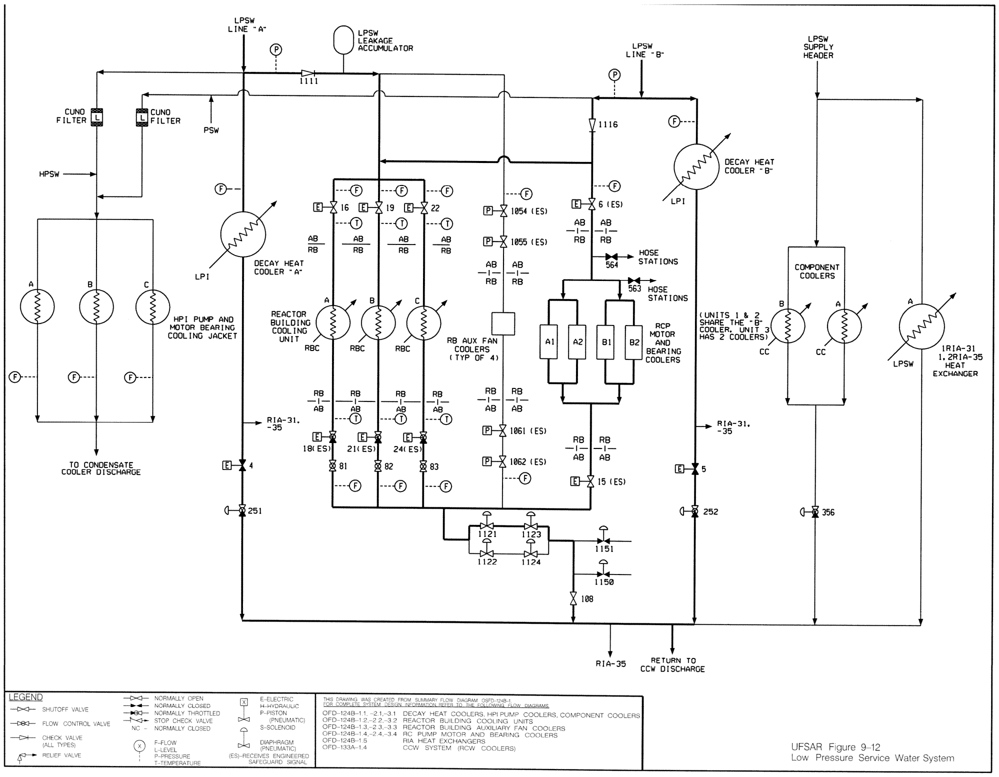


Figure 9-13. Recirculated Cooling Water System

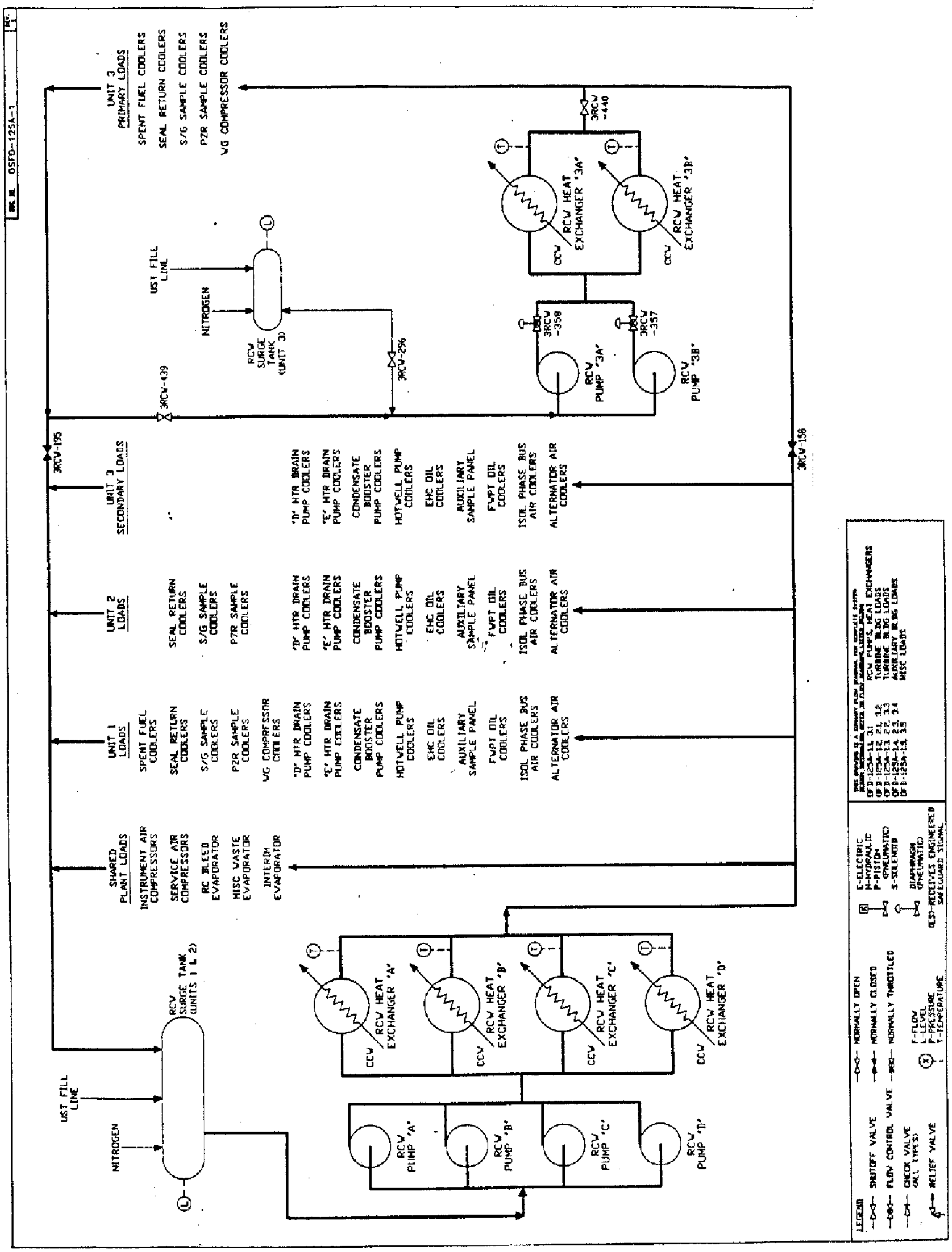


Figure 9-14. Deleted Per 1997 Update

Figure 9-15. Chemical Addition and Sampling System

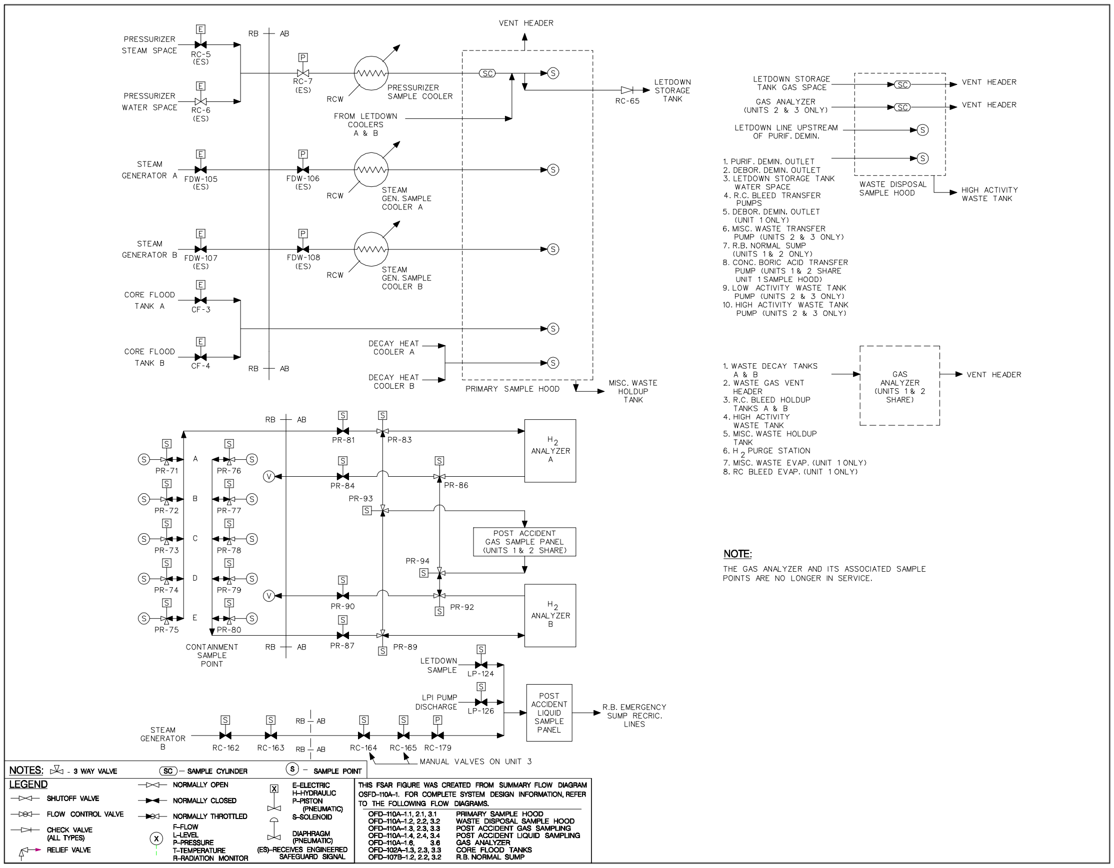


Figure 9-16. Chemical Addition and Sampling System

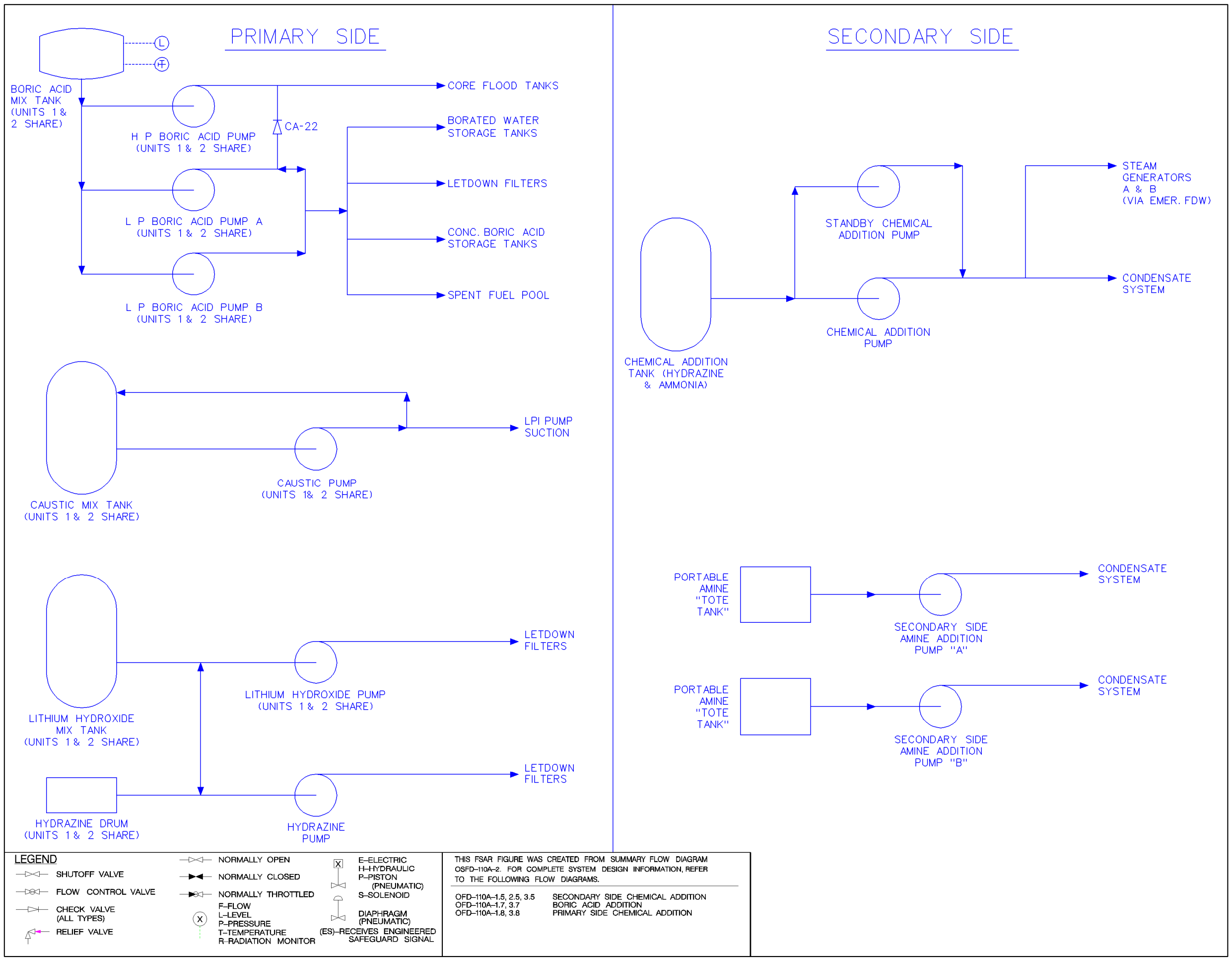


Figure 9-17. High Pressure Injection System

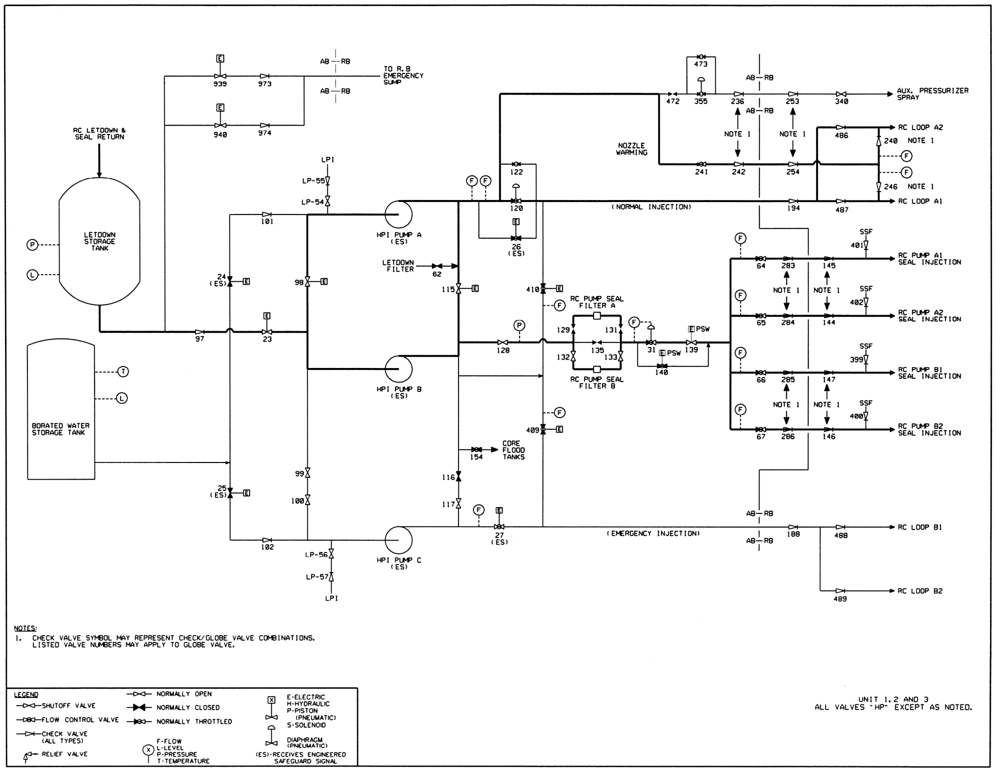


Figure 9-18. High Pressure Injection System

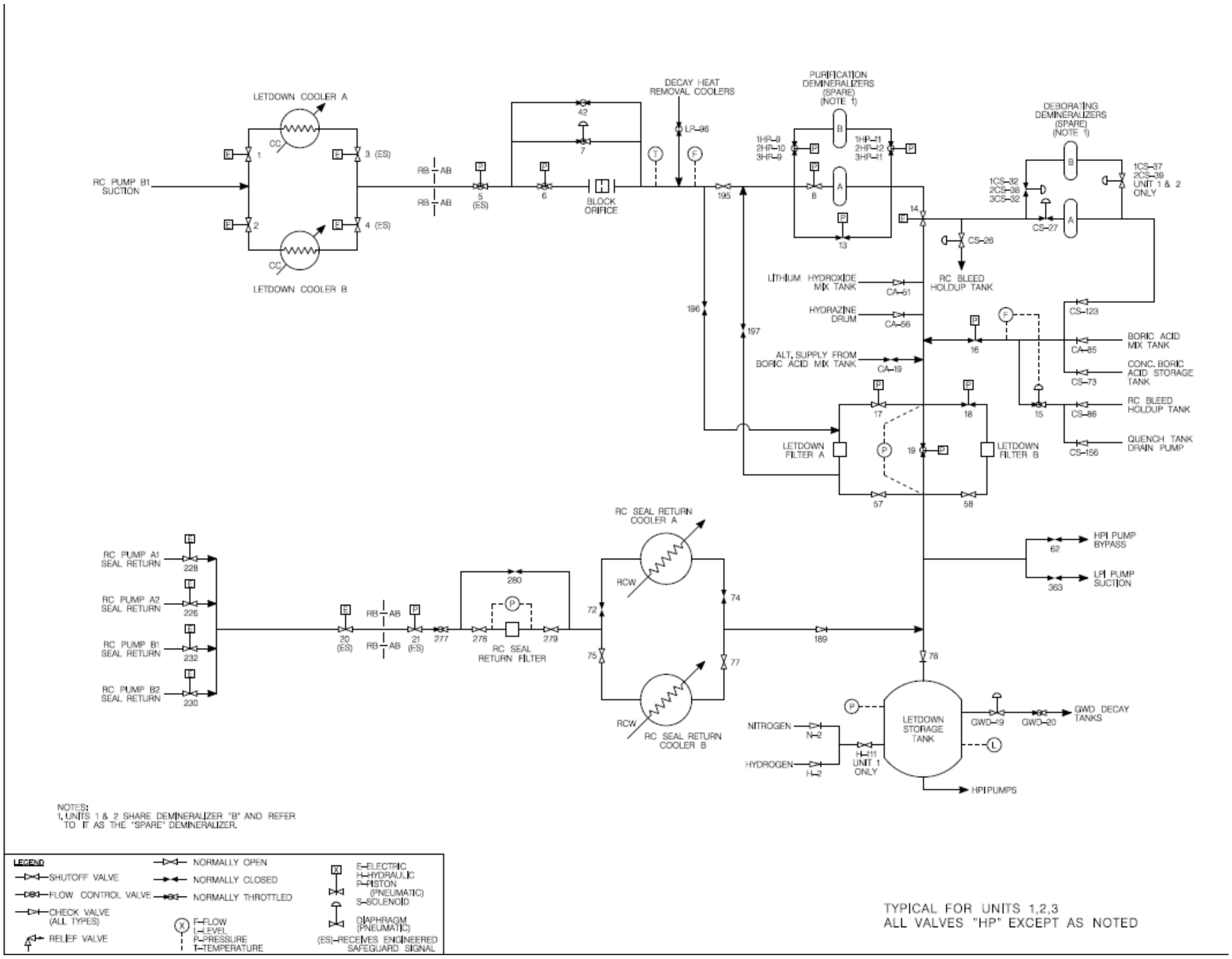


Figure 9-19. Low Pressure Injection System

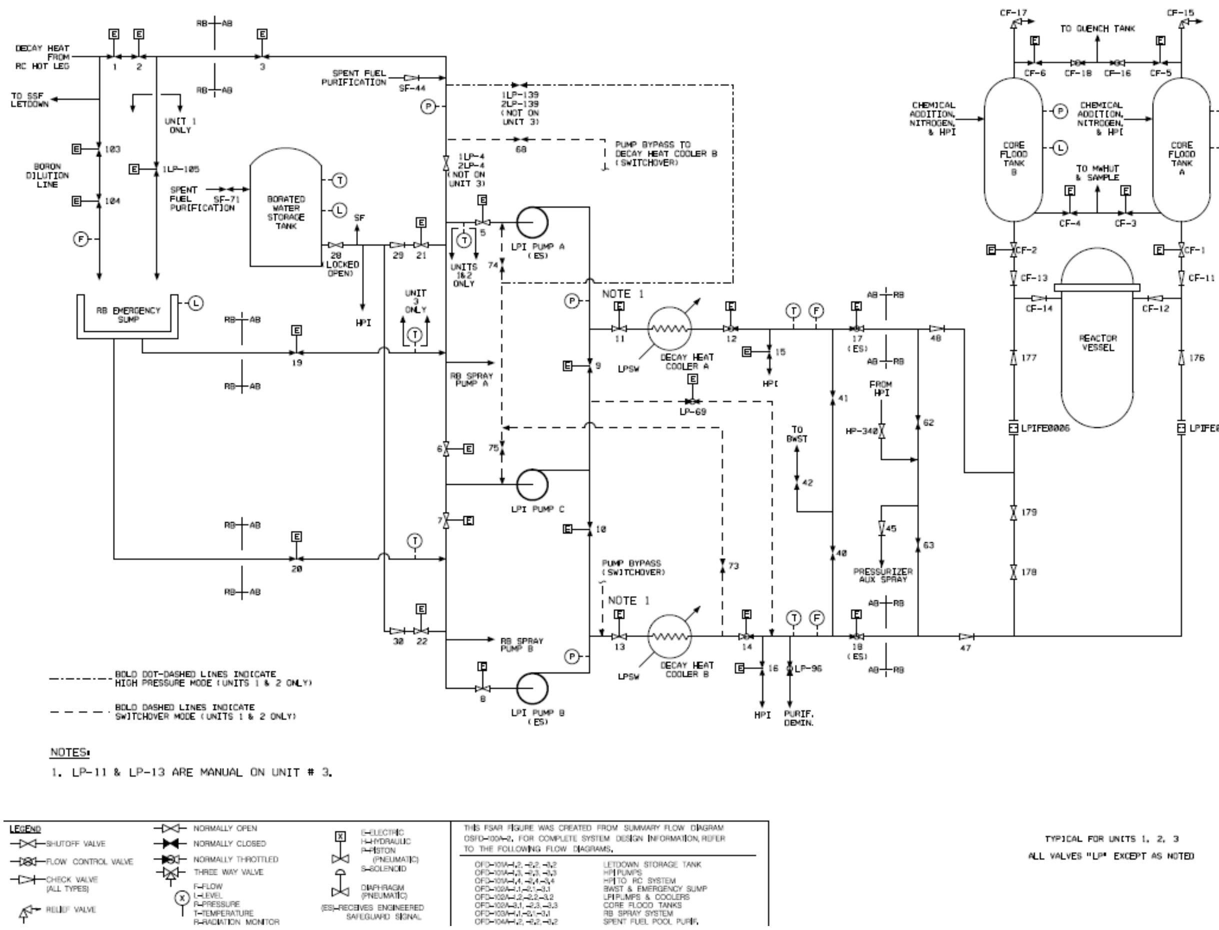


Figure 9-20. Coolant Storage System

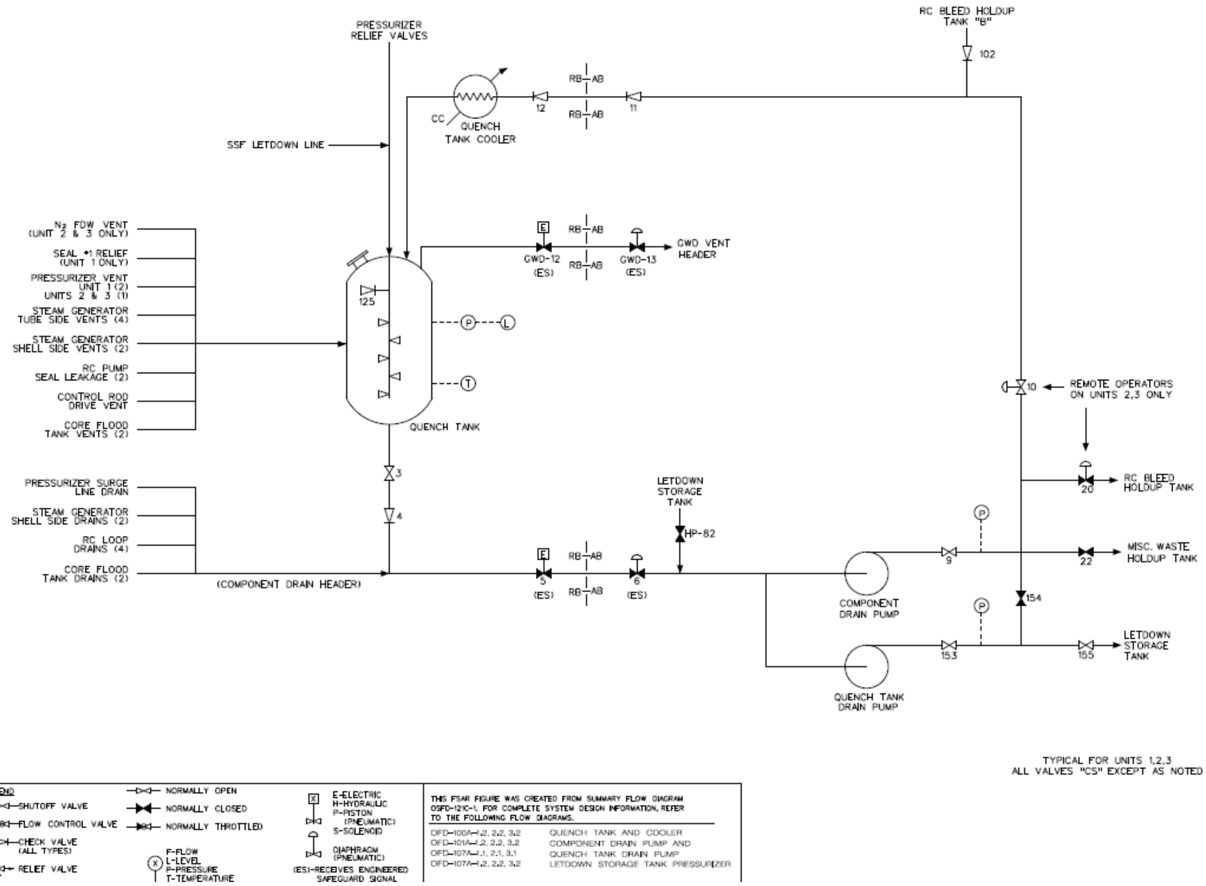


Figure 9-21. Coolant Treatment System

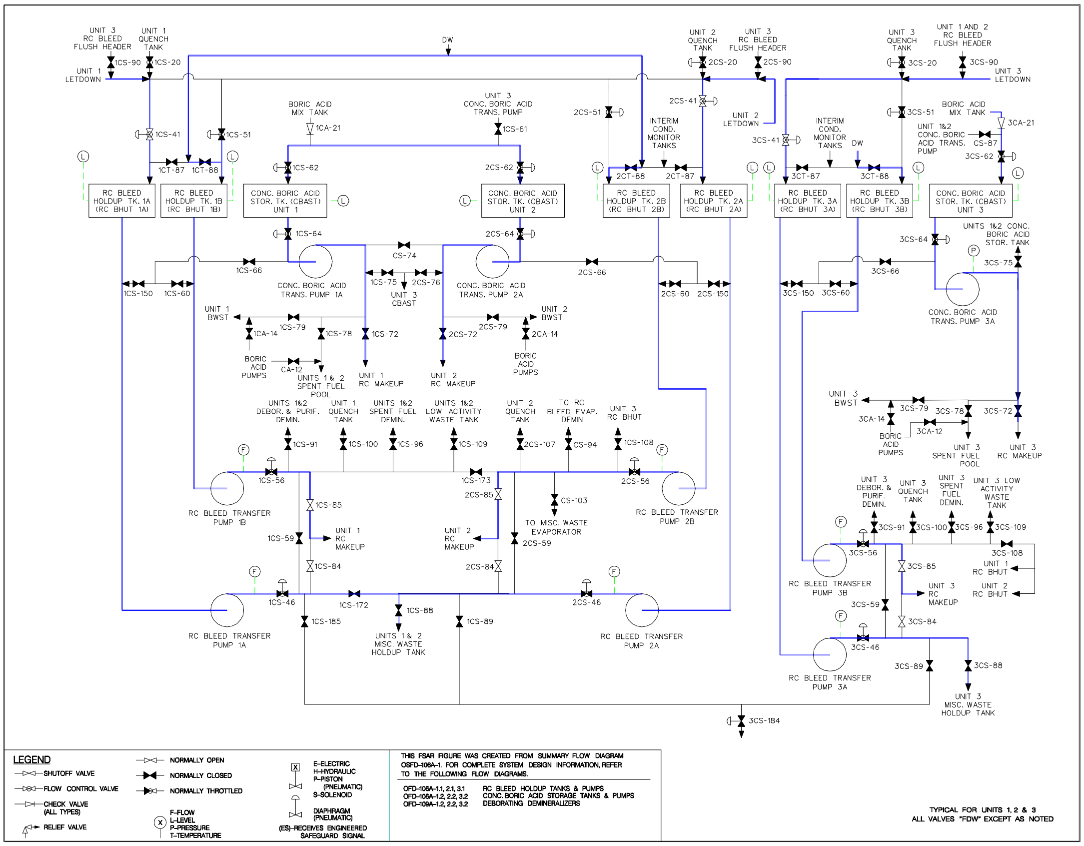


Figure 9-22. Post-Accident Liquid Sample System

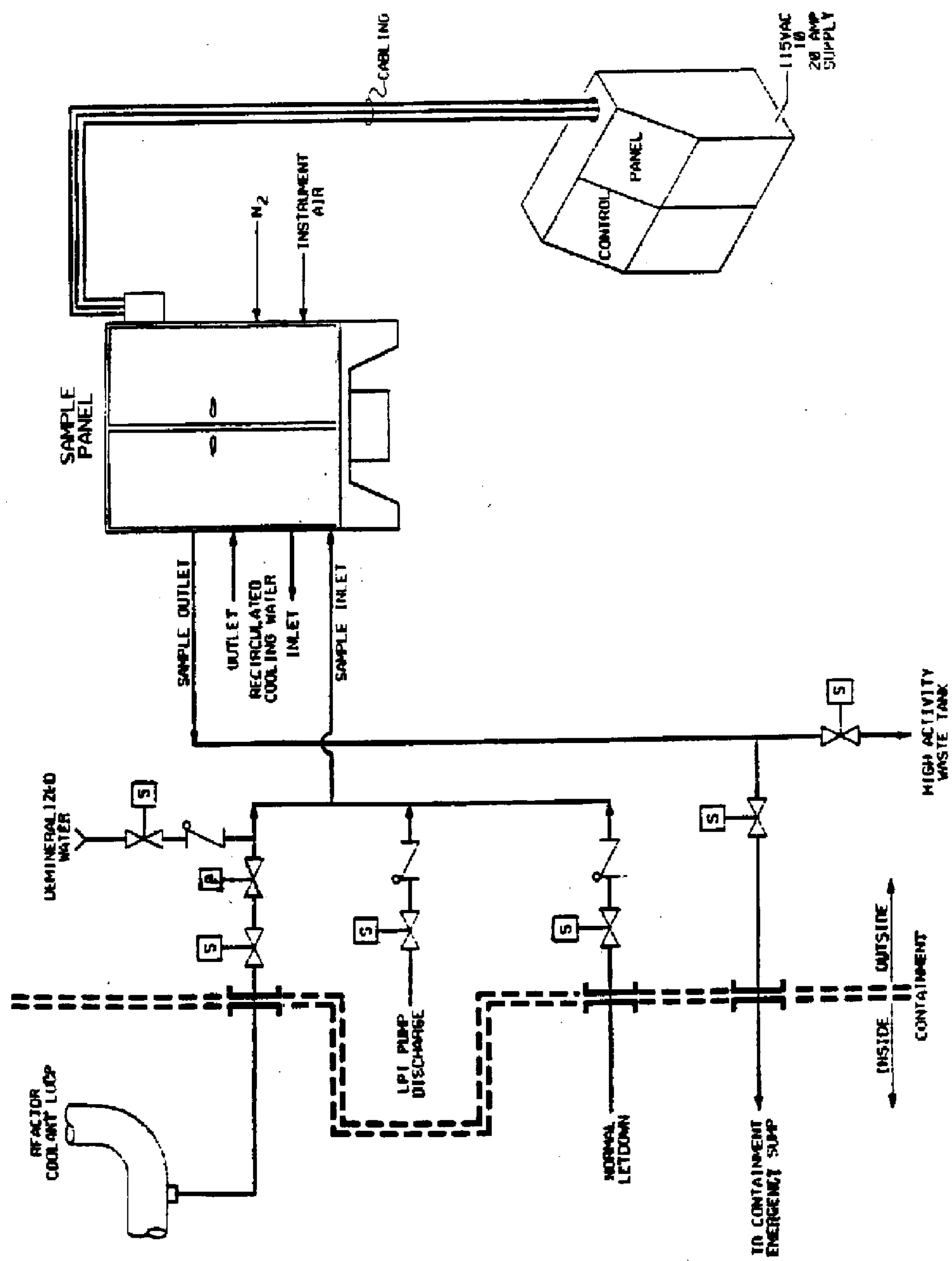


Figure 9-23. Post-Accident Containment Air Sample System

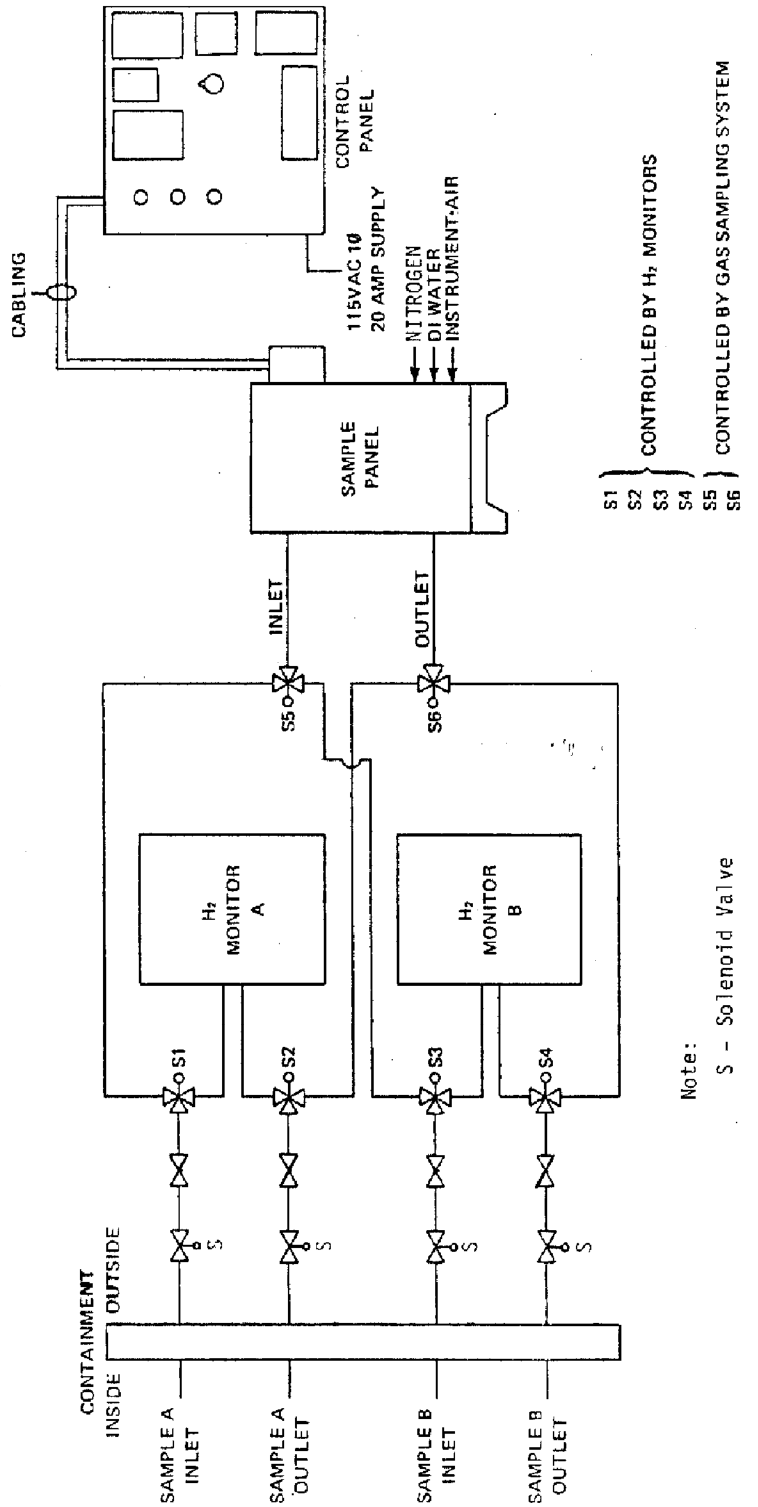


Figure 9-24. Control Room Area Ventilation and Air Conditioning System

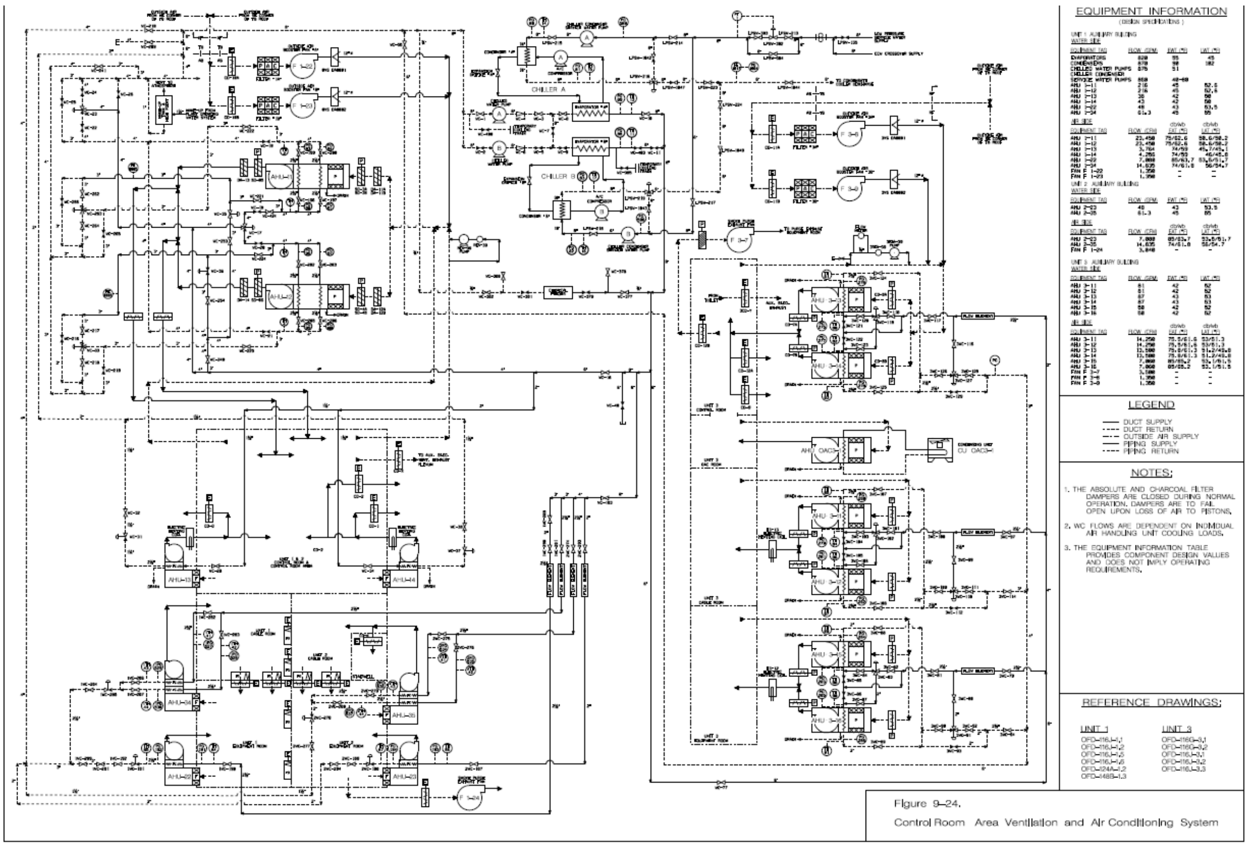


Figure 9-25. Spent Fuel Pool Ventilation System Unit 1 and 2

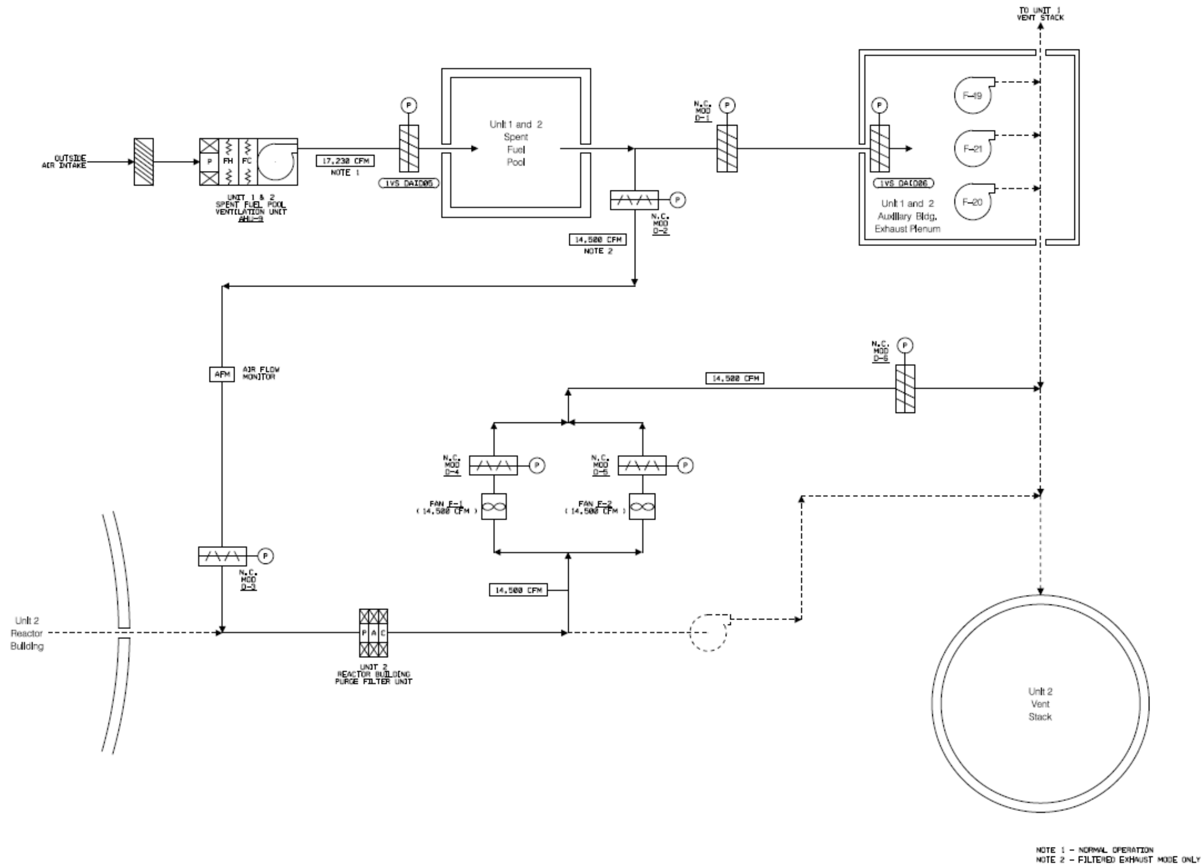


Figure 9-26. Spent Fuel Pool Ventilation System Unit 3

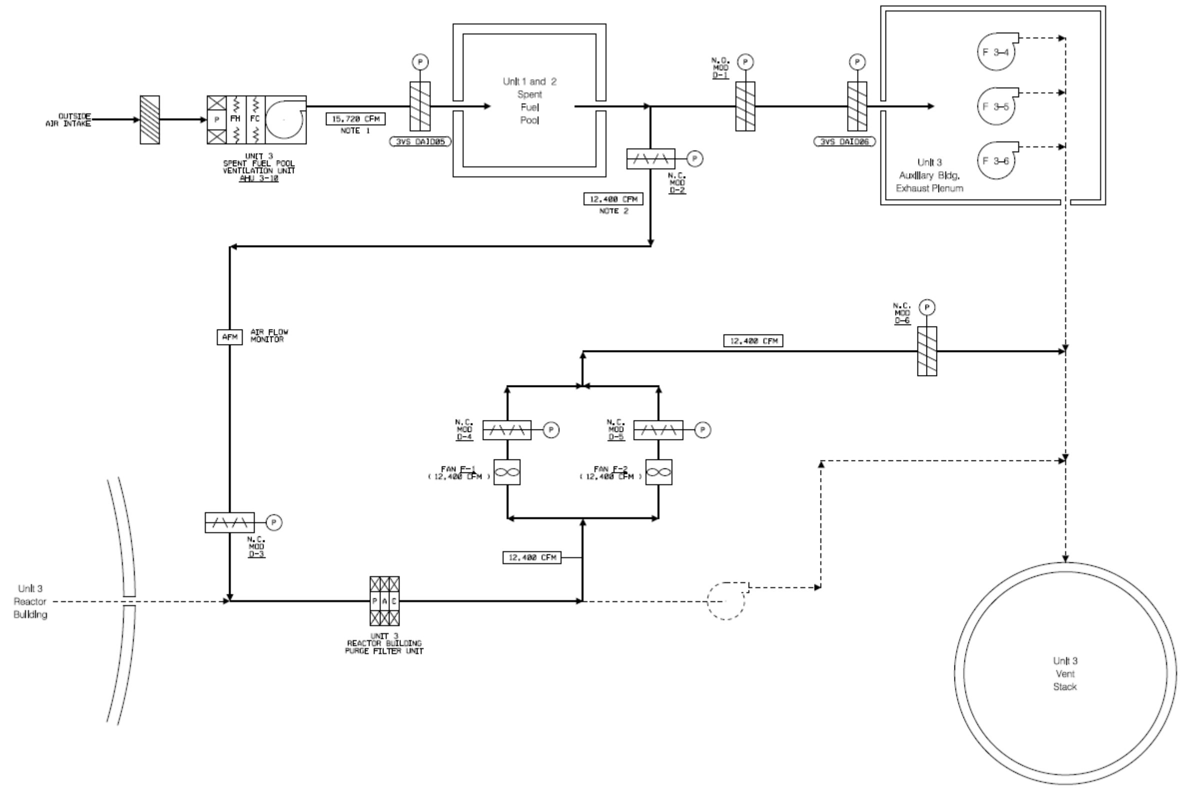


Figure 9-27. Auxiliary Building Ventilation System Unit 1 and 2

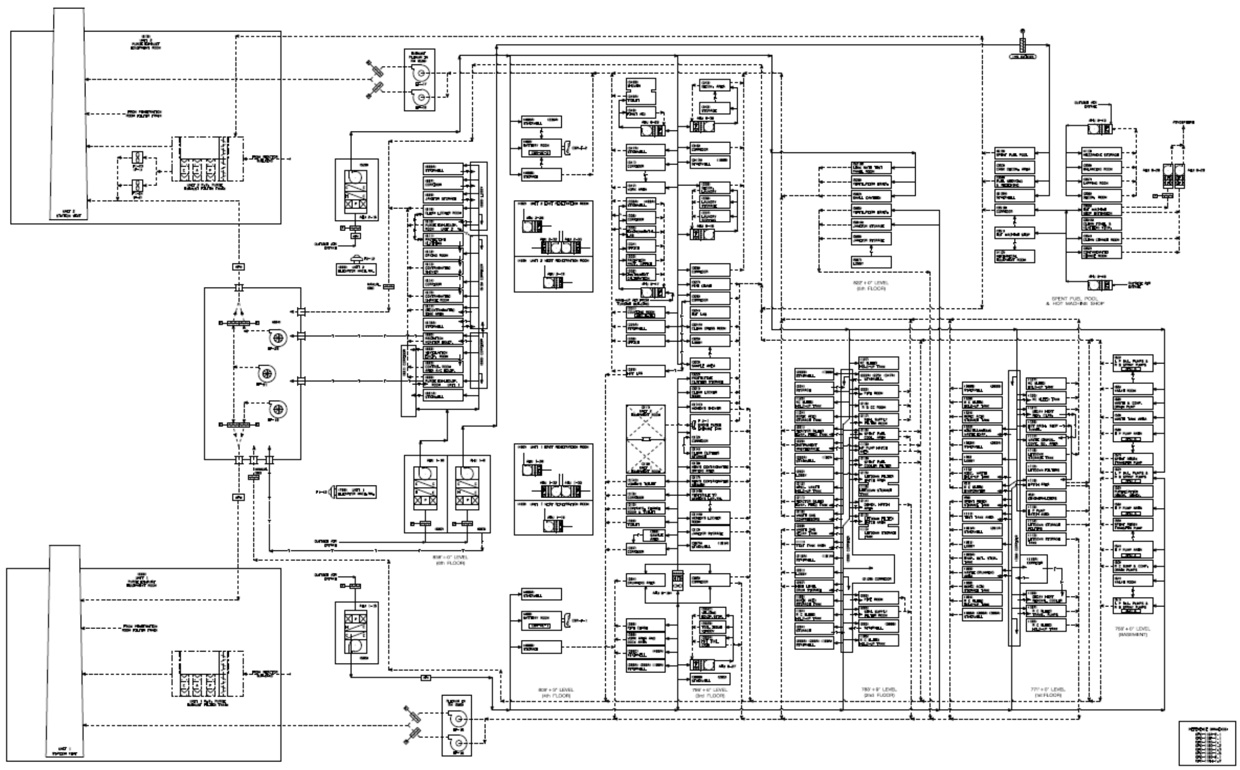


Figure 9-28. Auxiliary Building Ventilation System Unit 3

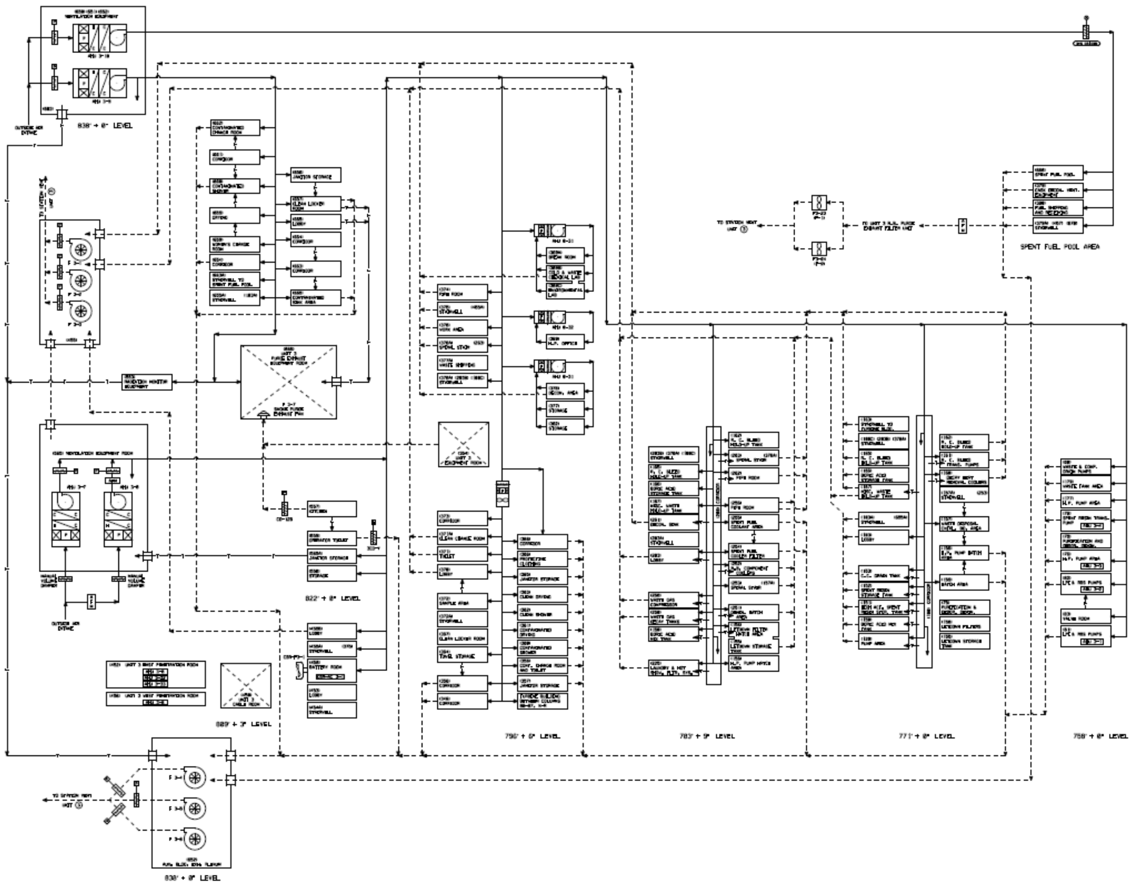


Figure 9-29. Deleted Per 1998 Update

Figure 9-30. SSF General Arrangements Longitudinal Section

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 9-31. SSF General Arrangements Plan Elevation 777' and 754'

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 9-32. SSF General Arrangements Plan Elevation 797+0

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 9-33. SSF General Arrangements Plan Elevation 817+0

Security-Related Withheld Under 10 CFR 2.390

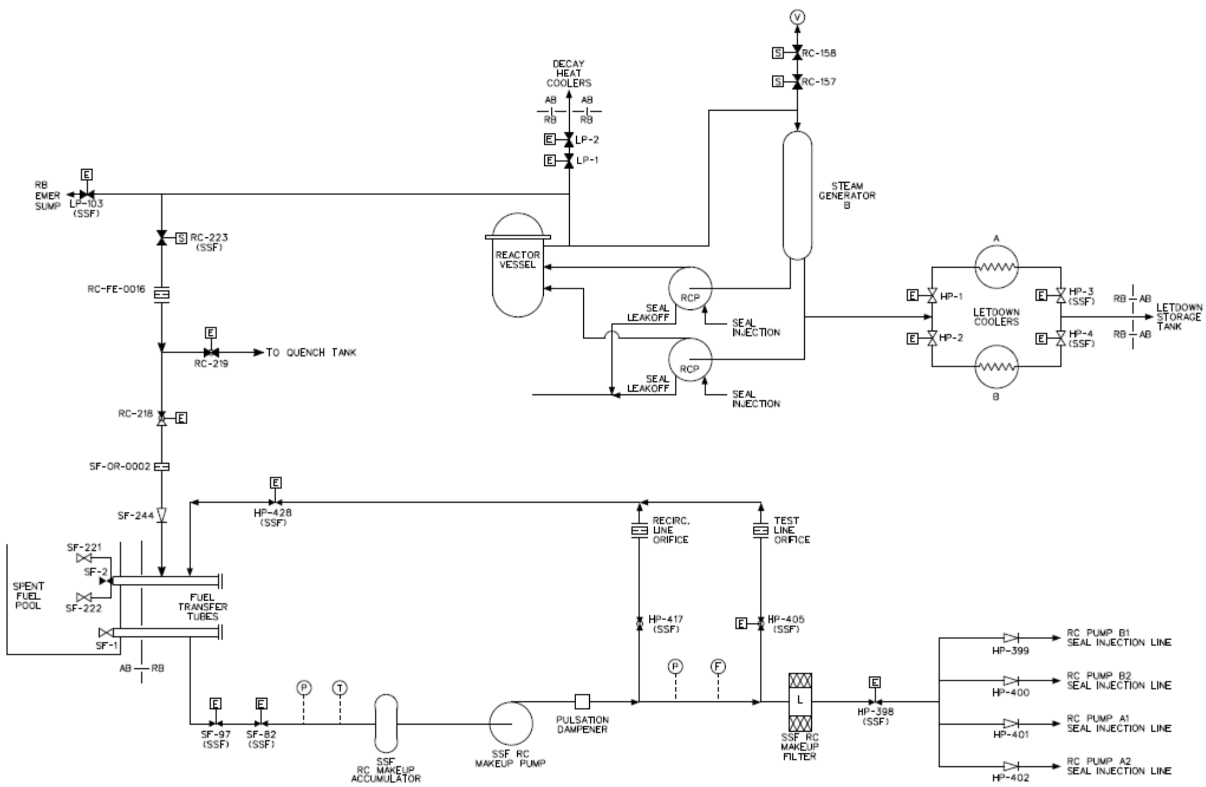
[redacted]

Figure 9-34. SSF General Arrangements Transverse Section

Security-Related Withheld Under 10 CFR 2.390

[redacted]

Figure 9-35. SSF RC Makeup System



NOTE:
(SSF) INDICATES THAT THE VALVE IS CONTROLLED FROM THE SSF CONTROL ROOM.

Figure 9-36. SSF Auxiliary Service Water System

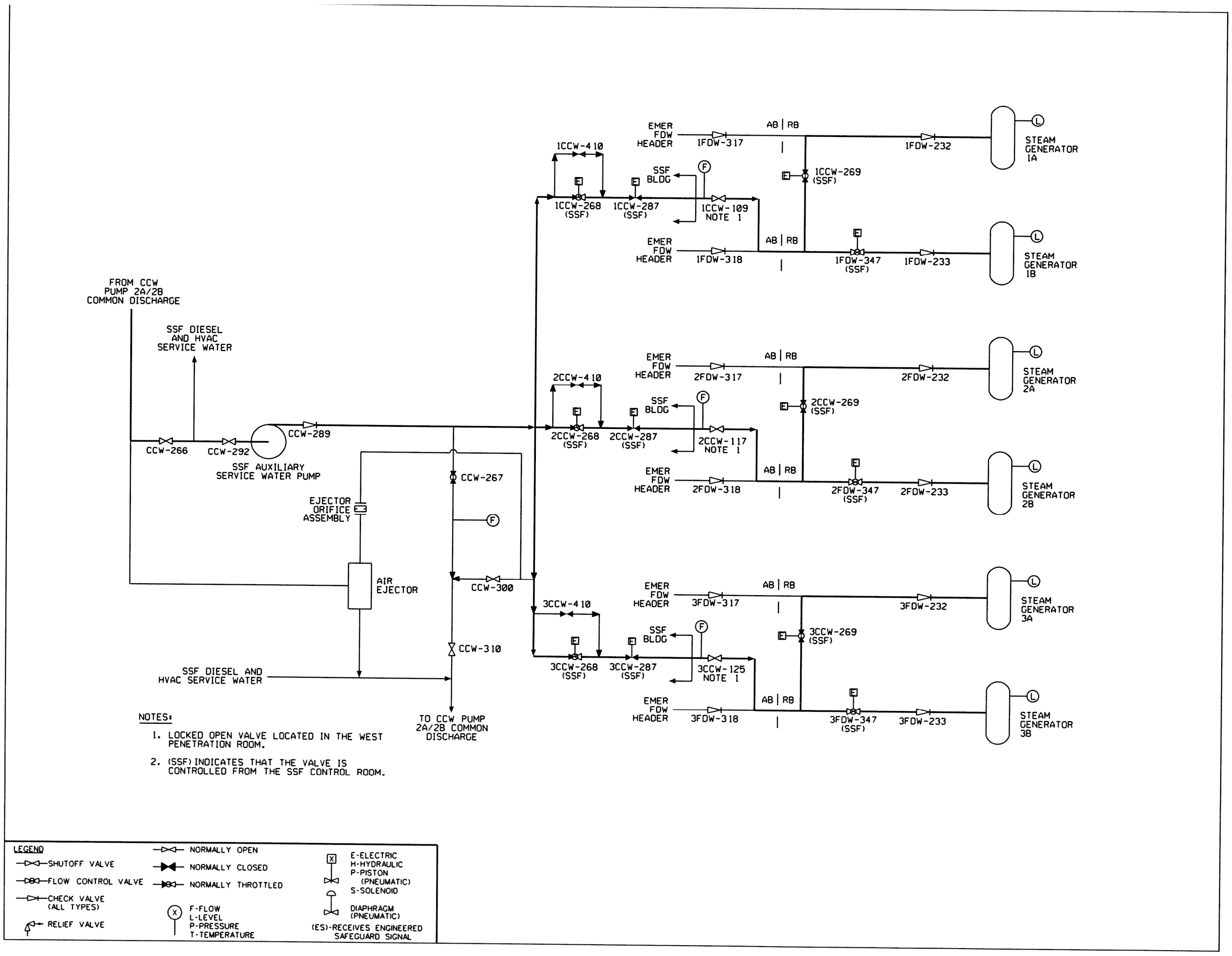


Figure 9-37. SSF HVAC Service Water System & SSF Diesel Cooling Water System

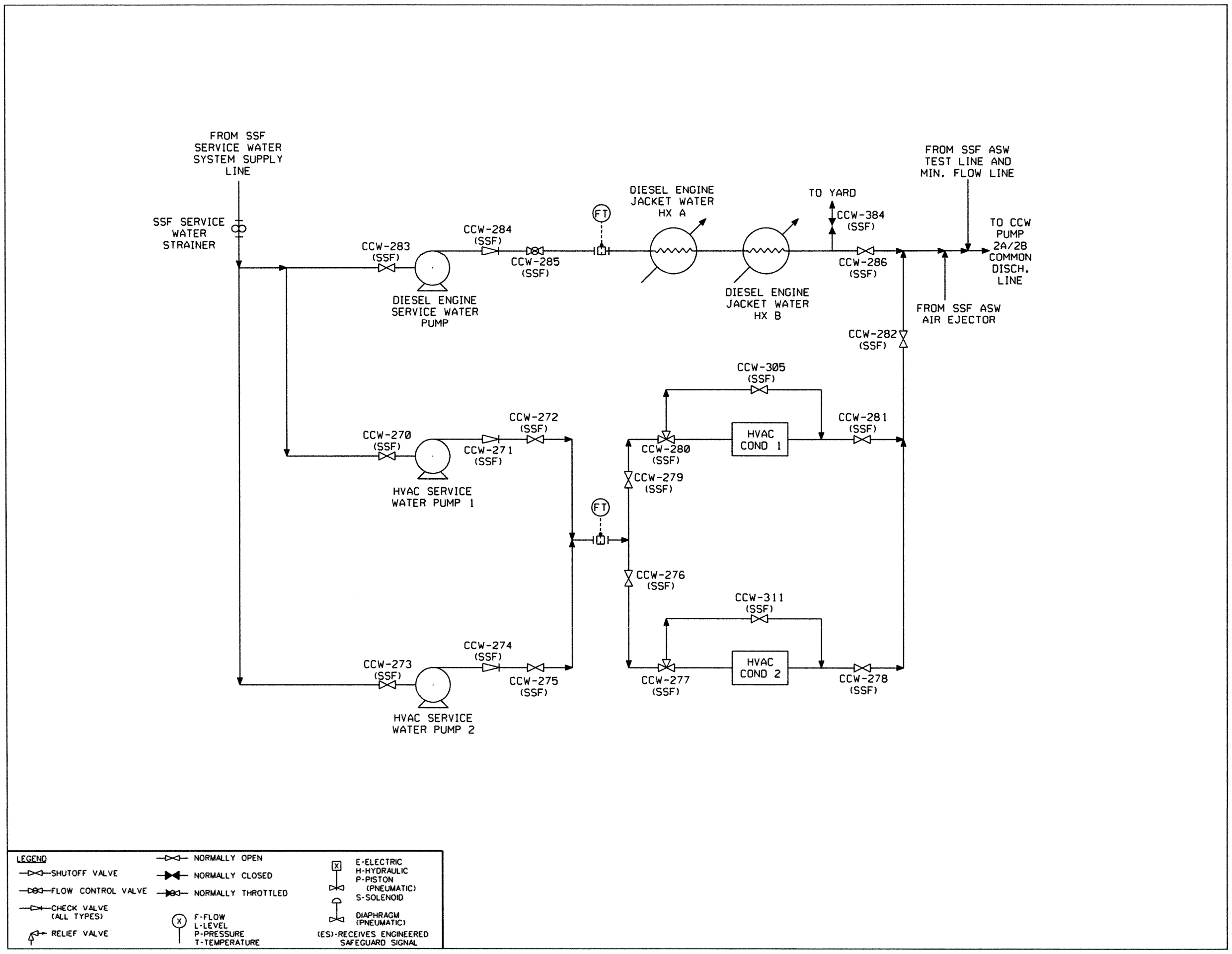


Figure 9-38. SSF Diesel Air Starting System

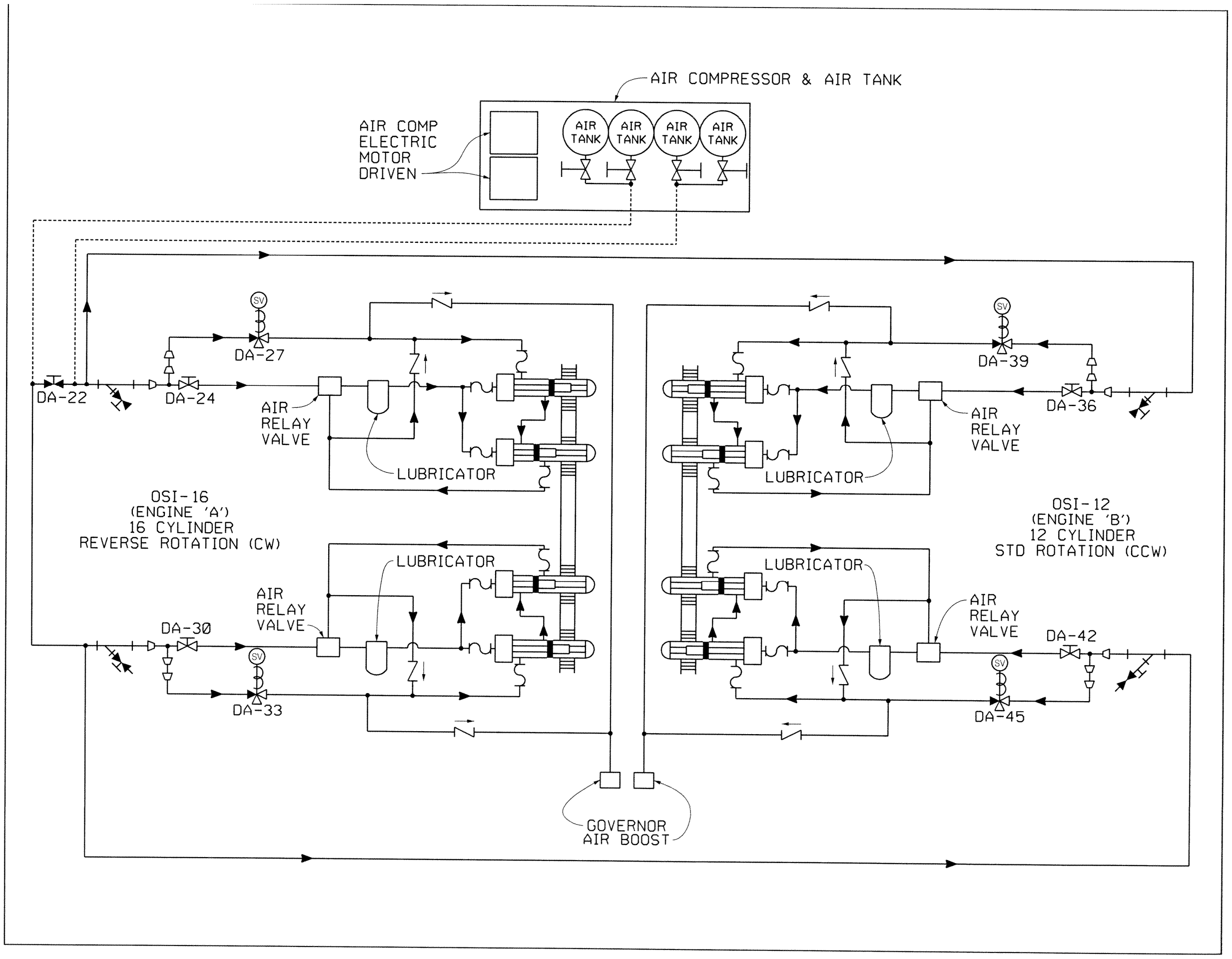


Figure 9-39. SSF Sump System

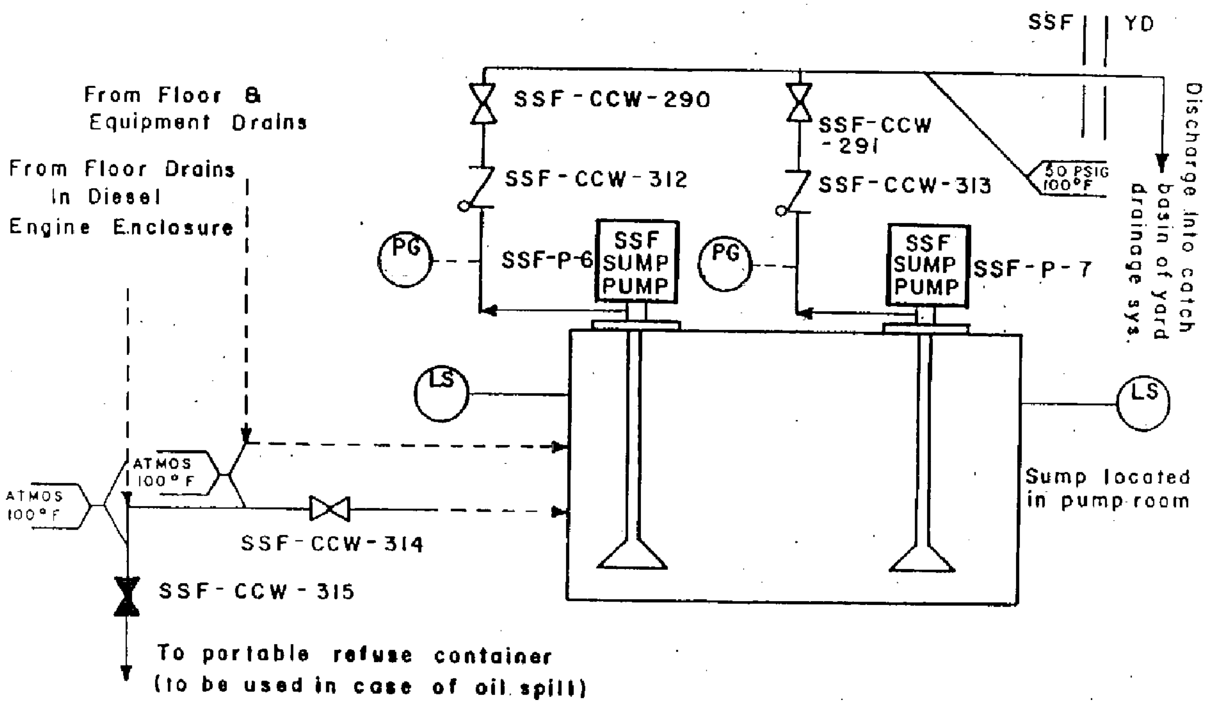


Figure 9-40. SSF 4160V/600V/208V Electrical Distribution

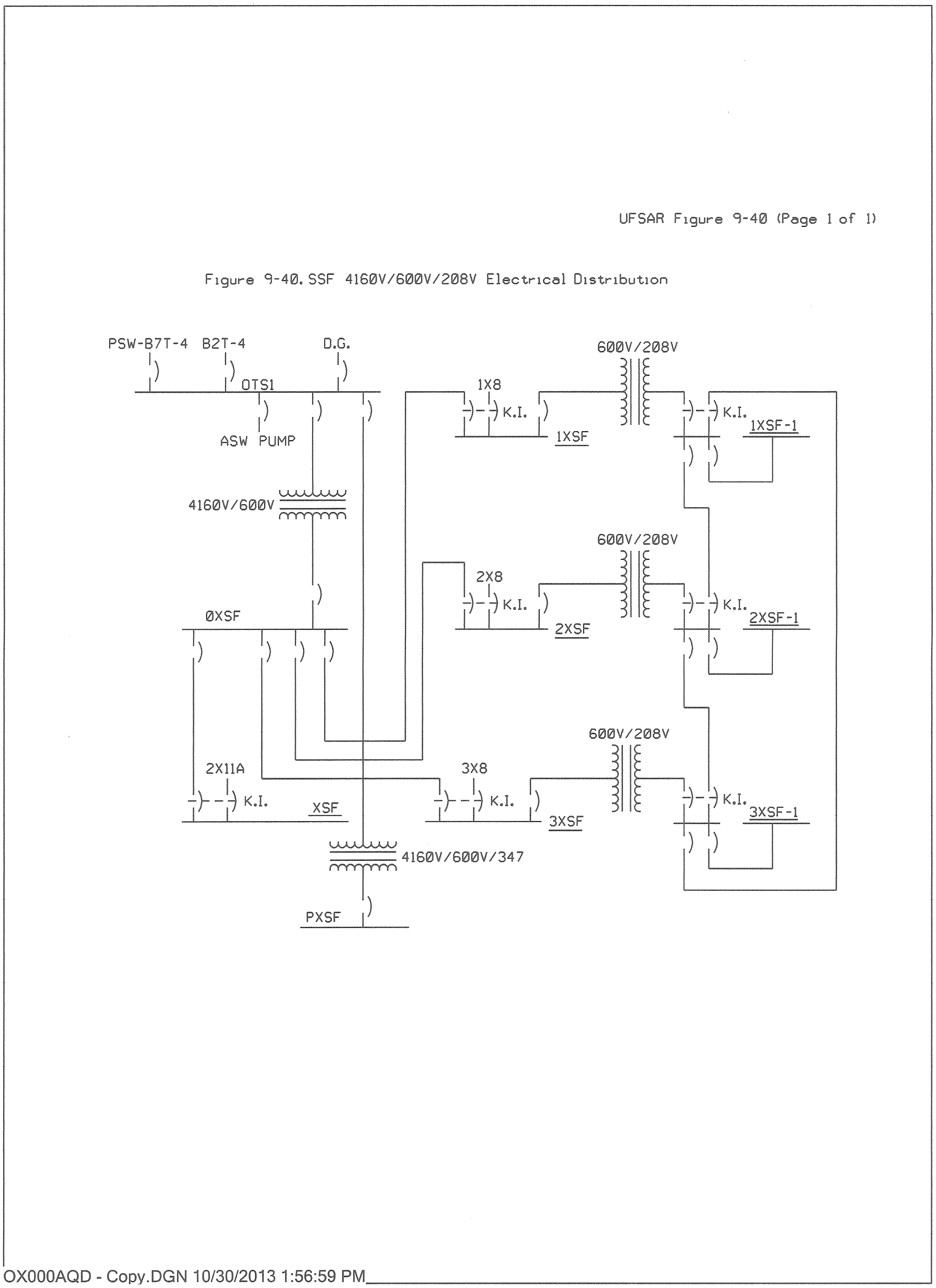


Figure 9-41. SSF 125 VDC Auxiliary Power Systems

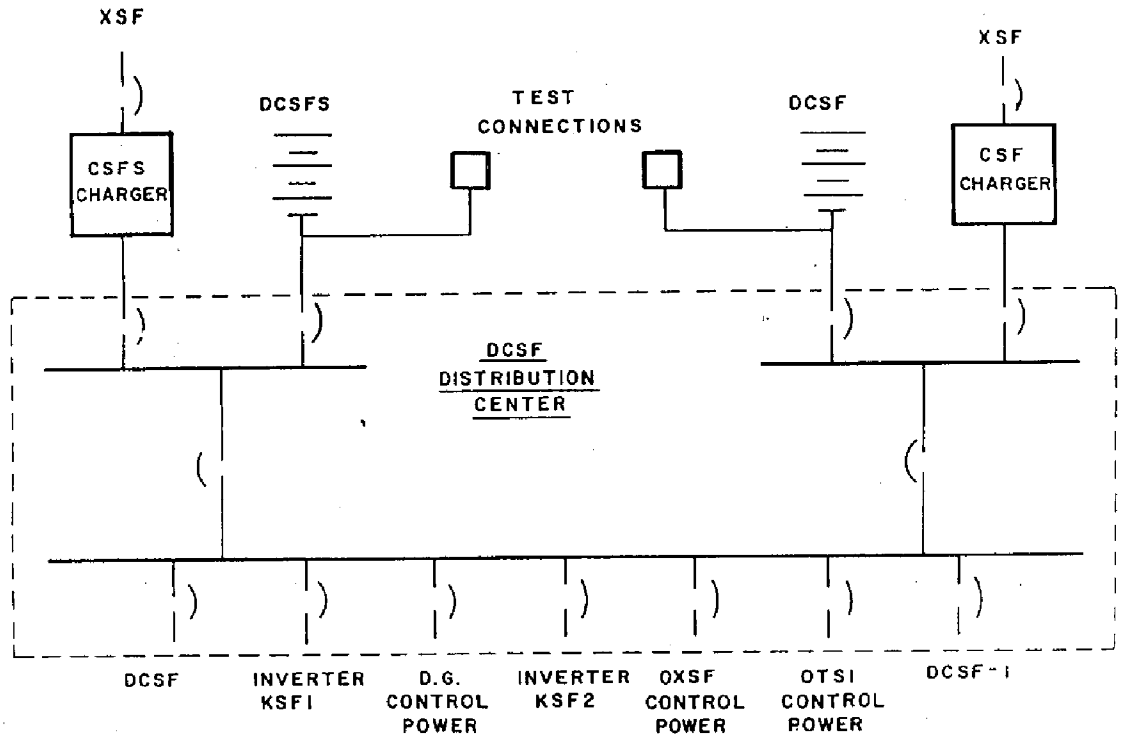


Figure 9-42. Essential Siphon Vacuum System

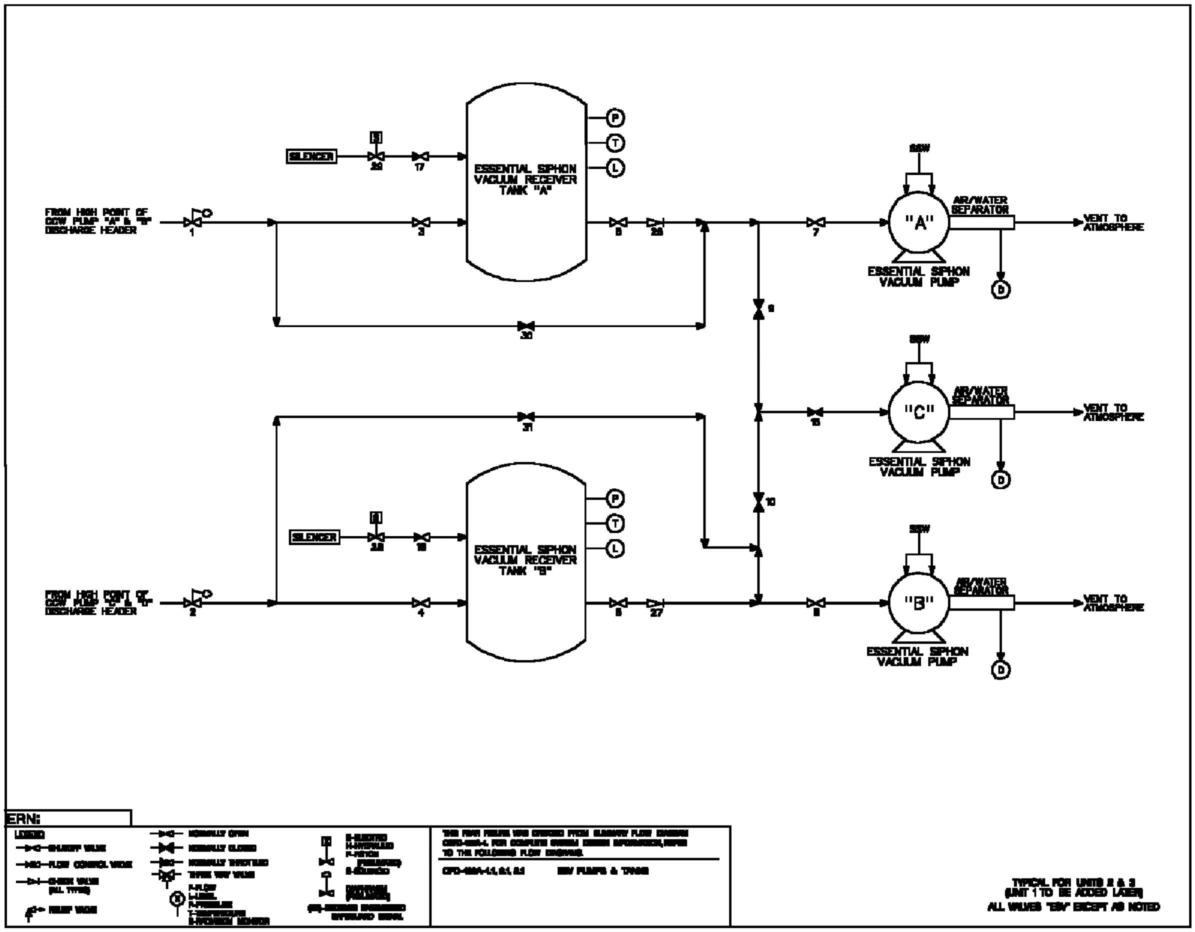


Figure 9-43. Siphon Seal Water System

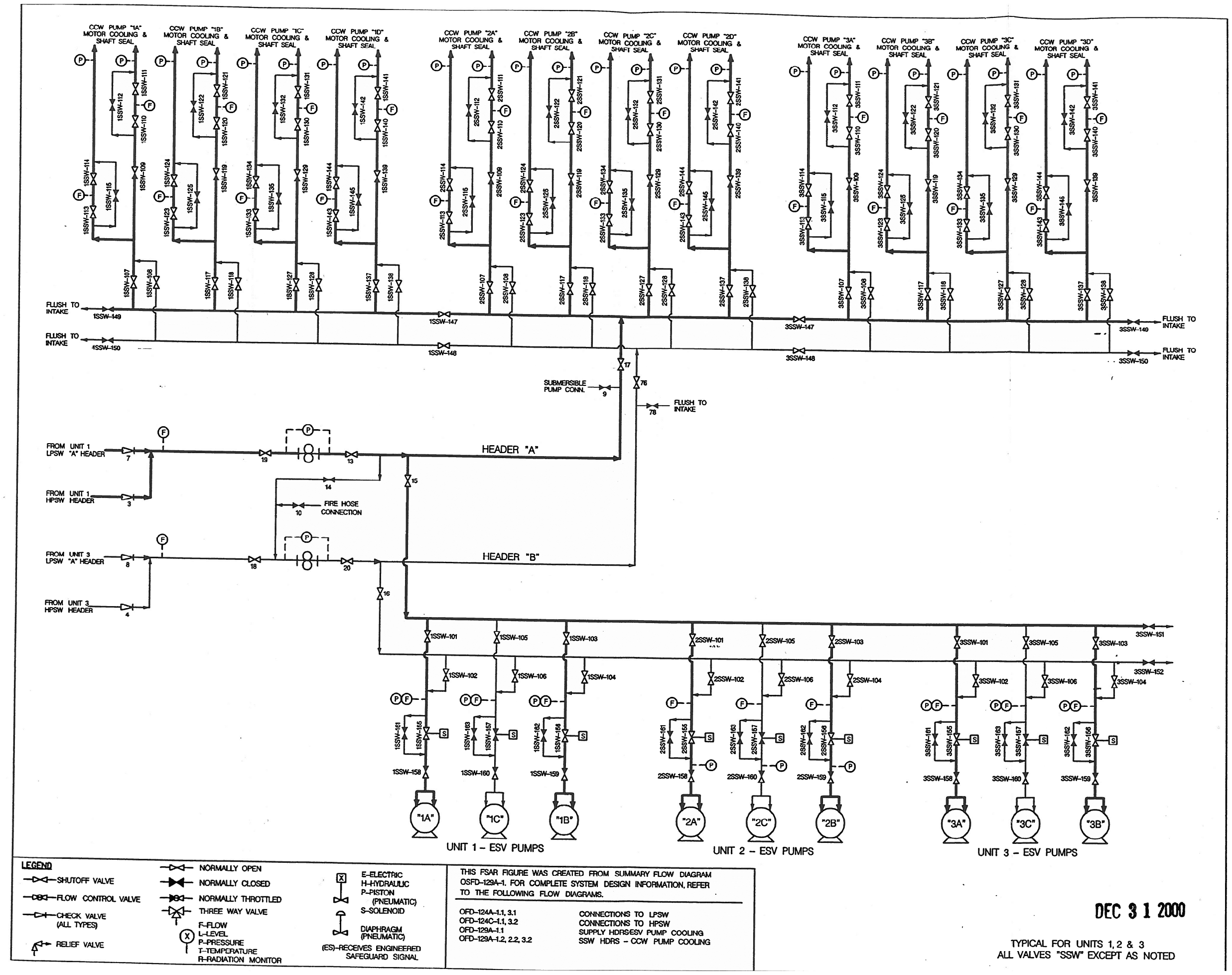


Figure 9-44. Protected Service Water

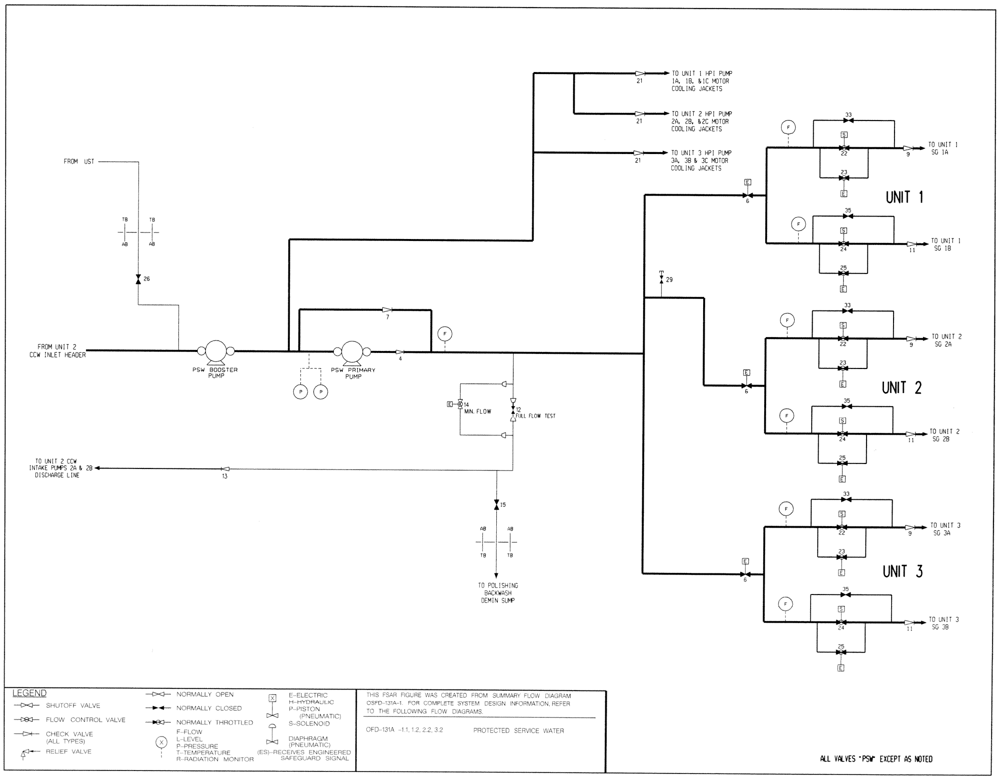


Figure 9-45. PSW AC Electrical Distribution

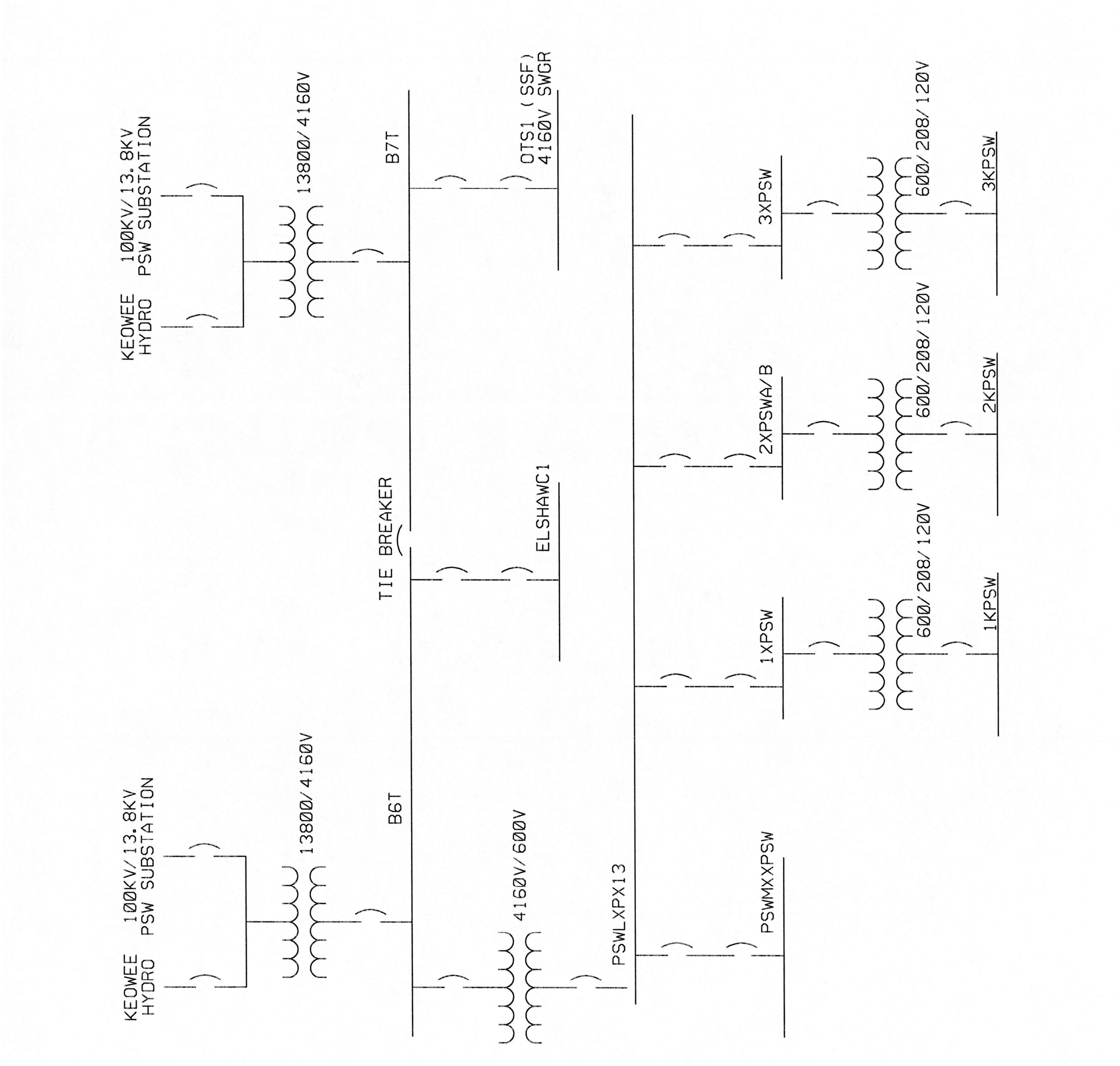


Figure 9-46. PSW DC Electrical Distribution

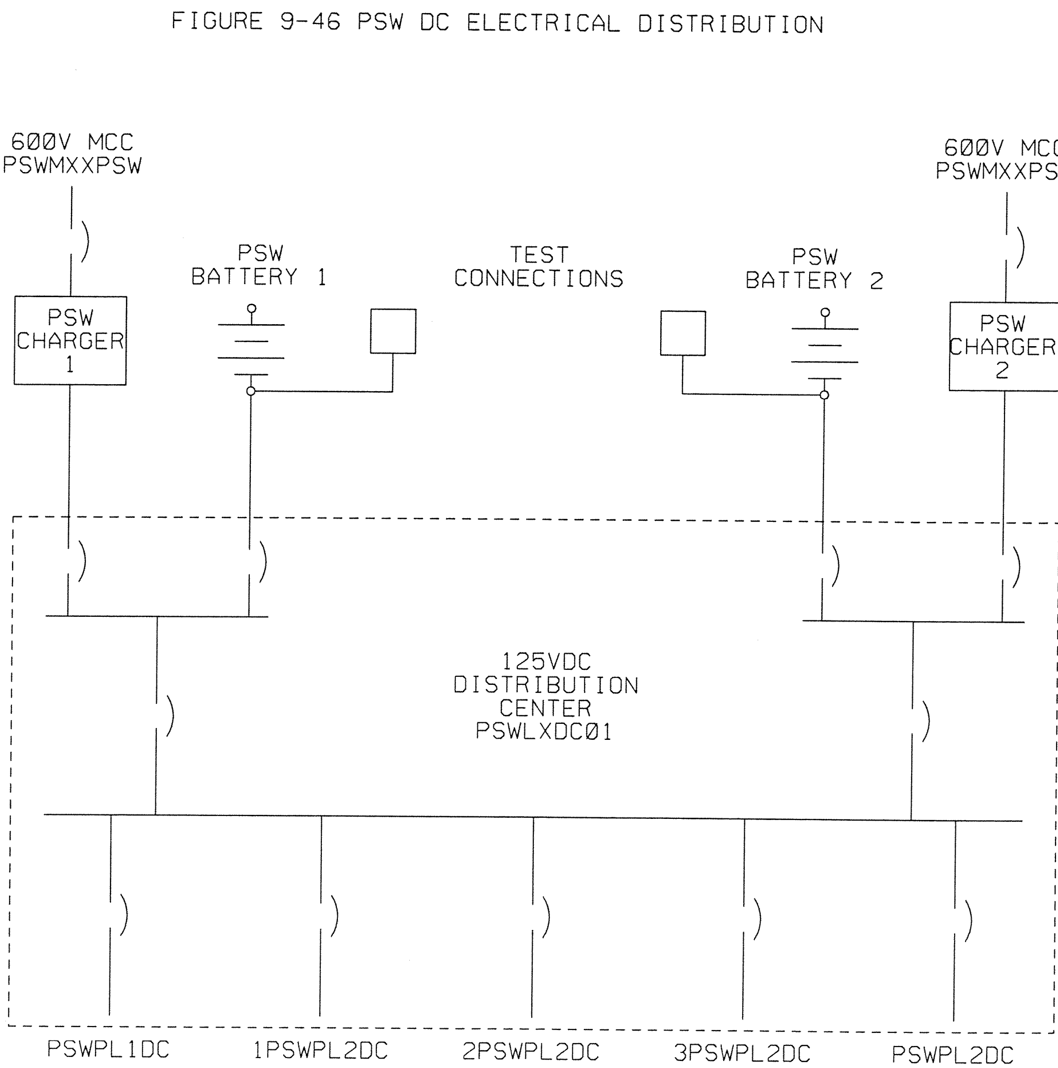


Table of Contents

List of Tables

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List of Figures

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10.0 Steam and Power Conversion System

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10.1 Summary Description

The Steam and Power Conversion System (SPCS) is designed to convert the heat produced in the reactor to electrical energy.

The superheated steam produced by the steam generators is expanded through the high pressure turbine and then exhausted to the moisture separator reheaters. The moisture separator section removes the moisture from the steam and the two stage reheaters superheat the steam before it enters the low pressure turbines. The steam then expands through the low pressure turbines and exhausts into the main condenser where it is condensed and returned to the cycle as condensate. The heat rejected in the main condenser is removed by the Condenser Circulating Water System.

The first stage reheaters are supplied with steam from the A bleed steam line and the condensed steam is cascaded to the B feedwater heaters. The second stage reheaters are supplied with main steam and the condensed steam cascades to the A feedwater heaters. Heat for the feedwater heating cycle is supplied by the moisture separator reheater drains and by steam from the turbine extraction points.

The hotwell pumps take suction from the condenser hotwell and discharge to the condensate polishing demineralizers. Downstream of the polishers, the condensate flows through the condensate coolers, generator water coolers, hydrogen coolers, condenser steam air ejectors and the steam packing exhaust steam seal condenser before discharging to the suction of the condensate booster pumps. After the condensate booster pumps, the condensate passes through three stages of low and intermediate pressure feedwater heaters (F, E, and D). The flow passes through the C feedwater heater, then it divides to the suction of the steam generator feedwater pumps. The steam turbine driven main feedwater pumps deliver feedwater through two stages of high pressure feedwater heaters (B and A), to a single feedwater distribution header where the feedwater flow is divided into two lines to the steam generators.

Deleted Paragraph Per Rev. 29 Update

The safety-related features of the SPCS include the main steam piping from the steam generators up to and including the main turbine stop valves. The steam lines supplying the emergency feedwater pump turbine are also safety-related. The feedwater piping from the feedwater control valves to the steam generator and the Emergency Feedwater System (EFWS) is also safety-related.

SPCS safety-related instrumentation includes the steam generator level instruments which input to the EFWS steam generator level control and steam generator dryout protection circuits. Another QA control circuit monitors Upper Surge Tank (UST) level and closes the UST to Hotwell isolation valves and the UST to Polishing Demineralizer Backwash Pump (PDBP) isolation valves regardless of hotwell level or PDBP status in order to maintain a minimum 6 foot level in the UST for an EFWS suction source. Other UST level indication is used for post-accident monitoring. The only additional safety-related instrumentation associated with the SPCS is the steam generator outlet pressure used for post-accident monitoring and as input to the Automatic Feedwater Isolation System circuitry.

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10.2 Turbine-Generator

10.2.1 Design Bases

The turbine-generator converts the thermal energy of steam produced in the steam generators into mechanical shaft power and then into electrical energy. Each unit is operated primarily as a base loaded unit, but may be used for load following when required.

A maximum rate of turbine load change of 10 percent full load per minute is permitted by the Turbine Electro-Hydraulic Control (EHC) System without restriction if the minimum load involved in the change is 46 percent full load or greater. Below 46 percent full load, the maximum rate of change is still 10 percent full load per minute, but the total load change may be restricted by turbine metal temperature considerations.

The rate of change of reactor power is limited to values consistent with the characteristics of the Reactor Coolant System and its control systems. These limitations are imposed by the Integrated Control System on the Steam and Power Conversion System. See Section 7.6.1.2 and Table 7-6.

Turbine-generator functions under normal, upset, emergency, and faulted conditions are monitored and controlled automatically by the Turbine Control System (TCS). The TCS includes redundant mechanical and electrical trip devices to prevent excessive overspeed of the turbine-generator. Additional external trips are provided to ensure operation within conditions that preclude damage to the turbine-generator. A standby manual control system is also provided in the event that the automatic control system is not available.

10.2.2 Description

Each unit's turbine-generator consists of a tandem (single shaft) arrangement of a double-flow high-pressure turbine, and three identical double-flow low pressure turbines driving a direct-coupled generator at 1800 rpm. The turbine is operated in a closed feedwater cycle which condenses the steam, and the heated feedwater is returned to the steam generators. The system is designed to utilize the entire output from the Nuclear Steam Supply System. The turbine generator is manufactured by the General Electric Company of Schenectady, New York.

The flow of main steam is from the steam generators to the high-pressure turbine through four stop valves and four control valves. After expanding through the high-pressure turbine, exhaust steam passes through external moisture separators and two stage steam-to-steam, shell and tube type reheaters. 'A' bleed extraction steam from the high-pressure turbine is supplied to the first reheater stage tube bundle in each reheater. Main steam is supplied to the second reheater stage tube bundle in each reheater. Reheated steam is admitted to the three low pressure turbines and expands through the low-pressure turbines to the main condensers.

Bleed steam for the six stages of feedwater heating is provided from the following sources:

Heater	Extraction Source
A	H-P turbine
B	H-P turbine
C	H-P turbine exhaust
D	L-P turbines

Heater	Extraction Source
E	L-P turbines
F	L-P turbines

Each main generator is a 1038 MVA, 1800 rpm, direct connected, 3 phase, 60 cycle, 19,000 volt conductor cooled synchronous generator rated at 0.90 P.F., and 0.50 SCR at hydrogen pressure of 60 psig. Generator rating, temperature rise, and class of insulation are in accordance with IEEE standards. Excitation is provided by a shaft driven alternator with its output rectified.

10.2.3 Turbine Disk Integrity

10.2.3.1 Materials Selection

Turbine wheels and rotors are made from vacuum melted or vacuum degassed Ni-Cr-Mo-V alloy steel by processes which minimize flaw occurrence and provide adequate fracture toughness. Tramp elements are controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long life fracture toughness for the environment in which the parts operate. The turbine wheel and rotor materials have the lowest Fracture Appearance Transition Temperatures (FATT) and highest Charpy V-notch energies obtainable, on a consistent basis from water quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Since actual levels of FATT and Charpy V-notch energy vary depending upon the size of the part and the location within the part, etc., these variations are taken into account in accepting specific forgings for use in turbines for nuclear application. Charpy tests essentially in accordance with Specification ASTM A-370 are included.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in Section 10.2 to produce a balance of adequate material strength and toughness to ensure safety while simultaneously providing high reliability, availability, and efficiency during operation. Bore stress calculations include components due to centrifugal loads, interference fit, and thermal gradients where applicable. The ratio of material fracture toughness, K_{IC} (as derived from material tests on each wheel or rotor) to the maximum tangential stress for wheels and rotors at speeds from normal to 5% above (the highest anticipated speed resulting from a loss of load) is at least $2\sqrt{\text{in}}$.

Turbine operating procedures are employed to preclude brittle fracture at start-up by ensuring that the metal temperature of wheels and rotors is adequately above the FATT and is sufficient to maintain the fracture toughness to tangential stress ratio at or above $2\sqrt{\text{in}}$.

10.2.3.3 Turbine Design

The turbine assembly is designed to withstand normal conditions and anticipated transients including those resulting in turbine trip without loss of structural integrity. The design of the turbine assembly meets the following criteria:

1. Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

2. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20 percent overspeed is controlled in the design and operation so as to cause no distress to the unit during operation.
3. The maximum tangential stress in wheels and rotors resulting from centrifugal forces, interference fit and thermal gradients does not exceed 0.75 of the yield strength of the materials at 5% above the highest anticipated speed resulting from a loss of load.

10.2.3.4 Pre-service Inspection

The pre-service inspection program is as follows:

1. Wheel and rotor forgings are rough machined with minimum stock allowance prior to heat treatment.
2. Each finish machined wheel and rotor is subjected to 100 percent volumetric (ultrasonic), surface, and visual examinations using General Electric acceptance criteria. These criteria are more restrictive than those specified for Class 1 components in the ASME Boiler and Pressure Code, Sections III and V, and include the requirement that subsurface sonic indications are either removed or evaluated to assure that they will not grow to a size which compromises the integrity of the unit during the service life.
3. All finish machined surfaces are subjected to a magnetic particle test with no flaw indications permissible.
4. Each fully bucketed turbine rotor assembly is spin tested at or above the maximum speed anticipated following a turbine trip from full load.

10.2.4 Safety Evaluation

The turbine-generator and all related steam handling equipment are of conventional proven design. This unit automatically follows the core thermal power demand (CTPD) requirements in order to meet the unit power demand, See Section 7.6.1.2. There is also a tie-in with Keowee Hydro Station which can carry auxiliary load upon turbine trip.

Under normal operating conditions, it is possible for this system to become contaminated only through steam generator tube leaks. In this event, radioactivity in the Main Steam System is detected and measured by monitoring condenser air ejector off-gas which is released through the unit vent and by monitoring the steam generator water samples.

No radiation shielding is required for the components of the turbine-generator and related steam handling equipment. Continuous access to the components of this system is possible during normal conditions.

The condensate polisher demineralizers are available to remove radioactive particulates from the condenser hotwell in the event of primary to secondary leakage.

The turbine-generator is designed and manufactured in accordance with General Electric Company design criteria and manufacturing practices, procedures, and processes, as well as its Quality Assurance Program. The turbine-generator equipment conforms to the applicable ASA, ASME, and IEEE standards.

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10.3 Main Steam System

10.3.1 Design Bases

The Main Steam System is designed to achieve the following:

1. Provide steam flow requirements at main turbine inlet design conditions.
2. Dissipate heat from the Reactor Coolant System following a turbine and/or reactor trip by dumping steam to the condenser and atmosphere.
3. Provide steam as required for:
    a. Main and emergency feedwater pump turbines
    b. Condenser air ejectors
    c. Main feedwater pump turbine seals
    d. Steam reheaters
    e. Miscellaneous auxiliary equipment
4. Conform to applicable design codes.
5. Allow visual in-service inspection.
6. Protect adjacent equipment against heat damage.

The following portions of the system are designed to withstand seismic loading (criteria for seismic loading defined in Section 3.2.2);

1. Main steam lines from steam generator through the turbine stop valves
2. Main steam line relief valves
3. The steam supply from the main steam lines to the emergency feedwater pump turbine including valve AS-38 and that portion of the auxiliary steam supply downstream from the valve
4. Through the first valve of all other lines leaving the main steam lines upstream of the turbine stop valves

10.3.2 Description

Main steam is generated in the two steam generators by feedwater absorbing heat from the Reactor Coolant System. Main steam is conveyed by two lines, one per steam generator, to the turbine inlet valves. A pressure equalization and steam distribution header is connected to each main steam line upstream of the turbine inlet valves. The Main Steam System from the steam generators through the turbine stop valves (including connected piping through the first isolating valve of connecting lines upstream of the turbine stop valves) is Duke Piping Class F, except for Unit 2, Trains A and B, which has some additional Class F piping associated with the Atmospheric Dump Valves. All other piping is Class G. Main Steam piping inside the Reactor Building is considered Reg. Guide 1.26 Quality Group B for purposes of Inservice Inspection. See Figure 10-1, Figure 10-2, and Figure 10-3.

Eight self-actuated safety valves are located on each main steam line (a total of sixteen) to prevent overpressurization of the Main Steam System under all conditions. The relief valve total capacity is such that the energy generated at the reactor high power level trip setting can be dissipated through this system at a pressure not exceeding 1155 psig (110 percent of system design pressure, 1050 psig). See Table 3-1 for applicable codes.

The main steam lines and the main and emergency feedwater lines are the only lines of the Steam and Power Conversion System which penetrate the Reactor Building. These lines can be isolated by the turbine stop valves and the main and emergency feedwater line valving. Each of the lines utilized for normal operation leaving the main steam lines before the turbine stop valves has motor operated valves to complete the isolation of a steam generator. These lines are:

1. Steam bypass to condenser and steam supply for auxiliary steam header (See Figure 10-1 for line to auxiliary steam header)
2. Supply to feedwater pump turbines and condenser air ejectors
3. Supply to steam reheaters
4. Supply to emergency feedwater pump turbine.

The arrangement of the valving and parallel piping shown schematically in Figure 10-1 minimizes blowdown of both steam generators from a single leak in the system with the assumption that the turbine stop valves close. For a majority of the Main Steam system, a postulated piping break would only depressurize one steam generator. However, if the break were to occur in either the steam supply to the auxiliary steam header or the emergency feedwater pump turbine cross-connect, blowdown of both steam generators could result. The motor operated valves that are used to isolate the leak require operator action to close and may not get closed until the steam generators are considerably depressurized. This situation has been analyzed and shown to have consequences that are bounded by the consequences of the accidents in Section 15.13 and Section 15.17.

Normally only one Unit is aligned to supply the Auxiliary Steam System. However, during periods of high steam usage, or when switching from one Unit to the other, multiple Units may be aligned to the Auxiliary Steam System. This situation has been analyzed, and determined that no unreviewed safety question exists (Reference 3).

The steam supply for the emergency feedwater pump turbine (Figure 10-1) will come from either of two sources (the main steam line or the auxiliary steam header) and exhausts to the atmosphere. The solenoid operated valve which controls the steam shutoff valve MS-93 is de-energized on loss of both main feedwater pumps, thus opening the steam shutoff valve. As the steam shutoff valve leaves the closed position, a limit switch starts the emergency feedwater pump turbine bearing oil pump. If a Main Steam Line Break is sensed by the Automatic Feedwater Isolation System, the solenoid valve (MS-SV-0074) will energize thus closing MS-93. MS-95 is designed to fail closed on loss of hydraulic oil pressure. An AFIS actuation will energize and close solenoid valve (TO-145) to isolate the hydraulic oil supply to close MS-95.

The ADV flow path for each steam generator is credited as a compensatory measure in Technical Specification (TS) 3.5.2, “High Pressure Injection (HPI).” In certain HPI configurations, the ADV flow path for one steam generator is credited to depressurize the steam generator and enhance primary-to-secondary heat transfer during certain small break loss of coolant accidents (LOCAs). This is done in conjunction with the EFW System providing cooling water to the steam generator.

10.3.3 Safety Evaluation

The Main Steam System delivers the generated steam from the outlet of the steam generators to the various system components throughout the Turbine Building without incurring excessive pressure losses. When replacement steam generators were initially put in service, steam was generated at approximately 60°F superheat conditions. Functional requirements of the system are as follows:

1. Achieve optimum pressure drop between the steam generators and the turbine steam stop valves.
2. Assure similar steam conditions between each steam stop valve and between each steam generator.
3. Achieve adequate piping flexibility for acceptable forces and moments at equipment interfaces.
4. Assure adequate draining provisions for startup and for operation with saturated steam.

The once-through nature of this recirculating steam condensate cycle is utilized in the removal of contaminants resulting from steam generator leaks, since it allows the flow through the steam generator to be subjected to purification. Radioactive contaminants will be removed by the Powdex polishing demineralizers and moisture separator reheaters (MSR) drain demineralizer as described for the control of impurities (Section 10.3.5.1). Provision is made for transferring the backwashed resins, when they contain radioactive material, as radwaste.

Trips, automatic corrective actions, and alarms will be initiated by deviations of system variables within the Steam and Power Conversion System. In the case of automatic corrective action in the Steam and Power Conversion System, appropriate automatic corrective action will be taken to protect the Reactor Coolant System. The more significant malfunctions or faults which cause trips, automatic actions or alarms in the Steam and Power Conversion System are listed in Section 10.4.6.5.

The analysis of the effect of loss of full load on the Reactor Coolant System is discussed in Section 15.8. Analysis of the effects of partial loss of load on the Reactor Coolant System is discussed in Section 7.6.1.2.3.2.

The effects of inadvertent steam relief or steam bypass are covered by the analysis of the steam line break given in Section 15.13, and in Section 15.17. The effects of an inadvertent rapid throttle valve closure are covered by the turbine trip discussion in Section 15.8.

Following a turbine trip, a reactor trip will occur if reactor power is above the anticipatory reactor trip system (ARTS) setpoint. The safety valves will relieve excess steam until the output is reduced to the point at which the steam bypass to the condenser can handle all the steam generated. Steam may also be released to the atmosphere through a manually operated angle-body control valve on each main steam line.

Pressure relief is required at the system design pressure of 1050 psig, and the first safety valve bank will be set to relieve at this pressure. The design pressure is based on the operating pressure of 925 psia plus a 10 percent allowance for transients and a 4 percent allowance for blowdown. Additional safety valve banks will be set at pressures up to 1104 psig, as allowed by the ASME Code. Pressure relief is provided by eight safety valves on each main steam line, and the valve relief pressures are:

Number of Valves	Relief Pressure (psig)	Allowable Relief Pressures (psig)
1	1050	1019 – 1060
1	1065	1033 - 1096

Number of Valves	Relief Pressure (psig)	Allowable Relief Pressures (psig)
1	1070	1038 - 1102
1	1075	1043 - 1107
2	1080	1048 - 1112
1	1090	1058 - 1122
1	1104	1071 - 1137

The relief valve total capacity is such that the energy generated at the reactor high power level trip setting can be dissipated through this system at a pressure not exceeding 1155 psig (110 percent of system design pressure, 1050 psig).

10.3.4 Inspection and Testing Requirements

Steam from the steam generators is admitted to the turbine through four cast 24 inch main steam stop valves, arranged in parallel and located in the main steam lines upstream from the turbine control valves (See Figure 10-1). In the event of a steam line rupture accident, the stop valves serve to isolate the unaffected steam generator. See Section 10.3.2.

The main steam stop valve is designed for tight seating throughout its life. The valve stem extends through a guide bushing which centers the disc on the stem with some degree of freedom, permitting self alignment of the disc on its seat. The valve seat and disc have spherical seating surfaces so that perfect contact is made even if they are not in precise alignment. The use of stem sealing permits relatively large stem to bushing clearance, minimizing the possibility of stem sticking. The seating surfaces of the valve and the stem seal are hardened inlay contact areas which resist erosion and mechanical damage and assure tightness. A coarse-mesh internal screen strainer with removable fine mesh startup strainer is provided for each stop valve.

The main steam stop valves are fail-safe, requiring hydraulic pressure to open and closure is spring-assisted. The number two stop valve, MS-104, on each unit is a continuously positioned valve while the other stop valves have only two positions: fully opened and fully closed. Each stop valve will be tested periodically (while the turbine is in operation) and any tendency of the valve to remain open in opposition to a control signal will be detected. A stop valve will be disassembled, inspected, and required corrective action taken when a valve test warrants such action. The stop valves will be disassembled and inspected in accordance with OEM/NEIL recommended intervals.

The main steam stop valves are designed and tested to assure proper functioning. In the event of a steam line rupture accident, the two stop valves serving the unaffected steam generator will close in the presence of steam flow in the normal direction, thus precluding the possibility of reverse flow through the other two stop valves.

The motor operated valve on each of the lines connected to the main steam lines can be tested for operability when the unit is shutdown. These valves, the main steam stop valves, and the check valves that are provided in the two branch lines that cross-connect the main steam lines prevent uncontrolled blowdown of the unaffected steam generator in the unlikely event of a main steam line break. Their ability to close will be verified at periodic intervals.

Proper operation of the emergency feedwater pump and turbine, the steam shutoff valve (Figure 10-1), and the valves in the emergency feedwater supply to the steam generators (Figure 10-8) can be demonstrated when the unit is shutdown. The emergency feedwater pump and turbine, and the steam shutoff valve can be tested anytime by utilizing the recirculation test line. Proper functioning of the emergency feedwater supply will be verified at periodic intervals.

10.3.5 Water Chemistry

10.3.5.1 Secondary Side Water Chemistry

Hydrazine and/or carbohydrazide is added to the feedwater downstream of the condensate polishing demineralizers for oxygen control. An alternate addition point is directly to the condensor hotwell.

Ethanolamine or an alternate approved amine is used to increase pH to minimize formation of corrosion products.

A Titanium solution may be injected into the feedwater system downstream of the main feedwater pumps to mitigate intergranular attack (IGA) and intergranular stress corrosion cracking (IGSCC) of steam generator tubing.

The condensate polishing demineralizer utilizes the Powdex process, developed by Graver Water Conditioning Company as a unique, high quality water purification system. The Powdex units will function as a combination demineralizer and high purity filter, treating 100 percent of the feedwater flow to the steam generator under conditions of startup, reduced load, and normal full-load operation.

The Powdex process uses extremely fine particle-size (60-400 mesh) ion exchange resins which are applied to the external surface of specially design filter elements. The rapid ion exchange rates of these fine resins allows the use of a thin coating (1/16 inch to 1/2 inch) on the elements and permits a greater utilization of the ultimate capacities of the resins than is the case of bead type resins.

The Powdex resins are not chemically regenerated for repeated use but are replaced with fresh resins upon exhaustion. This continued resin replacement allows complete flexibility in the selection of the most advantageous type of resin or combination of resins for the removal of specific impurities.

The resins are selected for the effective removal of dissolved metallic cations and also anions such as halides, silicates, and sulfates. In addition, the resin will also remove by filtration the suspended and colloidal trace impurities such as corrosion products.

Exhaustion of each batch of resins is monitored and is indicated by an increase in pressure drop or by a decrease in treated water quality. Exhausted resins are backwashed from the units and pumped to a disposal facility.

A portion of the moisture separator drain liquid can be sent through a deep-bed demineralizer in order to remove selected chemical species that precipitate out in the moisture separator drain liquid. The demineralizer effluent is normally returned to the condenser. This allows for an overall condensate quality improvement.

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10.4 Other Features of Steam and Power Conversion System

10.4.1 Main Condenser

10.4.1.1 Design Bases

The main condenser is designed to condense turbine exhaust steam for reuse in the steam cycle. The main condenser also serves as a collecting point for various steam cycle vents and drains to conserve condensate which is stored in the condenser hotwell. The condenser also serves as a heat sink for the Turbine Bypass System which is capable of handling approximately 25 percent of rated main steam flow. Rejected heat is removed from the main condenser by the Condenser Circulating Water System.

10.4.1.2 System Description

The main condenser consists of three surface type deaerating condenser shells with each shell condensing the exhaust steam from one of the three low pressure turbines. The condenser shells are of conventional shell and tube design with steam on the shell side and circulating water in the tubes. One low pressure feedwater heater is mounted in the neck of each of the condenser shells. The combined hotwells of the three condenser shells have a water storage capability equivalent to approximately 10 minutes of full load operation (nominally 142,000 gallons). The internal condenser design provides for the effective condensing of steam, scavenging and removal of noncondensable gases, and the deaeration of the condensate. Impingement baffles are provided to protect the tubes from incoming drains and steam dumps.

The main condenser can accept a bypass steam flow of approximately 18 percent of rated main steam flow without exceeding the turbine high backpressure trip point with design inlet circulating water temperature. This bypass steam dump to the condenser function is in addition to the normal condenser functions expected.

10.4.1.3 Safety Evaluation

The main condenser is not assigned a safety class as it is not required for a safe reactor shutdown. The inventory of radioactive contaminants in the main condenser is a function of primary to secondary system leakage.

10.4.1.4 Tests and Inspections

Cleaning and Inspection of the Main Condensers is performed each Refueling Outage or every 24 months. Condenser performance is monitored and trended per the Site Thermal Performance Program. The conductivity, sodium content, and oxygen content of the condensate leaving the hotwell is continuously monitored. The condensate system's polishing demineralizer will remove many of the contaminants and thus reduce the impact of any leakage from the Condenser Circulating Water upon final feedwater chemistry.

10.4.1.5 Instrumentation Application

The main condenser hotwell is equipped with level control devices for automatic control of condensate makeup and rejection. On low water level in the hotwell, control valves supply condensate from the upper surge tanks to the hotwell by gravity. A QA-1 control circuit monitors UST level and closes the UST Riser Automatic Isolation valves regardless of Hotwell level in order to maintain a minimum 6 foot water level in the UST for an EFW suction source. A low hotwell level alarm is provided in the control room. Loss of condenser vacuum will trip the respective unit turbine. All instrumentation for this system is operating instrumentation, and none is required for safe shutdown of the reactor.

10.4.2 Main Condenser Evacuation System

10.4.2.1 Design Bases

The Main Condenser Evacuation System is designed to remove noncondensable gases and air inleakage from the steam space of the three shells of the main condenser. The Main Condenser Evacuation System consists of the Condenser Steam Air Ejector System and the Main Vacuum System which are shown on Figure 10-5 for Oconee 1, 2 and 3.

10.4.2.2 System Description

The Condenser Steam Air Ejector System consists of three condenser steam air ejectors (CSAE) per unit. Normally each CSAE draws the noncondensable gases and water vapor mixture from one of the three main condenser shells to the first air ejector stage. The mixture then flows to the intercondenser where it is cooled to condense the water vapor and motive steam. The second air ejector stage draws the uncondensed portion of the cooled mixture from the intercondenser and compresses it further. The compressed mixture then passes through the aftercondenser where it is cooled and more water vapor and motive steam are condensed. The intercondenser drains back to the main condenser and the aftercondenser drains to the condensate storage tank.

The Main Vacuum System consists of three main vacuum pumps connected to the condenser crossties on the Condenser Steam Air Ejector System to allow the main vacuum pumps to evacuate the main condenser, the main turbine casing, and the upper surge tanks during startup. These pumps are only used during startup since normal operation requires the use of the CSAE only.

10.4.2.3 Safety Evaluation

The Main Condenser Evacuation System is not assigned a safety class as it is not required for a safe reactor shutdown. Control functions of the Main Condenser Evacuation System indirectly influence Reactor Coolant System operation in that upon loss of vacuum the main condenser no longer provides a heat sink.

The noncondensable gases and water vapor mixture discharged to the atmosphere from the Main Condenser Evacuation System are not normally radioactive; however, in the event of primary to secondary system leakage due to a steam generator tube leak, it is possible for the mixture discharged to become radioactive. A full discussion of the radiological aspects of a primary to secondary leakage including radioactive discharge rates under postulated design conditions is discussed in Chapter 11 and Chapter 15.

10.4.2.4 Tests and Inspections

Proper operation of the Main Condenser Evacuation System is verified during unit startup, and is subject to periodic inspections by plant operating personnel. A flowmeter is provided in the discharge piping of each CSAE. Periodic readings of these flowmeters will indicate whether or not the air inleakage to the condenser is within acceptable limits. These readings will also indicate the operating effectiveness of the CSAE.

10.4.2.5 Instrumentation Applications

A radiation monitor is provided in the exhaust line from the CSAE's with remote indicator, recorder, and alarm located in the Control Room. Local indicating devices for pressure, temperature, and flow are provided as required for monitoring system operation. All instrumentation for this system is operating instrumentation and none is required for safe shutdown of the reactor.

10.4.3 Turbine Gland Sealing System

10.4.3.1 Design Bases

The Turbine Gland Sealing System (TGS) is designed to seal the annular openings around the rotor shafts of the high pressure (HP) and low pressure (LP) main turbines and the feedwater pump (FDWP) turbines where the shafts emerge from the shell casings. All seals for the LP main turbines and the exhaust end seals for the FDWP turbines are designed to prevent the leakage of atmospheric air into the turbines since the turbine shell pressures at these seal locations are subatmospheric at all unit loads. All seals for the HP main turbine and the steam inlet end seals for the FDWP turbines are designed to prevent atmospheric air leakage into the turbines since the turbine shell pressures at these seal locations vary from subatmospheric to above atmospheric as these turbines progress from startup to normal operation.

10.4.4 Turbine Bypass System

10.4.4.1 Design Bases

The Turbine Bypass System (TBS) is designed to reduce the magnitude of nuclear system transients following large turbine load reductions by dumping main steam directly to the main condenser and/or to the atmosphere, thereby creating an artificial load on the reactor.

10.4.5 Secondary Cleanup System

10.4.5.1 Condensate Cleanup System

10.4.5.1.1 Design Bases

(See Section 10.3.5.1)

10.4.5.1.2 System Description

The Condensate Cleanup System (CCS) for each unit consists of five powdered resin condensate polishing demineralizer vessels. Normally, all five vessels will be in service. There is also a separate regeneration skid for each unit consisting of a recirculation/resin feed tank and a precoat pump.

The current revision of the SGOG PWR Secondary Water Chemistry Guidelines (Chapter 3) and vendor recommendations are used to derive the operating specifications which are addressed in site specific or fleet documents.

The condensate polishing demineralizers are designed for automatic operation following mode initiation. This means that the operator is required to initiate each Phase of operation but, having once done so the polishers will operate automatically through that mode (i.e., backwash, precoat, filter, and hold). A polisher cycle continues until the effluent water quality deteriorates or until a predetermined differential pressure drop is reached across the polisher. When either of these conditions occur, the polisher will be backwashed.

Each polisher vessel normally is backwashed as required to meet secondary-side chemistry specifications. The vessels are backwashed to the Powdex sump. Each backwash takes about 15,000 gallons of water and contains roughly 17 cubic feet of spent resin. The resin water mixture is pumped to the Radwaste Facility Powdex Backwash Tank. Water is supplied to the Powdex Backwash Pumps form the UST. This source of water is automatically isolated on a low UST level.

The handling of polisher backwash during and after a steam generator primary to secondary leak is discussed in Chapter 11.

10.4.5.1.3 Safety Evaluation

The Condensate Cleanup System is not assigned a safety class as it is not required for a safe reactor shutdown. The condensate polishing demineralizer vessels and all regeneration equipment are located in the Turbine Building. The spent resin and water mixture discharged to the backwash sump from the polisher vessels is not normally radioactive; however, disposal of the mixture in the event of a primary to secondary leakage is discussed in Chapter 11.

10.4.5.1.4 Tests and Inspections

Proper operation of the Condensate Cleanup System is verified during unit startup, and is subject to periodic inspections by plant operating personnel.

10.4.5.2 Moisture Separator Drain Demineralizer

A portion of the moisture separator drain liquid can be sent through a heat exchanger and a deep-bed demineralizer in order to remove selected chemical species that precipitate out in the moisture separator drain liquid. The demineralizer effluent is normally returned to the condenser. The flow rate through this portion of the system is adjustable. The heat exchanger is cooled by Low Pressure Service Water (LPSW).

10.4.6 Condensate and Main Feedwater Systems

10.4.6.1 Design Bases

The Steam and Power Conversion System for each unit is designed to remove heat energy from the reactor coolant in the two steam generators and convert it to electrical energy. The closed feedwater cycle condenses the steam and the heated feedwater is returned to the steam generators. The system is designed to utilize the entire output from the Nuclear Steam Supply System.

The Condensate and Main Feedwater Systems operate within the power rate of change constraints discussed in the "Turbine-Generator, Design Bases" section.

The Condensate and Main Feedwater Systems are shown in Figure 10-6 and Figure 10-7.

10.4.6.2 System Description

The closed cycle feedwater heaters are half-size units (two parallel strings), with the exception of “F” heater. There are three “F” heaters, one in each condenser neck. Deaeration is accomplished in the condenser.

All three hotwell pumps, two of the three one-half capacity condensate booster pumps and both of the main feedwater pumps are in normal use. Each of two main feedwater pumps is more than one-half capacity.

The main steam lines and the main and emergency feedwater lines are the only lines of the Steam and Power Conversion System which penetrate the Reactor Building. These lines can be isolated by the turbine stop valves and the normal and emergency feedwater line valving.

Feedwater supply to the steam generators following a reactor shutdown is assured by one of the following methods:

1. Either of the two main feedwater pumps is capable of supplying both steam generators at full secondary system pressure.
2. The hotwell and condensate booster pump combination has discharge shutoff head of approximately 620 psia. Three sets of half-size pumps are provided. If required, the Turbine Bypass System can be used to reduce secondary system pressure to the point where one of the hotwell and condensate booster pump combinations can supply feedwater to both steam generators.
3. A separate Emergency Feedwater System for each unit will supply feedwater at full system pressure (see Section 10.4.7).
4. Alternate auxiliary feedwater supplies are available from the Emergency Feedwater System of each of the other units.
5. The Protected Service Water System is capable of supplying both SGs of all three units at full secondary system pressure.
6. The SSF Auxiliary Service Water System is capable of supplying both steam generators of all three units at full secondary system pressure.

10.4.6.3 Safety Evaluation

The design, material, and details of construction of the feedwater heaters are in accordance with the ASME Code, Section VIII, Unfired Pressure Vessels.

The Feedwater System has been reviewed to determine the potential for "water hammer" during anticipated operational occurrences. It has been concluded that the existing Oconee Feedwater System is adequate to prevent flow instabilities. Because design features of the feedwater system preclude the probability of destructive "water hammer" forcing functions resulting from uncovering feedwater lines, no analyses have been performed nor test program conducted regarding this occurrence. The following considerations support this conclusion:

1. Neither the Main nor Emergency Feedwater Systems has horizontal or downward-sloping pipe runs adjacent to the steam generator. The auxiliary piping remains below the level of its junction with the steam generator. The main feedwater line rises above its steam generator connection only after downward and horizontal runs which effectively form a loop seal. Only in the unlikely event of steam generator shell pressure near the vapor pressure of the water in this pipe could a steam void occur.
2. The main and emergency feedwater distribution heads on the steam generator are designed to remain flooded regardless of steam generator water level, and would in any event be self-venting if steam were introduced. The main ring header is fed from the bottom, external to the steam generator, and empties upward through the vertical inlet lines. The auxiliary ring headers are similar in design to the main header. None of the feedwater headers can spontaneously drain into the steam generator.

3. Each steam generator has its auxiliary header separate from the main header. Therefore, there is no need to deliver the relatively cool auxiliary feedwater through the normal path for main feedwater. In addition, the QA-1 portions of Main FDW have been analyzed for pressure transient forces due to control valve closure and pump trip resulting from actuation of the Automatic Feedwater Isolation System circuitry.

10.4.6.4 Tests and Inspections

The operating characteristics of the hotwell, condensate booster, and main feedwater pumps are established throughout the operating range by factory tests. The main condensers, the hotwell pumps, the condensate polishing demineralizer vessels, the condenser steam air ejectors, the gland steam condenser, the condensate booster pumps, the feedwater heaters, and the main feedwater pumps are hydrostatically tested to the applicable code or standard.

Manways or removable heads are provided on all heat exchangers to provide access to the tube sheets for inspection and maintenance. A general routine visual surveillance of the system components and piping during operation and maintenance periods for signs of leakage or distress will be performed to verify system integrity.

10.4.6.5 Instrumentation Application

Sufficient instrumentation is provided to monitor system performance and to control the system automatically or manually under all operating conditions.

Trips, automatic corrective actions, and alarms will be initiated by deviations of system variables within the Steam and Power Conversion System. In the case of automatic corrective action in the Steam and Power Conversion System, appropriate automatic corrective action will be taken to protect the Reactor Coolant System. The more significant malfunctions or faults which cause trips, automatic actions, or alarms in the Steam and Power Conversion System are:

10.4.6.5.1 Turbine Trips

Following any turbine trip, a reactor trip will occur if reactor power is above the anticipatory reactor trip system (ARTS) setpoint.

1. Loss of 24V D-C supply to trip circuits
2. Low condenser vacuum
3. Loss of generator stator coolant (if runback fails)
4. Loss of both main feedwater pumps
5. Turbine overspeed
6. Reactor trip
7. Bearing oil low pressure
8. EHC Hydraulic Fluid low pressure
9. Moisture separator high level
10. Manual trip
11. Loss of speed feedback
12. OTSG Steam Generator high level
13. Turbine oil fire trip

14. Generator lockout relay 86GA or 86H

10.4.6.5.2 Automatic Actions

(Also see Integrated Control System Description.)

1. Low Water level in Upper Surge Tank

10.4.6.5.3 Principal Alarms

1. Low pressure at condensate booster pump suction
2. Low pressure at feedwater pump suction
3. Low vacuum in condenser
4. Low water level in condenser hotwell
5. High water level in condenser hotwell
6. High water level in steam generator
7. Low water level in steam generator
8. High pressure in steam generator
9. Low pressure in steam generator
10. Low feedwater temperature
11. Electrical malfunctions in the EHC
12. Low water level in Upper Surge Tank

10.4.6.6 Interactions with Reactor Coolant System

Following a turbine trip, the reactor will trip automatically if reactor power is above the anticipatory reactor trip system (ARTS) setpoint. The safety valves will relieve excess steam until the output is reduced to the point at which the steam bypass to the condenser can handle all the steam generated.

In the event of failure of a main feedwater pump, there will be an automatic runback of the power demand. The one main feedwater pump remaining in service will carry approximately 60 percent of full load feedwater flow. If both main feedwater pumps fail, the turbine and reactor will be tripped, and the emergency feedwater pumps started.

On a low feedwater pump suction header pressure condition, the spare condensate booster pump starts automatically, provided pump start permissives are satisfied.

10.4.7 Emergency Feedwater System

10.4.7.1 Design Bases

The Emergency Feedwater (EFW) System provides sufficient feedwater supply to the steam generators (SGs) of each unit, during events that result in a loss of the Condensate/Main Feedwater, to remove energy stored in the core and primary coolant.

Following a reactor trip, the EFW System is capable of providing sufficient inventory to maintain hot standby for at least 4 hours with or without offsite power available. The EFW System is also capable of providing sufficient feedwater to the steam generators to cool down the RCS to decay heat removal entry conditions following events that result in a loss of main feedwater with and without offsite power available and during a steam generator tube rupture accident with offsite power available. The minimum required capacity of the EFW System is sufficient to reduce primary coolant temperature at a rate of 100°F per hour, assuming the largest capacity EFW pump is inoperable. Cooldown is a manually performed function. EFW inventory requirements are based on maintaining hot standby conditions for one hour, followed by a 50°F per hour cooldown to decay heat removal entry conditions. Although the EFW system capacity is sufficient to support a 50°F per hour cooldown rate, this rate is not achievable during certain events, such as a natural circulation cooldown. The EFW System design basis includes the ability to perform its function in the event of a single active failure. However, in some instances, as addressed in Section 10.4.7.3, alternate capability and operator actions are credited for performing the EFW function to compensate for specific single failures and system vulnerabilities that have been identified. The EFW System is not considered to be an Engineered Safeguard System and therefore was not designed to meet all of the design criteria applicable to Engineered Safeguard Systems. The EFW System is shown in Figure 10-8.

For diversity, the EFW System includes two AC motor-driven pumps and one turbine-drive pump that is independent of AC power. Sources of steam for driving the turbine-driven EFW pump (TDEFWP) are available from both steam generators. Following a loss of all AC power, the turbine-driven EFW pump will automatically actuate and is capable of operating for at least two hours completely independent of AC power. The water inventory that is immediately available to the turbine-driven EFW pump is sufficient to supply feedwater to the steam generators for at least 40 minutes assuming automatic steam generator level control and no reliance on operator action.

The EFW System is designed to start automatically in the event of loss of both main feedwater pumps. The automatic start on loss of both main feedwater pumps meets the single failure criterion. All automatic initiation logic and control functions associated with the EFW pumps and control valves FDW-315 and FDW-316 are independent from the Integrated Control System (ICS). Each OTSG is provided with a level control system (see UFSAR Section 7.4.3.2) that, on demand, enables the EFW System to supply sufficient initial and subsequent flow to the necessary SG to assure adequate decay heat removal.

The seismic qualification of the EFW System and Quality Group Classification is described in UFSAR Section 3.2.2. Only those components listed in UFSAR Section 3.2.2 are seismically qualified. The TDEFWP supporting equipment is not fully seismically qualified and therefore is not credited for Maximum Hypothetical Earthquakes (MHEs). However, it has been evaluated against Seismic Qualification Utility Group (SQUG) criteria and is expected to be available following a seismic event. Although redundancy is provided by two full-capacity seismically qualified Motor Driven Emergency Feedwater Pumps (MDEFWPs), they are also susceptible to failure in a seismic event due to flooding induced by the event. However, alternative seismically qualified means of decay heat removal are provided by the Standby Shutdown Facility (SSF) Auxiliary Service Water (ASW) System and the High Pressure Injection (HPI) System.

The EFW System is seismically qualified to the MHE level out through the first isolation valves, consistent with the design criteria given in Section 3.7.3.9. Piping beyond these boundary points is not seismically qualified. The primary suction to the EFW pumps is from the UST. The Upper Surge Tank (UST) is seismically qualified. Operator action is relied upon to shift the suction of the EFW pumps from the UST to the non-safety condenser hotwell before the UST is completely depleted. The condenser hotwell is seismically qualified with a nominal capacity of 120,000 gallons (References 12, 13, and 14). However, not all piping from the condenser hotwell, such as the suction supply to the TDEFWP and to the hotwell pumps, is seismically qualified. The piping from the hotwell to the TDEFWP; however, is designed and supported such that it would be expected to withstand the design basis earthquake. The piping from the hotwell to the MDEFWPs is seismically qualified.

Portions of the EFW System are vulnerable to tornado missiles. Thus, the plant relies upon diverse means to provide feedwater to the SGs in the event of a tornado. These diverse means include the SSF ASW System and the PSW System.

The Emergency Feedwater System was not designed to withstand the effects of internally generated missiles. If such an event were to occur and if main feedwater were unavailable, the single train SSF ASW System would provide an assured means of providing heat removal from the SGs. A detailed evaluation of the capability of the existing EFW System to withstand missiles was not considered necessary (Reference 2).

The effects of High Energy Line Breaks have been analyzed as addressed in UFSAR Section 3.6.

Provisions for water hammer events are considered unnecessary due to the use of Once Through Steam Generators (OTSG) (Reference 9).

Portions of the Emergency Feedwater system are credited to meet the Extensive Damage Mitigation Strategies (B.5.b) commitments, which have been incorporated into the Oconee Nuclear Station operating license Section H - Mitigation Strategy License Condition.

10.4.7.1.1 Deleted Per 2002 Update

10.4.7.1.2 Deleted Per 2002 Update

10.4.7.1.3 Deleted Per 2002 Update

10.4.7.1.4 Deleted Per 2002 Update

10.4.7.1.5 Deleted Per 2002 Update

10.4.7.1.6 Deleted per 1996 Revision

10.4.7.1.7 Deleted Per 2002 Update

10.4.7.1.8 Deleted Per 2002 Update

10.4.7.1.9 Deleted Per 2002 Update

10.4.7.1.10 Deleted Per 2002 Update

10.4.7.2 System Description

There are three EFW pumps provided for each unit. There are two motor-driven pumps with a design flow rate of 450 gpm/pump. There is one turbine driven pump with a design flow rate of 1080 gpm. The motor-driven pumps are provided with automatic recirculation control valves that close when sufficient demand to the SGs occurs. The turbine driven pump is provided with a minimum recirculation path that is normally open and limited by fixed orifices. The flow rate through the fixed orifices is not available for feeding the SGs. The fixed orifices are sized to pass < 200 gpm. The total combined SG feed capacity of all three EFW pumps is therefore approximately 1780 gpm.

Each motor-driven pump normally serves a separate SG; while the turbine-driven pump normally serves both SGs. EFW is supplied to each SG through its auxiliary feedwater header. The three units are provided with separate EFW Systems. The discharge header of each EFW System can be cross-connected making each system capable of supplying any unit.

The EFW System can accommodate a plant cooldown at the maximum allowable cooldown rate. The EFW flow demand requirements for plant cooldown (from full power operation to RCS temperatures where switchover to Decay Heat Removal System is achievable) have been analyzed for two different cooldown rates. The analysis assumes the cooldown is initiated one hour after plant shutdown and that two reactor coolant pumps are secured prior to cooldown. An EFW suction temperature of 130°F is assumed. All heat sources (decay heat, pump heat, fuel, structural steel, and coolant sensible heat) have been included. The average EFW flow rate to support a cooldown rate of 100°F/hr from hot standby conditions to DHR entry conditions is 430 gpm. If a 100F°/hr cooldown rate is established 15 minutes following reactor trip, the average EFW flow rate during the first hour of the cooldown is 480 gpm. The average EFW flow rate to support a cooldown rate of 50°F/hr from hot standby conditions to DHR entry conditions is 340 gpm.

Cooldown of the Reactor Coolant System (RCS) is a manual function controlled by the operator to obtain the cooldown rate desired and within Technical Specification limits. Without crediting recirculation via the Turbine Bypass System, the condensate inventory consumed for a 100°F/hr cooldown to decay heat removal switchover is approximately 115,000 gallons. The condensate inventory consumed for a 50°F/hr cooldown to decay heat removal switchover is approximately 155,000 gallons. This inventory is well within the capacity available within the UST and hotwell (refer to Table 10-1).

10.4.7.2.1 Motor Driven EFW Pumps (MDEFWPs)

There are two MDEFWPs per unit. The pumps are physically located in the basement of the Turbine Building. Each of the MDEFWPs is normally aligned to a separate SG. Each of the MDEFWPs is supplied with its own independent starting circuit, as described in UFSAR Section 7.4.3.1, that allows the operator manual or automatic control of the pump. During periods of shutdown and cooldown the circuit selector switch is normally positioned to automatically start the MDEFWPs on a LOW STEAM GENERATOR WATER LEVEL signal in either steam generator after a time delay to prevent spurious actuation. The LOW STEAM GENERATOR

WATER LEVEL initiation function, which was added for SG dryout protection (Reference 11), is not designed to meet the single failure criterion as it is not relied upon for the mitigation of any accident. During normal plant operation, the selector switch is positioned to automatically start the MDEFWPs on a LOSS OF BOTH MAIN FEEDWATER PUMPS, LOW STEAM GENERATOR WATER LEVEL or AMSAC signal. Loss of both main feedwater pumps is sensed by pressure switches that monitor main feedwater pump turbine hydraulic oil pressure. The AMSAC start signal is described in Section 7.8.2.1. Once automatically started the MDEFW pumps will continue to operate until manually secured by the operator. Automatic starts of the MDEFWPs are disabled if a main steam line break is sensed by the Automatic Feedwater Isolation System (AFIS) circuitry. Upon AFIS actuation, the MDEFWP aligned to the affected steam generator will automatically stop and be inhibited from any automatic starts. The operator can manually start the motor driven pump by placing its selector switch to RUN. The MDEFWPs require cooling water for continuous operation. Sufficient cooling water is initiated automatically from the Low Pressure Service Water System, upon manual or automatic start of MDEFWPs.

The MDEFW pumps are powered from the 4160VAC Switchgear TD and TE. The switchgear are located side by side on the ground floor of the Turbine Building and are not protected from high energy line breaks. The normal station auxiliary AC Power System normally provides power for the switchgear. During loss of offsite power operation, these switchgear are automatically aligned to the Emergency AC Power System.

10.4.7.2.2 Turbine Driven EFW Pump (TDEFWP)

There is one TDEFWP per unit. The pump is physically located in the basement of the Turbine Building. The TDEFWP is normally aligned to supply both SGs. The TDEFWP is supplied with its own independent starting circuit, as described in UFSAR Section 7.4.3.1, that allows the operator manual or automatic control of the pump. During normal plant operation the circuit selector switch is positioned to automatically start the TDEFWP upon a LOSS OF BOTH MAIN FEEDWATER PUMPS or an AMSAC signal. Loss of both main feedwater pumps is sensed by pressure switches that monitor feedwater pump turbine hydraulic oil pressure. The AMSAC start signal is described in Section 7.8.2.1. Automatic starts of the TDEFWP are disabled if a main steam line break is sensed on either steam generator by the AFIS circuitry. Upon AFIS actuation, the TDEFWP will automatically stop and be inhibited from any automatic starts. The operator can manually start the TDEFWP by placing the selector switch to RUN. The TDEFWP can also be started locally in the basement of the Turbine Building.

For all units cooling water is automatically supplied to the turbine oil cooler via an AC driven cooling water pump. Analysis has shown that the turbine pump may operate in excess of 4 hours without cooling water to the oil cooler. Both of these cooling water supplies may be lost following a loss of AC power. A backup source of cooling for the oil cooler is provided by the High Pressure Service Water (HPSW) System and is automatically aligned following a loss of AC power. The HPSW System is capable of providing cooling through gravity feed from the Elevated Water Storage Tank.

Motive steam for the TDEFWP is provided from either of the two SGs by main steam lines upstream of the main turbine stop valves or by the auxiliary steam header, and is exhausted to the atmosphere. Any of the three steam supplies will provide sufficient steam for turbine operation, and both steam sources are normally aligned and available to supply the TDEFWP. Any steam supply may be isolated if necessary. A check valve is provided in each main steam supply line to minimize uncontrolled blowdown of more than one SG following a MSLB (refer to UFSAR Section 10.3.2 for further details). A check valve is also provided in the auxiliary steam supply line to prevent a loss of the main steam source should auxiliary steam be lost. Valve MS-

93, the TDEFWP steam admission valve, in the common supply to the turbine, is equipped with instrument air, auxiliary instrument air, and bottle nitrogen backups. The three sources are passed through a common, normally energized solenoid valve to the valve operator to maintain the valve closed. Upon receipt of a manual or automatic start signal, the solenoid valve will de-energize and isolate the supply air to MS-93. MS-93 is designed to fail open upon loss of compressed air or power to the normally energized solenoid valve. An AFIS actuation will re-energize the solenoid valve to supply compressed air to MS-93 operator. The bottled nitrogen backup will provide at least 2 hours of closure for MS-93.

Automatic or manual starting of the TDEFWP from the Control Room relies on DC power from the station power batteries. Each TDEFWP is equipped with a DC auxiliary oil pump (AOP). The auxiliary oil pump is located near the TDEFWP in the basement of the Turbine Building. Power for the AOP is supplied by 250VDC load center DP. This load center is located on the ground floor of the Turbine Building adjacent to the 4160VAC Switchgear TC, TD, and TE. The AOP automatically starts when MS-93 opens. The AOP provides the initial oil pressure to open the turbine governor valve (MS-95) and supply lube oil for the turbine bearings. The EFW pump turbine speed is controlled by MS-95. The position of MS-95 is regulated by a hydraulic oil speed governing mechanism, with oil supplied from either the auxiliary oil pump or the shaft driven oil pump. MS-95 is designed to fail closed on loss of hydraulic oil pressure. An AFIS actuation will energize and close solenoid valve (TO-145) to isolate the hydraulic oil supply to close MS-95. When the turbine approaches operating speed, the shaft driven oil pump will supply adequate oil pressure for the governor valve and bearing lubrication.

10.4.7.2.3 EFW Pump Suction Source

The condensate/feedwater reserve, specifically the Upper Surge Tank for each unit, is normally aligned to the EFW pump suctions. A minimum of 30,000 gallons of water is maintained in the UST. The UST consists of two connected tanks. The condensate/feedwater reserve for each unit is maintained among the sources in Table 10-1. The UST provides makeup to a common header which divides into three separate pathways to the non-safety condenser hotwell. The common header is automatically isolated on a low UST level. The UST also provides a source of water to other non-safety equipment. These pathways are normally isolated by closed manual valves. If power is available, inventory in the UST can be replenished from a variety of sources. These sources include the plant Demineralized Water System through the makeup demineralizers, the Condensate Storage Tank (CST) via the CST pumps, and the condenser hotwell via a hotwell pump recirculation pathway. The makeup sources are non-safety. If the UST inventory cannot be maintained following an accident, the EFW pump suction may be aligned to the condenser hotwell directly, which has a nominal inventory of 120,000 gallons. Condenser vacuum must be broken to provide adequate net positive suction head to the EFW pumps when aligned to the hotwell. Condenser vacuum is broken by the opening of a single vacuum breaker valve (V-186). This vacuum breaker valve is normally operated from the Control Room and is physically located on the ground floor of the Turbine Building on the east side of the condenser hotwell. The vacuum breaker would be locally operated in the event of a loss of offsite power. To complete the transfer of suction for the MDEFWPs, a single manual valve in the common suction piping (located in the basement of the Turbine Building near the MDEFWPs) must be closed. TDEFWP suction is transferred by opening the hotwell supply valve (C-391) and closing the UST supply valve (C-156 or C-157). Assuming that offsite power is not available, EFW pump suction can be transferred to the condenser hotwell in approximately 20 minutes. This is well within the time that is available based on the minimum required UST inventory. Limitations associated with hotwell inventory are further addressed in Section 10.4.7.3. All necessary valves in the discharge flow path are maintained in normal standby alignment to assure an open flow path for each pump, and to assure piping separation and independence. All manually operated valves in the piping from the UST to the suction of the EFW pumps are locked open (Reference 2).

10.4.7.2.4 EFW Pump Minimum Recirculation

A flow path is also provided to the UST dome for minimum recirculation flow and testing purposes. A continuous recirculation flow is provided for the TDEFWP, limited by fixed orifices. The orifices in the minimum flow recirculation loop were resized in 1992 in response to NRC Bulletin 88-04, Potential Safety-Related Pump Loss, to ensure the recirculation flowrate satisfies the manufacturer's requirement which was also revised in response to the bulletin, (Reference 15). A self-contained automatic recirculation valve is provided for each MDEFWP to assure individual pump minimum flow when needed during operation. A flow path is provided from the discharge of each MDEFWP to the UST for full flow testing. During normal system alignment, the test loops are isolated and pump minimum recirculation would be routed back to the UST for reuse.

10.4.7.2.5 EFW Discharge Flow Control Valves

Each EFW discharge line to each SG is provided with a control valve and check valve. Discharge flow from the EFW pumps is normally aligned and controlled by control valves FDW-315 and FDW-316. FDW-315 (EFW flow control to ‘A’ SG) is physically located in the East Penetration Room. FDW-316 (EFW flow control to ‘B’ SG) is physically located in the West Penetration Room. Open/Closed valve position indication is provided for each control valve at the valve manual loader in each Control Room.

The valves are arranged to fail to the automatic control mode upon loss of DC control power to the manual/auto select solenoid. If the selected train of automatic control fails, then the valve would fail open. Also, upon loss of station air, the valves will maintain their position with N2 backup. If N2 backup fails then the valve would fail open. These modes of operation show that emergency feedwater isolation is not possible with valve control circuitry or motive force failure. Open/Closed valve position indication is provided for each control valve in the main control room at the valve.

These valves are controlled independently of the Integrated Control System and arranged to fail to the automatic control mode upon loss of Control power to the Hand/Auto relay. If the output of the selected train of automatic control fails, then the valve would fail open. Also, upon loss of all station air, the valves will maintain their position with a nitrogen supply. If the nitrogen supply fails, then the valve would fail open. In automatic, the control valve Auto/Manual relay is de-energized, thereby aligning the valve to automatic control and positioning the valve per the automatic setting. Control valves FDW-315 and FDW-316 are modulated by separate control signals from the electric current to pneumatic converter. These valves may be automatically controlled, or manually controlled by the operator to limit or increase feedwater as necessary to maintain feedwater inventory and cooldown rate. A pushbutton on the respective Auto/manual station is provided for each control valve to allow the individual valve to be placed in either an automatic level control mode or in a manual mode of operation. Power to the controller is battery backed DC converted to AC via the vital inverters.

Independent level transmitters are utilized in the automatic control system circuit. Upon loss of all four reactor coolant pumps, such as during LOOP events, the level control setpoint is automatically raised to promote natural circulation in the Reactor Coolant System. For events where core subcooling margin has been lost, operators must manually control SG levels at the loss of subcooling margin setpoint.

10.4.7.2.6 Instrumentation and Controls

Each of the EFW pumps is supplied with an independent starting circuit (described in UFSAR Section 7.4.3.1). The independent control circuits are powered by the 125 VDC safety-related station batteries.

Sufficient indication is provided in the Control Room to allow the operator to monitor unit parameters during a cooldown. Specific indication provided for the EFW System is listed in Table 10-2.

Refer to Section 7.4.3 for additional discussion of the EFW controls.

10.4.7.2.7 Alternate Flow Path

Although not normally aligned or utilized in the safety related function of the EFW System, a redundant, separate flow path to the SGs and means of controlling EFW pump discharge flow is provided by MFW startup control valves FDW-35 and FDW-44. This additional non safety-related flow path may be aligned manually during startup, shutdown or following EFW flow control valve failures.

The 'A' MDEFWP can be aligned to feed the 'A' SG via the MFW startup path by opening motor operated valves FDW-38 and FDW-374 and closing motor operated valves FDW-33, FDW-36, and FDW-372. The 'B' MDEFWP can be aligned to feed the 'B' SG via the MFW startup path by opening motor operated valves FDW-47 and FDW-384 and closing motor operated valves FDW-42, FDW-45, and FDW-382. These motor operated valves are operated from the Control Room and receive non-safety power. FDW-36, FDW-38, FDW-45, and FDW-47 are DC motor operated valves that receive power from the station power batteries. FDW-372, FDW-374, FDW-382, and FDW-384 are AC motor operated valves that receive power from non-safety, non-load shed sources. FDW-33 and FDW-42 are AC motor operated valves that receive power from a non-safety, load shed source. The MDEFWPs must be stopped to allow alignment of this flow path.

The TDEFWP can also be aligned to feed both SGs via the MFW startup path by opening two manually operated valves (FDW-94 and FDW-96) located in the Turbine Building basement and closing motor operated valves FDW-368 and FDW-369. The motor operated valves are operated from the Control Room. FDW-368 and FDW-369 are AC motor operated valves that receive power from non-safety, non-load shed power. Repositioning of FDW-33, FDW-36, FDW-38, FDW-42, FDW-45, and FDW-47 would also be required as described in the alignment of the MDEFWP's to the MFW startup path. The TDEFWP must be stopped to allow alignment of this flow path.

Once the EFW pump is aligned to the MFW startup path, FDW-35 and/or FDW-44 are used to control EFW flow to the SGs. Using air that is supplied by the plant Instrument Air System, air operated control valves FDW-35 and FDW-44 are modulated by the ICS based on SG water levels. The control valves may be operated manually from the Control Room. The ICS and the plant instrument air are non-safety. As in the case of control valves FDW-315 and FDW-316, the level control setpoint is automatically raised upon loss of all four reactor coolant pumps to promote natural circulation in the Reactor Coolant System.

The alignment of EFW through the MFW startup path is vulnerable to LOOP events. FDW-33 and FDW-42 receive power from a load shed source. These valves would have to be manually closed locally or power must be restored to the load shed source to allow the valves to be operated from the Control Room. The valves are located on the ground floor of the Turbine Building. Plant instrument air is also vulnerable. Upon a LOOP that deenergizes the Primary IA Compressor or low Instrument Air Header Pressure, the Service Air Diesel Air Compressor(s) should automatically start and supply Instrument Air. The diesel service air compressors are located outside, south of the Turbine Building approximately between the Protected Service Water (PSW) Building and the Reactor Coolant Pump (RCP) Motor Refurbishment Facility. The startup and main feedwater control valves (FDW-32, FDW-35, FDW-41, and FDW-44) are supplied with backup compressed air from an accumulator tank. This source of compressed air is sufficient for their 2 hour mission time in the event they must be closed and stay closed in response to an AFIS signal for a steam line break, concurrent with a Loss of Offsite Power (LOOP). None of the feedwater control valves require operation of the Service Air Diesel Air Compressor(s).

10.4.7.2.8 Alarms

Sufficient alarms are provided to alert the operator of conditions exceeding normal limits. Essential plant parameters are annunciated or alarmed by the process computer in addition to the specific EFW System alarms as listed below:

1. MDEFWPs low suction pressure
2. SG low level alarms
3. Hotwell low level alarms
4. UST low level alarms
5. Low MDEFWP cooling water flow
6. MDEFWP stator winding high temperature
7. MDEFWP motor bearing high temperature
8. MDEFWP bearing high temperature
9. Motor cooler excessive leakage
10. MDEFWP A auto start blocked
11. MDEFWP B auto start blocked
12. TDEFWP EFW pump auto start blocked
13. MDEFWP A low level start
14. MDEFWP B low level start
15. TDEFWP turbine lube oil low pressure
16. TDEFWP turbine oil high temperature
17. TDEFWP turbine hydraulic oil low pressure
18. TDEFWP turbine auxiliary oil pump overload
19. TDEFWP tripped
20. FDW-315 controller Bypassed
21. FDW-316 controller Bypassed
22. Loss of Primary control power for FDW-315
23. Loss of Primary control power for FDW-316
24. FDW-315 Hand/Auto Station Failure

25. FDW-316 Hand/Auto Station Failure
26. FDW-315 Hand/Auto Station in Manual Mode
27. FDW-316 Hand/Auto Station in Manual Mode
28. FDW-315 Automatic Control on Primary Control
29. FDW-316 Automatic Control on Primary Control
30. FDW-315 Nitrogen Pressure A Low
31. FDW-316 Nitrogen Pressure A Low
32. FDW-315 Nitrogen Pressure B Low
33. FDW-316 Nitrogen Pressure B Low

10.4.7.3 Safety Evaluation

Feedwater inventory is maintained in the SGs following reactor shutdown by one of the following methods listed:

1. Either of the two main feedwater pumps in combination with a hotwell pump and a condensate booster pump are capable of supplying both SGs at full secondary system pressure.
2. The two MDEFWPs are capable of supplying their associated SG at full secondary system pressure.
3. The single TDEFWP is capable of supplying both SGs at full secondary system pressure.
4. An alternate EFW supply available from the EFW System of one of the other units, capable of supplying both SGs at full secondary system pressure.
5. The hotwell and condensate booster pump combination has a discharge shutoff head of approximately 620 psia. There are three hotwell pumps and three condensate booster pumps. If required, the Turbine Bypass System or the Atmospheric Dump Valves (ADVs) can be used to reduce secondary system pressure to the point where one hotwell and condensate booster pump combination can supply feedwater to both SGs.
6. The SSF Auxiliary Service Water System is capable of supplying both SGs of all three units at full secondary system pressure.
7. The Protected Service Water System is capable of supplying both SGs of all three units at full secondary system pressure.

A sufficient depth of backup measures is provided to allow SG water inventory to be maintained by any of the diverse methods listed above. Although redundancy and diversity is provided as listed above, the EFW System has been designed with special considerations to enable it to function when conventional means of feedwater makeup may be unavailable.

Redundancy is provided with separate, full capacity, motor and turbine driven pump subsystems. Except as noted in the subsections that follow, failure of either the MDEFWPs or the TDEFWP will not reduce the EFW System below minimum required capacity. Pump controls, instrumentation, and motive power are separate in design.

The transients that require EFW have been evaluated assuming only one MDEFWP is available to deliver the necessary feedwater. Except as noted in the subsections that follow, no single failure in the three pump, two flowpath EFW System design will result in only one available MDEFWP (i.e., two EFW pumps will remain available). Therefore, the evaluation assuming only one MDEFWP available is conservative. These analyses verify the acceptability of the EFW System design.

The Safety Analyses acceptance criteria for each EFW transient are as follows:

Conditions of Transient	**Acceptance Criteria**
Loss of Main Feedwater Loss of Offsite Power Turbine Trip	Peak RCS Pressure ≤ 2750 psig
Main Feedwater Line Break Main Steam Line Break	10CFR 50.67 dose limits
Small Break LOCA	10CFR 50.46 PCT limits 10CFR 50.67 dose limits
Steam Generator Tube Rupture	10CFR 100 dose limits

10.4.7.3.1 EFW Reponse Following a Loss of Main Feedwater

The plant transient that requires the highest EFW System flow is the loss of feedwater transient with offsite power available. A loss of main feedwater is the result of both main feedwater pumps tripping. All three EFW pumps would be available with or without offsite power being available. Both EFW flowpaths should remain available. With offsite power being available, the reactor coolant pumps are assumed to remain running. If any reactor coolant pump is operating, the EFW flow control valves will modulate to control steam generator level at 30 inches.

For this transient, it is assumed that MFW flow entering the SGs decreases to zero flow immediately after the MFW pumps trip off. A high initial 102 percent power level is assumed to maximize energy removal requirements. A low initial SG mass is assumed to minimize post-trip heat removal during SG boil down. The Turbine Bypass System is assumed to be unavailable such that steam relief is by the main steam safety valves. The analysis assumes a limiting single failure with respect to flowrate demand of an EFW control valve failed closed. In addition, no credit is taken for the TDEFWP. Thus, the EFW System is limited to one MDEFWP delivering flow to one SG. The maximum allowable Upper Surge Tank temperature of 130°F is assumed to minimize the heat removal capability of the EFW System. Reactor trip and the subsequent turbine trip are assumed to occur on the high RCS pressure trip function. Reactor coolant pumps are assumed to be left on to maximize the heat input. Decay heat power is based on end-of-cycle burnup. The flowrate demand on the EFW System for other transients is bounded by this loss of main feedwater transient (with offsite power available). The safety analyses model of EFW flow rate is a function of SG pressure. Based on the results of the accident analyses, one MDEFWP delivering 375 gpm at a SG pressure of 1064 psia and an EFW temperature of ≤ 130°F provides adequate heat removal capability for this transient.

If offsite power is not available, the reactor coolant pumps will not be operating and EFW flow control valves will modulate to control steam generator level at a higher setpoint to promote the natural circulation mode of heat removal. Since there is no reactor coolant pump heat, the initial EFW flow rate requirements for a loss of main feedwater transient are bounded by the loss of main feedwater transient with offsite power available.

The volumes maintained in the UST and the condenser hotwell satisfy the EFW inventory required to support a plant cooldown following a loss of main feedwater transient with or without offsite power available. Assuming automatic steam generator level control, the minimum Technical Specification required 30,000 gallon inventory in the UST will provide at least 40 minutes of EFW flow with all three EFW pumps operating simultaneously. This inventory requirement also assures that the plant operators have at least 20 minutes to act, following the UST low level alarm, before the UST is emptied. The EFW pumps will remain aligned to the UST as long as adequate inventory can be maintained. If the UST inventory cannot be maintained, EFW pump suction will be aligned to the hotwell. A combined inventory in the UST and condenser hotwell of 155,000 gallons is sufficient to permit cooldown of the primary coolant at a rate of 50°F per hour following a reactor trip to decay heat removal entry conditions assuming a maximum allowable UST and hotwell temperature of 130°F (see Section 10.4.7.2).

The non-safety hotwell is not designed to withstand a single active failure. The limiting single active failure with respect to EFW inventory is the failure to break condenser vacuum. This renders the hotwell as unavailable. In the event of this single failure, sufficient depth of backup measures is provided to allow steam generator water inventory to be maintained by either the PSW or the SSF Auxiliary Service Water (see Section 10.4.7.3.8).

10.4.7.3.2 EFW Response Following a HELB

For units with the HELB mitigation strategy (Reference 20) implemented, certain HELBs in conjunction with postulated single failure can disable all sources of emergency feedwater. These HELBs are evaluated in applicable analyses as addressed in UFSAR Section 3.6.2. For these cases in which EFW is not available (TDEFWP, MDEFWP, cross-connects), the PSW system and the SSF ASW system provide an additional source of secondary cooling water.

10.4.7.3.2.1 HELBs Resulting in Loss of TC, TD, TE Switchgear

Note: Section 10.4.7.3.2.1 applies to units without the HELB Mitigation Strategy (Reference 20) implemented.

HELBs in the vicinity of the TC, TD, TE switchgear could cause their failure. The consequence of the switchgear failure would cause a complete loss of the Condensate and Feedwater System (loss of pumps). This event is similar to a station blackout on the affected unit. This would also cause a loss of both MDEFWPs due to loss of power. In addition, the DC power supply to the auxiliary oil pump (AOP) for the TDEFWP could be lost due to its location being adjacent to the switchgear. Loss of the AOP results in an inability to start the TDEFWP from the Control Room. The TDEFWP could be locally started and has sufficient capacity to satisfy the flowrate requirements for this event. A single failure of the TDEFWP would lead to a complete loss of main and emergency feedwater. If the TDEFWP is the single failure, the SSF ASW System is credited to feed the SGs. In addition, alignment of an unaffected unit's EFW System could be performed to feed the SGs.

10.4.7.3.2.2 Feedwater/Main Steam Line Breaks Causing Loss of SG Pressure Boundary

Note: Section 10.4.7.3.2.2 applies to units without the HELB Mitigation Strategy (Reference 20) implemented.

Large line breaks in the Feedwater/Main Steam System that result in a depressurization of the steam generator will result in actuation of the Automatic Feedwater Isolation System (AFIS). Once actuated, all main feedwater will be automatically isolated to the faulted steam generator and the TDEFWP will be inhibited from automatically starting. The MDEFWPs will automatically start and feed both steam generators. If the AFIS rate of depressurization setpoint is exceeded coincident with low steam line pressure, the MDEFWP feeding the faulted steam generator will be tripped. For smaller break sizes that do not exceed the rate of depressurization setpoint, the operator is required to manually terminate EFW flow to the faulted steam generator by either closing the EFW flow control valve or by stopping the MDEFWP. These actions can be done from the Control Room. The operator has sufficient Control Room indication of SG level and pressure and would be aware of such a situation. Concurrently, the operator would monitor the intact SG to maintain adequate inventory and secondary heat removal via the EFW System.

In the event of a single active failure of the MDEFWP to the intact steam generator, manual operator action is required to start the TDEFWP to provide sufficient flow for adequate core cooling. AFIS would isolate main feedwater to the faulted steam generator, and inhibit the automatic start of the TDEFWP. The preferred method of mitigating this event, after having isolated flow to the affected SG, would be to restart the TDEFWP by manual operator action in the Control Room. However, if the TDEFWP is not available, the remaining MDEFWP could be aligned to the unaffected SG by manual operator action outside of the Control Room via the cross connect (FDW-313 and FDW-314).

In the event of a postulated failure of the EFW flow control valve to the intact steam generator, manual operator action would be required to align the MDEFWP through the main feedwater startup control valve. The AFIS circuitry must be disabled by the operator to allow EFW flow alignment through the non-safety MFW startup control valves. This alternate path through the main feedwater startup control valve relies on non-safety equipment and non-safety support systems (electrical power and instrument air). This alignment may not be available in LOOP events. The main feedwater startup block valves receive power from load shed power which may not be immediately available following a LOOP.

If the EFW control valve on the unaffected SG fails to open and the main feedwater startup path is unavailable, then the SSF ASW System would be required to feed the unaffected SG for heat removal. If the EFW flow control on the unaffected SG fails open (on a loss of compressed air and nitrogen), this could result in the SG overcooling and subsequent loss of EFW to the unaffected SG due to pump runout. The safety analyses assume both SGs are isolated within 10 minutes, with subsequent action outside the Control Room for local manual control of the EFW control valve if the valve failed open. The EFW flow control valves are located in the penetration rooms adjacent to the Control Room. Except in those cases where the break makes these valves inaccessible, an operator could manually adjust either valve. In the event this path were unavailable, the SSF ASW System provides an alternate means of establishing feedwater flow to the unaffected steam generator.

Certain breaks could deplete hotwell inventory. The impact of this loss of inventory is encompassed by the high energy line breaks described in Section 10.4.7.3.2.3.

10.4.7.3.2.3 Other Condensate/Feedwater Line Breaks that Result in a Loss of Condenser Hotwell Inventory

Section 10.4.7.3.2.3 applies to units without the HELB Mitigation Strategy (Reference 20) implemented.

This class of condensate and feedwater line breaks could result in depletion of stored inventory in the hotwell due to continued operation of the hotwell and condensate booster pumps. These line breaks cause the hotwell makeup valves to open to control hotwell level. On a low UST level, automatic closure signals are sent to close the UST Riser Automatic Isolation valves to preserve the minimum required inventory of 30,000 gallons in the UST. The SSF ASW System would be available for feeding the SGs. HPI forced cooling also remains available. In addition, EFW could be aligned from an alternate unit using the unit cross connects.

10.4.7.3.3 EFW Response Following a SBLOCA

For certain size small break loss of coolant accidents, feedwater is required to remove the decay heat and reactor coolant pump heat which is not relieved through the break. The EFW flow rate demand requirements for a SBLOCA, with and without a loss of offsite power, are bounded by the LOMFW event in Section 10.4.7.3.1 in which a break in the primary system is not present to help remove system heat.

10.4.7.3.4 EFW Response Following a SGTR

This event does not assume a loss of offsite power has occurred. With offsite power available, main feedwater should continue to operate and provide inventory to the SGs. In addition, the condenser should remain available as a means of removing heat from the SGs via the Turbine Bypass System to the Condenser Circulating Water (CCW) System. However, should the Main Feedwater System be unavailable, the EFW System would be required to provide secondary side cooling. All three EFW pumps would be available to provide inventory to the SGs. Prior to isolation of the ruptured SG, EFW inventory requirements are diminished to a certain degree due to primary system leakage boiloff in the ruptured SG. If the EFW flow control valve for the unaffected SG failed to open, the flow path can be realigned to bypass the failed valve and reach the SG through the main feedwater startup flow path. This alternate path through the main feedwater startup control valve relies on non-safety equipment and non-safety support systems (electrical power and instrument air). With offsite power being available, the main feedwater startup path should remain available. However, if this path were unavailable, the SSF ASW System provides an alternate means of establishing feedwater flow to the unaffected SG. Prior to cooling the unit down to DHR conditions, one RCP per loop is tripped, further reducing the demand for EFW. The flowrate and inventory demands for EFW following a SGTR event is bounded by the demand for EFW following a loss of main feedwater with offsite power available.

If the EFW flow control valve on the unaffected SG fails open (on a loss of compressed air and nitrogen), this could result in the SG overcooling. The safety analyses assume action outside the Control Room for local manual control of the EFW control valve if the valve failed open. The EFW flow control valves are located in the penetration room adjacent to the Control Room.

10.4.7.3.5 EFW Response Following a MHE

Original Licensing Basis (no pipe break postulated)

The original licensing of Oconee addressed earthquakes. UFSAR Section 3.2.1.2 states that all three units can be safely shut down in the event of a MHE. Section 3.2.2 lists the systems to which seismic design was originally applied (including portions of the EFW System). In addition, a series of letters between Duke Energy and NRC helped clarify the seismic licensing basis. This correspondence documented that a seismic event was used to provide the design criteria for piping, equipment, and structures used for mitigation and prevention of accidents for safe shutdown of the plant. The characteristics of those forces and loads were calculated and applied based on seismic analyses, but an actual earthquake, with all of its potential effects, is not postulated. More importantly, UFSAR Section 3.2.2 states, “pipe failures during a maximum hypothetical earthquake are not postulated as part of the accident analysis.” (Reference 18 and 19)

Generic Letter (GL) 81-14 Licensing (Earthquake induced pipe break floods EFW)

Post TMI, NRC issued GL 81-14 to specifically evaluate the seismic design of the licensees' Auxiliary Feedwater Systems. Although a seismically induced pipe break was not within Oconee's licensing basis, NRC postulated a break in the non-seismic CCW piping in the Turbine building as part of GL 81-14 that could cause flooding and failure of the EFW Pumps. In such an event, the SSF ASW System was credited for secondary side heat removal. The SSF ASW System is not single failure proof. Penetration seals and waterproof doors have been installed between the Turbine Building and Auxiliary Building in each unit to provide waterproofing up to a height of twenty feet above the Turbine Building basement floor. Thus the High Pressure Injection (HPI) System, located in the Auxiliary Building, would be available as an alternative to the EFW System and the SSF ASW System for shutdown decay heat removal (Reference 6).

As defined in Reference 6, Oconee was deemed to meet the criteria of Generic Letter 81-14 regarding adequate post-seismic event decay heat removal capability by:

1. requiring portions of the EFW System (defined in UFSAR Section 3.2.2) to be capable of withstanding a MHE, and
2. providing alternative seismically qualified means of decay heat removal with the SSF ASW System and the HPI System.

10.4.7.3.6 EFW Response Following Tornado Missiles

Reference 7 concludes that the Standard Review Plan probabilistic criterion is met based upon the probability of failure of the EFW and station ASW Systems combined with the protection against tornado missiles afforded the SSF ASW System. Subsequently, PSW replaced station ASW relative to this function.

10.4.7.3.7 EFW Response Following a SBO

This event is similar to the LMFW with LOOP analysis with the additional assumption that the onsite emergency AC power sources have been lost. This results in the loss of the MDEFWPs. The TDEFWP should be available for 2 hours during this event because of its AC power independence. The SSF ASW System; however, is credited to remove the decay heat in this event. The SBO event, which is not a design basis event, is described in UFSAR Section 8.3.2.2.4.

10.4.7.3.8 Initiation of SSF ASW, PSW, and HPI Forced Cooling

The SSF ASW System, PSW, and HPI forced cooling serve as alternate means of decay heat removal for some of the EFW design events described in Section 10.4.7.3.

Once the control room decides to use the SSF ASW system, the system can be aligned within 14 minutes, consistent with the assumptions in the safety analyses. The SSF ASW flow rate provided to each unit's steam generators is controlled using the motor operated valves on each unit's SSF ASW supply header. The SSF contains adequate instrumentation to maintain the plant in a safe shutdown condition. The SSF ASW System is described in Section 9.6 of the UFSAR.

The Protected Service Water (PSW) system is designed as a standby system for use under emergency conditions. The PSW System is powered from either the Central Tie Switchyard via a 100 kV transmission line to a 100/13.8 kV substation or the Keowee Hydroelectric Station. The PSW System is provided as an alternate means to achieve and maintain safe shutdown for one, two, or three units.

The PSW System is capable of cooling each unit's RCS to approximately 250°F and maintaining this condition for an extended period. Failures in the PSW System will not cause failures or inadvertent operations in existing plant systems. The PSW System is operated from the Main Control Rooms (MCRs) when existing diverse emergency systems are not available. The power to PSW controlled pressurizer heaters must be manually aligned outside the MCR.

Please note that information associated with powering the pressurizer heaters and vital I&C battery chargers will not be effective until completion of Milestone 5, but is being included in the UFSAR for completeness.

If feedwater is unavailable, operator action is taken on high RCS pressure or pressurizer level to initiate HPI forced cooling. These actions are from the control room and include starting HPI pumps, opening the PORV, and throttling HPI flow as necessary. HPI forced cooling is initiated within 5 minutes of exceeding the initiation criteria. The HPI System is described in Section 6.3 of the UFSAR.

10.4.7.4 Inspection and Testing Requirements

A comprehensive test program is followed for the EFW System. The program consists of periodic tests of the activation logic and mechanical components to assure reliable performance during the life of the unit.

During unit operation, the EFW System is tested by utilizing the recirculation test line to the upper surge tank dome. Pump head and flow is verified utilizing this method.

10.4.7.5 Instrumentation Requirements

Sufficient instrumentation and controls are provided to adequately monitor and control the EFW System. The safety related instrumentation and controls that monitor SG level and pressure, automatically start the EFW pumps, and automatically align the supply, meet the system requirements for redundancy, diversity and separation

10.4.7.5.1 Turbine Driven Emergency Feedwater Pump

Instrumentation used in the automatic initiation circuitry on loss of main feedwater pumps for the TDEFWP is safety grade, as listed in Section 3.1.1.1, but not all of the equipment required to provide auto start capability is safety grade. This non-safety grade equipment includes: the TDEFWP Auxiliary Oil Pump, the 250VDC Load Center DP (which supplies power to the TDEFWP Auxiliary Oil Pump), the limit switch for MS-93 and and the pressure switch (FDWPS0300) which senses hydraulic pressure for the TDEFWP. Instrumentation used in the automatic initiation of the pump following an ATWS event is not required to be safety grade. A failure in the automatic initiation circuitry will not prevent manual start capability from the Control Room.

10.4.7.5.2 Motor Driven Emergency Feedwater Pumps

Instrumentation used in the automatic initiation circuitry on loss of main feedwater pumps for the MDEFWPs is safety grade. Instrumentation used in the automatic initiation of the pumps following an ATWS event is not required to be safety grade. Instrumentation used to provide automatic initiation of the pumps on low steam generator level is QA-1, but is not single failure proof. A failure in the automatic initiation circuitry will not prevent manual start capability from the Control Room. All non-safety related instruments and controls are designed such that failure of this equipment will not cause degradation of any safety related equipment function.

10.4.7.5.3 EFW Flow Indication to the Steam Generators

Each MDEFWP has a (non safety) flow transmitter with remote indication in the Control Room. Each EFW flow path to the steam generators contains two safety grade flow transmitters with remote indication in the Control Room. Each steam generator contains two safety grade level transmitters that are used to provide steam generator level control for the EFW System. The operators are capable of manually selecting between the primary and backup level transmitter from the Control Room. Safety grade level indication is provided in the Control Room. All non-safety related instruments and controls are designed such that failure of this equipment will not cause degradation of any safety related equipment function.

10.4.7.5.4 UST Level Indication

The UST has two safety grade level instruments. These instruments are used by the operators to monitor UST inventory. The UST low level alarm allows the operators at least 20 minutes to swap suction of the EFW pumps to the hotwell prior to depleting the UST inventory.

10.4.8 OTSG Condenser Recirculation System

10.4.8.1 Design Bases

The basis of the OTSG recirculation system is to provide a means to control steam generator corrosion during non-operating periods by filling the steam generators, draining the steam generators, and recirculating the water in the steam generators.

10.4.8.2 System Description

Each unit has one OTSG recirculation pump for both steam generators, as seen in Figure 10-9. This pump is utilized to fill the steam generators, drain the steam generators, transfer water between steam generators, and recirculate the water in the steam generators. The OTSG recirculation pump can take its suction from several points on either steam generator. The recirculation pump is locally controlled in the reactor building. The recirculation pump is isolated during modes 1, 2, and 3 due to the pressure rating of the piping/components. A permanent connection near the OTSG recirculation pump inlet provides a means for chemical addition for wet lay-up of the OTSGs.

10.4.9 References

1. W. E. Van Scooter (Framatome), letter to R. R. St. Clair (Duke), DPD 00-234, March 17, 2000.
2. W. O. Parker (Duke) letter to H. R. Denton (NRC), April 3, 1981, page 32.
3. ONOE-11376, changes to support multiple unit alignment to the Auxiliary Steam Header.
4. Deleted per 1999 Update
5. NSM ON-13076, NSM ON-23076 and NSM ON-33076, Separation of Air Systems to FDW-315 and FDW-316.
6. NRC Safety Evaluation Report for Oconee Nuclear Station, Units 1, 2, and 3, regarding Seismic Qualification of the EFW System, dated January 14, 1987.
7. NRC Safety Evaluation Report on the Effect of Tornado Missiles on Oconee EFW System, dated July 28, 1989.

8. D. E. LaBarge (NRC) letter to W. R. McCollum, Jr. (Duke), Amendments 234, 234, and 233 to DPR-38, DPR-47, and DPR-55 for Oconee Nuclear Station, Units 1, 2, and 3, respectively, dated December 7, 1998.

9. J. F. Stolz (NRC) letter to W. O. Parker, Jr. (Duke), Safety Evaluation Report for Oconee Nuclear Station, Units 1, 2, and 3, regarding NUREG-0737 Item II.E.1.1, "Auxiliary Feedwater System Evaluation," dated August 25, 1981.

10. Deleted Per Rev. 29 Upate

11. L. A. Weins (NRC) letter to J. W. Hampton (Duke), Safety Evaluation Report for Response to Generic Letter 89-19, Steam Generator Overfill Protection, dated November 3, 1993.

12. OSC-2826, Seismic Qualification Study of Components Associated with the Hotwell.

13. OSC-2827, Seismic Qualificaiton Study of Components Associated with the Hotwell.

14. OSC-2633, Qualification of Condenser Hotwell Nozzles and Plates for Faulted Load Conditions.

15. J. W. Hampton (Duke) letter to NRC, Response to item 5 of IEB 88-04 Re: Safey-Related Pump Loss, dated October 12, 1992.

16. License Amendment 386, 388 and 387 for DPR-38, DPR-47, DPR-55 for Oconee Nuclear Station Units 1, 2, and 3, respectively, dated August 13, 2014.

17. License Amendment 325, 325 and 326 for DPR-38, DPR-47, DPR-55 for Oconee Nuclear Station Units 1, 2, and 3, respectively, dated June 11, 2002

18. Duke Energy letter to NRC, "Seismic Licensing Basis," May 25, 1994.

19. Duke Energy letter to NRC, "Seismic Licensing Basis," August 18, 1994.

20. License Amendment No. 421, 423, and 422 (date of issuance – March 15, 2021); HELB Mitigation.

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Appendix 10A. Tables

Table 10-1. Condensate/Feedwater Reserves (each unit)

Source	Max. Capacity
Upper Surge Tank A	36,000 gallons/unit
Upper Surge Tank B	36,000 gallons/unit
Condenser Hotwell	142,000 gallons/unit
Condensate Storage Tank	30,000 gallons/unit
Makeup Demineralizers	450 gallons/minute (Total Capacity)
	(225 gallons/minute in service and 225 gallons/minute in reserve)

Note:

1. Additional condensate feedwater may also be provided from condensate sources associated with the other units, if these sources are available and operable.

Table 10-2. Parameter Indication Location for EFW System

Parameter	Local	Control Room
Turbine Driven EFW Pump Suction Pressure	X	
Motor Driven EFW Pump A Suction Pressure	X	
Motor Driven EFW Pump B Suction Pressure	X	
Turbine Driven EFW Pump Discharge Pressure	X	X
Motor Driven EFW Pump A Discharge Pressure		X
Motor Driven EFW Pump B Discharge Pressure		X
Turbine Driven EFW Pump Recirculation Flow	X	
Turbine Driven EFW Pump Seal Injection Water Pressure	X	
Motor Driven EFW Pump A Discharge Flow		X
Motor Driven EFW Pump B Discharge Flow		X
Emergency-EFW Supply to Steam Generator A Flow		X
Startup Header EFW Supply to Steam Generator A Flow		X
Emergency-EFW Supply to Steam Generator B Flow		X
Startup Header EFW Supply to Steam Generator B Flow		X
Steam Generator A Level		X
Steam Generator B Level		X
Motor Driven EFW Pumps A&B Recirculation Flow	X	
Motor Driven EFW Pump Suction Strainer Differential Pressure	X	X
FDW-315 Nitrogen Bottle A Pressure	X	X
FDW-315 Nitrogen Bottle B Pressure	X	X
FDW-316 Nitrogen Bottle A Pressure	X	X
FDW-316 Nitrogen Bottle B Pressure	X	X
FDW-315 Nitrogen Bottle A Regulator Outlet Pressure	X	
FDW-315 Nitrogen Bottle B Regulator Outlet Pressure	X	
FDW-316 Nitrogen Bottle A Regulator Outlet Pressure	X	
FDW-316 Nitrogen Bottle B Regulator Outlet Pressure	X	

Appendix 10B. Figures

Figure 10-1. Main Steam and Auxiliary Steam System

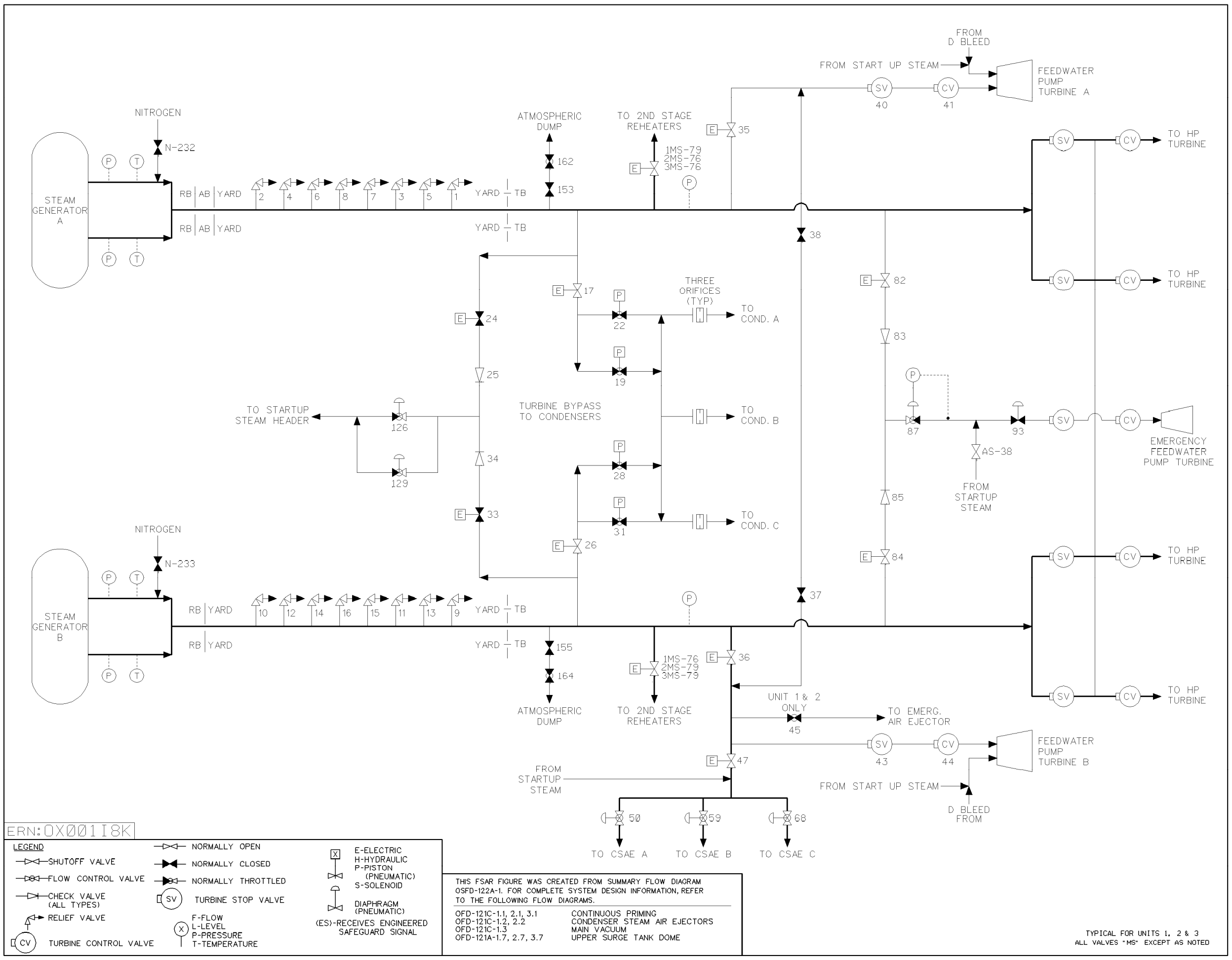


Figure 10-2. High Pressure Turbine Exhaust and Steam Seal System

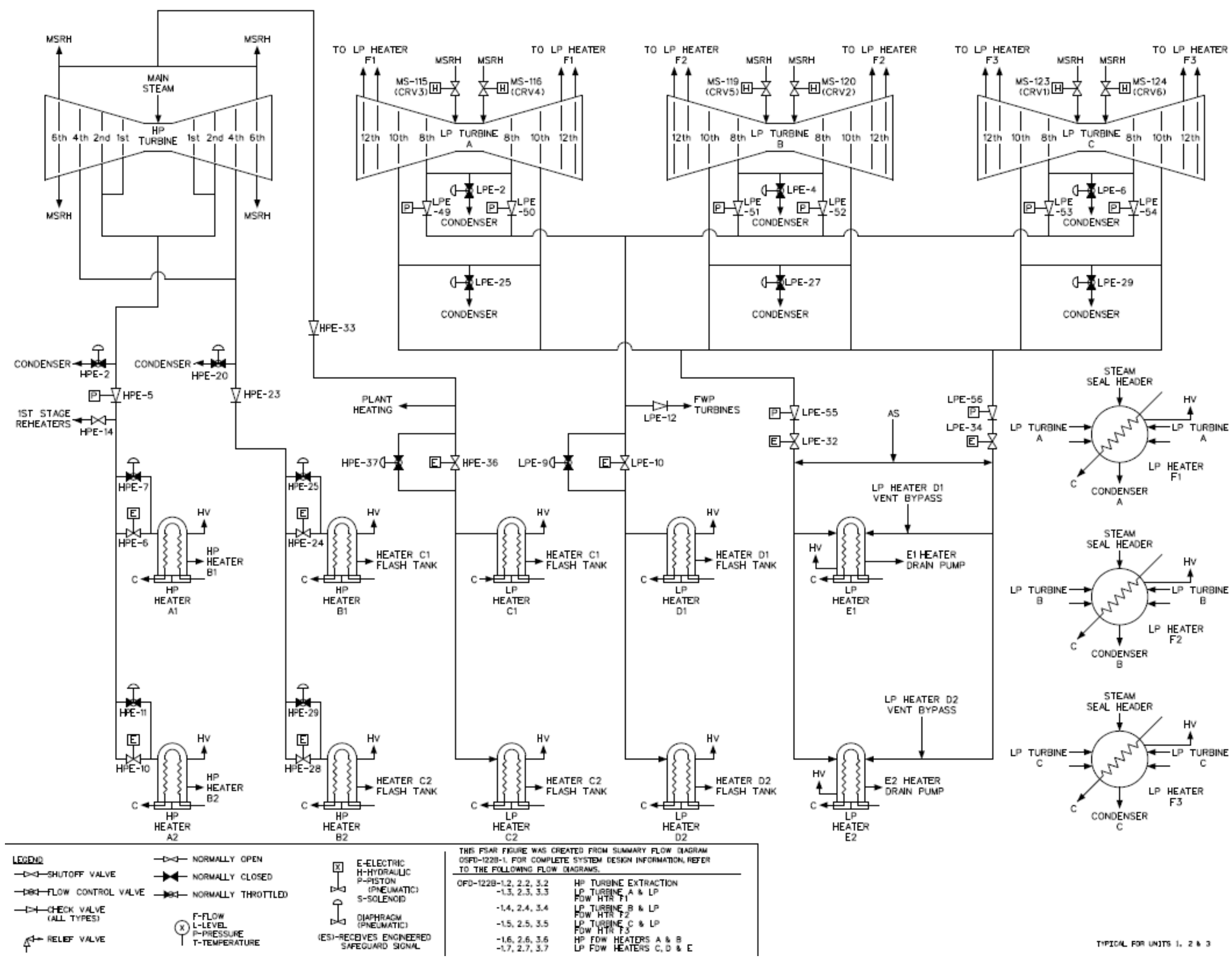


Figure 10-3. High Pressure Turbine Exhaust and Steam Seal System

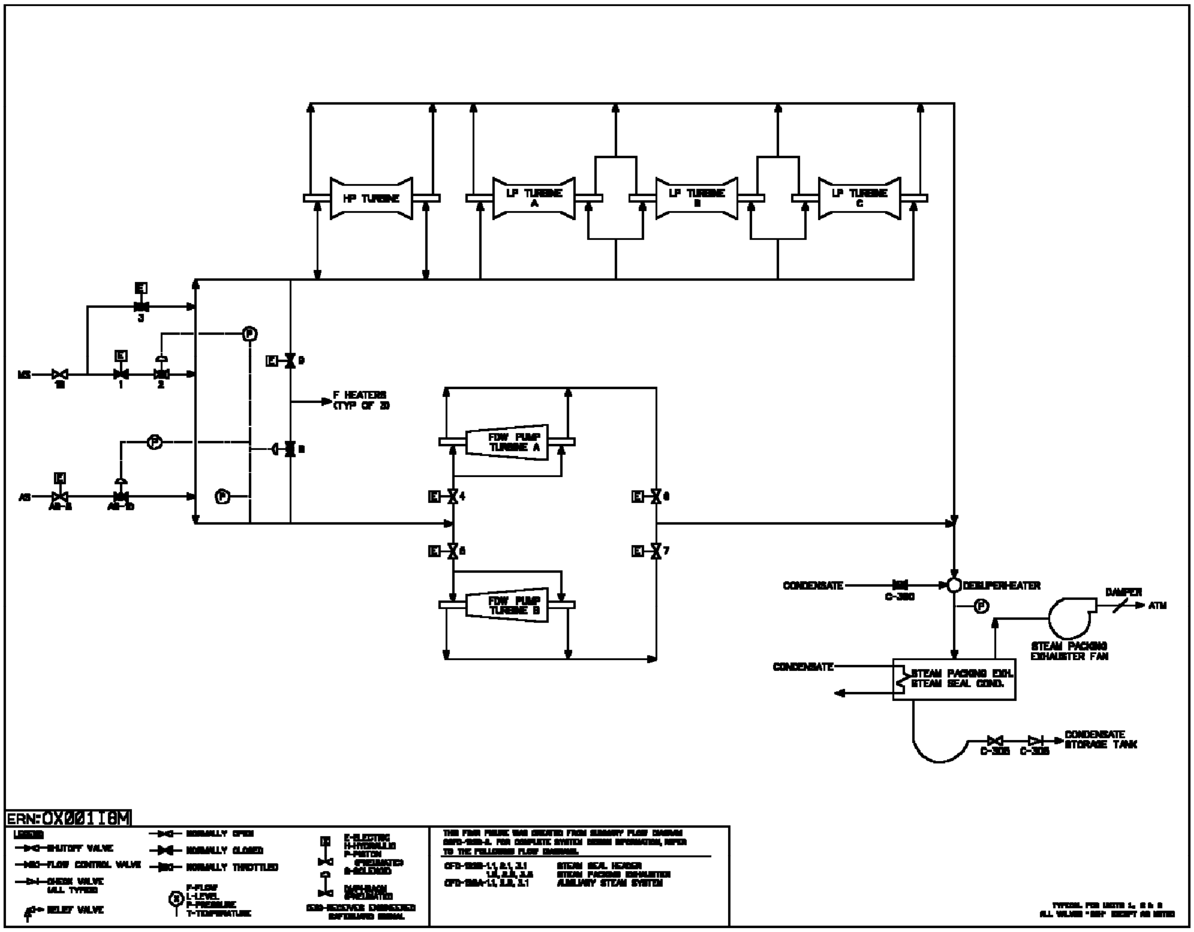


Figure 10-4. Moisture Separator and Reheater Heater and Drain System

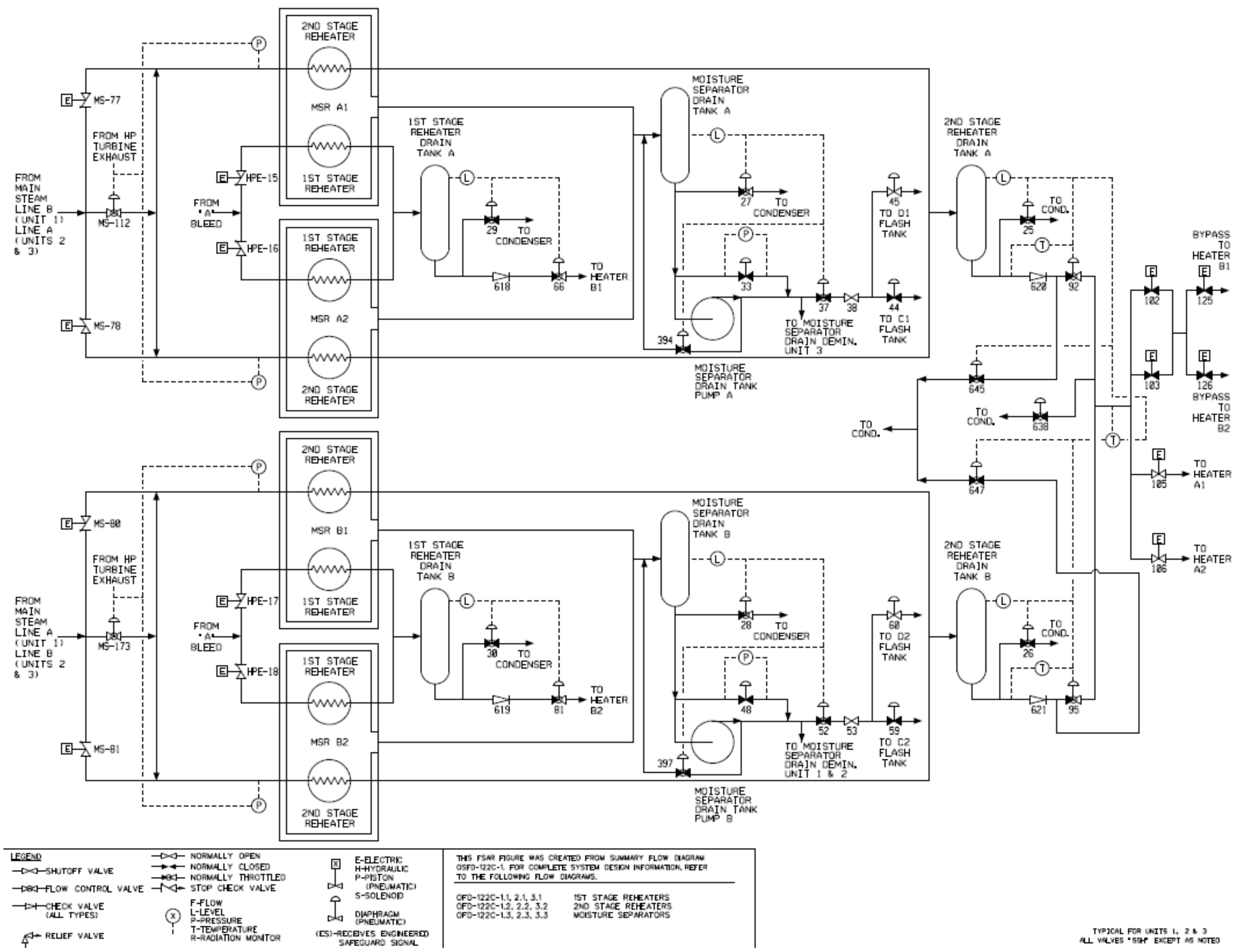


Figure 10-5. Vacuum System

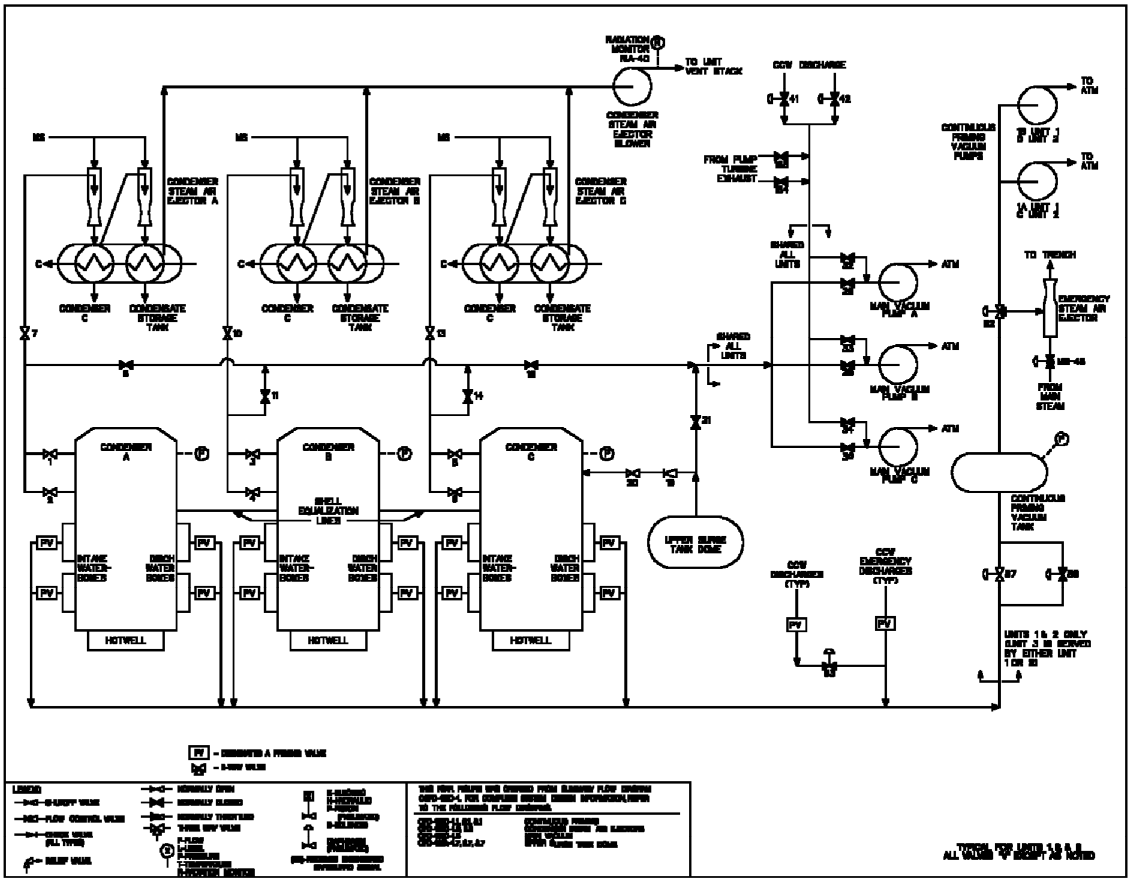


Figure 10-6. Condensate System

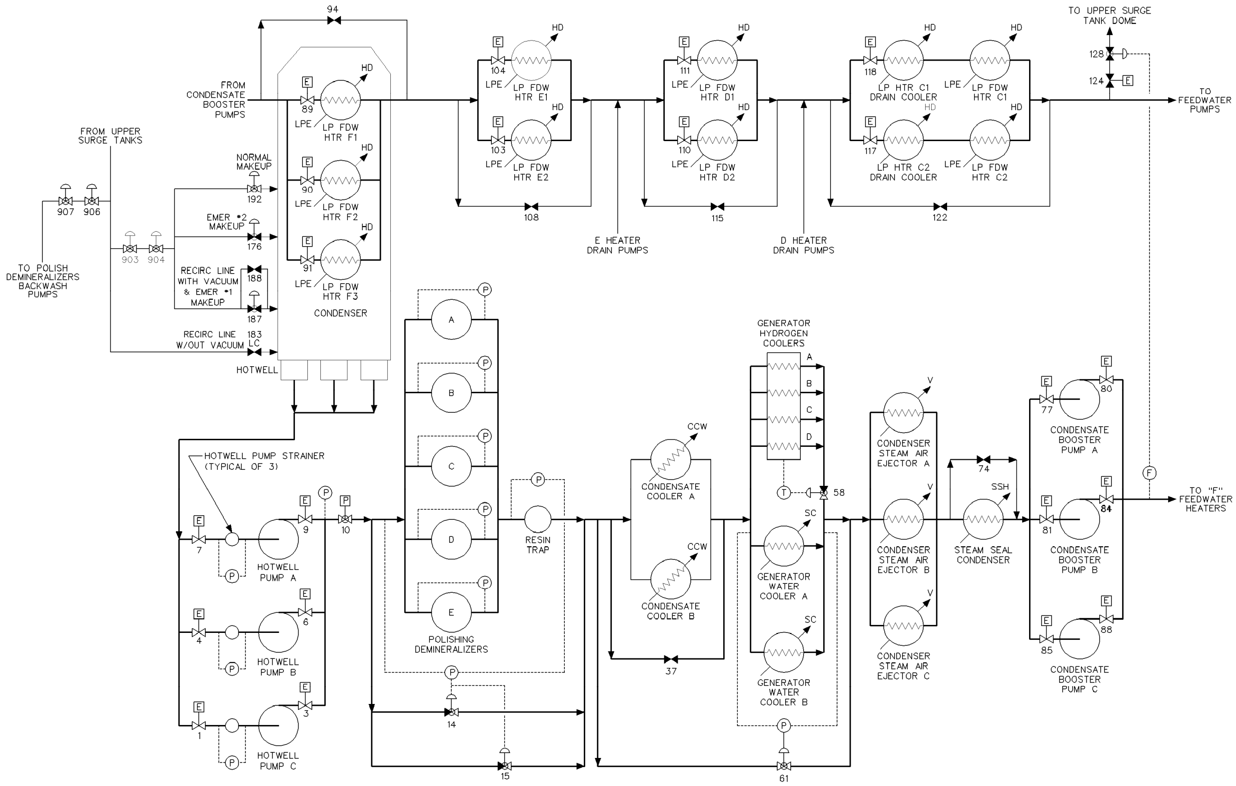


Figure 10-7. Main Feedwater System

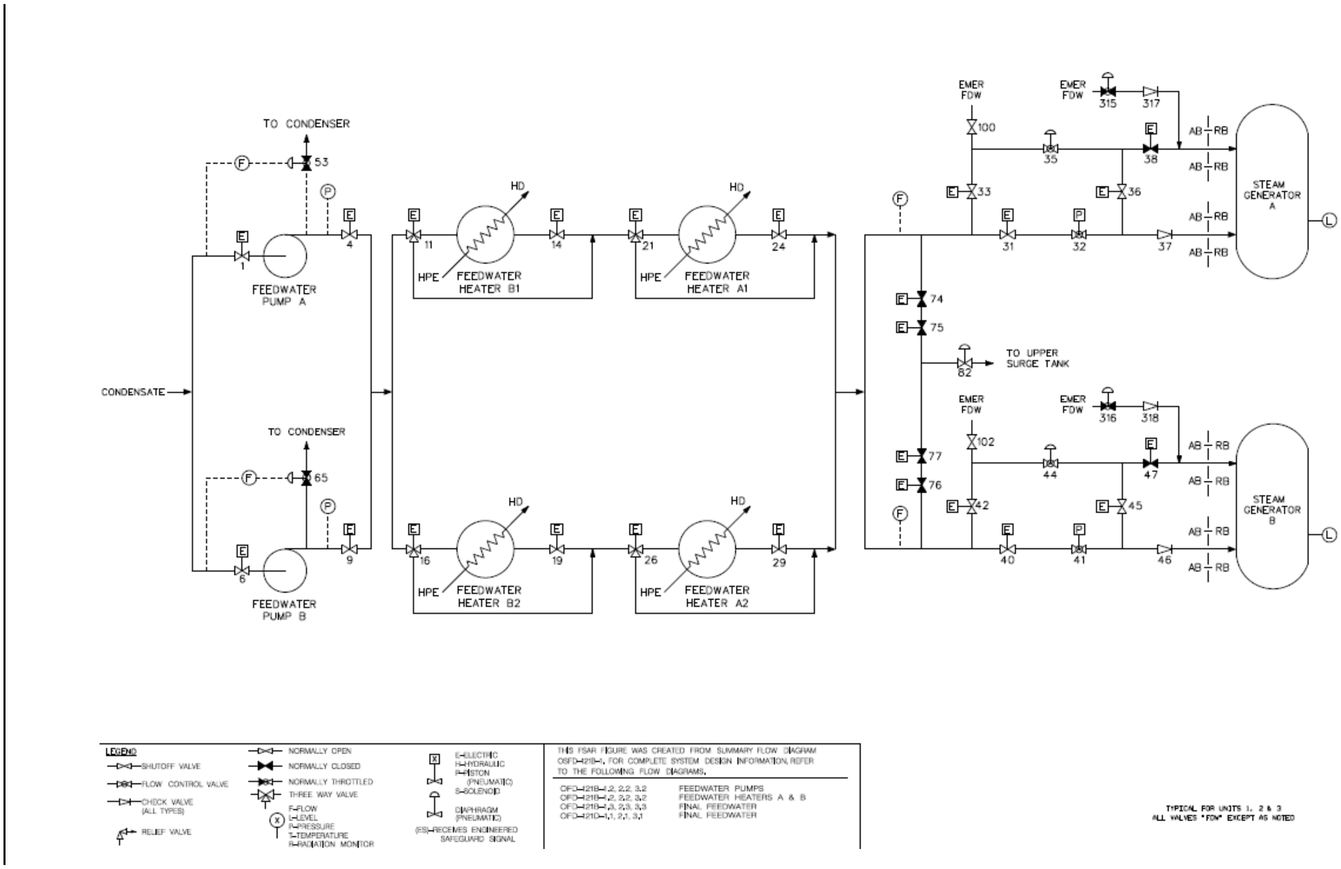


Figure 10-8. Emergency Feedwater System

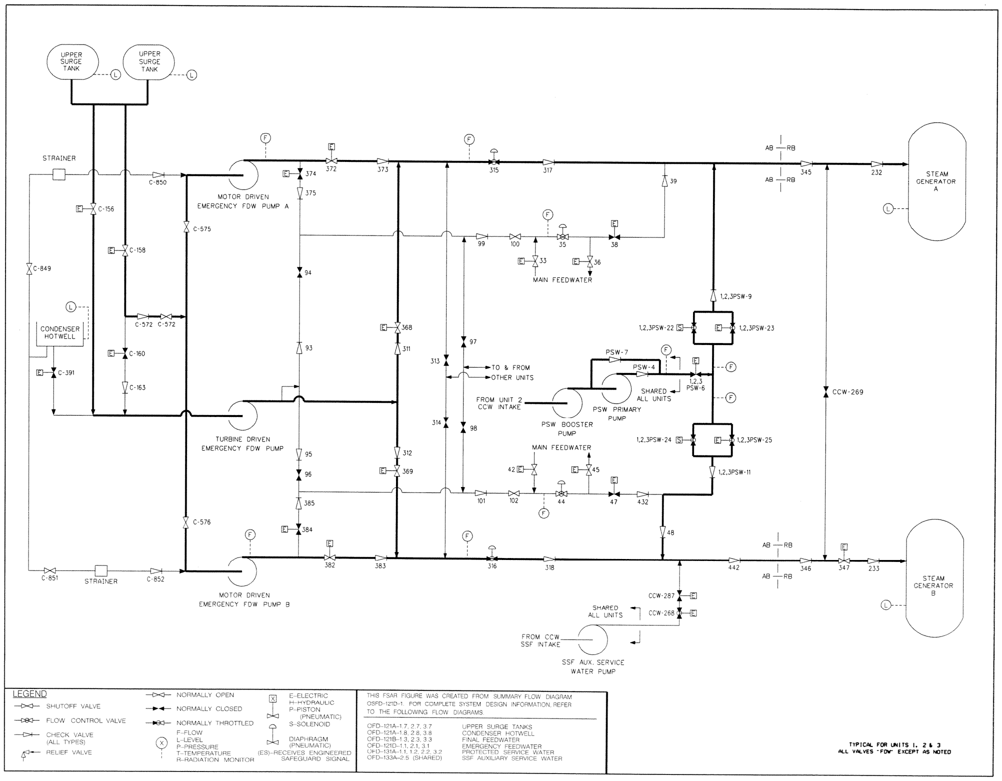
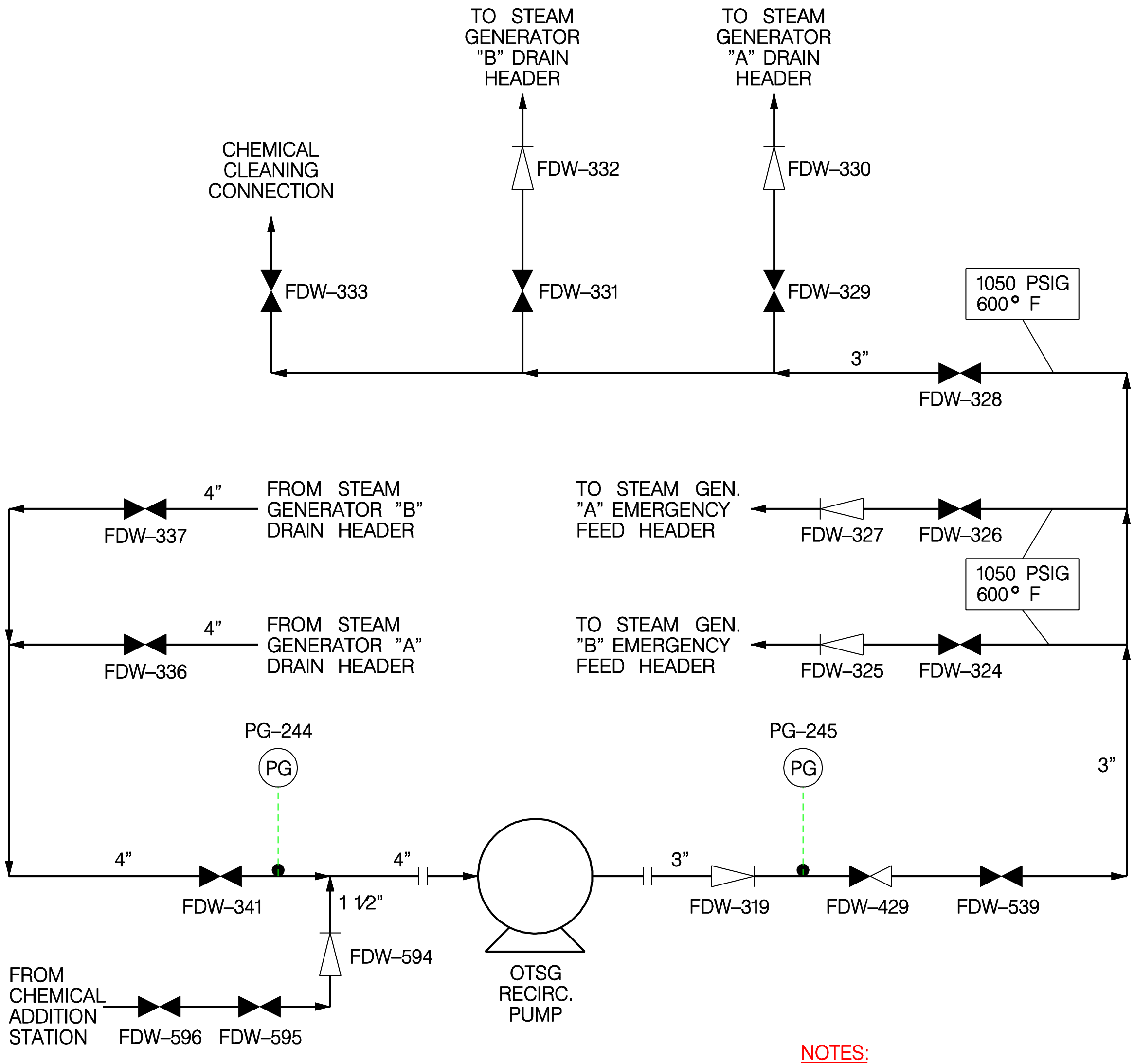


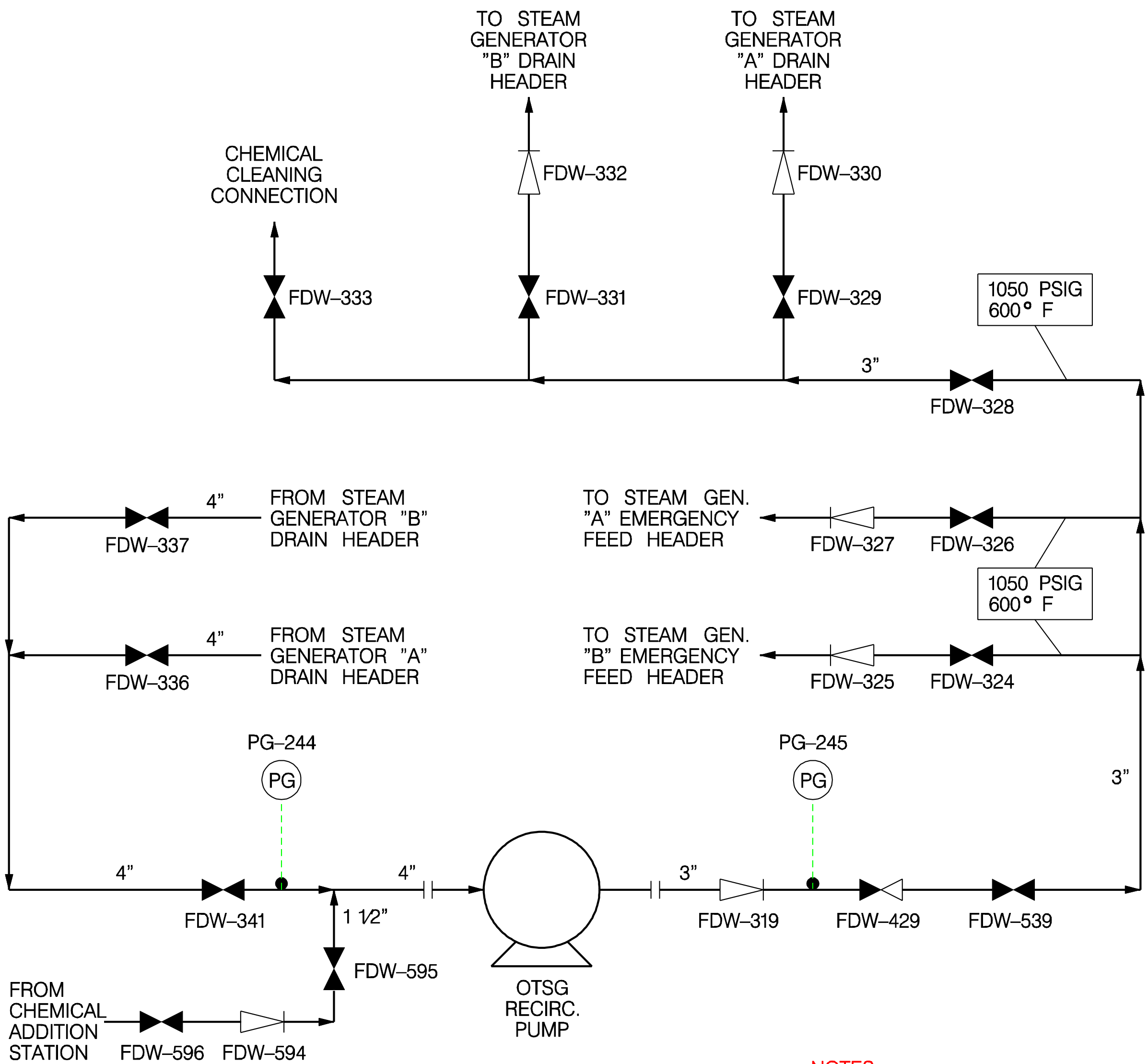
Figure 10-9. OTSG Recirculation System



NOTES:
1. VENTS AND DRAINS NOT SHOWN.
2. THIS FSAR FIG. IS TYP.FOR UNITS 1 & 2

OTSG RECIRCULATION SYSTEM

UNITS 1 & 2



NOTES:
1. VENTS AND DRAINS NOT SHOWN.
2. THIS FSAR FIG. IS FOR UNIT 3 ONLY

OTSG RECIRCULATION SYSTEM

UNIT 3 ONLY

Table of Contents

List of Tables

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List of Figures

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11.0 Radioactive Waste Management

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11.1 Design Basis

The liquid and gaseous radioactive waste management systems will be utilized to reduce radioactive liquid and gaseous effluents such that compliance with the dose limitations of the Selected Licensee Commitments is assured. These dose limitations require that:

1. the concentration of radioactive liquid effluents released from the site to the unrestricted area will be limited to 10 times the effluent concentration (EC) levels of 10CFR 20, Appendix B, Table 2;
2. the exposures to any individual member of the public from radioactive liquid effluents will not result in doses greater than the design objectives of 10CFR 50, Appendix I;
3. the dose rate at any time at the site boundary from radioactive gaseous effluents will be limited to: for noble gases; less than or equal to 500 mrem/yr to the whole body and less than or equal to 3000 mrem/yr to the skin; and for iodine-131 and 133, for tritium, and for all radioactive materials in particulate form with half-lives greater than 8 days; less than or equal to 1500 mrem/yr to any organ;
4. the exposure to any individual member of the public from radioactive gaseous effluents will not result in doses greater than the design objectives of 10CFR 50, Appendix I; and
5. the dose to any individual member of the public from the nuclear fuel cycle will not exceed the limits of 40CFR 190 and 10CFR 20.
6. the Solid Waste Management System shall be used in accordance with a Process Control Program, as described in Section 11.4, such that compliance with the Selected Licensee Commitments is assured.

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11.2 Liquid Waste Management Systems

11.2.1 Disposal Methods and Limits

Liquid wastes from the station are disposed of, under continuous radiation monitoring and control, in one of the following three ways depending on the concentration of radioactivity and quantities involved:

1. Collected, sampled, analyzed, and discharged directly to the tailrace of the Keowee Hydroelectric Plant if the water is required to be monitored during release. If the water does not require monitoring during release, it is discharged to the Chemical Treatment Pond #3.
2. Processed by filtration and/or demineralization, collected, sampled, and analyzed. The filters and/or spent resins are packaged and shipped offsite to an NRC or approved agreement state licensed burial ground. The processed water is discharged directly to the tailrace of the Keowee Hydroelectric Plant if the water is required to be monitored during release. If the water does not require monitoring during release, it is discharged to the Chemical Treatment Pond #3.
3. Processed by filtration and/or demineralization, collected, sampled, and analyzed. The filters and/or spent resins are packaged and shipped to various offsite vendor waste processors. The processed water is discharged directly to the tailrace of the Keowee Hydroelectric Plant if the water is required to be monitored during release. If the water does not require monitoring during release, it is discharged to the Chemical Treatment Pond #3.

Liquid waste effluent is diluted, as necessary in the hydroelectric plant tailrace to permissible concentration limits in accordance with Selected Licensee Commitments. Waste releases from the three units are integrated and controlled by process radiation monitors, interlocks, and by the operator so as not to exceed the appropriate station release limits. Where effluents can be released from more than one location, administrative controls are also provided to insure that station limits are not exceeded.

11.2.2 Disposal System Design

11.2.2.1 General Description

Liquid wastes are accumulated in storage tanks according to the waste source and expected process train. The Auxiliary Building coolant treatment header has been redesigned to facilitate the processing of liquid wastes from the high activity waste tanks, low activity waste tanks, and the miscellaneous waste holdup tanks in the Radwaste Facility. The liquid wastes are directed to the Radwaste Facility for processing by filtration and/or demineralization to segregate impurities for ultimate disposal as per Section 11.4.2. Based on the analysis, water is either reprocessed or released as per Section 11.2.2.2. The Liquid Waste and Recycle System is shown in Figure 11-2.

In addition, vendor supplied equipment may be utilized to process water and reduce waste volumes.

The Interim Radwaste Building (IRB) has the necessary equipment to process liquid waste. However, current operating practice does not make use of these systems. The Radwaste Facility (RWF) systems, as described in Section 11.6.3, are utilized.

When the IRB systems are in use, the IRB floor drains and equipment drains are collected in two sumps. The floor and low activity drains sump collects floor drains and low activity degassed equipment drains. This sump discharges to the Oconee 3 low activity waste tank in the Auxiliary Building. The floor and low activity sump is vented to the Oconee 3 vent stack.

High activity equipment drains in the IRB are collected in high activity equipment drains sump. Two sump pumps are aligned to transfer the sump contents to the Oconee 3 high activity waste tank in the Auxiliary Building. The high activity equipment drains sump is vented to the suction of the Oconee 3 waste gas compressors via the Oconee 3 waste gas vent header.

The Radwaste Facility floor drains and equipment drains are collected in two sumps. The radwaste curbed area sump collects low activity floor drains and low activity equipment drains. Two pumps are utilized to discharge sump contents to the waste monitor tanks in the Radwaste Facility. High activity equipment and floor drains in the Radwaste Facility are collected in the radwaste shielded area sump. Two sump pumps normally transfer the sump contents to the waste feed tank in the Radwaste Facility.

All piping and equipment in contact with reactor coolant are constructed of corrosion-resistant material. This equipment is arranged and located to permit detection and collection of system losses and to prevent escape of any unmonitored radioactive liquid to the environment. Component data are shown in Table 11-6.

The liquid waste discharge header to the Keowee Hydro tailrace is shown in Figure 11-1.

Waste tanks in the IRB and the Auxiliary Building are vented as necessary to the gaseous waste vent header to provide for filling and emptying without overpressurization or creating a vacuum. In addition, each waste tank is equipped with a relief valve and/or vacuum breaker. Nitrogen is supplied to each waste collection tank for purging to the Gaseous Waste Disposal System as needed.

Flush water is provided at appropriate locations in the system for flushing of piping and components.

11.2.2.2 Operation

Liquid wastes are collected in the Auxiliary Building and are transferred to the Radwaste Facility for processing by filtration and/or demineralization. Although it is not a normal process option, liquid wastes could be transferred to the IRB.

Liquid wastes are released from the Decant Monitor Tank, Recycle Monitor Tanks, and/or the Waste Monitor Tanks in the Radwaste Facility. After the liquid is mixed, sampled, and analyzed, a release rate consistent with dilution flow from the Keowee Hydro Station is determined and the radiation monitor alarm set points adjusted to comply with limits specified in Selected Licensee Commitments. The release is controlled from the Radwaste Facility control room and monitored by 1RIA 33. The RIA will terminate a release on a high alarm setpoint by closing LW-131. The release activity in CPM is recorded in the Radwaste Facility Control Room.

11.2.2.2.1 Deleted per 1996 Revision.

11.2.2.3 Liquid Waste Holdup Capacity

The information in this section is not updated and is included for historical purposes only. Potential waste generation rates are based on data gathered at ONS for years 1977 and 1978 and are found in "Evaluation of Compliance with 10CFR50 Appendix I," June 4, 1976. Actual amounts vary from year to year depending on unit operating history. Actual liquid waste generated is reported in the Oconee Annual Effluent Report in accordance with SLC 16.II.9.

The liquid waste holdup times are estimated using the following assumptions:

1. The potential liquid waste generation rates are as follows (See Table 11-1): Actual liquid waste generated is reported in the Oconee Annual Effluent Report.

(a) Primary System	161,019 ft^3 per year for 3 units
(b) Spent Fuel Pool	26,349 ft^3 per year for 3 units
(c) Cask Decontamination	17,566 ft^3 per year for 3 units
(d) Component Coolant	17,566 ft^3 per year for 3 units
(e) Service Water	58,553 ft^3 per year for 3 units
(f) Decontamination Room	87,828 ft^3 per year for 3 units
(g) Resin Sluice	23,421 ft^3 per year for 3 units
(h) Miscellaneous System Leakage	351,312 ft^3 per year for 3 units
(i) OTSG Tube Leaks	40,140 ft^3 per year for 3 units
(j) LHST	161,019 ft^3 per year for 3 units
TOTAL	944,773 ft^3 per year for 3 units

2. Design holdup capacity equals the contents of the miscellaneous waste holdup tanks, interim evaporator feed tanks, and condensate monitor tanks A and B which is 83,793 gallons for Oconee 1, 2 and 3.
3. The time for filling and discharging the tanks is 6 hours or less.
4. The tanks fill at a linear rate and the contents are discharged when the tanks become full and are sampled.

From the assumptions above the holdup times are:

Oconee 1 and 2 Holdup Time = 5.25 days

Oconee 3 Holdup Time = 11.46 days

The Radwaste Facility provides primary holdup and processing having 140,000 gallons of storage capacity.

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11.3 Gaseous Waste Management Systems

11.3.1 Disposal Methods and Limits

Gaseous activity is generated by the evolution of radioactive gases from liquids stored in tanks throughout the station. When this gaseous activity is present outside of specific piping systems or tanks, then it is collected and/or routed through various pathways in the plant. Gaseous wastes are disposed of, at a permissible rate, under continuous radiation monitoring or periodic sampling and control, by any of the following methods depending on the concentration of radioactivity, quantities, and source of the material involved:

1. Release of Auxiliary Building ventilation air and Reactor Building purges to the unit vents.
2. Release of Reactor Building purges through high efficiency particulate and charcoal iodine filters to the unit vents.
3. Release of waste gas directly or through high efficiency particulate and charcoal iodine filters to the unit vents.
4. Diversion to waste gas tanks with controlled release after sampling and analysis through the waste gas system high efficiency particulate and charcoal iodine filters to the unit vents.
5. Release of Radwaste Facility (RWF) HVAC and process exhaust.
6. Release of Penetration Room Ventilation Air to the unit vents.
7. Release of the Hot Machine Shop Ventilation Air through exhaust filters to the outside environment.
8. Release of the CSAE (Condenser Steam Air Ejector) air to the unit vents.
9. Release of the RCP Motor Refurbishment Facility exhaust to the outside environment (when facility ventilation system is operational).

Note that the Reactor Coolant Pump Motor Refurbishment Facility ventilation system and ventilation sampling system were “abandoned in place” in the last quarter of 2004, after completion of the Reactor Head Replacement Project. Electrical power to the ventilation and ventilation sampling systems was disconnected as part of the “abandonment” process. Although the ventilation system equipment and the ventilation system sampler remain in-place, this facility no longer discharges airborne radioactivity to the environment. This paragraph remains as a description of the operation of the ventilation system that was installed in the building to support the Reactor Head Replacement Project. This paragraph also remains in the event power is later restored to the ventilation and ventilation sampling systems. The Reactor Coolant Pump Motor Refurbishment Facility particulate constituents are continuously sampled by a filter paper sampling arrangement during procedurally controlled maintenance activities such as the Reactor Head Replacement Project. The sampling arrangement is periodically replaced and analyzed to quantify and qualify radioactivity present on the filter paper. Because of the type of work conducted in the Reactor Coolant Pump Motor Refurbishment Facility, noble gas and iodine activity is not released via the Reactor Coolant Pump Motor Refurbishment Facility vent. Therefore, noble gas and iodine monitoring capability is not required in the Reactor Coolant Pump Motor Refurbishment Facility.

The tank vent system is processed through carbon and high efficiency particulate filters.

Gaseous wastes are released from the station at a controlled rate so that permissible concentration limits for Unrestricted Areas will not be exceeded at the Exclusion Area boundary, when averaged over a year in accordance with the requirements of the Selected Licensee Commitments. The concentrations at the boundary are determined after applying appropriate dilution factors derived from on-site meteorological studies (Section 2.3).

Waste releases from the three units are integrated and controlled by process radiation monitors, interlocks, and by the operator so as not to exceed the appropriate station release limits. Where effluents can be released from more than one location, administrative controls are also provided to insure that station limits are not exceeded.

11.3.2 Disposal System Design

11.3.2.1 General Description

All components in the Auxiliary Building and Interim Radwaste Building that can contain potentially radioactive gases are vented to a vent header. The vent gases are subsequently drawn from this vent header by one of two waste gas compressors or a waste gas exhauster. The waste gas compressor discharges through a waste gas separator to one of two waste gas tanks. The waste gas tanks and the waste gas exhauster discharge to the unit vent after passing through a filter bank consisting of a prefilter, an absolute filter, and a charcoal filter. A flow diagram of this system with the necessary instrumentation and controls for operation is shown in Figure 11-3. Component data are shown in Table 11-6. The venting of RWF components that contain potentially radioactive gases is discussed in Section 11.6.3.6.

Oconee 1 and 2 share a Gaseous Waste Disposal System. Oconee 3 has a separate Waste Gas Disposal System, which can be interconnected to the Gaseous Waste Disposal System for Oconee 1 and 2 through double isolation valves between the vent headers. These are normally operated separately, but may be tied together to facilitate maintenance of either of the systems.

The purpose of the Gaseous Waste Disposal System is to:

1. Maintain a non-oxidizing cover gas of nitrogen in tanks and equipment that contain potentially radioactive gas.
2. Hold up radioactive gas for decay.
3. Release gases (radioactive or non-radioactive) to the atmosphere under controlled conditions.

11.3.2.2 Operation

One waste gas compressor is normally in continuous operation with the other compressor in a standby condition. The waste gas compressor takes suction on the vent header and normally discharges into waste gas tank “A” which is used as a surge tank. The vent header pressure control operates a bleedback valve (GWD-1) allowing a continuous circulation of gas through the vent header. As liquid storage tanks connected to the systems are filled, the excess gas is stored in the waste gas tank. As liquid storage tanks are emptied, gas flows from the waste gas tank back into the vent header. As waste gas tank “A” is filled, the inlet valve on waste gas tank “B” (GWD-3) is opened and waste gas tank “A” inlet valve (GWD-2) is closed. The gas in waste gas tank “A” is allowed to bleed back into the vent header and is directed into waste gas tank “B” by the waste gas compressor until the pressure in waste gas tank “A” is at the desired operating pressure. The valves are then repositioned to utilize waste gas tank “A” as a surge tank and waste gas tank “B” for radioactive decay. Gas in waste gas tank “B” is sampled for laboratory analysis to determine the permissible release rate or need for holdup for radioactive decay.

Release of gas from the waste gas tanks to the unit vent is controlled by the waste gas tank outlet valves GWD-4 and GWD-5. The volume of gas discharged to the unit vent is recorded in the Control Room and is documented on the Gaseous Waste Release (GWR) permit governing the release. Monitoring of the gas discharged to the unit vent for radioactivity is provided by a radiation monitor which, on a high radiation signal, will close the valves through which the gas is being discharged. In the event that the applicable radiation monitor is not available for service, two independent samples of the gas to be released are collected. The two samples independently verify the gas activity and serve as the basis for determining the gaseous waste release rate.

The waste gas exhauster is used when large volumes of gas containing little or no radioactivity are available for release to the unit vent. The waste gas exhauster and its isolation valves are interlocked to trip the exhauster and close the isolation valves in case of a high radiation level in the line going to the unit vent. The waste gas exhauster does not normally operate and is normally valved off by the manual valve upstream of GWD-6. Therefore, no unintentional release of significant activity is possible through this line.

Most of the Gaseous Waste Disposal system is located in the Auxiliary Building. Some equipment is located in the Interim Building, namely Interim Waste Gas Decay Tanks 1C, 1D, and 3C and their associated piping and valves. The control of the discharge flow for these tanks is similar to that for tanks “A” and “B” listed above, through the appropriate valves.

All indication and controls for this system are located in the Control Room.

11.3.2.3 Gaseous Waste Holdup Capacity

The information in this section is not updated and is included for historical purposes only. Potential waste generation rates are based on data gathered at ONS for years 1977 and 1978 and are found in "Evaluation of Compliance with 10CFR50 Appendix I," June 4, 1976. Actual amounts vary from year to year depending on unit operating history.

The estimates of potential gaseous waste holdup times are based on the following assumptions: (Assumptions and volumes are approximate and historical in nature) note that actual gaseous waste activity that is released is reported in the Oconee Annual Effluent Release Report.

1. An annual waste gas generation rate of 131,400 ft^3 is evolved from three units (Table 11-1). Oconee I, 2, and 3 contribute 43,800 ft^3 each per year.
2. Four waste gas tanks located in the Auxiliary Building and three waste gas tanks located in the Interin Radwaste Building provide holdup capacity for Oconee 1, 2, and 3.
3. Holdup capacity is as follows:

Auxiliary Building	Oconee 1 & 2	Oconee 3
Auxiliary Building Tanks (ft^3)	2200	2200
Interin Radwaste Building Tanks (ft^3)	2104	1052
Total Storage Volume	4304	3252

4. The times for filling and venting the waste gas tanks are negligible.
5. The waste gas tanks are initially filled with nitrogen at 10 psig and 100°F. The tanks may be filled to approximately 85 psig and 100°F.

11.3.3 Tests and Inspections

Each process radiation monitoring channel will be functionally tested and calibrated periodically to verify proper operation of components and to insure that the desired detector sensitivities are maintained.

A signal generator located within the process monitor panel will be used to check the alignment of electronic modules. After the electronic alignment is completed, a remote operated calibration source is actuated to determine proper functioning of the detector.

The flow measuring instrument and controls associated with the gaseous waste effluent lines will be calibrated periodically to insure proper accuracy, measurement, and control of radioactivity releases from the station.

Unless addressed by the Ventilation Filter Testing Program (VFTP) or other approved program, HEPA and Iodine charcoal filters are subject to the following requirements.

In place testing of both the HEPA and Iodine charcoal filters is performed in accordance with ANSI N-510-1975 and/or ASTM D3803-1989. DOP smoke is introduced upstream of the particulate filter and the quantity detected downstream of the filter is measured. The minimum acceptable efficiency for this test of the particulate filter is 99.97 percent. Field tests for the efficiency of Iodine charcoal filters will be performed using refrigerant-11 only. The system will be operating at rated flow. Refrigerant-11 is introduced upstream of the filter to produce an R-11 concentration of 50 ppm. With an upstream concentration of 50 ppm and a test of 2 minutes, the maximum allowable downstream concentration is 0.1 ppm.

11.3.3.1 Deleted Per 2000 Revision

11.3.3.2 Deleted Per 2000 Revision

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11.4 Solid Waste Management System

11.4.1 Design Bases

As per Selected Licensee Commitment 16.11-5, radioactive wastes shall be processed and packaged to ensure meeting the requirements of 10CFR Part 20, 10CFR Part 71, and Federal and State regulations governing the disposal of solid radioactive wastes.

11.4.1.1 Solid Waste Activities

Solid radioactive wastes are as described in Section 2 of the Oconee Nuclear Station 10CFR Part 61 Waste Classification and Waste Form Implementation Program. This activity is not released to the environment and influences only the shielding required to meet criteria stated in Section 12.3.1.

11.4.1.2 Disposal Methods and Limits

Solid wastes will be packaged to meet applicable regulations and shipped in accordance with DOT regulations to a processor or directly to either an NRC or state licensed disposal facility.

Disposal of slightly contaminated materials within the Company Controlled Area has been approved by the State of South Carolina and the NRC. Prior to disposal onsite, the waste is analyzed and confirmed to have acceptably low radionuclide concentrations. Permission is then obtained from the proper agencies per 10CFR20.2002 requirements. Each application for disposal is evaluated and approved on a case by case basis as determined by material quantities, material type, disposal methods, and radionuclide concentrations.

11.4.2 System Design and Evaluation

The Solid Waste Disposal System provides the capability to package solid wastes for shipment to an offsite NRC or approved agreement state licensed burial facility.

The disposal of the powdered resins may be accomplished by backwashing the resins from the filter elements to a sump in the Turbine Building and then to the Resin Recovery System for processing. The resin is allowed to settle to the bottom of the Backwash Receiving Tanks (BRT) in the Radwaste Facility. The excess water in the BRT is decanted to the Decant Monitor Tank for sampling and release to the environment. The powdered resins may then be used for processing waste. The resins are then prepared for shipment to a processor or directly to either an NRC or state licensed disposal facility

Bead resins can be sluiced to an approved shipping container where they are prepared for shipment to a processor or directly to either an NRC or state licensed disposal facility.

The Process Control Program Manual describes operation of the Solid Radioactive Waste System such that the final product of solidification or dewatering meet all shipping and transportation requirements during transit and meet disposal site requirements when received at the disposal site.

Low level trash such as dry active waste and spent filters are prepared for shipment to a processor or directly to either an NRC or state licensed disposal facility.

11.4.3 References

1. B. J. Youngblood (NRC) letter to H. B. Tucker (Duke) dated May 2, 1986.

THIS IS THE LAST PAGE OF THE TEXT SECTION 11.4.

11.5 Process and Effluent Radiological Monitoring and Sampling Systems

11.5.1 Design Bases and Evaluation

Radiation monitoring of process systems provides early warning of equipment, component, or system malfunctions, or potential radiological hazards. The Process Radiation Monitoring System includes alarms, indications, and recording of data in the Control Rooms. In some cases automatic action is taken upon an alarm condition; in others the alarm serves as a warning to the operator so that manual corrective action can be taken. Radioactive liquid and gaseous waste effluents, particularly, are monitored, coordinated between Control Rooms, and controlled to assure that radioactivity released does not exceed 10CFR 20 and 10CFR 50 Appendix I limits for the station as a whole.

The sensitivity and the ranges of the detectors have been coordinated with system and environmental dilution factors to assure that releases due to normal, transient, and accident conditions will be monitored and that normal releases will not exceed permissible concentrations. The release of radioactive waste will generally be on a batch basis. Waste releases will also be integrated and recorded. Interlocks are provided to terminate any release of liquid or gaseous waste if a pre-set radiation level is reached. The monitoring and controls exerted by the Process Radiation Monitoring System and the operator during the release will also be supplemented by manual sampling, laboratory analysis, and counting prior to release.

Various detectors are also shielded against ambient background radiation levels that would exist in their location due to normal, transient, or accident conditions, so that accurate readings of radioactivity will be obtained.

The process monitors have been given a primary calibration with the particular radionuclides that they are expected to monitor. Their energy response has been determined as an aid in measurement of other radionuclides that may also be encountered. A calibration source, related to primary calibration at the factory, is supplied with the system. The sources are held by Radiation Protection or I & E and used periodically to calibrate the detector. A check source is used only to verify that the detector is functional. Spectrometer grade amplifiers have been supplied with all of the sodium iodide scintillation (NaI) detectors so that they can be used with a gamma analyzer for the identification of the specific radionuclides being monitored.

Monitors are also provided on various non-radioactive cooling water systems to detect leakage from normally radioactive systems due to any component failures and thus prevent their accidental release to the environment. In addition to the manual sampling of waste prior to release, mentioned above, the measurement of radioactivity in other process fluids is also supplemented by manual sampling, laboratory analysis, and counting. This is particularly necessary for beta-emitting radionuclides such as tritium.

11.5.2 Description

The radiation monitoring equipment indications and alarms are located in the Control Rooms from which the systems being monitored are operated. Radiation monitor indications for liquid waste disposal and the Radwaste Facility vent effluents are displayed in the Radwaste Facility Control Room. Indications for unit vent effluents can be displayed in both Control Rooms. Outputs from all process monitor channels are recorded in the RIA computer system or on multipoint recorders. Control Room annunciation of high radiation level is provided for each channel. Most detector assemblies are equipped with a Control Room operated check source.

Table 11-7 lists the process radiation monitors and gives the following information:

1. Channel Number and Function - A Radiation Indicating Alarm (RIA) number has been assigned to each detector. Monitors serving the same function have the same number. Prefix numbers indicate the unit on which the detector is used. No prefix number indicates that the RIA is shared between two or more units. The function shows the system in which the monitor is employed.
2. Type of Detector - The standard detector type identification is given followed by the size of the crystal or the length of the detector. The lead shield thickness which has been applied to obtain the sensitivities indicated is also given.
3. Sensitivity - Monitor sensitivities are indicated in terms of background equivalent concentrations and count rate for the radionuclides listed. Background equivalent information shown in the table defines the ability of the monitor to detect the indicated radionuclide concentrations inside the sampler at a count rate that is equal to that resulting from a gamma field outside the sampler. The lead shielding is designed to reduce the count rate resulting from Cobalt-60 gammas in order to obtain the sensitivities shown. This information is taken from the manufacturer's technical manuals. The Sensitivity column of Table 11-7 is applicable for all process radiation monitors listed except the Main Steam N-16 Radiation Monitors. The Sensitivity column in Table 11-7 is not applicable to the N-16 Radiation Monitors 1, 2 and 3RIA-59 and 1, 2 and 3RIA-60 since there are so many factors that are involved in the computation of the Steam Generator Primary to Secondary Tube Leak rate beside counts per sec gamma e.g., % Reactor Power, Detector Temperature, Location of the Steam Generator of the Primary to Secondary Tube Leak, the Geometry of the Steam Line Piping and the location of the N-16 Detectors relative to the location of the tube leak and relative to the location of the adjacent Main Steam Line.
4. Range - Readout range of monitoring instrumentation, upper range limits, and range overlap between different detectors monitoring the same sample are indicated.

The following is a description of the various applications of these monitors as they are applied to systems:

1. 1,2 and 3RIA16 and 17 detectors monitor the A and B Main Steam line piping respectively for the presence of radioactivity in the process steam. The primary purpose for these monitors is to aid in the detection of a steam generator primary to secondary leakage fault. Readout and alarms for these monitors are located in the associated control rooms.
2. RIA-31 monitors gross gamma from the Low Pressure Service Water outlets of the A and B Low Pressure Injection Decay Heat Coolers of Units 1, 2 and 3. Samples from the cooler outlets are sequentially automatically valved and monitored. Sample valve scan rate is adjustable from the Unit 1 RIA computer system. Unit 1 control room contains the primary control terminal for the monitor. The output from the radiation monitor is indicated in all three control rooms. Alarms are also provided in the control rooms. The monitor is located inside the turbine building and is shielded to function during a loss of coolant accident, including 100 percent release of fission gases inside the Reactor Building. The monitor is provided to supplement indications from 1, 2 and 3RIA-35.
3. RIA-32 can monitor air from up to 12 locations and 3RIA-32 can monitor air from up to 6 locations, each within the Auxiliary Building for early detection and location of equipment malfunctions. They also are designed to warn personnel of the presence of radiological hazards. Each monitor incorporates a sample pump that continuously draws samples through a three-way valve manifold at the detector. Sample valves are sequenced by the RIA computer system to direct individual samples to shielded beta sensitive detectors.

Detector outputs are logged by the RIA computer system. Loss of sample flow is annunciated in the Control Rooms as a fault alarm detector.

Additionally, RIA-32 and 3RIA-32 are designed to monitor the discharge from the respective units penetration room fans. Manually-selectable sample points permit detection of gaseous activity in the Penetration Room resulting from Reactor Building design leakage following a Reactor Coolant System failure and subsequent release of fission gases into the Reactor Building.

4. RIA-33 is used to monitor total liquid waste effluent from the station. Loss of sample flow is annunciated in the Radwaste Facility Control Room. Interlocks from this monitor automatically terminate a release at preset levels.
5. 1RIA-35, 2RIA-35, and 3RIA-35 continuously monitor samples of LPSW for gross gamma in the main LPSW discharge headers from the Auxiliary Building. The main headers are monitored since they can contain radioactive leakage from normally radioactive systems due to component failures. Upon any indication of radioactivity in the effluent, the component suspected of leaking may be individually isolated thereby allowing repair of components. The detectors are located inside the Turbine Building. They are shielded to function in the presence of increased background from a Loss of Coolant Accident. Loss of sample flow is annunciated in the appropriate Control Room.
6. During times when LPSW temperature is high and greater cooling is desired inside the Reactor Building, chilled water can be provided to the Auxiliary Coolers in lieu of LPSW by a temporary chilled water system during modes 1-4 and to the Auxiliary Coolers and/or the “B” RBCU during modes 5, 6, and no mode. This is accomplished by tying temporary chilled water system piping into a portion of the LPSW piping going to the Reactor Building Auxiliary Coolers and the “B” RBCU. Since the chilled water is isolated from monitoring by 1/2/3RIA-35, grab samples are taken on a periodic frequency and evaluated for gross radioactivity. Grab samples are only required during modes 1-4.
7. RIA-37 and RIA-38 monitor waste gas effluent from Oconee 1 and 2. One instrument channel using a plastic beta scintillation detector (RIA-37) and one instrument channel using a Geiger-Mueller (G-M) tube (RIA-38) provide the dynamic range indicated on Table 11-7. This range covers normal and abnormal operating conditions with overlap as indicated. Interlocks from these monitors automatically terminate release at preset levels. 3RIA-37 and 3RIA-38 are functionally identical and serve the same purpose for Oconee 3. These monitors are shown on Figure 11-3.
8. RIA-39 for Units 1 and 2, and 3RIA-39 for Unit 3, monitor Control Room ventilation using beta sensitive detectors (Section 9.4.1.1). Samples of Control Room air are continuously pumped through shielded samplers. Loss of sample flow is annunciated in the appropriate Control Room.
9. 1RIA-40, 2RIA-40, and 3RIA-40 monitor condenser air ejector off gas effluent to each unit vent (Section 10.4.2) to detect activity in the steam system resulting from a steam generator tube leak. In addition to this protection, 1RIA-16 and 1RIA-17 are located adjacent to the main steam headers. For Oconee 2 and 3, this monitoring function is served by 2RIA-16, 2RIA-17, 3RIA-16, and 3RIA-17, respectively.
10. RIA-41 for Units 1 and 2, and 3RIA-41 for Unit 3, monitor ventilation air in both Spent Fuel Buildings using beta sensitive detectors (Section 9.4.2.1). Samples of Spent Fuel Building air are continuously pumped through shielded detectors. Loss of sample flow is annunciated in the appropriate Control Room.

11. RIA-42 for Units 1 and 2, and 3RIA-42 for Unit 3, monitor recirculated cooling water return from Auxiliary Building for gross gamma activity.

12. 1RIA-43, 1RIA-44, 1RIA-45, and 1RIA-46 monitor Oconee Unit 1 vent for radioactive air particulates, iodine, and gas. A vent monitor incorporates a sample nozzle, a pumping system, and four detector channels. The pump supplies samples to an air particulate monitor (moving filter paper), a fixed charcoal filter that is monitored for iodine, and to two gas monitors. The pump also draws a portion of the sample through an Iodine cartridge and filter paper for effluent analysis. Air particulates are detected by monitoring a moving filter paper with a plastic beta scintillator (1RIA-43). Iodine is monitored with a NaI scintillator (1RIA-44) monitoring a selected gamma energy range. Gaseous activity is detected by a plastic beta scintillator (1RIA-45) for normal ranges. A cadmium telluride solid state detector (1RIA-46) is used in a separate instrument gas channel to extend the dynamic range of the system. Sensitivity and overlap of the gaseous monitoring ranges are indicated in Table 11-7. Collection efficiency for the air particulate filter is 99 percent for particles 0.5 micron and larger. The activated charcoal cartridge type filter has a rated collection efficiency of at least 90 percent for radioiodine in forms anticipated.

    Malfunctions involving loss of sample flow and depleted, torn, or clogged filter paper are alarmed in the Control Room.

    For Oconee 2 and 3, this monitoring function is served by 2RIA-43, -44, -45, -46, and 3RIA-43, -44, –45, -46, respectively.

    When required by Technical Specifications to be operable, interlocks from the gas monitors automatically terminate a Reactor Building purge and close the purge isolation valves on high radiation level in accordance with the requirements of NUREG 0737, Item II.E.4.2.7. These monitors are shown on Figure 6-4.

    4RIA-45 monitors the Radwaste Facility HVAC for noble gas. Particulate and radioiodine activity are continuously sampled by a filter paper and charcoal cartridge sampling arrangement. The sampling filter paper and charcoal cartridge are periodically replaced and analyzed to quantify and qualify radioactivity present in the HVAC system. Noble gas activity is detected by a plastic beta scintillator for normal ranges. Sensitivity of the gaseous monitoring range is indicated in Table 11-7.

    a. 1RIA-47, 1RIA-48, 1RIA-49, 1RIA-49A and associated equipment make up the Reactor Building Airborne Activity Monitoring System for Oconee 1. The equipment provided is functionally identical to that described for the vent monitors except that a separate Iodine cartridge and filter paper are not available for effluent analysis. For Oconee 2 and 3, this monitoring function is performed by 2RIA-47, -48, -49, 49A, and 3RIA-47, -48, -49, 49A, respectively. On high radiation level, interlocks from the gas monitors automatically close the Reactor Building sump line isolation valves.

13. 1RIA-50 monitors Oconee 1 Component Cooling System for gross gamma using a NaI scintillator (Section 9.2.1.7). Sample flow loss is alarmed in the Control Room. For Oconee 2 and 3, this monitoring function is performed by 2RIA-50 and 3RIA-50, respectively.

14. RIA-53 is designed to monitor airborne effluent from the Interim Radwaste Building. One instrument channel using a plastic beta-scintillation detector provides the range indicated in Table 11-7. This range covers normal operating conditions. Interim Radwaste Building particulate and radioactive gas constituents are continuously sampled by a filter paper and charcoal cartridge sampling arrangement adjacent to the RIA-53 skid. The particulate and iodine sampling media are periodically replaced and analyzed to qualify and quantify radioactivity present on the media.

15. RIA-54 monitors the Unit 1 and 2 Turbine Building sump and stops pumps during loss of power or high activity. 3RIA-54 monitors the Unit 3 Turbine Building sump and stops pumps when high radioactivity levels are detected.

16. 1RIA-56, 2RIA-56 and 3RIA-56 are designed to monitor gross gamma activity in each unit vent stack. The detector is an ion chamber located on the vent stack with the readout in the control room. The monitor provides very high range monitoring capabilities for gaseous effluents exiting the unit vent under accident conditions.

17. 1, 2, 3RIA-57 and 58 are designed to monitor gross gamma activity in each unit containment building. These post-accident monitors are coaxial ion chambers with readouts in each control room. The monitors are located in the east and west penetration room associated with each unit. 1, 2, and 3RIA-58 have recorders in the Control Rooms.

18. The Hot Machine Shop Vent particulate and radioiodine constituents are continuously sampled by a filter paper and charcoal cartridge sampling arrangement. The sampling arrangement is periodically replaced and analyzed to quantify and qualify radioactivity present on the filter paper and/or cartridge. Because of the type of work conducted in the Hot Machine Shop, and because of the location of the Shop to the Auxiliary Building (and its associated ventilation system), noble gas activity is not released via the Hot Machine Shop vent. Therefore, noble gas monitoring capability is not required in the Hot Machine Shop.

19. Note that the Reactor Coolant Pump Motor Refurbishment Facility ventilation system and ventilation sampling system were “abandoned in place” in the last quarter of 2004, after completion of the Reactor Head Replacement Project. Electrical power to the ventilation and ventilation sampling systems was disconnected as part of the “abandonment” process. Although the ventilation system equipment and the ventilation system sampler remain in-place, this facility no longer discharges airborne radioactivity to the environment. This paragraph remains as a description of the operation of the ventilation system that was installed in the building to support the Reactor Head Replacement Project. This paragraph also remains in the event power is later restored to the ventilation and ventilation sampling systems. The Reactor Coolant Pump Motor Refurbishment Facility radioactive particulate and radioiodine effluent is continuously sampled by a filter paper and charcoal cartridge sampling arrangement during specified maintenance activities such as the Reactor Head Replacement Project. Note that due to work sequencing, radioiodine is not expected to be available for release from the facility; however, sampling for radioiodine is conducted to allow proper accounting of effluent in the event that radioiodine is identified. The sampling media is periodically replaced and analyzed to quantify and qualify radioactivity present on the filter paper and/or cartridge. Because of the type of work conducted in the Reactor Coolant Pump Motor Refurbishment Facility, noble gas activity and (byproduct) tritium activity are not released from the facility vent. Therefore, noble gas monitoring capability and tritium sampling capability are not required in the Reactor Coolant Pump Motor Refurbishment Facility.

20. 1, 2 and 3RIA-59 and 1, 2 and 3RIA-60 are N-16 Main Steam Line Radiation Monitors (Note: These are not to be confused with the Regulatory Guide 1.97 Main Steam Line Monitors described in Section 7.5.2.54 of this UFSAR.) 1, 2 and 3RIA-59 and 1, 2 and 3RIA-60 are specifically configured to detect N-16 gamma radiation. 1, 2 and 3RIA-59 and 1, 2 and 3RIA-60 each consists of the following components:

    a. An N-16 Radiation Scintillation Detector (the detector consist of a NaI(T1) 3”X2” crystal, Photo multiplier tube, embedded Am-241 seed source, and a Temperature sensor) located adjacent to the Main Steam Line on the fifth floor Turbine Building

b. A Local Process Display Unit (LPDU) which is a microprocessor that converts the gamma counts per second to gallons per day leakage based on the geometry of the Steam Generators and length of the Steam Lines from the Steam Generator to the Detector location and Reactor Power. The LPDU sends output signals to the OAC and the PMC and the Control Room View Node. The LPDU has an input signal from the ICS which corresponds to the Core Thermal Power Best % Reactor Power.

c. An Uninterruptible Power Supply (UPS) that feeds power to a Signal Power Junction Box and to alarm relays located in a Signal Junction Box.

d. Alarm relays that actuate Control Room Stat Alarms upon receipt of a signal from the LPDU that a Rad Monitor Fault has occurred or Rad monitor leakage rate setpoint has been reached.

21. Deleted per 2005 update

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11.6 Radwaste Facility

11.6.1 General Description

11.6.1.1 Safety Evaluation

The radwaste facility was evaluated under a 10CFR 50.59 safety evaluation and was found not to involve an unreviewed safety question. In accordance with 10CFR 20.305, pursuant to 10CFR 20.302 (now addressed in 10CFR 20.2004, pursuant to 10CFR 20.2002), Duke requested NRC approval to operate a low-level radioactive waste incinerator, discussed in Section 11.6.3.3, under the ONS Operating License and Technical Specifications (Reference 1). The NRC transmitted their safety analysis (Reference 2) which concluded that operation of the incinerator would not diminish the safe operation of ONS nor present an undue hazard to public health and safety.

11.6.1.2 Site Characteristics

The site is located south of the Unit 3 Turbine and Auxiliary Buildings. The yard grade elevation in this area is about 796 feet (MSL). Approximately 80 ft. southeast of the facility the yard fill slopes downward at 2 to 1 (horizontal to vertical) to original ground about 55 ft. below.

The test borings encountered a profile of materials consisting from the ground surface of fill residual soil, partially weathered rock and finally rock or refusal materials. The thickness of fill varied from 18 to just over 70 feet within the proposed facility. The fill soils classify primarily as micaceous silty sands with included clayey layers of low to moderate plasticity.

The fill consistency based on the standard penetration test is loose to dense. The fill appears to be relatively well compacted overall based on penetration resistances. The standard penetration resistances range from less than 5 to greater than 40 blows per foot with values predominantly between 21 and 30 blows per foot.

Below the fill soils, the residual materials weathered from the parent bedrock were encountered. The residual profile consists of a variable thickness of soil underlaid by partially weathered rock. The residual soils primarily are silty sands or sandy silts. The standard penetration test values range from 4 to over 100 blows per foot.

Beneath the fill and residual soils, the test borings encountered refusal materials at depths of 30 to 85 feet below the present surface. The nature of the refusal materials was investigated by rock coring procedures. The rock classified as mica-gneiss.

11.6.1.3 Facility Description

The Radwaste Facility is designed to process liquid and solid radioactive wastes. The wastes are separated into clean water and concentrated contaminants. The concentrated contaminants are prepared for disposal and the clean water is discarded or recycled for use in the station. The wastes consist of miscellaneous liquid waste (radioactive equipment drains and floor drains, etc.) reactor coolant, powdered resin, and miscellaneous radioactive trash (gloves, paper, etc.)

Liquid wastes are processed by an appropriate combination of equipment (filter, demineralizer, and/or evaporator) in the Liquid Waste and Recycle System. (The evaporator is in a state of 'dry layup' and is not in use.) Contaminants collected by the demineralizers and filters are sent to the

Dewatering System. Boric acid concentrated from reactor coolant by the evaporator are reused or sent to the Solidification System as are the waste concentrates.

Powdered resin used in the Condensate Polishing Demineralizers are collected and monitored in the Resin Recovery System. The resin can be used to process water from the LW System and/or the Laundry Hot Shower Tanks. Excess water will be removed from contaminated resin and the resin sent to the Volume Reduction System or vendor supplied liners for dewatering. The Liquid Waste and Recycle System is shown in Figure 11-2.

The Volume Reduction System (in dry layup) incinerates combustible wastes. The dried product (ash & salts) and wet wastes will be packaged to meet Federal and State regulations.

11.6.1.4 QA Condition Classifications and Inspection Program

11.6.1.4.1 Perspective

Duke Power Company's Quality Assurance program covers four QA conditions. Quality Assurance Condition 2 (QA 2) applies to radwaste systems and follows the guidance of Regulatory Guide 1.143. Regulatory Guide 1.143 lists systems to which it applies but does not contain criteria for determining applicability.

The criteria herein adopted for the application of QA 2 are based on the “as low as reasonably achievable” (ALARA) concept of radiation protection and generally relate to routinely expected occurrences. The criteria generally result in determinations which are consistent with Regulatory Guide 1.143.

11.6.1.4.2 General Criteria

An item or activity is ALARA related and a QA program is applied if:

a. Functional unavailability, lack of effectiveness, or non-catastrophic failures impair the ability to meet the ALARA objective for effluent releases.

b. Require routine maintenance or repair of anticipated failures would cause excessive or easily avoidable occupational exposure.

11.6.1.4.3 Implementation

a. Eliminating pressure boundary leakage of ALARA related piping systems (delineated on flow diagrams as Class E) is an ALARA related function, but pipe hangers and supports do not perform an ALARA related function because they are provided to prevent gross failure rather than leakage. Experience has shown that conventional power piping has a very low rate of gross failure but leakage is not unusual. Therefore, pipe hangers and supports are not QA Condition 2.

b. The pressure boundary of piping systems with only occasional radioactivity, very low radioactivity, and drains are not ALARA related. Generally, this applies to closed loop cooling and process steam, streams normally releasable without treatment and floor drains.

c. Equipment, parts, and components not part of an ALARA pressure boundary are functionally ALARA related if their failure would prevent the system from performing its intended function greater than 10% of a calendar quarter (about 10 days). Since most electrical equipment and small mechanical equipment can be repaired in this time, they are generally excluded.

d. Only the containment of leaks and spills within the structure is an ALARA related function which requires a QA 2 program by these criteria. Therefore, a QA 2 program will be applied to the "Bathtub Portion" of the radwaste facility structure.

11.6.2 Structures

11.6.2.1 Description of Building

The Oconee Radwaste Facility consists of two separate adjoining structures, separated by a 3 inch expansion joint, both supported by poured in place reinforced concrete mats. One structure is primarily of reinforced concrete construction with structural walls serving also as shielding for radioactive components or materials. The other structure is primarily of braced structural steel construction with floors of reinforced concrete on metal deck and conventionally formed reinforced concrete columns and floors supporting large tanks. Exterior walls are insulated metal siding on steel girts. Interior walls are gypsum wallboard on metal studs and concrete masonry.

11.6.2.2 Design Bases

The structures are modeled as space frames using the McDonald Douglas version of ICES STRUDL, a structural design language computer program. The two dimensional finite element capabilities of STRUDL are used to represent walls and slabs while one dimensional beam elements are used for beams and columns. The supported points of the model have spring stiffnesses representing the force-deflection relationship of the underlying soil, thus differential settlement is accounted for. A modal and shock spectrum analysis was performed using the capabilities of the STRUDL DYNAL feature of the STRUDL program up to Elevation 799+6 as a minimum.

Both portions of the Radwaste Facility are designed and erected so that all liquid inventory will be contained within the structures in the event of pipe or tank ruptures caused by a seismic event or from other causes. Therefore, the reinforced concrete mats and a concrete wall of sufficient height to contain the entire liquid inventory are designed to withstand the effects of seismic loads as well as conventional loads. Loadings due to failure of the upper structure portions during the seismic event were not considered. Design, procurement and erection meet the requirements of the Duke Power Company Quality Assurance Condition 2 (QA2) program up to Elevation 799+6. A wall erected to Elevation 799+6 (bathtub) can contain the entire liquid inventory of the building.

For the east side of the facility, between column lines B and F, the framing is primarily of structural steel, and the structural design includes the effects of seismic and conventional loads. Design, procurement, and shop fabrication of the structural steel meet the requirements of the Duke Power Company QA 2 Program. Structural steel erection meets AISC requirements, but has no formal Quality Assurance requirements. The south-east portion of this area is reinforced concrete up to the floor at Elevation 819+0. The floor, supporting large tanks, is not designed to seismic requirements; the concrete columns are designed for seismic loadings except that the tie bars are reduced in size and number from the requirements for seismic forces, to permit ease in construction.

The west side of the facility, between column lines G and K, is a reinforced concrete structure, and the analysis and design include the effects of seismic and conventional loads up to the bottom of the floor slab at Elevation 819+0. Design, procurement and construction of these parts meet the requirements of the Duke Power Company QA program. The floor slab at Elevation 819+0 and all reinforced concrete elements above this floor, except for load bearing walls, are analyzed and designed for conventional loads only, with good engineering practice applied to design, procurement and construction. The design of load bearing walls above Elevation 819+0 includes seismic loads with no Quality Assurance requirements applied to design, procurement or construction.

Independent loads are calculated on the following bases:

11.6.2.2.1 Wind Loadings

The design wind velocity is 95 mph at 30 ft. above the nominal ground elevation. According to ASCE Paper 3269, "Wind Forces on Structures," this represents the greatest wind velocity with a recurrence interval of 100 years. ANSI A58.1-1972, "Building Code Requirements for Minimum Design Loads in Building and Other Structures," recommends that buildings with a height-to-minimum horizontal dimension ratio exceeding five should be dynamically analyzed to determine the effect of gust factors. However, since this structure has a height-to-width ratio less than five, a gust factor of unity is used in determining wind forces. Tornado and tornado missiles are not included as a design load.

11.6.2.2.2 Water Level Design

The yard grade is at elevation 796+0. All openings into the structure will be no lower than 797+0. A 2'-6" minimum height curb is provided to contain any accidental spillage within the facility. The yard is provided with a surface water drainage system.

11.6.2.2.3 Dead Loads and Equipment Loads

A density of 150 1b/ft^3 is used for reinforced concrete dead weight computations. Structural steel weights are based on their nominal weight per foot as given in the AISC "Manual of Steel Construction", eighth edition. Weights of metal decking and siding are taken from supplier's catalogs. Weights of equipment, tanks, etc., weighing more than 1000 lbs are taken from information supplied by the manufacturer. An additional load of 150 lb/ft^2 is applied to floors, except for the drum storage area, and roofs in the reinforced concrete structure to account for suspended piping, electrical cable tray and small miscellaneous equipment weighing less than 1000 lbs. In the drum storage area, the additional load is 2250 lb/ft^2.

Additional loads of 50 lb/ft^2 on floors and 30 lb/ft^2 on roofs are applied in the structural steel portion, for the same reason. Where cable tray is banked, the cable tray loading are calculated and applied as additional equipment load. A dead load of 20 lb/ft^2 is applied to areas covered by grating.

11.6.2.2.4 Live Loads

In the concrete portion, a live load of 125 lb/ft^2 is applied to floors and roof. In the structural steel portion, a live load of 150 lb/ft^2 is applied to floors and 20 lb/ft^2 is applied to roofs. A live load of 100 lb/ft^2 is applied to areas covered by grating.

11.6.2.2.5 Seismic Design

A nonlinear finite element soil-structure analysis (FLUSH) is used to generate seismic response at the ground surface due to bedrock motion. The rock motion input is a synthetic 5%g time history developed so that response spectra derived from that motion envelope the NRC Regulatory Guide 1.60 curves. The design response spectra are developed using procedures set forth in NRC Regulatory Guide 1.60, with maximum ground acceleration in both horizontal and vertical directions obtained from the soil-structure interaction analysis. Response spectra analyses are performed for both horizontal directions. Vertical earthquake loads are obtained by applying the maximum vertical acceleration to static loads.

11.6.2.3 Loads and Loading Combinations

The loads and combinations thereof used in the analysis and design of the Radwaste Facility are described below:

1. Normal Loads

   Normal loads are those loads to be encountered during normal facility operation.

   They include the following:

   D - Dead loads, including permanent equipment loads and hydrostatic loads.

   L - Live loads, including any movable equipment loads and other loads which vary with intensity and occurrence, such as soil pressure.

2. Severe Environmental Loads

   Severe environmental loads are those loads that could infrequently be encountered during the facility life.

   Included in this category are:

   E - Loads generated by the Operating Basis Earthquake

   W - Loads generated by the design wind specified for the facility.

11.6.2.3.1 Load Combinations for Concrete Structures

U designates the section strength required to resist design loads and is based on methods described in ACI 318-77. The following load combinations will be satisfied:

1. U = 1.4D + 1.7L
2. U = .75 (1.4D + 1.7L + 1.7W)
3. U = .75 (1.4D + 1.7W)
4. U = .9D + 1.3W
5. U = .75 (1.4D + 1.7L + 1.87E)
6. U = .75 (1.4D + 1.87E)
7. U = .9D + 1.43E

11.6.2.3.2 Load Combinations for Steel Structures

S designates the section strength required to resist design loads and is based on the elastic design methods and the allowable stresses defined in Part I, Sections 1.5.1, 1.5.2, 1.5.3, 1.5.4 and 1.5.5 of the AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," seventh edition.

Y designates the section strength required to resist design loads and is based on plastic design methods described in Part 2 of AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," seventh edition.

The following load combinations are used for the elastic working stress method:

1. S = D + L
2. 1.33S = D + L + E
3. 1.33S = D + L + W

In load combinations 2 and 3, S is increased by one-third in accordance with Section 1.5.6 in the AISC specification.

The following load combinations are used for the plastic design method:

1. Y = 1.7D + 1.7L
2. Y = 1.3D + 1.3L + 1.3E
3. Y = 1.3D + 1.3L + 1.3W

Note: Loadings that include seismic factors are used as a design basis to design the “bathtub”.

11.6.3 Mechanical Systems

11.6.3.1 Liquid Waste and Recycle System

11.6.3.1.1 Design Bases

The Liquid Waste and Recycle System (LW) is designed to appropriately process all excess radioactive water generated at the station. Decontaminated water will be reused by the station as make up or released to the environment as appropriate. Generally, chemistry limits control recycle and radioactivity limits control discharge. Contamination removed from processed water will be transferred to the Volume Reduction and Solidification System for packaging and shipment to an approved processor or disposal facility.

Note: The HPD Evaporator System is placed into a 'dry layup' condition until operating economics can justify its use, and because of this water is not reclaimed for use/reuse by the station.

11.6.3.1.2 System Description

Four 10,000 gallon Feed Tanks are provided for batching reactor coolant and miscellaneous waste. These tanks are managed as needed to receive waste from the plant.

Feed pumps, process filters, demineralizers, and demineralizer fines filters are provided in pairs, each designed for ≤ 50 gpm. One 30 gpm evaporator is provided to be used either for concentration of boric acid from reactor coolant or, if necessary, for use with a filter and demineralizer to provide the greatest available decontamination for waste. An additional train of six demineralizers is available to process liquid waste. Sufficient crossconnection is provided so that two independent streams can be processed simultaneously. Possible lineups are: 1) a feed pump, filter, demineralizer, demineralizer fines filter, evaporator processing reactor coolant and 2) a feed pump, filter, demineralizer, and demineralizer fines filter processing miscellaneous floor drains. Other “normal” situations exist with total process rates from 5 to 100 gpm.

Six 10,000 gallon monitor tanks are provided for checking processed water quality and scheduling transfers. Water may be released to the environment through a radiation monitor or be transferred to Chemical Treatment Pond #3.

If dilution is required, processed water is released through a radiation monitor coordinated with a flow meter. The monitor will terminate discharge if it detects activity in excess of the setpoint.

The setpoint is determined based on laboratory analyses. The setpoint guards against errors in the laboratory results. Compensatory action is taken if the laboratory analysis can not be coordinated with the monitor's setpoint (monitor out of service or activity below capability of the monitor to detect). Independent samples are taken and analyzed instead of using the continuous monitor.

11.6.3.2 Powdered Resin Recovery System

11.6.3.2.1 Design Bases

The Powdered Resin Recovery System is designed to collect and sample each sluice (backwash) from the Condensate Polishing Demineralizer Backwash Sump and to separate water from spent resin. The sump can contain both bead and powdered resins from various demineralizers. In addition, the System can use the spent resin to process liquid from the Laundry Hot Shower Tanks, and the Liquid Waste System.

11.6.3.2.2 System Description

Each backwash is sent to one of the two Backwash Receiving Tanks, BRT-A, or BRT-B. There the resin is transferred to the Contaminated Backwash Receiving Tank (CBRT) where it can be used to process additional waste water.

The resin in the backwash receiving tanks may also be used to process laundry and hot shower water and to process/reprocess miscellaneous waste. This is accomplished by agitating the water and resin, then proceeding with the decanting as described above.

Backwashes are allowed to settle. After sufficient settling has occurred, the excess water is decanted. The decanted water is directed through the Resin Fines to the Decant Monitor Tank (DMT). Here the water is sampled and directed to one of two locations; 1) Liquid Waste System, or 2) Chemical Treatment Pond. The contaminated resin is transferred to the Facility Truck Bay and/or Drum Storage Facility for dewatering in DOT approved shipping containers.

The dewatered containers are sampled, prepared and shipped to a NRC disposal facility or vendor-site for further volume reduction.

11.6.3.3 Volume Reduction and Solidification System

11.6.3.3.1 Design Bases

The Volume Reduction and Solidification System (VR) is designed to prepare radioactive wastes for shipment and disposal, and to minimize the volume of waste shipped.

Note: The VR system (incinerator and dry product handling and drumming portions) has been placed in a layup condition until operating economics can justify its use.

11.6.3.3.2 System Description

In order to prepare wastes for shipment and minimize the volume of waste, wet wastes (e.g., contaminated oil, powdered resins) and dry trash are incinerated and the scrub liquor produced is completely dried. The results of both fluid bed processes are a dry, free-flowing mixture of salt granules and ash. This sand-like material is then packaged to meet Federal and State regulations. Resin which is too radioactive to incinerate will be solidified and/or packaged to meet Federal and State regulations.

The incinerator may be fed resin slurries, contaminated oil or shredded trash. Fluidizing air is electrically heated for startup and thereafter maintained by the combustion process. Liquid sprays (resin slurry or condensate) are provided to control temperature.

All normal operations of the Volume Reduction and Solidification System involving radioactive material are carried out remotely from the Radwaste Control Room. A remote control crane moves new drums from the clean fill stations to the waste drumming stations, stores or retrieves drums in the storage pit, and loads truck-mounted shielded casks used to ship solidified waste off site for disposal.

11.6.3.4 Instrument and Breathing Air Systems

These systems are described in Section 9.5.2.

11.6.3.5 Equipment Cooling System

11.6.3.5.1 Design Bases

The Equipment Cooling System is designed to remove heat from the components of the Liquid Waste Processing System and Radioactive Waste Solidification System. This system also supplies cooling water to the Radwaste Facility air compressors and HVAC coolers, and supplies service water for the facility.

11.6.3.5.2 System Description

The generating plants Condenser Circulating Water System serves as the suction source for the Equipment Cooling System. Two duplex basket-type strainers reduce particulate size to 1/16" and two 100% capacity EC Supply Pumps rated at 2400 gpm, @ 160 ft. deliver flow to the secondary side of two plate-type heat exchangers. The primary side flow is circulated by two 100% capacity EC Circulating Pumps rated at 1600 GPM @ 85 ft. This flow provides cooling for the Liquid Waste Evaporator and the Volume Reduction System. An auxiliary supply is taken off the EC Supply Pump discharge for miscellaneous service water use.

11.6.3.6 Heating Ventilation and Air Conditioning

11.6.3.6.1 Design Bases

The Radwaste Facility HVAC consists of a Ventilation System and an Air Conditioning System. The principal objectives of the HVAC System are to supply sufficient filtered fresh air to maintain an aseptic condition, control the temperature for effective operation of process equipment, meet the “ALARA” related consideration with air flow by supplying air to clean areas and exhausting air from high radiation areas and to sample the exhaust air to monitor the release of airborne radioactive material from the building.

11.6.3.6.2 System Description

11.6.3.6.2.1 Ventilation System

The Ventilation System will supply filtered and tempered air to each area in sufficient quantity to reduce the heat build up and keep the temperature below 110 degrees in the process areas. A positive exhaust system will be used to exhaust a quantity of air from each area which is sufficiently larger than the supply air to maintain a directed flow of air in the building. The exhaust air quality will be monitored. A filter train including rough, HEPA and charcoal filters will be used for the exhaust air from tank vents and fume hoods to minimize the emission of contamination from the building. There will be no recirculation of air to any process area.

11.6.3.6.2.2 Air Conditioning System

The Air Conditioning System will supply tempered and dehumidified air including fresh air to each area. The areas to be air conditioned include, but are not limited too, the control room, the count room, the Chem. & HP Lab, the Men and Women's Clean Change Areas, the Supervisor's office, and the clean and contaminated maintenance shops. The Contaminated Maintenance shop and the personnel areas will be air conditioned with 100% fresh air.

11.6.3.7 Drains

Roof drains and clean floor drains are piped to the station storm drain system.

Personnel area drains that are potentially contaminated are pumped to the facility sumps.

Sanitary drains are piped to the on-site sanitary sewer collection piping system.

Contaminated process and floor drains are piped to the facility sump.

11.6.4 Remote Control System

11.6.4.1 Design Bases

The Radwaste Remote Control System is designed to provide a means for operating the various mechanical and electrical systems in the Radwaste Facility from a centralized control area. This design will minimize the requirements for manning the facility, and will minimize the radiation exposure to the operator. While it is impractical to control all functions from a centralized location, remote control is employed in a practical manner where possible, particularly in situations involving radiation exposure to the operator.

11.6.4.2 System Description

The Radwaste Control Room (RCR) is located in the clean portion of the building where there are no radiation shielding requirements. A cable spreading room is provided behind the RCR to allow for control board and relay cabinet cable access.

Control boards designed by several different vendors as well as Duke-designed boards are located in the RCR. The electrical project engineer coordinates between all parties to insure as much compatibility between boards as is reasonably achievable. Human factors aspects of the control room and control board designs including color coding, control board enhancement, process mimics, operator/control interfaces, and RCR personnel traffic patterns are taken into consideration.

Since the RCR is the primary area of personnel activity for this facility, the Fire Detection System central alarm station as well as any other “Facility protective” monitors are located there. Annunciators, instrumentation, and control devices are installed as necessary to satisfy the intent of the Remote Control System purpose.

11.6.5 Fire Detection System

11.6.5.1 Design Bases

The Radwaste Fire Detection System is designed to provide early warning at a central location in the event of a fire or conditions preceding the break out of a fire.

11.6.5.2 System Description

The Radwaste Fire Detection System central alarm station is located in the Radwaste control room. Individual strings of various types of detectors emanate from the central alarm station to provide detection in selected areas of the facility. Detector locations and types (ionization, fixed temperature, rate-of-rise, etc.) are determined by the fire protection engineer.

The detection system installed is of the two-wire type which will allow trouble alarm indication. This design approach should minimize personnel radiation exposure encountered in maintaining the system. An alarm is provided in the Oconee plant (e.g., Unit 3 control room) to notify the plant operations personnel of a fire in the Radwaste Facility.

11.6.6 Radiation Monitoring System

11.6.6.1 Design Bases

The Radiation Monitoring System is designed to accurately monitor process, area and noble gas radiation within the facility. Particulate and iodine collection samplers are also installed in the exhaust system.

11.6.6.2 System Description

The Radiation Monitoring System consists of the components with their respective parameters as listed in Table 11-7.

11.6.7 Radiation Protection

11.6.7.1 Facility Design Features

The mechanical and electrical equipment is separated into clean, nonradioactive areas, curbed areas and shielded areas. Radioactive components are separated from each other to allow maintenance without subsequent exposure from nearby components. Radioactive equipment with valves is provided in a valve gallery containing the valves and remote valve operators in an intermediate radiation area. Separation of system piping is also stressed to eliminate exposure in these galleries. Air regulators and other instrumentation associated with valve and system operation are located outside of the valve gallery, inside of the labyrinth entrance in a lower zone.

Feed tank exposure is minimized by using stainless steel lined rooms. Mixer motors for these tanks are located above the shielded tank room.

Process particulate filters are the backflushable type to eliminate exposure with filter replacement and are remotely operated.

Process resin demineralizers are used for ion removal.

All equipment suspected of crud accumulation is flushed prior to maintenance. Periodic piping review insures minimum piping crud traps.

The Volume Reduction System layout utilizes several individually shielded cubicles to separate components containing the majority of the radioactive material from the mechanical components such as the pumps and blowers which contain small amounts of radioactive material and which are expected to require periodic maintenance. In addition, the components containing the majority of the radioactive material are all fitted with decontamination nozzles so that the radioactive salts can be flushed from the system and the components readily decontaminated prior to required maintenance.

11.6.7.2 Shielding

11.6.7.2.1 Source Terms

Radiation source terms for the Radwaste Facility are separated into three systems; the Liquid Waste and Recycle System (LW), the Resin Recovery System, and the Volume Reduction and Solidification System (VR). The liquid waste source terms are derived by OSC-1696, "Radwaste Facility LW Source Terms." The resin recovery source terms are derived by OSC-1823, "Oconee Radwaste Facility Contaminated Powdex Source Terms." The volume reduction and solidification source terms are derived by OSC-1824, "Oconee Radwaste Facility VR System Source Terms." These calculations either reference ANSI N237-1976/ANS-18.1, "Source Term Specification," or utilize computational code, N-237BURP, C-6.11-8, November 1977, Rev. 1 for the determination of source strengths.

11.6.7.2.2 Radiation Zone Designations

Radiation area and zone designations used at the Radwaste Facility for protection of operating personnel and the general public are described in UFSAR Chapter 12. Radiation zone designations used to evaluate the maximum integrated doses for electrical equipment qualification are listed in the Environmental Qualification Criteria Manual (EQCM).

During the design and construction of the low-level radioactive waste incinerator, radiation zones were established for the Radwaste Facility, per Regulatory Guide 8.8, to reflect the design maximum dose rate expected to exist during incinerator operation. Since the incinerator has never operated and is now abandoned, the design basis radiation zones established for operation of the incinerator (updated in 1993 to reflect the revision of 10 CFR 20) are listed below for historical information. The dose rates and work areas of the facility as it is currently used is monitored by Radiation Protection personnel to assure that the intent of the zones to maintain ALARA dose to workers is achieved.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Zone I: Designation for areas adjacent to the station site where Duke Power Company does not normally exercise authority to control access. In accordance with applicable regulations (10CFR 20.1301(a)(1)), the dose rate in these areas does not exceed 0.1 rem/yr.

Zone II: Areas within the station site where the station staff is expected to work continuously. For conservatism, the limiting dose rate is selected as 0.5 mrem/hr. This is comparable to the criteria given in 10CFR 20.1302.

Zone III: Areas within the station where staff occupancy is expected to be periodic rather than continuous. An employee could, however, remain in these areas and not exceed 5.0 mrem/hr.

Zone IV: Includes infrequently occupied work locations where the dose rate exceeds continuous occupational levels but access need not be physically restricted. The limit dose rate for this zone is designated as 50 mrem/hr. The precautions given in 10CFR 20.1601, 1602, and

1901 through 1905 for Radiation Areas are employed where local dose rate levels in Zone IV warrant.

Zone V: Encompasses all areas of the station where the dose rate exceeds that of Zone IV. Access to these areas is physically restricted, and Radiation Protection surveillance is required for occupancy, if any. The precautions given in 10CFR 20.1601, 1602, and 1901 through 1905 for High Radiation Areas are employed where local dose rate levels in Zone V warrant.

11.6.7.2.3 Shield Wall Thickness

The KAP VI computer code is used to determine the shield wall thickness for each component. KAP VI utilizes the point kernel technique to calculate radiation levels at detector points located within or outside a complex radiation source geometry.

11.6.8 References

1. H. B. Tucker (Duke) letter to H. R. Denton (NRC) dated June 10, 1985.
2. J. F. Stolz (NRC) letter to H. B. Tucker (Duke) dated October 30, 1986.

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11.7 Conventional Wastewater Treatment Systems

11.7.1 Design Bases

The Oconee Nuclear Station uses chemical processes to treat water for use in both the Reactor Systems and Steam and Power Conversion Systems. Many of these chemical processes are governed by regulatory criteria. For example, the National Pollutant Discharge Elimination System (NPDES) establishes criteria for chemical concentrations released from the station. The bases for the Conventional Wastewater Treatment Systems are to provide a means to treat wastewater prior to release so that it can meet regulatory criteria.

11.7.2 System Description

The Conventional Wastewater Treatment System as seen in Figure 11-4 consists of three treatment ponds: CTP#1, CTP#2, and CTP#3. CTP#1 and CTP#2 are parallel ponds with either in service as conditions warrant to provide treatment. Pumps are provided for recirculation and as a means for controlled discharge from CTP#1 or CTP#2 to CTP#3. The Conventional Wastewater Treatment System receives input from various drains and sumps throughout the plant. These ponds are controlled and monitored using approved plant operating procedures.

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11.8 Radiological Ground Water Protection Program

By 2006, industry experience had confirmed that spills, leaks and equipment failures at several commercial U.S. nuclear sites had led to inadvertent ground water contamination. Details of these experiences were documented by the Nuclear Regulatory Commission in NRC information Notice (IN) 2006-13: "Ground-water Contamination Due To Undetected Leakage of Radioactive Water" (July 10, 2006). Lessons learned from these experiences were captured through the development of a series of industry guidelines. Using the Nuclear Energy Institute (NEI): "Groundwater Protection Final Guidance Document", NEI 07-07 (August 2007), Duke Energy has established a radiological ground water protection program at Oconee Nuclear Station

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Appendix 11A. Tables

Table 11-1. Potential Radioactive Waste Quantities from Three Units

Waste Source	Quantity/Year[1] ($ft.^3$)	Assumptions & Comments
Reactor Coolant System		
Startup Expansion	39,800	Four cold startups per unit
Startup Dilution	49,000	One startup from cold condition at beginning of cycle, 77.5, 155 and 232.5 full power days, respectively, per unit
Lifetime Shim Bleed	43,800	Dilution 1070 to 180 ppm boron in each unit
System Drain	18,300	Drain of each unit to level of outlet nozzles during refueling
Liquid Waste		
Primary System	161,019	3300 gal/day Rate of Input
Spent Fuel Pool	26,349	540 gal/day Rate of Input
Cask Decontamination	17,566	360 gal/day Rate of Input
Component Coolant	17,566	360 gal/day Rate of Input
Service Water	58,553	1200 gal/day Rate of Input
Decontamination Room	87,828	1800 gal/day Rate of Input
Resin Sluice	23,421	480 gal/day Rate of Input
Miscellaneous System Leakage	351,312	5 gal/min Rate of Input
OTSG Tube Leaks	40,140	1 Tube Leak/Unit/yr => 1 Vol Drain + 3 Flush Vols of Secondary Side
LHST	161,019	3300 gal/day Rate of Input
Gaseous Waste		
Waste Gas	131,400	
Solid Waste		
Spent Bead Resins	2,000	
Spent Powdex Resin	5,000	.

Note:

1. Quantities based on data gathered at ONS for years 1977 and 1978, and values found in "Evaluation of compliance with 1OCFR50 Appendix I", June 4, 1976. Actual amounts vary from year to year depending on unit operating history. The actual liquid waste generated is reported in the Oconee Annual Effluent Report. The actual gaseous waste activity that is released is reported in the Oconee Annual Effluent Release Report.

Table 11-2. Estimated Maximum Rate of Accumulation Radioactive Wastes Per Operation

Waste Source	Maximum Rate of Accumulation	Assumptions and Comments
Reactor Coolant System(1)		
Startup Expansion & Dilution	9900 ft^3/22 hrs	Cold startup immediately prior to placing deborating demineralizers into service
Lifetime Shim Bleed(2)	1200 ft^3/10 days	Last 10 days of processing bleed prior to placing deborating demineralizers into service
System Drain	6100 ft^3/refueling	
Liquid Waste		
Demineralizers Sluice	100 ft^3/resin change	One change of purification demineralizer resin
Deborating Demineralizer Regeneration and Rinse	65 ft^3/resin change	One change of deborating demineralizer resin
Gaseous Waste		
Off-Gas from Reactor Coolant System(2)	400 ft^3/22 hrs	Cold startup immediately prior to placing deborating demineralizers into service
Letdown Storage Tank	900 ft^3/purge	
Pressurizer	60 ft^3/purge	
Solid Waste		
Demineralizer Resin	50 ft^3/resin change	One change of purification demineralizer resin

Note:

1. Treated as waste for purpose of evaluation
2. Wastes processed through holdup tanks
3. This table includes estimated values and is not updated (Reference OSC-256). Total effluent quantities are reported in the Annual Radioactive Effluent Release Report in accordance with SLC 16.11.9, "Radiological Effluents Control".

Table 11-3. Yearly Average Activity Concentrations in the Station Effluent for Three Units, Each Operating with One Percent Defective Fuel

Liquid Waste	
Operation	Yearly Average Concentration in Tailrace Discharge Fraction of MPC
Lifetime Shim Bleed Including Startup Expansion and Dilution	0.077
Discharge of Miscellaneous Wastes	0.16
Gaseous Wastes	
Operation	Yearly Average Concentration at Site Boundary, Fraction of MPC
Lifetime Shim Bleed	0.058
Startup Expansion and Dilution	0.18
Venting of Letdown Storage Tank	0.015
Venting of Pressurizer	0.011
Reactor Building Purge	0.11
Steam Generator Tube Leakage of 1 gal/min in one unit	0.089

Note:

1. This table includes estimated values and is not updated (Reference OSC-256). Total effluent quantities are reported in the Annual Radioactive Effluent Release Report in accordance with SLC 16.11.9, "Radiological Effluents Control".

Table 11-4. Escape Rate Coefficients for Fission Product Release

Element	Escape Rate Coefficient, sec^{-1}
Xe	1.0×10^{-7}
Kr	1.0×10^{-7}
I	2.0×10^{-8}
Br	2.0×10^{-8}
Cs	2.0×10^{-8}
Rb	2.0×10^{-8}
Mo	4.0×10^{-9}
Te	4.0×10^{-9}
Sr	2.0×10^{-10}
Ba	2.0×10^{-10}
Zr	1.0×10^{-11}
Ce, and other rare earths	1.0×10^{-11}

Note:

1. This table is included for historical purposes only (Reference OSC-256).

Table 11-5. Reactor Coolant Activity

(Calculated)					
µCi/ml at Operating Conditions					
Time, Full Power Days Isotope	100	150	200	260	310
Kr 85 m	1.5	1.5	1.5	1.5	1.5
Kr 85	8.7	9.7	9.1	6.3	1.3
Kr 87	.85	.85	.85	.85	.84
Kr 88	2.7	2.7	2.7	2.7	2.7
Rb 88	2.7	2.7	2.7	2.7	2.7
Sr 89	.041	.041	.041	.041	.038
Sr 90	.0027	.0028	.0030	.0032	.0031
Sr 91	.046	.046	.046	.046	.045
Sr 92	.017	.017	.017	.017	.017
Xe 131m	2.3	2.2	2.2	2.1	1.2
Xe 133m	2.8	2.8	2.8	2.8	2.3
Xe 133	248	246	242	234	166
Xe 135m	.94	.94	.94	.94	.93
Xe 135	6.6	6.6	6.6	6.6	6.3
Xe 138	.51	.51	.51	.51	.51
I 131	3.2	3.2	3.2	3.2	3.0
I 132	4.8	4.8	4.7	4.6	3.8
I 133	3.8	3.8	3.8	3.8	3.7
I 134	.50	.50	.50	.50	.50
I 135	1.9	1.9	1.9	1.9	1.9
Cs 136	.045	.045	.045	.045	.042
Cs 137	.29	.29	.29	.28	.26
Cs 138	.72	.72	.72	.72	.72
Mo 99	5.4	5.4	5.3	5.2	4.2
Ba 139	.082	.082	.082	.082	.082
Ba 140	.072	.072	.072	.072	.067
La 140	.025	.025	.025	.025	.022
Y 90	.24	.37	.51	.69	.84
Y 91	.18	.20	.20	.17	.076

Ca 144	.0028	.0029	.0029	.0030	.0028
Bleed Rate in Reactor Coolant volume/sec	6.7×10^{-8}	5.7×10^{-8}	7.8×10^{-8}	1.3×10^{-7}	5.1×10^{-7}

(Experimental)

Nuclide	**Concentration (μCi/cc)**[1]
H 3	2.1
F 18	7.8 (-2)[(3)]
Na 24	2.0 (-2)
Ar 41	8.9 (-2)
Mn 54	4.1 (-3)
Mn 56	1.9 (-2)
Co 58	7.8 (-3)
Kr 85m	1.6 (-2)
Kr 87	1.4 (-2)
Kr 88	2.2 (-2)
Sr 89	3.6 (-5)
Sr 90	7.3 (-5)
I 131	1.2 (-2)
I 132	7.5 (-2)
I 133	3.7 (-2)
I 134	1.4 (-1)
I 135	7.5 (-2)
Xe 131m	2.1 (-2)
Xe 133	3.1 (-1)
Xe 133m	4.1 (-3)
Xe 135	9.4 (-2)
Cs 134	2.0 (-3)
Cs 137	2.1 (-3)
Ba 139	1.5 (-2)

Note:

1. Concentrations obtained from reactor coolant sample of Unit 1 October 9, 1975
2. This table is included for historical purposes only (Reference OSC-256)
3. Denotes power of 10

Table 11-6. Waste Disposal System Component Data (Component Quantities for Three Units)

Low Activity Waste Tank	
Quantity	2
Volume each, cu. ft	398
Material	Concrete with Stainless Steel Liner
High Activity Waste Tank	
Quantity	2
Volume each, cu. ft.	262
Material	Concrete with Stainless Steel Liner
Misc. Waste Holdup Tank	
Quantity	2
Volume each, cu. ft	2,700 for Units 1 and 2 shared 1,550 for Unit 3
Material	Carbon Steel with Stainless Clad
Design Pressure	Vessel Full Plus 10 ft. Hydro Head
Spent Resin Storage Tank	
Quantity	2
Volume each, cu. ft.	450 for Units 1 and 2 shared 380 for Unit 3
Material	Stainless Steel
High Activity Spent Resin Storage Tank	
Quantity	1 for Unit 3
Volume, cu. ft.	380
Material	Stainless Steel
Reactor Building Normal Sump	
Quantity	3
Volume each, cu. ft.	48 (excluding embedded piping)
Material	Concrete
Reactor Building Emergency Sump	
Quantity	3
Volume each, cu. ft.	540
Material	Concrete
GWD Tank	
Quantity	4

Volume each, cu. ft.	1,098
Material	Carbon Steel
Design Pressure, psig	100
Misc. Waste Evaporator Feed Tank[3]	
Quantity	1
Volume, cu. Ft.	400
Material	Stainless Steel
Design Pressure	Vessel Full Plus 10 ft. Hydro Head
Waste Evaporator[3]	
Quantity	1
Process Rates, lb/hr	5,060
Material	Stainless Steel
Design Pressure, psig	15
Low Activity Waste Tank Pump	
Quantity	4
Capacity each, gal/min	100
Diff. Head, ft.	200
High Activity Waste Tank Transfer Pump	
Quantity	4
Capacity each, gal/min	50
Diff. Head, ft.	200
Misc. Waste Transfer Pump	
Quantity	4
Capacity each, gal/min	50
Diff. Head, ft.	200
"HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED"	
Spent Resin Sluicing Pump	
Quantity	*2*
Capacity each, gal/min	*50*
Diff. Head, ft.	*50*
Spent Resin Transfer Pump	
Quantity	*2*
Capacity each, gal/min	*10*
Diff. Head, ft.	*100*

Reactor Building Normal Sump Pump	
Quantity	6
Capacity each, gal/min	25
Diff. Head, ft.	25
Waste Evaporator Feed Pump(3)	
Quantity	1
Capacity, gal/min	7-1/2
Diff. Head, ft.	60
Waste Evaporator Recirculating Pump(3)	
Quantity	1
Capacity, gal/min	160
Diff. Head, ft.	53
Waste Evaporator Distillate Pump(3)	
Quantity	1
Capacity, gal/min	9-1/2
Diff. Head, ft(4)	62
GWD Filter	
Quantity	2
Rating, scfm	200
Type	Prefilter, Absolute and Charcoal
Material	11 Gauge Galvanized Steel
GWD Exhauster	
Quantity	2
Rating, scfm	200 at 6 in. Water Gauge External Static Pressure
Type	Backward Curved - Centrifugal
GWD Compressor	
Quantity	4
Capacity each, cfm	48 at 85 psig
Type	Centrifugal Displacement
Interim Evaporator Feed Tanks(3)	
Quantity	2
Volume, gal	17,000
Design Pressure	Static head plus 5 psig

Design Temperature, °F	200
Material	304 stainless steel
Interim Evaporator Condensate Monitor Tanks(3)	
Quantity	2
Volume, gal	9,000
Design Pressure	Static head plus 5 psig
Design Temperature, °F	200
Material	304 stainless steel
Interim Evaporator Concentrates Storage Tank(3)	
Quantity	1
Volume, gal	3,000
Design Pressure	Static head plus 5 psig
Design Temperature, °F	200
Material	304 stainless steel
Interim Evaporator Condensate Return Tank(3)	
Quantity	1
Receiver volume, gal	100
Design Pressure	Atmospheric
Design Temperature, °F	212
No. of Pumps	2
Design Flow, gal/min	25
Design Head, ft	65
Interim Evaporator Feed Filter(3)	
Quantity	1
Type	Cage Assembly (disposable synthetic cartridged)
Design Pressure, psig	200
Design Temperature, °F	250
Design Flow Rate, gal/min	35
Pressure Drop at Design Flow, psi	Clean – 5 Fouled - 20
Retention of 25 Microns particles	98%
Material	Stainless Steel
Interim Evaporator Condensate Filter(3)	

Quantity	1
Type	Cage Assembly (disposable synthetic cartridge)
Design Pressure, psig	300
Design Temperature, °F	250
Design Flow Rate, gal/min	150
Pressure Drop at Design Flow, psi	Clean - 5 Fouled - 20
Retention of 25 Micron Particles	98%
Material	Stainless Steel
Interim Evaporator Condensate Demineralizer(3)	
Quantity	1
Type	Non-regenerable
Design Temperature, °F	200
Design Pressure, psig	150
Vessel Volume, ft^3	55
Resin Volume, ft^3	50
Design Flow, gal/min	310
Material	Stainless Steel
Resin Type	Mixed bed
Interim Evaporator Feed Pump(3)	
Quantity	1
Type	Canned centrifugal
Design Flow, gal/min	35
Design Head, ft	250
Design Pressure, psig	150
Design Temperature, °F	200
Operating Temperature, °F	120
Material	Stainless Steel
Interim Condensate Monitor Tank Pumps(3)	
Quantity	2
Type	Canned centrifugal
Design Flow, gal/min	100
Design Head, ft	250
Design Pressure, psig	150

Design Temperature, °F	200
Operating Temperature, °F	120
Material	Stainless Steel
Interim Evaporator Concentrates Transfer Pump(3)	
Quantity	1
Type	Canned centrifugal
Design Flow, gal/min	35
Design Head, ft	250
Design Pressure, psig	150
Design Temperature, °F	200
Operating Temperature, °F	170
Material	Stainless Steel
Low Activity Equipment Drains Sump Pumps	
Quantity	2
Type	Vertical
Design Flow, gal/min	50
Design Head, ft	100
Material	Stainless Steel
High Activity Equipment Drains Sump Pumps	
Quantity	2
Type	Vertical
Design Flow, gal/min	50
Design Head, ft	100
Material	Stainless Steel
Interim Evaporator Distillate Pump(3)	
Quantity	1
Type	Canned Centrifugal
Design Flow, gal/min	15.6
Design Head, ft	208
Design Pressure, psig	150
Design Temperature, °F	220
Operating Temperature, °F	80-110
Material	Stainless Steel

Interim Waste Evaporator Package (Westinghouse)	
Quantity	1
Nominal Capacity, gal/min	15
Steam Supply Pressure, psig	50
Steam Flow, lb/hr	10,500
Cooling Water Flow, gal/min	780
Concentrates Batch Volume, gal	500
Max. Boron Concentration, ppm	21,000
Liquid DF(1)	10^6
Gaseous DF(2)	10^5
Interim GWD Tanks	
Quantity	3
Volume, ft^3	1070
Design Pressure, psig	100
Design Temperature, °F	Material
200	Carbon steel

Notes:

1. DF for liquid = $\dfrac{\text{activity in concentrates}}{\text{activity in distillate}}$
2. DF for gas = $\dfrac{\text{activity in feed}}{\text{activity in distillate}}$
3. Component is in a layup condition.
4. Waste Evaporator Distillate Pump data included for historical purposes only.

Table 11-7. Process Radiation Monitors

Channel Number and Function	Type Detector	MDC (Background Equivalent Concentration) and Sensitivity	Range (Monitor Readout)
RIA-31 Monitors LPSW (Multipoint)	NaI 1-½"D x 1"L 4" Pb shield	2.5 mR/hr = 1.6 x 10^{-7} µCi/ml 1.28 x 10^{8} cpm/µCi/ml	(10-10^{7} cpm)
RIA-32 3RIA-32 Aux. Bldg. Gas Monitor	Plastic beta Scint. 2.125"D x .01"T 3" Pb shield	2.5 mR/hr = 3.6 x 10^{-7} µCi/ml 2.94 x 10^{7} cpm/µCi/ml	(10-10^{7} cpm)
RIA-33 Waste Disposal (Normal)	NaI 1½"D x 1"L 4" Pb Shield	2.5 mR/hr = 6.2 x 10^{-8} µCi/ml 1.28 x 10^{8} cpm/µCi/ml	(10-10^{7} cpm)
1RIA-35 2RIA-35 3RIA-35 Total LPSW Discharge Header from Aux. Bldg.	NaI 1-½"D x 1"L 5" Pb Shield	2.5 mR/hr = 6.2 x 10^{-8} µCi/ml 1.28 x 10^{8} cpm/µCi/ml	(10-10^{7} cpm)
RIA-37 3RIA-37 Waste Disposal Gas (Normal)	Plastic beta scint. 2"D x 0.007"T 4" Pb shield	2.5 mR/hr = 1.34 x 10^{-2} µCi/ml 2.38 x 10^{7} cpm/µCi/ml	(10-10^{7} cpm)
RIA-38 3RIA-38 Waste Disposal Gas (High)	G.M. 4"Pb shield	2.5 mR/hr = 1.34 x 10^{-2} µCi/ml 7.47 x 10^{2} cpm/µCi/ml	(10-10^{6} cpm)
RIA-39 3RIA-39 Control Room Gas	Plastic beta scint. 2.125"D x .01"T 3" Pb shield	2.5 mR/hr = 3.6E-7 µCi/m 2.94 x 10^{7} cpm/µCi/ml	(10-10^{7} cpm)
1RIA-40 2RIA-40 3RIA-40 Condenser Air Ejector off gas	Plastic beta scint. 2.125"D x .01"T 3" Pb shield	2.5mR/hr = 3.6E-7 µCi/ml 2.94 x 10^{7} cpm/µCi/ml	(10-10^{7} cpm)

Channel Number and Function	Type Detector	MDC (Background Equivalent Concentration) and Sensitivity	Range (Monitor Readout)
RIA-41 3RIA-41 Spent Fuel Bldg. Gas	Plastic beta scint. 2.125"D x .01"T 3" Pb shield	2.5 mR/hr = 3.6E-7 µCi/ml 2.94 x 10^7 cpm/µCi/ml	(10-10^7 cpm)
RIA-42 3RIA-42 Recirculating Cooling Water	NaI 1-½"D x 1"L 4" Pb lead	2.5 mR/hr = 1.6 x10^7µCi/ml 1.28 x 10^8 cpm/µCi/ml	(10-10^7 cpm)
1RIA-43 2RIA-43 3RIA-43 Unit Vent Particulates	Plastic beta scint. 1-1/8" x 5/8" x .01"T 2.5" Pb shield	2.5 mR/hr = 7.0 x 10^{-12} µCi/ml (2 SCFM Flow) 3.31 x 10^{10} cpm/µCi/ml	(10-10^7 cpm)
1RIA-44 2RIA-44 3RIA-44 Unit Vent Iodine	NaI 2"D x 2"L 3" Pb shield	2.5 mR/hr = 3.1 x 10^{-11} µCi/ml (2 SCFM Flow) 2.72 x 10^9 cpm/µCi/ml	(10-1E7 cpm)
1RIA-45 2RIA-45 3RIA-45 Unit Vent Gas (Normal)	Plastic beta scint. 2"D x .01"T 3" Pb shield	2.5 mR/hr = 5.5 x 10^{-7} µCi/ml 1.41 x 10^7 cpm/µCi/ml	(10-1E7 cpm)
4RIA-45 Radwaste Facility Vent (Normal)	Plastic beta scint. 2"D x .01"T 5" Pb shield	5 mR/hr = 5.5 x 10^{-7} µCi/ml	$\simeq$ 2E - 7 to 2E - 1 µCi/ml Xe-133 (readout in µCi/ml)
1RIA-46 2RIA-46 3RIA-46 Unit Vent Gas (High)	Cadmium Telluride (CdTe) 2mm x 5mm x 2mm T 2" Pb shield	3.5 mR/hr = 1.1E-3 µCi/ml 3.15 x 10^3 cpm/µCi/ml	(10-1E7 cpm)
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Channel Number and Function	Type Detector	MDC (Background Equivalent Concentration) and Sensitivity	Range (Monitor Readout)
1RIA-47 2RIA-47 3RIA-47 Reactor Building Particulate	Plastic beta scint. 1 1/8" x 5/8" x .01"T 2.5" Pb shield	2.5 mR/hr=7.0 x 10^{-12} µCi/ml (3 SCFM Flow) 3.31 x 10^{10} cpm/µCi/ml	(10-1E7 cpm)
1RIA-48 2RIA-48 3RIA-48 Reactor Building Iodine	NaI 2"D x 2"L 3" Pb shield	2.5 mR/hr=3.1 x 10^{-11} µCi/ml (3 SCFM Flow) 2.72 x 10^{9} cpm/µCi/ml	(10-1E7 cpm)
1RIA-49 2RIA-49 3RIA-49 Reactor Building Gas	Plastic Beta Scint. 2"D x .01"T 3" Pb shield	2.5 mR/hr=5.5 x 10^{-7} µCi/ml 1.41 x 10^{7} cpm/µCi/ml	(10-1E7 cpm)
1RIA-49A 2RIA-49A 3RIA-49A Reactor Building Gas (High)	Cadmium Telluride (CdTe) 2mm x 5mm x 2mm T 2" Pb shield	3.5 mR/hr=1.1E-3 µCi/ml 3.15 x 10^{3} cpm/µCi/ml	(10-1E7 cpm)
1RIA-50 2RIA-50 3RIA-50 Component Cooling Water	NaI 1-½"D x 1"L 4" Pb shield	2.5 mR/hr = 1.6 x 10^{-7}µCi/ml 1.28 x 10^{8} cpm/µCi/ml	(10-10^{7} cpm)
RIA-53 Interim Radwaste Bldg. Vent Gas	Plastic Beta Scint. 2.125"D x 0.01"T 3" Pb shield	2.5 mR/hr = 3.6 x 10^{-7} µCi/ml 2.94 x 10^{7} cpm/µCi/ml	(10-10^{7} cpm)
RIA-54 Turbine Bldg. Sump 3RIA-54 Turbine Bldg. Sump	NaI Scint. 1-1½"D x 1"L 4" Pb shield	2.5 mR/hr=1.6 x 10^{-7} µCi/ml 1.28 x 10^{8} cpm/µCi/ml	10-10^{7} cpm

Channel Number and Function	Type Detector	MDC (Background Equivalent Concentration) and Sensitivity	Range (Monitor Readout)
1RIA-16 1RIA-17 2RIA-16 2RIA-17 3RIA-16 3RIA-17 Steam Header Gross Activity	G. M. Detector (Low Range)/ 3.2"D x 6.6"L Ion Chamber (High Range) 2.5"D x 9.2"L 3" Pb shield	500 cpm/mR/hr 1.2 E-10 Amp/R/hr	$0.01\text{-}10^{3}$ mR/hr $10^{2}\text{-}10^{7}$ mR/hr
1RIA-56 2RIA-56 3RIA-56 Unit Vent Gas(High High)	Ion Chamber unshielded	1×10^{-11} amp/R/hr	$1\text{-}10^{8}$ R/hr $1\text{-}10^{8}$ R/hr
1RIA-57 2RIA-57 3RIA-57 1RIA-58 2RIA-58 3RIA-58 Reactor Building Gas(High High)	Coaxial Ion Chamber unshielded	1×10^{-11} amp/R/hr	$1\text{-}10^{8}$ R/hr(1)
1RIA-59 1RIA-60 2RIA-59 2RIA-60 3RIA-59 3RIA-60 Steam Header N-16	NAI(Tl) Scintillation unshielded	Not applicable to N-16 Monitors	Configurable 0-1000 gallons/day

Note:

1. RIAs 57/58 are on-scale at approximately 1R/hr.

Appendix 11B. Figures

Figure 11-1. 3" Liquid Waste Discharge

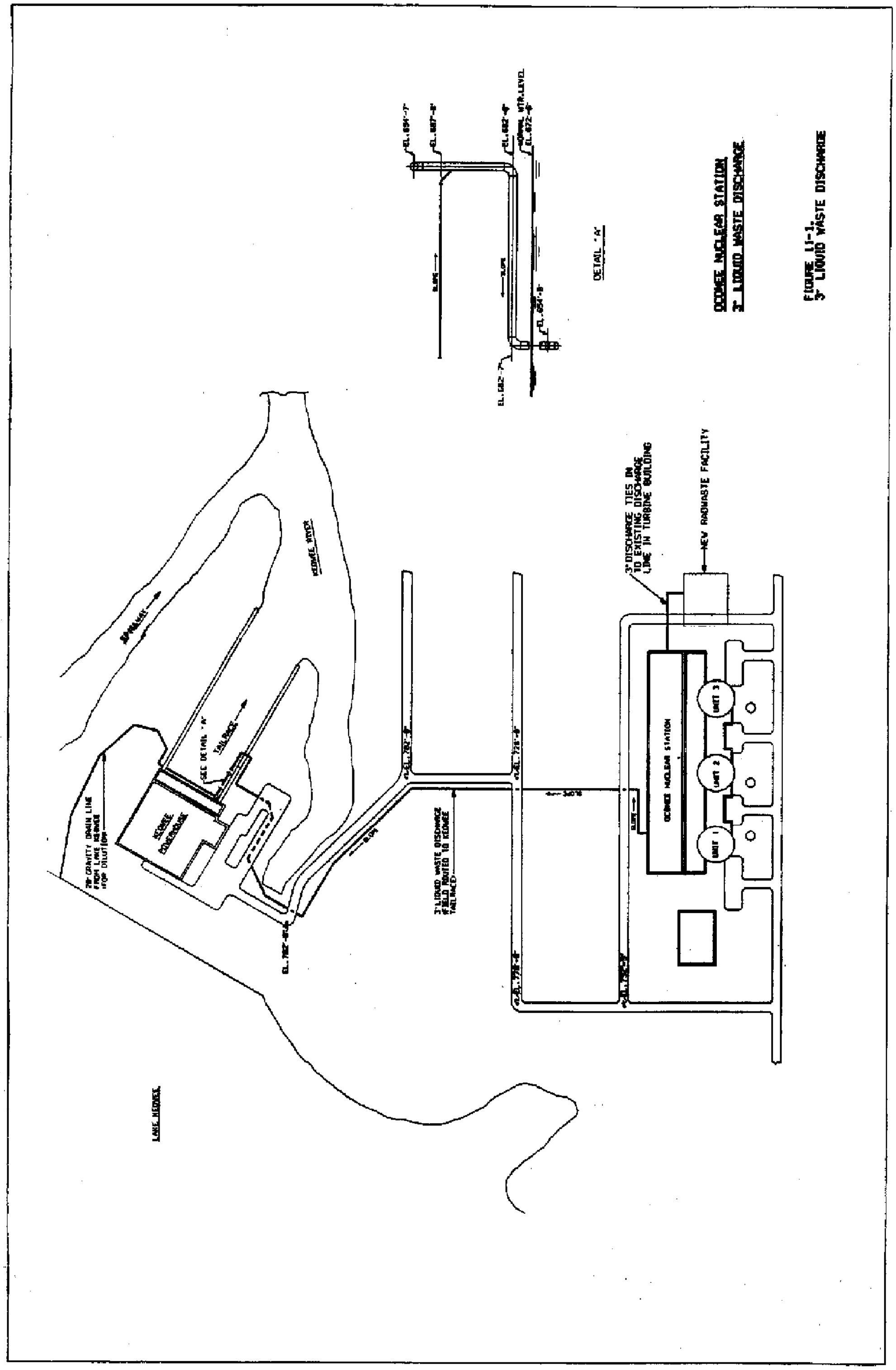

Figure 11-2. Liquid Waste Disposal System

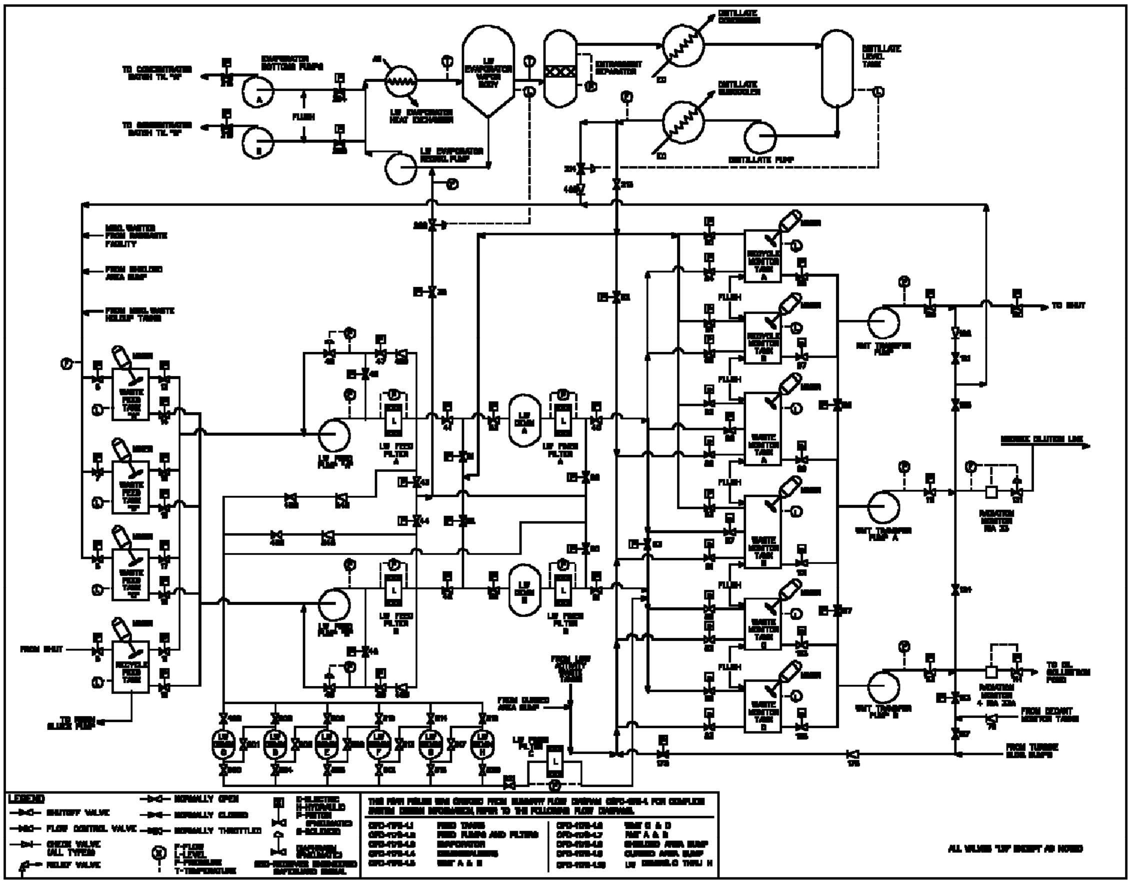

Figure 11-3. Gaseous Waste Disposal System

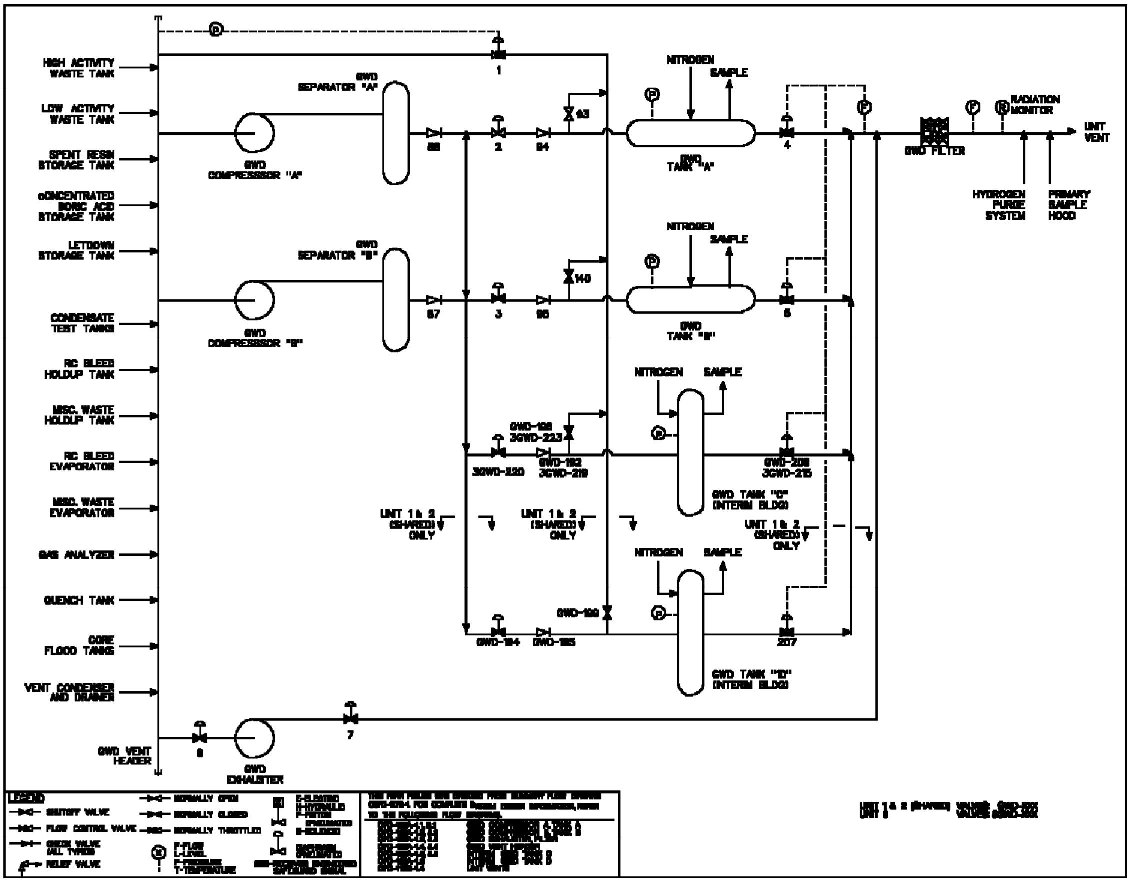

Figure 11-4. Waste Water Collection Basin

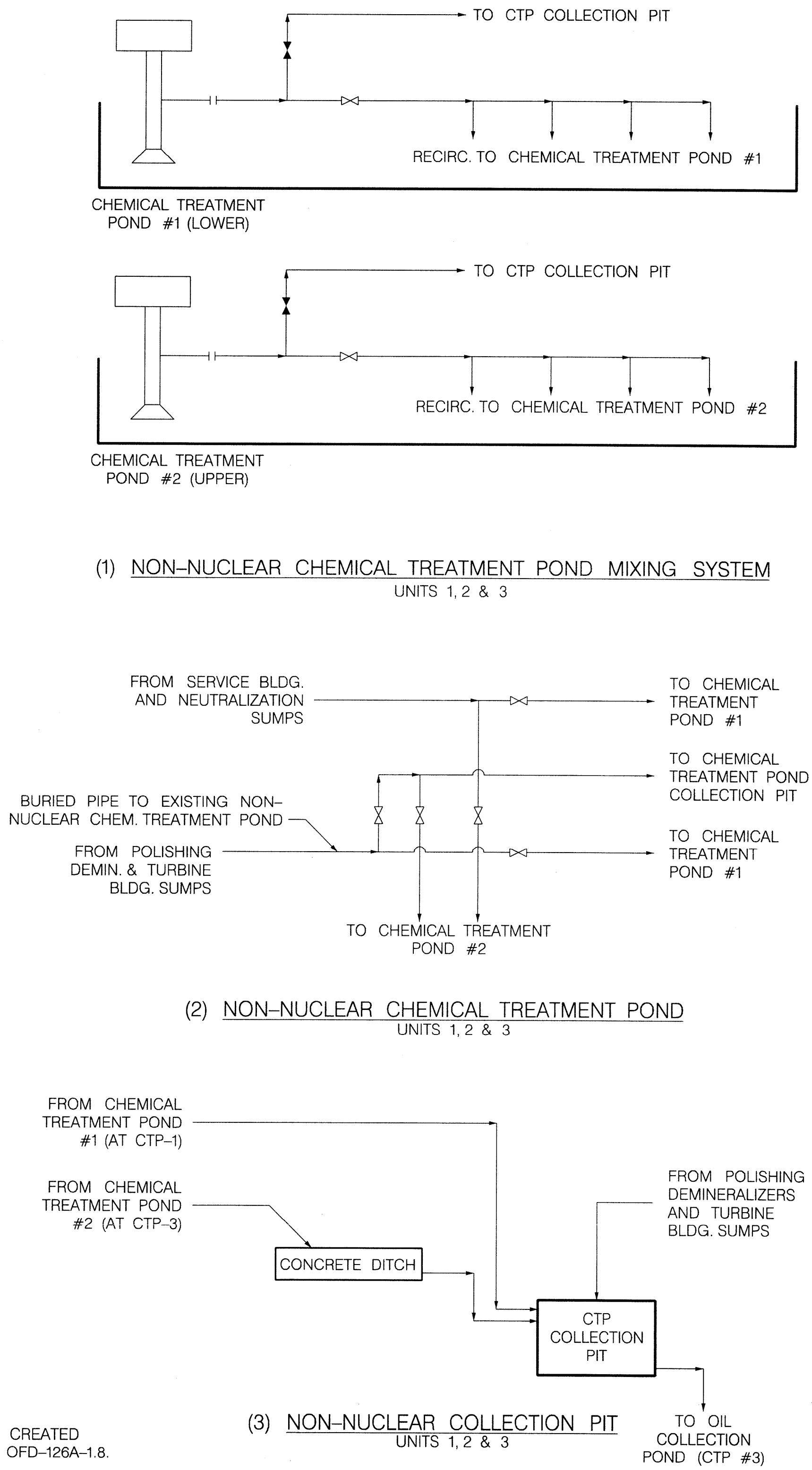

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Figure 11-5. Deleted Per 1999 Update

Figure 11-6. Deleted Per 1997 Update

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List of Tables

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12.0 Radiation Protection

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12.1 Ensuring That Occupational Radiation Exposures Are As Low As Is Reasonably Achievable (ALARA)

12.1.1 Policy Considerations

Duke Energy Carolinas, LLC management is firmly committed to the “As Low As Reasonably Achievable” (ALARA) philosophy for all nuclear operations. This commitment is stated in the Duke Energy Fleet ALARA Manual. A formal ALARA program has been established in order to convey and enforce Duke management's commitment to ALARA. This program was established in conformance with the requirements of Regulatory Guide 8.8, 8.10 and 10CFR20 to ensure that occupational exposures are maintained ALARA. In accordance with the requirements of 10CFR20, procedures and engineering controls will be used, to the extent practicable, to ensure that occupational doses and doses to members of the public are ALARA. This program consists of the following:

1. a published DPC ALARA Manual;
2. continued surveillance and evaluation of in-plant radiation and contamination conditions, as well as the monitoring and control of the exposure of personnel, by the station and General Office Radiation Protection staff; and
3. an ALARA Committee consisting of site management and representatives from applicable groups, whose purpose is to refine the site ALARA program.

The committee members have extensive background in nuclear plant radiation and exposure control, including such areas as layout, shielding, personnel access, ventilation, waste management, monitoring systems, operations, and maintenance.

Although upper level management is vested with the primary responsibility and authority for administering the Duke ALARA program, the responsibility for ALARA is extended through lower management to the individual employee. The specific responsibilities of the General Office and Station Radiation Protection staffs are to ensure that:

1. An effective ALARA program is established at each Duke nuclear station that appropriately integrates Duke management philosophy and NRC regulatory requirements and guidance;
2. A periodic written review of the on-site radiation control program is performed to assure that objectives of the ALARA program are attained;
3. Pertinent information concerning radiation exposure of personnel from other utilities and research work are reflected in the design and operation of Duke stations;
4. Appropriate radiological experience gained during the operation of nuclear power stations is factored into revisions of procedures to assure that the procedures continually meet the objectives of the ALARA program;
5. Necessary assistance is provided to ensure that operations, maintenance, and decommissioning activities are planned and accomplished in accordance with ALARA objectives; and
6. Trends in station personnel and job exposures are analyzed in order to permit corrective actions to be taken with respect to adverse trends.

Reports of the findings of the General Office and Station Radiation Protection staffs are also effectively conveyed to management.

Specific responsibilities of station personnel are to ensure:

1. Activities are planned and accomplished in accordance with the objectives of the ALARA program;
2. Procedures and their revisions are implemented in accordance with the objectives of the ALARA program; and
3. The General Office Radiation Protection staff and the Site Engineering staff are consulted as necessary for assistance in meeting ALARA program objectives.

Other group and individual responsibilities to the ALARA program are outlined in Section III of the DPC ALARA Manual.

12.1.2 Design Considerations

ALARA is a major design consideration which is carried out in accordance with section C.1 of Regulatory Guide 8.8. Consideration was given to such factors as projected component dose rates, space, mobility, accessibility, etc., during the initial design and construction phases of Oconee Nuclear Station. There is a large degree of component separation between high and low radiation levels. Several components are provided with flushing capability where the potential of exposure from CRUD exists. Engineering evaluations supplement a formal operational feedback program which is used to identify specific and/or generic problems and implement design improvements.

ALARA exposures receive further attention through the training of designers and in equipment selection. Section IX of the System ALARA Manual provides guidance to ensure that personnel who initiate and plan modifications are cognizant of dose reduction considerations by formal training.

This guidance provides designers with a working knowledge of radiation protection. Remedial or refresher training is also provided based upon experience and regulatory guidance, including any new technology or refinements.

12.1.3 ALARA Operational considerations

Consistent with Duke Power Company's overall commitment to keep occupational radiation exposures as low as is reasonably achievable (ALARA), specific plans and procedures are followed by station personnel to assure that ALARA goals are achieved. Operational ALARA policy statements are formulated at the corporate staff level in the Nuclear Generation Department through the issuance of the Radiation Protection Policy Manual, ALARA Manual and procedures. These statements and procedures are consistent with the intent of Section C.1 of Regulatory Guides 8.8, 8.10 and 10CFR20.

Personnel and job exposure trends are reviewed by site management and the general office, and appropriate action is taken. Summary reports of occupational exposure are provided that describe problem areas and jobs where high radiation doses are encountered. The reports identify which work group is accumulating the highest doses. Recommendations are then made for changes in operating, maintenance, and inspection procedures or for modifications to the station as appropriate to reduce doses.

Maintenance activities that could involve significant radiation exposure of personnel are carefully planned. They utilize any previous operating experience and are carried out using well trained personnel and proper equipment. Radiation Work Permits (RWP's) for non-routine operations, or Standing Radiation Work Permits (SRWP's) for routine operations are issued for each radiological job. (S)RWP's lists Radiation Protection requirements that shall be followed by all personnel working in the Radiation Control Area (RCA)/Radiation Control Zone (RCZ).

Where applicable, specific radiation exposure reduction techniques, such as those set out in Regulatory Guide 8.8, are evaluated and used. Applicable procedures for maintenance, inservice inspection, radwaste handling, and refueling, are well planned and developed by cognizant groups. These procedures are reviewed by the station radiation protection staff to ensure that exposures will be ALARA.

Careful personnel radiation and contamination monitoring are integral parts of such maintenance activities. During and upon completion of major maintenance jobs, personnel radiation exposures are evaluated and assessed relative to estimated exposures. From this appropriate changes can be made in techniques or procedures as soon as practicable for future jobs. The General Office Radiation Protection staff also conducts reviews of radiation exposure related activities to assure that procedures are adequate, that they are being followed properly, and that deficiencies are corrected as soon as practicable.

The station ALARA Committee carefully reviews operations and maintenance activities involving the major plant systems to further assure that occupational exposures are kept ALARA.

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12.2 Radiation Sources

System activity levels are based on the Reactor Coolant System design activity levels defined in Table 11-5. Operation of each unit at rated power is assumed. Other parameters employed in shielding analysis are listed in Table 12-1.

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12.3 Radiation Protection Design Features

12.3.1 Facility Design Features

The shielding is designed to perform two primary functions: (1) to ensure that, during normal operation, the radiation dose to operating personnel and to the general public is within the limits set forth in 10CFR 20 and is ALARA; and (2) to ensure that operating personnel are adequately protected in the event of a reactor accident so that the accident can be terminated without undue hazard to the general public.

Paragraph(s) Deleted Per 2000 Update

Piping and equipment components are shielded by concrete walls and floors of varying thickness, depending on the magnitude of the sources in each pipe section and component, and on the access requirements in a particular area. In some areas local shielding in the form of removable lead or concrete blocks are utilized to facilitate maintenance or repair operations.

12.3.2 Shielding

The material used for the primary, secondary, and Reactor Building shields is ordinary concrete with a density of approximately 140 lbs./ft^3. Since the primary and secondary shielding walls serve as the refueling structure, give support for the reactor coolant components under pipe rupture conditions, and provide missile shielding, they are reinforced and designed to be self-supporting. Descriptions of areas requiring shielding are presented below.

12.3.2.1 Reactor Building Shielding

12.3.2.1.1 Primary Shield

The primary shield consists of reinforced concrete which surrounds the reactor vessel and extends upward from the Reactor Building floor to form the walls of the fuel transfer canal. The shield thickness is 5 ft. up to the height of the reactor vessel flange, where the thickness is reduced to 4.5 ft. The primary shield is designed to meet the following objectives:

1. To attenuate the neutron flux in order to limit the activation of component and structural materials.
2. To limit the radiation level after shutdown so that access to the Reactor Coolant System equipment is permissible.
3. To reduce, in conjunction with the secondary shield, the radiation level from sources within the reactor vessel to allow limited access to the Reactor Building during normal full power operation.

12.3.2.1.2 Secondary Shield

The secondary shield is a 4 ft. thick reinforced concrete structure which surrounds the reactor coolant equipment, including the piping, pumps, and steam generators. The shielding is designed to reduce radiation levels from activity in the reactor coolant and to supplement the primary shield in the attenuation of neutrons and secondary gamma rays to permit limited access to the Reactor Building during full power operation.

12.3.2.1.3 Reactor Building Shield

The Reactor Building shield is a reinforced, prestressed concrete structure with 3.75 ft. thick cylindrical walls and a 3.25 ft. thick dome. In conjunction with the primary and secondary shields, it limits the radiation level outside the Reactor Building from all sources inside the Reactor Building to no more than 0.5 mrem/hr. at full power operation. The shielding is also designed to protect station personnel from radiation sources inside the Reactor Building following the Maximum Hypothetical Accident (gross release of fission products).

Other significant shielding inside the Reactor Building is listed in Table 12-2.

12.3.2.2 Auxiliary Building Shielding

The major radiation sources are piping and equipment components handling potentially contaminated fluid, practically all of which are located on the 758'-0", 771'-0", and 783'-9" levels. Groups of equipment or individual equipment items are separated by shielding walls such that systems and equipment can be isolated for maintenance with no significant radiation interference from other systems or equipment. During normal operation, there is no need to occupy these potentially radioactive equipment areas. Potential radiation sources and associated shielding are listed in Table 12-2. Additional shielding is also provided around the control room to ensure that exposure to operating personnel in the control room is within the design limits following a Design Basis Accident (DBA).

12.3.2.3 Post LOCA Shielding Review

A post LOCA Shielding review of the Oconee Nuclear Station was conducted pursuant to the requirements of NUREG-0578. Shielding review identified a potential for exceeding personnel exposures in GDC-19 for the control room due to its proximity to the mechanical penetration room. The low pressure recirculation piping routed through the mechanical penetration room could potentially contain highly radioactive water post LOCA. Permanently installed lead shielding was provided along the control room walls adjacent to the mechanical penetration rooms to ensure that the personnel exposures in the control rooms do not exceed the limits specified in GDC-19 (NSM-1393) for all units. Previously, caustic addition valves were relocated and provided with remote operators to assure operability and access. These valves are no longer required to be used due to the addition of Tri-Sodium Phosphate (TSP) Baskets. The Shielding review performed per NUREG-0737 II.B.2.2 verified that the required personnel access to all vital areas was feasible without exceeding the radiation exposure limits following a LOCA accident.

12.3.2.4 Original Steam Generator Retirement Facility

The Retirement Facility is a reinforced, cast-in-place concrete structure with 2-ft. thick walls and roof designed to hold the six retired Steam Generators, three retired Reactor Head assemblies and multiple strong-tight containers filled with original steam generator sub-components. The walls limit the radiation level at the perimeter of the Retirement Building to no more than 0.25 mrem/hr. The building is designed to protect station personnel from radiation sources possible at the location of the facility.

12.3.3 Area Radiation Monitoring System

12.3.3.1 Design Bases

The Area Radiation Monitoring System, consists of coaxial ion chambers, G-M detectors, and beta scintillation detectors. It is designed to indicate existing radiation levels and to alarm when levels exceed setpoints in various remote locations throughout the station where personnel are most likely to be exposed. Indications from the monitors are used in conjunction with station operating procedures to assure that radiation exposure of personnel does not exceed 10CFR 20 limits.

12.3.3.2 Description

Number, detector type, location, range, and nominal sensitivity are shown in Table 12-3.

Control room indication is provided for each monitor indicating R/hr, mrad/hr, or cpm. Indication for Oconee 1 and 2 monitors are located in Oconee 1 and 2 control room. Indication modules for Oconee 3 monitors are located in Oconee 3 control room.

Each detector assembly (except for the high range area detectors, and the beta scintillation detector assemblies) is equipped with a check source that is actuated on a periodic basis. The failure of any applicable channel to respond to the source will initiate an alarm in the control room. Radiation levels exceeding the alarm setpoint for any detector will cause an alarm at that detector location and in the control room.

12.3.3.3 Evaluation

The Area Radiation Monitoring System detectors are located throughout the station in locations where significant radiation levels may exist, and change with time and the operation being performed. They are designed primarily for the protection of personnel performing such operations as routine coolant sampling, refueling, Reactor Building entry, radioactive waste disposal operations, and for certain other operating and maintenance work. The system has sufficient range and flexibility to permit readout during routine operations and during any transient or emergency conditions that may exist. The equipment is self-checking for proper operation, and alarms both in the local area and in the respective control room. Where necessary or desirable, readout is also provided locally in certain locations.

Several channels of the Area Radiation Monitoring System will be utilized for primary indication and backup in evaluating the extent of fission product release involved in both the LOCA and DBA.

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12.4 Radiation Protection Program

The administrative organization of the Radiation Protection program and the qualifications of the personnel responsible for the program and for handling and surveying radioactive material are discussed in Section 13.1. The administrative organization is responsible for and has appropriate authority for assuring that the three basic objectives of the Radiation Protection program at Oconee Nuclear Station are achieved. These objectives are to:

1. Protect personnel
2. Protect the public
3. Protect the station

Protection of Personnel, includes surveillance and control over internal and external radiation exposure and maintaining the exposure of all personnel within permissible limits and as low as is reasonably achievable (ALARA).

Protection of the public, includes surveillance and control over all station conditions and operations that may affect the health and safety of the public. Included are such activities as radioactive gas, liquid and solid waste disposal, shipment of radioactive materials, an environmental radioactivity monitoring plan and maintaining portions of the station emergency plan.

Protection of the station, includes the continuous determination and evaluation of the radiological status of the station for operational safety and radiation exposure control purposes. This work is performed in order to warn of possible detrimental changes and exposure hazards, to determine changes or improvement needed, and to note trends for planning future maintenance work.

This administrative organization is also responsible for and has appropriate authority for maintaining occupational exposures as far below the specified limits as reasonably achievable by assuring that:

1. Station personnel are made aware of management's commitment to keep occupational exposures as low as is reasonably achievable;
2. Formal reviews are performed periodically to determine how exposures might be lowered;
3. There is a well-supervised radiation protection capability with specific defined responsibilities;
4. Station workers receive sufficient training;
5. Sufficient authority to enforce safe station operation is provided;
6. Modification to operating and maintenance procedures and to station equipment and facilities are made where they should substantially reduce exposures at a reasonable cost;
7. The radiation protection staff understand the origins of radiation exposures in the station and seeks ways to reduce exposures;
8. Adequate equipment and supplies for radiation protection work are provided.

The Station Manager is responsible for the protection of all persons against radiation and for compliance with NRC regulations and license conditions. This responsibility is in turn shared by all supervisors. Furthermore, all personnel are required to work safely and to follow the regulations, rules, and procedures that have been established for their protection.

The Duke Power Company, General Office Technical System Manager, Radiation Protection, establishes the Radiation Protection Program including the program for handling and monitoring radioactive material for Oconee that is designed to assure compliance with applicable regulations, technical specifications, and regulatory guides. The General Office Technical System Manager also provides technical guidance and support for conducting this program, reviews the results of the program to determine its effectiveness and modifies it as required based on experience and regulatory changes, to assure that occupational radiation exposure and exposure to the general public are maintained as low as is reasonably achievable.

This individual also provides technical assistance to the Executive Vice President, Nuclear Generation, who has management authority to implement the “as low as is reasonably achievable” (ALARA) occupational exposure policy, to which Duke Power Company is committed.

The Station Radiation Protection Manager at Oconee is responsible for conducting the Radiation Protection Program that has been established for the station. The Station Radiation Protection Manager has the duty and the authority to measure and control the radiation exposure of personnel; to continuously evaluate and review the radiological status of the station; to make recommendations for control or elimination of radiation hazards; to assure that all personnel are trained in radiation protection; to assist all personnel in carrying out their radiation protection responsibilities; and to protect the health and safety of the public both on-site and in the surrounding area.

In order to achieve the goals of the Radiation Protection Program and fulfill these responsibilities for radiation protection; radiological monitoring, survey and personnel exposure control work are performed on a continuing basis for station operations and maintenance.

The Radiation Protection Section performs the major portion of the radiation protection work for the station. Personnel in the Radiation Protection Section normally work on the day shift during periods of routine operation; and deploy onto the other shifts for major maintenance, shutdown, and refueling work. A supervisor and several Radiation Protection Technicians are also assigned to each operating shift. The Radiation Protection Section is organized into major areas, such as surveillance and control, support functions, staff and shift.

12.4.1 Personnel Monitoring Systems

Monitoring instruments are located at exits from the Radiation Control Area. These instruments are intended for use to prevent any contamination on personnel, materials, or equipment from being spread into the unrestricted/secondary systems areas of the station. Appropriate monitoring instruments are also used at various locations throughout the station for contamination control purposes. Portal monitors are utilized as appropriate, to monitor personnel leaving the station.

Personnel monitoring equipment consists of thermoluminescent dosimeters (TLD's), electronic dosimeters, or “self-reading” dosimeters which are worn by those persons who ordinarily work in the Radiation Control Area or RCZ. In addition, monitoring devices are readily available for use for measurement of extremity dose. This personnel monitoring equipment is issued by Radiation Protection. Personnel monitoring equipment is also available on a day-to-day basis for those persons, employees or visitors, not assigned to the station who have occasion to enter the Radiation Control Area or to perform work involving possible exposure to radiation.

The use of personnel monitoring equipment mentioned above refers specifically to compliance with 10CFR 20.1502. The Station Radiation Protection Manager may require additional equipment to be worn based on the actual or anticipated dose rates and other radiological problems encountered on the job.

Personnel monitoring badges are supplied by a centralized in-house personnel dosimetry service which meets all applicable requirements for sensitivity, range, and accuracy of measurement. This service is NVLAP approved. Conformance with appropriate standards is also required. This service has the response capability for both routine and emergency purposes.

A body burden analyzer for routine screening of personnel for internal exposure is provided in the low background counting area in the Administration Building. Outside services for radiobioassay and whole body counting are utilized as required for backup and support of this program. The station equipment is sufficiently sensitive to detect in thyroid, lungs or whole body a few percent of the allowable limit of intake for those gamma emitting radionuclides encountered.

12.4.2 Personnel Protective Equipment

Special “protective” or “anti-contamination” clothing is furnished and worn as necessary to protect personnel against contact with radioactive contamination.

This consists of coveralls, lab coats, hoods, gloves, and shoe covers. Change rooms are conveniently located in the Radiation Control Area of the station for proper utilization of this protective clothing. Approved respiratory protective equipment is also available to supplement process containment and ventilation controls, for the protection of personnel against airborne radioactive contamination. This equipment consists of compressed air systems, air-supplied respirators, air-purifying (filter) respirators and Self-Contained Breathing Apparatus (SCBA).

Maintenance of the respiratory protective equipment is in accordance with the manufacturer's recommendations and NUREG 0041. The use and maintenance of protective clothing and radiological respiratory protective equipment is under the direct control of the Radiation Protection Section and personnel are trained in the use of this equipment before using them in the performance of their work. The use of respiratory protective equipment is in accordance with appropriate regulations (10CFR 20.1202, 1204 and 1701-1704) Regulatory Guides and ANSI Standards.

12.4.3 Facilities and Access Provisions

Change room facilities are provided where personnel obtain clean protective clothing and other equipment required for station work. The change rooms serve the Reactor Buildings, the Auxiliary Building, the Spent Fuel Pools, and the Hot Machine Shop. A change room is also provided for female employees. These facilities are divided into clean and contaminated sections. The contaminated section of the change rooms is used for the removal and handling of contaminated protective clothing after use.

Radiation monitoring equipment is available in all change rooms for personnel monitoring. Decontamination facilities i.e. sinks, showers, are available in the unit 1 & 2, and Unit 3 men's change room, the women's change room located on the ground floor of the auxiliary building and in the Radwaste facility.

Personnel who are required to utilize protective clothing obtain these items in the change rooms. They first enter the change room on the “clean” side, don the required protective clothing, and then proceed to the job location. After completing work, they remove outer contaminated protective clothing at the exit of the Radiation Control Zone set up about the work area. They then proceed to the “contaminated” side of the change room, where they monitor themselves, if contaminated contact RP, if clean, remove inner protective clothing items, and proceed to the “clean” side, where they put on their personal clothing before leaving.

Routine entrance to and exit from the RCA is through the Single Point of Access (SPA). The SPA is located adjacent to the Work Control Center on the Unit 2 Turbine Floor. The SPA is equipped with appropriate monitoring equipment for individuals exiting the RCA through the SPA. Other RCA entrance and exit locations may be approved by RP management as needs dictate. The personnel entrance/exit points to/from the Auxiliary Building (RCA) are provided with contamination control checkpoints that are equipped with appropriate monitoring instrumentation. All other personnel-access points into the RCA in the Auxiliary Building are protected by restricted-in/free out doors in case of emergency. Contamination control check-points are strategically placed throughout the RCA to prevent the spread of contamination within this area.

Before leaving the Radiation Control Area, personnel are required to monitor themselves with the appropriate equipment, positioned near each control point exit door, to make sure that they are free of significant contamination.

In order to protect personnel from radiation and radioactive materials, the Radiation Control Area of the station is divided into areas of increasingly controlled access depending on radiation levels. Protection of personnel from access to radiation areas, high radiation areas, locked high radiation areas, and very high radiation areas that exist temporarily or permanently as a result of station operations and maintenance is by means of appropriate radiation warning signs, barricades, locked doors, audible and visual indicators and alarms, etc., as required by 10CFR 20 (References 1 and 2).

All work on systems or in locations where radioactive contamination or external radiation is present requires a Radiation Work Permit (RWP) prepared under the direction of the Station Radiation Protection Manager before work may begin. The radiological hazards associated with the job are determined and evaluated prior to issuing the permit whenever practical, and historical data will be used when this is not practical.

Keeping exposures ALARA is a major consideration. The Radiation Work Permit lists the precautions to be taken including, as appropriate, working time limits (for external and internal exposure), protective clothing to be worn, and any radiation monitoring that may be required during the performance of the work. The permit is issued for personnel use. A working copy is maintained by the Radiation Protection Section.

All persons performing radiological work are required to read and understand the instructions on the appropriate RWP and to respond to the prompts provided by the Electronic Dose Capture System (EDC), or fill out the required information on their Daily Exposure Time Record dose card before entering and after leaving the RCZ and/or Radiation Control Area if the EDC system is unavailable for use. The information from the EDC system or the dose card is entered into the Radiation Monitoring and Control (RM&C) System computer programs and serves, in part, as a personnel monitoring record for the individuals involved.

An equipment decontamination facility is provided at the station for large and small items of station equipment, components and tools. In addition, a cask decontamination area is provided adjacent to each spent fuel pool. A decontamination laundry and a respiratory protective equipment cleaning and repair facility are also provided.

Decontamination of work areas throughout the station is facilitated by the provision of janitor's sinks in the reactor containments and on elevations 783+9, 796+6, and 838+0 in the Auxiliary Building.

Drains from all of these facilities go to appropriate radioactive liquid waste drain tanks. Written procedures govern the proper use of protective clothing, the change rooms, and the decontamination facilities.

Radioactive material and contaminated equipment associated with plant operations shall be labeled/posted controlled and stored within the Restricted Area and/or the Owner Controlled Area in accordance with 10CFR20 requirements until such time that it is appropriate to transfer it to another location licensed to receive such radioactive material.

Note that the Reactor Coolant Pump Motor Refurbishment Facility ventilation system and ventilation sampling system were "abandoned in place" in the last quarter of 2004, after completion of the Reactor Head Replacement Project. Electrical power to the ventilation and ventilation sampling systems was disconnected as part of the "abandonment" process. Although the ventilation system equipment and the ventilation system sampler remain in-place, this facility no longer discharges airborne radioactivity to the environment. This paragraph remains as a description of the operation of the ventilation system that was installed in the building to support the Reactor Head Replacement Project. This paragraph also remains in the event power is later restored to the ventilation and ventilation sampling systems. The Reactor Coolant Pump Motor Refurbishment Building is available for maintenance activities. An effluent sampling system, including a negative pressure ventilation exhaust system, may be used during specified maintenance evolutions such as the Reactor Head Replacement Project. For instances in which the ventilation system is not available, controls are imposed by the radiological procedure governing the work to prevent or minimize airborne releases and to ensure that airborne radioactivity is sampled prior to release to the environment. The radiological control procedure will also specify conditions under which work will be performed in an enclosure with a HEPA-filtered exhaust. The HEPA-filtered exhaust will be monitored for the discharge of radioactivity during periods of HEPA system operation.

Note that the Carbon Dioxide Blast Facility has been "abandoned in place." Electrical power and air supply to the equipment were disconnected as part of the "abandonment" process. Although the Carbon Dioxide Blast equipment remains in-place, this facility is no longer used for decontamination purposes. This paragraph remains as a description of the operation of the decontamination system. This paragraph also remains in the event electrical power and air supply are later restored to the decontamination equipment. The Carbon Dioxide Blast Facility is available for decontamination activities that will not release uncontrolled airborne radioactivity to the environment. Controls are imposed by the radiological procedure governing the decontamination work to ensure that uncontrolled airborne radioactivity is not released to the environment from the facility. The blast facility is housed within a building that does not exhaust to the environment. Additionally during periods of operation, the process is exhausted through a HEPA filtration unit, to the outer facility. The HEPA-filtered exhaust is constantly monitored for the discharge of radioactivity during periods of HEPA system operation.

12.4.4 Radiation Protection and Chemistry Facilities

The major Radiation Protection facilities including a shielded counting room are centrally located at the Oconee 1 and 2 Auxiliary Building interface for efficiency of operation. These facilities are equipped for detecting, measuring, and analyzing radiation(s) of primary concern and for evaluating radiological problems that may be reasonably expected. Portable equipment calibration and respirator maintenance facilities are located at the Oconee 3 Auxiliary Building.

The chemistry facilities located in the auxiliary building include a primary lab and office area located at the Oconee 1 and 2 Auxiliary Building interface and a secondary lab and office area located in Oconee 3's Auxiliary Building. The primary lab is used to analyze primary system (reactor coolant, pressurizer, BWST, etc.) samples while the secondary lab is used to analyze secondary system (feedwater, hotwell, etc.) samples.

The chemistry facilities located outside the auxiliary building include a chemistry laboratory in the Radwaste Facility. The laboratory is used to perform chemical analyses on radwaste samples and to prepare samples for gamma spectra and beta counting.

Body burden analysis measurements for personnel internal dosimetry purposes is performed in the administration building. Environmental samples are collected and sent to a Duke Power Company environmental facility for analysis.

12.4.5 Radiation Protection Instrumentation

12.4.5.1 Laboratory and Portable Instruments

The various types of portable and laboratory instruments used in the Radiation Protection program measure alpha, beta, gamma, or neutron radiation. These instruments are required for measurements to provide protection against radiation for station personnel through surveys required by 10CFR 20.1501; to analyze and measure radioactivity prior to the release of effluents for the protection of the health and safety of the public; and to provide for all other radioactivity and radiation measurements and analyses necessary for personnel and public safety and for protection of property. They were selected to provide the appropriate detection capabilities, ranges, sensitivities, and accuracies for the anticipated levels of radiation at Oconee Nuclear Station during normal operation, anticipated transients and emergency conditions. Portable instrument and equipment calibrations are supported by the system calibration facility. Sufficient quantities are maintained for use, calibration, maintenance and repair.

Portable radiation survey and monitoring instruments for daily routine use are maintained with operational characteristics as indicated below:

Beta-gamma survey meters (Geiger counters) are used for detection of radioactive contamination on surfaces and for low level dose rate measurements.

Beta/gamma ionization chamber survey meters are used to cover the range of dose rate measurements necessary for radiation protection purposes.

The above mentioned portable instruments are subject to preoperational response checks to low activity Cs-137 sources. Calibrations are performed periodically. The Cs-137 Shepherd calibration sources and the variable pulse generator are also calibrated periodically using National Institute of Standards and Technology (NIST) traceable secondary standards.

Neutron REM survey instruments are used to measure the sum of thermal, intermediate, and fast neutron dose rates for radiation protection purposes. These instruments are calibrated periodically with a variable pulse generator and source checked using a Pu-Be source.

The laboratory equipment is maintained as indicated below:

Multi-channel analyzers are utilized in conjunction with solid state detectors, for identification and measurement of gamma emitting radionuclides in samples of reactor primary coolant, liquid and gaseous waste, airborne contaminants, etc.

Dual channel liquid scintillation counters are used for counting tritium, as well as gross beta activity, in reactor primary coolant and other radioactive liquids and wastes.

Smears for beta/gamma contamination are counted utilizing proportional or GM counter-scalers. Smears for alpha contamination are counted utilizing scintillator or proportional counter-scalers.

A shielded body-burden analyzer having adequate sensitivity to detect radionuclides of interest is located in the Administration Building and is used for personnel bioassay purposes.

The counting room equipment is subject to annual calibration/calibration check by NIST traceable sources in addition to daily response checks and routine inter-laboratory cross checks when equipment is in service.

Various portable airborne gaseous, particulates, and iodine samplers are available for routine use to evaluate air contamination. Samplers are calibrated periodically. Air flow standards used for calibration of these samplers are calibrated periodically by NIST traceable instruments.

Respiratory protective equipment includes air purifying full-face masks, air supplied respirators. Chemical cartridge particulate respirators are also available. All are maintained according to applicable regulations such as those contained in 10CFR Part 20. Respiratory protective equipment is stored in the respirator issue facility, the Control Room(s), the Operations Support Center, and other emergency locations.

Portable instrumentation for use in emergency situations is stored in emergency kits which are located at various assembly points and in the respirator issue facility. The kits are examined periodically for maintenance and calibration.

12.4.5.2 Inplant Radiation Monitoring

Inplant Radiation Monitoring Systems provide station personnel with capabilities to assess the radiological situation in various areas of significance during normal operation as well as during off-normal and emergency situations. The monitoring systems include the Area Radiation Monitoring Systems and the Process Radiation Monitoring System. Portable radiation and air monitoring equipment is also used to supplement these systems.

The Area Radiation Monitoring System is provided to monitor radiation levels in various plant locations that are potential personnel exposure areas. This system consists of gamma sensitive detectors, signal conditioning and readout instrumentation, radiation level alarm sensing logic, audible and visible alarm devices and outputs available for recording. A complete description of the number, detector type, location, range, and nominal sensitivity are presented in Section 12.3.3.2.

The Process Radiation Monitoring System is provided in part to monitor station effluents that are potential sources of radioactivity. Also, gases, particulates, and liquid and iodine levels are monitored in primary and secondary systems during normal operation, anticipated operational occurrences and emergencies. This system provides an indication of the radioactivity in the process line monitored and provides alarms in the control room at a preset level to ensure that concentrations are maintained within the limits specified in the DPC Oconee Nuclear Station Selected Licensee Commitments Manual. In addition some of the monitors perform control functions during postulated accident conditions. A complete description of the Process Radiation Monitoring system, including its number, function, range, nominal sensitivity, and detector type is presented in Section 11.5.

The process and area radiation monitoring systems are supplemented by periodic surveys and by periodic grab air samples, which are collected and analyzed by Radiation Protection and Chemistry, during normal and abnormal operations and maintenance. Appropriate cartridges are used for sampling air when the presence of iodine is suspected.

12.4.6 Radio-Bioassay and Medical Programs

Duke employees and contract service employees issued a personnel monitoring badge and who plan on entering the RCA/RCZ are given a body-burden analysis when the badge is initially issued and when employment is terminated or alternatively, when the person is transferred to a non-radiological assignment. Visitors who plan on entering the RCA/RCZ are generally given a body-burden analysis each time a monitoring badge is issued and at the termination of the station visit. In addition, badged station personnel and appropriate other Duke system personnel participate in a routine body-burden analysis program which provides for at least one body-burden analysis per year for each participant. Additional body-burden analysis can be required for personnel who experience significant exposure to airborne contamination or other conditions, (such as pregnancy or change in employee status). The Station Radiation Protection Manager may waive the requirement for any analysis on a case by case basis if in his judgement, the analysis is inappropriate or impracticable. No special medical examination is considered to be necessary for radiation workers whose exposure is maintained within permissible dose limits. However, a pre-employment physical is required of prospective radiation workers to determine their health status and their ability to perform the job. Also, personnel are also examined or screened by a physician to ensure that they are medically able to use respiratory equipment. Personnel using respiratory equipment are given the appropriate training for respiratory use and fit tested as required for the respirator(s) to be used.

Anyone onsite, whether badged or not, who is involved in a radiological accident where internal exposure is likely, is given a body-burden analysis as soon as practicable thereafter.

Dose commitments are calculated by the Site or General Office Radiation Protection Staff.

Medical observation and treatment are available in case of over-exposure or excessive contamination. Physicians, a medical clinic, and hospital facilities are available for the treatment of injuries. A local physician has been retained, and trained in the care and treatment of radiation injuries, and facilities have been established in a local hospital for the handling and treatment of possibly contaminated injured or irradiated patients. Back-up support is also available through the Oak Ridge Radiation Emergency Assistance Center/Training Site, REAC/TS. Radiation Protection personnel are responsible for the radio-bioassay program and are available to assist the physicians and the hospital in maintaining medical control of over-exposed or contaminated personnel.

These programs are designed to monitor and protect the health of all employees concerned, to confirm the adequacy of the radiation control methods employed at the station and to provide for the treatment of injuries.

12.4.7 Tests and Inspections

Routine radiological monitoring to detect radiation, radioactive contamination, and airborne radioactivity is performed throughout the plant on periodic schedules. Monitoring frequencies are determined by the Station Radiation Protection Manager based upon the actual or potential radiological conditions. Schedules of routine monitoring are issued to the technicians who initial the schedule when the routine is completed. As plant conditions change, the schedule is updated. Radiological surveys are performed before personnel enter potential or actual radiation areas where there is any doubt as to the existing conditions. Radiological surveys are also performed as a backup to routine monitoring when conditions change. All survey and routine monitoring data is recorded and filed in the Radiation Protection files. Retention of survey and monitoring records follows the requirements of 10CFR 20.2103 and the QA Topical Report.

The Radiation Protection Section and the system calibration facility perform the work necessary to maintain (other than repair) the Counting Room instruments and the portable radiation monitoring instruments. Periodic NIST traceable calibrations, instrument checks and evaluations, and other manual checks are performed. Duke Power Company participates in NRC approved performance testing programs. Electronic/Self-reading dosimeters are subjected to periodic tests and calibration.

Personnel monitoring instrumentation is subjected to a continuing Quality Control Program. The Quality Control Program includes the use of a computer program that compares TLD values and Electronic/ "self-reading" dosimeter totals covering the same monitoring period and lists those correlations that are unacceptable so that effective problem resolution can be performed as necessary, thus helping to maintain a high level of personnel monitoring equipment performance.

Duties concerning radioactive gaseous and solid waste disposal are performed by the Radiation Protection section. The detailed analyses and records required to characterize the nature of radioactive gaseous waste releases and solid waste disposal are under the control of the Radiation Protection section.

Duties concerning radioactive liquid waste disposal are performed by the Chemistry section. While the analyses of radioactive liquid waste releases are under the control of the Radiation Protection section, the records required to characterize the nature of liquid waste releases, both qualitatively and quantitatively, are under the control of the Chemistry section.

Training and qualification of personnel in Radiation Protection are the responsibility of the Station Radiation Protection Manager and are performed by the Radiation Protection Section, or by Nuclear Generation Department Training personnel, under his direction.

The Radiation Protection Section maintains the Offsite Radiological Monitoring Program for the station in conjunction with the system radiological environmental laboratory.

12.4.8 References

1. Regulatory Guide 8.38, "Control of Access to High and Very High Radiation Areas Section 2.4 Alternative Method for Control."

2. Letter from L.A. Wiens (NRC) to J.W. Hampton (ONS) dated February 14, 1994 regarding: Approval to control High Radiation Areas at the Oconee Nuclear Station in accordance with the alternate controls described in the Regulatory Position 2.4 of the Regulatory Guide 8.38.

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Appendix 12A. Tables

Table 12-1. Parameters Used for Shielding Analyses

Core Thermal Power	2568 MWt
Effective Core Diameter	128.9 in.
Active Fuel Length	144 in
Thickness of Core Liner	0.75 in.
Thickness of Core Barrel	2 in.
Thickness of Thermal Shield	2 in.
Reactor Vessel I.D.	171 in.
Reactor Vessel O.D.	188 in.
Volume of Reactor Coolant	11,478 ft^3
Normal Letdown Flow	1 reactor coolant system volume per day
Time Between Shutdown and Fuel Handling	100 hrs.
Coolant Transit Times (Seconds):	
Core Inlet to Core Exit	0.8
Core Exit to S.G. Inlet	2.8
S.G. Inlet to S.G. Outlet	5.2
S.G. Outlet to Core Inlet	4.0
Total Loop Time	12.8

Table 12-2. Principal Shielding

Reactor Building	
Component	**Concrete Thickness (ft)**
Primary Shield (Below Flange) (Above Flange)	5 4.5
Secondary Shield	4
Reactor Building Vertical Walls	3.75
Reactor Building Dome	3.25
Side Walls of Fuel Transfer Canal	4.5
End Walls of Fuel Transfer Canal	2.5,4
Floor of Fuel Transfer Canal	4
Nominal Water Over Active Fuel During Transfer	9
Auxiliary Building	
Component	**Concrete Thickness (ft)**
Spent Resin Tanks	4
Evaporator Equipment	3.0-4.0
Purification Demineralizers	4
Deborating Demineralizers	4
Component Drain Pump	1.5-4.0
Spent Resin Transfer Pump	2-4
Spent Resin Sluicing Pump	2-4
Waste Transfer Pump	1-4
Low Pressure Injection Pumps	2.5-3.5
High Pressure Injection Pumps	1.5-4.0
Coolant Bleed Holdup Tanks	1.5-4.0
Concentrated Boric Acid Storage Tank	1.5-2.0
Waste Drumming Area	1.5-2.0
Low Pressure Injection Coolers	3
Letdown Storage Tanks	4
Waste Holdup Tank	2.0
Waste Gas Tank	3.0-3.5
Waste Gas Compressors	3.0-3.5
Bleed Evaporator Feed Tank	2.0-3.0

Spent Fuel Coolant Pumps & Coolers	2.5-3.5
Side Walls of Storage Pool	3.5
End Walls of Storage Pool	5.5

Table 12-3. Area Radiation Monitors

RIA	Detector Type	Location	Range	Nominal Sensitivity
RIA-1	G-M	Control Room Unit 1&2, Unit 3	1E-1 to 1E4 mR/hr	100 cpm/mR/hr
RIA-3 High Range	G-M Ion Chamber	Reactor Building Refueling Deck Shield Wall Unit 1, 2, 3	1E-1 to 1E4 mR/hr 1E2 to 1E7 mR/hr	100 cpm/mR/hr 1.2E-10 A/R/hr
RIA-4 High Range	G-M Ion Chamber	Reactor Building Entrance Unit 1, 2, 3	1E-1 to 1E4 mR/hr 1E2 to 1E7 mR/hr	100 cpm/mR/hr 1.2E-10 A/R/hr
RIA-5	G-M	Incore Instrument Handling Area Unit 1, 2, 3	1E-1 to 1E4 mR/hr	100 cpm/mR/hr
RIA-6 High Range	G-M Ion Chamber	Spent Fuel Building Wall Unit 1&2, Unit 3	1E-1 to 1E4 mR/hr 1E2 to 1E7 mR/hr	100 cpm/mR/hr 1.2E-10 A/R/hr
RIA-7	G-M	Hot Machine Shop	1E-1 to 1E4 mR/hr	100 cpm/mR/hr
RIA-8	G-M	Hot Laboratory	1E-1 to 1E4 mR/hr	100 cpm/mR/hr
RIA-10	G-M	Sample Area Unit 1, 2, 3	1E-1 to 1E4 mR/hr	100 cpm/mR/hr
RIA-11	G-M	Auxiliary Building Corridor Elevation 796′ Unit 1&2, 3	1E-1 to 1E4 mR/hr	100 cpm/mR/hr
RIA-12	G-M	Chemical Addition Area Unit 1&2, Unit 3	1E-1 to 1E4 mR/hr	100 cpm/mR/hr
RIA-13	G-M	Waste Disposal Control Area Unit 1&2, Unit 3	1E-1 to 1E4 mR/hr	100 cpm/mR/hr
RIA-15 High Range	G-M Ion Chamber	High Pressure Injection Pump Room Unit 1&2, Unit 3	1E-1 to 1E4 mR/hr 1E2 to 1E7 mR/hr	100 cpm/mR/hr 1.2E-10 A/R/hr
RIA-16(1) High Range	G-M Ion Chamber	Steam Generator “A” Main Steam Header Unit 1, 2, 3	1E-2 to 1E3 mR/hr 1E2 to 1E7 mR/hr	500 cpm/mR/hr 1.2E-10 A/R/hr
RIA-17(1) High Range	G-M Ion Chamber	Steam Generator “B” Main Steam Header Unit 1, 2, 3	1E-2 to 1E3 mR/hr 1E2 to 1E7 mR/hr	500 cpm/mR/hr 1.2E-10 A/R/hr
RIA-32(2)	Plastic Beta	Auxiliary Building Corridor Multi Point Sampler Elevation 771′, Unit 1&2; Elevation 784′, Unit 3	1E1 to 1E7 cpm	2.94E7 cpm/uCi/ml
RIA-39(2)	Plastic Beta	Control Room Air Ventilation Equipment Room, Unit 1, 3	1E1 to 1E7 cpm	2.94E7 cpm/uCi/ml

RIA	**Detector Type**	**Location**	**Range**	**Nominal Sensitivity**
RIA-41[2]	Plastic Beta	Spent Fuel Pool Air Ventilation Equipment Room, Unit 1&2 Purge Equipment Room, Unit 3	1E1 to 1E7 cpm	2.94E7 cpm/uCi/ml
RIA-56	Ion Chamber	Unit Vent Unit 1, 2, 3	~1E0 to 1E8 R/hr	1E-11 A/R/hr
RIA-57, -58	Ion Chamber	Reactor Building/Penetration Room	~1E0 to 1E8 R/hr	1E-11 A/R/hr
RIA-61[3] [4]		Radwaste Facility (RMF) Northside of column D-16 (RW-106)		
RIA-62[3] [4]		Radwaste Facility Southside of col. D-17A (RW-106)		
RIA-63[3] [4]		Radwaste Facility East wall of RW-108		
RIA-64[3] [4]		Radwaste Facility East wall of RW-130		
RIA-65[3] [4]		Radwaste Facility South wall of RW-219		
RIA-66[3] [4]		Radwaste Facility Under Backwash Resin Tank-B		
RIA-67[3] [4]		Radwaste Facility Under Backwash Resin Tank-A		

Note:

1. These G-M/Ion Chamber detectors are used as Process Radiation Monitors, but are functionally similar to the Area Monitors and are contained in the same cabinets.
2. These beta scintillation detectors are process type RIAs, however they are used in an area monitoring situation.
3. Radwaste Facility Area Monitor. Because the Radwaste Facility is not used as originally designed, these monitors are not used in a personnel radiation protection capacity as originally intended. Therefore, only the number and location are provided for these RIAs.
4. Radwaste Facility Area Monitor. Area Monitors have been statused as inactive. Power has been removed and these area monitors are not in service.

Table of Contents

List of Tables

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List of Figures

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13.0 Conduct of Operations

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13.1 Organizational Structure

13.1.1 Corporate Organization

The corporate structure of Duke Energy is shown in Figure 13-1 and Figure 13-8.

13.1.1.1 Corporate Functions, Responsibilities and Authorities

Duke Energy has years of experience in the design, construction and operation of electric generating stations. As of 1994, Duke's total system capacity was approximately 18,000 MWe. Duke operated eight fossil stations with a 38% share of this total capacity, three nuclear steam-electric stations with a 60% share, and 27 hydroelectric stations, four pumped storage units, and combustion turbine and diesel peaking units accounting for the remaining 2% share.

Company involvement in nuclear power began in the early 1950's with various personnel receiving nuclear training. Selected personnel have been involved full time in nuclear projects since the mid-1950's. Duke participated in the Carolinas-Virginia Nuclear Power Associates (CVNPA), which resulted in a 17,000 kWe nuclear steam-electric unit at Parr, South Carolina. This unit, the Carolinas-Virginia Tube Reactor (CVTR), produced electricity over the period 1963 to 1967 as part of a five-year operating research program. Duke's three unit Oconee Nuclear Station began operation in 1973, the two unit McGuire Nuclear Station began operation in 1981, and two unit Catawba Nuclear Station began operation in 1984. As a result of these and other assignments, many personnel in the Duke organization have had prior nuclear experience as well as extensive experience in the power field.

Various departments within the Company have responsibility for design, construction, quality assurance and operation of each nuclear station. Duke contracts with a nuclear steam supply system (NSSS) vendor for the design and manufacture of the complete NSSS. The NSSS vendor also provides technical consultation in areas such as construction, testing, startup and initial fuel loading.

Duke's corporate functions, responsibilities and authorities for quality assurance are addressed in Topical Report Quality Assurance Program Description, DUKE-QAPD-001.

The Duke Energy Chair, President and Chief Executive Officer has overall responsibility for corporate functions involving planning, design, construction, operation, and decommissioning of the Company's generation, transmission, and distribution facilities.

Line responsibilities relative to Nuclear Generation are delegated through the Chair, President and Chief Executive Officer, to the Executive Vice President and Chief Operating Officer, to the Sr. Vice President and Chief Generation Officer, to the Senior Vice President and Chief Nuclear Officer.

13.1.1.2 Organization for Design and Construction

Effective November 1, 1991, Duke reorganized to create the Power Generation Group, which includes the Nuclear Generation Department. Separate organizations for design and construction ceased to exist.

13.1.2 Operating Organization

13.1.2.1 Nuclear Generation Department Organization

For a description of the Duke Energy Corporation organizational structure, refer to the Topical Report Quality Assurance Program Description, DUKE-QAPD-001. The Duke Energy Corporation organizational structure is shown in Figures 13-1 and 13-8.

The Duke Energy Nuclear Generation Department Organization is shown on Figure13-3.

13.1.2.2 Nuclear Site

13.1.2.2.1 Site Organization

The nuclear site organization centralizes the resources for safe and efficient nuclear plant operations under a vice president at the nuclear site.

The Site Vice President, Oconee has the responsibility for overall plant nuclear safety as established by Technical Specifications. The Site Vice President or his designee has the authority to approve all Site Directives and revisions. The site staff is fully capable and equipped to handle all situations involving safety of the station and public. The Oconee Nuclear Station staff is shown on Figure 13-4.

As established by the Duke Topical Report Quality Assurance Program Description, DUKE-QAPD-001, anyone involved in quality activities in the Duke organization has the authority and responsibility to stop work if they discover deficiencies in quality.

13.1.2.2.2 Personnel Functions, Responsibilities and Authorities

The functions and responsibilities of key supervisory staff are described in the succeeding paragraphs.

(a) Plant Manager

The Plant Manager reports to the Vice President, Oconee Site and has direct responsibility for operating the station in a safe, reliable and efficient manner. The Plant Manager is responsible for protection of the unit staff and the general public from radiation exposure and/or any other consequences of an accident at the station and bears the responsibility for compliance with the facility operating license. The Plant Manager or his designee shall approve, prior to implementation, each proposed test, experiment, or modification to systems or equipment that affect nuclear safety. The Plant Manager or his designee has the authority to approve and issue procedures. The Plant Manager is responsible for approval of all proposed changes to the Facility Operating License, Technical Specifications, Technical Specification Bases, and Selected Licensee Commitments.

(b) Operations Manager

The Operations Manager has the responsibility for directing the actual day-to-day operation of the station. In the event of the absence of the Plant Manager, the Operations Manager, if so designated, assumes the responsibilities and authority of the Plant Manager.

(c) Assistant Operations Manager - Shift

The Assistant Operations Manager - Shift is responsible for the overall activities of all the on-shift licensed and non-licensed operating personnel.

(d) Operations Shift Manager

An Operations Shift Manager is the senior licensed individual responsible for the overall operation of the station on his/her assigned shift. The Operations Shift Manager oversees the activities of the operators on shift and is cognizant of all maintenance activity being performed while on duty. The Operations Shift Manager on duty has both the authority and the obligation to shut down a unit if, in his/her opinion conditions warrant this action.

(e) Control Room Supervisor

The Control Room Supervisor (CRS) is responsible for the control room command function and assists the Operations Shift Manager in operation of the station on his/her assigned shift. The CRS on duty has both the authority and the obligation to shut down a unit if, in his/her opinion, conditions warrant this action.

(f) Reactor Operator

A Reactor Operator is responsible for the actual operation of a Unit on his/her assigned shift. The Reactor Operator has both the authority and obligation to shut down a unit if, in his/her opinion, conditions warrant this action.

(g) Non Licensed Operator

A Non Licensed Operator (NLO) is responsible for the operation of equipment outside of the Control Room.

(h) Radiation Protection Manager

The Radiation Protection Manager has the responsibility for conducting the radiation protection program. Duties include the training of personnel in use of equipment, control of radiation exposure of personnel, continuous determination of the radiological status of the station, surveillance of radioactive waste disposal operations, conducting the radiological environmental monitoring program and maintaining all required records. The Radiation Protection Manager has direct access to the Plant Manager in matters concerning any phase of radiological protection. The Radiation Protection Manager also has direct support as required from the Nuclear General Office Radiation Protection Manager and Staff.

(i) Chemistry Manager

The Chemistry Manager is responsible for overall chemistry and radiochemistry requirements, with special emphasis on primary and secondary system water chemistry.

(j) Maintenance Manager

The Maintenance Manager is responsible for directing maintenance activities in connection with electrical, instrument and control, and mechanical equipment. The Maintenance Manager also has responsibility for Preventative Maintenance and repair of all electrical, instrument and control, and mechanical equipment.

(k) Work Control Manager

The Work Control Manager manages the station's efforts to support Oconee Nuclear Station's operational and outage activities through the coordination, development, shift and outage management of a timely and effective integrated station schedule.

(l) Shift Technical Advisor

The Shift Technical Advisor (STA) is responsible for plant accident assessment functions during transients and operations assessment functions during normal operations. The STA provides advisory technical support to the Control Room Supervisor in the areas of thermal-hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit.

(m) Manager – Nuclear Support Services

The Manager – Nuclear Support Services is responsible for the activities of Regulatory Affairs, Performance Improvement, procedure activities, and Emergency Preparedness. This includes coordinating station interfaces with regulatory agencies and for providing review of appropriate station technical matters.

(n) Training Manager

The Site Training Manager is responsible for implementation and oversight of the training programs for site personnel. The Site Training division provides the analysis, design, development, implementation and evaluation of training and qualifications programs in support of personnel performing work in the nuclear station. Furthermore, the Site Training Division ensures station training programs meet or exceed all facility licensing, UFSAR, Nuclear Policy or regulatory requirements.

(o) Site Services Group Manager

The Site Services Group Manager is responsible for the maintenance of all commercial facilities at the Oconee Site. This includes coordination of any vendor contractors required to support maintenance of the commercial facilities.

(p) Engineering Manager

The Engineering Manager is a senior leader for the site and is the site single point of contact for site engineering issues as well as having many other ancillary site duties. Some site engineering activities include: System Engineering, Digital Process Systems, and Project Management. The Site Engineering Manager reports directly to the Vice President Oconee Nuclear Station and indirectly to the Senior Vice President, Nuclear Engineering.

13.1.2.3 Shift Crew Composition

The operating shift crew consists of an Operations Shift Manager, a Shift Technical Advisor, a Control Room Supervisor in each Control Room, and appropriate licensed and non-licensed operators. In addition, Radiation Protection, Chemistry, Maintenance and I&E technicians are on site at all times when there is fuel in a reactor.

13.1.2.4 Nuclear Corporate (Nuclear General Office) Organization

For a description of the Duke Energy Corporation organizational structure, refer to the Topical Report Quality Assurance Program Description, DUKE-QAPD-001. The Duke Energy Corporation organizational structure is shown in Figures 13-1 and 13-8.

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13.1.3 Qualifications of Site Personnel

The qualifications of personnel in the site organization are in accordance with Section 4 of ANSI 3.1-1978, “Selection and Training of Nuclear Power Plant Personnel,” with the exception of those specifically listed in Section 13.1.3.1.

Replacement personnel for positions in the nuclear stations are fully trained and qualified to fill their appointed positions. Qualifications of key site personnel are available for inspection on site.

13.1.3.1 Minimum Qualification Requirements

The qualifications of personnel in the site organization, except for the Operations Manager, Assistant Operations Manager – Shift, and licensed operators, are in accordance with Section 4 of the “Standard for Selection and Training of Nuclear Power Plant Personnel,” ANSI/ANS-3.1-1978. Requirements for the Operations Manager and Assistant Operations Manager are provided in TS 5.3.1. The education and experience eligibility requirements for licensed operators are in accordance with the guidelines outlined by the National Academy for Nuclear Training (NANT), which have been found acceptable by the Nuclear Regulatory Commission for meeting 10 CFR 55.31 and have been incorporated into applicable station training procedures. Replacement personnel for positions in the stations are fully trained and qualified to fill their appointed positions. Qualifications of key site personnel are available for inspection onsite. Reference Technical Specification 5.3.1.

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13.2 Training

13.2.1 Program Description

The principal objective of the Duke Energy employee training and qualification system is to assure job proficiency of all station personnel involved in safety related work. An effective training and qualification system is designed to accommodate future growth and meet commitments to and comply with applicable established regulations and accreditation standards.

Qualification is indicated by successful completion of prescribed training and demonstration of the ability to perform assigned work or tasks competently. Where required, maintaining a current and valid license issued by the regulating agency establishes the requirements.

The Vice President, Oconee Nuclear Station, is responsible for the quality of work performed by individuals at the nuclear site. Line Management is responsible for the timely and effective development of assigned personnel. The Oconee Site Training Manager has overall responsibility for the administration of the employee training and qualification system.

Training is analyzed, designed, developed, implemented, and evaluated according to a systematic approach to training. Employees are provided with formal training to establish the knowledge foundation and on-the-job training to develop work performance skills. Continuing training is provided, as required, to maintain proficiency in these knowledge and skill components and to provide further employee development.

The employee training and qualification system is designed to prepare initial and replacement station personnel for safe, reliable and efficient operation of the nuclear facility. The program is intended to meet or exceed INPO accreditation standards and Nuclear Regulatory Commission requirements.

Appropriate training for personnel of various training and experience backgrounds is provided. The level at which an employee initially enters the training and qualifications system for the particular area is determined by an evaluation of the employee's past experience and level of ability.

13.2.1.1 Regulatory Requirements

The applicable portions of the NRC regulations, regulatory guides, and reports listed below will be used in providing guidance in plant staffing and training.

1. 10CFR50 “Domestic Licensing of Production and Utilization Facilities”
2. 10CFR55 “Operators' Licenses” including Appendix A
3. 10CFR19 “Notices, Instructions and Reports to Workers; Inspections”
4. Regulatory Guide 1.8 “Personnel Selection and Training”
5. NRC “Operator Licensing Guide,” NUREG-0094, July 1976
6. “Utility Staffing and Training for Nuclear Power,” WASH-1130, USAEC Revised 1973
7. NUREG-0654
8. Regulatory Guide 8.2 “Guide for Administrative Practices in Radiation Monitoring”
9. Regulatory Guide 8.8 “Information Relevant to Maintaining Occupational Radiation Exposures as Low as Reasonably Achievable (Nuclear Power Reactor)”

10. Regulatory Guide 8.13, “Instructions Concerning Prenatal Radiation Exposure”
11. NUREG-0737
12. 10 CFR 20, “Standards for Protection Against Radiation”

13.2.2 Program Content Description

Station assigned personnel may be trained and qualified through participation in prescribed parts of the employee training and qualification system.

13.2.2.1 General Employee Training

General employee training encompasses those general administrative, safety, radiological and emergency procedures (administrative in nature) established by station management and applicable regulations.

All personnel granted unescorted access to the Restriced/Protected Area of a nuclear power plant receive training in the following areas commensurate with their level of knowledge and job duties:

a. Station Organization
b. Station Administration
c. Nuclear Power Plant Overview
d. Industrial Safety and Environmental Management
e. Fire Protection
f. The Quality Program
g. Plant Security
h. Emergency Response/Preparedness
i. Radiological Orientation
j. Access Authorization and Fitness for Duty
k. Radiation Protection
l. Respiratory Protection and fit testing

Requalification training is conducted on required basis.

13.2.2.1.1 Fire Brigade Training

The primary purpose of the Fire Brigade Training Program is to develop a group of site employees skilled in fire prevention, fire fighting techniques, and emergency response. They are trained and equipped to function as a team for the fighting of fires. The site fire brigade organization is intended to be self-sufficient with respect to fire fighting activities.

The Fire Brigade Training program provides for initial training of all new fire brigade members, quarterly classroom training and drills, annual practical training, and leadership training for fire brigade leaders.

13.2.2.2 Technical Training

Technical training is designed, developed and implemented to assist site employees in gaining an understanding of applicable fundamentals, procedures, and practices; and in developing manipulative skills necessary to perform assigned work in a competent manner. Technical training may consist of three segments:

Initial Training

On-the-job Training and Qualification

Continuing Training

13.2.2.2.1 Initial Training

Initial job training is designed to provide knowledge of the fundamentals, basic principles and procedures involved in work in which an employee is assigned. This training may consist of, but not limited to, live lectures, taped and filmed lectures, computer-assisted instruction, guided self-study, demonstrations, laboratories and workshops, on-the-job-training, and where applicable, simulator training.

Certain new employees or employees transferred from other department locations may be partially qualified by reason of previous applicable training and/or expertise. The extent of further training for these employees is determined by systematic approach with input from applicable regulations, performance in review sessions, comprehensive examinations, or other techniques designed to identify the employee's present level of ability.

Initial job training and qualification programs are developed for operations, maintenance, chemistry and radiation protection non-exempt classifications. Training for each program is presented in such a manner that specific behavioral objectives are accomplished. Trainee progress may be evaluated using written examinations, oral, or practical tests. Depending on the regulatory requirements, an individual's needs, or plant operating conditions, allowances are made to suit the specific situation. A brief description of initial training program content follows:

1. Operations Initial Training
   a. Initial Operator training is provided in accordance with applicable standards to provide the foundation in basic theory and plant familiarization for trainees to become competent operators. This program consists of both classroom and on-the-job training.
   b. Operations personnel receive basic instruction in administration, mathematics, physical science, safety, power plant fundamentals, general work practices, and station familiarization. These individuals also receive additional fundamental theory training in thermal science, electrical, and instrumentation areas. Application of theory as it relates to performance testing and measuring methods is also presented.
2. Maintenance, Radiation Protection and Chemistry
   a. Fundamental Training

      Provides basic instruction in administration, mathematics, physical science, safety, power plant fundamentals, general work practices, and station familiarization.
   b. Discipline-specific Training

      Provides instruction in the fundamentals and specific skills needed in his/her specialty area.

Maintenance personnel receive basic mechanical and/or electrical theory, tools and their use, basic component theory, and competent repair and troubleshooting skills.

Radiation Protection personnel receive a comprehensive and theoretical understanding of the theory of radiation, radiation detection and instrumentation, and application of Radiation Protection Technology with emphasis on hypothetical problem solving and practical applications.

Chemistry personnel receive basic Chemistry theory and its application in the nuclear power plant. Basic techniques and procedures are presented and practiced.

3. Engineering Support Initial Training

   a. On-the-Job Orientation (OJO)

   This training module provides an orientation to the various sections and departments at the nuclear site. A structured plan is provided to the trainee with objectives to be accomplished.

   b. Engineering Fundamentals Training

   The Fundamentals portion of initial training has been designed to meet the intent and recommendations provided by INPO ACAD 98-004. Three modules (Basic Principles and Components, Reactor Theory, and Thermodynamics) provide instruction in electrical science, properties of materials, reactor theory, heat transfer and fluid flow, chemistry, valve and pump theory, and process control systems principles.

   c. Site Specific Systems Training

   Systems training provides an overview of plant systems, normal and emergency operation, components, and flow paths necessary to operate the nuclear site safely and efficiently. The course includes specific modules covering Core Damage Mitigation that meets the intent of INPO Guidelines.

   d. Position-Specific Training

   Position-Specific Training is defined and managed by the Engineering line organization to ensure that individuals are qualified for the specific responsibilities assigned to them.

13.2.2.2.2 On-the-Job Training and Qualification

On-the-job training is a systematic method of providing the required job related skills and knowledge for a position. The Qualification process consists of three steps: 1) Training conducted in the work environment/simulated work environment by qualified OJT trainers; 2) an independent evaluation; and 3) a signature by the trainee's supervisor or a member of management awarding qualification. Applicable tasks and related procedures make up the OJT/qualifications program for each technical area which is designed to supplement and compliment training received through formal classroom, laboratory, and/or simulator training. The objective of the program is to assure the trainee's ability to perform job tasks as described in the task descriptions and the Training and Qualification Guides.

13.2.2.2.3 Continuing Training

Continuing Training is any training not provided as Initial Qualification and Basic Training or training which maintains and improves job-related knowledge and skills such as the following:

a. Plant Systems and Component Changes

b. OJT/Qualification Program Retraining/Requalification

c. Procedure and Directive Changes

d. Operating Experience Program Documents Review to include Industry and In-House Operating Experiences

e. Continuing Training required by Regulation (Emergency Plan Training, etc.)

f. General Employee, Special, Administrative, Vendor, and/or Advanced Training topics supporting tasks.

g. Training identified to resolve deficiencies (task-based) or to reinforce seldom used knowledge and skills

h. Refresher training on initial training topics

i. Structured pre-job instruction, mock-up training, walk-throughs, etc.

Deleted paragraph(s) per 2002 updated.

Continuing Training may consist of formal and informal components. Each Section or Division's Continuing Training Program is developed using a systematic approach that includes job performance information from a job and task analysis, and safe operation, as the basis for determining the content of continuing training.

Once the objectives for Continuing Training have been established, the methods for conducting the training may vary. The method selected should provide clear evidence of objective accomplishment and consistency in delivery.

13.2.2.2.3.1 Operator Requalification Training

Licensed Operator Requalification training is designed based upon a systematic approach to training to maintain and demonstrate continued competence of all licensed operators. The training is described in applicable standards.

13.2.2.3 Leadership Training

Leadership training may consist of various classes for different management personnel levels. An individual's training and development will depend on his/her position description and nomination by management.

13.2.3 Operator License Training

Duke Energy’s reactor operator and senior reactor operator training programs are based upon “a systematic approach to training” as defined by 10CFR55.4. These training programs were initially accredited by the Institute of Nuclear Power Operations and the National Nuclear Accrediting Board on August 17, 1983. Certification of these training programs' accreditation has been made to the NRC. Accreditation renewal of these programs had occurred on a four-year basis since the date of initial accreditation.

13.2.3.1 Operations Oversight training

Operations Shift Manager (SM) and Shift Technical Advisor Training (STA) are positions on each shift with oversight responsibilities. Separate training programs above and beyond licensed training are conducted for each of these positions in accordance with Duke Energy training procedures

13.2.3.1.1 SM Training and Qualification Program

The SM training and qualification program consists of a combination of mentoring guides, and simulator evaluation and is based on INPO guidance from ACAD 97-004, Guidelines for Shift Manager Selection, Training and Qualification, and Professional Development.

13.2.3.1.2 STA Training and Qualification Program

The STA training and qualification program provides the individual with the knowledge and skills necessary to furnish engineering and/or technical guidance to the Operations Shift Manager for diagnosing and mitigating emergency or abnormal plant conditions. Initial and continuing STA training is based on a "systematic approach to training" and guidance from INPO 90-003, Guidelines for the Training and Qualification of Shift Technical Advisors; and consists of classroom and simulator training in STA roles and responsibilities, reactivity management, and severe accident mitigation at a minimum.

13.2.3.2 Deleted per 2002 update

13.2.3.3 Deleted per 2002 update

13.2.4 Training Program Evaluation

Training and qualifications activities are monitored by the designated station personnel, with assistance from Nuclear Training and Operations Services personnel. Trainees and vendors may provide input concerning training program effectiveness. Methods utilized to obtain this information may be surveys, questionnaires, performance appraisals, staff evaluation, training program effectiveness evaluation instruments, etc. Classes are routinely evaluated at a frequency sufficient to determine program effectiveness. Evaluation information may be collected through:

1. verification of program objectives as related to job duties for which intended;
2. testing to determine student accomplishment of these objectives;
3. student evaluation of the instruction;
4. instructor evaluations of the students;
5. supervisor's evaluation of trainee performance on the job, following the training;
6. supervisor's evaluation of the instructor; or
7. periodic working (review) group evaluation.
8. periodic self-evaluation of the accredited programs

The performance and competency of Licensed Reactor Operators and Senior Reactor Operators is evaluated as described in AD-TQ-ALL-0068, License Operator Continuing Training Program.

13.2.5 Training and Qualifications Documentation

Training and qualification records are maintained in accordance with AD-DC-ALL-0001 Document Control, AD-DC-ALL-0002 Records Management, and in accordance with AD-TQ-ALL-0680 Records Management.

The site Engineering Manager is accountable for the implementation of requirements of document management as it applies to site document management activities (AD-DC-ALL-0001 Document Control, AD-DC-ALL-0002 Records Management).

The site Training Manager is accountable for the retention and maintenance of training and qualification records as stated in AD-TQ-ALL-0680 Records Management.

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13.3 Emergency Planning

The Emergency Program for the Duke Energy's Oconee Nuclear Site consists of the Oconee Nuclear Site Emergency Plan and related implementing procedures. Also included are related radiological emergency plans and procedures of state and local governments. The purpose of these plans is to provide protection of plant personnel and the general public and to prevent or mitigate property damage that could result from an emergency at the Oconee Nuclear Site. The combined emergency preparedness programs have the following objectives:

1. Effective coordination of emergency activities among all organizations having a response role.
2. Early warning and clear instructions to the population-at-risk in the event of a serious radiological emergency.
3. Continued assessment of actual or potential consequences both on-site and off-site.
4. Effective and timely implementation of emergency measures.
5. Continued maintenance of an adequate state of emergency preparedness.

The Emergency Plan has been prepared in accordance with Section 50.47 and Appendix E of 10CFR Part 50. The plan shall be implemented whenever an emergency situation is indicated. Radiological emergencies can vary in severity from the occurrence of an abnormal event, such as a minor fire with no radiological health consequences, to nuclear accidents having substantial onsite and/or offsite consequences. In addition to emergencies involving a release of radioactive materials, events such as security threats or breaches, fires, electrical system disturbances, and natural phenomena that have the potential for involving radioactive materials are included in the plans. The plan contains adequate flexibility for dealing with any type of emergency that might occur.

The activities and responsibilities of outside agencies providing an emergency response role are detailed in the State of South Carolina emergency plans and the emergency plans for Oconee and Pickens Counties.

The emergency response resources available to respond to an emergency consist of the following: 1. ONS Site Personnel, 2. Duke Energy corporate headquarters personnel, 3. Other Duke Energy nuclear station personnel, and, in the longer term, federal emergency response organizations (e.g. NRC, DOE, FEMA). The first line of defense in responding to an emergency lies with the normal operating shift on duty when the emergency begins. Therefore, members of the Oconee staff are assigned emergency response roles that are to be assumed whenever an emergency is declared. The overall management of the emergency is initially performed by the Operations Shift Manager until he/she is relieved by the Plant Manager/Designee. In the event of an emergency, he/she serves as the Emergency Coordinator. Onsite personnel have preassigned roles to support the Emergency Coordinator and to implement his/her directives.

Special provisions have been made to assure that ample space and proper equipment are available to effectively respond to the full range of possible emergencies. The emergency facilities available include the Oconee Control Room, Operational Support Center, Technical Support Center, Joint Information Center, and the Emergency Operations Facility. These facilities are described in the site emergency plan.

Emergency plan implementing procedures define the specific actions to be followed in order to recognize, assess, and correct an emergency condition and to mitigate its consequences. Procedures to implement the Plan provide the following information:

1. Specific instructions to the plant operating staff for the implementation of the Plan.
2. Specific authorities and responsibilities of plant operating personnel.
3. A source of pertinent information, forms, and data to ensure prompt actions are taken and that proper notifications and communications are carried out.
4. A record of the completed actions.
5. The mechanism by which emergency preparedness will be maintained at all times.

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13.4 Review and Audit

Review and Audit is addressed in the description of the Quality Assurance Program referenced in Chapter 17.

13.4.1 Onsite Review

The Onsite Review Committee is addressed with the Independent Review function in the description of the Quality Assurance Program referenced in Chapter 17.

13.4.2 Independent Review

The Independent Review function is addressed in the description of the Quality Assurance Program referenced in Chapter 17.

13.4.3 Audit Program

The Audit Program is addressed in the description of the Quality Assurance Program referenced in Chapter 17.

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13.5 Station Procedures

13.5.1 Administration of Station Procedures

13.5.1.1 Conformance With Regulatory Guides

Regulatory Guide 1.33, "Quality Assurance Program Requirements," and ANSI N18.7-1976, "Standard for Administrative Controls for Nuclear Power Plants" shall be used for the preparation of administrative and plant procedures.

13.5.1.2 Preparation of Procedures

The preparation, review and approval of procedures is performed in accordance with the Quality Assurance Program Description referenced in Chapter 17.

13.5.1.3 Administrative Procedures

Station administrative procedures are written as necessary to control station testing, maintenance, and operating activities. Listed below are several areas for which administrative procedures are written, including principle features:

13.5.1.3.1 The Reactor Operator's Authority and Responsibility

The reactor operator is given the authority to manipulate controls which directly or indirectly affect core reactivity, including a reactor trip if he deems necessary. He is also assigned the responsibility for knowing the limits and setpoints associated with safety-related equipment and systems as specified in the Technical Specifications and designated in the operating procedures.

13.5.1.3.2 The Senior Reactor Operator's Authority and Responsibility

The senior reactor operator, in addition to the authorities and responsibilities described for the reactor operator, is given the authority to direct the licensed activities of the reactor operator, and ultimately is held responsible for all licensed activities at the station within his control.

13.5.1.3.3 Activities Affecting Station Operation or Operating Indications

Prior to removing any instrumentation or controls from service, station personnel shall notify the Work Control Center SRO (WCC SRO). The WCC SRO ensures appropriate notifications of work that may affect unit operations or control room indications are made to the Control Room Supervisor.

The WCC SRO is the primary contact for both outage and innage work.

13.5.1.3.4 Manipulation of Facility Controls

No one is permitted to manipulate the facility controls who is not a licensed reactor operator or senior reactor operator, except for license trainees operating under the direction of a licensed operator. The licensed operators are required to comply with the requalification program as described in Section 13.2.

Operations Management Procedures are written that delineate the responsibilities of the reactor operators on the control board and the responsibilities of the senior reactor operator in the

Control Room. When Technical Specifications require one (1) man in the Control Room (at the controls) this is defined as: Must be in visible line of Nuclear Instrumentation. See cross hatched area on Figure 13-5 and Figure 13-6. One (1) R.O. will be "at the controls" as defined above and the second R.O. will be inside the CAD key doors that are used for entering and exiting the Control Room.

13.5.1.3.5 Responsibility for Licensed Activities

Responsibility for directing the licensed activities of licensed operators is assigned to individuals with senior reactor operator licenses by virtue of their position within the station organization.

13.5.1.3.6 Relief of Duties

This procedure provides a detailed checklist of applicable items for shift turnover.

13.5.1.3.7 Equipment Control

Equipment control is maintained and documented through the use of tags, labels, stamps, status logs, or other suitable means.

13.5.1.3.8 Master Surveillance Testing Schedule

This procedure establishes a master surveillance testing schedule to assure that required testing is performed and evaluated on a timely basis. Surveillance testing is scheduled such that the safety of the station is not dependent on the performance of a structure, system, or component which has not been tested within its specified testing interval. The master surveillance testing schedule identifies surveillance and testing requirements, applicable procedures, and required test frequency. Assignment of responsibility for these requirements is also indicated.

13.5.1.3.9 Log Books

The following log books are maintained and reviewed by appropriate personnel:

1. Switchboard Record - This document contains data on station and unit electrical power generation, bus voltages, etc.
2. Operations Logbook - This document contains documentation of significant events occurring each shift. Examples include reactivity changes, alarms received, abnormal conditions of operation due to auxiliary equipment and all releases of radioactive waste. It contains a summary of unit operation for each shift. Entries are made by Reactor Operators and/or Senior Reactor Operators.

13.5.1.3.10 Temporary Procedures

The use of temporary procedures is discussed in Section 13.5.2.1.3.

13.5.1.3.11 Fire Protection Procedures

Fire protection procedures are written to address such topics as: periodic testing and surveillance, maintenance activities, control of combustibles, fire impairments, hot work authorization, training of the fire brigade, reporting of fires, and control of fire stops. The fire protection engineer in Engineering has responsibility for fire protection procedures in general. All fire protection related procedures and programs contain either an initial review or a subsequent review when the content changes affects a fire technical requirement; however procedural ownership is dependent upon the implementing group such as: Maintenance, Operations, Commodities & Facilities, and Station or General Office Engineering.

13.5.2 Operating and Maintenance Procedures

13.5.2.1 Operating Procedures

13.5.2.1.1 System Procedures

Operating activities which affect the proper functioning of the station's safety-related systems and components are performed in accordance with approved, written procedures. These procedures are intended to provide a pre-planned method of conducting operations of systems, in order to eliminate errors due to on-the-spot analyses and judgements.

Operating procedures are sufficiently detailed that qualified individuals can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and operating procedures, therefore, contain a degree of flexibility appropriate to the activities for which each is applicable.

Typical activities addressed by operating procedures are:

Auxiliary Building Ventilation System Operation

Emergency Feedwater System Operation

Boron Recycle System Operation

Chemical and Volume Control System Operation

Component Cooling Water System Operation

Condensate and Feedwater Systems Operation

Condenser Circulating Water System Operation

Reactor Building Ventilation System Operation

Reactor Building Spray System Operation

Control Room Ventilation System Operation

Degasification of the Reactor Coolant System

Demineralizer Resin Removal and Replacement

Electrical Systems Operation

Failed Fuel Detection and Handling

Filling and Draining of the Refueling Canal

Filling, Venting and Draining of the Reactor Coolant System

Fire Protection Systems Operation

Instrument Air System Operation

Low Pressure Service Water System Operation

Nitrogen System Operation

Nuclear Fuel Control and Accountability

Reactor Coolant Pump Operation

Receipt, Inspection and Storage of New Fuel

Recirculated Cooling Water System Operation

DHR Cooling System Operation

Injection System Operation

Spent Fuel Pool Cooling and Purification System Operation

Spent Fuel Handling and Shipping

Standby Shutdown Facility Systems Operation

Steam Generator Secondary Side Operation

Turbine-Generator Operation

Unit Operation at Power

Unit Shutdown

Unit Startup

13.5.2.1.2 Emergency Procedures

Emergency procedures are written which specify steps to be taken during foreseeable emergency situations. These procedures are based on a sequence of observations and actions, with emphasis placed on operator responses to indications in the Control Room. When immediate operator actions are required to prevent or mitigate the consequences of an emergency situation, procedures require that those actions be implemented at the earliest possible time, even if full knowledge of the emergency situation is not yet available.

The actions outlined in emergency procedures are based on a conservative course of action to be followed by the operating crew. Written procedures, however, cannot address all contingencies, and emergency procedures, therefore, contain a degree of flexibility consistent with the fact that an emergency situation may not follow an anticipated sequence.

Typical situations addressed by emergency procedures are:

Abnormal Release of Radioactivity

Acts of Nature (Earthquake, Flood, Tornado, etc.)

Inoperable Control Element Assemblies

Loss of Component Cooling

Loss of Containment Integrity

Loss of Control Room

Loss of Electrical Power

Loss of Feedwater

Loss of Instrument Air

Loss of Reactor Coolant

Loss of Reactor Coolant Flow

Loss of Residual Heat Removal

Reactor Trip

Spent Fuel Damage

Steam Generator Tube Failure

Steam Supply System Rupture

Turbine-Generator Trip

Loss of Low Pressure Injection System

Loose parts in Reactor Coolant System

High Activity in Reactor Coolant System

Duke Energy has also in place a program for preparing and implementing emergency operating procedures. This program was developed in response to NUREG-0737 Item I.C.1, “Guidance for the Evaluation and Development of Procedures for Transients and Accidents.” Duke Energy’s program for developing emergency operating procedures for Oconee Units I, 2, and 3 has been reviewed and approved by NRC. (Letter from John F. Stolz (NRC) to Hal B. Tucker (Duke) date June 7, 1985. Subject: Safety Evaluation Report on “Procedures Generation Package”).

13.5.2.1.3 Temporary Operating Procedures

Temporary operating procedures are approved written procedures issued for operating activities which are of a nonrecurring nature. Examples of such uses are: (a) to direct operating activities during special testing or maintenance; (b) to provide guidance in unusual situations not within the scope of normal procedures; and (c) to assure orderly and uniform operations for short periods of time when the station, a unit, a structure, a system, or, a component is performing in a manner not addressed by existing procedures, or has been modified or extended in such a manner that portions of existing procedures do not apply.

The format of these procedures includes a purpose, limits and precautions, initial conditions, and step-by-step instructions for each mode of operation and necessary enclosures.

Temporary operating procedures are sufficiently detailed that qualified individuals can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore contain a degree of flexibility appropriate to the activities for which each is applicable.

13.5.2.1.4 Annunciator Response Procedures

Annunciator response procedures are written which specify operator actions necessary to respond to an off-normal condition as indicated by an alarm. The format for annunciator response procedures includes alarm setpoints, automatic actions, manual actions, alarm sources, and references.

In order to insure that annunciator response procedures are readily accessible for reference, a positive method is employed to allow their retrieval. Each annunciator panel is designated by a unique and obvious nameplate. All of the annunciator windows within a panel are designated by identifying names. The annunicator response procedures are grouped by panels, then subdivided by annunciator names so that the response procedure for any annunciator may be quickly located.

13.5.2.2 Other Procedures

13.5.2.2.1 Maintenance Procedures

Maintenance of station safety-related structures, systems, and components is performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances (for example, skills normally possessed by qualified maintenance personnel may not require detailed step-by-step delineation in a written procedure) which conform to applicable codes, standards, specifications, criteria, etc. Where appropriate sections of related vendor manuals, instructions, or approved drawings with acceptable tolerances do not provide adequate guidance to assure the required quality of work, an approved, written maintenance procedure is provided.

Maintenance procedures are sufficiently detailed that qualified workers can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore, contain a degree of flexibility appropriate to the activities for which each is applicable.

The Maintenance Superintendent has responsibility for preparation and implementation of maintenance procedures.

The administrative control of maintenance is maintained as follows:

1. In order to assure safe, reliable, and efficient operation, a comprehensive maintenance program for the station's safety-related structures, systems, and components is established.
2. The Maintenance Superintendent is responsible for directing the performance of station maintenance activities affecting instrumentation and electrical and mechanical equipment.
3. Personnel performing maintenance activities are qualified in accordance with applicable codes and standards, as appropriate.
4. Maintenance is performed in accordance with written procedures which conform to applicable codes, standards, specifications, criteria, etc.
5. Maintenance is scheduled so as not to jeopardize station operation or the safety of a reactor or reactors.
6. Maintenance histories are maintained on station safety-related structures, systems, and components.
7. The effectiveness of maintenance, including maintenance procedures, is covered by the Maintenance Rule Program which has been implemented in accordance with 10 CFR 50.65, “Requirement for monitoring the effectiveness of maintenance at nuclear power plants.”

The administrative control of modifications is discussed in “Quality Assurance Program”, Topical Report, DUKE-1A.

13.5.2.2.2 Instrument Procedures

Maintenance, testing, and calibration of station safety-related instruments is performed in accordance with written, approved procedures.

Instrument procedures are sufficiently detailed that qualified workers can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore contain a degree of flexibility appropriate to the activities for which each is applicable.

The Maintenance Superintendent has responsibility for preparation and implementation of instrument procedures.

13.5.2.2.3 Periodic Test Procedures

Testing conducted on a periodic basis to determine various station parameters and to verify the continuing capability of safety-related structures, systems, and components to meet performance requirements is conducted in accordance with approved written procedures. Periodic test procedures are utilized to perform such testing, and are sufficiently detailed that qualified personnel can perform the required functions without direct supervision.

Periodic test procedures are performed by the station's Engineering, Operations, and Maintenance groups.

13.5.2.2.4 Chemistry Procedures

Chemical and radiochemical activities associated with station safety-related structures, systems, and components are performed in accordance with approved, written procedures and site specific or fleet documents.

Each procedure is sufficiently detailed that qualified workers can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore contain a degree of flexibility appropriate to the activities for which each is applicable.

The Chemistry Manager has responsibility for preparation and implementation of chemistry procedures.

13.5.2.2.5 Radioactive Waste Management Procedures

Radioactive waste management activities associated with the station's liquid, gaseous, and solid waste systems are performed in accordance with approved, written procedures.

Each procedure is sufficiently detailed that qualified workers can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore contain a degree of flexibility appropriate to the activities for which each is applicable.

The station's Operations group, Chemistry, and Radiation Protection sections have responsibility for preparation and implementation of the radioactive waste management procedures.

13.5.2.2.6 Radiation Protection Procedures

Information concerning these procedures is presented in Chapter 12.

13.5.2.2.7 Plant Security Procedures

Station Security Procedures shall be developed to implement the scope of Safeguard Activities required by the safeguard plans addressed in Section 13.6 of the FSAR.

13.5.2.2.8 Emergency Preparedness Procedures

Information concerning these procedures is presented in the Oconee Nuclear Site Emergency Plan which is discussed in topic 13.3.

13.5.2.2.9 Material Control Procedures

Information concerning these procedures is presented in the Duke Energy Topical Report, Quality Assurance Program, DUKE-IA.

13.5.2.2.10 Modification Procedures

Information concerning these procedures is presented in the Duke Energy Topical Report, Quality Assurance Program, DUKE-IA.

13.5.2.2.11 Fire Protection Procedures

Information concerning these procedures is presented in Section 13.5.1.3.11.

13.5.2.2.12 Threaded Fastener Maintenance Procedure

The NRC issued IE Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," on June 2, 1982 to notify licensees about incidents of severe degradation of bolts and studs in reactor coolant pressure boundary closures and to require actions to minimize future degradation and to detect and correct existing deterioration. One of the actions was to develop and implement maintenance procedures for threaded fasteners (studs and bolts) in the reactor coolant pressure boundary. These procedures include, but are not limited to: (1) maintenance crew training of proper bolting/stud practices, tools application, specifications and requirements, (2) detensioning and retensioning practices (torque iteration), specified tolerances, and other controls for disassembly and reassembly of component closure/seal connections, (3) gasket installation and controls, and (4) pretensioning methods and other measures to eliminate reactor coolant leakage during operations. When the alternate HydraNut tensioning system is utilized, all studs are tensioned simultaneously. Quality assurance measures also include proper selection, procurement, and application of fastener lubricants and injection sealant compounds to minimize fastener susceptibility to stress corrosion cracking.

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13.6 Nuclear Security

The Commission-approved Physical Security Plan, Training and Qualification, Safeguards Contingency Plan, and Cyber Security Plan referred to collectively as “Security Plans” describes the comprehensive security program for Oconee Nuclear Station to implement the requirements as required in 10 CFR 73.55.

13.6.1 Physical Security

A combined Duke Energy Physical Security Plan, Security Training and Qualification Plan, Safeguards Contingency Plan, and Independent Spent Fuel Storage Installation Security and Contingency Plan is submitted for the protection of Oconee Nuclear Station against potential acts of radiological sabotage via a determined violent external assault, attack by stealth, or deceptive actions, an internal threat, a land vehicle bomb assault, and a waterborne vehicle bomb assault. This information is to be withheld from public disclosure pursuant to 10 CFR 73.21.

The general scope of activities encompassed by the Duke Energy Physical Security Plan, Security Training and Qualification Plan, Safeguards Contingency Plan and Independent Spent Fuel Storage Security and Contingency Plan include:

1. Performance Objectives;
2. Performance Evaluation Program;
3. Physical Security Organization;
4. Qualification for Employment in Security;
5. Security Personnel Training;
6. Liaison with Local Law Enforcement;
7. Physical Security Barriers, Posts and Structures;
8. Nuclear Site Access and Control Requirements;
9. Surveillance, Observation and Monitoring for detection of unauthorized instrusion;
10. Security Communications Systems;
11. Response to Security Threats;
12. Review, Evaluation, and Audit of the Physical Security Program;
13. Special Situations Affecting Security;
14. Maintenance, Testing and Calibration of Security Systems and Equipment;
15. Compensatory Measures for degraded Physical Barriers and Security Systems;
16. Security Records; and
17. Temporary Suspension of Security Measures.

The Duke Energy Physical Security Plan, Security Training and Qualification Plan, and Safeguards Contingency Plan conforms to the requirements of 10 CFR 50.34(c)(2), (d)(2) and (e), and 10 CFR 73.55. The Duke Energy Independent Spent Fuel Storage Installation Security and Contingency Plan conforms to the requirements of 10 CFR 72.212.

13.6.2 Cyber Security

A separate Duke Energy Cyber Security Plan is submitted for the protection of the Oconee Nuclear Station against potential acts of radiological sabotage via cyber attack to digital computer and communication systems and networks associated with:

1. Safety-related and important to safety functions;
2. Security functions;
3. Emergency preparedness functions, including offsite communications; and
4. Support systems and equipment which if compromised, would adversely impact safety, security, or emergency preparedness functions.

The safety-related and important-to-safety functions, security functions, and emergency preparedness functions including offsite communications are herein referred to as SSEP functions.

In the context of cyber security, systems or equipment that perform important to safety functions include structures, systems, and components (SSCs) in the balance of plant (BOP) that could directly or indirectly affect reactivity at a nuclear power plant and could result in an unplanned reactor shutdown or transienst.

The Duke Energy Cyber Security Plan conforms to the requirements of 10 CFR 50.34(c) (2), 10 CFR 73.54 and 10 CFR 73.55.

This information is to be withheld from public disclosure pursuant to 10 CFR 2.390 (d).

13.6.3 Reference

1. American National Standard ANSI/ANS-3.1-1978.
2. Letter, from R. Michael Glover, Duke Energy to NRC, “Duke Energy Physical Security Plan, Revision 16,” dated April 15, 2010
3. Letter, from R. Michael Glover, Duke Energy to NRC, “Response to Requested changes Regarding Duke Energy License Amendment Request for Cyber Security Plan,” dated August 9, 2011.

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Appendix 13A. Tables

Table 13-1. Deleted in 1991 update.

Table 13-2. Deleted Per 1999 Update

Appendix 13B. Figures

Figure 13-1. Duke Energy Corporation Structure

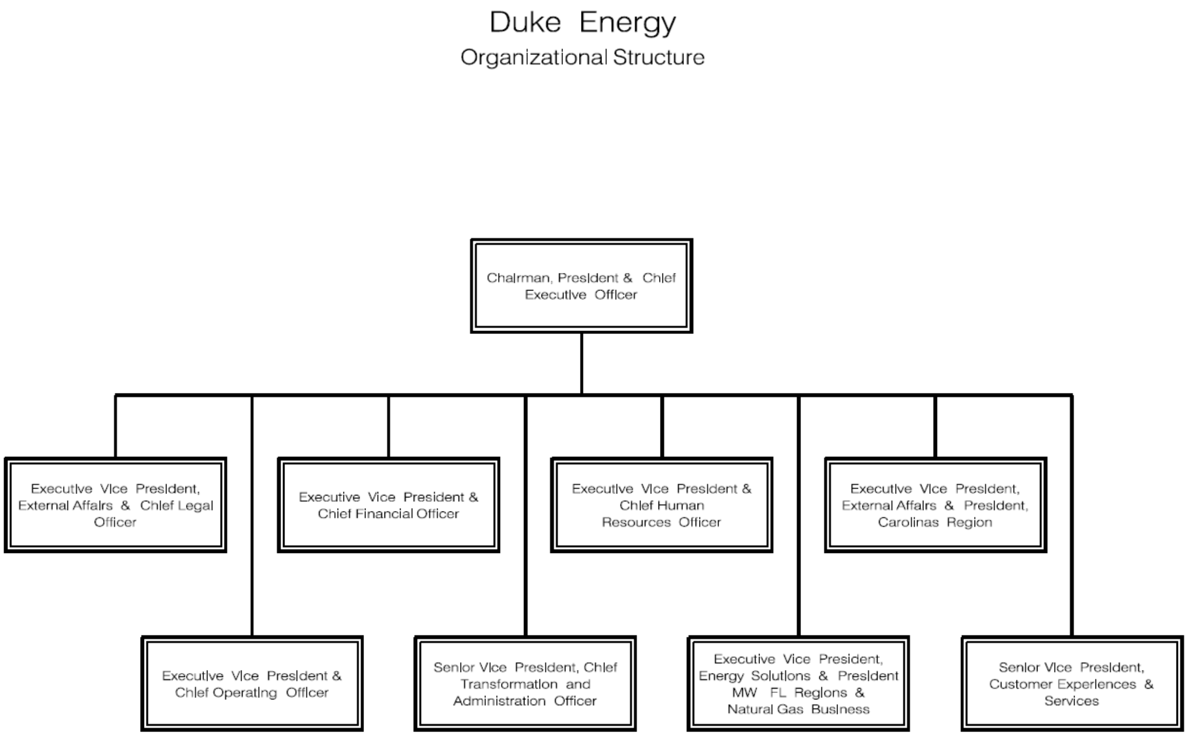

Figure 13-2. Deleted Per 1999 Update

Figure 13-3. Nuclear Generation Department

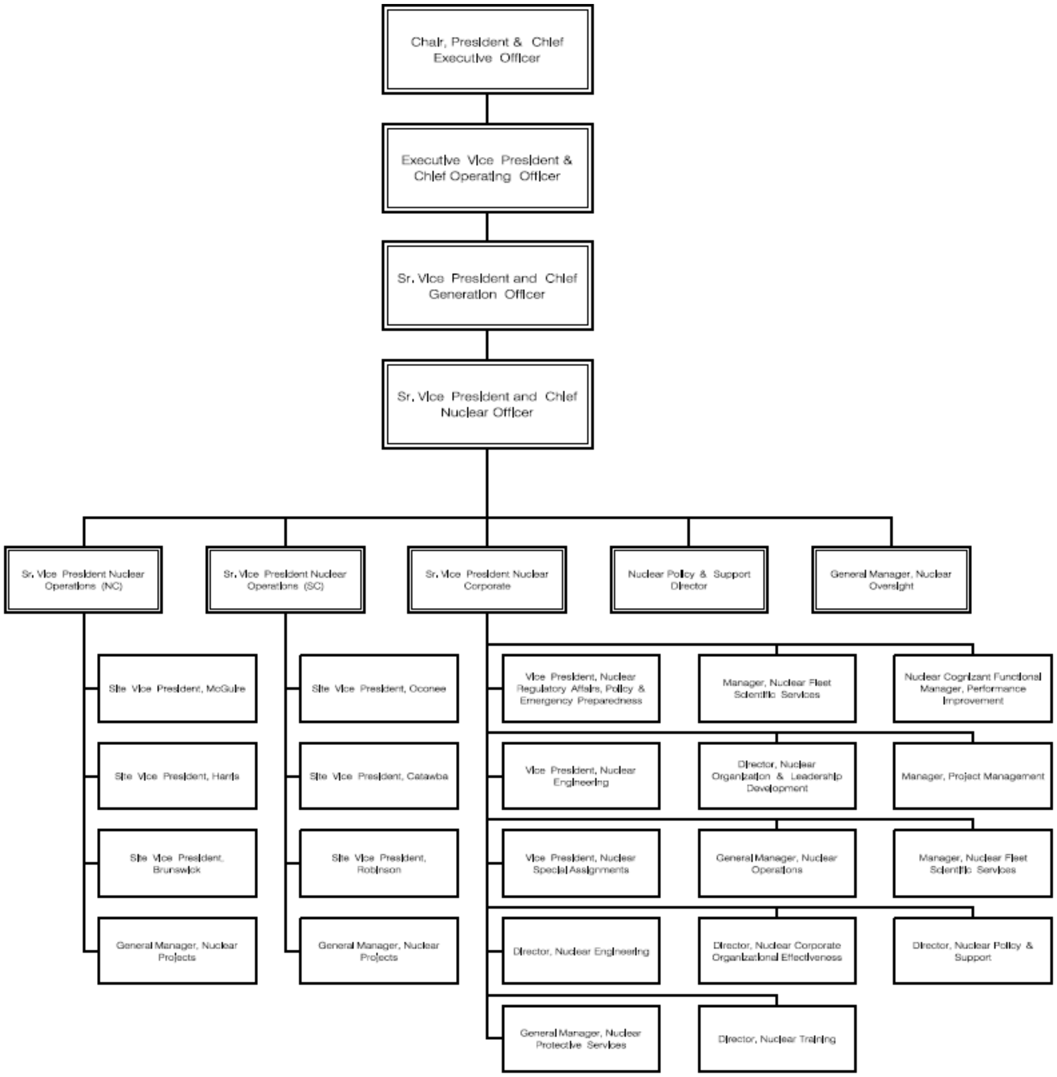

Figure 13-4. Nuclear Generation - Oconee Nuclear Site

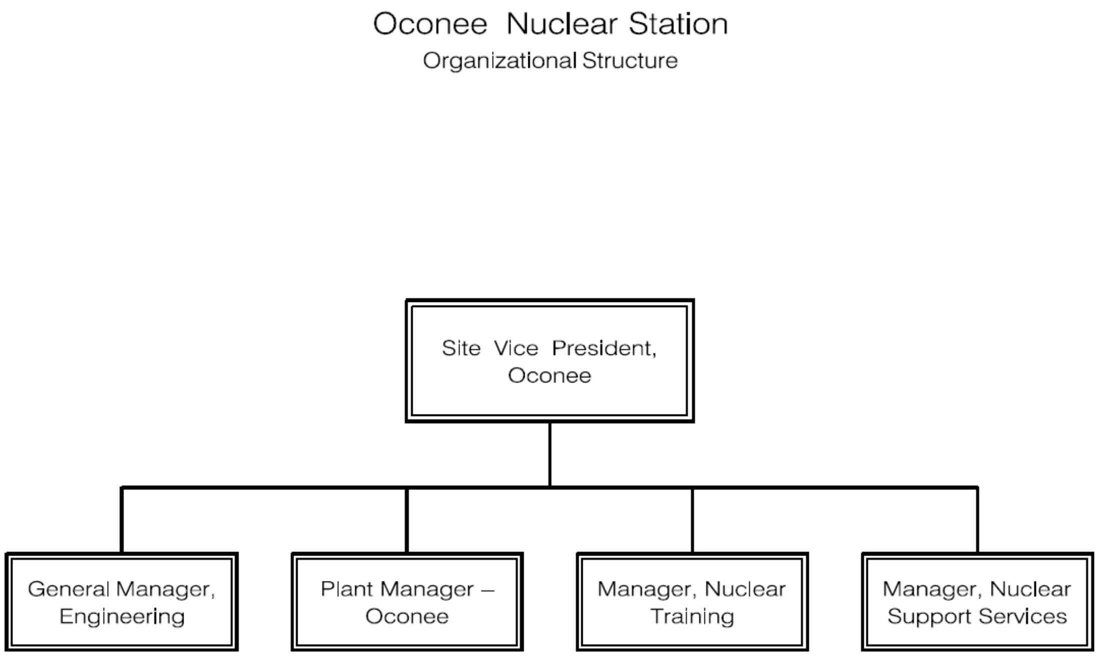

Figure 13-5. "At the Controls" Definition - Unit 1 & 2

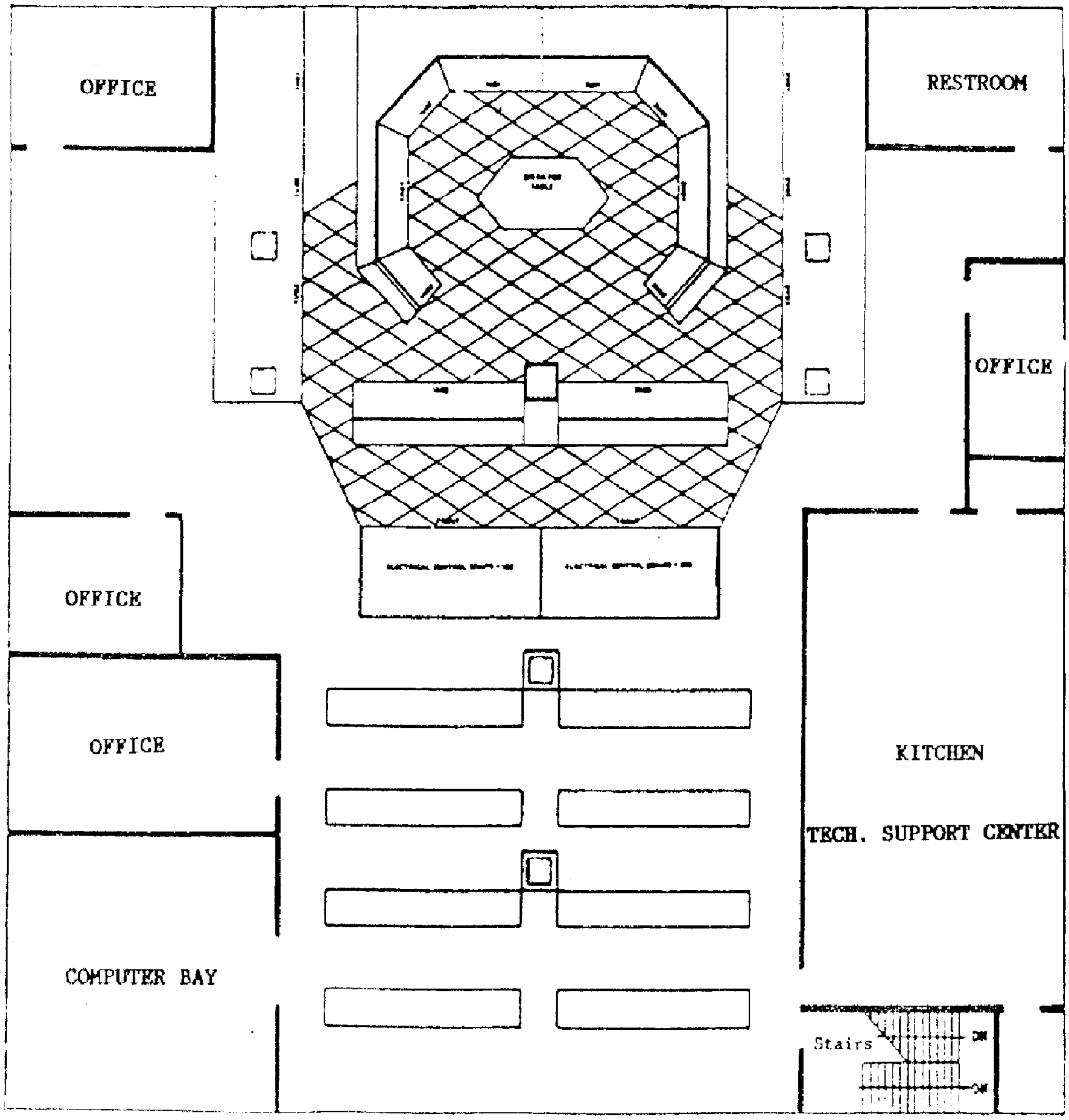

Figure 13-6. "At the Controls" Definition - Unit 3

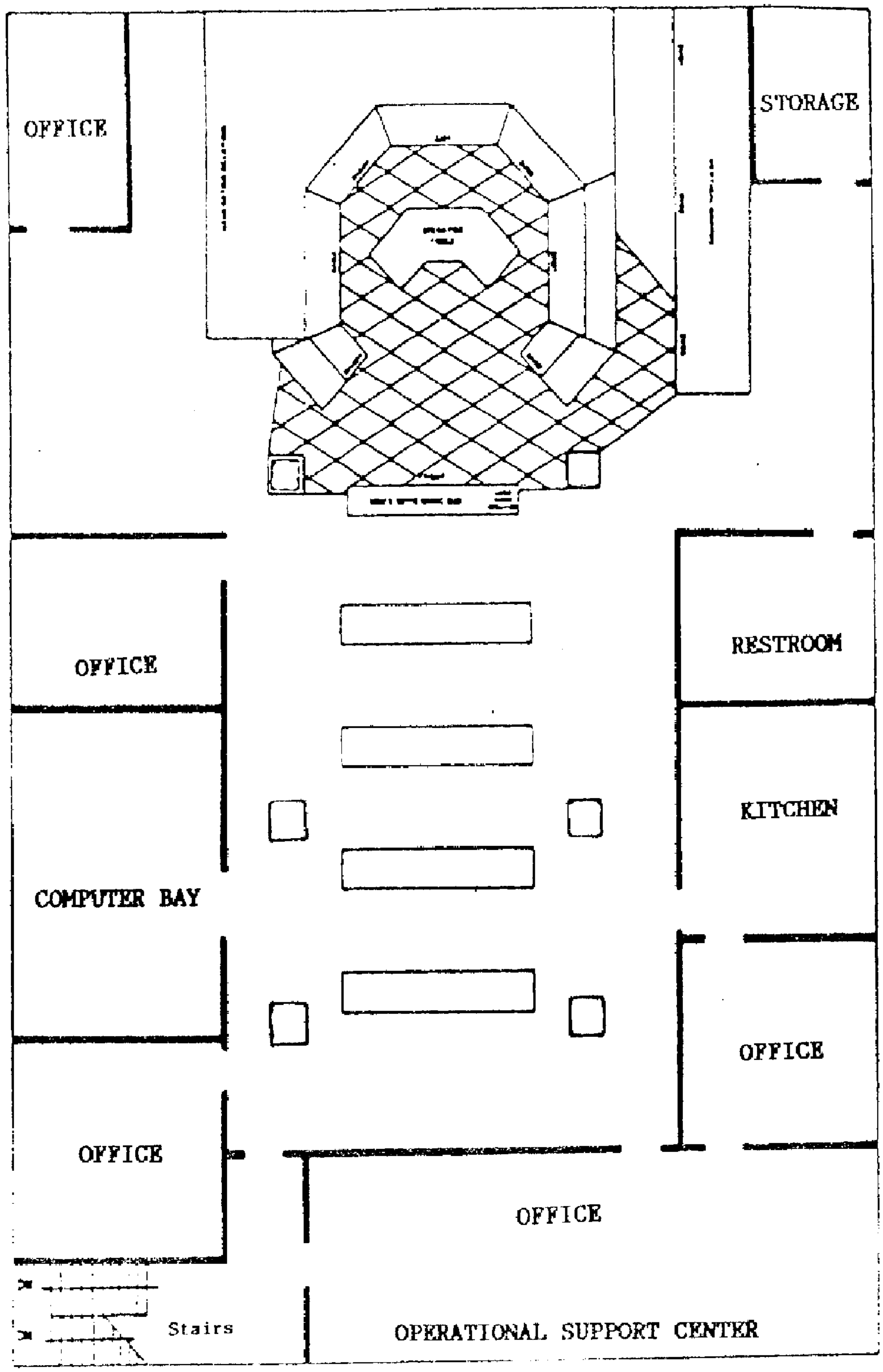

Figure 13-7. Deleted Per 2012 Update

Figure 13-8 Nuclear & PMC Organizational Structure

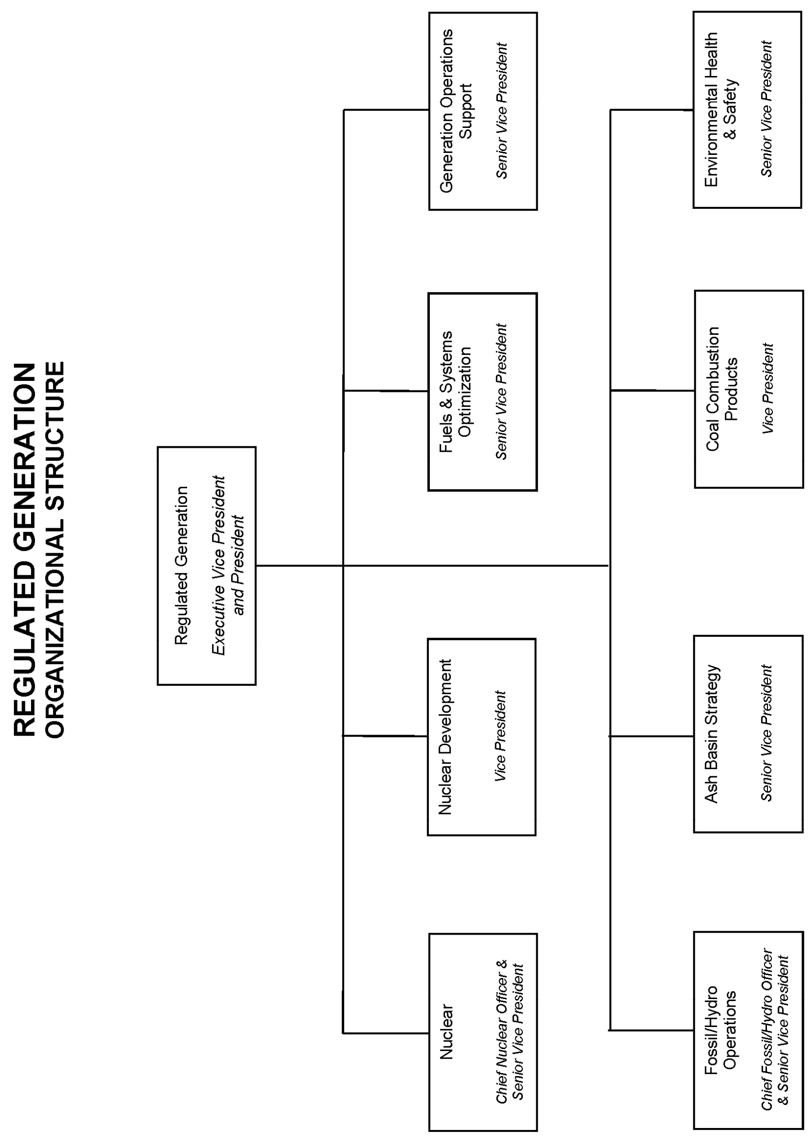

Table of Contents

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List of Tables

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14.0 Initial Tests and Operation

A comprehensive initial testing and operating program was conducted at the Oconee Nuclear Station. The purpose of this program was (1) to assure that the equipment and systems perform in accordance with design criteria, (2) to effect initial fuel loading in a safe efficient manner, (3) to determine the nuclear parameters, and (4) to bring the unit to rated capacity.

The test program began as installation of individual components and systems was completed. The individual components and systems were tested and evaluated according to written test procedures. An analysis of the test results verified that each component and system performed satisfactorily.

The written procedures for the initial tests and operation included the purpose, conditions, precautions, limitations, prerequisites, and the acceptance criteria.

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14.1 Organization of Test Program

14.1.1 General Organization

The organization for development and execution of the test program had major participants from the Oconee Nuclear Station operating personnel, the Nuclear Production Department General Office staff, and Babcock & Wilcox (B&W) Site Operations. Additional participants were from the Duke Engineering Department; Construction Department; and Electrical, Maintenance, and Construction Department. Bechtel Corporation participated in the tests associated with the Reactor Building.

The Oconee Nuclear Station organization for the test program consisted of the Superintendent, Assistant Superintendent, Station Review Committee (SRC), and a station test coordinator assigned for each test.

The Nuclear Production Department General Office staff organization for the test program consisted of a Nuclear Production General Office test coordinator assigned for each test.

The B&W Site Operations organization for the test program consisted of the Site Operations Manager, Site Operations Engineer, and Site Service Engineers who worked in the specific areas of test procedures, testing, startup, operations, maintenance, fueling, field analysis, and reports. The test program had technical support from B&W Nuclear Power Generation Division engineers. This support included technical analysis of the test results of certain tests with the result analyses transmitted to the Nuclear Production Department through normal channels of communication for checking and final analyses prior to test completed approval. Special rapid channels of communication were utilized where results were needed as soon as possible for other operations to proceed. The qualifications for the B&W Site Operations organization are listed below:

1. The minimum qualification for the B&W Site Operations Manager are:
    a. Graduate in engineering, or related physical science, or equivalent experience. (2 years experience for one year of college).
    b. Four years of responsible power plant experience or two years of responsible nuclear reactor experience.
    c. One year engineering or test program preparation experience for this or similar nuclear plant.
2. The minimum qualifications for the B&W Site Operations Engineer are:
    a. Graduate in engineering, or related physical science or equivalent experience. (2 years experience for one year of college).
    b. Two years of responsible power plant experience or one year of responsible nuclear reactor experience.
    c. One year engineering or test program preparation experience for this or similar nuclear plant.

Various individuals from the Mechanical, Electrical, and Civil sections of the Duke Engineering Department furnished technical support as needed in specific areas. Similarly, individuals in the Duke Construction Department, Duke Electrical, Maintenance, and Construction Department; and Bechtel Corporation furnished technical support as needed. This support principally applied to the review of test procedures prior to approval, analysis of test results, and the development and installation of modifications to the equipment and systems as required and identified during the test program. Qualifications for Duke personnel are contained in Chapter 13.

During the initial criticality (including fuel loading) and post-criticality phases of the test program, the nuclear physics and thermal hydraulics aspects of the reactor operation were under the technical responsibility of the Nuclear Production Department Nuclear Engineer and the Oconee Technical Support Engineer with assistance from B&W Site Operations, B&W Nuclear Power Generation Division, and Duke Engineering Department nuclear engineers as needed. A very close coordination between these groups existed with the appropriate support available when needed.

14.1.2 Responsibilities

14.1.2.1 Superintendent

The Superintendent or his authorized representative has final responsibility for the overall test program which included the approval of the test procedures, modification of test procedures, scheduling, completion of the tests, and approval of the test results. Approval of test procedures, modifications of test procedures, and approval of test results was not be made without giving proper consideration to recommendations of Babcock and Bechtel in their areas of interest.

14.1.2.2 Test Working Group

A Test Working Group (TWG) coordinated the activities of B&W, Duke Construction, and Nuclear Production Department during the preoperational test program. Representatives were from Oconee Nuclear Station and B&W (Site Operations Engineer). Duke Engineering; Construction; Steam Production General Office; and Electrical, Maintenance, and Construction Departments had representatives participate as required. The Oconee representative was chairman of the TWG. The TWG met at regular intervals; approximately every week during the most active phases of the program.

14.1.2.3 Station Test Coordinator

A station test coordinator was designated for each test. His responsibility was to develop the test procedure, coordinate the performance of the test, analyze results, identify discrepancies in test and acceptance criteria, initiate action to correct discrepancies, obtain approval of other parties when test had been completed satisfactorily, and file results in the master final documentation file.

14.1.2.4 Nuclear Test Engineer

A general office nuclear test engineer was designated for the testing program. His responsibility was to furnish technical guidance for the test program; to assist in the development of the approved procedures; and to assist the station personnel in conducting and evaluating the tests. Other members of the general office staff assisted in the test program as necessary.

14.1.2.5 Nuclear Safety Review Committee

An audit of safety related tests and their results was performed by the Nuclear Safety Review Committee.

14.1.3 Resolution of Discrepancies

Any discrepancies in systems or equipment found during the Test Program was promptly reported by the station test coordinator to the Superintendent. A corrective action request was made to the appropriate departments by the Superintendent to initiate any revision or repair deemed necessary. After the corrective action had been completed the Superintendent or his authorized representative was notified. Retests were performed on systems and components as necessary to verify the adequacy of the corrective action.

Prior to any revisions relating to the health and safety of the public or plant personnel, structural integrity of plant components and systems, and items covered by codes and nuclear standards, review and approval was necessary by the Duke Power Design Engineering Department with assistance from vendors or consultants as necessary.

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14.2 Tests Prior to Reactor Fuel Loading

The tests prior to reactor fuel loading assure that systems are complete and operate in accordance with design. The test program was divided into two phases: Preheatup Test Phase and Hot Functional Test Phase. In many instances systems were tested during both the Preheatup Test Phase and the Hot Functional Test Phase. A list of the tests performed prior to fuel loading is provided in Table 14-1. This section summarizes the initial test program prior to fuel loading for Oconee I, 2, and 3. The startup reports and supplements, References 1 through 14, provide the results of the startup test program for each unit.

The types of tests are classified as hydro/leak, operational, electrical, and functional with the following definitions for each classification:

Hydro/Leak Test	– Structural integrity leak test of the various systems and components at the appropriate pressure.
Operational Test	– Operation of systems and equipment under operating conditions.
Electrical Test	– Consists of: grounding, megger, continuity, and phasing checks; circuit breaker operation and control checks; potential measurement and energizing of buses and equipment to ensure continuity, circuit integrity, and proper functioning of electrical apparatus.
Functional Test	– Tests to verify that systems and equipment will function as intended.

Instruments and controls of each system or component were also subjected to a preoperational instrumentation and controls calibration prior to the initial operation of that system or component to assure proper operation.

An Engineered Safeguard Actuation System test was performed to assure actuation and proper operation of the Engineered Safeguards System and to evaluate the test method and frequency for future testing.

A one-time emergency power ES functional test which involves the three Oconee units during shutdown conditions has been evaluated. The scope of the test was described in NRC Safety Evaluation related to Amendment No. 220 to Facility Operating License DPR-38, Amendment No. 220 to Facility Operating License DPR-47, and Amendment No. 217 to Facility Operating License DPR-55 issued January 2, 1997, Duke letters to the NRC dated November 21, 1996, and December 11, 1996 (as supplemented by letters dated December 17, 19, and 26, 1996). This test verified certain design features of the emergency power system in an integrated fashion. Oconee Unit 3 was defueled and Oconee Units 1 and 2 were at cold shutdown with fuel in the reactor core during the performance of the test.

A one time Keowee Emergency Power - Engineering Safeguards Functional Test which involves Oconee Unit 3 during 3EOC17 has been evaluated. This test verifies certain design features of the emergency power and engineering safeguards systems in an integrated fashion. The scope of the test supports Nuclear Station Modification (NSM) ON-53014. This integrated test will emergency start the Keowee Unit aligned to the underground power path from shutdown condition and accept loads from the shutdown Oconee Unit through the standby bus.

14.2.1 Preheatup Test Phase

The objective of the Preheatup Test Phase was to assure that the equipment and systems perform as required for hot functional testing. This phase of the testing included certain preoperational calibration, hydro/leak, operational, electrical, and functional tests as required. The Reactor Building Containment System has undergone a structural integrity and integrated leakage rate test to verify the building design and to ensure that leakage is within the design limit.

14.2.2 Hot Functional Test Phase

The Hot Functional Test Phase was a period of hot operation of the Reactor Coolant System and the associated auxiliary systems prior to the initial fueling of the reactor. The Reactor Coolant System was heated up to no-load operating pressure and temperature.

The Hot Functional Test Phase continued the preparation toward the initial fuel loading. The objectives of this phase of the test program were:

1. Operational test of systems, components, and non-nuclear instrumentation and controls at no load operating pressure and temperature.
2. Operator training.
3. Verification of normal operating procedures.
4. Verification of emergency operating procedures.

Following the hot functional test, the reactor vessel intervals were removed and inspected for signs of distress, e.g., loose parts, cracking, or fretting.

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14.3 Initial Criticality Test Program

The Initial Criticality Test Program consists of the initial fuel loading followed by initial criticality.

14.3.1 Initial Fuel Loading

Fuel was loaded into the reactor in accordance with a step-by-step written procedure. This procedure contains a number of safety precautions and operating limitations.

The fuel loading procedure includes:

1. A sequence of loading temporary detectors, sources, control rods, and fuel assemblies in order to maintain shutdown margin requirements.
2. The conditions under which fuel loading may continue after any step.
3. An identification of responsibility and authority.
4. During any reactivity changes, a minimum of two detectors will be operating and indicating neutron level after the source has been inserted. At all other times, at least one detector shall be indicating neutron level.
5. Two completely independent plots of reciprocal neutron multiplications as a function of the parameter causing reactivity change are maintained.
6. Reactivity effects for each fuel assembly addition are checked prior to the release of the fuel assembly by the fuel handling grapple.
7. An estimate of the reactivity effect for the next fuel addition is made prior to insertion of the next fuel assembly.
8. The boron concentration in the reactor vessel, spent fuel pool, and Reactor Coolant System is maintained at a value to assure the required subcritical margin at all times.
9. The valve alignment of the auxiliary systems connected to the Reactor Coolant System is checked periodically to prevent dilution of the reactor coolant boron concentration.
10. Chemical analysis and water level monitoring is used to assure that inadvertent dilution of the reactor coolant boron concentration has not occurred.
11. Communication between control room and fuel handling areas is maintained.
12. The Plant Radiation Monitoring Systems are in operation.
13. Radiation Protection and chemistry monitoring and services are provided.

14.3.2 Preparation for Initial Criticality

Upon completion of the initial fuel loading, prestartup checks were completed prior to the approach to initial criticalty. The prestartup checks included:

1. Control rod trip test
2. Reactor coolant flow test
3. Reactor coolant flow coastdown test

A reactor coolant flow test and a reactor coolant flow coastdown test were conducted under cold reactor conditions to assure that the flow characteristics of the Reactor Coolant System had not materially changed as a result of the reactor core installation.

14.3.3 Initial Criticality

A written procedure was followed during the approach to initial criticality. This procedure specified in detail the sequence to be followed, the limitations and precautions, the required plant status, and the prerequisite system conditions. (This procedure also specified the alignment of fluid systems to assure controlled boron dilution and core conditions under which the approach to criticality proceeded.)

Permissible rod group withdrawal and deboration are based on calculated reactivity effects. Two independent plots of inverse multiplication characteristics are maintained during rod group withdrawal and deboration. A predicted rod group position or boron concentration for criticality is determined before the next rod group withdrawal or deboration is started.

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14.4 Postcriticality Test Program

The Postcriticality Test Program was performed to provide assurance that the plant is operating in a safe and efficient manner. Systems and components which cannot be operationally tested prior to initial criticality were tested during the Postcriticality Test Program to verify reactor parameters and to obtain information required for plant operation. A list of the postcriticality tests is provided in Table 14-2. This section summarizes the test program after each unit achieved initial criticality. The startup reports and supplements, References 1 through 14, provide the results of the startup test program for each unit.

14.4.1 Zero Power Physics Tests

Following initial criticality, a program of reactor physics measurements was undertaken to verify the physics parameters. Measurements were made under zero power condition at sufficient temperature plateaus to verify calculated worths of individual control rods and control rod groups, moderator temperature coefficient, boron worth, and excess reactivity of the core. In addition, the response of the source and intermediate range nuclear instrumentation were verified.

Detailed written procedures specifying the sequence of tests, parameters to be measured, and conditions under which each test is to be performed were followed. These tests involve a series of prescribed control rod configurations and boron concentrations with intervening measurements of control rod and/or boron worth during boron dilution or boron injection.

14.4.2 Power Escalation Test Program

Following determination of the operating characteristics and physics parameters of the reactor at zero power, a detailed power escalation test program was conducted. This program consists of specified incremental increases in power levels up to full power with appropriate testing conducted at each power level. An analysis of the significant parameters at each step was made prior to initiating an additional power escalation.

At selected power levels, the following tests were performed:

1. Unit heat balance test
2. Power coefficient measurement
3. Core power distribution measurement
4. Unit load steady state test
5. Unit transient test.

Other Power Escalation Tests were performed at one or more power levels in the test sequence.

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14.5 Startup Physics Test Program

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14.6 Operating Restrictions

During initial operations and associated testing, the normal plant safety procedures and technical specifications are in effect. In addition, special safety precautions and limitations are included in the test procedures and more restrictive operating limitations than those in the technical specifications are imposed, where required, from initial criticality through the power escalation program. The Reactor Protective System power level trip point was initially set at a low value and raised as the power escalation program progresses.

14.6.1 References

1. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), November 16, 1973, Oconee 1 Startup Report.
2. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), February 14, 1974, Oconee 1 Startup Report - Supplement 1.
3. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), May 15, 1974, Oconee I Startup Report - Supplement 2.
4. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), August 12, 1974, Oconee I Startup Report - Supplement 3.
5. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), November 11, 1974, Oconee I Startup Report - Supplement 4.
6. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), February 7, 1975, Oconee 1 Startup Report - Supplement 5.
7. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), May 8, 1975, Oconee I Startup Report - Supplement 6.
8. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), August 9, 1974, Oconee 2 Startup Report.
9. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), November 7, 1974, Oconee 2 Startup Report - Supplement 1.
10. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), February 5, 1975, Oconee 2 Startup Report - Supplement 2.
11. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), May 6, 1975, Oconee 2 Startup Report - Supplement 3.
12. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), March 14, 1975 Oconee 3 Startup Report.
13. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), June 12, 1975, Oconee 3 Startup Report - Supplement 1.
14. Parker, W. O. Jr. (DPC), Letter to Moseley, N.C. (NRC), August 25, 1975, Oconee 3 Startup Report - Supplement 2.
15. Parker, W. O. Jr. (DPC), Letter to Denton, H. R. (NRC), August 15, 1980.
16. Parker, W. O. Jr. (DPC), Letter to Denton, H. R. (NRC), August 15, 1980.
17. Stolz, J. F. (NRC), Letter to Parker, W. O. Jr (DPC), March 23, 1981.

18. Thies, A. C. (DPC), Letter to Denton, H. R. (NRC), May 29, 1981.
19. Wagner, P. C. (NRC), Letter to Parker, W. O. Jr. (DPC), November 30, 1981.
20. Tucker, H. B. (DPC), Letter to Denton, H. R. (NRC), September 2, 1986.
21. Stolz, J. F. (NRC), Letter to Tucker, H. B. (DPC), October 7, 1986.

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Appendix 14A. Tables

Table 14-1. Tests Prior to Initial Fuel Loading

Penetration Room Pressure Drop and Filter Test
Reactor Building Structural Integrity Test
Reactor Building Leak Tests
Reactor Building Cooling System Functional Test
Reactor Building Purge System Functional and Operational Test
Reactor Internals Vent Valve Inspection Test
Core Flooding System Engineered Safeguards Test
High Pressure Injection System Engineered Safeguards Test
Low Pressure Injection System Functional Test
Low Pressure Injection System Engineered Safeguards Test
Reactor Building Spray System Functional Test
Soluble Poison Control Test
Low Pressure Service Water System Test
Condenser Circulating Water System Gravity Flow Test
Steam Generator Hydrostatic Test
Integrated Control Rod Drive System Test
Control Rod Drive Trip Test
Process Radiation Monitoring System Calibration and Functional Test
Area Radiation Monitoring System Calibration and Functional Test
Reactor Coolant Hot Leakage Test
Control Rod Drive Operational Test
Electrical System Normal and Emergency Operation Test
Integrated Safeguards Actuation Test
Reactor Protective System Functional Test
Keowee Hydro Emergency Power Functional Test
Control Rod Drive Mechanism Temperature Test

Table 14-2. Postcriticality Tests

Zero Power Physics Test
Reactor Coolant Flow Test
Reactor Coolant Flow Coastdown Test
Controlling Procedure for Power Escalation
Loss of Control Room
Nuclear Instrumentation Power Calibration
Biological Shield Survey Test
Natural Circulation Test
Reactivity Coefficients at Power
Xenon Reactivity Worth and Rapid Depletion Test
Core Power Distribution Test
Reactor/Turbine Trip Test
Induced Power Oscillation Test
Rod Worth at Power Test
Power lmbalance Detector Correlation Test
Nuclear Steam Supply System Heat Balance
Unit Load Steady-State Test
Unit Transient Test

Table of Contents

List of Tables

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List of Figures

15.0 Accident Analyses

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15.1 Methodology

15.1.1 Overview

This chapter details the expected response of the plant to the spectrum of transients and accidents which constitute the design basis events. The methodologies used to analyze the Chapter 15 transients and accidents fall into three general categories. These are the non-LOCA transient and accident analysis methodologies which are detailed in the Duke Power topical report DPC-NE-3005-PA (Reference 1), the AREVA NP. LOCA analysis methodology (Reference 2) described in Section 15.14, and the Duke Power offsite dose analysis methodology described in Section 15.1.10.

The DPC-NE-3005-PA topical report methodology was used to establish a new set of licensing basis analyses beginning with Oconee Unit 2 Cycle 18. The following transients and accidents are analyzed with the new methodology. The specific cases analyzed for each transient or accident are listed in Table 15-32.

15.2	Startup Accident
15.3	Rod Withdrawal at Power Accident
15.4	Moderator Dilution Accidents
15.5	Cold Water Accident
15.6	Loss of Coolant Flow Accidents
15.7	Control Rod Misalignment Accidents
15.8	Turbine Trip Accident
15.9	Steam Generator Tube Rupture Accident
15.12	Rod Ejection Accident
15.13	Steam Line Break Accident
15.17	Small Steam Line Break Accident

Section 15.1, "Uncompensated Operating Reactivity Changes", in the original FSAR was deleted since the plant transient response due to the effects of fuel depletion and xenon buildup are insignificant and do not challenge the Reactor Protective and Engineered Safeguards Systems or approach any design limits. Sections 15.10, 15.11, 15.15, and 15.16 do not require thermal-hydraulic transient analyses methods and were not reanalyzed in DPC-NE-3005-PA.

15.1.2 Topical Reports

The topical reports which describe the analysis methodologies used in this chapter are as follows:

DPC-NE-3000-PA

DPC-NE-3000-PA, "Thermal-Hydraulic Transient Analysis Methodology," (Reference 4) describes the RETRAN-3D (Reference 38) system transient thermal-hydraulic models and the VIPRE-01 (Reference 6) core transient thermal-hydraulic models used by Duke Power to analyze most of the non-LOCA transients and accidents. This report includes the standard nodalization model and the various code options that are used.

DPC-NE-3005-PA

DPC-NE-3005-PA, "UFSAR Chapter 15 Transient Analysis Methodology," (Reference 1) describes the Duke Power methodology for analyzing the UFSAR Chapter 15 non-LOCA transients and accidents for the Oconee Nuclear Station. This report includes a description of the computer codes used, the physics parameters, the setpoint methodology, and details of the initial conditions, boundary conditions, acceptance criteria, and all other aspects of the methodology. The computer codes comprising this methodology are RETRAN-3D (Reference 38), VIPRE-01 (Reference 6), CASMO-3 (Reference 7) or CASMO-4 (Reference 44), SIMULATE-3 (Reference 8), SIMULATE- 3K (Reference 9), and TACO-3 (Reference 10).

DPC-NE-1004-A

DPC-NE-1004-A, "Nuclear Design Methodology Using CASMO-3 / SIMULATE-3P," (Reference 11) describes the Duke Power methodology for the neutronic simulation of the Oconee reactors with the CASMO-3 (Reference 7)/ SIMULATE-3 (Reference 8) codes.

DPC-NE-1006-PA

DPC-NE-1006-PA, "Oconee Nuclear Design Methodology using CASMO-4/SIMULATE-3" (Reference 45) describes the Duke Power methodology for the neutronic simulation of the Oconee reactors with the CASMO-4 (Reference 44)/ SIMULATE-3 (Reference 8) codes.

DPC-NE-2003-PA

DPC-NE-2003-PA, "Core Thermal-Hydraulic Methodology Using VIPRE-01," (Reference 12) describes the Duke Power methodology for core thermal-hydraulic analysis for Oconee using the VIPRE-01 code. The non-statistical DNBR limit using the BWU CHF correlation is developed in this report.

DPC-NE-2005-PA

DPC-NE-2005-PA, "Thermal-Hydraulic Statistical Core Design Methodology," (Reference 13) describes the Duke Power methodology for determining the statistical DNBR limits using the VIPRE-01 code. This methodology allows the uncertainty in many of the DNB-related parameters to be combined into a statistical DNBR limit, rather than to include each uncertainty explicitly in the thermal-hydraulic analysis. For some of the transients and accidents the primary flowrate associated with less than four pumps in operation, and the higher flow uncertainty at reduced flowrates, result in different statistical DNBR design limits. The applicable limit is given for each analysis. The non-statistical DNBR limits using the BWU correlations are developed in this report.

BAW-10192-PA

BAW-10192-PA, "BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator Plants," (Reference 2) describes the RELAP5-based AREVA NP, LOCA Evaluation Model. This topical report has been accepted by the NRC as in compliance with 10 CFR Appendix K (Reference 14). The model changes necessary to analyze M5 cladding are contained in a separate topical report (Reference 37). The computer codes which comprise this methodology are RELAP5/MOD2-B&W (Reference 15), CONTEMPT (Reference 16), REFLOD3B (Reference 17), and BEACH (Reference 18). The Oconee large-break and small-break LOCA events are analyzed with this Evaluation Model.

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15.1.3 Computer Codes and CHF Correlations

RETRAN-3D

The non-LOCA system transient thermal-hydraulic analyses use the RETRAN-3D code (Reference 38). RETRAN-3D was developed by Computer Simulation & Analysis, Inc. for EPRI to enhance and extend the simulation capabilities of the RETRAN-02 code (Reference 5). RETRAN-O2 has the flexibility to model any general fluid system by partitioning the system into a one-dimensional network of fluid volumes and connecting junctions. The mass, momentum, and energy equations are then solved by employing a semi-implicit solution method. The equations are based on a homogeneous two-phase mixture, with capability for phase separation via bubble rise and slip models. A non-equilibrium pressurizer model, special component models for pumps, valves, and control systems, and general heat transfer modeling are included.

RETRAN-3D has many new and enhanced capabilities relative to RETRAN-02, in particular, a 3-D kinetics core model, improved two-phase models, an improved heat transfer correlation package, and an implicit numerical solution method. Most of the capabilities of the RETRAN-02 code have been retained within RETRAN-3D as options, except for a limited number of models and correlations that were not in use. For transients which challenge the DNBR limit, RETRAN-3D provides core boundary conditions to VIPRE-01 and SIMULATE-3.

VIPRE-01

The core thermal-hydraulic and fuel pin analyses use the VIPRE-01 code (Reference 6) developed by the Electric Power Research Institute. VIPRE-01 uses the subchannel analysis approach in which the fuel assembly is divided into a number of quasi-one-dimensional channels that communicate laterally by diversion crossflow and turbulent mixing. Conservation equations of mass, axial and lateral flow, and momentum are solved. The flow field is assumed to be incompressible and homogeneous, with models for subcooled boiling and co-current phase slip. VIPRE-01 accepts boundary conditions from RETRAN-3D and SIMULATE-3 and determines the DNBR using the applicable CHF correlations.

CASMO-3

Nuclear constants are generated with the Studsvik of America code CASMO-3 (Reference 7) for use in Oconee reload design (Reference 11). CASMO-3 is used for generating data used as input to the SIMULATE codes.

CASMO-4

Nuclear constants are generated with Studsvik Scandpower code CASMO-4 (Reference 44) for use in Oconee reload design (Reference 45). CASMO-4 is used for generating data used as input to the SIMULATE codes.

SIMULATE-3

Nuclear parameters and core power distributions are generated with the Studsvik of America code SIMULATE-3 (Reference 8) for use in Oconee reload design (References 11 and 45). Nuclear constants are input to SIMULATE-3 from the CASMO-3 or CASMO-4 code. SIMULATE-3 outputs are input to the RETRAN-3D and VIPRE-01 codes.

SIMULATE-3K

The Studsvik of America code SIMULATE-3K (Reference 9) is used for transient three-dimensional modeling of the rod ejection accident. SIMULATE-3K provides the same neutronics solution to steady-state 3-D calculations as SIMULATE-3. Nuclear constants are input to SIMULATE-3 from the CASMO-3 or CASMO-4 code. SIMULATE-3K rod ejection analysis results are input to RETRAN-3D and VIPRE- 01.

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TACO-3

The TACO-3 code (Reference 10) developed by AREVA NP is used to calculate the initial fuel pin thermal and mechanical conditions for the non-LOCA analyses performed by Duke Power, and for the LOCA analyses performed by AREVA NP.

RELAP5/MOD2-B&W

The RELAP5/MOD2-B&W code (Reference 15) developed by AREVA NP, is used for best-estimate and licensing transient simulation of pressurized water reactors. It has also been modified to include the conservative models required for LOCA analysis per Appendix K to 10 CFR 50 (Reference 14). The solution technique contains two energy equations, a two-step numerics option, a gap conductance model, constitutive models, and control and component system models. This code is used for the blowdown simulation in Oconee large-break LOCA analyses, and for the thermal-hydraulic response in the small-break LOCA analyses.

CONTEMPT

The CONTEMPT code (Reference 16) as modified by AREVA NP, is used to calculate the containment pressure following LOCA. The containment pressure is used as an input to the RELAP5 blowdown analysis and the REFLOD3 refill and reflood analysis.

REFLOD3B

The REFLOD3B code (Reference 17) developed by AREVA NP, is used for simulation of the refill and reflood periods of the large-break LOCA analysis. The program calculates flows, mass and energy inventories, pressures, temperatures, and steam qualities along with variables associated with the refilling of the reactor lower plenum and the recovery of the core.

BEACH

The BEACH code (Reference 18) developed by AREVA NP, is used for the prediction of reflood heat transfer during the large-break LOCA analysis. It calculates the peak cladding temperature and the local oxidation for comparison with the 10 CFR 50.46 (Reference 22) acceptance criteria.

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BHTP Critical Heat Flux Correlation

The BHTP critical heat flux correlation (Reference 41) is used in the VIPRE-01 code to calculate the DNBR for non-LOCA transient and accident analyses for the Mark-B-HTP fuel assembly design.

BWU-Z Critical Heat Flux Correlation

The BWU-Z critical heat flux correlation (Reference 24) is used in the VIPRE-01 code to calculate the DNBR for non-LOCA transient and accident analyses for fuel assemblies with mixing vane grids.

BWU-N Critical Heat Flux Correlation

The BWU-N critical heat flux correlation (Reference 24) is used in the VIPRE-01 code to calculate the DNBR for non-LOCA transient and accident analyses for fuel assemblies with mixing vane grids, but in the lower part of the fuel assembly where there are no mixing vane grids. This correlation can also be used for the steam line break DNBR analysis.

W-3S Critical Heat Flux Correlation

The W-3S critical heat flux correlation as programmed in the VIPRE-01 code (Reference 6) is used to calculate the DNBR for the steam line break accident, when the core conditions are beyond the correlation ranges for the other critical heat flux correlations.

Modified-Barnett CHF Correlation

The modified-Barnett (MBAR) CHF correlation (Reference 42) is used to calculate the DNBR for the steam line break accident for the Mark-B-HTP fuel assembly design when the core conditions are beyond the BHTP correlation ranges.

15.1.4 Initial Conditions

The generic initial conditions assumed in the transient and accident analyses are summarized in Table 15-34 and referenced figures. These values have been selected to ensure that the results of each analysis have an appropriate level of overall conservatism. Many of the initial conditions are determined based on the nominal value of the plant parameter plus or minus the uncertainty associated with each parameter. Parameters for which the uncertainty is included in the statistical DNBR limit are set to the nominal value. Initial conditions which are not included in this table are provided in the detailed description of each analysis.

Sometimes it is desirable to extend the full power operation of a reload cycle by reducing the average Reactor Coolant System temperature (RCS T-ave) at end-of-cycle (EOC) conditions. Reducing RCS T-ave adds positive reactivity due to moderator temperature feedback and extends the full power operation capabilities. The safety analyses events described in this chapter have been evaluated for an end-of-cycle T-ave reduction of up to 10°F lower than the RCS T-ave values shown in Table 15-34. The 10°F reduced RCS T-ave with 4 Reactor Coolant Pumps (RCPs) operating is acceptable and does not create more limiting accident results than those reported in this chapter.

15.1.5 Setpoints and Delay Times

The Reactor Protective System and Engineered Safeguards Protective System trip setpoints and delay times are summarized in Table 15-35. The setpoints are based on the technical specification values, and are either increased or decreased to account for setpoint drift depending on whether an earlier or later reactor trip is conservative. Trip delay times account for instrument string delays and component delays, such as the control rod gripper coil release delay.

15.1.6 Reactivity Insertion Following Reactor Trip

The reactivity insertion following reactor trip is a combination of a minimum available tripped rod worth and a normalized insertion rate. The minimum available tripped rod worth assumed in safety analyses must ensure, as a minimum, that the shutdown margin in the technical specifications is preserved. This shutdown margin assumes that the most reactive rod remains in the fully withdrawn position and that the other control rods drop from their power dependent insertion limits. The normalized reactivity insertion rate is determined by bounding control rod drop times as determined by plant testing, and by developing a conservative relationship between rod position and normalized reactivity worth.

15.1.7 Decay Heat

In the non-LOCA transients and accident analyses for which the post-trip decay heat is an important modeling consideration, the ANSI/ANS-5.1-1979 Standard (Reference 25) is used. The inputs to the calculation of the time-dependent decay heat per the ANS Standard are based on Oconee-specific core physics parameters. This modeling is implemented in the application of the RETRAN-3D code using either the built-in ANS standard with inputs to account for Oconee-specific core parameters, or as an input table of decay heat vs. time. The decay heat modeled by AREVA NP in the LOCA analysis is 1.2 times the 1971 ANS Standard as required by 10 CFR 50 Appendix K (Reference 14).

15.1.8 Single Failure and Loss of Offsite Power Assumptions

A limiting active single failure in the Reactor Protective System or in the Engineered Safeguards is assumed. A single failure in the Emergency Feedwater System is also considered. A failure of the manual atmospheric dump valves is not considered. A loss of offsite power is only applied to the Section 15.13 steam line break accident, for which it is assumed to be lost at time zero, and for the Section 15.14 LOCA analyses.

15.1.9 Credit for Control Systems and Non-Safety Components and Systems

Control systems are generally assumed to respond as designed or remain in manual control (inactive), whichever assumption is more conservative. Non-safety components and systems are generally not credited in the analyses. The following are specific exceptions to the general modeling philosophy on control systems, and the situations where non-safety components and systems are credited in the analyses:

1. In the dropped rod event, the Integrated Control System will respond by initiating a plant runback to a reduced power level. Since this plant runback assists in the mitigation of the dropped rod event, no credit is taken for this control system design feature. This assumption is an additional conservatism that is not required by the methodology philosophy.
2. For a loss of all reactor coolant pumps without a loss of the Main Feedwater System, the Integrated Control System is credited for raising steam generator levels to the natural circulation setpoint. This design feature is implicitly credited in the loss of coolant flow event, and involves non-safety equipment. A failure of this design function would be mitigated manually by operator action to start the Emergency Feedwater (EFW) System.
3. The moderator dilution accident credits the control rod insertion limit alarm to alert the operator that a boron dilution event is in progress. This alarm relies on non-safety equipment and the plant computer.
4. Many of the transient and accident analyses involve control rod movement. These analyses credit the normal withdrawal sequence, overlap, and rod speed, which are controlled by non-safety control systems.
5. For certain failures in the EFW System, credit is taken for realigning EFW flow through the non-safety MFW System.
6. Steaming of the steam generators with manual non-safety atmospheric dump valves is credited.
7. Deleted per 2003 update

8. The capability to remotely throttle certain valves is credited. Some of the controls required to remotely throttle these valves are not safety-grade.
9. Electrical bus voltage and frequency control are credited. These are controlled by non-safety components.
10. The Integrated Control System trips both main feedwater pumps on a high steam generator level indication. A high level indication may occur following a main steam line break due to the pressure drops that result from the blowdown of the steam generator. Tripping of the main feedwater pumps will be assumed to occur in the steam line break analysis only if the plant response is more limiting.

15.1.10 Environmental Consequences Calculation Methodology

Environmental Consequences

A summary of the offsite doses is presented in Table 15-16. A description of each accident analysis is given in the appropriate section.

Fission Product Inventories

Inventory in the Core: Fission product inventories within the core are calculated based on the ORIGEN methodology (e.g., ORIGEN-ARP or SAS2H/ORIGEN-S of the SCALE computer code)(Section 15.1, Ref. 27). The core inventories for the Maximum Hypothetical Accident are shown in Table 15-15.

Inventory in the Fuel Pellet Clad Gap: The fuel pin gap activities were determined using Regulatory Guide 1.183 (Section 15.1, Ref. 35). For non-DNB fuel pins that exceed the rod power/burnup criteria of Footnote 11 in RG 1.183, the gap fractions from RG 1.183 are increased by a factor of 4 for Kr-85, Cs-134, and Cs-137. The gap fractions for all other isotopes remain at their pertinent RG 1.183, Table 3 values (References 46 and 47). The fuel cycle design ensures that none of these fuel pins experience DNB following any design basis accident. The fuel cycle design also ensures that no fuel rod predicted to experience DNB in any other non-LOCA accidents (e.g., locked rotor accident or rod ejection accident) will have operated beyond the power/burnup criteria of Footnote 11 in Regulatory Guide 1.183 and that the gap fractions used in these non-LOCA accident analyses remain those stated in Table 3 of RG 1.183. The environmental consequences of the control rod ejection accident, and fuel handing accidents are based on the assumption that the fission products in the gap between the fuel pellets and the cladding of the damaged fuel rods are released as a result of cladding failure. The inventories used for the control rod cluster assembly ejection accident are shown in Table 15-50. The gap inventory for the fuel handling accident is shown in Table 15-1.

Inventory in the Reactor Coolant: The quantity of fission products released to the reactor coolant during steady state operation is based on the use of escape rate coefficients (sec^{-1}) derived from experiments involving purposely defected fuel elements. (Section 15.1, References 29, 30, 31, 32) These coefficients represent the fraction of the activity in the fuel that is released, per unit time. Values of the escape rate coefficients used in the calculations are shown in Table 11-4.

Calculations of isotopic specific activities in the reactor coolant arising from steady-state fission product releases from the fuel (except for Kr-85) were performed with the Duke computer code PWR-SOURCE. The code calculates equilibrium reactor coolant fission product inventories and specific activities from the steady-state solutions to the differential equations for the radioactive decay chains for more than 150 isotopes. Due to the extremely long half life of Kr-85, an equilibrium activity level will not be reached in the reactor coolant during an operating cycle. For this particular isotope, the activity level is calculated from the exact solution of the decay chain, utilizing equilibrium activities of parent isotopes as inputs.

The reactor coolant activity levels are listed in Table 15-51. Dose Equivalent Iodine (DEI) and Dose Equivalent Xenon (DEX) calculations are shown in Table 15-65 and Table 15-66.

Inventory in the OTSGs and Secondary-Side Systems: The concentration of the iodine isotopes in the steam generators and secondary system coolant are assumed to be at the Technical Specification limit of 0.1 μCi/gm dose equivalent I-131, unless otherwise stated in a specific accident analysis. No credit is taken for removal of iodine from the secondary coolant by station demineralizers.

The concentrations of noble gases in the secondary side coolant are assumed to be negligible, and therefore are not modeled. Noble gases entering the secondary coolant system are continuously vented to the atmosphere via the condenser off-gas system. Thus, there would be only very small quantities of these gases within the secondary side coolant that could be released during an accident, and their contribution to the overall whole body dose will be negligible.

Calculation of Accident Doses

The Code of Federal Regulations, Title 10, Part 100, Section 11 (Section 15.1, Ref. 34) requires a dose consequence evaluation of postulated accidents resulting in fission product releases to the environment. Two types of doses are calculated for purposes of analyzing these accidents: internal doses to the thyroid resulting from inhalation of iodines and external whole body doses resulting from submersion in noble gases and iodines.

The dose consequences of a Maximum Hypothetical Accident, a Rod Ejection Accident, Large and Small Main Steam Line Break Accidents and Fuel Handling Accidents have been evaluated using an Alternative Source Term in accordance with the Code of Federal Regulations, Title 10, Part 50, Section 67 (Reference 39). For these evaluations, a total effective dose equivalent (TEDE) dose is calculated. Control room doses are also reported for these accidents.

Doses are calculated at two locations: the exclusion area boundary (EAB) and the outer boundary of the low population zone (LPZ). Doses calculated at the EAB and LPZ are modeled as a receptor located in a semi-infinite cloud of activity per Reg. Guide 1.109. (Section 15.1, Ref. 33).

For accidents using Alternative Source Term methodology, control room doses are calculated, and follow Regulatory Guide 1.183 (Reference 35). Values assumed for rate of unfiltered inleakage into the control room and airflow imbalance between dual control room air intakes bound the tested site values.

Atmospheric dispersion factors (χ/Qs) used in calculating control room doses are given in Table 15-61, and conform in general to the regulatory positions of Regulatory Guide 1.194 (Reference 43). Table 15-61 values represent bounding χ/Qs from a particular release type to either control room air intake. For use in dose analyses, these values may be adjusted to represent Oconee's dual control room intake configuration.

15.1.11 Reload Safety Evaluation

Each fuel reload cycle design is reviewed to determine if the values of the safety analysis physics parameters assumed in the UFSAR Chapter 15 licensing basis transient and accident analyses remain valid. If the licensing basis assumptions remain bounding for the reload core, then no additional actions are required. If the predicted values violate the licensing basis assumptions for any of the key parameters, then reanalysis of the affected transients and accidents is required.

15.1.12 Use of Westinghouse WH-177 Lead Test Assemblies

Technical Specification 4.2.1 allows for a limited number of lead test assemblies (LTAs) to be included in the reactor core. As required in this technical specification, these LTAs are placed in non-limiting locations. Although currently there are no LTAs in use, previous Oconee core designs have used LTAs with the Westinghouse WH-177 fuel design. These LTAs have some differences in thermal-hydraulic parameters due to variations in the assembly design relative to the Framatome Mk-B11 and Mk-B10 fuel designs comprising the rest of the core. These design differences are described in UFSAR Section 4.2.2.2.1.

The Westinghouse WH-177 LTAs were evaluated with respect to the transients and accidents contained in Chapter 15 of the UFSAR and appropriate analyses were performed. Chapter 15 of the UFSAR contains transients and accidents that are sensitive to global and local effects. Global analyses whose results are controlled by core average parameters are not affected by the presence of LTAs. The core transient analysis for any of the non-LOCA design basis transients or accidents that are potentially sensitive to local effects were explicitly analyzed for the differences in hydraulic design and performance of the different fuel assembly types. An evaluation was also performed for the LOCA analysis.

The behavior of the minimum departure from nucleate boiling ratio (DNBR) was calculated for the mixed core of LTAs and Framatome Mk-B11 and Mk-B10 fuels. The co-resident fuel types were analyzed with their respective critical heat flux correlations and limits. As a result each fuel type has specific limits that include the effects of flow variations as well as fuel assembly feature performance. The limits derived from these calculations were applied to the LTAs and the Mk-B11 and Mk-B10 fuels to ensure DNBR criterion was met.

Centerline fuel melt (CFM) checks were performed for both the Framatome Mk-B11 and Mk-B10 fuels and the Westinghouse WH-177 LTAs to ensure that the CFM criterion was met.

The REA peak fuel pellet enthalpy for the WH-177 LTAs is bounded by the Mark B fuel results due to the lower enrichment of the WH-177 LTAs. The analysis performed for the Mark B fuel demonstrated that the peak fuel enthalpy was well below the peak enthalpy acceptance criterion.

The LOCA analysis was also evaluated for WH-177 LTAs. Westinghouse determined a peaking penalty to ensure the WH-177 fuel is non-limiting. This peaking penalty was applied to the WH-177 LTAs when designing the Oconee Unit 3 core to assure that the LTAs are non-limiting with respect to LOCA acceptance criteria. Thus, the Framatome fuel assemblies remain the limiting fuel with respect to LOCA.

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15.1.13 USE of AREVA Mark-B-HTP Fuel Assemblies

Starting from Oconee Unit 1 Cycle 28, Oconee has transitioned to full cores of AREVA Mark-B-HTP fuel assemblies from mixed cores of AREVA Mark-B11 and AREVA Mark-B-HTP fuel assemblies. DPC-NE-2003-PA (Reference 12), DPC-NE-2005-PA (Reference 13), DPC-NE-3000-PA (Reference 4), and DPC-NE-3005-PA (Reference 1) describe the methodologies to be used by Duke for performing the UFSAR Chapter 15 non-LOCA transient and accident analyses, for the AREVA Mark-B-HTP fuel assemblies.

The AREVA Mark-B-HTP fuel assemblies are evaluated with respect to the transients and accidents contained in Chapter 15 of the UFSAR and appropriate analyses were performed. An evaluation was also performed for the LOCA analysis.

The behavior of the minimum departure from nucleate boiling ratio (DNBR) was calculated for the full core of Mark-B-HTP fuel. The limit derived from this calculation was applied to the Mk-B-HTP fuel to ensure DNBR criterion was met.

Centerline fuel melt (CFM) checks were performed for the Mark-B-HTP fuel to ensure that the CFM criterion was met. The REA peak fuel enthalpy was well below the peak enthalpy acceptance criteria for the Mark-B-HTP fuel.

The LOCA analysis was also evaluated for Mark-B-HTP fuel assemblies using the existing LOCA methodologies. All of the 10 CFR 50.46 criteria were met.

The full cores of Mark-B-HTP fuel assemblies contained in the Oconee cores were evaluated with respect to the transients and accidents contained in Chapter 15 of the UFSAR and found to meet all acceptance criteria.

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15.2 Startup Accident

15.2.1 Identification of Cause and Description

The startup accident is an uncontrolled withdrawal of a control rod group from a zero power initial condition. It is caused by an operator error or a malfunction in the Rod Control System and can result in a nuclear power excursion. Since the heat removal capability of the secondary system is not increased during the power excursion, the resultant power mismatch would cause an increase in the Reactor Coolant System (RCS) and secondary system temperatures and pressures. The control rod motion would also cause the core power peaking to change. The reactor would be expected to trip on high flux or high RCS pressure.

The startup accident is analyzed from a hot zero power beginning-of-cycle condition, with three reactor coolant pumps (RCPs) in operation. The maximum control rod withdrawal rate is assumed. The system analysis determines the transient peak RCS pressure, and the transient core boundary conditions for the detailed core thermal-hydraulic analysis. In the peak RCS pressure analysis, the pressurizer spray and the pressurizer PORV are assumed to be inoperable. The pressurizer code safety valves (PSVs) are modeled using conservative assumptions for drift, blowdown, and valve capacity that minimize relief flow. The analysis methodology and the computer codes used in the analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

The reactivity addition rate assumed in the analysis is based on control rod group overlap, rod speed, and withdrawal sequence, which are controlled by non-safety systems. The loop with two RCPs in operation will indicate a lower hot leg pressure than the loop with only one active RCP. Therefore, the analysis assumes a single failure of one of the narrow range pressure channels on the loop with only one active RCP. This requires the high pressure reactor trip to be generated by the loop with a lower RCS pressure, which is conservative since it will delay reactor trip.

The startup accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the peak RCS pressure does not exceed 110% (2750 psig) of the design pressure, and that the minimum DNBR remains above the design limit.

15.2.2 Analysis

The startup accident analysis assumes three RCPs in operation and considers a maximum control rod withdrawal rate of 11.5 pcm/sec. The system thermal-hydraulic analyses have been performed for a core loaded with Mk-B-HTP fuel. The results presented model the replacement steam generators. The analysis duration of 100 seconds is sufficient to demonstrate the peak thermal power and peak RCS pressure. The analysis results are shown in Figure 15-1 through Figure 15-6, and the sequence of events is given in Table 15-36. Figure 15-1 shows the neutron power and thermal power transients. Neutron power does not begin to appreciably increase until the inserted reactivity begins to approach one dollar at approximately 46 seconds. Reactor trip occurs on high power at 51.0 seconds with neutron power at approximately 155% of 2568 mwth. The thermal power rises to a peak value of 80.5% of 2568 mwth at 51.1 seconds. Figure 15-2 shows the reactivity response. The reactivity insertion rate due to rod withdrawal is constant until reactor trip. Fuel heatup causes negative reactivity insertion due to Doppler temperature feedback until reactor trip. System heatup prior to reactor trip causes the moderator temperature to increase, which inserts positive reactivity due to the assumed positive moderator temperature coefficient of reactivity. Figure 15-3 and Figure 15-4 show the cold leg and hot leg temperature transients. Because of the reduced flow due to the inactive RCP, the temperature response in the loop with the inactive RCP is delayed. After reactor trip and the opening of the PSVs, the temperatures in both loops decrease. Figure 15-5 shows the pressurizer level response. During the thermal power excursion, level rises rapidly due to the insurge of liquid into the pressurizer. After reactor trip and the opening of the PSVs, the pressurizer level rises more slowly and then stabilizes. Figure 15-6 shows the RCS pressure (hot leg indication) as a function of time. RCS pressure rises to a maximum value of approximately 2673.5 psig at 53.8 seconds, and then decreases due to PSV lift. The peak RCS pressure of 2723.6 psig occurs at the bottom of the reactor vessel.

15.2.3 Conclusions

The startup accident results in a peak core thermal power of 80.5% of 2568 mwth. The RCS conditions at the peak thermal power, specifically core inlet flow and temperature, have significant margin to conditions leading to DNB. The cooler inlet flow and relatively high RCS flow provide additional DNB margin. Therefore, DNB is not a concern for this transient. The peak RCS pressure for this transient is 2723.6 psig. All of the acceptance criteria are met.

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15.3 Rod Withdrawal At Power Accident

15.3.1 Identification of Causes and Description

The rod withdrawal at power accident is caused by an operator error or a failure in the Rod Control System which results in an uncontrolled withdrawal of a control rod group while the reactor is at power. The rod withdrawal causes a nuclear power excursion and a resultant heatup and pressurization of the Reactor Coolant System (RCS). The expected plant response to a rod withdrawal event would include the following. Feedwater flow would follow the increase in reactor power, thereby maintaining adequate RCS heat removal until the reactor is tripped on high flux or flux/flow/imbalance. Following reactor trip, the Turbine Bypass System (TBS) and main steam code safety valves would relieve steam in order to control the post-trip steam generator pressures. RCS pressure would be controlled by the pressurizer spray, PORV, and heaters. In addition, feedwater would be automatically controlled to maintain the post-trip steam generator level.

Separate analyses are performed to investigate the peak RCS pressure and the core cooling capability following the rod withdrawal event. The results presented model the replacement steam generators. The core cooling analysis covers a spectrum of initial power levels that bounds the range of permissible power levels given the number of operating reactor coolant pumps (RCPs). Four and three RCPs in operation are considered. Initial power levels below 15% are assumed to be bounded by the startup accident. In the peak RCS pressure analysis, the pressurizer spray, pressurizer PORV, and the Turbine Bypass System are assumed to be inoperable. In addition, the pressurizer and main steam code safety valves are modeled using conservative assumptions for drift, blowdown, and valve capacity that minimize relief flow. Both the peak RCS pressure and the core cooling analyses hold main feedwater and main steam flow rates constant prior to reactor trip. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards System setpoints and delay times are given in Table 15-35.

The reactivity addition rates assumed in the analyses are bounded by minimum and maximum values which are calculated based on control rod group overlap, rod speed, and withdrawal sequence, which are controlled by non-safety systems. No single failure has been identified which adversely impacts the results of the cases initiated from four RCP operation. For the cases initiated from three RCP operation, the analysis assumes a single failure of one of the narrow range pressure channels on the loop with only one active RCP. This requires the high pressure reactor trip to be generated by the loop with a lower RCS pressure, which is conservative since it will delay reactor trip.

The rod withdrawal at power accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the minimum DNBR remains above the design limit, and the peak RCS pressure does not exceed 110% (2750 psig) of design pressure.

15.3.2 Peak RCS Pressure Analysis

The RETRAN system thermal-hydraulic analysis results are valid for the full core with Mk-B-HTP fuel.

The limiting peak RCS pressure case assumes a full power initial condition and a withdrawal rate equivalent to 2.5 pcm/sec. Since the maximum RCS pressure is expected to occur near the time of reactor trip, the analysis duration is 10 seconds following the reactor trip. The transient response for this limiting case is shown in Figure 15-11, Figure 15-12, Figure 15-13, and Figure 15-14 and the sequence of events is given in Table 15-37. Neutron power (Figure 15-11) increases at a constant rate until the reactor trips on high RCS pressure at about 37 seconds. Since the reactivity insertion is fairly slow, the thermal power essentially stays in equilibrium with the neutron power prior to reactor trip. RCS hot and cold leg temperatures are given in Figure 15-12. The cold leg temperature increases gradually prior to trip and then increases rapidly following the turbine trip due to increasing saturation temperature in the steam generators. Hot leg temperatures increase both due to the rising cold leg temperatures and due to the increasing reactor power. Pressurizer level (Figure 15-13) increases steadily as the RCS heats up, expands, and causes an insurge into the pressurizer. The RCS pressure response (Figure 15-14) essentially mirrors the pressurizer level, with a peak value reached at about 41 seconds. At this point, a peak pressure of 2635.5 psig is reached at the bottom of the reactor vessel.

15.3.3 Core Cooling Capability Analysis

The RETRAN system thermal-hydraulic analysis results are valid for the full core with Mk-B-HTP fuel.

The limiting DNBR case assumes a full power initial condition and a withdrawal rate equivalent to 0.5 pcm/sec. The transient response for this limiting case is shown in Figure 15-15, Figure 15-16, Figure 15-17, Figure 15-113, and Figure 15-114, and the sequence of events is given in Table 15-38. While the trends are very similar to those shown in the peak RCS pressure case, the duration of the analysis is much longer due to a significantly lower reactivity insertion rate. Since the minimum DNBR occurs near the time of reactor trip, the analysis duration is 10 seconds following the reactor trip. In order to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic analysis. Neutron power and thermal power (Figure 15-15) increase at a constant rate until the reactor trips on high RCS temperature at about 204 seconds. RCS hot and cold leg temperatures are given in Figure 15-16. The cold leg temperature increases gradually prior to trip and then increases rapidly following the turbine trip due to increasing saturation temperature in the steam generators. Hot leg temperatures increase both due to the rising cold leg temperatures and due to the increasing reactor power. Pressurizer level (Figure 15-17) increases steadily as the RCS heats up, expands, and causes an insurge into the pressurizer. The RCS pressure response (Figure 15-113) essentially mirrors the pressurizer level, although the increase is suppressed by pressurizer spray.

15.3.4 Conclusions

The rod withdrawal at power accident results in a peak RCS pressure of 2635.5 psig. The transient minimum DNBR (Figure 15-114) is 1.519 for the full core with Mk-B-HTP fuel at 205.2 seconds. The minimum DNBR value is above the design limit. All of the acceptance criteria are met.

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15.4 Moderator Dilution Accidents

15.4.1 Identification of Causes and Description

A moderator dilution accident occurs when the soluble boric acid concentration of makeup water supplied to the Reactor Coolant System (RCS) is less than the concentration of the existing reactor coolant, and the water is injected in an uncontrolled manner. The cause of such an event can be attributed to any one of a number of failure modes in the systems that are capable of supplying unborated water to the RCS. With the reactor initially at power, control rods would insert to offset the reduction in RCS boron concentration. The operator would be alerted by the control rod insertion and terminate the event by identifying the dilution source and isolating it.

The moderator dilution accident is analyzed at the initial conditions of beginning-of-cycle power operation (Mode 1) with the Integrated Control System (ICS) in either the automatic or manual mode. Manual operator action is relied on to terminate the dilution. Mode 1 is analyzed to demonstrate that there is adequate time for the operator to terminate the dilution when maximum dilution source flowrates are assumed. The accident is precluded in Mode 6 by Technical Specification 3.9.7. Therefore, no analysis is presented. In Mode 1 with the ICS in manual, mitigation does not begin until reactor trip occurs. This conservatively ignores any other alarms or indications of the increase in reactor power, pressurizer level, and RCS pressure. In Mode 1 with the ICS in automatic, mitigation of the event does not begin until the rod withdrawal limit alarm actuates. This conservatively ignores the indications of the control rods inserting to control the power level and temperature. The analysis assumes conservatively high dilution flowrates, high initial boron concentrations, and small mixing volumes. The moderator dilution accident potentially results in a loss of shutdown margin and an inadvertent criticality, approaching the DNBR limit, or challenging the peak RCS pressure limit. This accident is conservatively analyzed to ensure that the operator terminates the boron dilution prior to exceeding these criteria.

As discussed in the preceding paragraph, alarm actuation is credited for alerting the operator that a boron dilution event is in progress. The rod withdrawal limit alarm relies on non-safety equipment. No single failure has been identified that would prevent the operators from successfully isolating the possible dilution sources and terminating the accident.

The moderator dilution accident is considered to be a fault of moderate frequency. The acceptance criteria for manual operator action to terminate the dilution event is 15 minutes during Mode 1 following the actuation of the alarm credited for alerting the operator of the event. By meeting this operator action time and preventing core re-criticality, it is assured that the plant response will not approach the DNBR limit or the peak RCS pressure limit.

15.4.2 Full Power Initial Condition Analysis

<u>Mode 1 With ICS in Automatic</u>

A conservative upper bound on the dilution flowrate of 300 gpm of unborated water is assumed, which is the design capacity of two bleed transfer pumps. At this flowrate re-criticality would not occur until 17.2 minutes following the rod withdrawal limit alarm which alerts the operator. Therefore there is sufficient time for the operator to terminate the dilution event.

<u>Mode 1 With ICS in Manual</u>

A conservative upper bound on the dilution flowrate of 300 gpm of unborated water is assumed, which is the design capacity of two bleed transfer pumps. At this flowrate re-criticality would not occur until 15.6 minutes following the reactor trip alarm which alerts the operator. Therefore there is sufficient time for the operator to terminate the dilution event.

15.4.3 Refueling Initial Condition Analysis

Technical Specification 3.9.7 isolates all unborated water sources in Mode 6. Therefore, this is not a credible accident in Mode 6.

15.4.4 Conclusions

Two moderator dilution accident cases were performed corresponding to Mode 1 with the ICS in automatic and Mode 1 with the ICS in manual. The Mode 1 analyses calculate 17.2 minute and 15.6 minute operator action times for the ICS in automatic and manual cases, respectively. The accident is not credible in Mode 6. All of the acceptance criteria are met.

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15.5 Cold Water Accident

15.5.1 Identification of Causes and Description

The cold water accident is caused by an inadvertent startup of the fourth reactor coolant pump (RCP) from an initial three RCP operating condition. The increase in core flow as a result of the fourth RCP starting causes a decrease in the core average temperature. If the moderator temperature coefficient of reactivity is negative, an insertion of positive reactivity and an increase in reactor power will occur. Administrative controls limit the power level at which the fourth RCP can be started to less than 50% power. The normal plant response to this event would be for the Integrated Control system (ICS) to insert control rods in an attempt to maintain the initial power level.

The cold water accident is analyzed from an 80% of 2568 MWth power end-of-cycle initial condition. A conservative RCP start time is assumed. The system analysis determines the transient core boundary conditions for the detailed core thermal-hydraulic analysis. It is assumed that rod control is in manual and the pressurizer heaters are inoperable. The pump control circuitry interlock that prevents startup of an idle pump if the power is above 50 percent full power is assumed to be inoperable. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

No single failure has been identified which adversely affects this accident.

The cold water accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the minimum DNBR remains above the design limit, and the peak RCS pressure does not exceed 110% (2750 psig) of design pressure. Since this event results in a minor RCS pressurization that does not approach the limit, only the minimum DNBR acceptance criterion is of concern.

15.5.2 Analysis

The cold water accident analysis results are shown in Figure 15-18, Figure 15-115, Figure 15-116, Figure 15-117 and Figure 15-118 and the sequence of events is given in Table 15-39. The system thermal-hydraulic analyses were performed for the replacement steam generators with a core loaded with Mk-B-HTP fuel. Since the minimum DNBR occurs near the time the RCP has come up to speed, the analysis is terminated 10 seconds after the RCP achieves full speed. Following the start of the fourth RCP, RCS flow (Figure 15-18) rapidly increases to full flow, resulting in a decrease in the core average temperature (Figure 15-115). Neutron power and thermal power (Figure 15-116) increase during this time period due to the positive reactivity insertion from the decrease in the core average temperature, and reach maximum values of 107.6% and 97.5%, respectively. No reactor trip setpoints are exceeded. A combination of Doppler feedback and increasing RCS cold leg temperatures (Figure 15-117) after the pump has reached full speed stop the power excursion, with power nearly returning to its initial condition by the end of the analysis. The RCS pressure (Figure 15-118) does not go above 2200 psig during the simulation. Since the maximum thermal power that occurs during this event is less than 100% full power, and the other core conditions are relatively close to nominal full power conditions, DNB is not a concern during this event.

15.5.3 Conclusions

The results of the cold water accident demonstrate that since the maximum power level remains less than 100%, the minimum DNBR remains well above the limit. The RCS pressure transient does not approach the peak RCS pressure limit. All of the acceptance criteria are met.

15.5.4 References

1. Deleted per 1996 Update
2. Deleted per 1999 Update
3. Deleted per 1999 Update

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15.6 Loss of Coolant Flow Accidents

15.6.1 Identification of Cause and Description

A loss of coolant flow accident occurs if one or more of the reactor coolant pumps (RCPs) stops due to a loss of electrical power or a mechanical failure. The loss of coolant flow accident resulting from an electrical failure results in one or more RCPs coasting down. The limiting loss of coolant flow accident resulting from a mechanical failure is a locked rotor in one pump. If the reactor is at power at the time of the accident, the immediate effect of a loss of coolant flow is a rapid increase in the core coolant temperature. This temperature increase could result in approaching DNB with subsequent fuel damage if the reactor is not tripped promptly. During the loss of coolant flow accident, the Reactor Protective System (RPS) will trip the reactor on the flux/flow/imbalance trip, or on the pump monitor trip. If all RCPs trip, the plant transitions to the natural circulation mode of core cooling.

During a RCP coastdown event, the flux/flow/imbalance trip function trips the reactor when the setpoint is reached, and the pump monitor trip trips the reactor when any two of the four RCPs trip if the reactor power is greater than 2%. The pump monitor trip function has only one channel per pump. Therefore, assuming a single failure of the pump monitor trip on one pump, the possible RCP coastdown events with four or three RCPs in operation are determined. In order to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic analysis. Since some of the RCP coastdown events are bounded by others, only the following five RCP coastdown events are analyzed. Results for Cases 2, 3, and 4 are presented since they bound the other cases.

Case	RCP Coastdown(1)	Power Level (%)	Trip Function
1	4/1	100	flux/flow
2	4/2(2)	100	flux/flow
3	4/4	100	pump monitor
4	3/1(2)	80	flux/flow
5	3/3	80	pump monitor

Note:

1. 4/1 means 1 RCP coasting down with 4 RCPs in operation
2. The RCP(s) coasting down can be in the same loop or in different loops

For the locked rotor accident analysis a single failure in the pump monitor trip is assumed for both four and three RCPs in operation. Therefore, the flux/flow/imbalance trip provides DNB protection for the locked rotor event. With three RCPs in operation, a locked rotor in the loop with both RCPs operating is the limiting case. In order to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic analysis. The results presented model the replacement steam generators.

The analysis methodology and the computer codes used in the loss of flow accident analyses are given in Table 15-33. The initial conditions are given in Table 15-34. Beginning-of-cycle conditions are limiting. The RPS and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

A single failure in the pump monitor trip function is assumed in the loss of flow accident analyses. This failure results in relying on the flux/flow/imbalance trip function to trip the reactor in most of the analyzed cases. The RCS will transition to the natural circulation cooling mode if all RCPs have stopped. Natural circulation is then established by raising steam generator levels to the natural circulation setpoint. If the Main Feedwater System is in operation, the increase in steam generator levels is controlled by the non-safety Integrated Control System. Otherwise, the Emergency Feedwater System actuates and the safety-grade Emergency Feedwater Control System controls the steam generator level to the natural circulation setpoint.

The RCP coastdown accidents are considered to be faults of moderate frequency (fewer than all RCPs coast down) or infrequent fault (all RCPs coast down) events. The acceptance criterion for all RCP coastdown accidents is that the minimum DNBR remains above the design limit. The DNBR design limit for each accident is identified in the analysis results discussion. The RCP locked rotor accident is categorized as a limiting fault. The acceptance criteria for the RCP locked rotor accident are that any fuel damage calculated to occur must be of a sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability, that the peak RCS pressure does not exceed 110% (2750 psig) of the design pressure, and that the calculated offsite doses are less than 100% of the 10CFR Part 100 limits. To evaluate the third criterion on offsite doses, the extent of fuel failures are quantified with the assumption that any fuel pin that exceeds the DNBR limit is considered failed. The fuel failure results are then used in the offsite dose calculations to verify that the offsite dose criteria are satisfied. The results of the locked rotor analysis demonstrates that the peak RCS pressure limit is not challenged.

15.6.2 Four RCP Coastdown from Four RCP Initial Conditions Analysis

The RETRAN system thermal-hydraulic analysis results are valid for the full core with Mk-B-HTP fuel.

The 4/4 RCP coastdown accident analysis results are shown in Figure 15-19, Figure 15-20, Figure 15-21, Figure 15-22, Figure 15-23, and Figure 15-24, and the sequence of events is given in Table 15-40. The Mk-B-HTP fuel type is analyzed. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 20 seconds. The flow in both loops (Figure 15-19) behaves identically since the 4/4 RCP coastdown event is essentially symmetrical. The loop flows decrease towards zero flow during the transient. The pump monitor trip function trips the reactor at 0.9 seconds. The core thermal power (Figure 15-20) follows the trend of the neutron power with a thermal delay. The hot and cold leg temperatures (Figure 15-21) change only slightly in response to the change in flow during the transient. The pressurizer level (Figure 15-22) increases due to the increase in the RCS average temperature, and then decreases following the reactor trip. RCS pressure (Figure 15-23) increases initially due to the increase in pressurizer level, and decreases post-trip. The transient minimum DNBR (Figure 15-24) of 1.818 occurs at 2.1 seconds for a full core with Mk-B-HTP fuel. The minimum DNBR value is above the design limit.

15.6.3 Two RCP Coastdown from Four RCP Initial Conditions Analysis

The RETRAN system thermal-hydraulic analysis results are valid for the full core with Mk-B-HTP fuel.

The results of the 4/2 RCP coastdown accident analysis with the tripped RCPs in the same loop are presented since it is the bounding event for the four RCP initial conditions. The results are shown in Figure 15-25 and Figure 15-119, Figure 15-120, Figure 15-121, Figure 15-122, Figure 15-123, and the sequence of events is given in Table 15-41. The Mk-B-HTP fuel type is analyzed. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 20 seconds. The transient behavior of many of the key parameters trend those of the 4/4 RCP coastdown accident. The flux/flow imbalance trip function trips the reactor at 4.2 seconds. The core flow (Figure 15-25) decreases after the RCPs trip, and approaches the equilibrium two RCP flowrate at the end of the analysis. The faulted loop flow decreases toward zero flow, while the intact loop flow increases from its initial value. The hot leg temperatures (Figure 15-120) change only slightly in response to the change in flow during the transient. The cold leg temperatures in the affected loop decrease due to the decrease in primary flow, and then increase due to the post- trip increase in steam pressure. The cold leg temperatures in the unaffected loop initially remain stable and then increase due to the flow reversal in the loop. The transient minimum DNBR (Figure 15-123) of 1.68 occurs at 4.9 seconds for a full core with Mk- B-HTP fuel. The minimum DNBR value is above the design limit.

15.6.4 One RCP Coastdown from Three RCP Initial Conditions Analysis

The RETRAN system thermal-hydraulic analysis results are valid for the full core with Mk-B-HTP fuel.

The results of the 3/1 RCP coastdown accident analysis with the tripped RCP in the same loop as the initially idle RCP are presented since it is the bounding event for the three pump initial conditions. The results are shown in Figure 15-124, Figure 15-125, Figure 15-126, Figure 15-127, Figure 15-128, and Figure 15-129 and the sequence of events is given in Table 15-42. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 20 seconds. The transient behavior of many of the key parameters trend those of the 4/2 RCP coastdown accident. The flux/flow imbalance trip function trips the reactor at 5.0 seconds. The RCS flow transient (Figure 15-124) approaches the two RCP equilibrium flowrate at the end of the analysis. While the affected loop flow decreases and reverses direction, the intact loop flow increases from its initial value. The transient minimum DNBR (Figure 15-129) of 1.97 occurs at 5.5 seconds for a full core with Mk-B-HTP fuel. The minimum DNBR value is above the design limit.

15.6.5 Locked Rotor from Four RCP Initial Conditions Analysis

The RETRAN system thermal-hydraulic analysis results are valid for the full core with Mk-B-HTP fuel.

The locked rotor accident from four RCP initial conditions analysis results are shown in Figure 15-130, Figure 15-131, Figure 15-132, Figure 15-133, Figure 15-134, and Figure 15-135, and the sequence of events is given in Table 15-43. Mk-B-HTP fuel type is analyzed. Since the transient minimum DNBR occurs near the time of reactor trip, the analysis is terminated at 10 seconds. The core flow (Figure 15-130) rapidly decreases after the locked rotor occurs, and approaches the equilibrium three RCP flowrate at the end of the analysis. The locked rotor cold leg flow rapidly decreases to a negative value, and the other cold leg flow increases towards the three RCP flowrate. The flux/flow trip function trips the reactor at 1.7 seconds. The core thermal power (Figure 15-131) follows the trend of the neutron power with a thermal delay. The hot leg temperatures (Figure 15-132) increase initially due to the decrease in flow. After the reactor trips, the hot leg temperatures begin to decrease. The cold leg temperature in the affected loop decreases slightly due to the decrease in primary flow. The cold leg temperature of the unaffected loop remains stable initially, and then increases post-trip due to the increase in steam pressure. The pressurizer level (Figure 15-133) increases initially due to the increase in RCS temperatures, and then decreases post-trip. The RCS pressure response (Figure 15-134) trends with the change in pressurizer level. The limiting transient minimum DNBR (Figure 15-135) of 1.41, which occurs at 2.2 seconds, for the Mk-B-HTP fuel is equal to the design limit. A fuel pin census analysis is performed to determine if DNBR margin exists or the number of fuel pins that exceed the DNBR limit. A range of pin radial peaks and axial shapes are assumed to determine the peaking factors at which the DNBR limit is exceeded. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel pin in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the DNBR limit is exceeded. All fuel pins that exceed the DNBR limit are assumed to experience cladding failure and are counted in the source term for the offsite dose calculation. The results of the fuel pin census analysis for the locked rotor accident from four RCP initial conditions is that DNBR margin exists for all of the fuel pins. Due to no fuel failures, the offsite dose consequences for the locked rotor accident are bounded by the offsite dose consequences for the steam line break accident.

The peak maximum RCS pressure is 2501 psig, which is well below 110% of the design pressure (2750 psig).

15.6.6 Locked Rotor from Three RCP Initial Conditions Analysis

The system thermal-hydraulic analyses were performed for a full core loaded with Mk-B-HTP fuel.

The locked rotor accident from three RCP initial conditions (Table 15-34) analysis results are shown in Figure 15-136, Figure 15-137, Figure 15-138, Figure 15-139, Figure 15-140, and Figure 15-141, and the sequence of events is given in Table 15-44. Since the transient minimum DNBR occurs near the time of reactor trip, the analysis is terminated at 10 seconds. The analysis results are similar to those of the four RCP initial condition analysis. The flows in the unaffected loop and the core (Figure 15-136) approach the two RCP equilibrium flowrates at the end of the analysis. The transient minimum DNBR (Figure 15-141) of 1.446 occurs at 2.4 seconds for the full core with Mk-B-HTP fuel. Both minimum DNBR values are above the design limits. A fuel pin census analysis is performed. The results of the fuel pin census analysis for the locked rotor accident from three RCP initial conditions is that DNBR margin exists for all of the fuel pins. Due to no fuel failures, the offsite dose consequences for the locked rotor accident are bounded by the offsite dose consequences for the steam line break accident.

15.6.7 Natural Circulation Capability Analysis

The natural circulation capability analysis determines the stable natural circulation flowrates for a range of post-trip decay heat values. The natural circulation flowrates are shown to be greater than the decay heat power levels on a percentage basis, thereby limiting the temperature rise across the core to less than that at full power conditions. Therefore, adequate core cooling will be maintained during natural circulation.

Decay Heat Power (MW_{th})	(% Power)	Natural Circulation Flowrate (% Full Flow)
80	3.1	3.8
70	2.7	3.6
60	2.3	3.5
50	1.9	3.3

Decay Heat Power (MW_{th})	(% Power)	Natural Circulation Flowrate (% Full Flow)
40	1.6	3.0
30	1.2	2.7
20	0.8	2.4
10	0.4	1.9

15.6.8 Environmental Consequences

The radiological consequences of a locked rotor accident are bounded by the consequences of the large main steam line break accident.

15.6.9 Conclusions

The results of the RCP coastdown accident analyses show that the limiting RCP coastdown event is two RCPs coasting down from a four RCP initial condition. The minimum DNBR is 1.68 for a full core with Mk-B-HTP fuel. The minimum DNBR is above the design limit. The results of the locked rotor accident analyses show that the limiting locked rotor event is from a four RCP initial condition. The results of a pin census analysis for the locked rotor show that DNBR margin exists for all of the fuel rods. Therefore, no fuel rod failures are assumed in the offsite dose analysis. The results of the locked rotor analysis demonstrate that the peak RCS pressure limit is not challenged. The peak maximum RCS pressure is 2501 psig, which is far below the design pressure. The results of the natural circulation capability analysis show adequate flow for core cooling and decay heat removal by natural circulation after all RCPs trip. All of the acceptance criteria are met.

15.6.10 References

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15.7 Control Rod Misalignment Accidents

15.7.1 Identification of Causes and Description

Control rods are normally grouped into patterns which maintain a symmetric core power distribution. A mechanical or electrical failure can cause a control rod to become misaligned from its group, causing an asymmetric reactivity distribution and, if the control rod is stuck, a reduction in the total available control rod worth for shutdown of the reactor. Three modes of misalignment can occur. The first mode, the statically misaligned rod accident, occurs during withdrawal or insertion of a control rod group when one rod becomes stuck at some position as the rod group continues in motion. This condition will affect the power distribution in the core and could lead to excessive power peaking. The second mode of misalignment, the stuck rod accident, can occur on reactor trip if one rod fails to insert. This condition requires an evaluation to determine that sufficient negative reactivity is available for tripping the reactor when considering the maximum worth stuck rod. The third mode, the dropped rod accident, can occur when one rod drops partially or fully into the core. The resulting plant transient response is a rapid reduction in power and a possible subsequent increase in power due to a negative moderator coefficient of reactivity. The expected plant response is that the Integrated Control System (ICS) will respond to an indicated dropped control rod by initiating a power runback and by inhibiting control rod withdrawal. A reactor trip may occur on variable low pressure-temperature for some dropped rod accidents.

For the statically misaligned rod accident, the core designs are evaluated to confirm that the resulting core power distribution is acceptable. For the stuck rod accident, each core design is required to be capable of maintaining a 1% $\Delta k/k$ shutdown margin at hot shutdown conditions with the assumption of the maximum worth rod stuck in the fully withdrawn position. The dropped rod accident is analyzed for a set of dropped rod worths for initial conditions of 102% of 2568 MWth with four reactor coolant pumps (RCPs) in operation, and for 75% of 2568 MWth with three RCPs in operation. Physics parameters for the beginning-of-cycle (BOC) condition are analyzed. The expected action taken by the ICS on indication of a dropped rod is to inhibit control rod withdrawal and to run back power demand to 55 percent of rated load at 1 percent per minute. This non-safety action by the ICS is not credited in the analysis. The ICS is assumed to respond to the decrease in reactor power by withdrawing control rods to meet the load demand, which is a conservative assumption. A reactor trip on high flux or flux/flow/imbalance may occur for some cases. The system analysis determines the transient core boundary conditions for the detailed core thermal-hydraulic analysis. The results presented model the replacement steam generators. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System (RPS) and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

Due to the asymmetric core power distribution resulting from the dropped rod, the excore power range flux channels which input to the RPS high flux trip function will indicate different transient power responses. The limiting single failure for the dropped rod analysis is the excore power range flux channel adjacent to the quadrant with the highest indicated core power level. This assumption results in the third highest (or second minimum) excore flux channel determining whether the high flux trip setpoint is reached based on the 2/4 RPS logic design.

The three identified modes of control rod misalignment accidents are considered to be faults of moderate frequency. The acceptance criteria for these accidents are that the minimum DNBR remains above the design limit, that the centerline fuel melt limit is not exceeded, and that the peak RCS pressure does not exceed 110% (2750 psig) of design pressure. Since this event results in a minor RCS pressurization which does not approach the limit, only the minimum DNBR and centerline fuel melt acceptance criteria are of concern.

15.7.2 Dropped Rod Analysis

The limiting dropped rod accident is a 20 pcm dropped rod from full power at BOC conditions. The RETRAN system thermal-hydraulic analysis results are valid for a full core with Mk-B-HTP fuel. The duration of the analysis is less than 40 seconds (see Table 15-45), which is sufficient for the time of minimum DNBR. The transient response is shown in Figure 15-26, Figure 15-27, Figure 15-28, Figure 15-143 and Figure 15-144, and the sequence of events is given in Table 15-45. The initial decrease in reactor power (Figure 15-26) is caused by the reactivity inserted by the dropped rod. The ICS response, due to the asymmetric power distribution, causes control rods to be withdrawn and results in an increase in reactor power. Hot and cold leg temperatures (Figure 15-27) increase at a steady rate due to the power mismatch between reactor power and steam generator heat removal. The trends of pressurizer level (Figure 15-28) and RCS pressure (Figure 15-143) reflect this power mismatch. The maximum RCS pressure is less than 2350 psig. The transient minimum DNBR (Figure 15-144) of 1.878 occurs at 77.7 seconds for a full core of Mk-B-HTP fuel. This minimum DNBR value is greater than the design limit.

15.7.3 Statically Misaligned Rod Analysis

The results of the generic evaluation of the statically misaligned rod event show that this event is bounded by the dropped rod event.

15.7.4 Conclusions

The stuck rod accident cannot result in insufficient negative reactivity insertion on reactor trip due to the core design criteria. The statically misaligned rod accident has been shown to be bounded by the dropped rod accident. The minimum DNBR is shown above and greater than the design limit. No fuel centerline melt is predicted. The RCS pressure transient does not approach the peak primary pressure limit. All of the acceptance criteria are met.

15.7.5 References

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15.8 Turbine Trip Accident

15.8.1 Identification of Causes and Description

The turbine trip accident is caused by events including a generator trip, low condenser vacuum, loss of turbine lubrication oil, turbine overspeed, main feedwater pump trip, high steam generator level, or a reactor trip. The rapid closure of the main turbine stop valves results in a rapid increase in the secondary pressure and temperature. This degradation in the secondary heat sink creates a mismatch between power generated in the Reactor Coolant System (RCS) and heat removed by the secondary. As a result, the RCS temperature and pressure increase. The expected plant response to a turbine trip would be an immediate reactor trip initiated by the turbine trip signal. The Turbine Bypass System (TBS) and main steam code safety valves would then relieve steam in order to control the post-trip steam generator pressures. RCS pressure would be controlled by the pressurizer spray, PORV, and heaters. In addition, feedwater would be automatically controlled by the Integrated Control System (ICS) to maintain the post-trip steam generator levels at setpoint.

The turbine trip accident is analyzed from a full power initial condition at beginning-of-cycle. The analysis assumes that the pressurizer spray, pressurizer PORV, and the TBS are inoperable. In addition, the pressurizer and main steam code safety valves are modeled using conservative assumptions for drift, blowdown and valve capacity that minimize relief flow. The anticipatory reactor trip on turbine trip is not credited. Main feedwater is isolated coincident with the turbine trip in order to maximize the steam generator pressure. Also, no credit is taken for the Emergency Feedwater System (EFW), since the peak pressure will be reached before EFW flow can start and have an effect on the transient response. The results presented model the replacement steam generators. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards System setpoints and delay times are given in Table 15-35.

No single failure has been identified which adversely impacts the results of the turbine trip analysis.

The turbine trip accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the minimum DNBR remains above the design limit, and that the peak RCS pressure does not exceed 110% (2750 psig) of design pressure. The DNBR limit is not challenged since the increase in RCS pressure more than offsets the slight increase in RCS temperature.

15.8.2 Analysis

The turbine trip accident analysis results are shown in Figure 15-145, Figure 15-146, Figure 15-147, Figure 15-148, and Figure 15-149, and the sequence of events is given in Table 15-46. Mk-B-HTP fuel type is analyzed. The analysis duration of 40 seconds is sufficient to demonstrate the peak RCS pressure. The closure of the main turbine stop valves results in a rapid increase in steam line pressure (Figure 15-145) and temperature. The RCS hot and cold leg temperatures (Figure 15-146) increase due to the increasing secondary side temperature. The increase in RCS temperatures causes pressurizer level (Figure 15-147) and RCS pressure (Figure 15-148) to increase, resulting in a reactor trip on high RCS pressure at 3.6 seconds. Following the reactor trip, the RCS temperatures, pressurizer level, and RCS pressure all decrease towards the post-trip values. Figure 15-149 shows the power remains constant prior to trip. The RCS pressure at the bottom of the reactor vessel reaches a maximum value that is below 2750 psig.

15.8.3 Conclusions

The turbine trip accident analysis results in a peak RCS pressure that is below 2750 psig. All of the acceptance criteria are met.

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15.9 Steam Generator Tube Rupture Accident

15.9.1 Identification of Causes and Description

The steam generator tube rupture (SGTR) accident is caused by a double-ended rupture of a single steam generator tube. The expected plant response is as follows. The tube rupture initiates a blowdown of primary coolant into a steam generator. The plant response to this event is similar to a small break LOCA in that the Reactor Coolant System (RCS) pressure and pressurizer level would decrease as coolant inventory is lost through the ruptured steam generator tube. Makeup flow to the RCS would increase in response to the decrease in pressurizer level. The Integrated Control System (ICS) would reduce main feedwater (MFW) to the ruptured steam generator to compensate for the break flow. Without operator action, the reactor would trip on the variable low pressure-temperature trip function. With operator action, actions would be taken to initiate a rapid shutdown of the reactor. This would be accomplished by making up for the loss of RCS inventory through the break with flow from the High Pressure Injection System (HPIS). When the reactor power level has been reduced to below the capacity of the Turbine Bypass System (TBS), a manual reactor trip would be performed. Following the reactor trip, the TBS would relieve steam to control steam generator pressure. MFW would be automatically controlled by the ICS to maintain the post-trip steam generator level at setpoint. The operator would then isolate the ruptured steam generator and depressurize the RCS to decrease the subcooled margin, thereby minimizing primary-to- secondary leakage. A plant cooldown and depressurization would then be initiated using the TBS and the unaffected steam generator to bring the plant to the conditions where the Low Pressure Injection System (LPIS) can be aligned for decay heat removal, and break flow could then be terminated. The ruptured steam generator would be steamed and/or drained as necessary to prevent overfill during the course of the event.

The SGTR accident is analyzed from a full power initial condition at end-of-cycle with maximum decay heat. Analysis assumptions are selected to maximize the environmental consequences. Offsite power remains available. A conservatively long delay time is assumed for the Reactor Protective System to trip the reactor to maximize the pre-trip primary coolant leakage into the ruptured steam generator. It is further assumed that the operator takes action to maintain RCS pressure and pressurizer level at the initial conditions such that the primary-to-secondary leakage is maximized. The reactor is then assumed to trip from a full power condition which results in the largest post-trip steam release through the main steam safety valves (MSSVs). The MFW pumps are assumed to trip on reactor trip to minimize the secondary heat sink, which actuates the emergency feedwater (EFW) pumps. A penalty for the turbine-driven EFW pump is taken in the analysis since the steam supply to its turbine originates from the SG with the tube rupture and exhausts directly to the atmosphere. However, no EFW flow from the turbine-driven pump is credited. The non-safety TBS is also not credited in the analysis. The results presented model the replacement steam generators. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The RPS and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

The analysis credits the non-safety manual steam line atmospheric dump valves (ADVs) to cool down the plant. The single failure assumed in this event is the EFW control valve on the unaffected steam generator failing to open following the reactor trip. This results in only the ruptured steam generator being available for cooling down the plant until operator action is taken to establish an alternate EFW alignment. The following operator actions are credited during this event:

1. Immediate action to maximize HPI flow.
2. Identify the failed-closed position of the EFW control valve and restore EFW to the unaffected steam generator. A delay time of 23 minutes after reactor trip is assumed.
3. The ruptured steam generator is identified 10 minutes after EFW restoration to the unaffected steam generator.
4. Cooldown of the plant to 532°F begins 52 minutes after the ruptured steam generator is identified.
5. The ruptured steam generator is isolated after the plant has been cooled down to 532°F.
6. The RCS subcooled margin is minimized 12 minutes after the ruptured steam generator is identified.
7. One reactor coolant pump (RCP) in the loop without the pressurizer is tripped off 20 minutes after the RCS has been cooled down to 532°F. Operators trip one RCP in loop with pressurizer at 400°F.
8. A shift changeover delay of one hour is assumed after the RCS has been cooled down to 532°F and one RCP in the loop without the pressurizer has been tripped.
9. An RCS cooldown to 450°F begins after the shift changeover is complete.
10. Cooldown of the RCS is stopped upon reaching 450°F while the RCS boron concentration is verified. A delay time of 90 minutes is assumed.
11. Boration of the RCS is performed to achieve the cold shutdown boron concentration requirement. A delay time of 30 minutes is assumed.
12. Cooldown to decay heat removal conditions resumes 5 minutes after the cold shutdown boron concentration has been achieved.
13. Periodic steaming of the ruptured steam generator is performed to prevent water from entering the steam lines.
14. A 90 minute delay is assumed to align the LPIS for decay heat removal. RCS temperature and pressure are held constant during this time.

The steam generator tube rupture accident is considered to be a limiting fault event. The acceptance criterion for this event is that the calculated doses at the site boundary are less than 100% of the 10CFR100 guidelines.

15.9.2 Analysis

The SGTR accident analysis results are shown in Figure 15-150, Figure 15-151, Figure 15-152, Figure 15-153, Figure 15-154, Figure 15-155, and Figure 15-156, and the sequence of events is given in Table 15-47. The duration of the analysis is until the plant has been cooled down and steam releases to the atmosphere have terminated, which is 40,725 seconds (11.3 hours). As a result of the tube rupture and immediate operator action to increase HPIS flow to compensate for the loss of RCS inventory, RCS conditions remain relatively stable until the RPS is assumed to trip the reactor at 1200 seconds. The reactor power response is shown in Figure 15-150. MFW flow is automatically throttled to compensate for the break flow (Figure 15-151) entering the ruptured steam generator. A normal post-trip response occurs, with RCS pressure (Figure 15-152) and pressurizer level (Figure 15-153) decreasing due to RCS shrinkage and steam generator pressures (Figure 15-154) increasing to the MSSV lift setpoints. MFW flow is lost on reactor trip. Steam generator levels (Figure 15-155) decrease to the post-trip setpoints, and then the unaffected steam generator continues to boil down to a dried out condition due to the failure of its EFW control valve to open. Post-trip heat removal is provided by the ruptured steam generator until an alternate EFW flowpath to the unaffected steam generator is aligned at 2580 seconds. After restoration of EFW to both steam generators, the ruptured steam generator is identified at 3180 seconds due to the EFW flow imbalance between the steam generators. The RCS subcooled margin is reduced at 3900 seconds to minimize primary-to-secondary leakage. This is conservatively assumed to be accomplished using pressurizer spray which is slower than other potentially available means of depressurizing the RCS (i.e.; RCS PORV, Auxiliary Spray). At 6300 seconds, the unit is cooled down to 532°F (Figure 15-156) using the ADVs on both steam lines. The ruptured steam generator and EFW to the ruptured steam generator are isolated after reaching 532°F (~7,040 seconds), with all steam release flowpaths being isolated by 8,240 seconds. After one RCP is tripped in the loop without the pressurizer, the RCS is held at a constant temperature and pressure while a shift changeover occurs. During the shift changeover, steaming of the ruptured steam generator begins due to the water level reaching the high level setpoint (10,621 seconds). Steaming the ruptured steam generator continues for the remainder of the analysis. The plant cooldown is resumed following the shift changeover, with RCS temperatures reaching 450°F at 15,191 seconds. RCS Boron concentration determination is initiated and boration to cold shutdown conditions is accomplished by 22,391 seconds, with the plant cooldown resuming at 22,691 seconds. LPIS decay heat removal conditions are reached at 31,455 seconds, where RCS pressure and temperature are held constant while this system is aligned. The plant cooldown continues at 36,855 seconds, with the RCS reaching 215°F at 40,725 seconds. The analysis is terminated at this time since steam releases to the atmosphere have stopped.

15.9.3 Environmental Consequences for the Steam Generator Tube Rupture

The postulated accidents involving release of steam from the secondary system do not result in a significant release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators as with the SGTR. A conservative analysis of the potential offsite doses resulting from a SGTR accident is presented assuming a pre-existing primary to secondary leakage. This activity is released to the environment by releases associated with the normal operation of plant equipment or the operation of plant equipment as intended in response to the accident, and as part of the subsequent cooldown activities.

Two RCS source terms are examined as part of this analysis. The first models an initial RCS activity of one percent of the core averaged isotopic inventory. This source term bounds the allowed normal RCS DEI activity concentration permitted by Technical Specifications. The second source term models the maximum DEI activity concentration permitted by Technical Specifications for an iodine spike at full power. This “pre-existing” spike is postulated to occur at the time of accident initiation. Both of these source terms are modeled to be released instantaneously and homogeneously such that the RCS activity is in equilibrium at the start of the accident. Both source terms also bound Technical Specification limits for non-iodine isotopes. Source term isotopics are based upon fuel depletion and projected fission product inventories at the end of the cycle with the maximum thermal power uncertainty applied.

An initial source term is also modeled for the secondary side. The maximum Technical Specification allowed DEI concentration is modeled to be present in the secondary side water, the steam generators and any makeup water supplied to the unit. Thus, the secondary side is essentially modeled as an infinite source of water at the secondary side Technical Specification DEI concentration limit.

In order to transport and release primary activity to the environment, a primary to secondary release path is modeled in the steam generators. This path is postulated to exist at the start of the accident, but is not caused by the SGTR. The tube leakage into the unaffected steam generator modeled bounds the maximum allowed tube leakage rate into one steam generator. The affected steam generator is modeled with a break flow that is based on the thermal/hydraulic model.

The thermal/hydraulic model discussed in the previous sections is used as the basis for the plant response and steam releases modeled in the environmental analysis. The plant is initially operating in a normal mode at full power (plus maximum thermal power uncertainty) with primary to secondary leakage. When the break initiates, the activities in the primary and secondary side are modeled to be instantaneously and homogeneously released to their respective systems. Shortly after the break initiates, the reactor is automatically tripped and radioactive decay (and daughter product production) is begun in the model. The steam generators begin to discharge their activity directly to the environment through the Atmospheric Dump Valves (ADVs).

In order to maximize releases to the environment, the condenser is assumed to not be available. This requires that the unit be cooled down using the steam generators by discharging steam from the steam generators directly to the environment through the ADVs. No credit is taken for the condenser and no partitioning credit is taken for releases.

The steam generator tube rupture causes the Turbine Driven Emergency Feedwater Pump (TDEFWP) to start and briefly supply makeup water. The TDEFWP is driven by steam from the Main Steam System or the Auxiliary Steam System and exhausts directly to the environment, and therefore, is a release path that is included in the environmental analysis.

Since Oconee Nuclear Station is a B&W designed plant, it uses once through steam generators which provide for vertical tubing which carries primary coolant from the top of the generator to its bottom while exchanging heat with the secondary fluid on the shell side. Because of this tubing arrangement, the tube leakage is modeled to occur above the secondary water mass in the steam generator. Therefore, no credit is taken for iodine partitioning in the steam generator. No credit is taken for iodine plateout in the steam lines or any other surface.

When the thermodynamic conditions are met for the Low Pressure Injection (LPI) system to remove decay heat from the primary, cooldown releases from the ADVs cease and decay heat removal is accomplished by the LPI system. Primary to secondary leakage and its release to the atmosphere continue until the temperature of the primary water leaking is less than the boiling point for water at atmospheric conditions. At this point all releases of activity from the plant model cease.

Offsite atmospheric dispersion factors from the Updated Final Safety Analysis Report Chapter 2 were used. Dose conversion factors from Federal Guidance Reports 11 and 12 were used.

Based upon this model, releases of activity to the environment from the primary and secondary systems can be calculated and used to calculate doses offsite at the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ). The doses calculated meet the regulatory criteria of 10 CFR 100 for each of the source terms examined. The results are presented in Table 15-16.

15.9.4 Conclusions

The steam generator tube rupture accident is analyzed to provide conservative inputs to the environmental consequences analysis. The results of the environmental consequences analyses are within the 10CFR100 limits. All of the acceptance criteria are met.

15.9.5 References

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15.10 Waste Gas Tank Rupture Accident

15.10.1 Identification of Accident

Rupture of a waste gas tank would result in the release of the radioactive contents of the tank to the plant auxiliary building ventilation system and to the atmosphere through the unit vent. The release is assumed to occur over a two hour period to maximize the exclusion area boundary dose. Dose to a receptor at the site boundary and the control room dose evaluated.

15.10.2 Analysis and Results

A tank is assumed to contain the maximum inventory expected based on a technical specification limit which requires that offsite dose from a tank rupture be limited to 500 millirem. The tank inventory assumed in this analysis is far greater than the expected operational inventory and is not based on actual operation of the system. The shared unit 1 & 2 tank is considered as the limiting case and is assumed to contain the following noble gas inventory.

Isotope	Waste Gas Tank Inventory Activity (Ci)
Kr-85m	888
Kr-85	68,657
Kr-87	484
Kr-88	1,519
Xe-133m	2,560
Xe-133	186,345
Xe-135m	282
Xe-135	5,344

The Total Effective Dose Equilivant from a puff release of this inventory to the site boundary is calculated to be 0.44 Rem at the exclusionary boundary and 0.048 Rem at the Low Population Zone boundary. Control Room Dose is less than 0.338 Rem TEDE.

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15.11 Fuel Handling Accidents

15.11.1 Identification of Accident

Spent fuel assemblies are handled entirely under water. The Core Operating Limits Report, refueling boron concentration, ensures shutdown margin is maintained. Procedures ensure that fuel assemblies are in configurations such that this shutdown margin is maintained In the spent fuel storage pool, the fuel assemblies are stored under water in storage racks with a minimum boron concentration as specified by the Core Operating Limits Report (COLR) in the pool water. Under these conditions, a criticality accident during refueling is not considered credible. Fuel handling consists of all fuel assembly shuffling and transfer operations between the reactor, the spent fuel pool, the fuel shipping casks, and dry storage transfer cask. Mechanical damage to the fuel assemblies during transfer operations is possible but improbable. The mechanical damage type of accident is considered the maximum potential source of activity release during refueling operations.

15.11.2 Analysis and Results

15.11.2.1 Base Case Fuel Handling Accident in Spent Fuel Pool

During fuel handling operations, it is possible that a fuel assembly can be dropped, causing mechanical damage with a subsequent release of fission products. To conservatively evaluate the offsite dose consequences of such an accident, conservative assumptions are made. The following analysis assumes the accident occurs within the spent fuel pool building.

The fuel assembly gap inventory is assumed to contain a fission product inventory from a maximum burned fuel assembly at a radial peaking factor of 1.65. The gap fractions used are from Reg. Guide 1.183 and the reactor has been shutdown for 72 hours, which is the minimum time for RCS cooldown, reactor closure head removal, and removal of the first fuel assembly. For fuel pins that exceed the rod power/burnup criteria of Footnote 11 in RG 1.183, the gap fractions from RG 1.183 are increased by a factor of 4 for Kr-85, Cs-134, and Cs-137. The gap fractions for all other isotopes remain at their pertinent RG 1.183, Table 3 values. The actual isotopic curie contents are listed in Table 15-1. It is also assumed that all 208 fuel pins are mechanically damaged such that the entire gap inventory is released to the surrounding water. Since the fuel pellets are cold, only the gap inventory is released.

The gases released from the damaged fuel assembly pass upward through the spent fuel pool water prior to reaching the Auxiliary Building atmosphere. Noble gases are assumed to not be retained in the pool water. According to Reg Guide 1.183, an iodine decontamination factor of 200 can be used for water depths of 23 feet or greater. Since the spent fuel pool racks are at an elevation of 816.5 feet and the minimum water level in the Spent Fuel Pool is equal to or greater than 837.84 feet, there is a minimum of 21.34 feet of water over the fuel storage racks, including instrument error. An experimental test program (Reference 2) evaluated the extent of removal of iodine released from a damaged irradiated fuel assembly. Iodine removal from the released gas takes place as the gas rises through the water. The extent of iodine removal is determined by mass transfer from the gas phase to the surrounding liquid and is controlled by the bubble diameter and contact time of the bubble with the water. The following analytical expression is given as a result of this experimental test program:

Iodine Decontamination Factor (DF) = $73\ e^{0.313\ (t/d)}$

Where:

t = bubble rise time, seconds

d = effective bubble diameter, cm

Since the minimum water depth over a dropped fuel assembly is less than 23 feet (21.34 feet), the assumed iodine DF must be less than 200, according to Reg. Guide 1.183, and calculated with comparable conservatism. Using the above relationship, with a water depth of 21.34 feet, a comparable DF is equal to 183 (Revision 1).

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The activity released from the water's surface is released within a two-hour period as a ground release. The atmospheric dilution is calculated using the two-hour ground release dispersion factor of 2.2 x 10^4 sec/m^3.

The total effective dose equivalent (TEDE) doses are given in Table 15-16. These values are below the limits given in Regulatory Guide 1.183.

15.11.2.2 Base Case Fuel Handling Accident Inside Containment

The offsite dose consequences for a fuel handling accident inside containment were evaulated per the guidance given in Reg. Guide 1.183. Since the shallow end of the fuel transfer canal is at an elevation of 816.5 feet, the same iodine decontamination factor used for the Fuel Handling Accident in the Spent Fuel Pool is used for the Fuel Handling Accident inside Containment. The activity released from the refueling water is released as a ground release, which has an atmospheric dispersion factor of 2.2 x 10^4 sec/m^3. There is no credit taken for any containment closure/integrity resulting in the released activity from the refueling water going straight outside.

Using the fuel assembly gap inventory in Table 15-1, and assuming all 208 fuel pins are damaged, the calculated doses are appropriately within the guidelines given in Regulatory Guide 1.183. For fuel pins that exceed the rod power/burnup criteria of Footnote 11 in RG 1.183, the gap fractions from RG 1.183 are increased by a factor of 4 for Kr-85, Cs-134, and Cs-137. The gap fractions for all other isotopes remain at their pertinent RG 1.183, Table 3 values. The limiting doses for a fuel handling accident for a single fuel assembly event are given in Table 15-16.

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15.11.2.4 Shipping Cask Drop Accidents

Fuel shipping casks are used to transport irradiated fuel assemblies from the site and also between the Oconee 1 and 2 spent fuel pool and the Oconee 3 spent fuel pool.

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The worst case fuel handling accident sequence in which the fuel shipping cask impacts on the irradiated fuel assemblies in a spent fuel pool is evaluated. At no time is the cask suspended above the spent fuel; however, it is credible that with failure of the cask hoist cable that the cask, yoke, hook, and load block could, as a result of an eccentric drop, deflect and fall into the spent fuel pool and impact on top of the assemblies in the pool. The analysis is performed separately for the shared Unit 1 and 2 spent fuel pool and the Unit 3 spent fuel pool. In the first part of the analysis, the number of fuel assemblies damaged as a result of the cask drop is found. Subsequently the radiological consequences of the damaged assemblies are determined.

The following conservative assumptions are employed for determining the number of fuel assemblies damaged.

1. The cask, lifting yoke and load block are free to fall from elevation 844 ft., the top of the spent fuel pool, to elevation 816 ft. 5 in., the top of the fuel storage racks.
2. The drag on the cask, lifting yoke and load block from falling through 25.5 ft. of water is neglected.
3. The ability of the fuel storage cells to absorb energy beyond the point of elastic buckling is neglected.
4. The energy which is expended in deformation of the rack interconnecting members is neglected.
5. A deformed fuel storage cell results in the total loss of integrity of one fuel assembly.
6. The projected areas of the cask, lifting yoke and load block are oriented to contact the maximum number of fuel assemblies.

Using the above assumptions, the falling cask, lifting yoke, and load block will have 2.093×10^6 ft-lbf of kinetic energy at the instant of impact with the storage racks. This energy must be absorbed by the strain energy in the storage racks. For additional conservatism it is assumed that the storage racks which are directly impacted by the falling load in turn buckle and deflect into adjacent racks until the total energy of the falling cask is absorbed. The Unit 1 and 2 spent fuel pool contains 154 fuel storage positions under the direct impact area, with a total of 576 spent fuel assemblies which can potentially suffer a loss of integrity during a cask drop accident. The Unit 3 pool contains 156 fuel storage positions under the projected impact area, with a total of 518 assemblies which can be damaged during the accident. These analyses are based on the TN8 three element shipping cask.

Once the number of fuel assemblies which could be damaged is determined, dose analyses are performed which are consistent with Regulatory Guide 1.183, and NUREG0612. The following assumptions apply:

1. Spent fuel stored in the first 36 rows of the Unit 1 and 2 spent fuel pool closest to the spent fuel cask handling area has decayed at least 55 days. This is consistent with Technical Specification 3.7.15.a, "Plant Systems".
2. All fuel assemblies assumed damaged in excess of two full cores (354 assemblies) in the Unit 1 and 2 spent fuel pool are assumed to have decayed at least one year.
3. Spent fuel stored in the first 33 rows of the Unit 3 spent fuel pool closest to the spent fuel cask handling area has decayed at least 70 days. This is consistent with Technical Specification 3.7.15.b., "Plant Systems".
4. All fuel assemblies assumed damaged in excess of one full core (177 assemblies) in the Unit 3 spent fuel pool are assumed to have decayed at least one year.
5. The affected assemblies have the maximum core activity corresponding to a radial peaking factor of 1.2.
6. All rods of the affected assemblies are ruptured.
7. The iodine decontamination factor in pool water is 183.
8. There is no removal of activity by the spent fuel pool ventilation system filters prior to release to the environment.
9. Activity is released at ground level with an assumed χ/Q factor of 2.2×10^4 sec/m^3.

10. The fractions of noble gases and iodine in the gaps are shown below. For fuel pins that exceed the rod power/burnup criteria of Footnote 11 in RG 1.183, the gap fractions from RG 1.183 are increased by a factor of 4 for Kr-85, Cs-134, and Cs-137. The gap fractions for all other isotopes remain at their pertinent RG 1.183, Table 3 values (Reference 1).

Kr85, I131	10%, 8%
All other noble gases	5%
All other iodines	5%

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The offsite radiological consequences of the postulated cask drop accident in either spent fuel pool is within the Regulatory Guide 1.183 limits. The limiting doses for a fuel cask handling accident for a multiple fuel assembly event are given in Table 15-16.

15.11.2.5 Dry Storage Transfer Cask Drop Accident in Spent Fuel Pool Building

Dry storage transfer operations from the spent fuel pool (SFP) buildings to the Independent Spent Fuel Storage Facility (ISFSI) are routinely performed at Oconee. The major steps in the process involve transporting the transfer cask/dry storage canister (DSC) into the fuel building, placing into the SFP, loading with 24 qualified fuel assemblies, drying/sealing, and removing to the ISFSI. The potential exists for dropping the cask in the SFP area during transfer operations.

15.11.2.5.1 Criticality Analyses for Dry Storage Transfer Cask Drop Scenarios

While the transfer cask is never carried directly over spent fuel, the potential always exists for failure of the overhead crane or handling equipment. Thus, an analysis was performed assuming the cask, yoke, and yoke block are deflected into the Unit 1&2 SFP. In such a case, it was postulated that 1024 spent fuel assemblies (SFAs) would be damaged (the first 64 rows, each containing 16 SFAs). It was assumed that 220 fuel storage cells directly beneath the falling parts buckle and deflect into adjacent cells until all the energy of the dropping cask is absorbed. For a cask drop in the smaller Unit 3 SFP, it was assumed all 825 fuel cell locations would be damaged.

The potential for criticality in the SFPs was analyzed using the methodology identified in NUREG0612. It was assumed the racks and fuel were deformed such that keff was maximized. Credit was taken for pool boron and stainless steel walls to determine the keff under the assumed damage conditions. The confirmatory calculations utilized a specific neutronic analysis for each SFP with the following assumptions:

1. An infinite array of SFAs is crushed together into a geometry that optimizes keff.
2. The affected SFAs are unirradiated and have the maximum enrichment permitted for storage in the Oconee SFPs.
3. The minimum technical specification for SFP boron concentration is maintained.

The acceptance criteria for this accident per NUREG0612, is that k_{eff} will be less than or equal to 0.95 including all uncertainties. A series of calculations involving cases of varied pin pitch modeling the crushed cells and SFAs was performed. The maximum k_{eff} value determined for the Unit 1&2 SFP was 0.9491. The maximum k_{eff} value calculated for the Unit 3 SFP was 0.9392. These analyses verify that subcriticality in the SFP will be maintained after a dry storage cask drop accident (Reference 9).

The DSC internals are designed to prevent criticality during the wet loading and unloading process. As long as the SFP boron concentration is within the limit specified in CoC 1004 for the NUHOMS Storage System and for DSCs loaded under the Site Specific License SNM2503, the DSC is drained of water within 50 hours of loading the SFAs, criticality is precluded. Strict administrative controls are in place at Oconee to ensure the SFP boron concentration is maintained above the minimum required and that the draining time for Site Specific DSC's limit is not exceeded.

The consequences of dropping the dry storage transfer cask outside the fuel building are described in the ISFSI FSAR (Reference 11, 12).

15.11.2.5.2 Potential Damage to SFP Structures from Dry Storage Transfer Cask Drop

The concrete floor slab is designed to withstand the 100 ton cask drop. However, localized concrete could be crushed and the steel liner plate punctured in the area of dry storage cask impact. For the purpose of analyzing the event, a gap of 1/64 inch for a perimeter of 308 inches in the liner plate was assumed. The calculated leakage of pool water through the gap is 21.3 gallons per day. This amount of water loss is within the capability of the SFP makeup sources.

15.11.2.5.3 Radiological Dose from Dry Storage Transfer Cask Drop

The worst radiological consequences resulting from a dry storage cask drop accident into either the Unit 1&2 or the Unit 3 SFP were analyzed. The calculation assumes a total of 1024 SFAs would be damaged in the Unit 1&2 SFP. Of this number, two full core inventories (354 SFAs) with worst case fission product concentration and less than 1 year decay time are assumed to be present. For the Unit 3 SFP, all 825 fuel cell locations are assumed to contain SFAs that would be damaged by the cask drop. One full core inventory (177 SFAs) with worst case fission product inventory and less than 1 year decay is considered to be present in the Unit 3 pool. Thus, the analysis assumes 670 and 648 SFAs, for Unit 1&2 and Unit 3 SFPs respectively, have a minimum of 1 year decay time.

Oconee Technical Specification 3.7.15.c, "Plant Systems," requires that fuel stored in the first 64 rows closest to the cask handling area be decayed a minimum of 65 days prior to movement of the dry storage transfer cask in the Unit 1&2 SFP area. Likewise, Technical Specification 3.7.15.d, "Plant Systems," requires all SFAs stored in the Unit 3 pool must be decayed a minimum of 57 days before movement of the cask is permitted in that area. The maximum fission product inventories for the iodine and noble gas nuclides of interest at times of 57 days, 65 days, and 1 year were calculated in Reference 3. This information, in conjunction with the assumed pool inventories, was used to determine the curies of each nuclide released from the postulated cask drop accidents. The total activity releases for each pool were used to determine the worst case dose consequences.

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The calculated doses are less than the Regulatory Guide 1.183 limits. Therefore, the accident dose criteria will not be exceeded for the limiting postulated dry storage cask drop accident.

15.11.3 References

1. DPC Engineering Calculation OSC7738, "Fuel Handling Accidents (FHA) Dose Analysis", dated September 10, 2018.
2. WCAP7828, "Radiological Consequences of a Fuel Handling Accident", December 1971.
3. DPC Engineering Calculation OSC9154, "Oconee Isotopic Source Term Calculations", dated July 23, 2008.
4. Deleted per 2005 Update.
5. Parker, W. O. Jr., Letter to Rusche, B. C. (NRC), November 3, 1975.
6. Parker, W. O. Jr. (Duke), Letter to Denton, H. R. (NRC), July 25, 1980.
7. Tucker, H. B. (Duke), Letter to Denton, H. R. (NRC), November 19, 1985.
8. Deleted per 2005 Update.
9. DPC Engineering Calculation OSC3631 Rev 2, "Criticality Consequences of a Heavy Load Drop in the Spent Fuel Pool", dated February 7, 1996.
10. Deleted per 2002 update.
11. Oconee Nuclear Station Site Specific Independent Spent Fuel Storage Installation, Final Safety Analysis Report, Chapter 8.
12. Oconee Nuclear Station Independent Spent Fuel Storage Installation General License, Updated Final Safety Analysis Report.
13. Deleted per 2006 update.
14. Deleted per 2006 update.
15. Deleted per 2006 update.
16. Deleted per 2006 update.

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15.12 Rod Ejection Accident

15.12.1 Identification of Causes and Description

The rod ejection accident is caused by a failure of a control rod drive mechanism housing, which allows a control rod to be rapidly ejected from the reactor by the Reactor Coolant System (RCS) pressure. The control rod is ejected in 0.15 seconds from the fully inserted position. A power excursion will result, and if the reactivity worth of the ejected control rod is large enough, the reactor will become prompt critical. The resulting power excursion will be limited by the fuel temperature feedback and the accident will be terminated when the Reactor Protective System (RPS) trips the reactor on high neutron flux or high RCS pressure. RCS pressure increases due to the core power excursion, and pressurizer spray, the pressurizer PORV, and the pressurizer code safety valves will respond to mitigate the pressure increase. If a rod ejection were to occur, the nuclear design of the reactor and limits on control rod insertion will limit any potential fuel damage to acceptable levels. Cladding failure can result from the core power excursion and the highly peaked core power distribution near the ejected rod location. The failure of the control rod drive mechanism housing also constitutes a 1.50 inch diameter small-break LOCA (SBLOCA). The Emergency Core Cooling System (ECCS) will actuate on low RCS pressure or high Reactor Building pressure and will maintain core cooling. This type of SBLOCA is bounded by the limiting SBLOCA analyses presented in Sections 6.2 and 15.14.

Analyses are performed for a full core loaded with Mk-B-HTP fuel with UO_2-Gadolinium (Gad) fuel rods with different initial core conditions and number of reactor coolant pumps (RCPs) in operation. Analysis results are shown in Table 15-2. Six cases are analyzed for the full Mk-B-HTP with UO_2 Gad Fuel rods core as follows (Table 15-34). Two cases initiate at zero power (1E-7% of full power) with three RCPs in operation, at both BOC and EOC; two cases initiate at 77% power with three RCPs in operation, at both BOC and EOC; two cases initiate at 102% with four RCPs in operation, at both BOC and EOC. Since cladding failure due to exceeding the DNBR limit will result, the different possible RCP operating conditions are analyzed to bound the effect of core flowrate on DNBR. Zero power and full power are both analyzed to bound the range of ejected rod worths, initial fuel temperatures, and core power distributions. The ejected rod worth for each case is based on the power level dependent rod insertion limit including uncertainty. The negative reactivity inserted on reactor trip assumes that the most reactive control rod remains in the fully withdrawn position. The pressurizer spray and PORV are not credited for mitigating the pressure transient in the evaluation of the peak RCS pressure response. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The RPS and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35. The results presented model the replacement steam generators.

Due to the asymmetric core power distribution resulting from the rod ejection, the excore power range flux channels which input to the RPS high flux trip function will indicate different transient power responses. The analyses assume a single failure of the excore flux channel which indicates the highest power level. This assumption results in the third highest excore flux channel determining the time of reactor trip based on the 2/4 RPS trip logic design.

The rod ejection accident is considered to be a limiting fault. The acceptance criteria for the rod ejection accident analysis are that the accident will not further damage the RCS, and that the doses will be less than the 10CFR50.67 limits. The first criterion of no further damage to the RCS is interpreted to mean that the peak RCS pressure and the peak pellet radial average enthalpy both remain below a specified limit. The peak primary pressure limit is to remain within Service Limit C as defined by the ASME Code (Reference 13), which is 120% of the 2500 psig design pressure, or 3000 psig. The peak enthalpy limit is such that the radially averaged fuel pellet enthalpy shall not exceed 280 cal/gm at any location in the core. To evaluate the second criterion of dose being within the 10CFR50.67 limits, the extent of fuel failures are quantified with the assumption that any fuel pin that exceeds the CHF DNB design limits is considered failed. The fuel failure results are used in the dose calculations to verify that the dose criteria are satisfied. The dose analysis also considers the SBLOCA release to the Reactor Building.

15.12.2 Core Kinetics Analysis

The rod ejection accident core kinetics response is determined with a three dimensional space/time analysis using SIMULATE-3K for each of the six full core Mk-B-HTP with UO_2-Gad cases. Important inputs and results for all of the cases are shown in Table 15-2. Only the ejected rod worth at BOC and EOC transients at hot zero power is large enough to achieve prompt criticality (reactivity greater than one dollar). The neutron power transients for all six cases of full core Mk-B-HTP with UO_2-Gad are shown in Figure 15-29, Figure 15-30, Figure 15-31, Figure 15-32, Figure 15-33, and Figure 15-34. For all cases the power excursion is terminated by the Doppler temperature feedback and the reactor is shut down by the reactor trip on high flux or flux/flow setpoints.

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15.12.3 Fuel Pellet Enthalpy Analysis

For each of the six rod ejection accident cases, the core power excursion and the time-dependent three-dimensional power distribution from the Mk-B-HTP with UO_2-Gad fuel rods SIMULATE-3K core kinetics analyses are used as input to the calculation of the fuel pellet peak radial average enthalpy. The results for the six cases are shown in Table 15-2. The limiting case is at 102% power and has a peak enthalpy of 134.0 cal/gm.

15.12.4 Core Cooling Capability Analysis

For each of the six rod ejection accident cases, the core power excursion from the Mk-B-HTP with UO_2-Gad fuel rods SIMULATE-3K core kinetics analysis is combined with the core flowrate, temperature, and pressure transients from the system analysis to determine the DNBR response. A range of assembly peaking factors and axial shapes are assumed to determine the peaking factors at which the DNBR limit is exceeded for each of the six cases. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel rod in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the fuel rod exceeds the DNBR limit. All fuel rods that exceed the DNBR limit are assumed to experience cladding failure and are included in the source term for the offsite dose calculation. Table 15-2 shows the percentage of fuel pins that exceed the DNBR limit for each case.

15.12.5 Peak RCS Pressure Analysis

The peak RCS pressure for the SIMULATE-3K rod ejection accident is determined by a system analysis simulation that uses a boundary condition of the coolant expansion rate in the core. The core coolant expansion rate is calculated for each fuel assembly and is summed into a total expansion rate. The total coolant expansion rate is then input to the system analysis, which results in a pressurizer insurge and a compression of the pressurizer steam bubble. The peak RCS pressure results from the 102% power BOC case. Figure 15-36 shows the pressure transient for the Mk-B-HTP core with UO_2-Gad fuel rods.

15.12.6 Environmental Consequences

A conservative consequences analysis for a postulated rod ejection accident is performed to determine the resulting radiological consequences. The rod ejection accident calculation is based on the approach provided in Regulatory Guide 1.183. Activity is released to the environment by releases associated with the normal operation of plant equipment or the operation of plant equipment as intended in response to the accident, and as part of the subsequent cooldown activities.

Two activity release paths are evaluated separately. The first release path is via containment leakage resulting from release of activity from the primary coolant and failed fuel pins to the Reactor Building. The second path is the contribution of primary-to secondary leakage and contaminated secondary coolant release to the atmosphere. At the time of the accident, forty-five percent (45%) of the fuel rods in the core are assumed to fail due to DNB, releasing stored gap activity; no fuel melting is assumed to occur. The source term isotopic inventory is based upon fuel depletion and projected fission product inventories at the end of the cycle with the maximum thermal power uncertainty applied. An initial source term inventory is also modeled for the secondary side. The maximum Technical Specification allowed DEI concentration is modeled to be present in the secondary side water. Radioactive depletion by decay is credited during the accident.

Fission products in the fuel gap regions of fuel pins undergoing DNB are assumed to be instantaneously released to the Reactor Building atmosphere. The assumed containment leak rate is the maximum rate allowed by Technical Specifications. No credit is taken for iodine removal from the containment atmosphere by the Reactor Building sprays. Credit is taken for removal of particulates in the Reactor Building atmosphere by natural deposition.

In order to transport and release primary activity to the environment, a primary to secondary release path is modeled in the steam generators. This path is postulated to exist at the start of the accident, but is not caused by the rod ejection accident. The assumed primary to secondary steam generator tube leakage rate is the maximum rate allowed by ONS Technical Specifications.

The thermal/hydraulic model discussed in the previous sections is used as the basis for the plant response and steam releases modeled in the environmental analysis. The plant is initially operating in a normal mode at full power (plus maximum thermal power uncertainty) with primary to secondary leakage. When the break initiates, the activities in the primary and secondary side are modeled to be instantaneously and homogeneously released to their respective systems. Shortly after the initiation of the event, the reactor is automatically tripped. The steam generators are assumed to discharge activity directly to the environment. This steam header will repressurize resulting in lifting its Main Steam Relief Valves. Since the steam release from the affected steam generator is not isolable, this release will continue as long as water and conditions conducive to boiling exist in this steam generator. Plant cooldown is achieved by discharging steam directly to the environment through the Atmospheric Dump Valves (ADVs). No credit is taken for the condenser.

Since Oconee Nuclear Station is a B&W designed plant, it uses once through steam generators which provide for vertical tubing which carries primary coolant from the top of the generator to its bottom while exchanging heat with the secondary fluid on the shell side. Because of this tubing arrangement, the tube leakage is assumed to occur above the secondary water mass in the steam generator. Iodine partitioning in the steam generator is credited in accordance with Regulatory Guide 1.183 but no credit is taken for iodine plateout in the steam generator or steam lines.

When the thermodynamic conditions are met for the Low Pressure Injection (LPI) system to remove decay heat from the primary, cooldown releases from the ADVs cease and decay heat removal is accomplished by the LPI system. Primary to secondary leakage continues until the temperature of the primary water leaking is less than the boiling point for water at atmospheric conditions. Offsite atmospheric dispersion factors from the Updated Final Safety Analysis Report Chapter 2 were used.

Based upon this model, releases of activity to the environment from the primary and secondary systems can be calculated and used to calculate doses offsite at the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ) and in the Control Room. The doses calculated meet the regulatory criteria of 10 CFR50.67 for each of the source terms examined. The results are presented in Table 15-16.

15.12.7 Conclusions

The rod ejection accident is analyzed for six cases which include different initial conditions for power level, number of RCPs in operation, ejected rod worth, and core physics parameters associated with BOC and EOC conditions. For the full Mk-B-HTP core with UO_2-Gad fuel rods, Table 15-2 shows the peak fuel pellet radial average enthalpy and fuel cladding failure percentage limit, for each of the transient scenarios, and peak RCS pressure for the limiting scenario. The environmental consequences analysis results are within the 10CFR50.67 limits. All of the acceptance criteria are met.

15.12.8 References

1. Deleted per 1999 Update
2. Deleted per 1999 Update
3. Deleted per 1999 Update
4. Deleted per 1999 Update
5. Deleted per 1999 Update
6. Deleted per 1999 Update
7. Deleted per 1999 Update
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9. Deleted per 1999 Update
10. Deleted per 1999 Update
11. Deleted per 1999 Update
12. Deleted per 1996 Update
13. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components", ASME

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15.13.1 Steam Line Break Accident

15.13.2 Identification of Causes and Description

The steam line break accident is caused by a rupture of one of the two main steam lines. A spectrum of break sizes up to and including a double-ended guillotine rupture are postulated. For steam line breaks that result in reactor trip, the limiting break size is a double-ended guillotine rupture since it maximizes the cooldown of the RCS. Smaller steam line breaks that do not result in reactor trip are analyzed in Section 15.17. The expected plant response to a double-ended guillotine rupture of one the main steam lines with offsite power maintained is as follows. The break initially results in a rapid blowdown of both steam generators. The steam generator depressurization initiates a rapid Reactor Coolant System (RCS) cooldown and depressurization, which results in a reactor trip on variable low pressure-temperature within the first few seconds of the accident. The reactor trip causes the main turbine stop valves to close, thereby isolating the affected steam generator from the unaffected steam generator. The affected steam generator continues to depressurize while the unaffected steam generator repressurizes. The main feedwater (MFW) pumps are tripped, the main and startup FDW control valves on the affected steam generator are closed, and the turbine-driven emergency feedwater (EFW) pump is inhibited from starting, Automatic Feedwater Isolation System (AFIS) circuitry is actuated on low steam generator pressure. The motor-driven EFW pumps start on main feedwater pump trip. The operator will manually trip all reactor coolant pumps (RCPs) on a loss of the subcooled margin. The motor-driven EFW pump to the affected steam generator is tripped by the AFIS circuitry when the rate of depressurization setpoint is exceeded. EFW flow is automatically controlled to the unaffected steam generator to provide the secondary heat sink. The High Pressure Injection System (HPI) will actuate on low RCS pressure and will begin restoring RCS inventory. The operator will then throttle HPI flow to maintain pressurizer level to the normal post-trip level.

The steam line break accident is analyzed both with and without offsite power. The with offsite power maintained case analyzes end-of-cycle core conditions to maximize the positive reactivity addition resulting from the RCS cooldown and any resulting return-to-power. The without offsite power case analyzes beginning-of-cycle (BOC) core conditions to conservatively predict the approach to DNB as the reactor coolant pumps (RCPs) coast down. No credit is taken for the Automatic Feedwater Isolation System (AFIS) circuitry since some of the components that actuate are non-safety grade. The non-safety grade Integrated Control System (ICS) is assumed to be in manual control with no operator action, since this assumption has been demonstrated to be conservative relative to assuming ICS control of MFW. This results in uncontrolled MFW flow and actuation of the EFW System. The results presented model the replacement steam generators. The analysis methodology and the computer codes used in the analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

Operator action to isolate MFW flow to the broken steam generator is credited at 10 minutes. The limiting single failure for the with offsite power analysis is the failure of a train of engineered safeguards that results in only one train of HPI. No single failure was identified which affects the results of the without offsite power analysis. The maximum worth control rod is assumed to remain in the fully withdrawn position.

The steam line break accident is considered to be a limiting fault. The acceptance criteria for this event are that the core will remain intact for effective core cooling and that the offsite doses will be within 100% of the 10CFR50.67 limits. The RETRAN system thermal-hydraulic analysis results are valid for the full core with Mk-B-HTP fuel.

15.13.3 With Offsite Power Analysis

The steam line break accident with offsite power analysis is concerned with the magnitude of any post-trip return-to-power. A significant return-to-power with the presence of a stuck rod may challenge the DNB limit. The limiting scenario with respect to maximizing the overcooling and reactivity addition has been determined to be the case with the ICS in manual control with no operator action, which results in uncontrolled MFW flow and actuation of the EFW System. This limiting scenario has been determined to bound scenarios with the ICS controlling MFW flow to the post- trip steam generator level setpoint increased by an allowance for uncertainty. The duration of the analysis is 10 minutes, which includes the core conditions of minimum DNB margin. The results of the analysis are shown in Figure 15-40, Figure 15-41, Figure 15-42, Figure 15-43, Figure 15-157, Figure 15-158, and Figure 15-159, and the sequence of events is given in Table 15-5.

The steam line break initially causes the pressure to decrease in both steam generators (Figure 15-40). The reactor trips in 3.1 seconds. Break flowrates (Figure 15-41) for both steam generators rapidly increase. After the turbine stop valves close, break flow from the unaffected steam generator stops. Break flow from the affected steam generator decreases with decreasing pressure, and the unaffected steam generator repressurizes until about 30 seconds. The uncontrolled main feedwater flow overfills the affected steam generator at approximately 240 seconds, and the unaffected steam generator at 214 seconds. The cooldown in the affected loop leads the cooldown in the unaffected loop, as shown in the cold leg and hot leg temperature responses (Figure 15-42). RCS has cooled to less than 250°F by the end of the simulation.

The total, moderator, Doppler, boron and control rod reactivities are presented in Figure 15-43. The negative reactivity insertion at the beginning of the transient is due to the reactor trip and control rod insertion. The cooldown causes positive reactivity insertion due to the negative moderator and Doppler coefficients. The core remains subcritical throughout the post-trip period, with the minimum subcritical margin reached at about 110 seconds. Boron injection from the core flood tanks, and then later the HPI system, provides sufficient negative reactivity to maintain the subcritical margin. The reactor power (Figure 15-157) decreases rapidly on reactor trip. The thermal power generally follows the neutron power response and then approaches the decay heat power level. The minor fluctuations in the heat flux are caused by flow surges in the core which result from flow degradation due to two-phase conditions in the unaffected loop. RCS pressure (Figure 15-158) rapidly decreases until the affected loop and reactor vessel head begin to saturate at approximately 4 seconds. After this time, RCS pressure continues to decrease for the remainder of the simulation.

Core inlet mass flow (Figure 15-159) initially increases with time due to the decreasing RCS temperatures. However, as the unaffected loop begins to void and RCP performance degrades, core inlet flow decreases to approximately 80% of the initial flow. Core flood tank and HPI System injection refill the RCS, and single phase flow is restored by 160 seconds.

Based on the reactor remaining subcritical post-trip, no return-to-power occurs. Therefore, the DNBR is bounded by the steam line break without offsite power case, and no detailed VIPRE-01 analysis is necessary.

15.13.4 Without Offsite Power Analysis

The steam line break accident without offsite power analysis assumes a loss of offsite power coincident with the break which trips the reactor and causes the RCPs to coast down. For this scenario the steam line break accident is a loss of flow accident with a coincident depressurization. The minimum DNBR statepoint occurs within the first few seconds of the RCP coastdown, therefore the duration of the analysis is 5 seconds. The results of the analysis are shown in Figure 15-161, Figure 15-162, Figure 15-163, Figure 15-164, Figure 15-165, Figure 15-166 and Figure 15-167, and the sequence of events is given in Table 15-48. The steam line break initially causes the pressure to decrease in both steam generators (Figure 15-161). Once the main turbine stop valves close, the unaffected steam generator starts to repressurize. The affected steam generator has depressurized to about 750 psig by the end of the analysis. The break flow response is similar to the offsite power analysis. The cooldown in the affected loop is almost the same as in the unaffected loop during the first 5 seconds, as shown in the cold leg temperature response (Figure 15-162). The increase in hot leg temperatures is caused by the flow coastdown. The affected loop hot leg temperature is slightly higher than the unaffected loop hot leg temperature due to the post-trip outsurge from the pressurizer. The RCS volumetric flow decreases for the duration of the simulation (Figure 15-163). The control rod insertion on loss of offsite power determines the core kinetics response (Figure 15-164). Due to the assumed BOC kinetics parameters and the short duration of the analysis, the moderator and Doppler reactivity feedback is negligible. The reactor neutron power decreases rapidly on reactor trip (Figure 15-165), with the thermal power responding slower due to the thermal delay. RCS pressure (Figure 15-166) rapidly decreases due to the effects of the overcooling from the steam line break and from the control rod insertion. As flow and primary-to-secondary heat transfer begin to degrade, RCS pressure begins to recover.

The system analysis results are input to the detailed core thermal-hydraulic analysis to determine the limiting DNBR. The transient minimum DNBR (Figure 15-167) is 1.73 for the full core with Mk-B-HTP fuel. The minimum DNBR value is greater than the design limit.

15.13.5 Environmental Consequence for the Large Steam Line Break

A conservative consequences analysis is performed for a postulated double ended break of a main steam line. This break results in an increased thermal demand on the reactor coolant system (RCS) and a rapid cooldown and positive reactivity addition from a negative temperature coefficient. This transient is not postulated to induce fuel failures, steam generator tube failures or any other failures of fission product barriers or primary system pressure boundaries, or any other pieces of equipment. Thus, the environmental consequences result from plant releases of pre-existing RCS activity transported to the secondary side by postulated steam generator tube leakage, and of pre-existing secondary activity. This activity is then released to the environment by releases associated with the normal operation of plant equipment or the operation of plant equipment as intended in response to the accident, and as part of the subsequent cooldown activities.

Two RCS source terms are examined as part of this analysis: a preaccident iodine spike and a concurrent iodine spike. The first models the maximum Dose Equivalent Iodine (DEI) activity concentration permitted by Technical Specifications for an iodine spike at full power. This preaccident spike is postulated to occur at the time of accident initiation. This source term is modeled to be released instantaneously and homogeneously such that the RCS activity is in equilibrium at the start of the accident. The second source term models a concurrent iodine spike, where the primary system transient associated with the accident causes an iodine spike in the primary system. The increase in primary coolant iodine concentration uses a spiking model that assumes that the iodine release rate from the fuel rods to the primary coolant increases to a value 500 times greater than the release rate corresponding to the iodine concentration at the equilibrium value specified in Technical Specifications. Both iodine spike source terms also bound Technical Specification limits for Dose Equivalent Xenon (DEX).

An initial source term is also modeled for the secondary side. The maximum Technical Specification allowed DEI concentration is modeled to be present in the secondary side water, the steam generators and any makeup water supplied to the unit. Thus, the secondary side is essentially modeled as an infinite source of water at the secondary side Technical Specification DEI concentration limit.

In order to transport and release primary activity to the environment, a primary to secondary release path is modeled in the steam generators. This path is postulated to exist at the start of the accident, but is not caused by the steam line break. The tube leakage into the unaffected steam generator modeled bounds the maximum allowed tube leakage rate into one steam generator. The affected steam generator is modeled with a leakage rate that bounds the maximum allowed unidentified primary to secondary leakage allowed by Technical Specifications.

The thermal/hydraulic model discussed in the previous sections is used as the basis for the plant response and steam releases modeled in the environmental analysis. The plant is initially operating in a normal mode at full power (plus maximum thermal power uncertainty) with primary to secondary leakage. The only releases occurring at the start of the accident are from the condensate steam air ejectors (CSAEs), which discharge a mixture of motive steam and condensate gases. Since the CSAEs operate continuously, no gases are assumed to be in the secondary system, as they would be removed by the CSAEs when introduced into the secondary system. When the break initiates, the activities in the primary and secondary side are modeled to be instantaneously and homogeneously released to their respective systems. Shortly after the break initiates, the reactor is automatically tripped and radioactive decay (and daughter product production) is begun in the model. The affected steam generator begins to discharge all of its activity directly to the environment. The unaffected steam generator also discharges its inventory directly to the environment through the break until the Turbine Stop Valves close shortly after reactor trip. This steam header will repressurize resulting in lifting its Main Steam Relief Valves. Since the steam release from the affected steam generator is not isolable, this release will continue as long as water and conditions conducive to boiling exist in this steam generator.

In order to maximize releases to the environment, the condenser is assumed to not be available. This requires that the unit be cooled down using the unaffected steam generator by discharging steam from this steam generator directly to the environment through the Atmospheric Dump Valves (ADVs). No credit is taken for the condenser and no partitioning credit is taken for CSAE releases which are modeled to occur until the beginning of cooldown.

The large steam line break causes the Turbine Driven Emergency Feedwater Pump (TDEFWP) to start and briefly supply makeup water. The TDEFWP is driven by steam from the Main Steam System or the Auxiliary Steam System and exhausts directly to the environment, and therefore, is a release path that is included in the environmental analysis.

Since Oconee Nuclear Station is a B&W designed plant, it uses once through steam generators which provide for vertical tubing which carries primary coolant from the top of the generator to its bottom while exchanging heat with the secondary fluid on the shell side. Because of this tubing arrangement, the tube leakage is modeled to occur above the secondary water mass in the steam generator. Therefore, no credit is taken for iodine partitioning in the steam generator. No credit is taken for iodine plateout in the steam lines or any other surface.

After the plant is stabilized following the initial transient, a soak is required. After the soak is completed, the plant is cooled down at the maximum rate permitted by Technical Specifications. This rate is reduced as required by Technical Specifications at the appropriate temperature. When the thermodynamic conditions are met for the Low Pressure Injection (LPI) system to remove decay heat from the primary, cooldown releases from the ADVs cease and decay heat removal is accomplished by the LPI system. Primary to secondary leakage and its release to the atmosphere continue until the temperature of the primary water leaking is less than the boiling point for water at atmospheric conditions. At this point all releases of activity from the plant model cease.

Offsite atmospheric dispersion factors from the Updated Final Safety Analysis Report Chapter 2 were used. Dose conversion factors from Federal Guidance Reports 11 and 12 were used.

Based upon this model, releases of activity to the environment from the primary and secondary systems can be calculated and used to calculate doses at the Exclusion Area Boundary (EAB), the Low Population Zone (LPZ), and in the Control Room. The doses calculated meet the regulatory criteria of 10 CFR 50.67 for each of the source terms examined. The results are presented in Table 15-16.

15.13.6 Conclusions

The steam line break accident has been analyzed both with and without offsite power. The results of the analysis show that DNBR margin exists. The results of the environmental consequences analyses are within the 10CFR 50.67 limits. All of the acceptance criteria are met.

15.13.7 References

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15.14.1 Loss of Coolant Accidents

15.14.2 Identification of Accidents

A failure of the RCS pressure boundary will result in a loss of primary coolant inventory and the potential for the core to uncover. These hypothetical failures are considered to occur in all piping and components up to and including a double-ended rupture of the largest pipe in the system. If the core is not rapidly reflooded and long term heat removal established, decay heat will cause the fuel cladding to fail and release the fission product inventory. The Emergency Core Cooling System (ECCS) is designed to deliver sufficient coolant to provide the necessary core decay heat removal for all credible loss-of-coolant accidents (LOCA).

15.14.3 Acceptance Criteria

In order to judge the acceptability of the performance of the ECCS in mitigating a LOCA, the Final Acceptance Criteria specified in 10CFR50.46 require that the results of the LOCA analysis meet the following criteria.

15.14.3.1 Peak Cladding Temperature

The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

15.14.3.2 Maximum Cladding Oxidation

The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation. As used in this subparagraph total oxidation means the total thickness of cladding metal that would be locally converted to oxide if all the oxygen absorbed by and reacted with the cladding locally were converted to stoichiometric zirconium dioxide. If cladding rupture is calculated to occur, the inside surfaces of the cladding shall be included in the oxidation, beginning at the calculated time of rupture. Cladding thickness before oxidation means the radial distance from inside to outside the cladding, after any calculated rupture or swelling has occurred but before significant oxidation. Where the calculated conditions of transient pressure and temperature lead to a prediction of cladding swelling, with or without cladding rupture, the unoxidized cladding thickness shall be defined as the cladding cross-sectional area, taken at a horizontal plane at the elevation of the rupture, if it occurs, or at the elevation of the highest cladding temperature if no rupture is calculated to occur, divided by the average circumference at that elevation. For ruptured cladding the circumference does not include the rupture opening.

15.14.3.3 Maximum Hydrogen Generation

The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

15.14.3.4 Coolable Geometry

Calculated changes in core geometry shall be such that the core remains amenable to cooling.

15.14.3.5 Long-Term Cooling

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

Conformance with the acceptance criteria must be demonstrated in a LOCA analysis which is conducted within the guidelines of 10CFR50 Appendix K, "ECCS Evaluation Models." Appendix K outlines the assumptions and analytical methods which have been accepted by the Nuclear Regulatory Commission (NRC) for evaluating the consequences of LOCA. The ECCS evaluation model applicable to Oconee is detailed in the following section.

15.14.4 ECCS Evaluation Model

15.14.4.1 Methodology and Computer Code Description

The large break LOCA (LBLOCA) evaluation model, which has been approved by the NRC, is detailed in the topical report "BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator Plants" (Reference 40). The LBLOCAs are analyzed with the RELAP5/MOD2-B&W computer code (Reference 38). The LBLOCA evaluation model has been shown to conform to the requirements of 10 CFR 50 Appendix K.

The RELAP5/MOD2-B&W code (Reference 38) solves the evolution of system hydrodynamics, core power generation, and clad temperature response during blowdown for the LBLOCA. The REFLOD3B code (Reference 4) is used to determine the length of the refill period and the flooding rates during reflood. The CONTEMPT code (Reference 5) calculates the Reactor Building pressure response. The BEACH code (Reference 39) is used with the output from REFLOD3B and CONTEMPT to determine the fuel thermal and mechanical response and the PCT during the reflood period. The code interfaces for the LBLOCA are shown in Figure 15-44 for cold leg breaks larger than 2 ft^2.

Cold leg break sizes between approximately 0.75 ft^2 and 2 ft^2 produce thermal-hydraulic behaviors that are transitional in nature, having both large and small break characteristics with respect to the evaluation model assumptions. The smaller break sizes result in slower transients for which no refill period exists. The smallest breaks may also begin reflooding the core shortly after core flood tank flow begins. The analysis of break sizes in this range requires adjustments to the nominal RELAP5-based LBLOCA evaluation model. These adjustments are described in Reference 40.

Hot leg breaks have many thermal-hydraulic similarities to the transitional breaks. There is no refill period due to direct venting of core steam to the break. Core reflooding begins shortly after core flood tank flow begins. Thus, the cold leg break LOCA methods are not suitable for analyzing these breaks. The techniques used to analyze the hot leg breaks with RELAP5/MOD2-B&W are described in Reference 40.

The small break LOCA (SBLOCA) evaluation model, which has been approved by the NRC, is detailed in the topical report “BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator Plants” (Reference 40). The SBLOCA events are analyzed with the RELAP5/MOD2-B&W computer code (Reference 38). The SBLOCA evaluation model has been shown to conform to the requirements of 10CFR50 Appendix K.

15.14.4.2 Simulation Model

The RELAP5 LBLOCA nodalization is presented in Reference 40. A detailed nodalization of the primary loop and reactor vessel is included. For break locations other than the pump discharge, the nodalization is appropriately modified.

The RELAP5 SBLOCA nodalization is detailed in Reference 40. A detailed nodalization of the primary loop and reactor vessel is included. The secondary side nodalization is sufficient for modeling the effects of emergency feedwater delivery and steaming.

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15.14.4.3 Thermal Hydraulic Assumptions

Thermal hydraulic conditions and parameters are assumed in accordance with 10 CFR 50 Appendix K.

15.14.4.3.1 Sources of Heat

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The reactor is initially operating at 102 percent of 2,568 MWt, the maximum rated power for an Oconee class plant. Core peaking factors are obtained from the analysis based on the criteria of 10CFR50.46. Core stored energy and fuel temperatures are calculated using the TACO3 code (Reference 35). Fission product decay heat is given by 1.2 times the ANS standard and decay of actinides is also assumed greater than the ANS decay curve. Direct moderator heating accounts for 2.7 percent of the fission energy released during the blowdown. Metal-water reaction is calculated using the Baker-Just equation without steam limiting. Heat transfer from non-fuel sources is accounted for, as is primary to secondary heat transfer.

15.14.4.3.2 Fuel Mechanical and Thermal Response

The detailed fuel response throughout the duration of the transient is predicted by the RELAP5/MOD2-B&W and BEACH codes for large break LOCA and the RELAP5/MOD2 – B&W code for small break LOCA. Thermal expansion, elastic and plastic deformation, and the events leading to possible clad rupture are considered. Approved models for heat capacity and conductivity in the fuel, and gap conductance and heat transfer are used. Models for cladding, swelling and rupture are described in NUREG-0630 and are incorporated in Reference 40. Evaluation model changes to analyze M5 cladding material are documented in Reference 43.

15.14.4.3.3 Blowdown Model

ECCS bypass is predicted to occur as long as the flow velocity is calculated to be sufficient to carry the ECCS fluid away from the core. The end of blowdown is considered either when zero leak flow occurs or when ECCS water starts entering the core. Friction and form loss factors account for system pressure drops and compare well with measured plant data. Single-phase and two-phase pump models are derived from homologous relationships.

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Break flow is calculated using the Extended Henry-Fauske equation for qualities up to 0.0 at which time a switch to the Moody correlation occurs. A range of discharge coefficients is evaluated in the LBLOCA break spectrum analysis. The critical heat flux (CHF) correlations used are the B-HTP, BWC, BWCMV, Barnett, and modified Barnett. In the low flow regime, a combination of the MacBeth and Griffith correlations is used. Pre-CHF heat transfer uses the maximum of the Dittus-Boelter or Rohsenow-Choi correlations for forced convection and a combination of the Chen, Thom, and Schrock-Grossman correlations for the nucleate boiling and forced convection vaporization regimes.

The post-CHF heat transfer regimes include transition boiling, film boiling, and single-phase steam heat transfer. For transition boiling, the correlation of McDonough, Milich, and King is used. The maximum of the Condie-Bengston and Rohsenow-Choi correlations is used in the film boiling regime. The single-phase heat transfer to steam correlation is the sum of a convective term and a radiation term. The convection heat transfer is the maximum of the McEligot or Rohsenow-Choi correlations. The radiation heat transfer is from the Sun correlation.

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15.14.4.3.4 Post-Blowdown Model

The evaluation of the LOCA during refill and reflood is conservatively conducted assuming the minimum containment backpressure consistent with the Reactor Building Cooling Systems performance, the ECCS injection with the design single failure, and conservative containment initial conditions, volume, and heat sink data. The REFLOD3B code calculates the heat transfer and hydraulic response with containment pressure input from CONTEMPT. During the refill period the core undergoes an adiabatic heatup. Steam venting and steam-water interaction, liquid entrainment, hot wall effects, and refill-reflood heat transfer are accounted for.

15.14.4.3.5 Availability of Reactor Coolant Pumps

Sensitivity studies have shown that for the large break LOCA the highest PCT results for the case with reactor coolant pumps (RCPs) tripped. Therefore, for large break LOCA the pumps trip and coast down on a loss of offsite power coincident with the break.

The SBLOCA has been analyzed assuming that the reactor coolant pumps trip and coast down coincident with reactor trip. This results in the coolant inventory change due to loss out the break and HPIS injection being reflected by the reactor vessel mixture level. The break size which resulted in the highest PCT was determined by a break spectrum analysis. This scenario was expected to represent the worst case SBLOCA, since if the reactor coolant pumps were running, the core would be cooled by pumping a two-phase mixture through the core, and no heatup would occur. Studies (Reference 14) have shown that for certain SBLOCAs characterized by a limited range of break sizes and break locations, that a delayed reactor coolant pump trip at high system void fractions can result in extended core uncovery and consequences in excess of the 10CFR50.46 criteria. This constituted a new worst case scenario. This situation resulted in the implementation of operating procedures which instruct the operator to trip the reactor coolant pumps upon loss of subcooled margin (Reference 15).

15.14.4.3.6 ECCS Performance and Single Failure Assumption

The ECCS is comprised of two passive core flood tanks (CFT), each of which injects through its associated core flood line into the reactor vessel downcomer; three low pressure injection pumps separated into two trains which inject into separate core flood lines; and three high pressure injection pumps separated into two trains which split and inject into each cold leg. The ECCS configuration was analyzed with the CRAFT2-based evaluation model (Reference 1) to determine the worst single failure in addition to the assumption of the loss of offsite power for each LOCA (Reference 33). Historically, the worst single failure for a LOCA is the loss of one bus of emergency power which results in the loss of one train of HPI and one train of LPI. The failure of transformer CT-4 has been identified as a more limiting single failure for the large break LOCA. The failure of transformer CT-4 results in a longer delay until delivery of ECCS fluid to the RCS. However, two ECCS trains are available with this single failure. Reference 33 demonstrates that having two ECCS trains injecting at a later time is more limiting than having one ECCS train injecting at an earlier time.

The Keowee hydro unit will start up and accelerate to full speed in 23 seconds or less (Section 6.3.3.3). The failure of transformer CT-4 results in an additional 10 second delay before power is available to the ECCS pumps. The time delay between breaker closure and valve/pump motors operating at rated voltage/speed is 5 seconds. Thus, for the large break LOCA analyses performed with the RELAP5-based evaluation model (Reference 40), the LPI valves will begin to open at 38 seconds with a stroke time of 36 seconds or less. Credit is taken in the analysis for flow through the LPI valves while the valves are traveling to their full open position. Full LPI flow will be obtained within 74 seconds. Two ECCS trains are available with the single failure of transformer CT-4. However, only one train of LPI flow is credited in the actual large break LOCA analyses (Reference 42).

For the limiting large break LOCA, the core heatup following blowdown is mitigated by core flood tank injection. Typically the time of PCT is prior to the actuation of pumped ECCS flow from the LPI and HPI pumps. Flow from one LPI pump provides for the long-term cooling of the core. For smaller large break LOCAs down to the transition break size, some HPI flow contributes to core cooling prior to the time of PCT, but it is a small contribution relative to the core cooling provided by the core flood tanks and the LPI pump. The PCTs for the smaller large break LOCAs have a large margin to the 2200°F acceptance criterion, and the small contribution of HPI flow to core cooling is not significant. Therefore HPI pumps are not required for large break LOCA mitigation.

A SBLOCA does not progress as rapidly as a large break LOCA. Thus, for a SBLOCA, the timing of ECCS injection is not as significant as with a large break LOCA. For this reason, the worst single failure for a SBLOCA remains the loss of one bus of emergency power. With the selection of an adverse break location, one half of the available HPI train would inject into the broken loop. With these assumptions the ECCS is reduced to the two CFTs, one LPI train, and one half of one HPI train. The SBLOCA analyses assume a 48 second delay until full ECCS flow is delivered to the RCS.

For the SBLOCA which does not depressurize to below the core flood tank setpoint (600 psig), only one half of one HPI train was available if the break is assumed to be in the cold leg pump discharge. This was identified as an unacceptable scenario (Reference 16). In order to deliver the required HPIS flow of 350 gal/min at 600 psig (Reference 17), the HPIS was modified to allow cross connecting of the pump discharges in order to balance the flow from two HPI pumps into the four injection locations (Reference 18, 19). This manual realignment of the HPIS is assumed to be completed within ten minutes of HPIS actuation.

The performance of the ECCS is also evaluated assuming that one of the three HPI pumps is initially unavailable. The limiting single failure leaves only one HPI pump available to inject following a SBLOCA. With only one HPI pump operating, the realignment to cross connect the pump discharges, described above, cannot be performed as a result of pump runout concerns at low primary system pressure. Significantly less HPI flow capacity results, and the power level must be reduced to 50% full power for the SBLOCA analyses to meet the acceptance criteria.

15.14.5 LOCA Analyses

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15.14.5.1 Large Break LOCA

Large break LOCA (LBLOCA) accidents can be treated analytically in three separate phases: blowdown, refill, and reflood.

The blowdown phase is characterized by the rapid depressurization of the Reactor Coolant System to a condition nearly in pressure equilibrium with its containment surroundings. Break flow is calculated using the Extended Henry-Fauske equation for qualities up to 0.0 at which time a switch to the Moody correlation occurs. A range of discharge coefficients is evaluated in the LBLOCA break spectrum analysis. Core flow is variable and dependent on the nature, size, and location of the break. Departure from nucleate boiling (DNB) is calculated to occur very quickly, at the higher power locations, and core cooling is by a film boiling process. Since film boiling is only capable of removing a limited amount of heat, the cladding temperature may increase up to ~1000°F at the peak power location. Core flood tank (CFT) flow begins after the RCS depressurizes below the CFT fill pressure. Steam condensation caused by the CFT liquid aids the negative core flows that reduce the fuel pin temperatures during the middle blowdown period. During the last phase of blowdown, cooling is by convection to steam, and the cladding temperature begins to rise again.

The end of blowdown is considered to have occurred either when zero leak flow occurs or the ECCS water starts to enter the core. ECCS bypass is predicted to occur when the flow velocity is calculated to be sufficient to carry the ECCS fluid away from the core.

Following blowdown, a period of time is required for the CFTs to refill the bottom of the reactor vessel before reflood and final core recovery can be established. During this period, core cooling is marginal and the cladding experiences a near-adiabatic heatup. This period is designated as the refill phase, because the CFT flow is refilling the reactor vessel lower plenum.

When the water level reaches the bottom of the active fuel the reflood phase begins. Core cooling is by steam generated below the rising water level. The cladding temperature excursion is generally terminated before a particular elevation is covered by water since the steam-water mixture is sufficient to remove the relatively low decay heat being generated at this time. A two-phase mixture eventually covers the core, and the path to long-term cooling is established through initiation of Low Pressure Injection (LPI) System flow near the time the CFTs empty and subsequent operator action to maintain pumped injection.

The evaluation of the LOCA during refill and reflood is conservatively conducted assuming the minimum containment back pressure consistent with the Reactor Building Cooling System performance, the ECCS injection with designed single failure, and conservative containment initial conditions, volume, and heat sink data. The REFLOD3B computer code (Reference 4) calculates the heat transfer and hydraulic response with containment pressure input from the CONTEMPT computer code (Reference 5). The containment pressure used in the Oconee large break LOCA analysis is presented in Figure 15-177.

15.14.5.1.1 Large Break LOCA Break Spectrum

Using the CRAFT2-based evaluation model (Reference 1), a spectrum of large breaks was analyzed for both double-ended and longitudinal split breaks in all locations. The methodology used to identify the worst break was as follows. A double-ended break with discharge coefficient C_D = 1.0 was analyzed at the hot leg, cold leg pump suction, and pump discharge. The cold leg pump discharge was determined to be the worst break location. The break size was then varied for both double-ended and split breaks.

The RELAP5 large break LOCA analyses have replaced the CRAFT2 large break analyses. The generic break spectrum studies performed with the RELAP5 evaluation models have selected the transition break size to be 0.75 ft^2, based on the onset of the occurrence of early cladding DNB during the blowdown phase. Both of these break spectrum studies have shown that the phenomena in the transition break size range are predicted to be similar, and that the PCTs in the vicinity of the transition break size are non-limiting.

The break spectrum analysis was also performed using the RELAP5-based evaluation model for the generic raised loop design (Reference 40) for break sizes ranging from 0.75 ft^2 up to and including the cross sectional area of the largest pipe in the system. Breaks that were clearly shown to be non-limiting in the generic break spectrum analysis were not reanalyzed for the Oconee-specific break spectrum. A double-ended break with discharge coefficient C_D = 1.0 was analyzed at the cold leg pump discharge and cold leg pump suction in the Oconee-specific break spectrum. The cold leg pump discharge was determined to be the worst break location. This break location was further analyzed for a double-ended break with discharge coefficients of C_D = 0.8 and C_D = 0.6. A split break at the cold leg pump discharge was also analyzed. The results of these analyses are shown in Table 15-6 and Figure 15-50. A symmetric power shape with an axial peaking factor of 1.7 and a peak linear heat rate of 17.5 kW/ft is assumed.

The worst break was identified as the double-ended cold leg break at the pump discharge with C_D = 1.0. Using the RELAP5-based evaluation model (Reference 40), this break of 8.55 ft^2 area yielded a predicted PCT of 1957°F and a maximum local metal-water reaction of 2.02 percent. The same break size at the pump suction showed a predicted PCT of 1830°F and a maximum local metal-water reaction of 1.54 percent. The range of break sizes smaller than the full area double-ended break at the pump discharge all showed less severe consequences.

A series of large breaks are analyzed from an initial condition where three reactor coolant pumps are in operation. Three possible break locations associated with this mode of operation were identified.

An evaluation was made using the RELAP5-based evaluation model on a generic basis for a raised-loop plant (Reference 40). Breaks were analyzed with the idle pump simulated in the intact loop, broken leg, and intact leg of the broken loop. The case with the idle pump in the broken leg was determine to be limiting. Thus, a double-ended break with the idle pump in the broken leg and a C_D = 1.0 was analyzed for Oconee using the RELAP5-based evaluation model with three pumps. This analysis, which was performed at 80 percent FP with a moderator temperature coefficient of +1 pcm/°F, was shown to be less limiting than the 100 percent FP case with a moderator temperature coefficient of 0 pcm/°F (Reference 42).

15.14.5.1.2 Deleted Per 2014 Update

15.14.5.1.3 Deleted Per 2014 Update

15.14.5.1.4 Deleted Per 2014 Update

15.14.5.1.5 Full Core Mark-B-HTP Large Break LOCA Linear Heat Rate Limits

Beginning with Oconee Unit 2 Cycle 26, Oconee core designs will consist of a full-core of Mark-B-HTP fuel assemblies, incorporating gadolinia as an integral burnable neutron absorber, operating on 24-month fuel cycles. To support this fuel transition, new LOCA analyses were performed to determine linear heat rate (LHR) limits and corresponding PCT for the Mark-B-HTP fuel assembly with gadolinia in a full-core configuration.

The limiting break identified in the break spectrum analysis (a double-ended pump discharge break with a CD = 1.0) was used to analyze the limiting linear heat rate limits for Oconee in accordance with the LOCA evaluation model described in Reference 40. The core model is separated into a hot pin, hot channel, and average channel as documented in Reference 38. The Oconee-specific RELAP5/MOD2-B&W model was used, including the replacement once-through steam generators (ROTSG) and the passive LPI cross connect modification (Reference 50).

In addition to the Oconee input model changes made to reflect the ROTSG and the passive LPI cross connect modification, another evaluation model change is a result of resolution of Preliminary Safety Concern (PSC) 1-99. It was determined for Oconee (Reference 44) that a minimum two-phase RCP degradation model produced more limiting results than maximum pump degradation. This model assumption is different than that presented in Reference 40. Since the minimum two-phase pump degradation model produced more limiting results, all Oconee LOCA limit calculations use this model assumption.

The ONS LBLOCA analysis was performed to satisfy a Nuclear Regulatory Commission (NRC) commitment to complete a full LBLOCA re-analysis that incorporates the NRC-approved burnup-dependent fuel Thermal Conductivity Degradation (TCD) method (Reference 54). The NRC-approved method to address fuel TCD impacts is described in Supplement 1P-A (Reference 56) to the B&W Plant LOCA Evaluation Model BAW-10192PA (Reference 40).

Previously identified LBLOCA model error corrections for the modeling upper plenum column weldments, ECCS end of bypass timing, and a control variable used for the calculation of the core flows, as reported in References 52 and 53, are incorporated into the TCD LBLOCA reanalysis. The re-analysis also explicitly incorporated EM error corrections and model changes that have been identified since the last Oconee LBLOCA analysis, specifically (1) updated M5 cladding swelling and rupture model, (2) LOCA evaluation model documentation error correction for M5 cladding properties, (3) updated M5 cladding initial inside oxidation thickness versus burnup model, (4) updated BEACH lower plenum pressure to include the elevation head of the minimum downcomer level from REFLOD3 for use in determining the fluid inlet subcooling used in the BEACH analyses, and (5) updated adjustment of the Bottom of Core Recovery (BOCR) time used in BEACH, if RELAP5 reached the minimum Core Flood Tank (CFT) temperature during blowdown.

Using this model, LOCA linear heat rate limits were determined for the Mark-B-HTP fuel assembly design. Specific calculations were performed to simulate five axial power peaks centered at the middle of the five grid spans (at core elevations of 2.506, 4.264, 6.021, 7.779, and 9.536 feet). These cases were analyzed with an axial peak of 1.7 and the radial peak was adjusted to obtain an allowable LHR limit. The initial fuel conditions for the desired peaking conditions are obtained from the TACO3 fuel performance code (Reference 35) for UO_2 fuel, and the GDTACO fuel performance code for gadolinia fuel. The fuel initializations consider the methodology changes implemented to address burnup-dependent fuel TCD as described in Reference 56.

Calculations are performed for all five elevations for the beginning-of-life (BOL), middle-of-life (MOL), and end-of-life (EOL) conditions. The results of the LOCA limits analyses are tabulated in Table 15-62 for UO_2 fuel, and Table 15-63 for fuel with UO_2-gadolinia fuel rods. Plant operation within these LHR limits assures that the 10CFR 50.46 acceptance criteria are not exceeded. In addition, the results for the 2.506 foot elevation at MOL conditions are presented in Figure 15-219, Figure 15-220, Figure 15-221, Figure 15-222, Figure 15-223, Figure 15-224, Figure 15-225 and Figure 15-226. These figures are representative of the results that are seen at all core elevations and times in life. These results indicate a maximum PCT of 1987.9 °F, a maximum local oxidation of less than 3.0 percent, and a whole core hydrogen generation of less than 0.2 % for a full-core of Mark-B-HTP fuel.

The gadolinia fuel has a lower fuel thermal conductivity and volumetric heat capacities than the UO_2 fuel, and therefore will respond more slowly to changes in the thermal environment. These small property differences are accounted for by reducing the LHR limits for gadolinia to keep the calculated results for gadolinia pins similar to the UO_2 results. The gadolinia pins were analyzed for LHR limits at core elevations of 2.506, 4.264, 6.021, 7.779, and 9.536 feet for BOL, MOL, and EOL conditions.

The end-of-life (EOL) UO_2 LHR limits were established at the design rod average burnup of 62 GWd/mtU. Gadolinia fuel will be limited to a maximum rod average burnup of 55 GWd/mtU. However, at EOL, the TACO3 LOCA initialization is limited to a LHR that achieves a maximum initial pin pressure, because it is generally not limited by the LOCA PCT. LBLOCA analysis at all core elevations is performed to confirm that EOL is not PCT limited

15.14.5.1.6 Deleted Per Rev. 29 Update

15.14.5.2 Small Break LOCA and Break Spectrum Analysis

The transient progression for SBLOCAs is summarized here to identify the key phenomena and controlling thermal-hydraulic behavior during each phase of the event. A potentially limiting SBLOCA generally progresses through five phases: (1) subcooled depressurization, (2) reactor coolant pump and loop flow coastdown and natural circulation, (3) loop draining, (4) boiling pot, and (5) refill and long-term cooling. The subcooled depressurization phase begins at the leak initiation. This phase is characterized by the period of time before the RCS begins to saturate and voids begin to form in the RV upper head and hot leg U-bends. During this period, the pressurizer will begin to empty, the RCS will depressurize to the low RCS pressure reactor trip setpoint, and the turbine will trip. With the assumption of a loss of off-site power coincident with reactor trip, the MFW pumps and RC pumps will trip and EFW will be initiated following a 69-second delay.

Following the RCP coastdown, the RCS flow tends to evolve to a natural circulation flow condition. The energy generated by the core is transferred by convection to the steam generators during the flow phase. The continued loss of the RCS liquid inventory allows steam voids to form in the upper reactor vessel head and the upper hot leg U-bends. Natural circulation ends when the U-bend steam void displaces the hot leg mixture levels below the U-bend spillover elevation. Flow is usually interrupted first in the hot leg containing the pressurizer surge line connection, because of the additional flashing of the saturated pressurized liquid that enters during the subcooled depressurization. Near the end of the flow phase, alternating periods of RCS repressurization can cause intermittent spillovers of hot-leg liquid into the steam generator primary region.

With the interruption of the RCS loop flow, the loop-draining phase begins. As the entire RCS approaches saturated conditions, the onset of subcooled and saturated nucleate boiling occurs in the core because of the high decay heat levels and the RCS depressurization. The flashing within the hot legs increases the size of the voids in the U-bends and eventually interrupts RCS flow and decreases the primary-to-secondary heat transfer. For the larger SBLOCAs, the RCS will continue to depressurize as the loops drain. For smaller breaks, however, the reduced heat transfer can interrupt the RCS depressurization. Also for these smaller breaks, the volumetric expansion of the RCS, due to continued steam formation, can exceed the volumetric discharge from the break, causing the RCS pressure to temporarily stabilize or even increase.

In the reactor vessel, the steam void in the upper head displaces enough liquid to uncover the reactor vessel vent valves (RVVVs), creating a manometric imbalance between the core and the downcomer. The imbalance forces the RVVVs to open and pass steam into the reactor vessel downcomer. The downcomer steam volume grows until the cold leg nozzle is exposed to steam. As soon as the downcomer liquid level decreases below the cold leg nozzle spillunder elevation, a steam venting path develops from the core through the RVVVs to the cold leg break, enhancing the RCS depressurization.

During the loop draining phase, the steam voids that developed in the U-bends can become large enough that the primary liquid level is displaced into the steam generator tube region below the EFW nozzles. If feedwater (MFW or EFW) is injecting through the EFW nozzles, improved primary-to-secondary heat transfer can then be restored through condensation on the tubes wetted by the feedwater. This heat transfer process within a once through steam generator (OTSG) is referred to as boiler-condenser mode (BCM) cooling. When BCM cooling takes place near the location of the EFW nozzles, it is referred to as high-elevation BCM cooling. If high-elevation BCM occurs, the RCS depressurization rate will be increased. Later in the loop draining phase, a different form of BCM cooling can occur if the RCS tube liquid level decreases below the secondary liquid level. This cooling process is referred to as pool BCM cooling, and will continue if (1) RCS condensation and ECCS injection do not cause the RCS liquid level to increase above the secondary level and, (2) the secondary fluid temperature is maintained below the temperature of the steam on the primary side of the OTSG tubes. Further, if the secondary liquid level is several feet above the RCP spillover elevation then the condensate formed during this process augment the ECCS flow to the core. For the smaller breaks, the combination of leak flow (with upper-RV venting through the RVVVs), BCM cooling, and HPI cooling will cause the RCS pressure to decrease.

Also during the loop draining phase, the reactor vessel outlet annulus mixture level will decrease to the hot leg nozzle spillunder elevation. If the top of the hot leg nozzles void, steam will flow up the hot leg riser section, and liquid from the hot leg risers will drain back into the vessel. This hot leg draining allows the mixture level in the outlet annulus to remain near the top of the hot leg nozzle until the hot leg liquid level drops into the RV exit nozzle horizontal piping.

After the hot legs empty, another path for the direct venting of steam to the break can be opened if the loop seals in the RCP suction piping are cleared. Depending on the break size, the RCS depressurization can be rapid enough to cause significant flashing in the suction piping, causing the liquid level to decrease below the suction piping spillunder elevation. The loop seals will then be clear, creating another steam relief path, in addition to the path through the RVVVs.

When loop draining ends, the break site void fraction will be based on core steam plus broken loop HPI flow. At that point, the only RCS liquid available for core cooling is the liquid remaining in the reactor vessel and the ECCS flow plus any SG condensate from the intact loops if the loop seal has not cleared. This portion of the transient is defined as the “boiling pot” phase. The increased void fraction at the break will further increase the RCS depressurization rate. The reactor vessel levels will continue to decrease; however, if the ECCS injection plus SG condensate cannot match the reactor vessel liquid loss from flashing, decay heat, and passive metal heat.

The break flow allows the RCS to continue to depressurize. Once the CFT or the HPI flow rate exceeds the break discharge rate, the RCS will refill to the break elevation. Before either of these conditions occurs, the mixture levels may descend into the core heated region resulting in a heatup of the fuel cladding in the uncovered portion of the core.

The clad temperature increases calculated for the upper core elevations are conservative because a power shape skewed to the core exit is used. The peak power occurs at the 9.536-ft core elevation. This power shape bounds the positive imbalance limits at the limits of normal operation. During the period of partial core uncovering, the clad may swell and possibly rupture if the clad temperatures exceed 1300 F. The potential for clad rupture is increased in the SBLOCA analytical model by assuming an initial internal pin pressure typical of the end of fuel life (EOL). If clad rupture is calculated, a sensitivity study is needed to show that the calculated PCT will bound the fuel pin conditions at any time-in-life condition.

An SBLOCA transient analysis is normally terminated at some point after the entire core is refilled and the cladding temperatures returned to within a few degrees of RCS saturation temperature. For the level to increase, core inflow (ECCS plus SG condensate) must exceed the liquid loss rate. Continued RCS depressurization permits higher ECCS injection rates that hastens core refill. The additional ECCS flow assures that the core can be kept covered. Once the core has been completely quenched, the analytical results are checked to ensure a path to long-term cooling is established. For long-term cooling to be assured, the HPI flow and/or LPI flow must match core boiling due to decay heat and wall metal heat plus flashing. When long-term cooling is assured, the LOCA analysis is terminated.

The SBLOCA is considered to be those break sizes greater than the normal makeup capacity and less than 0.75 ft^2. The minimum size corresponds to a break size of approximately 0.0008 ft^2 with letdown flow isolated or 0.0004 ft^2 assuming normal letdown. Break locations in both the cold leg pump suction and discharge piping are considered, along with a spectrum of break sizes (0.07, 0.1, 0.125, 0.15, 0.175, 0.2, 0.3, 0.5, and 0.75 ft^2). Breaks between 0.50 and 0.75 ft^2 are part of the Mark-B11 spectrum only. Mk-B-HTP break sizes greater than 0.50 ft^2 are considered part of the LBLOCA spectrum. This approach ensures that the limiting case is identified. In addition, two special cases are analyzed. These are the 0.44 ft^2 core flood line break, and the 0.025 ft^2 HPI injection line break. These two cases are unique due to the different fraction of the ECCS flow that can spill out of the break and not contribute to core cooling. Breaks at the connection of the HPI injection line to the cold leg are limited in size to the injection line itself. A larger break at this location, which would be a nozzle break, is not required per the NRC-approved evaluation model.

The SBLOCA analyses have demonstrated that the ECCS supplies sufficient emergency coolant injection to meet the 10CFR50.46 acceptance criteria for all SBLOCAs. The HPI flow rates assumed in the core flood line, pump discharge, and HPI line break analyses are shown in Tables 15-28, 15-29, and 15-30, respectively. To address the possibility of spilling HPI water for cold leg pump discharge breaks and HPI line breaks, credit is taken in the analyses for realigning the HPI system by opening valves HP-409 and/or HP-410 within 10 minutes after ES actuation.

The SBLOCA analyses assume that the operator manually controls the Emergency Feedwater System to raise the steam generator levels to the loss of subcooled margin setpoint. Operator action to begin raising levels to the loss of subcooling margin setpoint, which enhances primary-to-secondary heat transfer, is credited starting at 20 minutes for one steam generator, and 30 minutes for the second steam generator. For all SBLOCAs below a break size of 0.06 ft^2, credit is also taken for the operator to manually steam the steam generators at 60 minutes. This action is very effective in cooling and depressurizing the primary, decreasing break flow, and increasing ECCS flow. The normal method of steaming the steam generators in remotely using the Turbine Bypass System. The analysis credits steaming the steam generators locally using the atmospheric dump valves.

15.14.5.2.1 Deleted Per 2014 Update

15.14.5.2.2 Deleted Per 2014 Update

15.14.5.2.3 Full Core Mark-B-HTP SBLOCA and Break Spectrum Analysis

A full-break spectrum was analyzed to ensure that the limiting case was appropriately determined for the full-core Mark-B-HTP configuration. A total of 17 separate break sizes were analyzed for the SBLOCA full-break spectrum. These include the 0.01, 0.04, 0.07, 0.1, 0.125, 0.15, 0.175, 0.2, 0.3, 0.4, and 0.5 ft^2 CLPD pipe breaks with LOOP. If offsite power remains available, as considered in PSC 2-00 (References 45, 46, and 47), there are break sizes that can produce an increase in cladding temperature with a manual two-minute RCP trip compared to the LOOP assumption, therefore the 0.3, 0.4, and 0.5 ft^2 CLPD pipe breaks with a manual RCP trip two minutes after reaching the loss of subcooling margin (LSCM) setpoint were analyzed. Also, a 0.02464 ft^2 HPI line break with LOOP and the 0.44 ft^2 CFT line break (with LOOP and 2-minute RCP trip) were also analyzed.

Gadolinia fuel has lower fuel thermal conductivity and volumetric heat capacities than the UO_2 fuel. The allowed LHR limits for gadolinia are reduced to control the LBLOCA PCTs. The reduction in LHR limits for gadolinia is larger than the volumetric heat capacity differences between gadolinia and UO_2. Since the LHR limit reduction for gadolinia is greater than the volumetric heat capacity ratio, the PCTs for gadolinia rods will be lower, so they are not explicitly included in the SBLOCA analyses.

A new consideration regarding axial power shapes was developed while performing scoping studies for the full-core Mark-B-HTP SBLOCA analyses. The potential of extended core uncovery was called to question for the bounding nature of the EM axial power shapes as described in the LOCA evaluation model (Reference 40). It was found that the location for the most bounding axial power shape with a peaking factor of 1.7 for any time during the cycle is now found to be 11-ft (Reference 51). Therefore, the Oconee Mark-B-HTP full-core SBLOCA analyses use a top-skewed end-of-cycle 11-ft axial power shape peaked at the 11-ft core elevation. This top-skewed axial power shape maximizes the cladding temperature increase during the time of core uncovering.

The results for the full-core Mark-B-HTP SBLOCA break spectrum at 102% of 2568 MWt are summarized in Table 15-64 and Figure 15-227. The limiting break is a 0.15 ft^2 break at the cold leg pump discharge, with a peak cladding temperature of 1597.5°F and a maximum local oxidation of less than 1.0 percent. The transient results for this limiting case are provided in Figure 15-228, Figure 15-229, Figure 15-230, Figure 15-231, and Figure 15-232.

15.14.5.2.4 Partial-Power SBLOCA Analysis

SBLOCA analyses are also performed assuming that one of the three HPI pumps is initially unavailable, and that a single failure leaves only one pump available for credit in the analysis. In this situation there is the potential for a significant fraction of the HPI flow to be spilled out of the break. The realignment of the HPI System described above cannot be performed with only one HPI pump operating. For the limiting break sizes and locations, the available HPI flow is only capable of cooling the core for initial power levels of up to 50% full power (analysis value of 52% FP). These analyses also assume that the operator raises the steam generator levels to the loss of subcooled margin setpoint as described above. Steaming of the steam generators at 25 minutes using the atmospheric dump valves is also credited.

A spectrum of potentially limiting break sizes and locations were also analyzed to determine the limiting PCT at 52% of 2568 MWt considering a full-core of Mark-B-HTP . The limiting breaks considered in the analyses were: 0.01, 0.04, 0.06, 0.07, 0.072, 0.08, 0.10, 0.13, 0.20, and 0.40 ft^2 CLPD pipe breaks considering LOOP coincident with reactor trip. If off-site power remains available, as considered in PSC 2-00 (References 45, 46, and 47), the analyses considered CLPD break sizes of 0.3, 0.4 and 0.5 ft^2 with manual reactor coolant pump trip two minutes after LSCM. Other cases considered include a 0.02464 ft^2 HPI line break and a 0.44 ft^2 CFT line break (Reference 55).

The results for the SBLOCA break spectrum at 52% are summarized in Figure 15-213. The limiting break was determined to be a 0.072 ft^2 CLPD break, with a PCT of 1480.2°F and a maximum local oxidation of 0.44 percent. The transient results for this case are shown in Figure 15-214, Figure 15-215, Figure 15-216, Figure 15-217, and Figure 15-218.

15.14.5.3 Evaluation of Reduced T_{ave} Operation

An analysis was performed to assess the condition under which an end-of-cycle (EOC) T_{ave} reduction could be performed. The reduced T_{ave} LBLOCA analysis was completed at 102% of 2568 MWt at the 2.506 foot elevation with an RCS temperature of 567 °F, which is the nominal RCS T_{ave} reduced by 12 °F (10 °F reduction with a 2 °F uncertainty). Using a moderator temperature feedback table based on a –10 pcm/°F, the results showed that the fuel and cladding temperature response at or near the peak power elevation are lower than in the nominal T_{ave} analysis. Therefore, an EOC T_{ave} reduction of up to 10 °F is acceptable with respect to the LOCA analysis provided the MTC is more negative than –10 pcm/°F.

15.14.5.4 10 CFR 50.46 Reporting Summary

In addition to the LOCA analyses presented in Subsection 15.14.5.1 and 15.14.5.2, LOCA evaluations may be performed as needed to address evaluation model changes or errors, or to support plant changes that affect the LOCA analysis of record. The errors or changes are evaluated, and the impact on the peak cladding temperature (PCT) is determined. The resultant increase or decrease in PCT is added to the analysis of record PCT. 10 CFR 50.46 allows for the estimates of errors in, or changes to, an ECCS evaluation model or its application. These PCT changes for the limiting transient are reported to the NRC, in accordance with requirements of 10 CFR 50.46.

For the Oconee Large Break LOCA analysis for full-core Mark-B-HTP fuel, the analysis of record as described in Subsection 15.14.5.1 has a PCT value of 1987.9°F. For 10 CFR 50.46 reporting purposes, this is rounded up to 1988°F. For the Small Break LOCA analysis for full-core Mark-B-HTP fuel, the analysis of record as described in Subsection 15.14.5.2 has a PCT value of 1597.5°F, which is rounded up to 1598°F for 10 CFR 50.46 reporting purposes. Other assessments for PCT impacts due to ECCS evaluation model changes or errors for the limiting transients are listed below.

Oconee Large Break LOCA Analysis of Record PCT:	1988°F
LBLOCA PCT Assessments:	None
Oconee Large Break LOCA Licensing Basis PCT for 10 CFR 50.46 Reporting:	1988°F

15.14.6 Evaluation of Non-Fuel Core Component Structural Response

The temperature transient in the core can produce significantly higher than normal temperatures in components other than fuel rods. Therefore a possibility of eutectic formation between dissimilar core materials exists. Considering the general area of eutectic formation in the entire core and reactor vessel internals, the following dissimilar metals are present, with major elements being in the approximate proportions shown:

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Control Rod Poison Material

80% silver

15% indium

5% cadmium

Zircaloy-4

98% zirconium

1-3/4% tin

M5

99% zirconium

1% niobium

Inconel 625

58% nickel

21.5% chromium

9% molybdenum

5% iron

3.65% Nb-Ta

0.5% silicon

0.5% manganese

0.4% titanium

0.4% aluminum

Inconel 718

53% nickel

19% chromium

3% molybdenum

5% Nb-Ta

1% titanium

0.5 % aluminum

remainder iron

All these alloys have relatively high melting points (≥ 2,300°F) except those for silver, cadmium, and indium. The melting point of the silver-indium-cadmium alloy is about 1,470°F.

The binary phase diagram indicates that zirconium in the proportion 75 to 80 percent has a eutectic point with either iron, nickel, or chromium at temperatures of approximately 1,710, 1,760, and 2,380°F, respectively. If these dissimilar metals are in contact and if those eutectic points are reached, then the materials could theoretically melt even though the temperature is below the melting point of either material taken singly.

The Mk-B10 through Mk-B11A use Zircaloy-4, rather than inconel, for the intermediate spacer grids. Only the end grids are made of inconel and these grids are outside of the active fuel region. The Mk-B-HTP fuel design uses M5 material for the fuel cladding, guide tubes, and the intermediate and top spacer grids. Only the bottom spacer grid and end fittings are made from Inconel 718. Therefore, the current assembly designs are less susceptible to this phenomenon than older designs, which had inconel grids at each location.

B&W conducted experimental tests in which specimens of Zircaloy-4 tubing in contact with sections of INCONEL 718 spacer grids material were subjected to a thermal transient closely approximately that of the clad hot spot following a LOCA. These tests verified that the eutectic reaction is limited to the small region of contact between the clad and the spacer grid tips (dimples), and that it terminates as these materials melt at the point of contact. Both the clad and the grid material maintained their structural integrity because the amount of material involved was small and melting was localized.

Another area of dissimilar metal contact is that of a zirconium or M5 guide tube with the stainless steel cladding of the control rod. As noted in UFSAR Section 4.5.2.2, the Oconee units use the extended life control rod assembly (ELCRA) design which uses Inconel 625 as the cladding material. To determine whether the temperatures in the control rod following a LOCA could become high enough to approach either the temperature required for possible eutectic formation between the clad and the guide tube or the melting temperature of the Ag-In-Cd alloy, the thermal performance of a control rod assembly following a LOCA was examined analytically.

AREVA has performed a generic post-LOCA control rod survivability analysis to support all 177 fuel assembly B&W plants. The analyses for control rod integrity model the entire active length of the control rod, guide tube and annular flow channel between the control rod and the inside of the guide tube. The features are added to the RELAP5 model used in the ECCS evaluation model approved by the NRC, BAW-10192PA [Reference 40], which is performed using the RELAP5/MOD2-B&W code [Reference 38].

The control rod survivability analyses use a temperature of 1715ºF as the acceptance criterion for all eutectic interactions. This value is conservative with respect to NUREG 1230, which states that a eutectic reaction can occur at approximately 1736ºF, based on phase diagrams for iron-zircaloy and nickel-zircaloy.

The LBLOCA analyses model a hot pin, hot channel, and average channel. The hot pin represents a fuel pin with maximum peaking conditions. The hot channel is also modeled with the maximum peaking conditions and represents one fuel assembly minus the hot pin. The average channel is representative of the core average peaking conditions and represents the remaining assemblies in the core. Five axial peak locations along the active fuel length are typically analyzed for LBLOCA: 2.506-, 4.264-, 6.021-, 7.779-, and 9.536-ft. The peak cladding temperature (PCT) is generally related to the time it takes to quench a given location. Peak power locations higher in the core result in longer times of core uncovery. Consequently, the top of the control rods and guide tubes can be uncovered longer as well, which tends to elevate temperatures in those components. Therefore, the highest elevation for LBLOCA was analyzed. The analyzed core power and Linear Heat Rate Limits (LHRs) also affect the analyses. A core power level of 3026 MWt is used in the generic analysis. This power level bounds the rated thermal power limit for Oconee, with significant margin. A higher initial core power increases the initial core average fuel temperatures (i.e., stored energy) and increases the decay heat generation during the transient. More stored energy and higher decay heat rates increase the steam production and hinders the core flooding rate, increasing the time of core uncovering. The LBLOCA control rod integrity analysis uses an LHR value of 17.8 kW/ft, which is the highest LHR limit for all B&W plants. Coupled with the selected core power, using the highest LHR limit maximizes the local heatup effects for the core components of interest.

During normal operations, the regulating rods (Groups 5, 6, and 7) are often partially inserted at the top of the core, with the safety rods (Groups 1, 2, 3, and 4) fully withdrawn. For the purposes of this analysis, the initial temperature of the control rods will reflect that of the rods being fully withdrawn. However, immediately at the start of the transient, the control rods will be conservatively assumed to be fully inserted to ensure that they are exposed to higher temperatures for a longer period of time. Consistent with limiting ECCS evaluation model analyses, a break at the cold-leg pump discharge (CLPD) will be the break location for both the LBLOCA and SBLOCA analyses for control rod integrity. The CLPD break location provides the worst transient results since it reduces available ECCS.

Under these conditions, the fluid temperatures and time at elevated temperature were maximized in order to minimize the control rod heat removal during the transient. The results of the LBLOCA analysis indicate that, even with conservative treatment, no control rod melt will occur for LBLOCA events with the initial conditions modeled. The maximum control rod silver-indium-cadmium absorber temperature is 1435ºF, which is less than the silver-indium-cadmium melt temperature of 1470ºF. Considering the melt temperature is not reached, the eutectic temperature is not reached (1715ºF), so even if there is contact between the control rod cladding sheath and the M5 guide tube, the control rod will remain intact. The maximum guide tube temperature attained was 1397ºF.

The generic SBLOCA survivability analyses reflect a 17.3kW/ft LHR for the hot channel, which is the highest LHR limit for SBLOCA analyses for the B&W plants. The 11-ft (10.811-ft actual) bounding axial power shape is utilized since the clad temperature is maximized when a power shape that is highly skewed to the core exit is used for SBLOCAs. These inputs and assumptions comprise a bounding set of conditions postulated on the SBLOCA analyses. The control rods, guide tubes, and flow channels are modeled using the same approach as the LBLOCA analysis.

Two power levels were analyzed for SBLOCA, 3026 MWt and 2827 MWt, to establish the sensitivity to power level. Neither case exceeded the acceptance criteria of 10 CFR 50.46, and the hot pin PCTs were 1836ºF and 1645ºF respectively. However, at 3026 MWt, the analysis predicted localized control rod absorber melting near the top of the core. This reflects the assumption of the highly skewed axial profile. Since there is a small gap between the absorber and the sheathing, there would be little relocation of any molten AIC material within the sheathing. The extent of the localized melting would be limited to only the area of direct contact and would not grossly impact the control rod or guide tube geometry. Also, the localized melt would not affect the reactivity contribution of the control rod, since it is predicted to occur very near the top of the assembly where reactivity effects are typically less pronounced with the control rods fully inserted, and a very limited volume is available to relocate melted silver-indium-cadmium material. Further, both control rod sheathing and guide tube temperatures (1640ºF and 1650ºF, respectively) remained below the eutectic temperature of 1715ºF. This indicates that the overall control rod integrity would be preserved. The generic post-LOCA control rod survivability analysis does not require any cycle specific verifications because of the extremely bounding assumptions of core power and LHR limits used in both the LBLOCA and SBLOCA analyses.

15.14.7 Conformance with Acceptance Criteria

The NRC-approved ECCS Evaluation Models used for the LOCA analysis for Oconee class plants have been shown to be within the guidelines of 10CFR50 Appendix K. These models have been used to perform detailed sensitivity studies to assure that any adverse phenomena are identified and adequately addressed. These analyses have demonstrated that the consequences of hypothetical LOCA's up to and including a double-ended break of the largest pipe in the RCS are within the limits prescribed in 10CFR50.46, as follows:

15.14.7.1 Peak Cladding Temperature

The maximum peak cladding temperature was calculated to be 1987.9°F, which is less than the 2200°F limit.

15.14.7.2 Maximum Cladding Oxidation

The maximum local cladding oxidation was calculated to be less than 3.0 percent, which is less than the 17 percent limit.

15.14.7.3 Maximum Hydrogen Generation

The worst case core average hydrogen generation was calculated to be less than 0.2 percent, which is less than the 1 percent limit.

15.14.7.4 Coolable Geometry

Changes in core geometry due to thermal and irradiation effects and mechanical loading have been calculated and show that no gross core blockage or disfiguration will occur. The core will maintain a coolable geometry.

15.14.7.5 Long-Term Cooling

Subsequent to the blowdown, refill, and reflood phases of a LOCA, long-term cooling to remove core decay heat for an extended period of time must be established. The ECCS is designed to perform this function. Operator action is assumed to be available fifteen minutes following a LOCA. Several operational modes are available to provide the necessary cooling and also to assure that adequate coolant circulation exists to prevent any concentration of boric acid in a region of the RCS (Refer to Section 6.3.3.2.1). Redundancy in the design of the ECCS and multiple available flowpaths for removing core heat provide for sufficient long-term cooling.

15.14.8 Environmental Evaluation

The radiological consequences of a LOCA are bounded by the consequences of the Maximum Hypothetical Accident.

15.14.9 Conclusions

A complete spectrum of LOCAs have been conservatively analyzed with the NRC-approved evaluation models which conform to 10CFR50 Appendix K. The results of these analyses meet the acceptance criteria of 10CFR50.46. The off-site environmental consequences are within the dose limits of 10CFR50.67. Therefore, the consequences of all design basis LOCAs have been shown to be acceptable.

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15.15 Maximum Hypothetical Accident

15.15.1 Identification of Accident

The analyses in the preceding sections have demonstrated that even in the event of a LOCA accident, no significant core melting will occur. However, to demonstrate in a still more conservative manner that the operation of a nuclear power plant at the proposed site does not present any undue hazard to the general public, a maximum hypothetical accident (MHA) involving a gross release of fission products is evaluated. No mechanism whereby such a release occurs is postulated, since this would require a multitude of failures in the engineered safeguards which are provided to prevent such an occurrence. Fission products are assumed to be released from the core as stated in Regulatory Guide 1.183 (Reference 2. The Reactor Building Spray System is credited with removal of a portion of the remaining iodine from the building atmosphere. The total core fission product inventory of interest is given in Table 15-15 (Reference 1).

15.15.2 Environmental Evaluation

The Reactor Building leak rate is assumed to be 0.20 percent per day by volume for the first 24 hours, and then 0.10 percent per day for the next 29 days. The other assumptions are consistent with Regulatory Guide 1.183 (Reference 2).

Total Effective Dose Equivalent (TEDE) doses for the 2 hour exposure at the exclusion area boundary, and for the 30-day exposure at the low population zone distance are calculated These dose consequences are within the 10 CFR 50.67 limits. A summary of the dose consequences for all transients and accidents is given in Table 15-16.

15.15.3 Effect of Washout

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To provide a further evaluation of the suitability of the site, the effects of washout on surrounding drinking water reservoirs following the MHA are analyzed. Calculations are made for the case of continuous rain lasting 24 hr covering the general area of the reservoir and the site. The maximum washout rate as a function of distance is calculated from the following equation (Reference 3):

$$\omega_{max} = \frac{Q_o e^{-(y^2 / 2\sigma^2{}_y)}}{xe\sigma_y \sqrt{2\pi}}$$

where

ω_{max} = maximum washout rate $\frac{\mathrm{Ci}}{\mathrm{sec-m^2}}$

x = downwind distance (m)

σ_y = horizontal dispersion (m)

y = crosswind distance from plume axis (m)

Q_o = release rate $(\frac{Ci}{sec})$

The equation above is conservative since the results do not consider the wind speed or vertical distribution in the cloud. The wind direction is assumed to remain towards Lake Keowee for the 24 hr period with the plume center lines uniformly distributed over this section. Washout is assumed to occur under neutral stability conditions, Pasquill D, which is typical for a rainy day.

The average release rate from the Reactor Building during the 24-hr period following the accident is 0.37 equivalent curies of iodine-131 per sec. Using the above equation, the maximum iodine washout is calculated by assuming that all of the iodine that has washed out remains in the surrounding reservoir and is not affected by runoff. The average number of curies in the reservoir during a one-year period is reduced by a factor of 0.0318 due to the natural decay of iodine. Assuming that this activity mixes in the reservoir and that an adult drinks 0.8 m^3 per year (Reference 4) of the contaminated water, the total dose to the thyroid has been calculated using the methods of TID-14844. The nearest drinking water intake is approximately two miles from the site. At this distance, the total integrated one-year ingestion dose to the thyroid is 1.0 rem. This dose is well below the limits of 10CFR 100.

15.15.4 Effects of Engineered Safeguards Systems Leakage

An additional source of fission product leakage during the maximum hypothetical accident can occur from leakage of the engineering safeguards systems external to the Reactor Building during the recirculation phase for long-term core cooling. A detailed analysis of the potential leakage from these systems is presented in Section 6.1.3. A value of 12 gallons per hour (gph) leakage from LPI, HPI and BS systems was assumed in the MHA dose analysis. The MHA dose analysis also assumes back-leakage to the Borated Water Storage Tank (BWST) at a rate of 5 gallons per minute (gpm). The iodine release model in the MHA dose analysis assumes this back-leakage enters the BWST below the water level in the tank.

It is assumed that the water being recirculated from the Reactor Building sump through the external system piping contains the entire amount of iodine released from the RCS. The assumption that all of the iodine escaping from RCS is absorbed by the water in the Reactor Building is conservative since much of the iodine released from the fuel will be plated out on the building walls. It is assumed that 10 percent of all the iodine contained in the water leaking to the Auxiliary Building is released to the Auxiliary Building atmosphere.

The Auxiliary Building is ventilated and discharges to the unit vent. The activity is assumed to be continuously released from the unit vent during the recirculation phase (which is assumed not to start until 25 minutes into the event). Combined with other sources of exposure during a maximum hypothetical accident, these doses are within the guidelines specified in 10 CFR Part 50.67. Total TEDE doses from the MHA are given in Table 15-16.

15.15.5 References

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15.16 Post-Accident Hydrogen Control

15.16.1 Introduction

The purpose of this section is to summarize the analyses performed to:

Evaluate the hydrogen generation following a LOCA.

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In this section the potential for radiolytic hydrogen generation including the dose, or energy deposited in the coolant following the accident, and the basis for the selection of the hydrogen generation constant ("G" value) is analyzed. Since the FSAR analyzes the potential zircaloy-water reaction in other sections, this analysis is not presented herein and a 5 percent zirc-water reaction is assumed in the reference case described in subsequent sections. The potential for hydrogen generation from a zinc-boric acid reaction when borated water spray solution contacts galvanized steel and aluminum in the Reactor Building at the post-accident temperature is also considered. The analysis shows the radiolytic hydrogen generation rate plus the hydrogen contributed by the zircaloy and other reactions.

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Regulatory Guide 1.7 "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident" has been referenced in several sections of this analysis (Reference 14). Even though the Regulatory Guide has been used for guidance and information, Oconee is not committed to Regulatory Guide 1.7 (Reference 14).

15.16.2 Post-Accident Hydrogen Generation

Section 15.16.2 is supported by Reference 15 in its entirety.

15.16.2.1 Radiolytic Hydrogen Generation

Water radiolysis is a complex process involving reactions of numerous intermediates. However, the overall radiolytic process may be described by the reaction:

$$2H_2O \text{ ------> } 2H_2 + O_2$$

Of interest here is the quantitative definition of the rates and extent of radiolytic hydrogen production following the Design Basis LOCA. An extensive program was conducted by Westinghouse to investigate the radiolytic decomposition of the core cooling solution following the Design Basis LOCA. In the course of that investigation, it became apparent that two separate radiolytic environments exist in the Containment at Design Basis Accident conditions. In one case, radiolysis of the core cooling solution occurs as a result of the decay energy of fission products in the fuel. In the other case, the decay of dissolved fission products, which have escaped from the core, results in the radiolysis of the sump solution.

15.16.2.1.1 Core Solution Radiolysis

As the emergency core cooling solution flows through the core, it is subjected to gamma radiation by decay of fission products in the fuel. This energy deposition results in solution radiolysis, and the production of molecular hydrogen and oxygen. The initial production rate of these species will depend on the rate of energy absorption and the specific radiolytic yields.

The energy absorption rate in solution can be assessed from knowledge of the fission products contained in the core, and a detailed analysis of the dissipation of the decay energy between core materials and the solution. The results of Westinghouse studies show essentially all of the beta energy is absorbed within the fuel and cladding, and that this represents approximately 50 percent of the total beta-gamma decay energy. This study shows further that of the gamma energy, a maximum of 7.4 percent will be absorbed by the solution in the core. However, for this analysis 10 percent will be used as a conservative estimate. For the maximum credible accident case, the energy deposited in the sump accounts for the assumed TID 14844 release of 50 percent halogens and 1 percent other fission products. The noble gases are assumed by the TID 14844 model to excape to the Containment vapor space where little or no water radiolysis would result from decay of these nuclides.

For the purposes of this analysis, the calculations of hydrogen yield from core radiolysis are performed with the very conservative value of 0.45 molecules per 100 ev. This value is conservative and a maximum for this type of aqueous solution and gamma radiation is confirmed by many published works.

15.16.2.1.2 Sump Solution Radiolysis

Another potential source of hydrogen assumed for the post accident period occurs from water contained in the Containment sump being subjected to radiolytic decomposition by fission products. In this case, an assessment must be made as to the decay energy deposited in the solution and the radiolytic hydrogen yield, much in the same manner as given above for core radiolysis. The energy deposited in solution is computed using the following basis:

1. For the maximum credible accident, a TID-14844 release model is assumed where 50 percent of the total core halogens and 1 percent of all other fission products, excluding noble gases, are released from the core to the sump solution.
2. The quantity of fission products released is equal to that from a reactor operating at full power (2568 MWt) for 980 days prior to the accident.
3. The total decay energy from the released fission products, both beta and gamma, is assumed to be fully absorbed in the sump solution.

A conservative value for the hydrogen yield for sump radiolysis of 0.30 molecules per 100 ev is used in the maximum credible accident case.

15.16.2.1.3 Deleted per 2000 Update

15.16.2.2 Chemical Hydrogen Generation

In addition to the radiolytic hydrogen generation sources (core and sump radiolysis) following a Design Basis Accident, hydrogen may also be evolved from two chemical sources: (1) zirconium-water reaction involving clad material, and (2) from the reaction of zinc and aluminum within the Reactor Building with the borated coolant water.

15.16.2.2.1 Method of Analysis

The quantity of zirconium which reacts with the core cooling solution depends on the performance of the Emergency Core Cooling System. 10CFR50.46(b)(3) states that the total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 1% of the hypothetical amount that would be generated if all the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

Aluminum is more reactive with the Reactor Building spray solution than other plant materials such as galvanized steel, copper, and copper-nickel alloys. However, because of the relatively large amount of exposed galvanized and zinc-based painted surfaces in the Reactor Building, zinc corrosion must be considered as a contributing hydrogen source.

It should be noted that zirconium-water reaction and the aluminum and zinc corrosion with Reactor Building spray are chemical reactions and thus essentially independent of the radiation field inside the Reactor Building following a LOCA. Radiolytic decomposition of water is dependent on the radiation field intensity. The radiation field inside the Reactor Building is calculated for the maximum credible accident in which the fission product activities given in TID-14844 are used.

15.16.2.2.2 Typical Assumptions

The following discussion outlines the assumptions used in the calculations.

15.16.2.2.3 Zirconium-water Reaction

Hydrogen can be generated during a LOCA by the reaction of hot zirconium cladding with the surrounding steam. The zirconium-water reaction is described by the chemical equation:

$Zr + 2H_2O$ ------> $ZrO_2 + 2H_2$ + Heat

The quantity of zirconium which reacts with the core cooling solution depends on the performance of the Emergency Core Cooling System (ECCS). For Oconee the maximum of 1% zirconium-water reaction is assumed. Regulatory Guide 1.7 requires that the assumption for hydrogen produced from the zirconium-water reaction equal 5 times the extent of the maximum calculated reaction under 10CFR50.46, i.e., 5.0%. Per Regulatory Guide 1.7, the zirconium-water hydrogen source is assumed to be released over a 2 minute period from the start of the transient, and is assumed to be distributed uniformly throughout Containment.

15.16.2.2.3.1 Corrosion of Plant Materials

Another possible source of hydrogen could occur from metal surfaces exposed to an environment containing high-temperature steam, corrosive sprays, fission products, and radioactivity. Such exposure might result in surface corrosion reactions that produce hydrogen. Corrosive tests have been performed to determine the behavior of various metals that are used in Containment when exposed to a post-LOCA environment. As applied to the quantitative definition of hydrogen production rates, the results of the corrosion tests have shown that only aluminum will corrode at a rate that will significantly add to the hydrogen accumulation in the Containment atmosphere. However, because of the relatively large amount of exposed galvanized and zinc-based painted surfaces in Containment, zinc corrosion must be considered as a contributing hydrogen source.

The corrosion of aluminum and zinc may be described by the following reactions:

$2Al + 3H_2O$ -----> $Al_2O_3 + 3H_2$

$Zn + H_20$ -----> $ZnO + H_2$

The time-temperature cycle considered in the calculation of aluminum and zinc corrosion are based on a conservative representation of the postulated post accident Containment transient. The corrosion data points include the effects of temperature, alloy, and spray solution conditions. NOTE: In Section 5, Part C of Regulatory Guide 1.7 it is stated that values given in Table 1 for evaluating production of combustible gases following a LOCA may be changed on the basis of additional experimental evidence and analyses. As a result the minimum assumed value give for aluminum corrosion rate of 200 mpy is not used in the analysis.

15.16.2.3 Primary Coolant Hydrogen

The quantity of hydrogen assumed in the primary coolant is 450 scf. This value is expected to bound the total of the hydrogen dissolved in the coolant water at and corresponding equilibrium hydrogen in the pressurizer gas space. The 450 scf of hydrogen is assumed to be released immediately into Containment at the initiation of the LOCA.

15.16.3 EVALUATION OF HYDROGEN CONCENTRATIONS

15.16.3.1 Hydrogen Flammability Limits

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The hydrogen generation which occurs following a design basis LOCA is a slow process driven by sump radiolysis and metal corrosion (Reference 15). The concentration thirty days following a design basis LOCA is approximately 6.4 volume percent. Studies of containment structural capacity and the effects of hydrogen combustion have shown concentrations much higher than 4 volume percent are required to threaten the integrity of a large dry containment like the Oconee containments. Furthermore, studies have shown that the majority of risk to the public is from accident sequences that lead to containment failure or bypass, and that the contribution to the risk from accident sequences involving hydrogen combustion is actually quite small for large, dry containments such as Oconee's. This is true despite the fact that hydrogen produced in these events is substantially larger than the hydrogen production postulated by 10 CFR 50.44(d) and RG 1.7 (Reference 26). NUREG/CR-4551 also states that hydrogen combustion in the period before vessel failure is now generally considered to present no threat to large, dry containments.

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15.16.3.2 Evaluation of Hydrogen Concentrations

Prediction of hydrogen generation following the loss-of-coolant accident using the assumptions and method of analysis described in Section 15.16.2 shows that although hydrogen production rate decreases as the post-accident time increases, total hydrogen accumulation can exceed the lower flammability limit of 4 volume percent. The analysis shows that using conservative assumptions, post-LOCA hydrogen concentrations can reach 3 volume percent in approximately 216 hours (9 days) and 4 volume percent in approximately 360 hours (15 days) (Reference 15).

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Post accident hydrogen concentrations are indicated by the Containment Hydrogen Monitoring System (CHMS). The CHMS is described in Section 9.3.7 and is shown in Figure 9-15. This instrumentation provides two redundant channels of hydrogen monitoring that can monitor hydrogen concentrations at different levels of the containment including CHRS inlet and return concentrations.

In order to assure high concentration pockets of hydrogen do not exist and that representative samples of hydrogen can be obtained, adequate mixing of hydrogen throughout containment should exist. Mixing in the Reactor Building atmosphere is expected to be good. The Reactor Building cooling fans or sprays will introduce considerable turbulence to the building atmosphere to provide good mixing of hydrogen in the early stages of the accident. In addition, all the Reactor Building volumes are connected by large vent areas (stair wells, elevator shafts, grating) to promote good air circulation.

Figure 15-89 shows the Reactor Building cross-section. The hydrogen generated will be primarily from the corrosion of metals in the large open area of the containment and from radiolysis of water in the sump and water leaking from the RCS. These locations are within the unrestricted main volume of the building and will permit the hydrogen to diffuse rapidly and provide a uniform mixture in this area. This rapid mixing occurs because hydrogen has a high diffusion rate and a low generation rate, and is capable of diffusing in all directions. The hydrogen will diffuse very rapidly giving an even distribution under the conditions existing in the Reactor Building. This situation is not analogous to one where attempts are made to mix streams of gases under dynamic conditions where residence times and mixing distances are critical. In addition, the thermal mixing effects, heating of air above the hot sump water, and possible steam releases from the RCS will move the hydrogen laden air from the points of generation toward the cold external walls and emergency cooling equipment. Although hydrogen is lighter than air, it will not tend to concentrate in high areas because of the high diffusion rate and because of the open design of the Reactor Building.

Since the hydrogen is generated primarily from corrosion of metals and core radiolysis in the large open areas, the hydrogen must diffuse from the major volumes into those minor volumes which are enclosed. The minor volumes or those not having good communication with the major volumes would be at a lower hydrogen concentration because the hydrogen is diffusing from the higher concentration level to a lower concentration level. Accordingly, pockets, if they exist, will be low concentration pockets rather than high concentration pockets.

The ability of hydrogen to diffuse rapidly into all volumes is inferred by a condensing steam environment (CSE) experiment (Reference 8) which measured the spatial concentration of iodine in the various compartments. The tests showed very good mixing in the main chamber and a rapid interchange by diffusion and mixing with the atmosphere of other chambers which had limited communication. The diffusivity of hydrogen is approximately 10 times that of iodine so a more uniform mixture would be expected for hydrogen than for iodine. Also, the higher concentrations would provide greater concentration gradients for better diffusion than was indicated by the CSE tests.

During a DBA LOCA, the operation of Reactor Building sprays and RBCUs will provide mixing in containment. This along with the fact that the hydrogen generation rates are low for the majority of the accident support the conclusion that a nearly uniform hydrogen concentration will exist in containment.

Hydrogen concentrations on the order of 6 percent or less are bounded by hydrogen generated during a severe accident and would not be a threat to containment integrity since there is ample time between burns to reduce elevated containment temperatures using the installed containment heat removal systems. Based on analysis, Oconee could withstand the consequences of uncontrolled hydrogen-oxygen recombination without loss of safety function with up to 100 percent metal-water reaction.

15.16.4 Deleted per 2003 update

15.16.5 Deleted per 2003 update

15.16.6 Conclusions

Figure 15-175 shows that if no measures were taken to control hydrogen accumulation in the Reactor Building, the hydrogen concentration within the Reactor Building can be expected to reach the lower flammability limit of 4 volume percent at approximately 360 hours (Reference 15).

Based on analysis, Oconee could withstand the consequences of uncontrolled hydrogen-oxygen recombination without loss of safety function with up to 100 percent metal-water reaction.

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15.17 Small Steam Line Break Accident

15.17.1 Identification of Causes and Description

The small steam line break accident is caused by small breaks in the steam lines or by failures of valves connected to the steam lines. The break flowrate, the reactor kinetic behavior, and the status of the control systems have a large effect on the plant response. The initial plant response to the increase in steam flow is a decrease in steam generator pressure and an overcooling of the Reactor Coolant System (RCS). The expected plant response with the Integrated Control System (ICS) in automatic would be for the main turbine control valves to close to return turbine header pressure to the setpoint, the control rods would insert to offset the increase in the reactor power due to the negative moderator coefficient of reactivity, and main feedwater (MFW) flow would be controlled to maintain the secondary heat sink in balance with the reactor power. This automatic response may be successful in not tripping the reactor. With the ICS in automatic or manual control, a reactor trip on high neutron flux, flux/flow/imbalance, variable low pressure-temperature, on turbine trip due to main feedwater pump trip, or by manual operator action would be expected.

The small steam line break accident analyses assume that the ICS is in manual control for initial conditions of full power with four reactor coolant pumps (RCPs) in operation, and 75% power with three RCPs in operation. The ICS in manual control is more limiting than with the ICS in automatic. A range of break sizes and moderator temperature coefficients are analyzed to determine the combination that approaches the most limiting conditions relative to the DNBR limit. The effect of a decrease in the reactor vessel downcomer temperature on the indicated excore power range flux is modeled. Several non-safety systems could cause a trip of the MFW pumps thereby mitigating the consequences of the transient. These include AFIS circuitry (which actuates some non-safety grade components), the ICS high steam generator level trip, and the low MFW pump discharge pressure trip. None of these non-safety systems are credited in the analyses. The results presented model the replacement steam generators. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35. It is conservatively assumed that offsite power is maintained since a loss of offsite power would result in reactor trip. Operator action is credited with manually tripping the reactor at 10 minutes if an automatic reactor trip has not occurred. No single failure has been identified which adversely affects this transient.

A small steam line break accident is considered to be either a fault of moderate frequency (valves failing open) or an infrequent fault (pipe break). To bound both types of events, the analysis assumes pipe breaks as initiating events, with acceptance criteria corresponding to the less severe fault of moderate frequency category. The acceptance criteria for this accident are that the minimum DNBR remains above the limit (1.34 for four and three RCP operation for the Mk-B-HTP fuel type), that the centerline fuel melt limit is not exceeded, and that the offsite doses will be within 10% of the 10CFR50.67 limits.

15.17.2 Analysis

The RETRAN system thermal-hydraulic analysis results are valid for the full core with Mk-B-HTP fuel. The limiting small steam line break accident for DNB considerations is a break size of 1.46 ft^2 initiated from four RCP operation, with a moderator temperature coefficient of -7 pcm/°F. The transient response is given in Figure 15-168, Figure 15-169, Figure 15-170, Figure 15-171,

Figure 15-172 and Figure 15-173 and the sequence of events is given in Table 15-49. The duration of the analysis is 600 seconds, which includes the core conditions of minimum DNBR margin. The blowdown out the break increases the steam flow exiting the steam generators by approximately 27% (Figure 15-168). The steam generator pressure decrease (Figure 15-169) propagates throughout the secondary system, causing main feedwater flow to increase (Figure 15-170) and a decrease in main feedwater temperature. RCS temperatures decrease (Figure 15-171) causing a power increase (Figure 15-172) due to the negative moderator temperature coefficient of reactivity. The moderator and Doppler feedback mitigates the power excursion. The transient reaches a sustained power level of approximately 139%. The high flux and the flux/flow/imbalance trips do not actuate due to the effect of the decrease in the reactor vessel downcomer temperature. The RCS pressure response (Figure 15-173) follows RCS average temperature. RCS pressure eventually increases due to backup heaters energizing and increased makeup flow. The system analysis results are input to a detailed core thermal-hydraulic analysis assuming a standard reference power distribution. The transient minimum DNBR is 1.435, which is greater than the design limit, for the full core with Mk-B-HTP fuel. A fuel pin census analysis is performed to determine and affirm if DNBR margin exists or the number of fuel pins that exceed the DNBR limit. The results of the fuel pin census analysis for the small steam line break accident is that DNB margin exists for all of the fuel pins. Thus, no fuel failure is expected. The centerline fuel melt limit has been evaluated and it is not violated.

15.17.3 Environmental Consequences for the Small Steam Line Break

A conservative consequences analysis is performed for a postulated break of a small steam line or an auxiliary steam line. This break results in an increased thermal demand on the reactor coolant system (RCS) and a rapid cooldown and positive reactivity addition from a negative temperature coefficient. This transient is not postulated to induce fuel failures, steam generator tube failures or any other failures of fission product barriers or primary system pressure boundaries, or any other pieces of equipment. Thus, the environmental consequences result from plant releases of pre-existing RCS activity transported to the secondary side by postulated steam generator tube leakage, and of pre-existing secondary activity. This activity is then released to the environment by releases associated with the normal operation of plant equipment or the operation of plant equipment as intended in response to the accident, and as part of the subsequent cooldown activities.

Two RCS source terms are examined as part of this analysis: a preaccident iodine spike and a concurrent iodine spike. The first models the maximum Dose Equivalent Iodine (DEI) activity concentration permitted by Technical Specifications for an iodine spike at full power. This preaccident spike is postulated to occur at the time of accident initiation. This source term is modeled to be released instantaneously and homogeneously such that the RCS activity is in equilibrium at the start of the accident. The second source term models a concurrent iodine spike, where the primary system transient associated with the accident causes an iodine spike in the primary system. The increase in primary coolant iodine concentration uses a spiking model that assumes that the iodine release rate from the fuel rods to the primary coolant increases to a value 500 times greater than the release rate corresponding to the iodine concentration at the equilibrium value specified in Technical Specifications. Both iodine spike source terms also bound Technical Specification limits for Dose Equivalent Xenon (DEX).

An initial source term is also modeled for the secondary side. The maximum Technical Specification allowed DEI concentration is modeled to be present in the secondary side water, the steam generators and any makeup water supplied to the unit. Thus, the secondary side is essentially modeled as an infinite source of water at the secondary side Technical Specification DEI concentration limit.

In order to transport and release primary activity to the environment, a primary to secondary release path is modeled in the steam generators. This path is postulated to exist at the start of the accident, but is not caused by the steam line break. The tube leakage into the unaffected steam generator modeled bounds the maximum allowed tube leakage rate into one steam generator. The affected steam generator is modeled with a leakage rate that bounds the maximum allowed unidentified primary to secondary leakage allowed by Technical Specifications.

The thermal/hydraulic model discussed in the previous sections is used as the basis for the plant response and steam releases modeled in the environmental analysis. The plant is initially operating in a normal mode at full power (plus maximum thermal power uncertainty) with primary to secondary leakage. The only releases occurring at the start of the accident are from the condensate steam air ejectors (CSAEs), which discharge a mixture of motive steam and condensate gases. Since the CSAEs operate continuously, no gases are assumed to be in the secondary system, as they would be removed by the CSAEs when introduced into the secondary system. When the break initiates, the activities in the primary and secondary side are modeled to be instantaneously and homogeneously released to their respective systems. The reactor is manually tripped by the operators after allowing for the maximum postulated time for them to identify the accident. Radioactive decay (and daughter product production) is then begun in the model. The affected steam generator begins to discharge all of its activity directly to the environment. The unaffected steam generator also discharges its inventory directly to the environment through the break until the Turbine Stop Valves close shortly after reactor trip. This steam header will repressurize resulting in lifting its Main Steam Relief Valves. Since the steam release from the affected steam generator is not isolable, this release will continue as long as water and conditions conducive to boiling exist in this steam generator.

In order to maximize releases to the environment, the condenser is assumed to not be available. This requires that the unit be cooled down using the unaffected steam generator by discharging steam from this steam generator directly to the environment through the Atmospheric Dump Valves (ADVs). No credit is taken for the condenser and no partitioning credit is taken for CSAE releases which are modeled to occur until the beginning of cooldown.

The small steam line break does not cause the Turbine Driven Emergency Feedwater Pump (TDEFWP) to start. Thus, there is no discharge to the environment from the TDEFWP exhaust, and therefore, this release path is not included in the environmental analysis.

Since Oconee Nuclear Station is a B&W designed plant, it uses once through steam generators which provide for vertical tubing which carries primary coolant from the top of the generator to its bottom while exchanging heat with the secondary fluid on the shell side. Because of this tubing arrangement, the tube leakage is modeled to occur above the secondary water mass in the steam generator. Therefore, no credit is taken for iodine partitioning in the steam generator. No credit is taken for iodine plateout in the steam lines or any other surface.

The thermal/hydraulic response of the plant to a small steam line break does not result in the need for a soak prior to cooldown. Thus, after the plant is stabilized, cooldown can be commenced at the maximum rate permitted by Technical Specifications. This rate is reduced as required by Technical Specifications at the appropriate temperature. When the thermodynamic conditions are met for the Low Pressure Injection (LPI) system to remove decay heat from the primary, cooldown releases from the ADVs cease and decay heat removal is accomplished by the LPI system. Primary to secondary leakage and its release to the atmosphere continue until the temperature of the primary water leaking is less than the boiling point for water at atmospheric conditions. At this point all releases of activity from the plant model cease.

Offsite atmospheric dispersion factors from the Updated Final Safety Analysis Report Chapter 2 were used. Dose conversion factors from Federal Guidance Reports 11 and 12 were used.

Based upon this model, releases of activity to the environment from the primary and secondary systems can be calculated and used to calculate doses at the Exclusion Area Boundary (EAB), the Low Population Zone (LPZ), and in the Control Room. The doses calculated meet the regulatory criteria of 10 CFR 50.67 for each of the source terms examined. The results are presented in Table 15-16.

15.17.4 Conclusions

The small steam line break accident analysis results show that DNBR margin exists for all of the fuel rods, and that no fuel failures due to centerline fuel melt occur. The environmental consequences meet the acceptance criteria. All of the acceptance criteria are met.

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15.18 Anticipated Transients Without Trip

An anticipated transient without trip (ATWT) or anticipated transient without scram (ATWS) is an anticipated operational occurrence (such as loss of feedwater, loss of condenser vacuum, or loss of offsite power) that is accompanied by a failure of the reactor trip system to shutdown the reactor. Studies on ATWS at B&W plants showed that an alternate method is required to provide a scram and initiate turbine trips and auxiliary feedwater flow.

The effects of ATWS are not considered as part of the design basis for transients analyzed in Chapter 15.0. The final USNRC ATWS rule requires that all US B&W - designed plants install a diverse scram system (DSS) to initiate control rod insertion, and ATWS mitigation system actuation circuitry (AMSAC) to initiate a turbine trip and actuate auxiliary feedwater, independent of the reactor trip system. The AMSAC and DSS are part of the ATWS Mitigation System described in Section 7.8.

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Appendix 15A. Tables

Table 15-1. Reg. Guide 1.183 Fuel Handling Accident Source Term

Isotope	Gap Fraction (See Note 1)	72 Hour Gap Inventory (Ci/Fuel Assembly)
Kr-83m	0.05	2.34E-05
Kr-85m	0.10	3.72E-01
Kr-85	0.10	8.53E+02
Kr-87	0.05	2.39E-13
Kr-88	0.05	8.26E-04
Xe-131m	0.05	4.81E+02
Xe-133m	0.05	1.21E+03
Xe-133	0.05	5.26E+04
Xe-135m	0.05	5.38E+00
Xe-135	0.05	7.21E+02
Deleted Row(s) per 2009 Update		
I-131	0.08	4.35E+04
I-132	0.05	2.59E+04
I-133	0.05	6.44E+03
Deleted Row(s) per 2009 Update		
I-135	0.05	3.29E+01

Note:

1. For fuel pins that exceed the rod power/burnup criteria of Footnote 11 in RG 1.183, the gap fractions from RG 1.183 are increased by a factor of 4 for Kr-85, Cs-134, and Cs-137. The gap fractions for all other isotopes remain at their pertinent RG 1.183, Table 3 values.

Table 15-2. Rod Ejection Accident Analysis Results

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Mk-B-HTP with UO_2-Gad fuel rods						
Parameter	**Value**					
Cycle Exposure	**BOC**	**BOC**	**BOC**	**EOC**	**EOC**	**EOC**
Initial core power (% of 2568 MWt)	102	77	0	102	77	0
Number of RCP running	4	3	3	4	3	3
Initial rod position (% wd)	58	31	0	58	31	0
Ejected rod worth ($)	0.164	0.362	1.207	0.202	0.394	1.149
MTC (pcm/°F)	0.0	0.56	7.0	-28.0	-28.0	-12.0
DTC (pcm/°F)	-1.10	-1.16	-1.42	-1.19	-1.22	-1.53
Maximum neutron power (% of 2568 MWt)	118	108	426	122	114	160
Peak UO_2 fuel pellet average enthalpy (cal/gm)	115	95	72	103	107	45
Peak UO_2 -Gad fuel pellet average enthalpy (cal/gm)	129`	113	91	134	130	45
Percent pins exceeding DNBR (%)	<45%					
Maximum RCS pressure (psig)	2301	2273	See Note 1			

[1]RCS pressurization is not analyzed for these conditions since they are not limiting.

Table 15-3. Deleted Per 2008 Update

Table 15-4. Deleted Per 2004 Update

Table 15-5. Steam Line Break Accident - With Offsite Power Case Sequence of Events

Event	Time (sec)
Break opens	0.0
Third CBP starts	0.5
Reactor trip on variable low pressure-temperature	3.0
Control rod insertion begins	3.1
Turbine stop valves closed Control rods fully inserted	3.1
Deleted row(s) per 2003 update	
HPI actuates	35.5
Deleted row(s) per 2003 update	
CFT injection begins	97.4
Boron from CFT B starts	110.1
Boron from CFT A starts	115.1
Boron injection from HPI begins	115.8
Deleted row(s) per 2003 update	
Unaffected SG becomes water-solid	310.0
End of simulation	600.0

Table 15-6. Summary of LOCA Break Spectrum Break Size and Type

Parameter		CLPD DE	CLPD DE	CLPD DE	CLPD Split	CLPS DE
Break C_D		1.0	0.8	0.6	1.0	1.0
Unruptured node		12	12	13	13	12
	PCT, °F	1915.1	1895.9	1851.9	1811.5	1829.9
	Time, sec	33.549	41.515	37.100	34.086	32.151
	Local oxidation, %	1.7364	1.5650	1.0324	0.9773	1.0277
Ruptured node		11	13	12	12	13
	PCT, °F	1957.1	1889.6	1820.9	1745.0	1796.3
	Time, sec	28.604	29.845	31.511	31.055	32.284
	Local oxidation, %	2.0190	1.8633	1.6000	1.4752	1.5446
Clad rupture time, sec		19.02	20.655	23.21	21.02	19.19
CFTs begin injection, sec		11.80	12.80	14.60	12.20	13.00
End of bypass, sec		18.14	19.29	21.56	18.90	17.70
End of blowdown, sec		20.16	21.46	24.20	21.01	22.94
End of adiabatic heatup, sec		26.562	27.721	29.988	27.475	25.542
Water mass in reactor vessel lower plenum at end of blowdown, lbm		16701.6	17695.6	20418.6	16811.3	36238.7

Table 15-7. Deleted Per 1997 Update

Table 15-8. Deleted Per 1995 Update

Table 15-9. Deleted Per 1995 Update

Table 15-10. Deleted Per 1995 Update

Table 15-11. Deleted Per 1995 Update

Table 15-12. Deleted Per 1995 Update

Table 15-13. Deleted Per 1995 Update

Table 15-14. Deleted Per 2004 Update

Table 15-15. Total Core Activity for Maximum Hypothetical Accident

Isotope	Total Ci in Core[1]
AM241	2.02E+04
AM242M	1.35E+03
AM242	7.66E+06
AM243	3.22E+03
BA139	1.31E+08
BA140	1.27E+08
BA141	1.18E+08
BR83	8.95E+06
BR85	1.93E+07
BR87	3.04E+07
CE141	1.20E+08
CE143	1.12E+08
CE144	9.64E+07
CM242	4.61E+06
CM244	5.84E+05
CS134	1.52E+07
CS136	4.33E+06
CS137	1.07E+07
CS138	1.37E+08
CS139	1.28E+08
EU154	7.08E+05
EU155	2.92E+05
EU156	1.87E+07
I130	1.50E+06
I131	7.20E+07
I132	1.05E+08
I133	1.47E+08
I134	1.65E+08
I135	1.40E+08
KR83M	9.01E+06
KR85M	1.94E+07

Isotope	Total Ci in Core[1]
KR85	1.01E+06
KR87	3.85E+07
KR88	5.17E+07
KR89	6.46E+07
LA140	1.33E+08
LA141	1.19E+08
LA142	1.15E+08
LA143	1.11E+08
MO99	1.33E+08
NB95M	1.41E+06
NB95	1.24E+08
NB97	1.24E+08
ND147	4.74E+07
NP238	3.08E+07
NP239	1.54E+09
PD109	2.68E+07
PM147	1.55E+07
PM148M	3.69E+06
PM148	1.27E+07
PM149	4.16E+07
PM151	1.43E+07
PR143	1.09E+08
PR144M	1.35E+06
PR144	9.69E+07
PU236	3.92E+01
PU238	3.61E+05
PU239	3.42E+04
PU240	4.94E+04
PU241	1.30E+07
PU243	3.30E+07
RB86	1.41E+05
RB88	5.25E+07

Isotope	Total Ci in Core[1]
RB89	6.90E+07
RB90	6.26E+07
RH103M	1.19E+08
RH105	7.97E+07
RU103	1.19E+08
RU105	8.59E+07
RU106	4.69E+07
SB127	6.90E+06
SB129	2.12E+07
SM153	3.44E+07
SR89	7.18E+07
SR90	8.05E+06
SR91	9.02E+07
SR92	9.61E+07
SR93	1.06E+08
TC99M	1.18E+08
TC101	1.24E+08
TE127M	1.15E+06
TE127	6.79E+06
TE129M	3.82E+06
TE129	1.99E+07
TE131	6.09E+07
TE132	1.02E+08
TE133M	6.95E+07
TE133	7.87E+07
TE134	1.33E+08
XE131M	9.62E+05
XE133M	4.57E+06
XE133	1.43E+08
XE135M	3.11E+07
XE135	5.33E+07
XE137	1.32E+08

Isotope	Total Ci in Core[1]
XE138	1.26E+08
Y90	8.26E+06
Y91M	5.23E+07
Y91	9.32E+07
Y92	9.72E+07
Y93	1.09E+08
Y94	1.14E+08
Y95	1.18E+08
ZR95	1.23E+08
Z R97	1.23E+08
U237	6.61E+07

Note:

1. Core activity values bound both 18-month and 24-month cycle scenarios.

Table 15-16. Summary of Transient and Accident Doses Including the Effects of High Burnup Reload Cores with Replacement Steam Generators

		Doses (rem)	
Fuel Handling Accident for Single Fuel Assembly Event			
	TEDE at EAB		1.18
	TEDE at LPZ		0.13
	TEDE in Control Room		2.19
Deleted row(s) per 2016 update			
Steam Generator Tube Rupture		Case 1	Case 2
	Thyroid at EAB	4.24E+1	2.80E+2
	Whole body at EAB	1.46E-1	1.82E-1
	Thyroid at LPZ	1.00E+1	6.93E+1
	Whole body at LPZ	3.04E-2	4.00E-2
Waste Gas Tank Failure			
	TEDE at EAB	4.4E-1	
Rod Ejection		Containment Release	Secondary Side Release
	TEDE at EAB	5.23	2.66
	TEDE at LPZ	2.00	1.35
	TEDE in Control Room	4.46	4.92
Deleted row(s) per 2009 update			
Large Main Steam Line Break		Preaccident Iodine Spike	Concurrent Iodine Spike
	TEDE at EAB	0.18	0.70
Deleted row(s) per 2012 Update			
	TEDE at LPZ	0.05	0.22
	TEDE in Control Room	0.76	1.30

		Doses (rem)	
Small Main Steam Line Break		Preaccident Iodine Spike	Concurrent Iodine Spike
	TEDE at EAB	0.29	0.68
Deleted row(s) per 2012 Update			
	TEDE at LPZ	0.06	0.24
	TEDE in Control Room	1.29	1.69
Deleted row(s) per 2004 update			
Maximum Hypothetical Accident			
	TEDE at EAB	10.86	
	TEDE at LPZ	2.74	
	TEDE in Control Room	4.39	
	Deleted row(s) per 2008 update		
Fuel Cask Handling Accident for Multiple Fuel Assembly Event			
	TEDE at EAB	1.93	
	TEDE at LPZ	0.21	
	TEDE in Control Room	3.62	
Deleted row(s) per 2008 update			
Deleted row(s) per 2004 update			
Deleted row(s) per 2008 update			

Table 15-17. Deleted Per 2000 Update

Table 15-18. Deleted Per 2000 Update

Table 15-19. Deleted Per 1995 Update

Table 15-20. Deleted Per 1995 Update

Table 15-21. Deleted Per 1995 Update

Table 15-22. Deleted Per 1995 Update

Table 15-23. Deleted Per 1995 Update

Table 15-24. Deleted Per 1997 Update

Table 15-25. Deleted Per 2001 Update

Table 15-26. Deleted Per 1995 Update

Table 15-27. Deleted Per 2003 Update

Table 15-28. HPI Flow Assumed in Core Flood Line Small Break LOCA Analyses

102% Full Power SBLOCA	
Flow rates prior to credit for operator realignment of HPI at 10 minutes	
RCS Pressure (psig)	**HPI Flow (gpm)**
0	428
600	428
1200	333
1500	294
1600	280
1800	250
2400	127
Flow rates after credit for operator realignment of HPI at 10 minutes	
RCS Pressure (psig)	**HPI Flow (gpm)**
0	817
600	817
1200	653
1500	573
1600	544
1800	482
2400	230
52% Full Power SBLOCA	
RCS Pressure (psig)	**HPI FLow (gpm)**
0	389
600	389
1200	303
1500	262
1600	248
1800	216
2400	84

Table 15-29. HPI Flow Assumed in RCP Discharge Small Break LOCA Analyses

102% Full Power SBLOCA		
Flow rates prior to credit for operator realignment of HPI at 10 minutes		
RCS Pressure (psig)	**Broken Leg Flow (gpm)**	**Intact Leg Flow (gpm)**
0	243	185
600	243	185
1200	189	144
1500	167	127
1600	159	121
1800	142	108
2400	69	53
Flow rates after credit for operator realignment of HPI at 10 minutes		
RCS Pressure (psig)	**Broken Leg Flow (gpm)**	**Intact Leg Flow (gpm)**
0	243	574
600	243	574
1200	189	464
1500	167	406
1600	159	385
1800	142	340
2400	72	158
52% Full Power SBLOCA		
RCS Pressure (psig)	**Broken Leg FLow (gpm)**	**Intact Leg Flow (gpm)**
0	223	167
600	223	167
1200	174	130
1500	151	113
1600	142	106
1800	124	93
2400	48	36

Table 15-30. HPI Flow Assumed in HPI Line Small Break LOCA Analyses

102% Full Power SBLOCA		
Flow rates prior to credit for operator realignment of HPI at 10 minutes		
RCS Pressure (psig)	**Broken Leg/Spill Flow (gpm)**	**Intact Leg Flow (gpm)**
0	259	181
600	320	124
1200	382	47
1500	408	0
Flow rates after credit for operator realignment of HPI at 10 minutes		
RCS Pressure (psig)	**Broken Leg/Spill Flow (gpm)**	**Intact Leg Flow (gpm)**
0	259	570
600	320	513
1200	383	366
1500	407	279
52% Full Power SBLOCA		
RCS Pressure (psig)	**Broken Leg Flow (gpm)**	**Intact Leg Flow (gpm)**
0	236	165
300	269	134
600	303	101
1200	377	15
1500	385	0
1600	385	0
1800	385	0
2400	385	0

Table 15-31. Deleted Per 2008 Update

Table 15-32. Summary of Transient and Accident Cases Analyzed

UFSAR Section	Description of Transient	Summary of Cases Analyzed
15.2	Startup Accident	Peak RCS pressure
15.3	Rod Withdrawal at Power	1. Core cooling capability 2. Peak RCS pressure
15.4	Moderator Dilution Accidents	1. Power operation 2. Refueling
15.5	Cold Water Accident	Core cooling capability
15.6	Loss of Coolant Flow	Core cooling capability: 1. Four RCP trip from four-RCPs 2. Two RCP trip from four-RCPs 3. One RCP trip from three-RCPs 4. Locked rotor from four-RCPs 5. Locked rotor from three-RCPs
15.7	Control Rod Misalignment Accidents	Core cooling capability 1. Dropped rod from four-pumps 2. Dropped rod from three-pumps 3. Statically misaligned rod
15.8	Turbine Trip	Peak RCS pressure
15.9	Steam Generator Tube Rupture	Offsite dose
15.10	Waste Gas Tank Rupture	Offsite dose
15.11	Fuel Handling Accidents	Offsite dose 1. Fuel handling accident in Spent Fuel Pool 2. Fuel handling accident in containment 3. Fuel shipping cask drop 4. Dry storage canister cask drop

UFSAR Section	Description of Transient	Summary of Cases Analyzed
15.12	Rod Ejection	Peak fuel enthalpy 1/4. Four-pump BOC and EOC 2/5.Three-pump BOC and EOC 3/6.Three-pump BOC and EOC, HZP Core cooling capability 1/4.Four-pump BOC and EOC 2/5.Three-pump BOC and EOC 3/6.Three-pump BOC and EOC, HZP Peak RCS pressure 7. Three-pump BOC 8. Four-pump BOC
15.13	Steam Line Break	Core cooling capability 1. With offsite power 2. Without offsite power
15.14	Loss of Coolant Accidents	10CFR50.46 and offsite dose 1. Large-break LOCA spectrum Full-core Mk-B-HTP LOCA limits 2. Small-break LOCA spectrum (full power) Full-core Mk-B-HTP LOCA limits 3. Small-break LOCA spectrum (reduced power) Full-core Mk-B-HTP LOCA limits
15.15	Maximum Hypothetical Accident	Large Break LOCA - offsite dose
15.16	Post-Accident Hydrogen Control	Large Break LOCA - flammability limit
15.17	Small Steam Line Break	Core cooling capability

Table 15-33. Methodology Topical Reports and Computer Codes Used in Analyses

	UFSAR Section	Topical Reports	Computer Codes
15.2	Startup Accident	DPC-NE-3005-PA	RETRAN-3D SIMULATE-3
15.3	Rod Withdrawal at Power Accident	DPC-NE-3005-PA	RETRAN-3D VIPRE-01 SIMULATE-3
15.4	Moderator Dilution Accidents	DPC-NE-3005-PA	N/A
15.5	Cold Water Accident	DPC-NE-3005-PA	RETRAN-3D
15.6	Loss of Coolant Flow Accidents	DPC-NE-3005-PA	RETRAN-3D VIPRE-01 SIMULATE-3
15.7	Control Rod Misalignment Accidents	DPC-NE-3005-PA	RETRAN-3D VIPRE-01 SIMULATE-3
15.8	Turbine Trip Accident	DPC-NE-3005-PA	RETRAN-3D
15.9	Steam Generator Tube Rupture Accident	DPC-NE-3005-PA	RETRAN-3D
15.12	Rod Ejection Accident	DPC-NE-3005-PA	SIMULATE-3K SIMULATE-3 RETRAN-3D VIPRE-01
15.13	Steam Line Break Accident	DPC-NE-3005-PA	RETRAN-3D VIPRE-01 SIMULATE-3
15.14	Loss of Coolant Accident		
	Large Breaks	BAW-10192-PA	RELAP5/MOD2-B&W CONTEMPT REFLOD3 BEACH
	Small Breaks	BAW-10192-PA	RELAP5/MOD2-B&W CONTEMPT
15.17	Small Steam Line Break Accident	DPC-NE-3005-PA	RETRAN-3D VIPRE-01 SIMULATE-3

Table 15-34. Summary of Input Parameters for Accident Analyses Using Computer Codes

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F) (Note 16)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
15.2	N/A	1.0E-7	532	2155	272,624	285	+7.0E-5	Note 15	0.0065	0
15.3	1	102	579	2125	378,400	195	0.0	Note 2	0.0065	0
	2	102	581	2155	371,360	285	0.0	Note 2	0.0065	5
15.5	N/A	80	579	2125	282,665	195	-35.0E-5	Note 3	0.0049	0
15.6	1	102	579	2125	378,400	195	0.0	Note 2	0.0065	0
	2	102	579	2125	378,400	195	0.0	Note 2	0.0065	0
	3	80	579	2125	282,665	195	0.0	Note 2	0.0065	0
	4	102	579	2125	378,400	195	0.0	Note 2	0.0065	0
	5	75	579	2125	282,665	195	+0.56E-5	Note 2	0.0065	0
15.7	1	102	579	2125	381.920	195	0.0	Note11	.0058	0
	2	75	579	2125	282,665	195	+0.56E-5	Note 11	.0058	0
15.8	N/A	102	581	2185	374,493	285	0.0	Note 2	0.0065	5
15.9	N/A	102	577	2185	371,360	285	-35.0E-5	Note 4	0.0049	5
15.12 (Note 7)	1	102	581	2095	374,880	N/A	0.0	-1.10E-5	0.0058	N/A
	2	77	581	2095	275,614	N/A	+0.56E-5	-1.16E-5	0.0058	N/A
	3	0	540	2095	275,614	N/A	+7.0E-5	-1.42E-5	0.0058	N/A
	4	102	581	2095	374,880	N/A	-28.0E-5	-1.19E-5	0.0047	N/A
	5	77	581	2095	275,614	N/A	-28.0E-5	-1.22E-5	0.0047	N/A
	6	0	540	2095	275,614	N/A	-12.0E-5	-1.53E-5	0.0047	N/A

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F) (Note 16)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
	7	77	581	2095	275,614	285	+0.56E-5	-1.16E-5	0.0058	5
	8	102	581	2095	374,880	285	0.0	-1.10E-5	0.0058	5
15.13	1	102	577	2095	371,360	195	Note 8	Note 5	0.0	0
	2	102	579	2125	378,400	285	0.0	Note 6	0.0065	0
15.14	1	102	579	2155	374,880(10)	220	0.0	Note 4	0.007	7
	2	102	579	2155	374,880(10)	220	0.0	Note 4	0.007	7
	3	52	579	2155	374,880(10)	220	+5.0	Note 4	0.007	7
15.17	N/A	102	579	2125	381,902(17)	195	-7.0	Note 14		0

Note:

1. This flow rate corresponds to 105.5% of Design Flow.
2. Doppler Reactivity assumption as function of average fuel temperature:
   Accident Analyses: 15.3, 15.6 (Cases 1-5), 15.8

Average Fuel Temperature	Doppler Coefficient
(°F)	Δk/k-°F (x10^{-5})
230.0	-1.89
450.0	-1.58
750.0	-1.27
1450.0	-1.02

Note:

3. Doppler reactivity assumption as function of average fuel temperature:
   Accident Analyses: 15.5

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F) (Note 16)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)

Average Fuel Temperature	Doppler Coefficient
(°F)	Δk/k-°F (x10^{-5})
472.18	-1.7290
632.60	-1.5926
889.68	-1.3738
1358.65	-1.2662

Note:

4. Doppler reactivity assumption as function of average fuel temperature:
   Accident Analyses: 15.9, 15.14 Case 1

Average Fuel Temperature	Doppler Coefficient
(°F)	Δk/k-°F (x10^{-5})
452.38	-2.1782
754.3	-1.8795
1149.79	-1.6651
1350	-1.5566

Note:

5. Doppler reactivity assumption as function of average fuel temperature:
   Accident Analysis: 15.13 Case 1

Average Fuel Temperature	Doppler Reactivity
(°F)	%Δk/k
953.8	0
940.55	0.0221

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F) (Note 16)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
950.0			0.0							
938.59			0.0169							
918.39			0.0477							
532			0.8804							
512			0.9194							
500			0.9419							
450			1.0398							
400			1.1398							
Average Fuel Temperature			Doppler Reactivity							
350			1.2423							
300			1.3480							
250			1.4571							
200			1.570							

Note:

6. Doppler reactivity assumption as function of average fuel temperature:
   Accident Analysis 15.13 Case 2

Average Fuel Temperature	Doppler Reactivity
(°F)	%Δk/k/°F
1450	-1.02E-5
750	-1.27E-5
450	-1.58E-5

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F) (Note 16)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
230			-1.89E-5							
Deleted Row(s) Per 2008 Update										

Note:

7. Actual physics parameter values determined from code cross section library for 15.12 Cases 1-7, target values listed for moderator and doppler reactivities and β-effective
8. Moderator reactivity assumption as a function of moderator density.
   Accident Analysis: 15.13 Case 1

Moderator Density	Moderator Reactivity
(lbm/ft^3)	%Δk/k
44.6590	0
45.2758	0.2253
Moderator Density	Moderator Reactivity
46.0125	0.4866
47.6731	0.6991
47.6658	1.0369
47.8133	1.0824
49.1185	1.6595
49.5917	1.8547
51.5476	2.6327
52.0171	2.8095
53.7633	3.4392
54.1503	3.5729

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F) (Note 16)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
55.7105			4.0921							
56.0313			4.1950							
Deleted Row(s) Per 2008 Update										
9. Deleted Row(s) Per 2008Update										

Note:

10. This flow rate corresponds to 106.5% of Design Flow.

11. Doppler reactivity assumption as a function of average fuel temperature:
Accident Analyses: 15.7

Average Fuel Temperature	Doppler Coefficient
(°F)	Δk/k-°F (x10^{-5})
230.0	-1.89
450.0	-1.58
Average Fuel Temperature	Doppler Coefficient
750.0	-1.27
1450.0	-1.02

12. Deleted Row(s) per 2008 Update

Note:

13. Doppler reactivity assumption as a function of average fuel temperature:
Accident Analysis: 15.17

Average Fuel Temperature	Doppler Coefficient
(°F)	Δk/k-°F (x10^{-5})

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F) (Note 16)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
230.0			-1.89							
450.0			-1.58							
750.0			-1.27							
1450.0			-1.02							

Note:

14. Doppler reactivity assumption interpolated between the following:

BOC		EOC	
Average Fuel Temperature	Doppler Coefficient	Average Fuel Temperature	Dopler Coefficient
(°F)	Δk/k-°F (x10^{-5})	(°F)	Δk/k-°F (x10^{-5})
230.0	-1.89	472.18	-1.7290
450.0	-1.58	632.60	-1.5926
750.0	-1.27	889.68	-1.3738
1450.0	-1.02	1358.65	-1.2662
Average Fuel Temperature	Doppler Coefficient	Average Fuel Temperature	Dopler Coefficient
βeff interpolated between the following			
BOC	EOC		
.0065	.0054		

Note:

15. Doppler reactivity assumption as a function of temperature:
Accident Analysis: 15.2

Average Fuel Temperature	Doppler Coefficient

UFSAR Section	Case Identifier	Power Level (%FP)	RCS T-ave (°F) (Note 16)	RCS Pressure (psig)	RCS FLOW (gpm)	Pressurizer Level (inches)	MTC (Δk/k./°F)	DTC (Δk/k./°F)	β-effective	SG Tube Plugging (%)
(°F)			Δk/k-°F (x10^{-5})							
231.4			-2.0174							
452.47			-1.6873							
743.78			-1.3838							
1434.14			-1.1136							

Note:

16. All accident analyses have been evaluated for an end-of-cycle T-ave reduction of up to 10°F lower than the T-ave values shown in this table.

17. This flow rate corresponds to 108.5% of Design Flow.

Table 15-35. Trip Setpoints and Time Delays Assumed in Accident Analyses

Trip Functions	Nominal Setpoint	Limiting Trip Setpoint Assumed in Analyses	Time Delay (seconds)
RPS:			
High Flux (8)	107.5% FP	108.5% 112.0% (10)	0.4
High Flux(11)	80.5% FP	81.5%	0.4
High Pressure	2355 psig	2362 psig	0.5
Low Pressure	1800 psig	1793 psig(2)	0.5
Variable Low Pressure-Temperature	Trip if: (1) $P<11.14 * T_{hot}-4706$	Trip if: (1) $P<11.14 * T_{hot}-4716$	0.7
High Temperature	618°F	618.85°F	0.7
Flux/Flow (8)	Trip if: (3) $\Phi > 109.4\%FP/flow * Fm$	Trip if: (3) $\Phi > 109.4\%FP/flow * Fm + 2.2\%FP$	1.2
Pump Monitor		NA	0.9

ESPS:	**HPI Trip Setpoint**	**HPI Time Delay (seconds)**	**LPI Time Delay (Seconds)**	**CFT Setpoint**
Nominal Setpoint	1590 psig			2 psid
Transient				
LBLOCA	N/A	N/A	38 + 36 sec. ramp	(Note 7)
SBLOCA	1500 psig	48 (LOOP)	N/A	(Note 7)
Large Steam Line Break	1400 psig	15 (no LOOP) 38 (LOOP)	N/A	+6.5 psid (CFT A) –2.5 psid (CFT B)
Small Steam Line Break	1450 psig	15 (no LOOP) 38 (LOOP)	N/A	N/A
Rod Ejection	(Note 5)	(Note 5)	N/A	N/A
SGTR	(Note 6)	(Note 6)	N/A	N/A

Notes:

1. "P" is gauge pressure.
2. SBLOCA assumes 1765 psig.
3. "Fm" is measured flow.
4. Deleted per 2003 update.
5. Rod ejection assumes HPI actuation 5 seconds after the event begins.
6. SGTR assumes HPI actuation coincident with the tube rupture.
7. LOCA analyses assume a CFT nitrogen pressure of 550 psig. The CFT line break case considers a pressure of 547 psig to account for check valve leakage.
8. %FP is % of 2568 mwth.
9. Deleted per 2010 update.
10. Rod Ejection at 102% FP.
11. 3 RCP Small Steam Line Break.

Table 15-36. Startup Accident Sequence of Events

Event	Time(sec)
Rod withdrawal begins	0.0
Pressurizer control heaters de-energize	49.3
High power reactor trip	50.6
Control rod insertion begins	51.0
Pressurizer safety valves open	53.3
Peak RCS pressure occurs	53.7
Pressurizer safety valves reseat	55.5
End of simulation	100.0

Table 15-37. Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis Sequence of Events

Event	Time (sec)
Rod withdrawal begins	0.0
High RCS pressure reactor trip setpoint reached	36.7
Control rod insertion begins	37.2
Turbine trip on reactor trip	37.2
Main steam safety valves lift	39.8 - 41.2
Peak RCS pressure occurs	41.0
Main steam safety valves begin to reseat	47.3
End of simulation	47.3

Table 15-38. Rod Withdrawal at Power Accident - Core Cooling Capability Analysis Sequence of Events

Event	Time (sec)
Rod withdrawal begins	0.0
Pressurizer spray actuates	92.7
High temperature reactor trip setpoint reached	204.4
Control rod insertion begins	205.1
Turbine trip on reactor trip	206.1
Main steam safety valves lift	208.4 – 210.4
Pressurizer spray terminates	211.2
End of simulation	215.2

Table 15-39. Cold Water Accident Sequence of Events

Event	Time (sec)
Fourth RCP starts	0.1
RCP reaches full speed	5.1
Maximum heat flux occurs (97.5%)	6.9
End of simulation	15.0

Table 15-40. Loss of Flow Accidents Four RCP Coastdown from Four RCP Initial Conditions Sequence of Events

Event	Time (sec)
All RCPs trip	0.0
Pump monitor reactor trip	0.0
Rod motion begins	0.9
Turbine trip on reactor trip	1.1
Pressurizer spray initiates	2.7
MSSVs lift	3.9 - 4.7
Pressurizer spray terminates	11.4
End of simulation	20.0

Table 15-41. Loss of Flow Accidents Two RCP Coastdown from Four RCP Initial Conditions Sequence of Events

Event	Time (sec)
Two RCPs trip	0.0
Flux/flow reactor trip setpoint reached	3.0
Rod motion begins	4.2
Turbine trip on reactor trip	4.4
Pressurizer spray initiates	5.4
MSSVs lift	6.5 – 11.2
End of simulation	20.0

Table 15-42. Loss of Flow Accidents One RCP Coastdown from Three RCP Initial Conditions Sequence of Events

Event	Time (sec)
One RCPs trip	0.0
Flux/flow reactor trip setpoint reached	3.8
Rod motion begins	5.0
Turbine trip on reactor trip	5.2
MSSVs lift	7.4 – 9.8
End of simulation	20.0

Table 15-43. Loss of Flow Accidents Locked Rotor from Four RCP Initial Conditions Sequence of Events

Event	Time (sec)
Locked rotor occurs	0.0
Flux/flow reactor trip setpoint reached	0.5
Rod motion begins	1.7
Turbine trip on reactor trip	1.8
Pressurizer spray initiates	2.8
MSSVs lift	3.9 - 7.8
End of simulation	10.0

Table 15-44. Loss of Flow Accidents Locked Rotor from Three RCP Initial Conditions Sequence of Events

Event	Time (sec)
Locked rotor occurs	0.0
Flux/flow reactor trip setpoint reached	0.4
Rod motion begins	1.6
Turbine trip on reactor trip	1.8
Pressurizer spray initiates	3.5
MSSVs lift	4.8 - 8.8
End of simulation	10.0

Table 15-45. Control Rod Misalignment Accidents - Dropped Rod Accident Sequence of Events

Event	Time (sec)
Control rod drops	0.01
ICS initiates control rod withdrawal	0.6
Control rod withdrawal terminates	12.9
Pressurizer spray initiates	21.6
Terminate Pressurizer Spray	68.2
End of Simulation	90.0

Table 15-46. Turbine Trip Accident Sequence of Events

Event	Time (sec)
Turbine trip	0.01
MFW isolation	0.01
Main steam safety valves start to lift	2.5
High RCS pressure reactor trip	3.6
Control rod insertion begins	4.1
Peak RCS pressure occurs	6.0
Main steam safety valves start to reseat	11.3
End of simulation	40.0

Table 15-47. Steam Generator Tube Rupture Accident Sequence of Events

Event	Seconds
SGTR occurs	0.1
HPIS injection flow starts	0.1
Reactor trip	1,200
Turbine trip on reactor trip	1,200
MFW pumps trip	1,200
MSSVs lift and begin cycling	1,202
EFW flow to ruptured SG begins	1,380
Operator identifies EFW control valve is failed closed	1,980
EFW to both SG is restored	2,580
Operator identifies ruptured SG	3,180
Operator begins minimizing subcooled margin	3,900
Operator begins cooldown to 532°F with ADVs	6,300
All MSSVs have reseated	6,300
RCS cooled down to 532°F	7,040
Operator completes isolation of the ruptured SG	8,240
Operator trips one RCP in loop without pressurizer	8,240
Shift changeover begins	8,240
Steaming of ruptured SG due to high SG level begins	10,621
Shift changeover completed	11,840
Operator begins RCS cooldown to 450°F.	12,140
RCS temperature reaches 450°F. - RCS Boron Concentration is determined and boration to cold shutdown initiated.	15,191
Operator begins cooldown to LPIS conditions	22,691
Operator trips one RCP in loop with the pressurizer	24,605
LPIS conditions reached	31,455
Start cooldown with LPIS	36,855
Plant cooled down to 212°F	40,725

Table 15-48. Steam Line Break Accident - Without Offsite Power Case Sequence of Events

Event	Time (sec)
Break initiates, offsite power lost, reactor trips	0.0
RCPs begin to coast down	
Deleted row(s) per 2003 update	
Control rod insertion begins	0.14
Turbine stop valves closed	1.72
Control rods fully inserted	2.54
End of simulation	5

Table 15-49. Small Steam Line Break Accident Sequence of Events

Event	Time (sec)
Break occurs	10
Pressurizer heater backup banks energize, makeup flow starts	10.6
Third Condensate Booster Pump actuates	18.7
Pressurizer heater control and backup banks de-energize on low pressurizer level	174.5
MDNBR occurs	195
Pressurizer heater control and backup banks energize	248.6
Peak neutron power	610.0
Problem termination	610

Table 15-50. Failed Fuel Source Term for the Rod Ejection Accident (Curies)

Nuclide	Single DNB Assembly Activity	Release Fraction	Failed Fuel Gap Release Source Term[1]
I--130	2.14E+04	10%	1.70E+05
I--131	6.20E+05	10%	4.94E+06
I--132	9.14E+05	10%	7.28E+06
I--133	1.33E+06	10%	1.06E+07
I--134	1.55E+06	10%	1.23E+07
I--135	1.26E+06	10%	1.00E+07
BR--83	1.04E+05	5%	4.16E+05
BR--85	2.41E+05	5%	9.59E+05
BR--87	3.96E+05	5%	1.58E+06
KR--83M	1.04E+05	10%	8.32E+05
KR--85M	2.42E+05	10%	1.92E+06
KR--85	8.30E+03	10%	6.61E+04
KR--87	4.93E+05	10%	3.93E+06
KR--88	6.72E+05	10%	5.35E+06
KR--89	8.58E+05	10%	6.84E+06
XE131M	8.02E+03	10%	6.39E+04
XE133M	4.01E+04	10%	3.19E+05
XE-133	1.27E+06	10%	1.01E+07
XE135M	2.64E+05	10%	2.10E+06
XE-135	4.20E+05	10%	3.34E+06
XE-137	1.21E+06	10%	9.65E+06
XE-138	1.23E+06	10%	9.83E+06
RB--86	1.68E+03	12%	1.60E+04
RB--88	6.77E+05	12%	6.47E+06
RB--89	8.98E+05	12%	8.58E+06
RB--90	8.46E+05	12%	8.09E+06
CS-134	1.94E+05	12%	1.85E+06
CS-136	4.67E+04	12%	4.46E+05
CS-137	9.61E+04	12%	9.19E+05
CS-138	1.32E+06	12%	1.26E+07

Nuclide	Single DNB Assembly Activity	Release Fraction	Failed Fuel Gap Release Source Term[1]
CS-139	1.24E+06	12%	1.19E+07

Note:

1. Assumes 45% failed fuel.

Table 15-51. Reactor Coolant System Fission Product Source Activities - 500 EPFD Equilibrium Cycle[1]

Nuclide	Maximum Specific Activity [2] (μCi/gm)	Maximum Total Coolant [3] Activity (Curies)
I-131	5.80E+0	1.39E+3
I-132	8.36E+0	1.68E+3
I-133	7.03E+0	1.42E+3
I-134	7.76E-1	1.55E+2
I-135	3.32E+0	6.63E+2
Xe-131m	6.04E+0	1.21E+3
Xe-133m	6.42E+0	1.28E+3
Xe-133	4.67E+2	9.32E+4
Xe-135m	7.06E-1	1.41E+2
Xe-135	1.34E+1	2.67E+3
Xe-138	7.40E-1	1.48E+2
Kr-83m	5.34E-1	1.06E+2
Kr-85m	2.23E+0	4.44E+2
Kr-85	1.72E+2	3.43E+4
Kr-87	1.21E+0	2.42E+2
Kr-88	3.81E+0	7.60E+2

Note:

1. Reactor coolant activities at equilibrium assuming 1 percent failed fuel randomly distributed throughout the core.
2. Based on steady-state operation with no RCS leakage and no continuous pressurizer spray flow. Used for calculating doses arising from reactor coolant leaks to the secondary systems.
3. Based on steady-state operation with no RCS leakage and 1 gpm continuous pressurizer spray flow.

Table 15-52. Deleted Per 2003 Update

Table 15-53. Deleted Per 2003 Update

Table 15-54. Deleted Per 2003 Update

Table 15-55. Deleted Per 2003 Update

Table 15-56. Deleted Per 2014 Update

Table 15-57. Deleted per 2014 Update

Table 15-57. Deleted Per 2014 Update

Table 15-58. Parameters Used To Determine Hydrogen Generation

Reactor Thermal Power (102%)		2,568 MWt
Reactor Operating Time (average cycle length)		980 Days
Containment Free Volume		1.79E+06 ft^3
Weight Of Zirconium Surrounding The Fuel		41,000 lbm
Hydrogen Generated From 5.0% Zr-Water Reaction		17,435 scf
Hydrogen Dissolved In Primary Coolant And Pressurizer Gas Space		450 scf
Corrodable Metals		Aluminum, Zinc
Hydrogen Generated From Radiolysis		
Sources	Core Radiolysis	Sump Radiolysis
Percent of total halogens retained in solution	50	50
Percent of total noble gases retained in solution	0	0
Percent of other fission products retained in solution	99	1
Energy Distribution		
Percent of total decay energy - Gamma	50	50
Percent of total decay energy - Beta	50	50
Energy Absorption by the Solution		
Percent of gamma energy absorbed	10	100
Percent of beta energy absorbed	0	100
Molecules of H2 Produced per 100 ev Energy Absorbed	0.45	0.3

Table 15-59. Deleted Per 2001 Update

Table 15-60. Deleted per 2014 Update

Table 15-61. Control Room Atmospheric Dispersion Factors (χ/Qs)

Release Type	**Bounding χ/Q (sec/m^3)**
Units Vent Releases	
0 to 2 hr	9.43E-04
2 to 8 hr	6.00E-04
8 to 24 hr	2.41E-04
1 to 4 days	1.87E-04
4 to 30 days	1.54E-04
Main Steam Penetration Releases	
0 to 2 hr	5.76E-04
2 to 8 hr	4.09E-04
8 to 24 hr	1.72E-04
1 to 4 days	1.34E-04
4 to 30 days	1.08E-04
Equipment Hatch Releases	
0 to 2 hr	6.59E-04
2 to 8 hr	4.86E-04
8 to 24 hr	2.13E-04
1 to 4 days	1.65E-04
4 to 30 days	1.28E-04
ADV Releases	
0 to 2 hr	1.79E-03
2 to 8 hr	1.25E-03
8 to 24 hr	5.45E-04
1 to 4 days	4.17E-04
4 to 30 days	3.34E-04
MSSV Releases	
0 to 2 hr	1.91E-03
2 to 8 hr	1.33E-03
8 to 24 hr	5.86E-04
1 to 4 days	4.52E-04
4 to 30 days	3.54E-04

Release Type	**Bounding χ/Q (sec/m^3)**
MSLB Releases	
0 to 2 hr	1.21E-03
2 to 8 hr	8.39E-04
8 to 24 hr	3.70E-04
1 to 4 days	2.81E-04
4 to 30 days	2.23E-04
Fuel Handling Building Roll-up Door Releases	
0 to 2 hr	3.19E-04
2 to 8 hr	2.50E-04
8 to 24 hr	1.04E-04
1 to 4 days	7.89E-05
4 to 30 days	6.10E-05
BWST Releases	
0 to 2 hr	4.76E-04
2 to 8 hr	3.27E-04
8 to 24 hr	1.35E-04
1 to 4 days	1.05E-04
4 to 30 days	8.99E-05

Table 15-62. Results of LBLOCA Analyses for Mark-B-HTP Full Core Sequence of Events

UO_2 BOL Conditions	Core Elevation, ft				
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	17.8	17.6	17.3	17.3	17.3
End of blowdown, sec	22.7	22.6	22.5	22.5	22.4
LPI begins injecting, sec	42.3	42.2	42.1	42.1	42.2
CFTs empty, sec	48.8	48.8	48.8	48.7	48.7
Unruptured node:					
Hot Pin Peak cladding temperature, °F	1845.4	1812.9	1783.6	1798.1	1832.4
Time, sec	28.3	36.2	35.7	35.2	78.4
Local oxidation, %	1.04	1.13	1.08	0.96	1.66
Rupture node:					
Hot Pin Peak cladding temperature, °F	1871.4	1831.6	1778.4	1742.5	1760.6
Time, sec	28.3	28.2	28.2	28.1	34.6
Local oxidation, %	1.56	1.52	1.41	1.42	1.52
Rupture time, sec	22.0	23.1	24.3	25.2	25.2
Whole core hydrogen generation, %	<0.12	<0.12	<0.11	<0.12	<0.13
UO_2 MOL Conditions	**Core Elevation, ft**				
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	17.8	17.6	17.3	17.3	17.3
End of blowdown, sec	22.7	22.6	22.5	22.5	22.4
LPI begins injecting, sec	42.3	42.2	42.1	42.3	42.2
CFTs empty, sec	48.8	48.8	48.8	48.7	48.7
Unruptured node:					
Hot Pin Peak cladding temperature, °F	1987.9	1880.6	1861.6	1848.9	1832.6
Time, sec	28.3	33.2	35.2	34.9	36.8
Local oxidation, %	1.87	1.70	1.80	1.77	1.67
Rupture node:					
Hot Pin Peak cladding temperature, °F	1951.1	1857.5	1753.3	1802.8	1832.2
Time, sec	28.3	28.3	32.6	34.8	34.6
Local oxidation, %	2.22	2.00	1.59	1.76	1.88
Rupture time, sec	19.7	20.9	22.1	22.3	23.5
Whole core hydrogen generation, %	<0.10	<0.09	<0.09	<0.10	<0.10

UO_2 EOL Conditions	**Core Elevation, ft**				
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	12.7	12.7	12.8	12.8	12.8
End of blowdown, sec	22.7	22.6	22.5	22.5	22.4
LPI begins injecting, sec	42.3	42.2	42.1	42.3	42.2
CFTs empty, sec	48.8	48.8	48.8	48.8	48.7
Unruptured node:					
Hot Pin Peak cladding temperature, °F	1776.4	1771.9	1764.1	1717.9	1724.2
Time, sec	33.0	35.1	34.8	36.8	36.3
Local oxidation, %	1.39	1.42	1.45	1.40	1.33
Rupture node:					
Hot Pin Peak cladding temperature, °F	1729.0	1748.1	1708.5	1666.5	1716.0
Time, sec	28.2	32.7	34.6	34.5	36.4
Local oxidation, %	1.63	1.71	1.59	1.60	1.66
Rupture time, sec	20.7	21.1	21.9	22.9	24.2
Whole core hydrogen generation, %	<0.04	<0.04	<0.04	<0.04	<0.05

Table 15-63. Results of LBLOCA Analyses for Full Core Mark-B-HTP; Gadolinia Fuel Pins

BOL Conditions, 2 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	16.9	16.7	16.4	16.4	16.4
Unruptured node:					
Peak cladding temperature, °F	1795.5	1770.6	1746.8	1761.8	1805.6
Time, sec	28.3	36.3	35.7	65.6	79.0
Local oxidation, %	0.88	0.99	0.97	1.24	1.49
Rupture node:					
Peak cladding temperature, °F	1823.3	1774.4	1737.7	1709.1	1724.1
Time, sec	28.3	28.2	28.2	28.1	34.6
Local oxidation, %	1.32	1.26	1.20	1.22	1.31
Rupture time, sec	23.1	24.5	25.5	26.5	26.3
Pin initial pressure, psia	673.5	669.9	665.3	663.6	661.9
MOL Conditions, 2 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	16.2	16.0	15.7	15.7	15.7
Unruptured node:					
Peak cladding temperature, °F	1857.9	1825.8	1812.0	1810.1	1794.8
Time, sec	28.3	33.2	35.2	34.9	36.8
Local oxidation, %	1.45	1.52	1.62	1.62	1.53
Rupture node:					
Peak cladding temperature, °F	1859.3	1771.6	1704.6	1744.5	1773.5
Time, sec	28.3	28.3	28.1	34.8	34.6
Local oxidation, %	1.77	1.61	1.39	1.53	1.64
Rupture time, sec	20.3	21.9	23.0	23.0	24.2
Pin initial pressure, psia	1329.1	1309.8	1281.5	1280.2	1277.3
EOL Conditions, 2 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	12.6	12.6	12.5	12.5	12.5
Unruptured node:					
Peak cladding temperature, °F	1767.3	1754.8	1707.7	1729.0	1710.6
Time, sec	33.0	35.1	34.8	36.8	36.4
Local oxidation, %	1.33	1.35	1.34	1.38	1.27
Rupture node:					
Peak cladding temperature, °F	1732.0	1723.0	1717.3	1644.3	1732.4
Time, sec	28.2	32.7	34.8	34.5	36.4
Local oxidation, %	1.58	1.58	1.62	1.48	1.64
Rupture time, sec	20.9	22.0	23.1	23.6	24.7
Pin initial pressure, psia	1969.3	1947.5	1921.3	1924.6	1941.4

BOL Conditions, 4 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	16.2	16.0	15.7	15.7	15.7
Unruptured node:					
Peak cladding temperature, °F	1796.4	1769.7	1748.3	1761.7	1792.9
Time, sec	28.3	36.3	35.7	35.2	79.0
Local oxidation, %	0.86	0.97	0.94	0.83	1.43
Rupture node:					
Peak cladding temperature, °F	1832.8	1778.0	1742.0	1715.7	1727.9
Time, sec	28.3	28.2	28.2	28.1	34.6
Local oxidation, %	1.35	1.26	1.20	1.24	1.32
Rupture time, sec	22.9	24.5	25.4	26.3	26.2
Pin initial pressure, psia	673.3	669.7	665.2	663.7	661.9
MOL Conditions, 4 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	15.3	15.1	14.8	14.8	14.8
Unruptured node:					
Peak cladding temperature, °F	1827.1	1827.8	1784.4	1811.9	1799.0
Time, sec	33.6	33.2	35.2	34.9	36.8
Local oxidation, %	1.39	1.49	1.55	1.59	1.50
Rupture node:					
Peak cladding temperature, °F	1883.6	1777.2	1757.6	1736.1	1787.5
Time, sec	28.3	28.3	35.2	34.8	34.6
Local oxidation, %	1.85	1.62	1.79	1.49	1.66
Rupture time, sec	20.1	21.8	22.9	23.2	23.9
Pin initial pressure, psia	1380.9	1359.8	1334.4	1336.0	1339.2
EOL Conditions, 4 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	11.9	11.9	11.8	11.8	11.8
Unruptured node:					
Peak cladding temperature, °F	1793.3	1778.1	1723.9	1727.3	1720.0
Time, sec	33.0	35.1	34.8	36.8	36.3
Local oxidation, %	1.37	1.38	1.35	1.36	1.28
Rupture node:					
Peak cladding temperature, °F	1753.9	1751.5	1753.9	1673.9	1748.7
Time, sec	28.2	32.7	34.8	34.5	36.4
Local oxidation, %	1.65	1.67	1.73	1.57	1.68
Rupture time, sec	20.8	21.4	22.4	22.8	24.5
Pin initial pressure, psia	2138.2	2109.3	2086.5	2093.2	2119.1

BOL Conditions, 6 w/o Gadolinia Concentration	Core Elevation, ft				
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	15.6	15.4	15.2	15.2	15.2
Unruptured node:					
Peak cladding temperature, °F	1790.1	1768.8	1747.3	1762.8	1783.5
Time, sec	28.3	36.3	35.7	35.2	79.0
Local oxidation, %	0.83	0.95	0.92	0.81	1.39
Rupture node:					
Peak cladding temperature, °F	1838.2	1782.8	1744.3	1717.8	1731.9
Time, sec	28.3	28.2	28.2	28.1	34.6
Local oxidation, %	1.37	1.27	1.20	1.24	1.33
Rupture time, sec	22.9	24.4	25.3	26.2	26.1
Pin initial pressure, psia	673.1	669.7	665.2	663.7	661.9
MOL Conditions, 6 w/o Gadolinia Concentration	**Core Elevation, ft**				
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	14.9	14.7	14.5	14.5	14.5
Unruptured node:					
Peak cladding temperature, °F	1857.4	1840.3	1823.7	1827.3	1837.9
Time, sec	28.3	33.2	35.2	34.9	34.6
Local oxidation, %	1.41	1.51	1.59	1.60	1.46
Rupture node:					
Peak cladding temperature, °F	1922.9	1805.5	1719.5	1751.9	1772.2
Time, sec	28.3	28.3	28.1	34.8	34.5
Local oxidation, %	2.03	1.71	1.43	1.54	1.73
Rupture time, sec	19.8	21.6	22.8	23.1	23.8
Pin initial pressure, psia	1366.1	1346.8	1321.1	1322.7	1322.0
EOL Conditions, 6 w/o Gadolinia Concentration	**Core Elevation, ft**				
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	11.6	11.6	11.5	11.5	11.5
Unruptured node:					
Peak cladding temperature, °F	1797.6	1780.8	1730.7	1731.6	1727.6
Time, sec	33.0	35.1	34.8	36.8	36.3
Local oxidation, %	1.40	1.41	1.38	1.39	1.31
Rupture node:					
Peak cladding temperature, °F	1757.7	1745.8	1689.3	1669.9	1761.7
Time, sec	28.2	32.7	34.6	34.5	36.4
Local oxidation, %	1.68	1.67	1.52	1.58	1.73
Rupture time, sec	20.8	21.6	22.6	23.0	24.6
Pin initial pressure, psia	2036.0	2021.9	2000.8	2000.6	2005.7

BOL Conditions, 8 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	15.1	14.9	14.7	14.7	14.7
Unruptured node:					
Peak cladding temperature, °F	1760.9	1767.4	1745.3	1763.1	1776.8
Time, sec	34.1	36.3	35.7	35.2	49.7
Local oxidation, %	0.79	0.93	0.89	0.80	1.35
Rupture node:					
Peak cladding temperature, °F	1843.5	1786.0	1745.3	1718.7	1735.1
Time, sec	28.3	28.2	28.2	28.1	34.6
Local oxidation, %	1.38	1.27	1.19	1.23	1.34
Rupture time, sec	22.7	24.4	25.3	26.3	26.0
Pin initial pressure, psia	672.9	669.6	665.3	663.9	662.2
MOL Conditions, 8 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	14.6	14.4	14.1	14.1	14.1
Unruptured node:					
Peak cladding temperature, °F	1837.4	1821.8	1806.4	1815.8	1805.2
Time, sec	28.3	33.2	35.2	34.9	36.8
Local oxidation, %	1.36	1.45	1.53	1.56	1.49
Rupture node:					
Peak cladding temperature, °F	1908.7	1792.0	1710.5	1743.3	1797.3
Time, sec	28.3	28.3	28.1	34.8	34.6
Local oxidation, %	1.95	1.65	1.39	1.51	1.69
Rupture time, sec	20.2	21.9	23.0	23.2	24.0
Pin initial pressure, psia	1337.9	1318.5	1295.4	1297.8	1299.0
EOL Conditions, 8 w/o Gadolinia Concentration			**Core Elevation, ft**		
	2.506	4.264	6.021	7.779	9.536
Allowable peak linear heat rate, kW/ft	11.4	11.4	11.3	11.3	11.3
Unruptured node:					
Peak cladding temperature, °F	1805.3	1793.7	1733.3	1733.2	1785.3
Time, sec	33.0	35.1	34.8	36.8	36.3
Local oxidation, %	1.39	1.41	1.36	1.38	1.45
Rupture node:					
Peak cladding temperature, °F	1772.2	1756.0	1692.3	1673.3	1710.4
Time, sec	28.2	32.7	34.6	34.5	36.3
Local oxidation, %	1.71	1.68	1.51	1.57	1.51
Rupture time, sec	20.7	21.6	22.6	23.0	24.6
Pin initial pressure, psia	2013.5	2000.7	1980.7	1979.4	1984.2

Table 15-64. Results of 102% FP SBLOCA Analyses for Full Core Mark-B-HTP

Break Size and Description	PCT (°F)	Time of PCT (sec)	Local Oxidation (%)	Whole Core H_2 Generation (%)
0.01 ft^2 CLPD with LOOP	711.9 (1)	0.005	0.08	<0.01
0.04 ft^2 CLPD with LOOP	711.9 (1)	0.005	0.08	<0.01
0.07 ft^2 CLPD with LOOP	711.9 (1)	0.005	0.08	<0.01
0.1 ft^2 CLPD with LOOP	1288.2	959.8	0.16	<0.01
0.125 ft^2 CLPD with LOOP	1515.4	739.0	0.48	<0.02
0.15 ft^2 CLPD with LOOP	1597.5	641.6	0.88	<0.04
0.175 ft^2 CLPD with LOOP	1565.9	557.7	0.70	<0.03
0.2 ft^2 CLPD with LOOP	1474.1	498.9	0.34	<0.02
0.3 ft^2 CLPD with LOOP	1310.3	330.2	0.13	<0.01
0.4 ft^2 CLPD with LOOP	1126.3	214.4	0.08	<0.01
0.5 ft^2 CLPD with LOOP	1103.5	126.9	0.08	<0.01
0.3 ft^2 CLPD with 2 Min RCP Trip	711.9 (1)	0.005	0.08	<0.01
0.4 ft^2 CLPD with 2 Min RCP Trip	1175.9	233.1	0.09	<0.01
0.5 ft^2 CLPD with 2 Min RCP Trip	1255.5	210.0	0.10	<0.01
0.02464 ft^2 HPI with LOOP	711.9 (1)	0.005	0.08	<0.01
0.44 ft^2 CFT with LOOP	711.9 (1)	0.005	0.08	<0.01
0.44 ft^2 CFT with 2 Min RCP Trip	1072.8	215.9	0.08	<0.01

Notes:

1. Indicates initial steady-state cladding temperature.

Table 15-65. Dose Equivalent Iodine (DEI) Calculation

Isotope	Concentration (µCi/gm)	FGR No. 11, Table 2.1 DCFs (Sv/Bq)	DEI (µCi/gm)
I-131	9.55E-01	8.89E-09	9.55E-01
I-132	1.42E-01	1.03E-10	1.64E-03
I-133	2.48E-01	1.58E-09	4.40E-02
I-134	1.32E-02	3.55E-11	5.27E-05
I-135	7.38E-02	3.32E-10	2.76E-03
		DEI	1.00E+00

Table 15-66. Dose Equivalent Xenon (DEX) Calculation

Isotope	Concentration (µCi/gm)	FGR No. 12, Table III.1 DCFs (Sv-s/Bq-m3)	DEX (µCi/gm)
KR-85M	2.15E+00	7.48E-15	1.03E+01
KR-85	1.82E+01	1.19E-16	1.39E+00
KR-87	1.18E+00	4.12E-14	3.11E+01
KR-88	3.69E+00	1.02E-13	2.41E+02
XE-131M	4.39E+00	3.89E-16	1.09E+00
XE-133M	5.76E+00	1.37E-15	5.06E+00
XE-133	3.93E+02	1.56E-15	3.93E+02
XE-135M	4.47E-01	2.04E-14	5.84E+00
XE-135	1.14E+01	1.19E-14	8.67E+01
XE-138	7.19E-01	5.77E-14	2.66E+01
		DEX	8.02E+02

Table 15-67. Deleted Per Rev. 29 Update

Table 15-68. Deleted Per Rev. 29 Update

Appendix 15B. Figures

Figure 15-1. Startup Accident

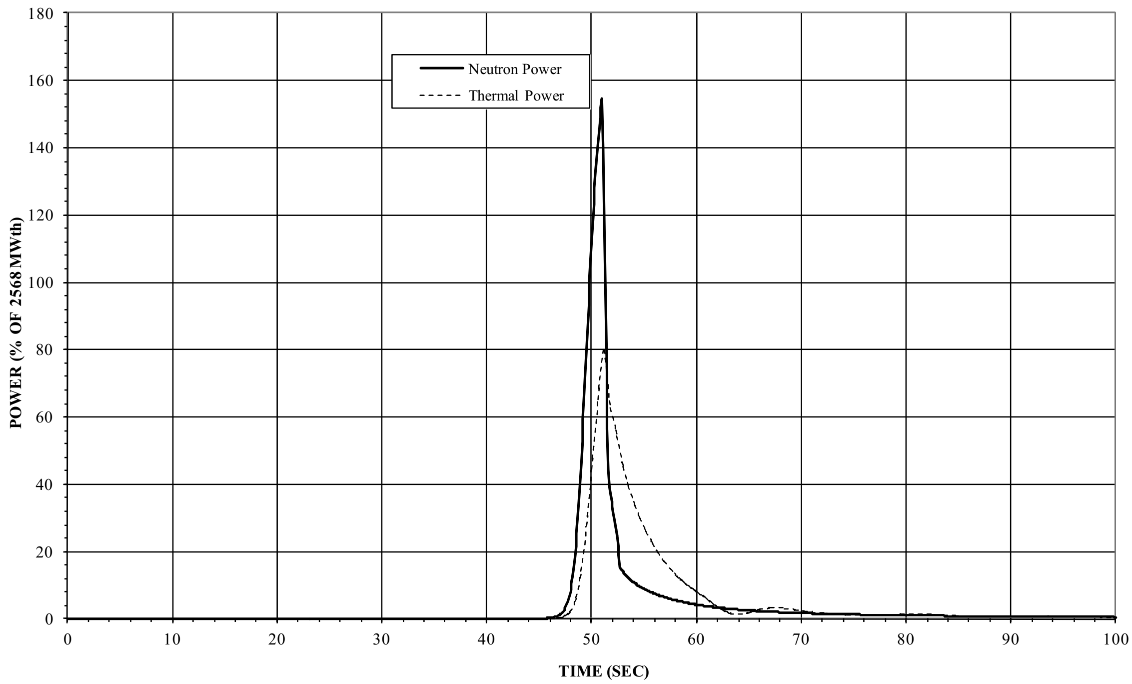

Figure 15-2. Startup Accident

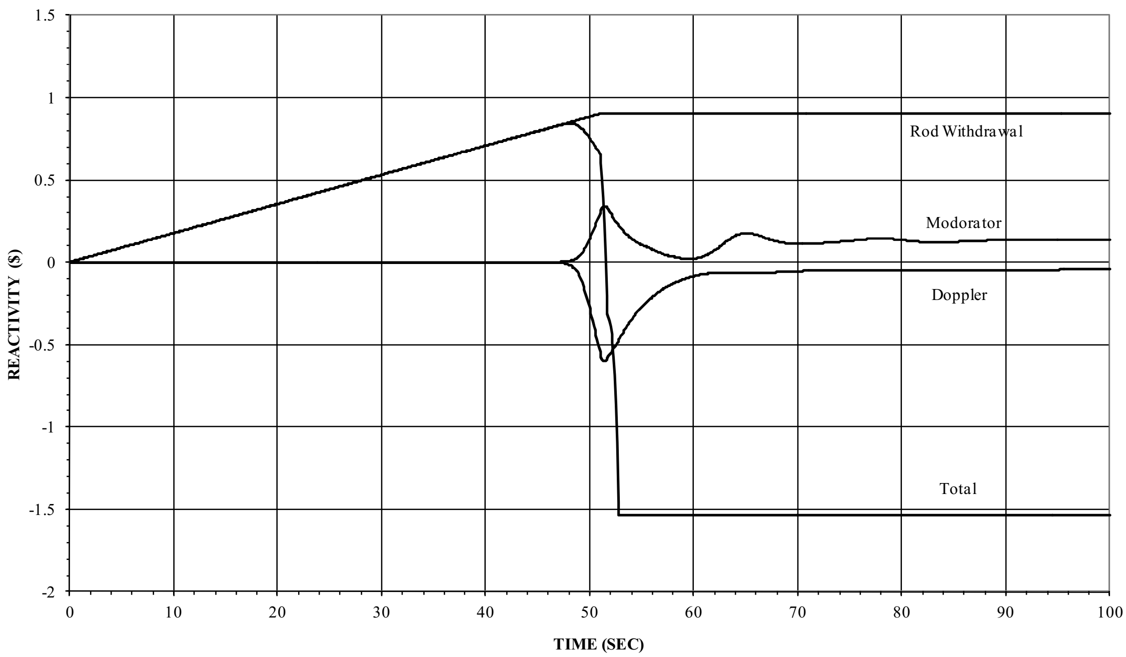

Figure 15-3. Startup Accident

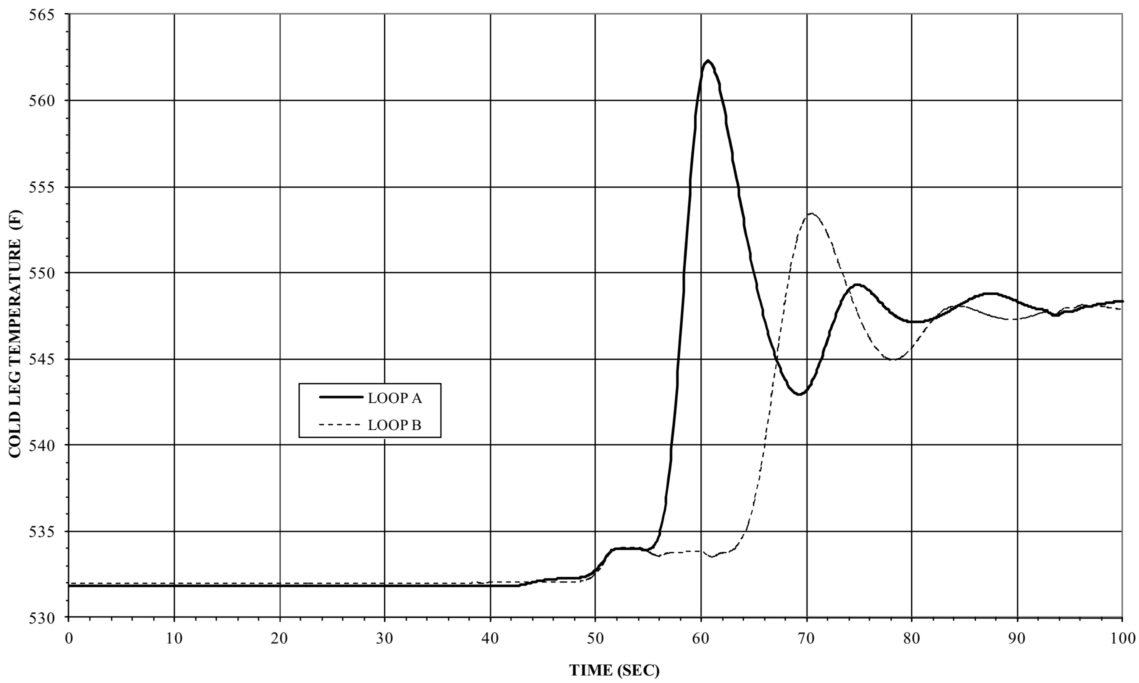

Figure 15-4. Startup Accident

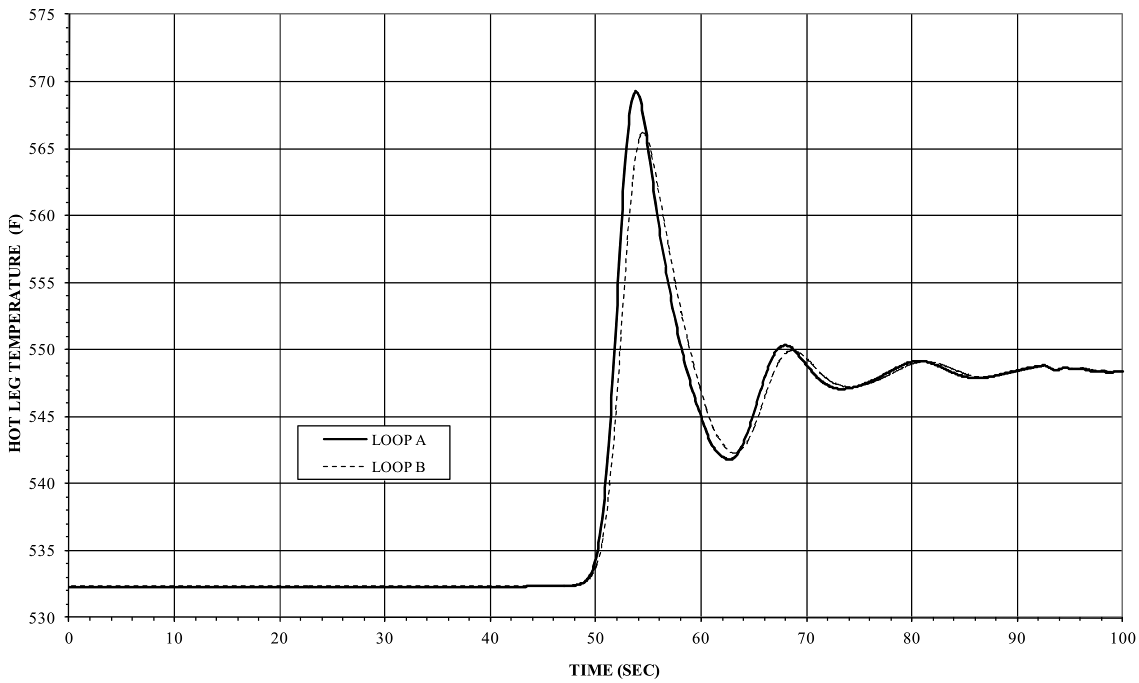

Figure 15-5. Startup Accident

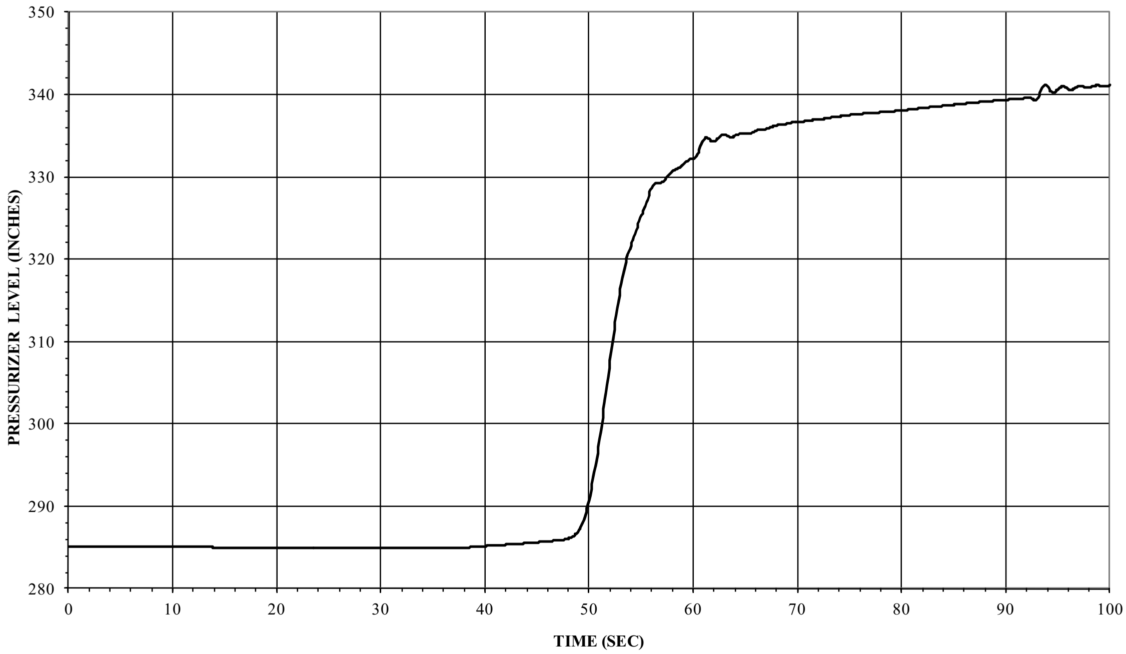

Figure 15-6. Startup Accident

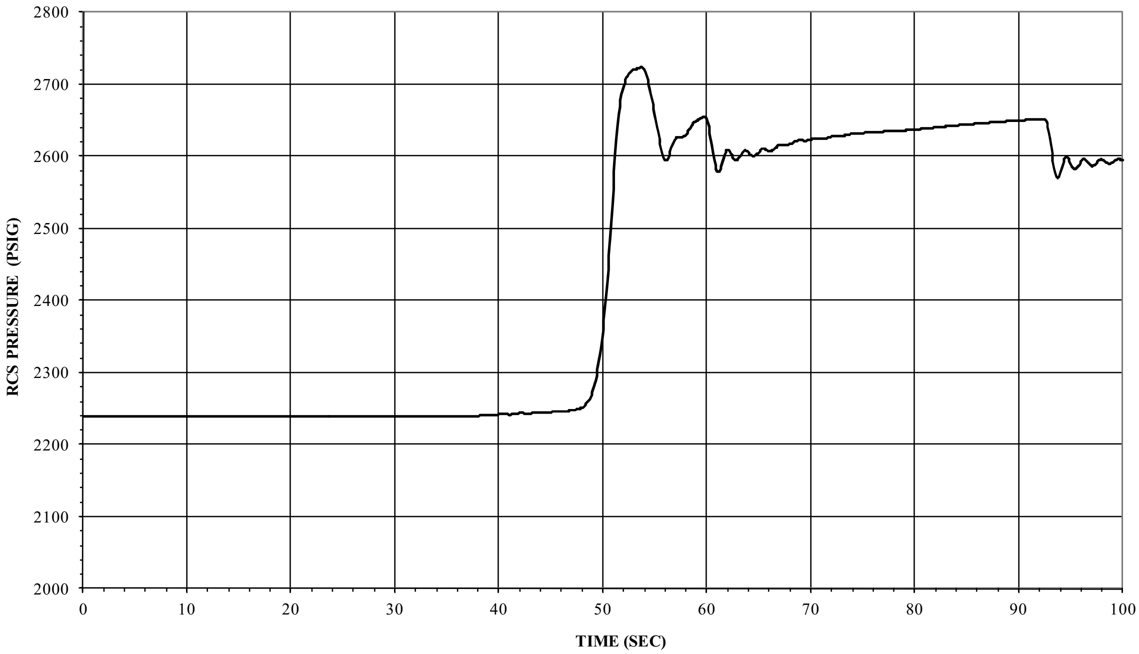

Figure 15-7. Deleted Per 1998 Update

Figure 15-8. Deleted Per 1998 Update

Figure 15-9. Deleted Per 1998 Update

Figure 15-10. Deleted Per 1998 Update

Figure 15-11. Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis Power

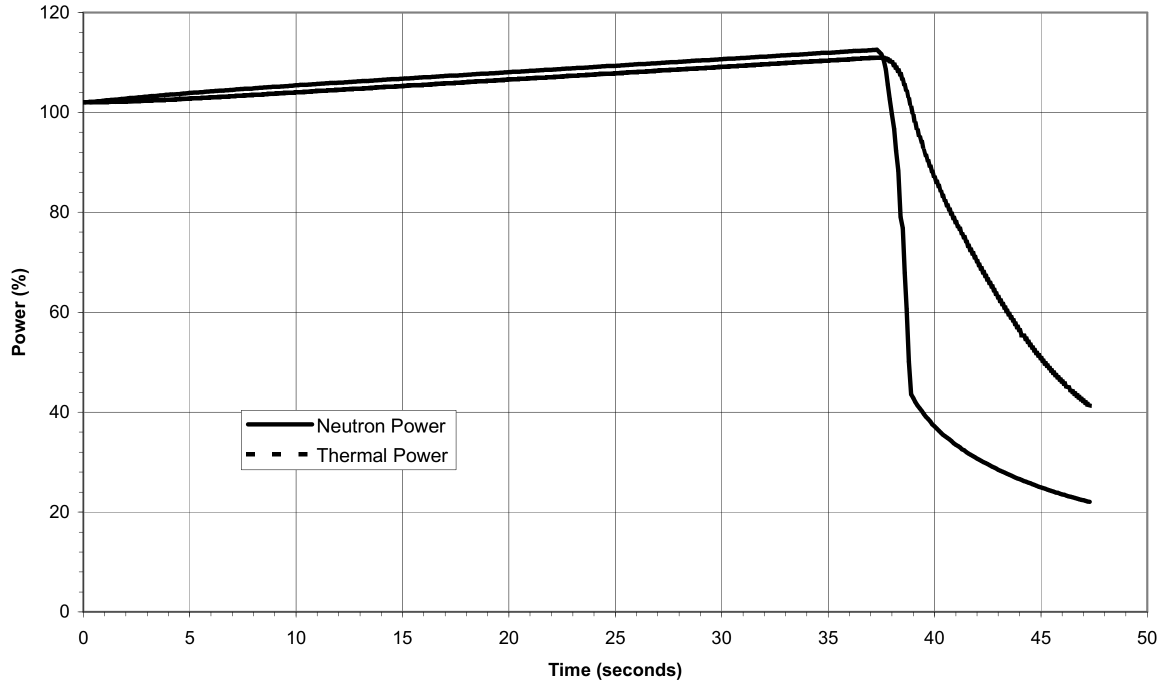

Figure 15-12. Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis RCS Temperatures

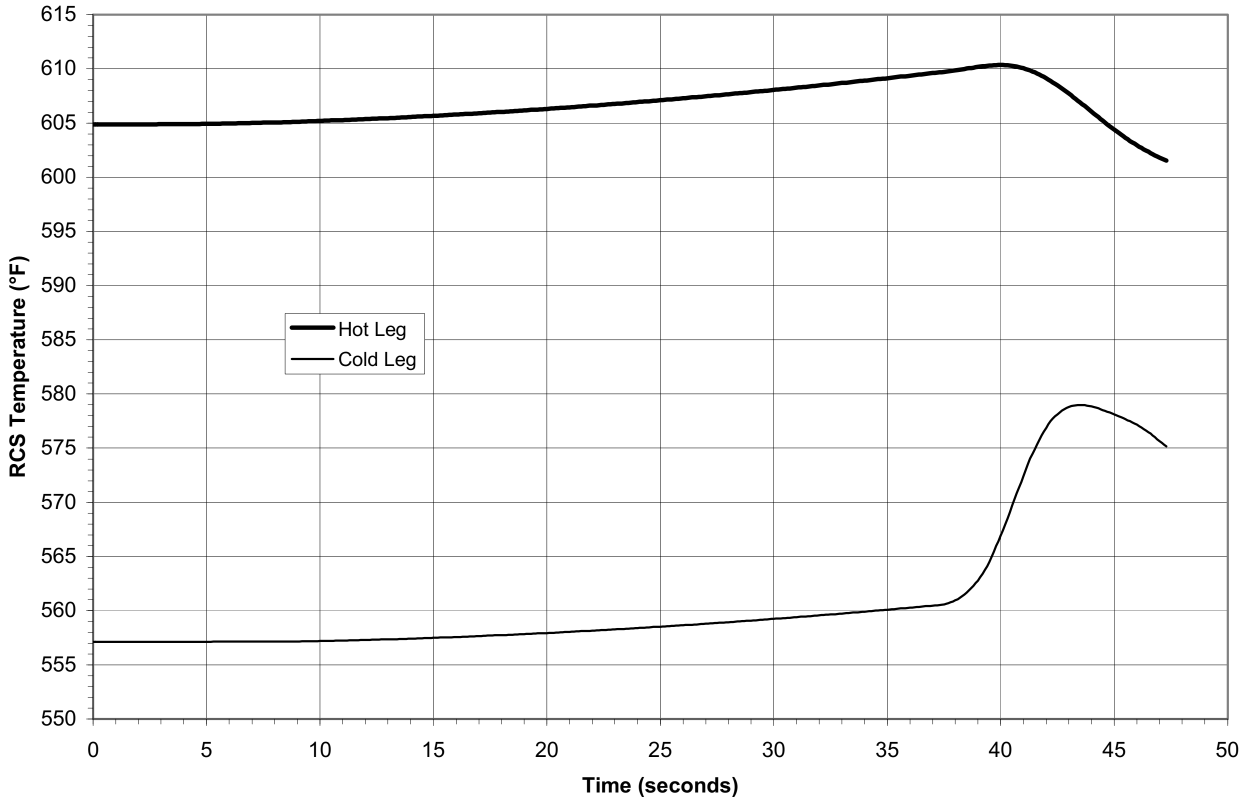

Figure 15-13. Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis Pressurizer Level

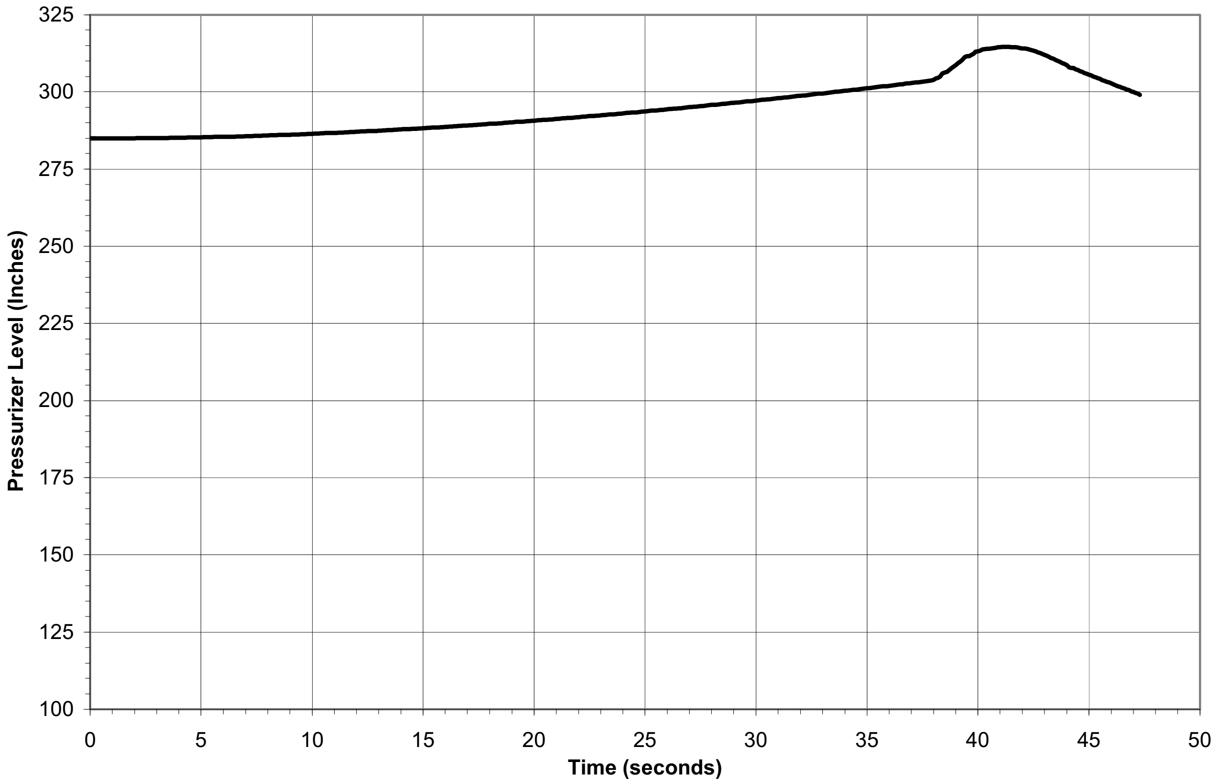

Figure 15-14. Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis RCS Pressure

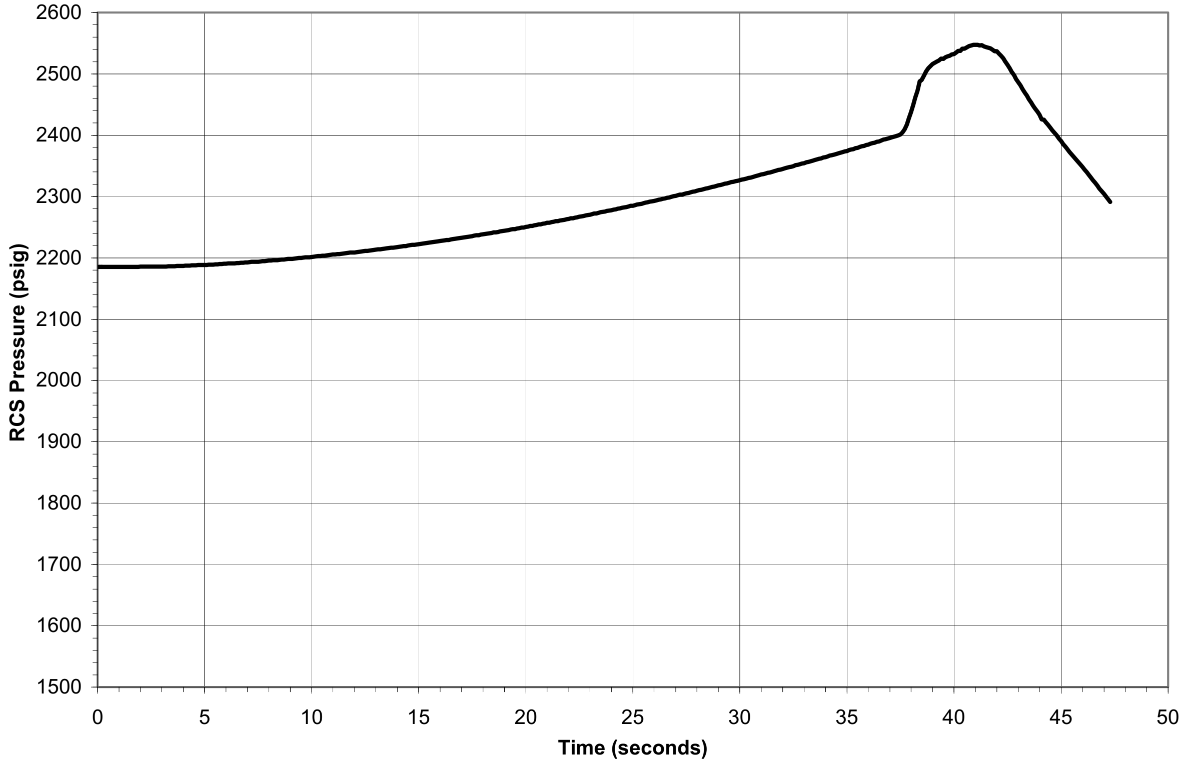

Figure 15-15. Rod Withdrawal at Power Accident - Core Cooling Capability Analysis Power

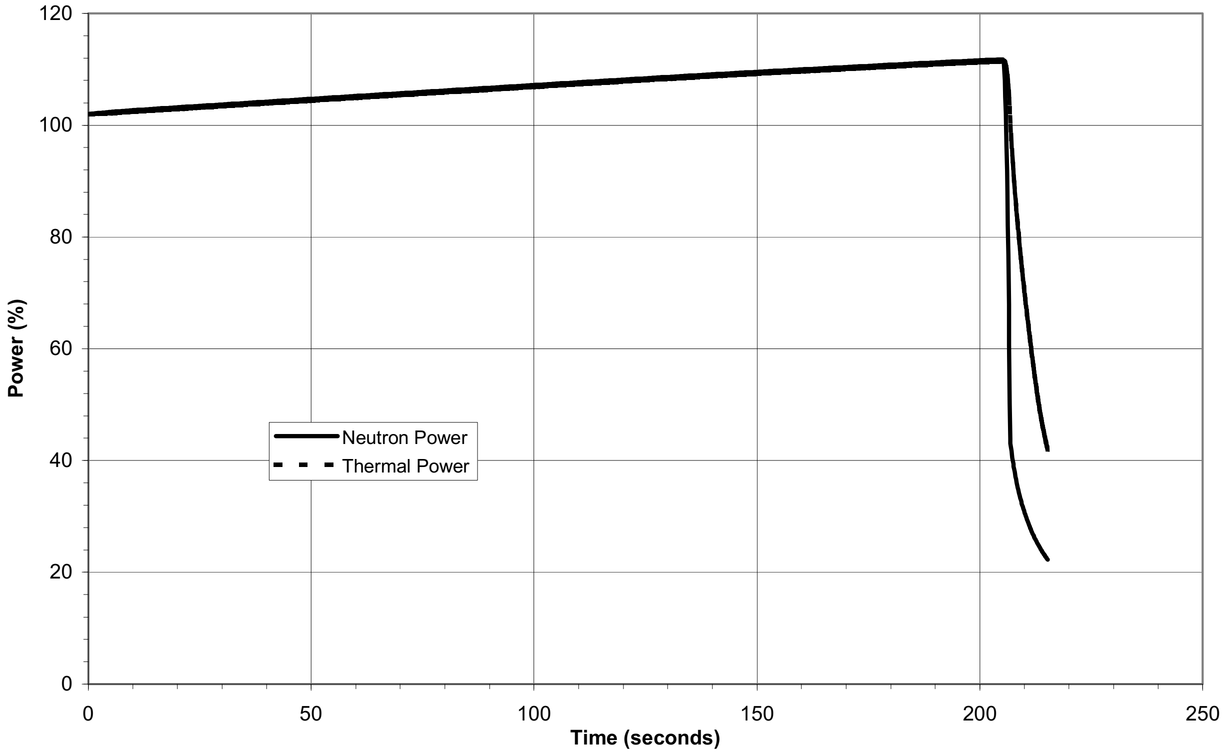

Figure 15-16. Rod Withdrawal at Power Accident - Core Cooling Capability Analysis RCS Temperatures

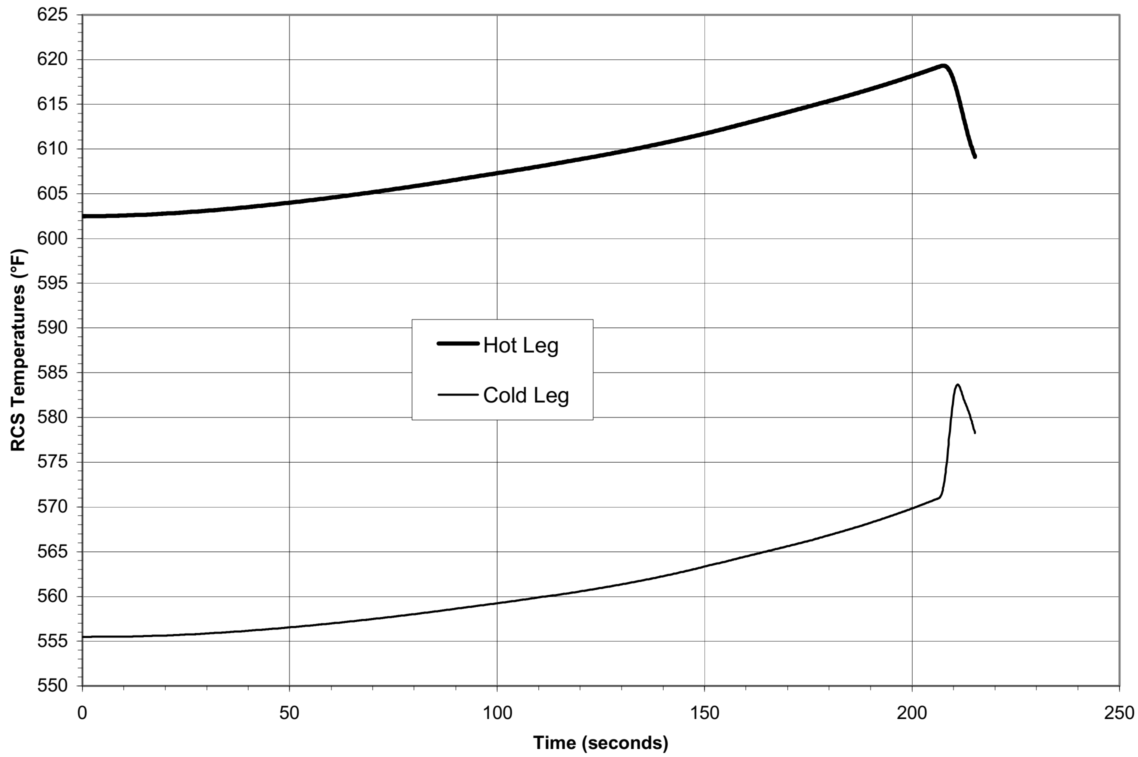

Figure 15-17. Rod Withdrawal at Power Accident - Core Cooling Capability Analysis Pressurizer Level

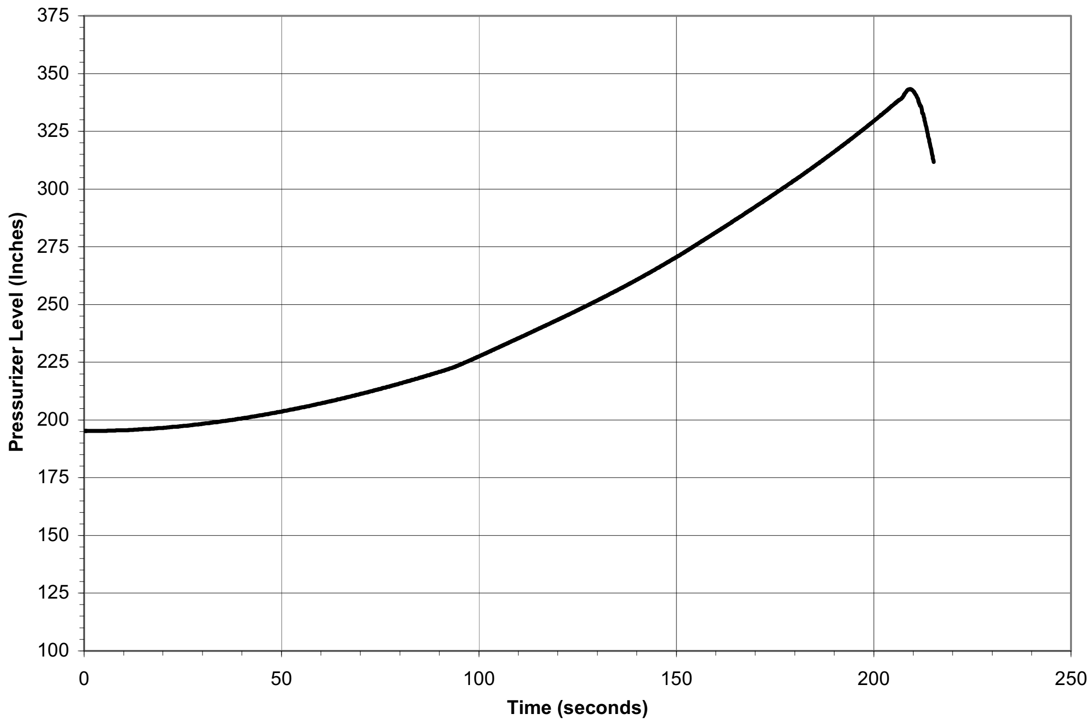

Figure 15-18. Cold Water Accident - RCS Flow

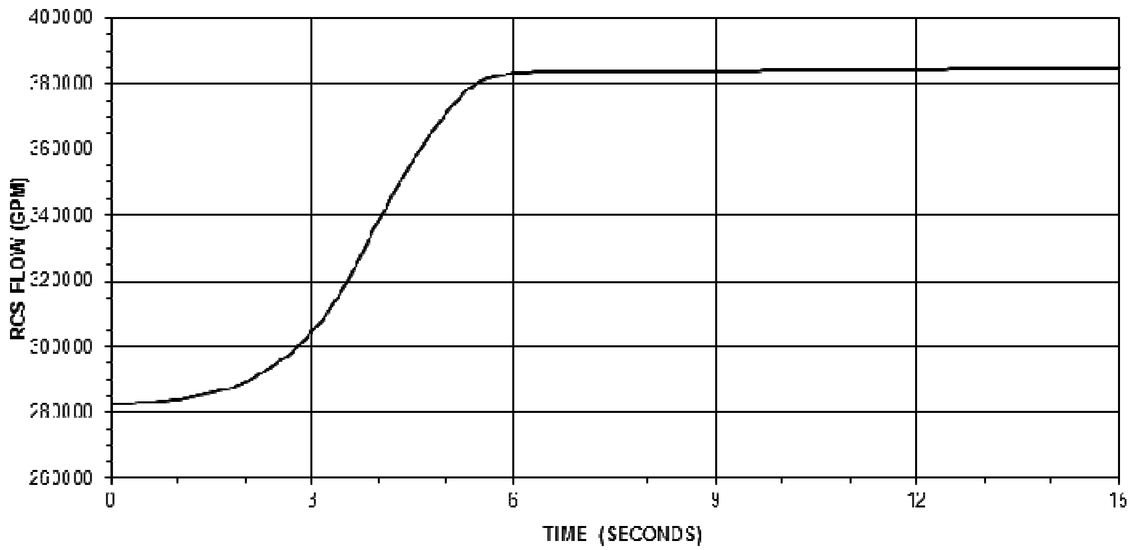

Figure 15-19. Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis - RCS Flow

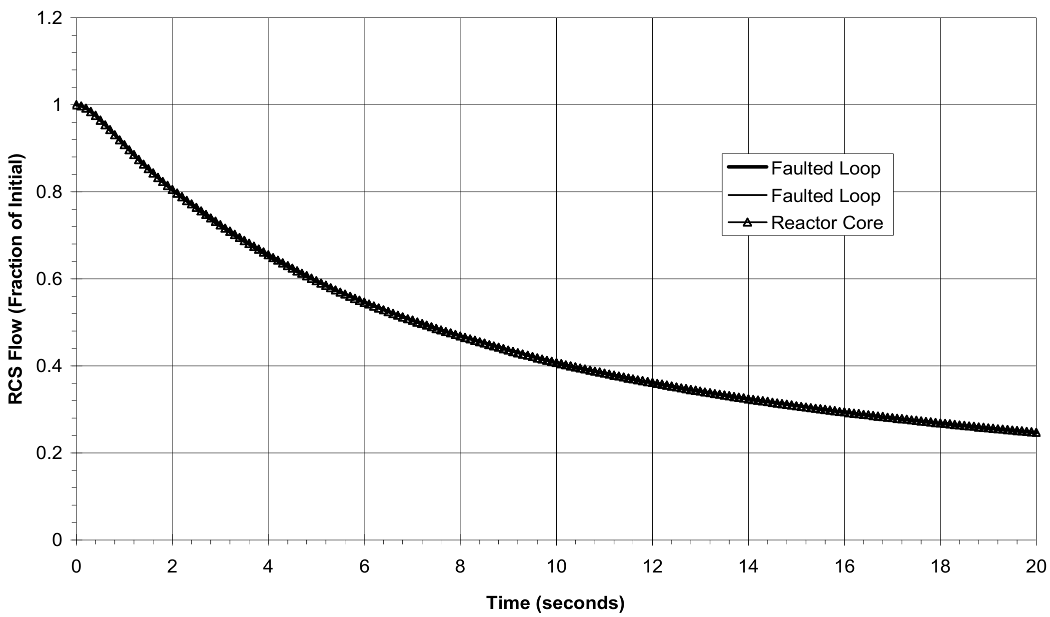

Figure 15-20. Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis - Power

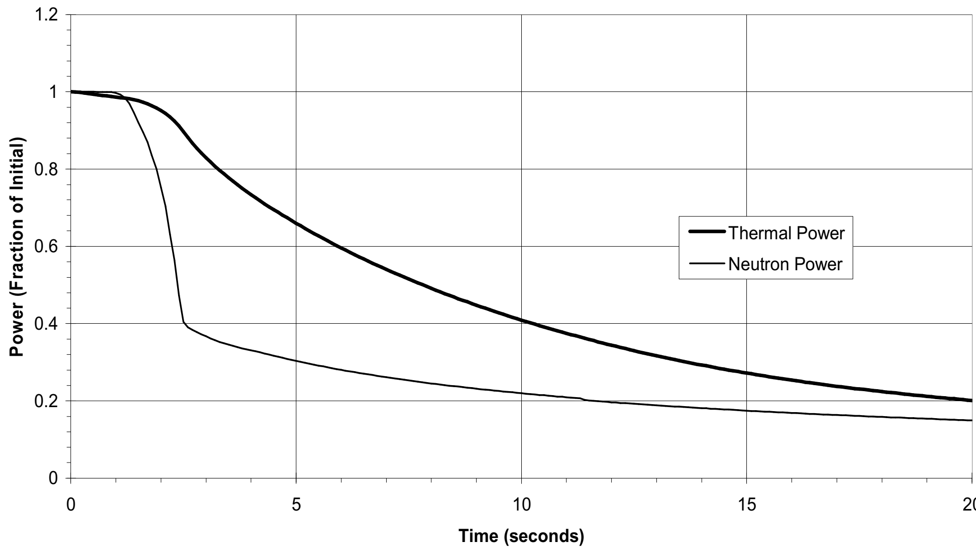

Figure 15-21. Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis - RCS Temperature

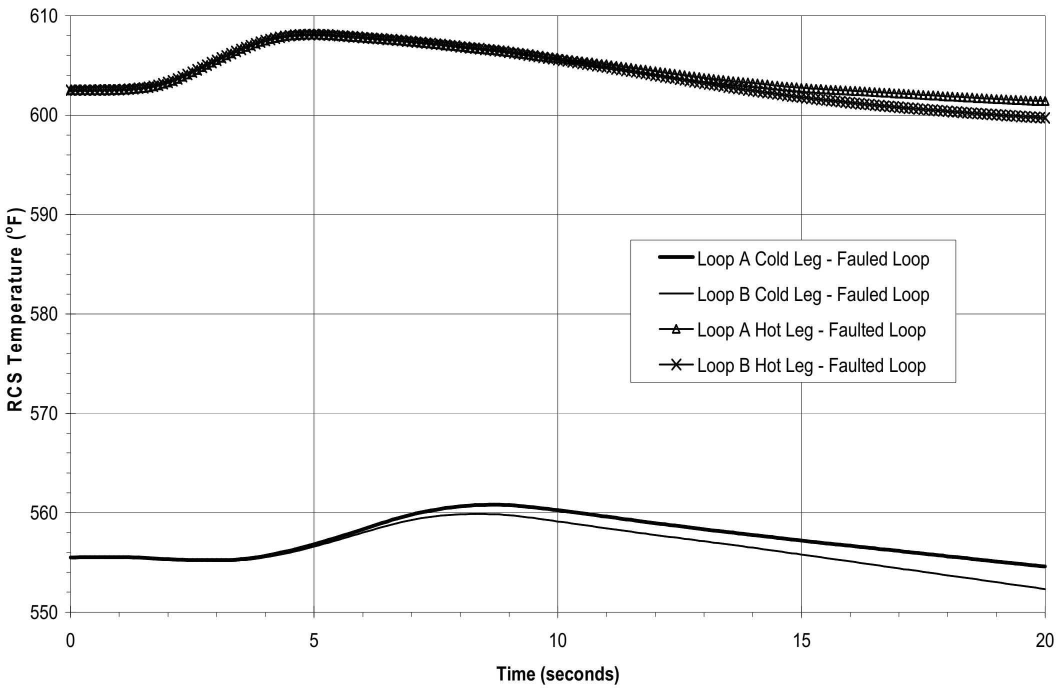

Figure 15-22. Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis - Pressurizer Level

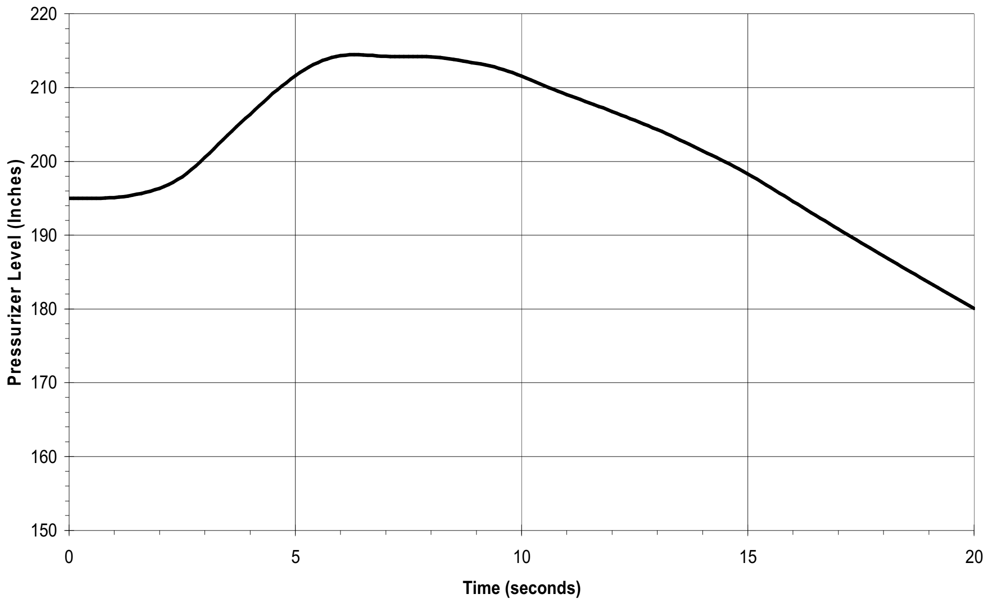

Figure 15-23. Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis - RCS Pressure

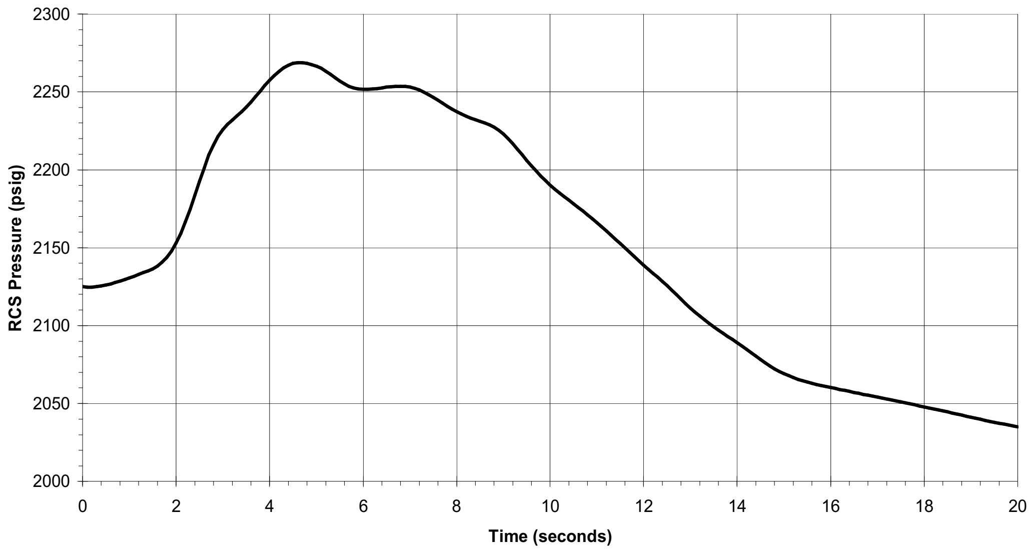

Figure 15-24. Loss of Coolant Flow Accidents - Four RCP Coastdown From Four RCP Initial Conditions Analysis - DNBR

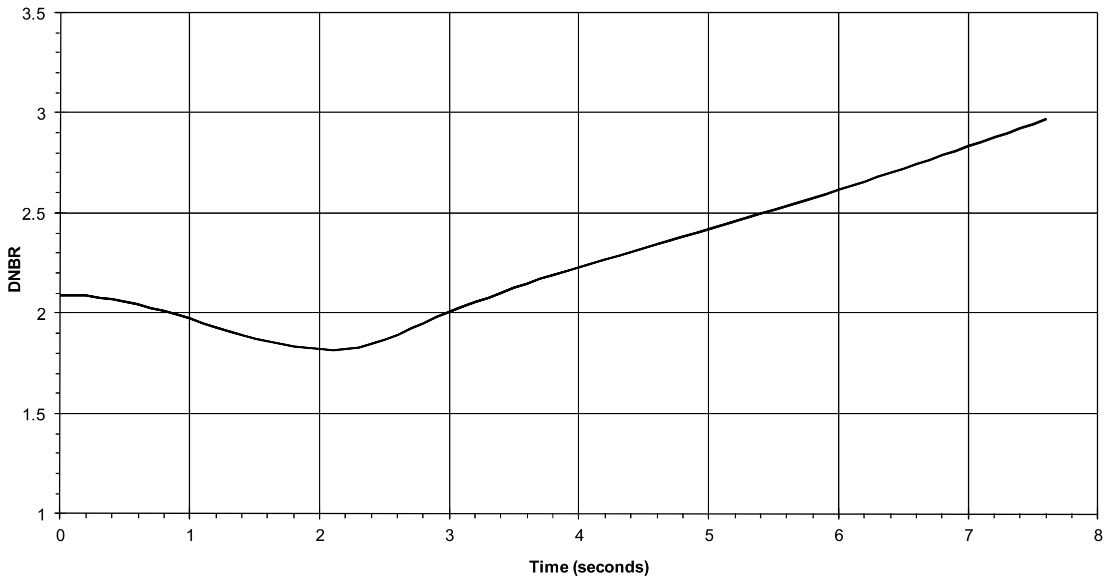

Figure 15-25. Loss of Coolant Flow Accidents - Two RCP Coastdown From Four RC P Initial Conditions Analysis - RCS Flow

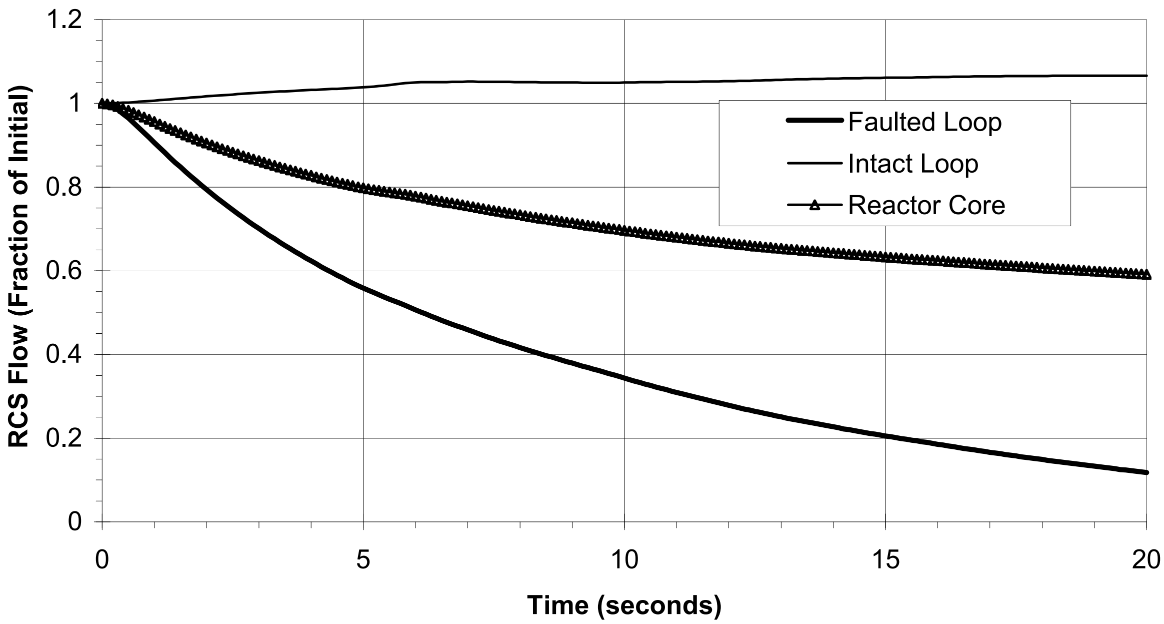

Figure 15-26. Control Rod Misalignment Accidents - Dropped Rod Analysis - Neutron Power

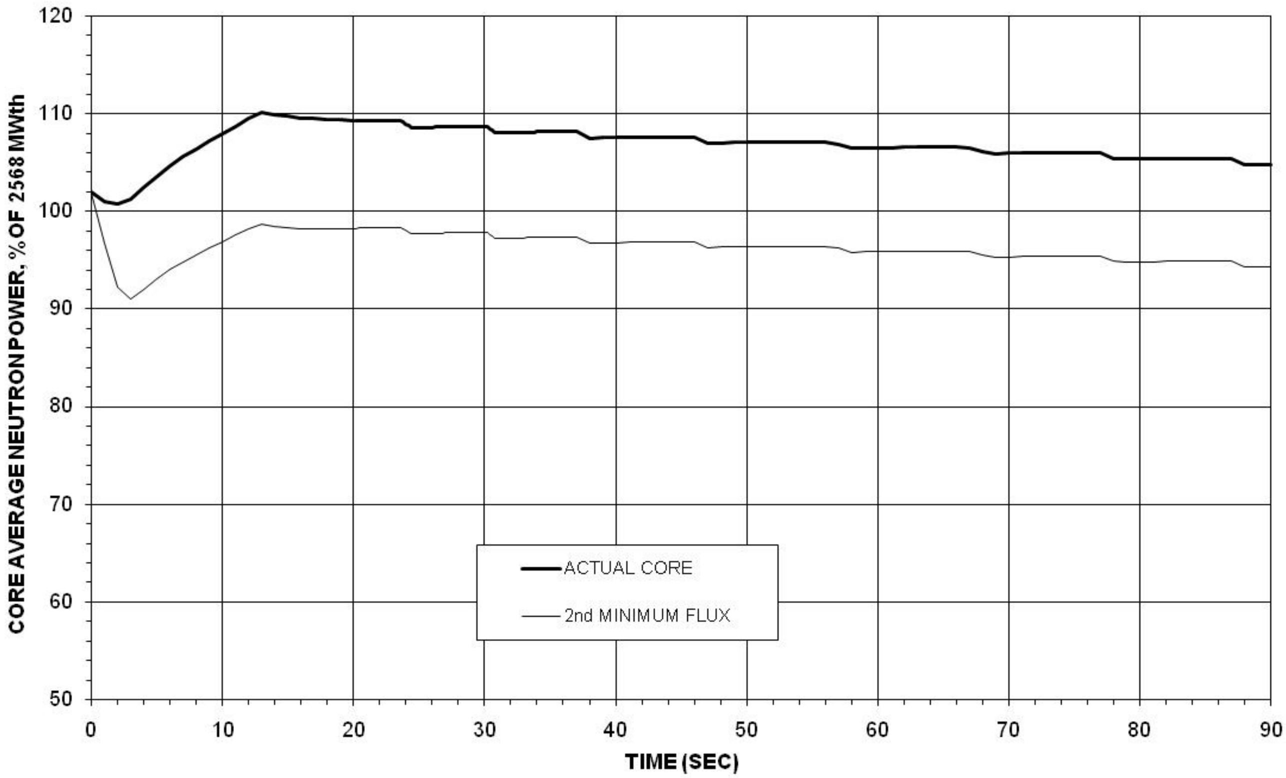

Figure 15-27. Control Rod Misalignment Accidents - Dropped Rod Analysis - RCS Temperatures

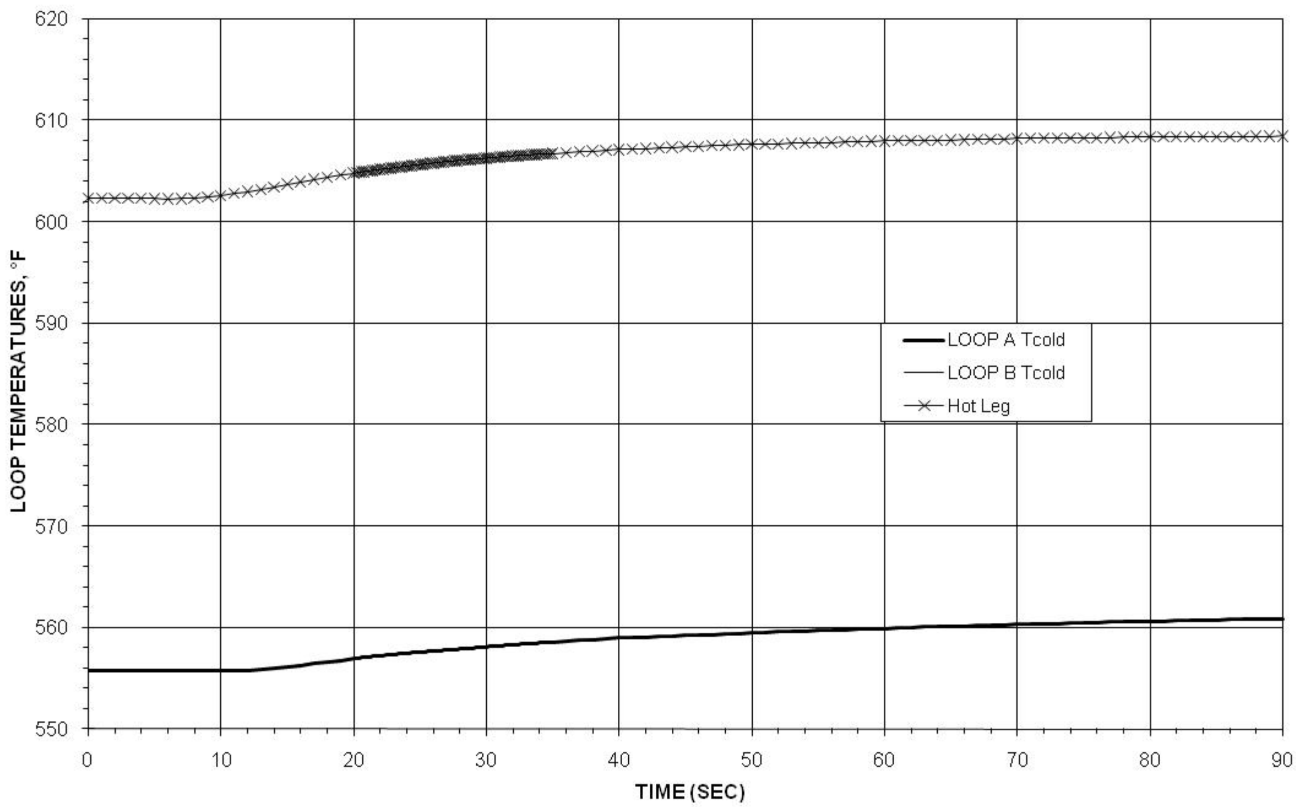

Figure 15-28. Control Rod Misalignment Accidents - Dropped Rod Analysis - Pressurizer Level

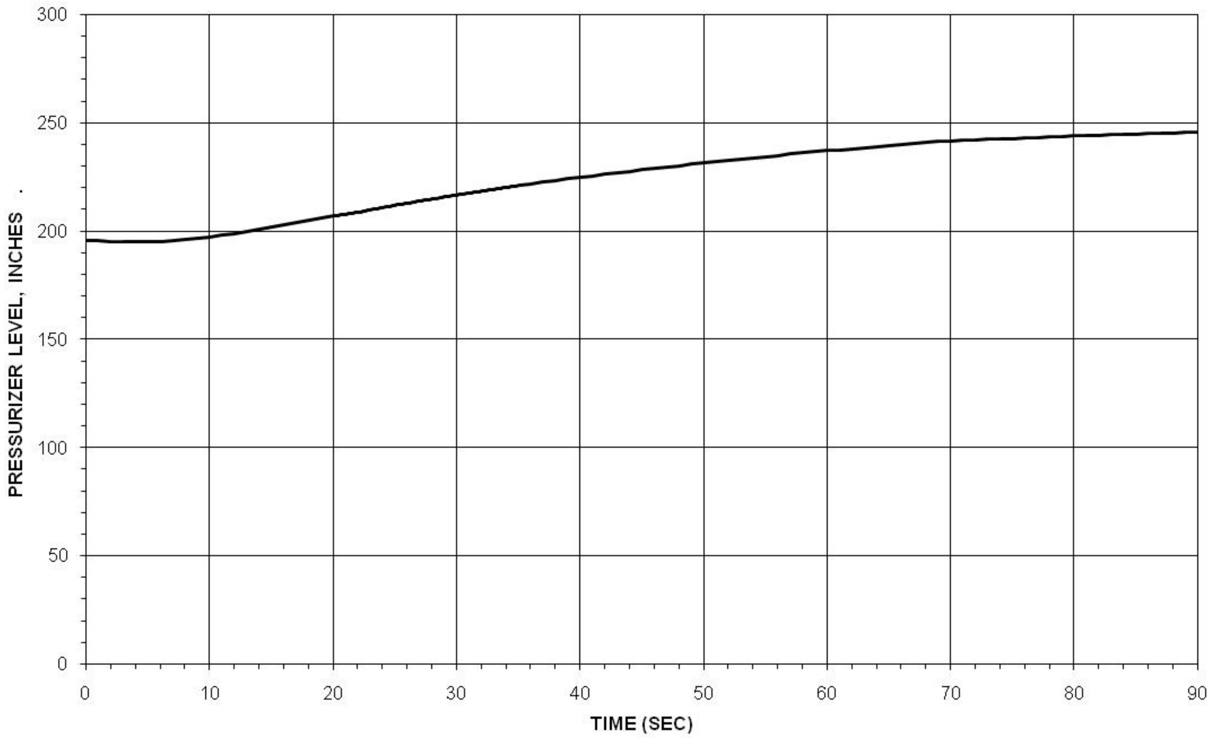

Figure 15-29. Rod Ejection Accident - BOC Four RCPs - Power

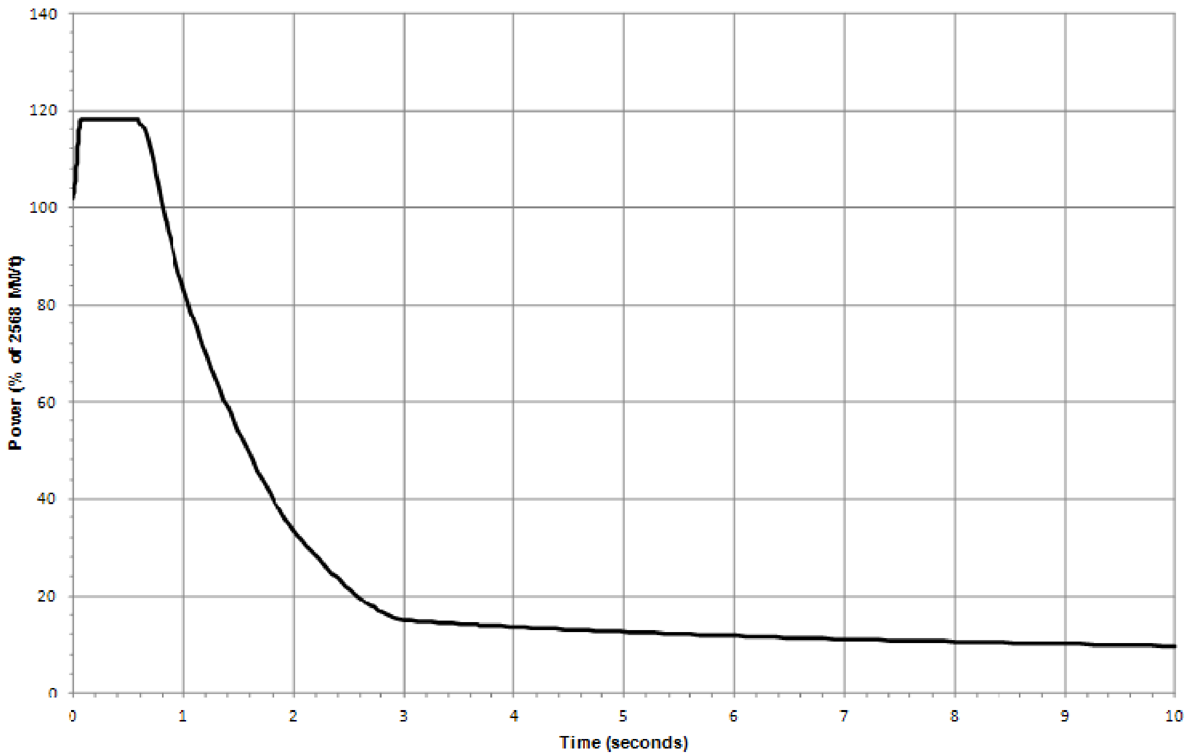

Figure 15-30. Rod Ejection Accident - BOC Three RCPs - Power

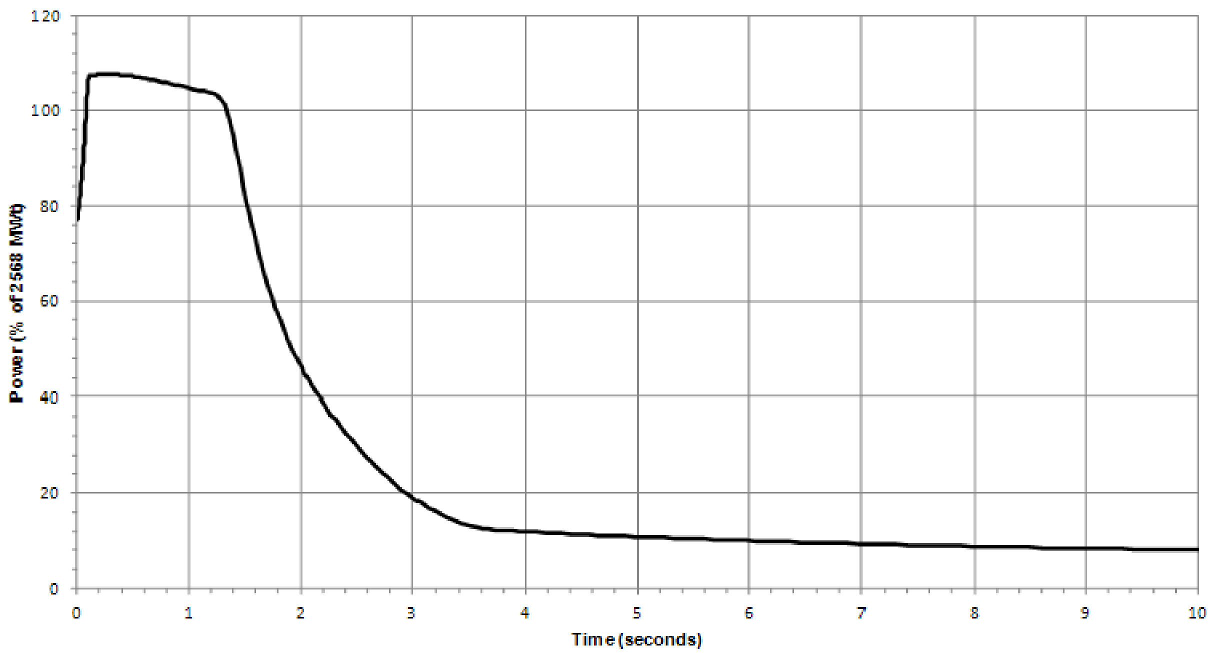

Figure 15-31. Rod Ejection Accident - BOC HZP - Power

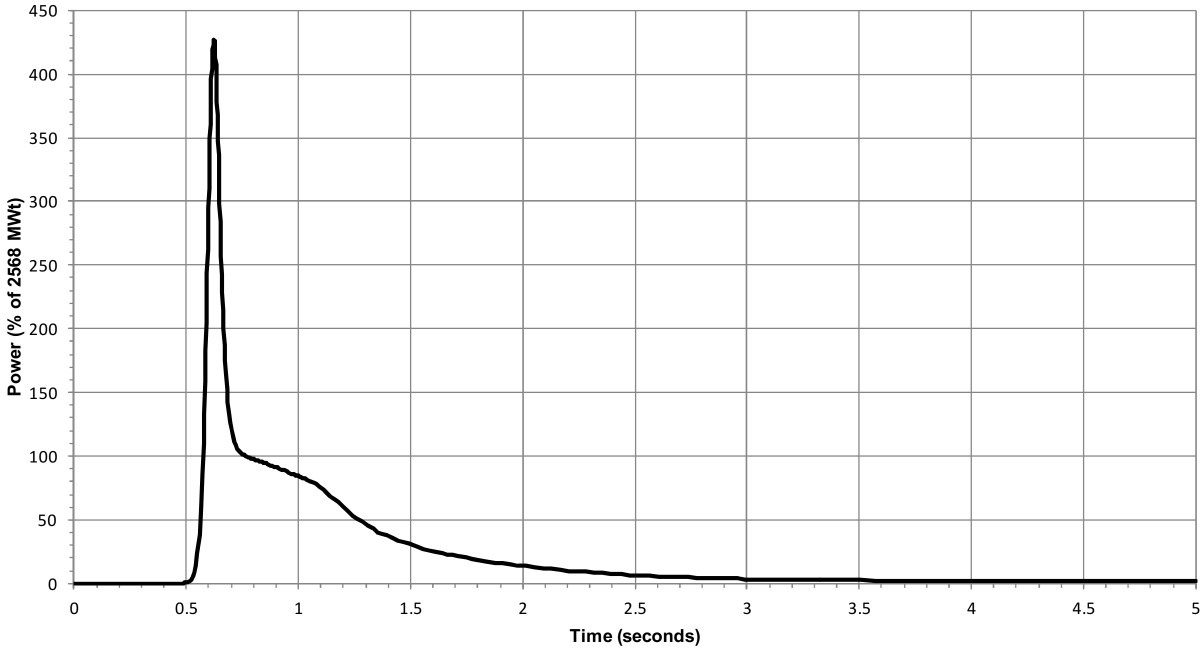

Figure 15-32. Rod Ejection Accident - EOC Four RCPs - Power

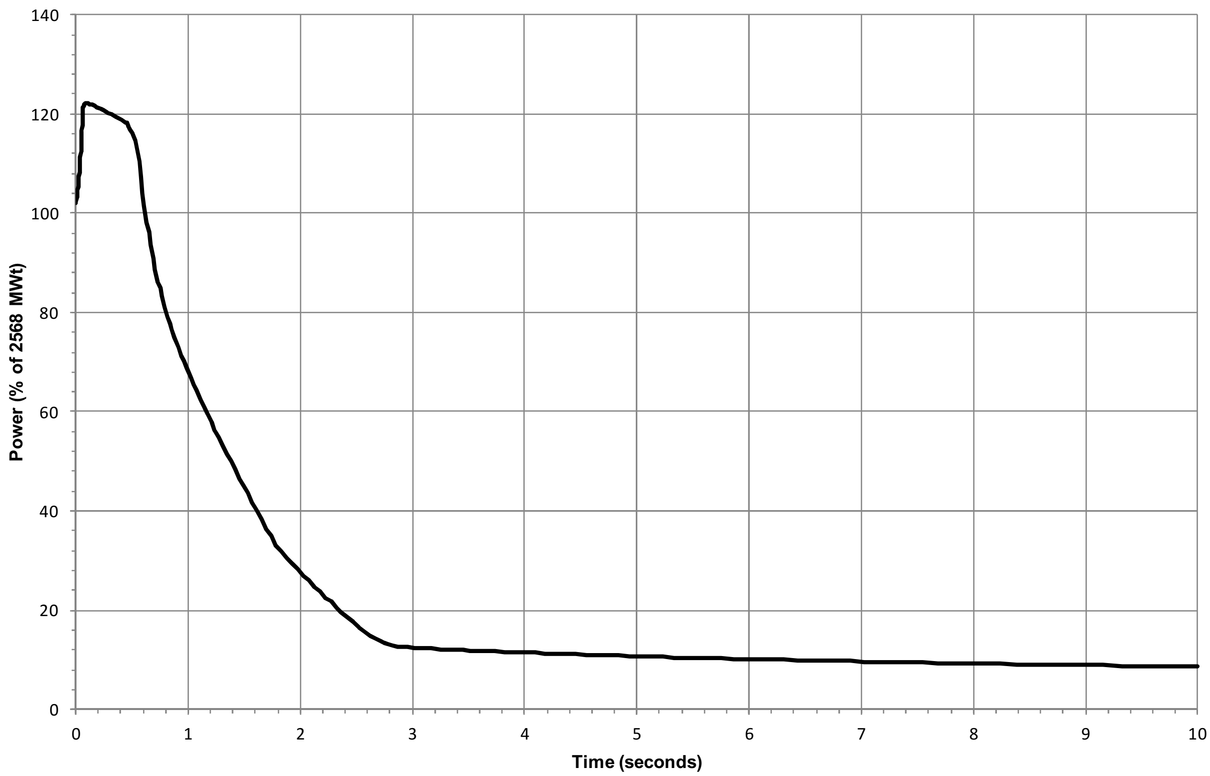

Figure 15-33. Rod Ejection Accident - EOC Three RCPs - Power

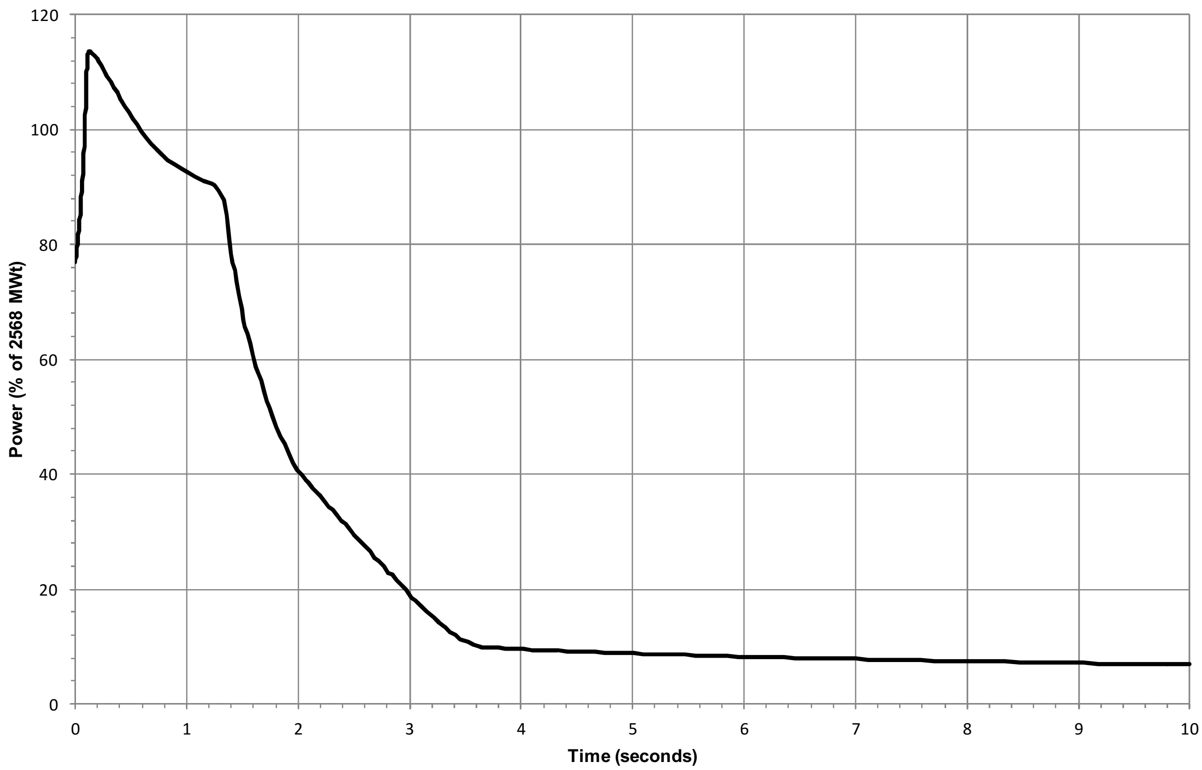

Figure 15-34. Rod Ejection Accident - EOC HZP - Power

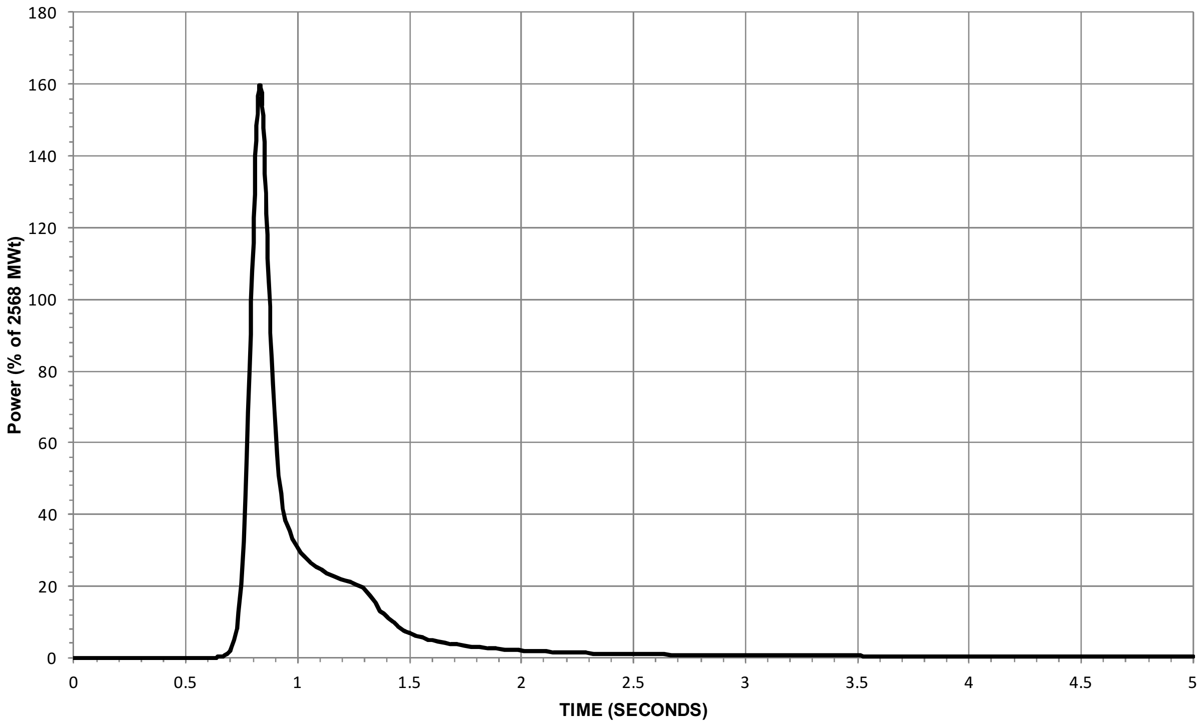

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Figure 15-36. Rod Ejection Accident - BOC Four RCPs - RCS Pressure

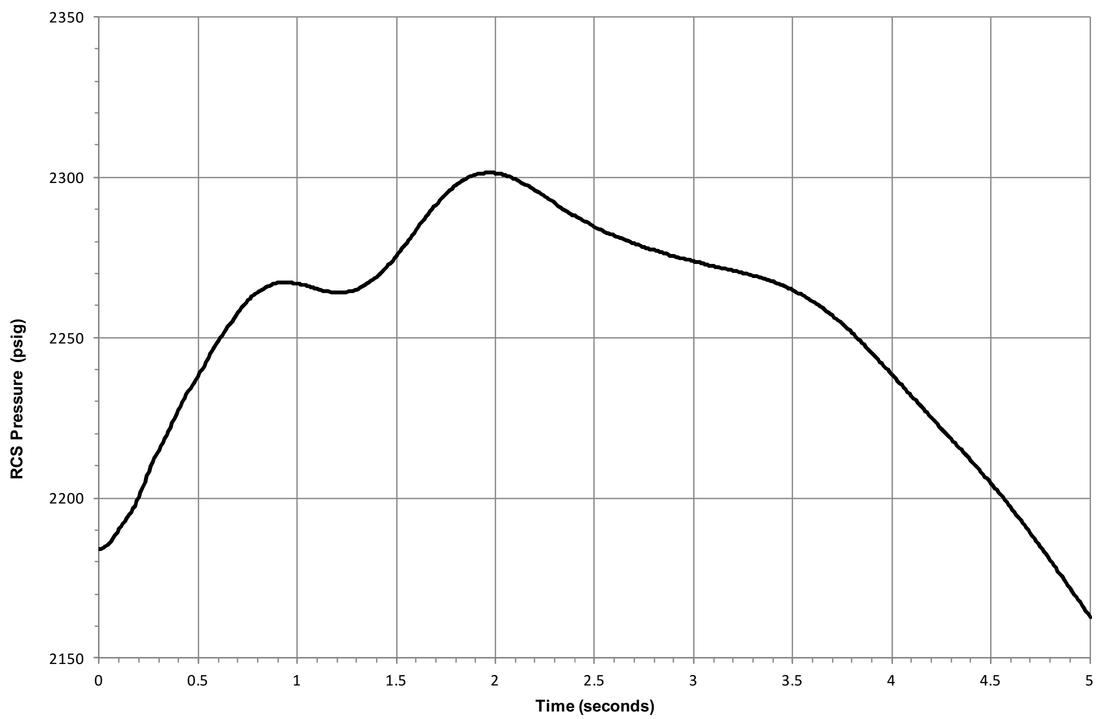

Figure 15-37. Deleted Per 1999 Update

Figure 15-38. Deleted Per 1999 Update

Figure 15-39. Deleted Per 1999 Update

Figure 15-40. Steam Line Break Accident - With Offsite Power - Steam Line Pressure

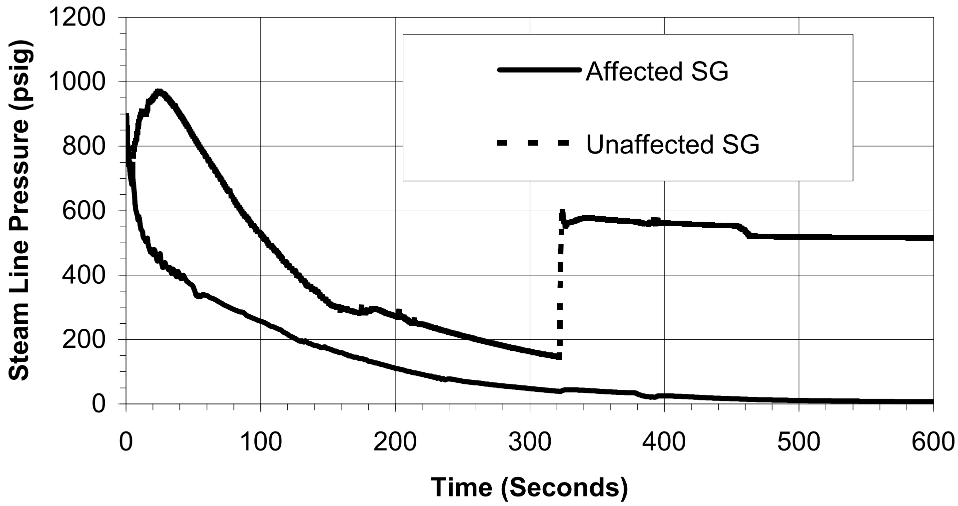

Figure 15-41. Steam Line Break Accident - With Offsite Power - Break Flowrate

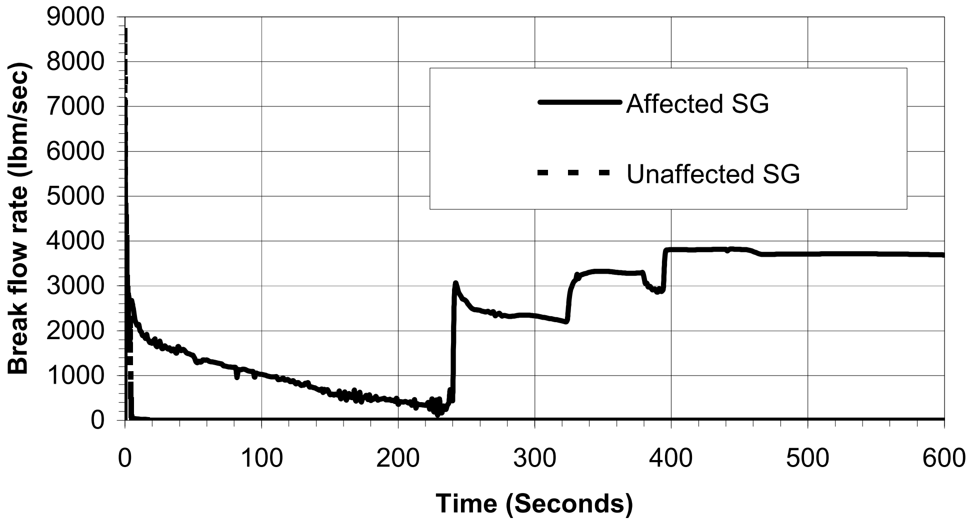

Figure 15-42. Steam Line Break Accident - With Offsite Power - RCS Temperature

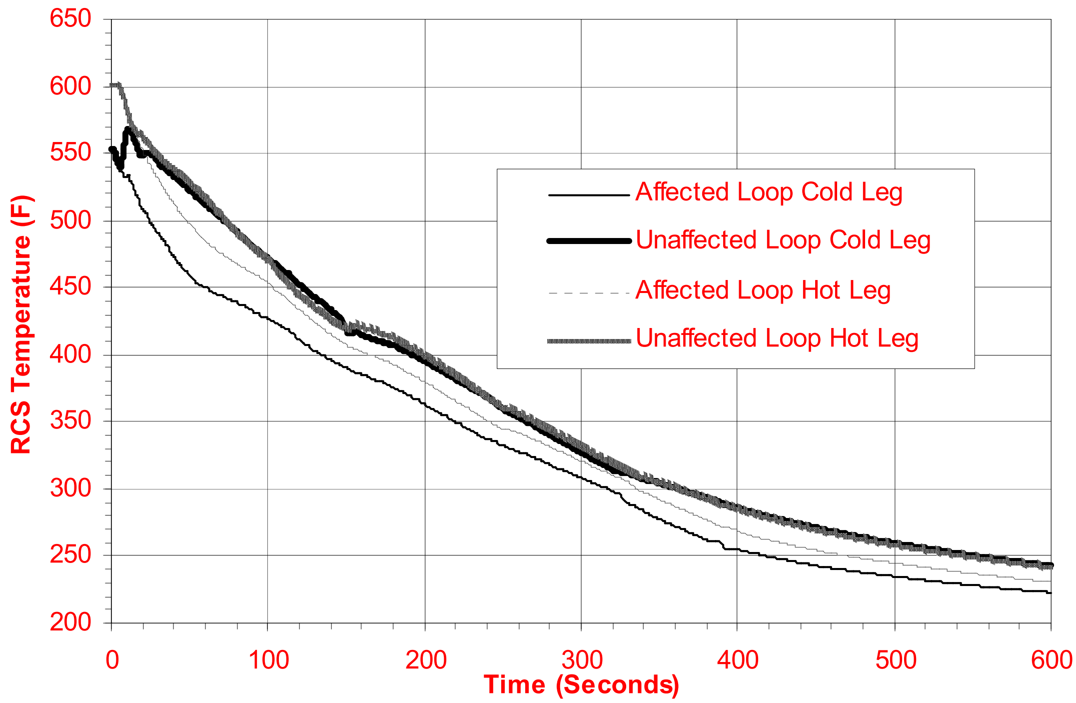

Figure 15-43. Steam Line Break Accident - With Offsite Power - Reactivity

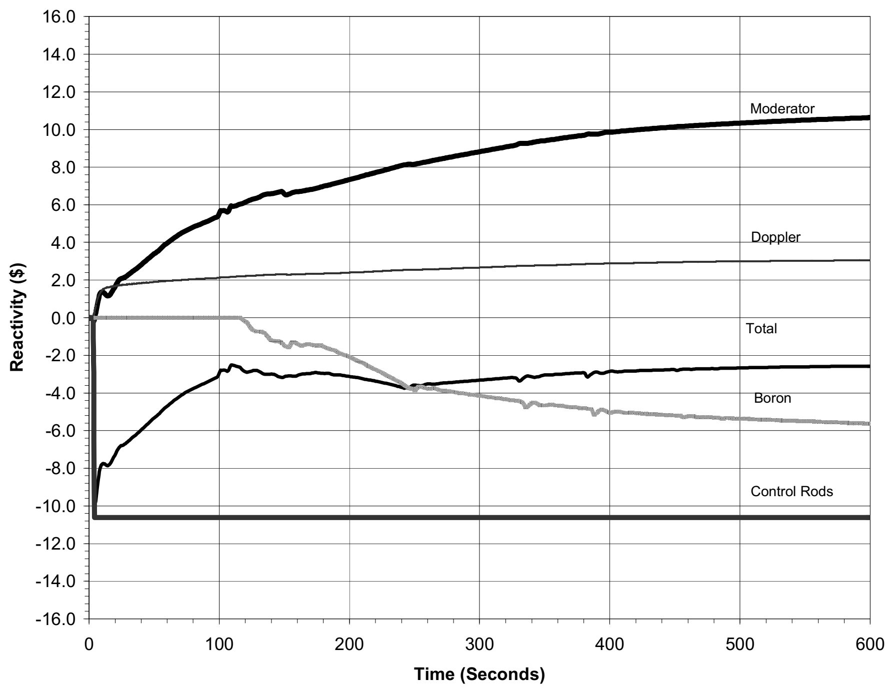

Figure 15-44. LOCA - Large Break Analysis Code Interfaces

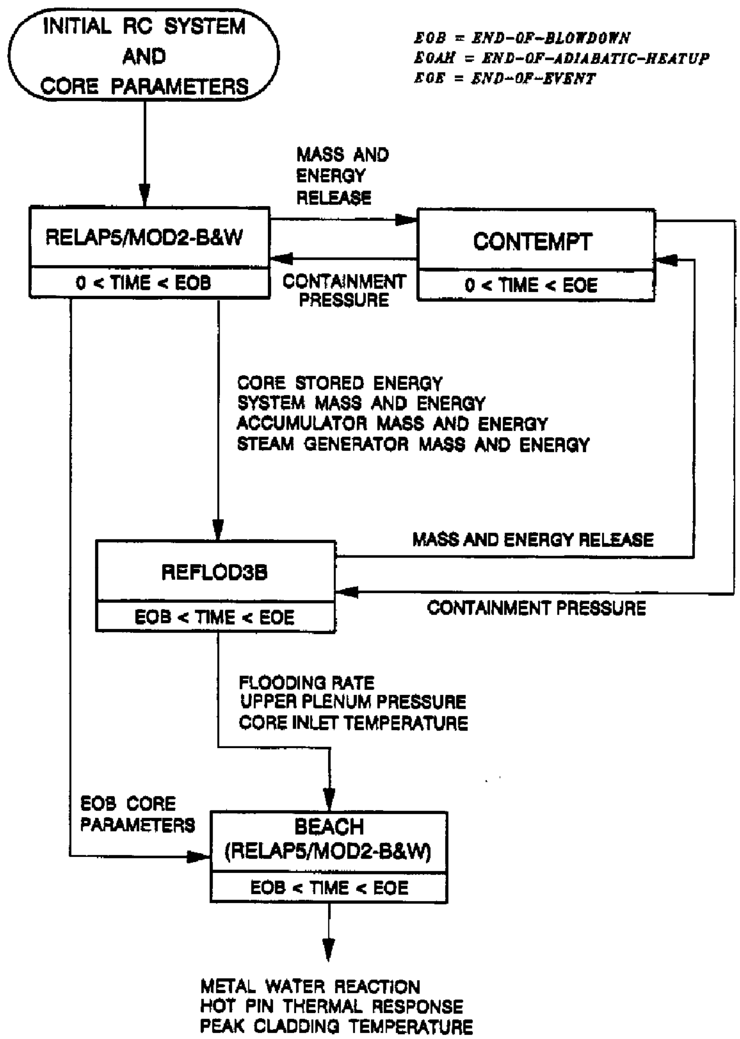

Figure 15-45. Deleted Per 2000 Update

Figure 15-46. Deleted Per 1990 Update

Figure 15-47. Deleted Per 1997 Update

Figure 15-48. Deleted Per 1997 Update

Figure 15-49. Deleted Per 2000 Update

Figure 15-50. LOCA - Peak Cladding Temperature vs Break Size for LBLOCA Spectrum

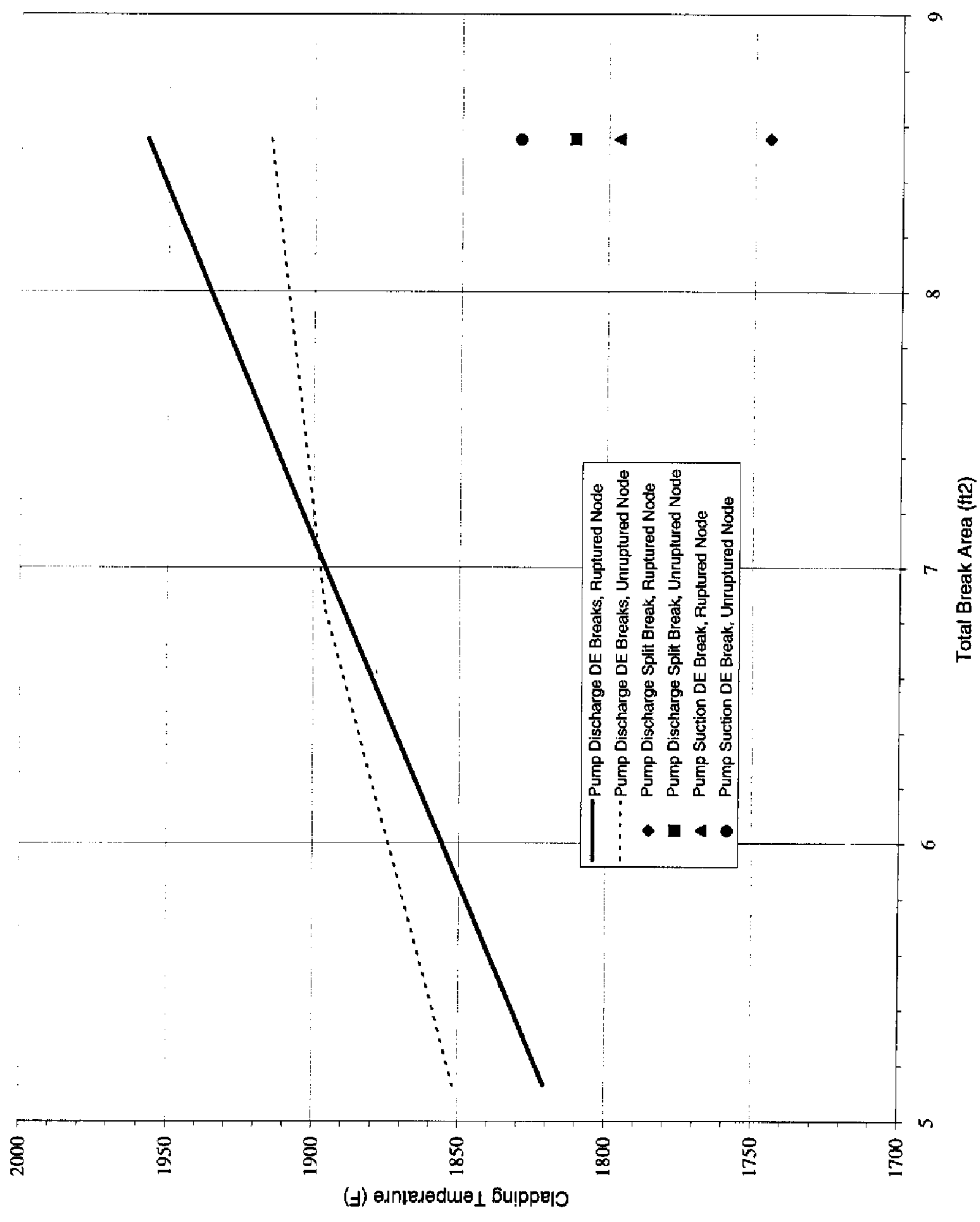

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Figure 15-53. Deleted Per 1995 Update

Figure 15-54. Deleted Per 1995 Update

Figure 15-55. Deleted Per 1995 Update

Figure 15-56. Deleted Per 1995 Update

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Figure 15-70. Deleted Per 1995 Update

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Figure 15-72. Deleted Per 1995 Update

Figure 15-73. Deleted Per 1995 Update

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Figure 15-77. Deleted Per 1995 Update

Figure 15-78. Deleted Per 1995 Update

Figure 15-79. Deleted Per 1995 Update

Figure 15-80. MHA - Integrated Direct Dose

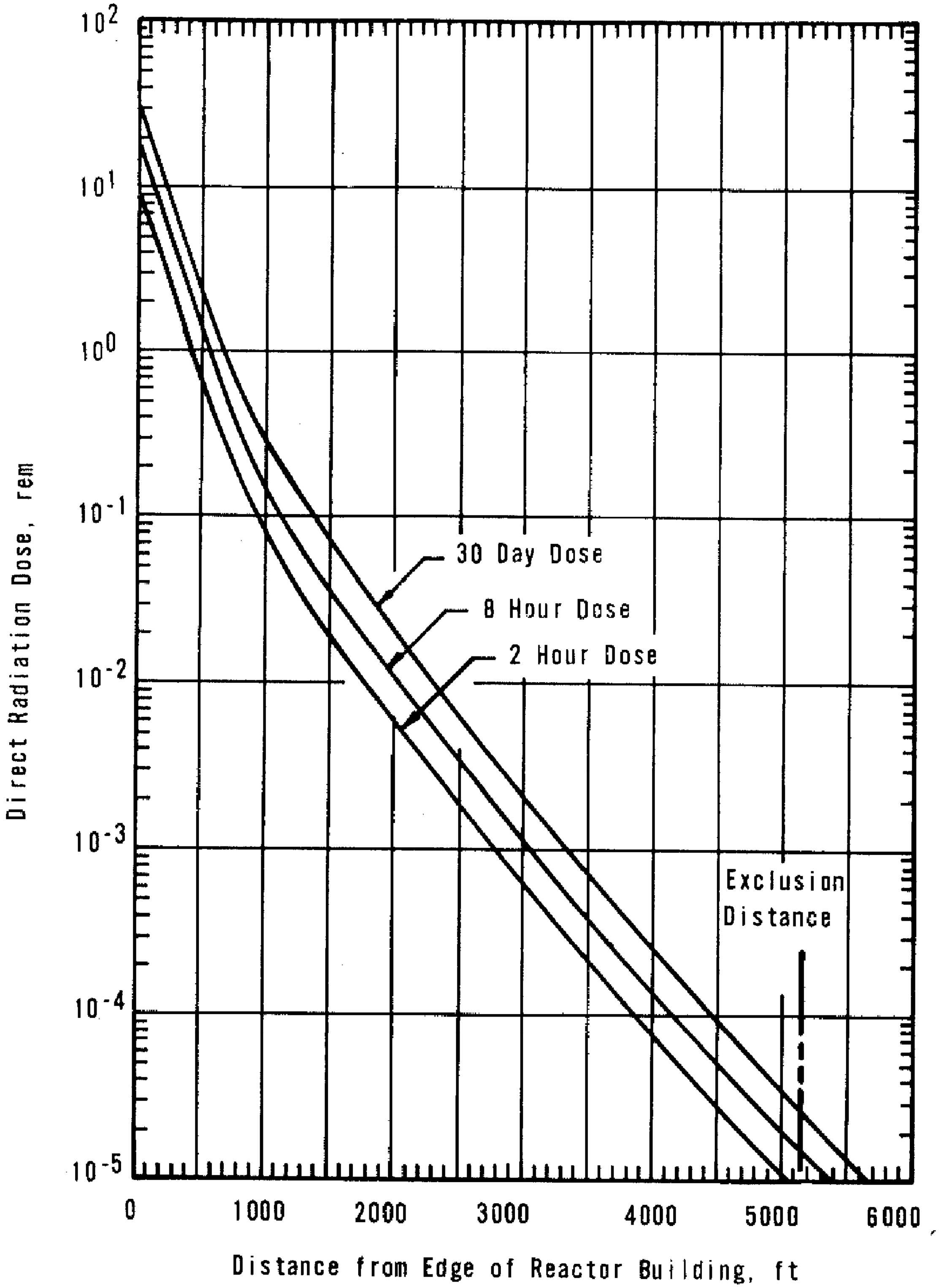

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Figure 15-85. Deleted Per 2000 Update

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Figure 15-87. Deleted Per 2000 Update

Figure 15-88. Deleted Per 1995 Update

Figure 15-89. Post-Accident Hydrogen Control - Reactor Building Arrangement

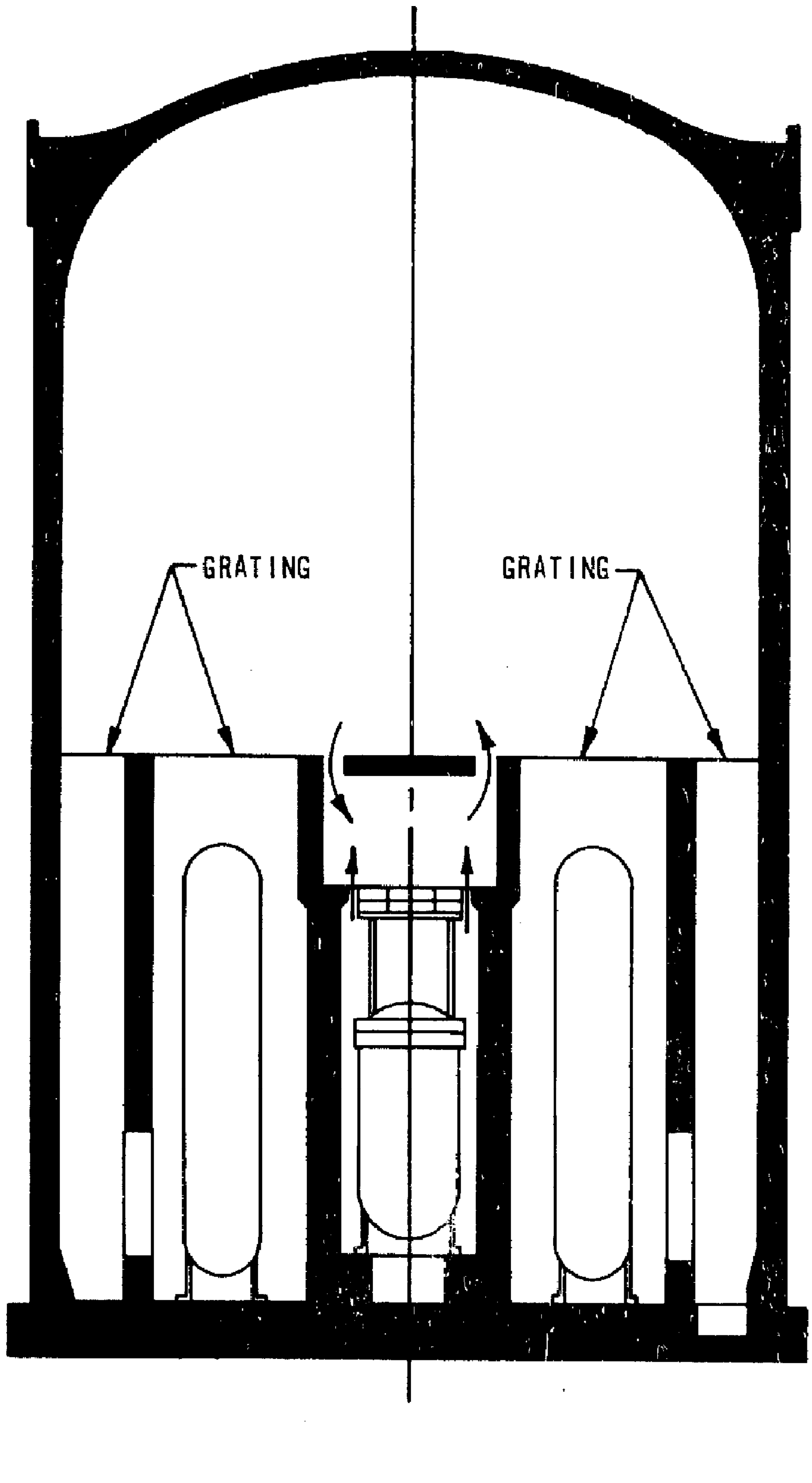

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Figure 15-104. Deleted Per 1995 Update

Figure 15-105. Deleted Per 1995 Update

Figure 15-106. Deleted Per 1995 Update

Figure 15-107. Deleted Per 1995 Update

Figure 15-108. Deleted Per 1995 Update

Figure 15-109. Deleted Per 1995 Update

Figure 15-110. Deleted Per 2001 Update

Figure 15-111. Deleted Per 2003 Update

Figure 15-112. Deleted Per 2014 Update

Figure 15-113. Rod Withdrawal at Power Accident - Core Cooling Capability Analysis RCS Pressure

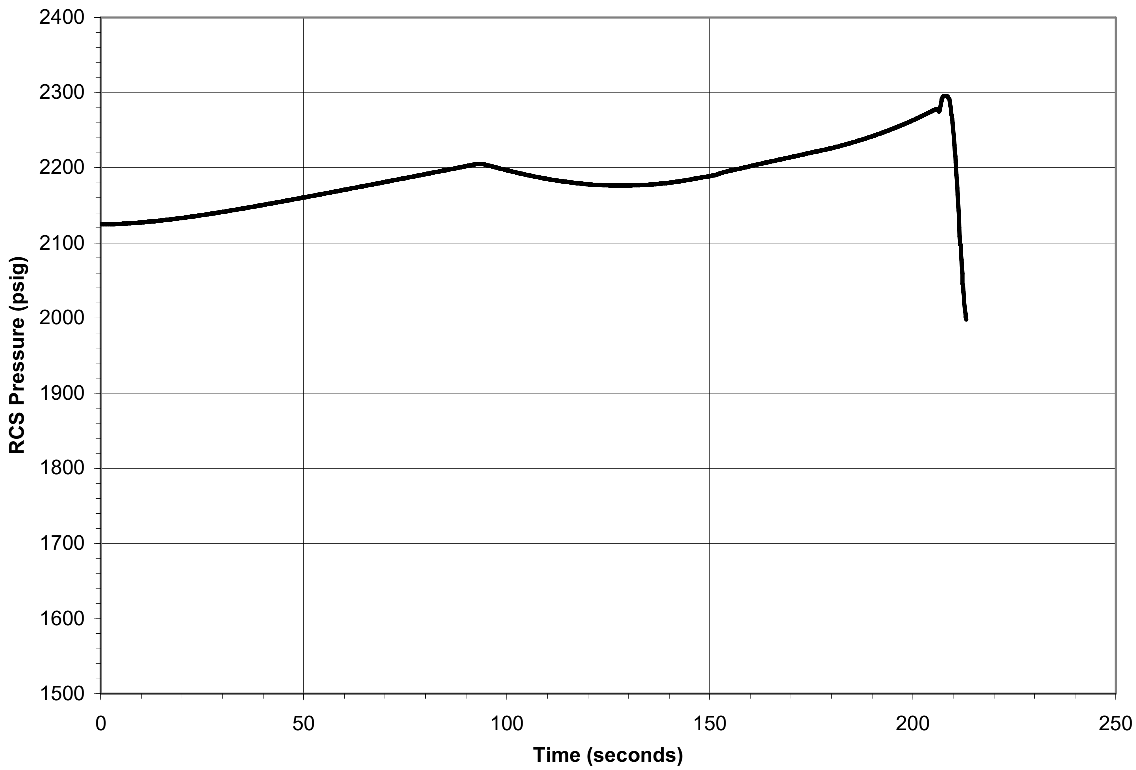

Figure 15-114. Rod Withdrawal at Power Accident - Core Cooling Capability Analysis DNBR

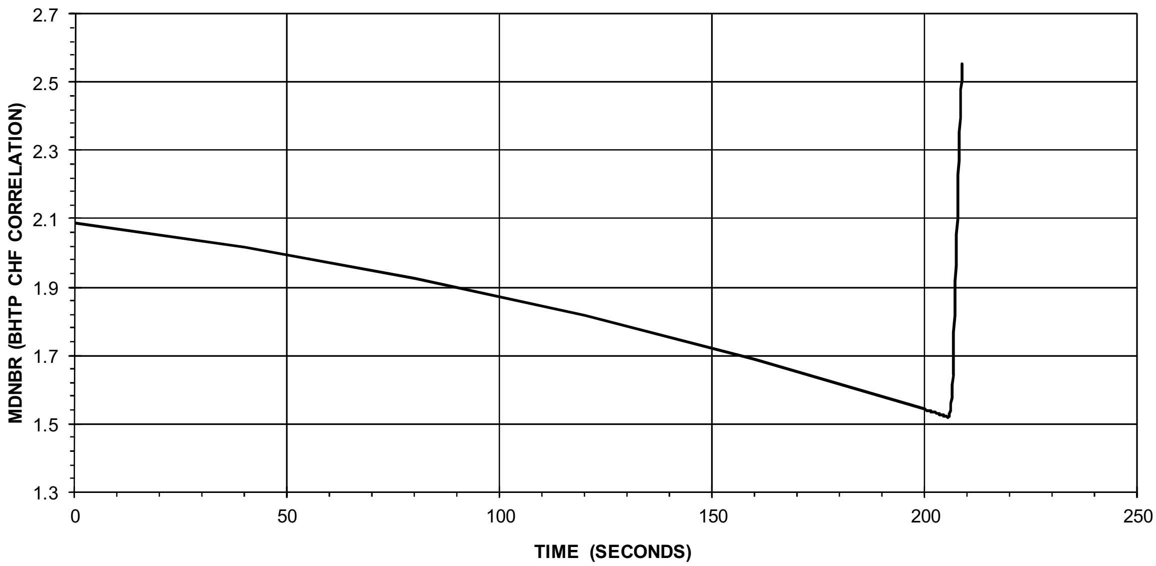

Figure 15-115. Cold Water Accident - Core Average Temperature

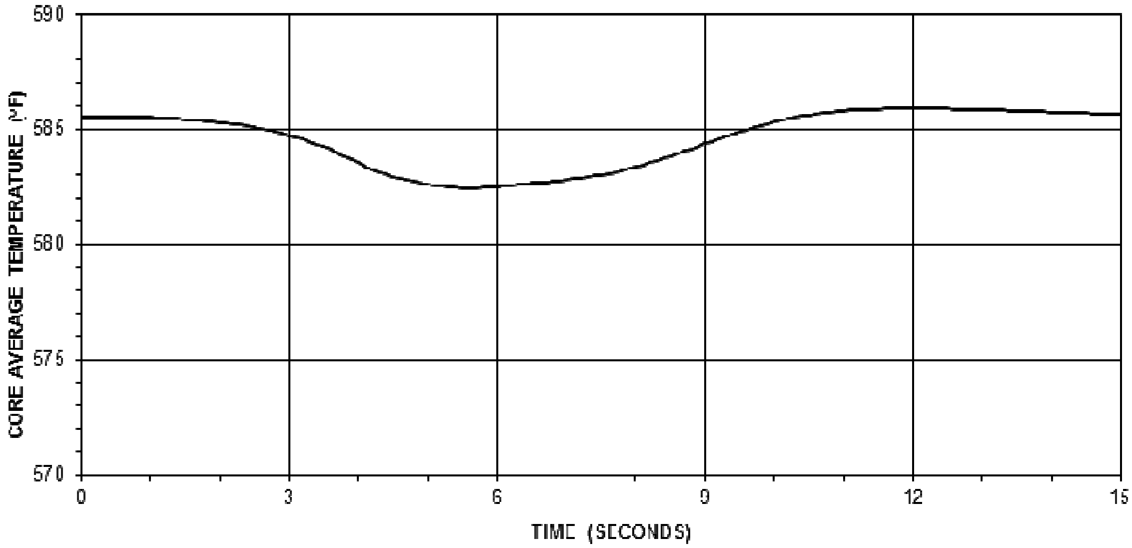

Figure 15-116. Cold Water Accident - Power

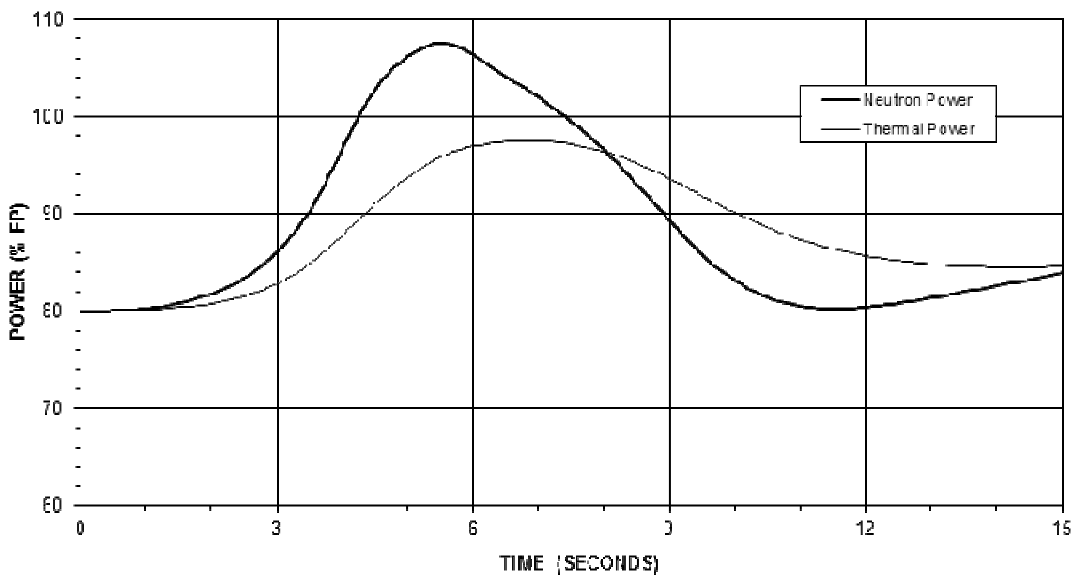

Figure 15-117. Cold Water Accident - Cold Leg Temperature

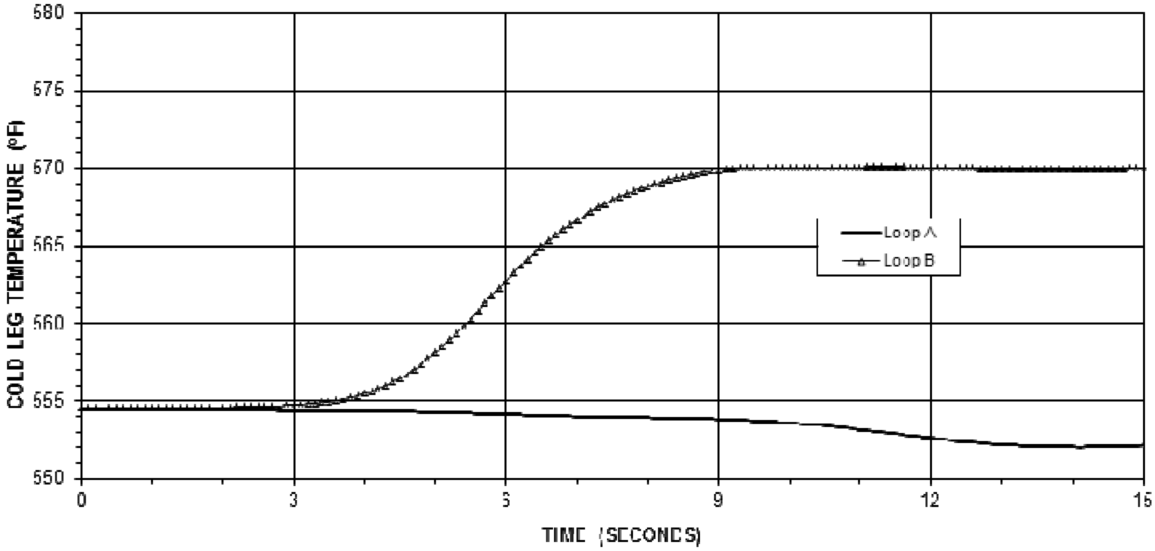

Figure 15-118. Cold Water Accident - RCS Pressure

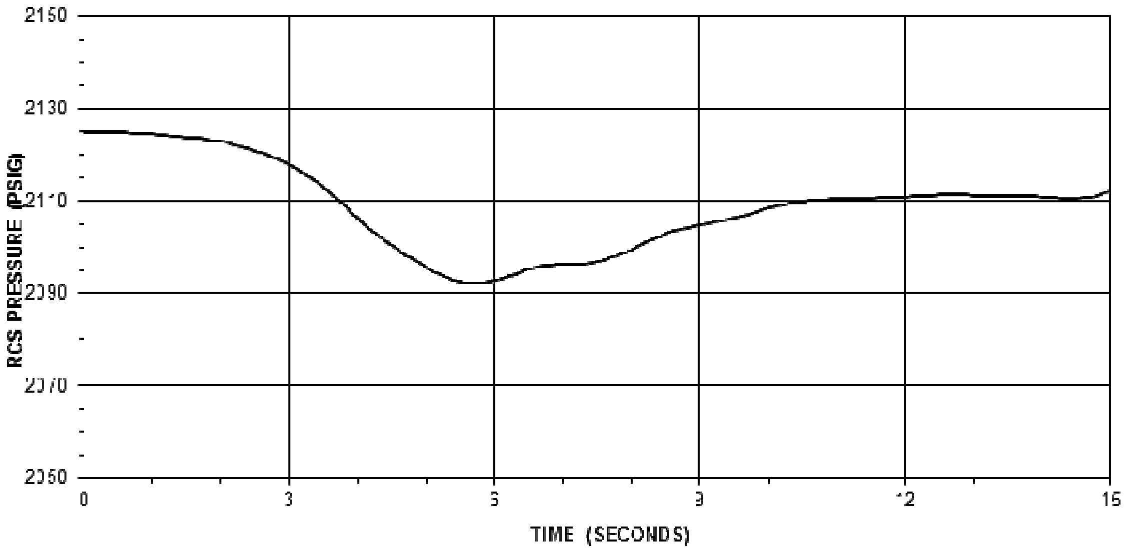

Figure 15-119. Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis - Power

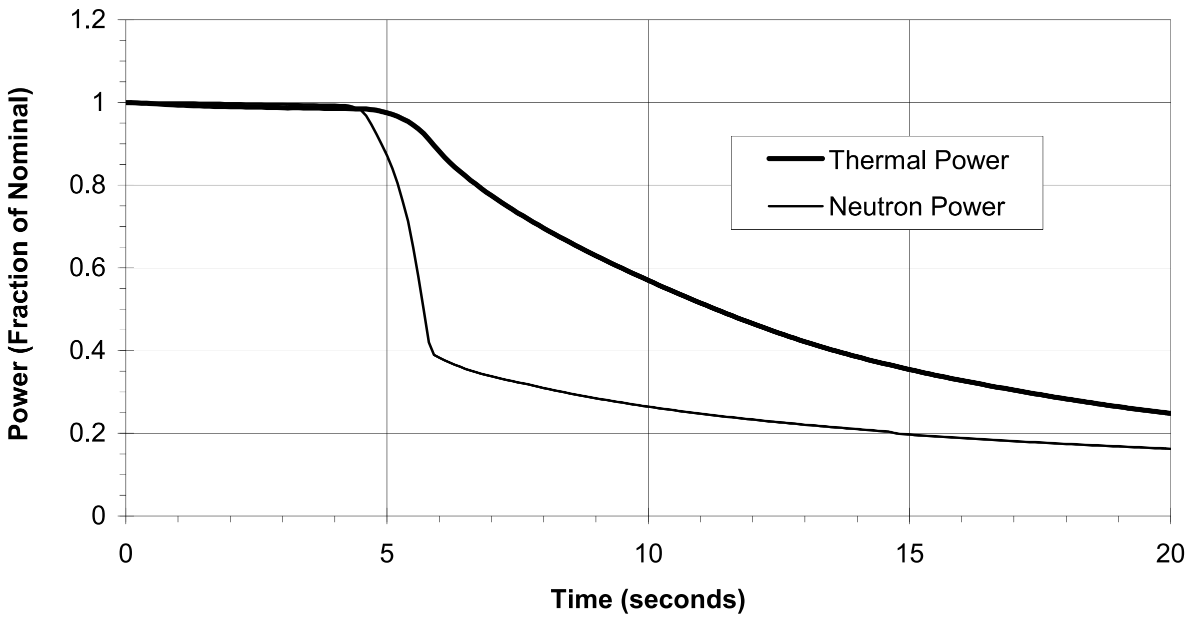

Figure 15-120. Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis - RCS Temperature

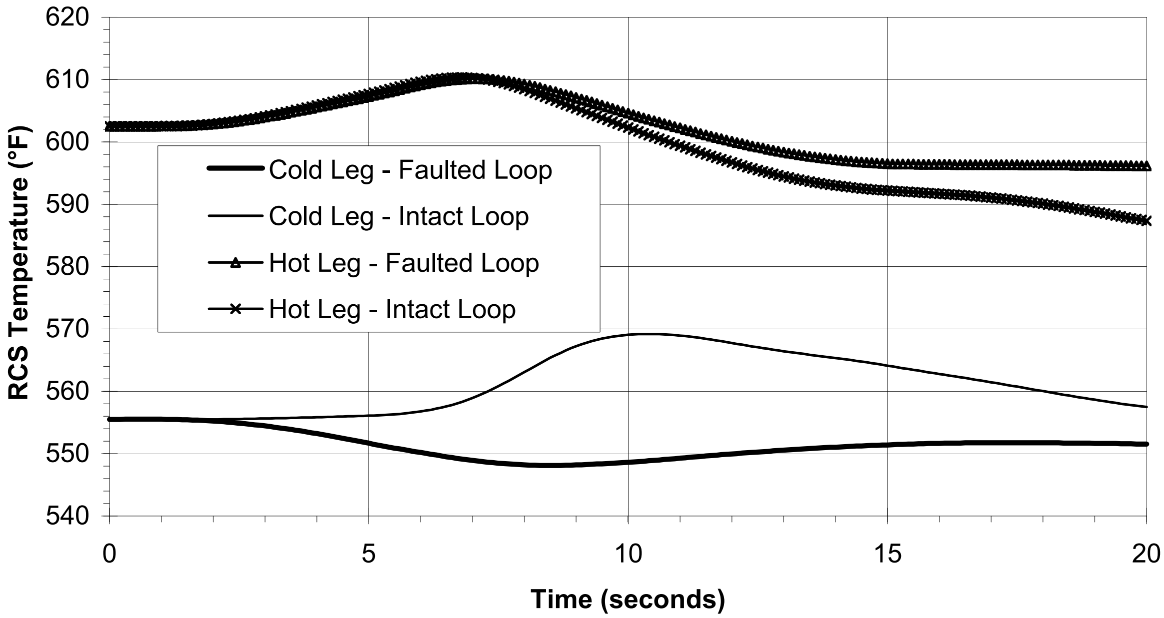

Figure 15-121. Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis - Pressurizer Level

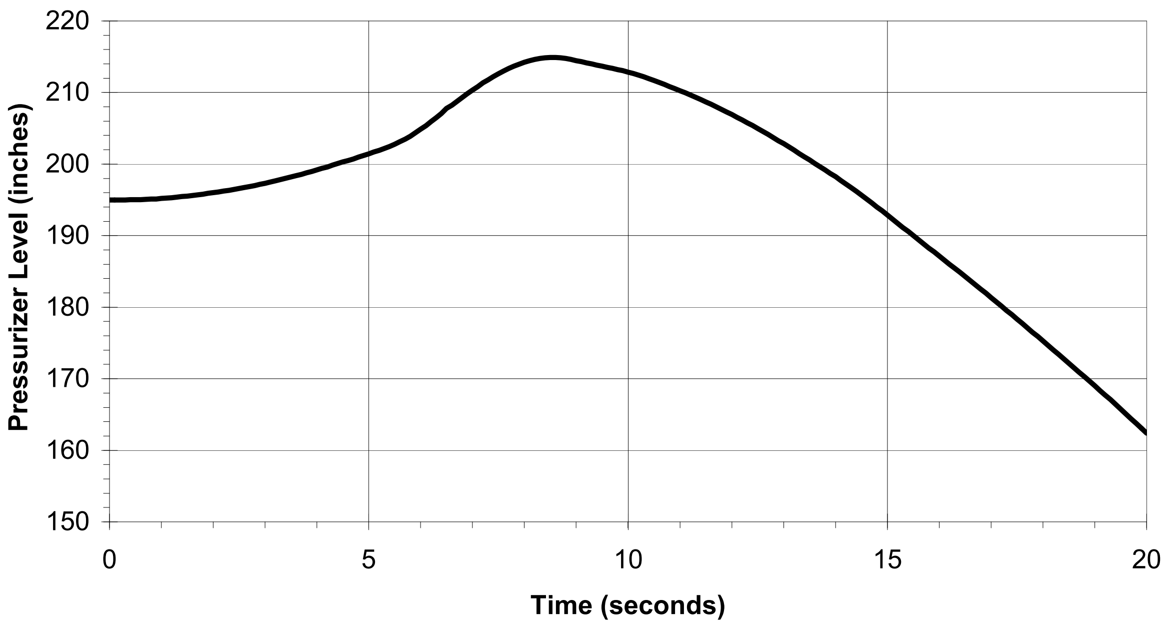

Figure 15-122. Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis - RCS Pressure

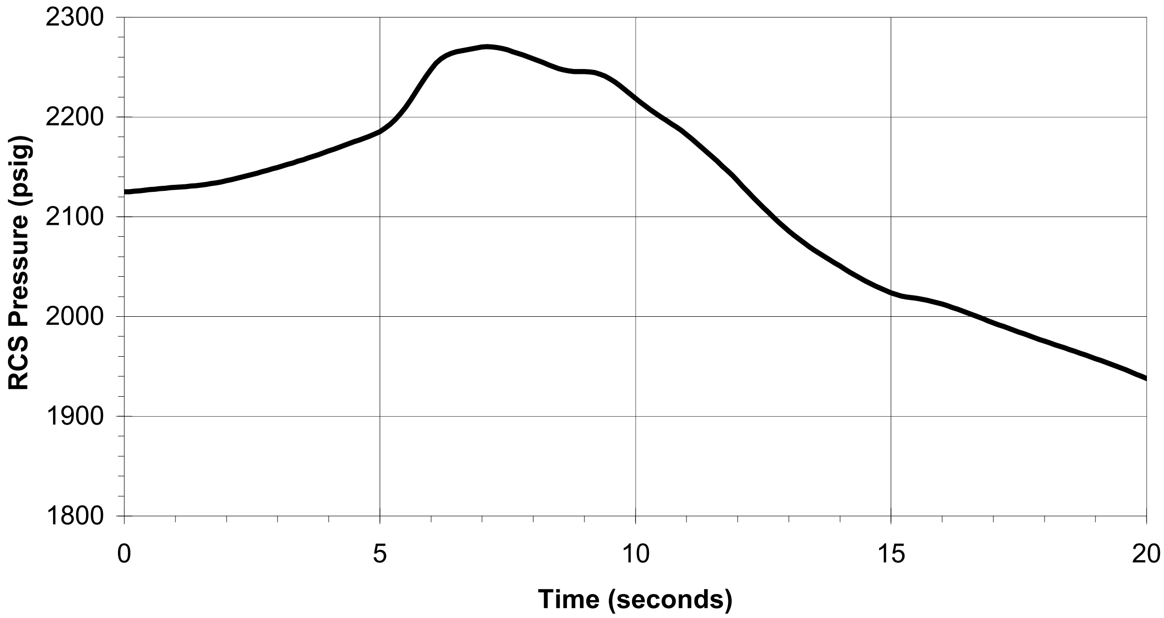

Figure 15-123. Loss of Coolant Flow Accidents - Two RCP Coastdown from Four RCP Initial Conditions Analysis - DNBR

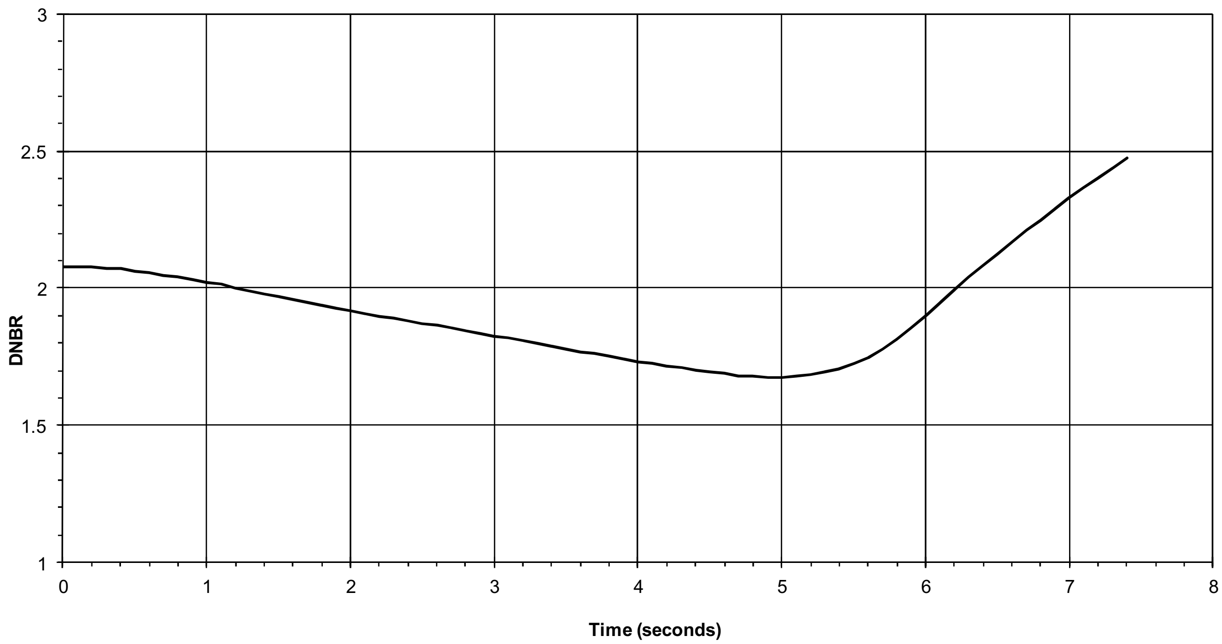

Figure 15-124. Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis - RCS Flow

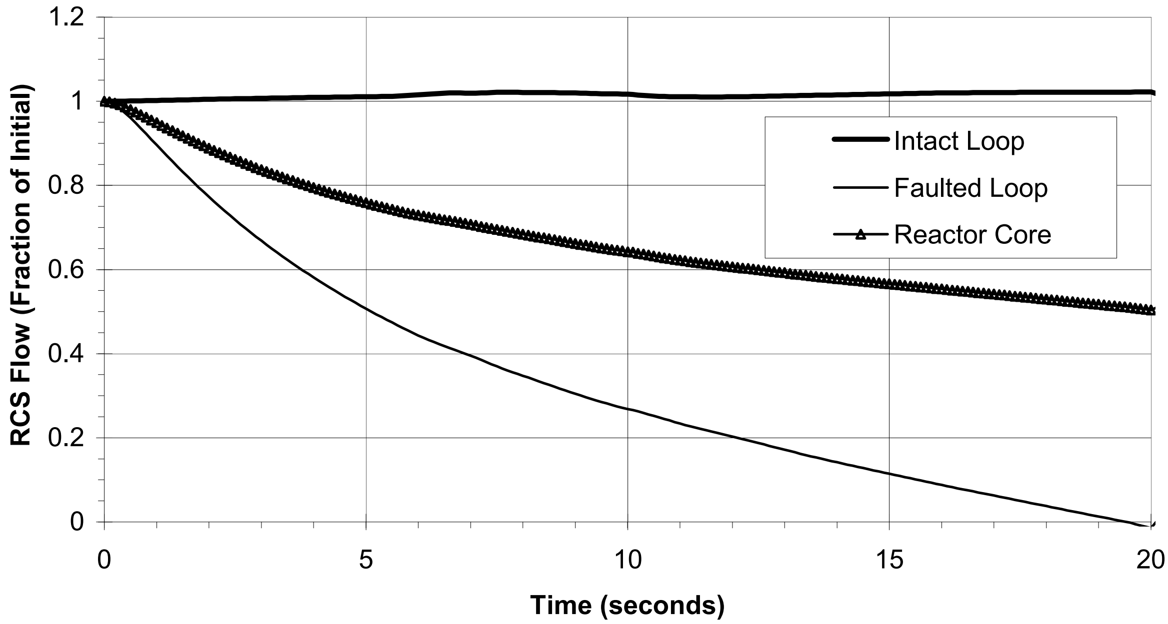

Figure 15-125. Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis - Power

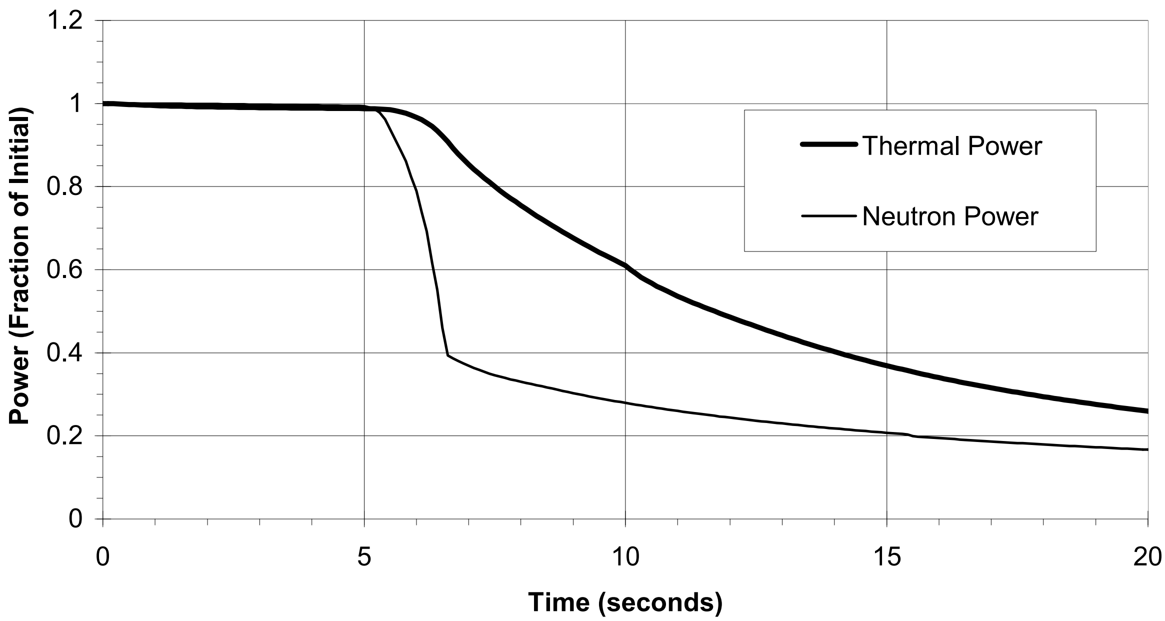

Figure 15-126. Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis - RCS Temperature

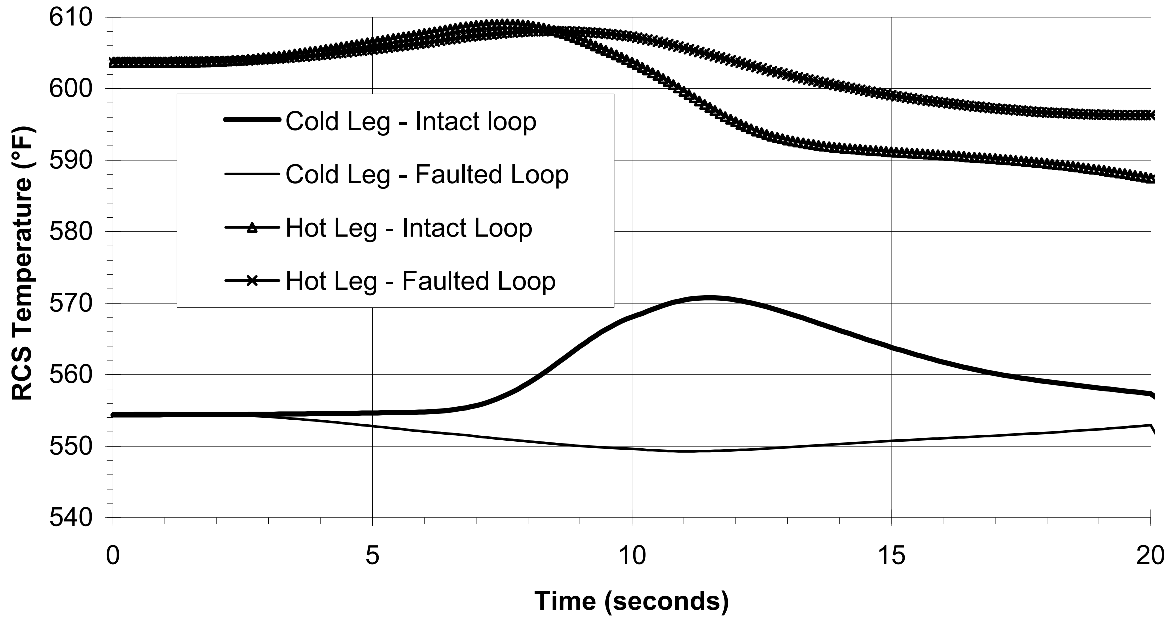

Figure 15-127. Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis - Pressurizer Level

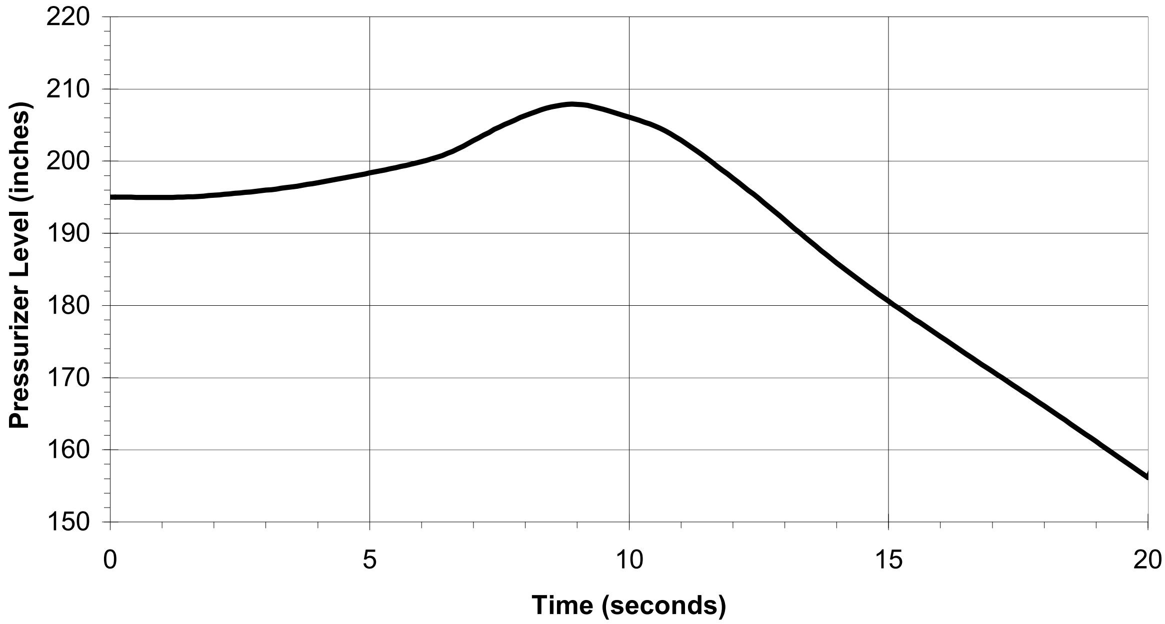

Figure 15-128. Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis - RCS Pressure

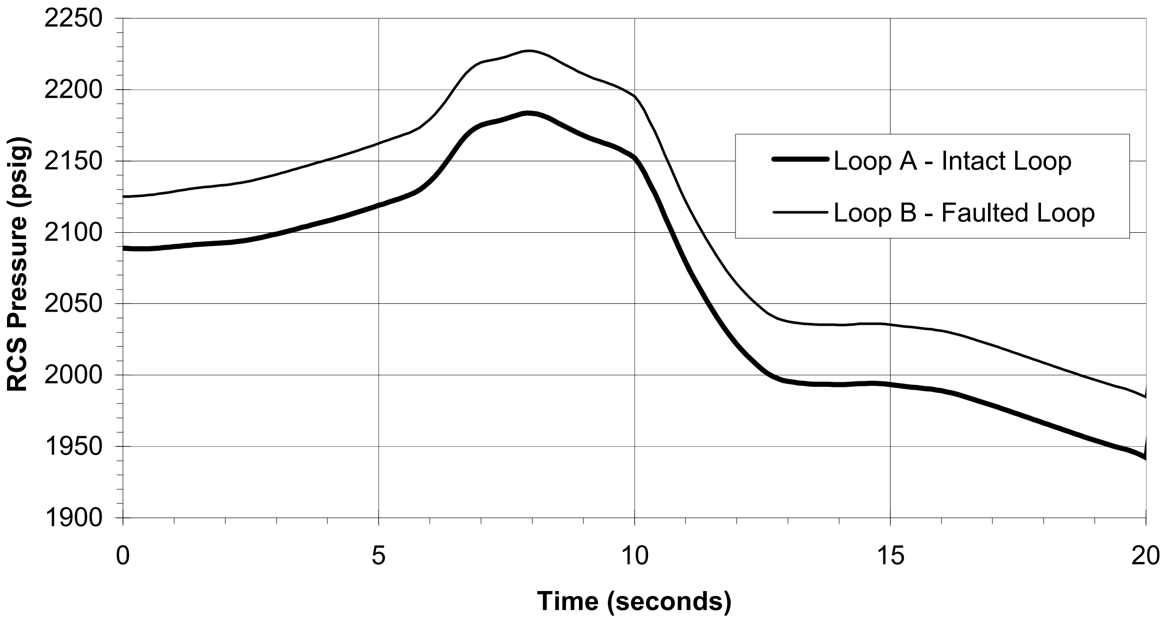

Figure 15-129. Loss of Coolant Flow Accidents - One RCP Coastdown from Three RCP Initial Conditions Analysis - DNBR

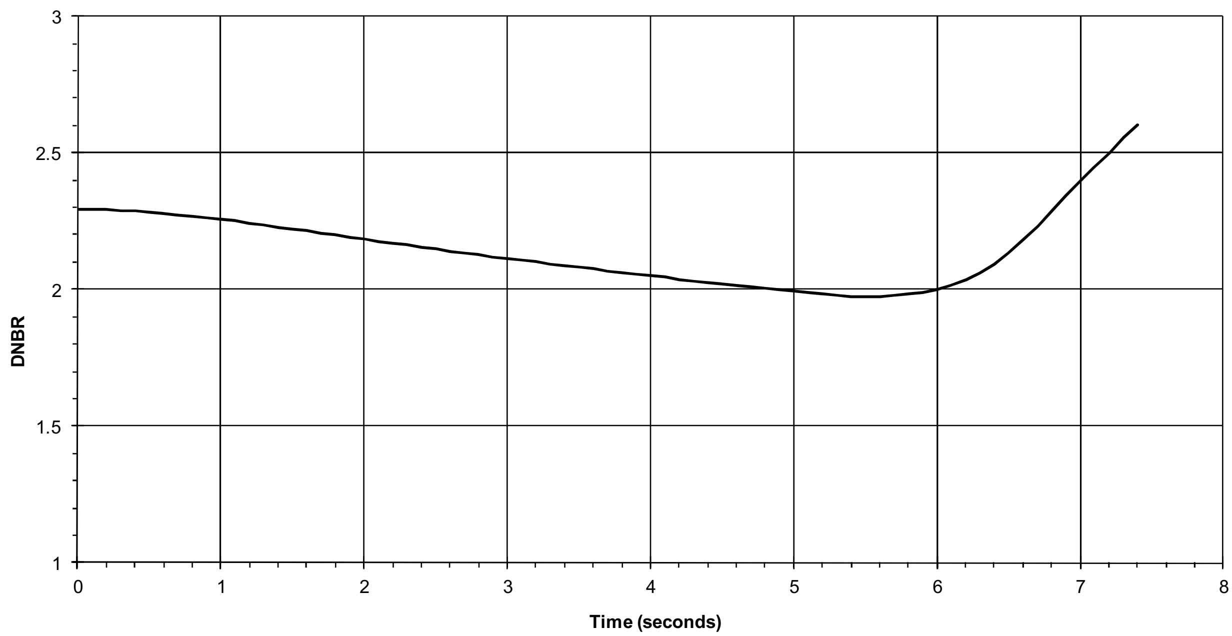

Figure 15-130. Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - RCS Flow

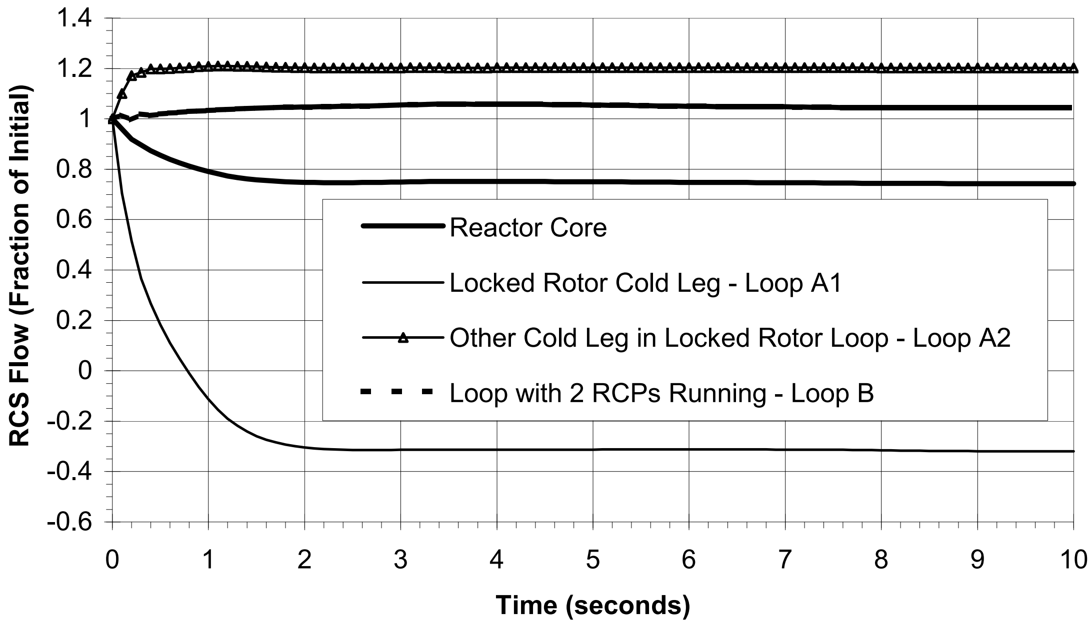

Figure 15-131. Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - Power

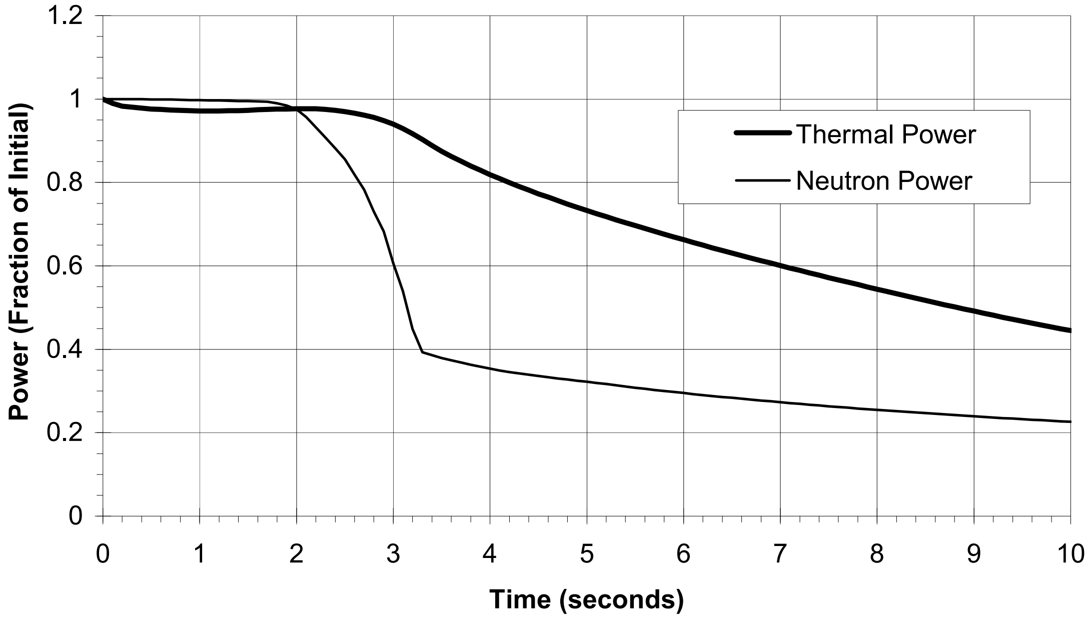

Figure 15-132. Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - RCS Temperature

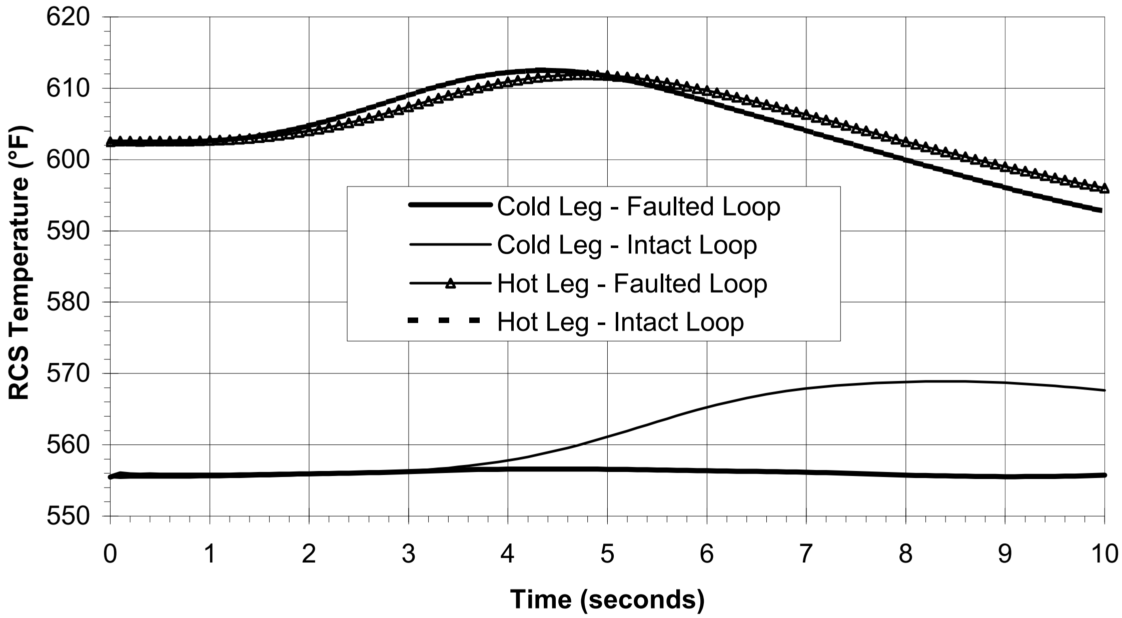

Figure 15-133. Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - Pressurizer Level

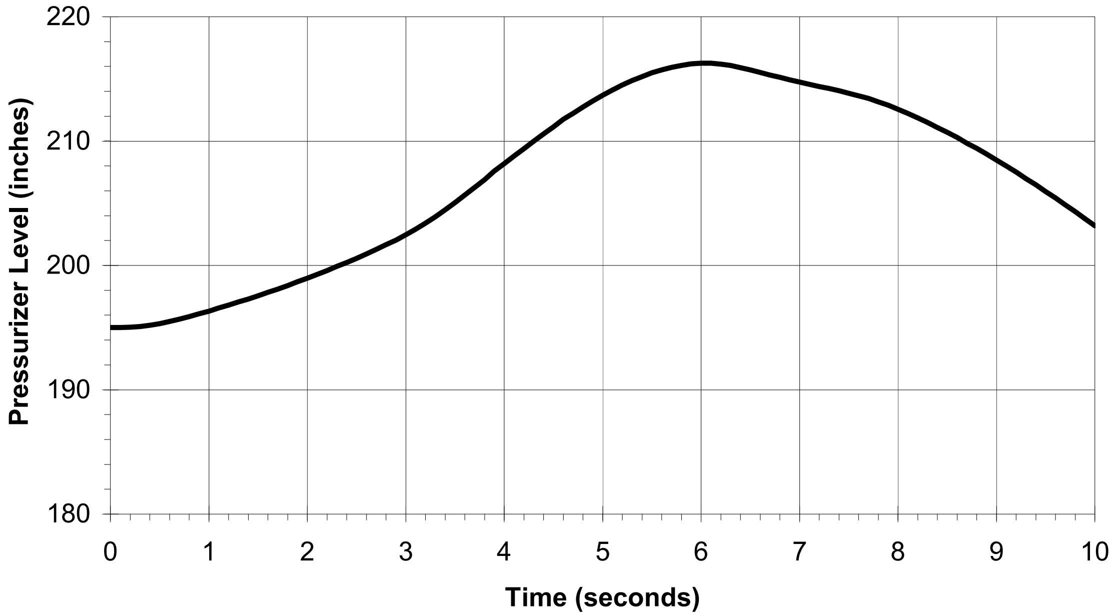

Figure 15-134. Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - RCS Pressure

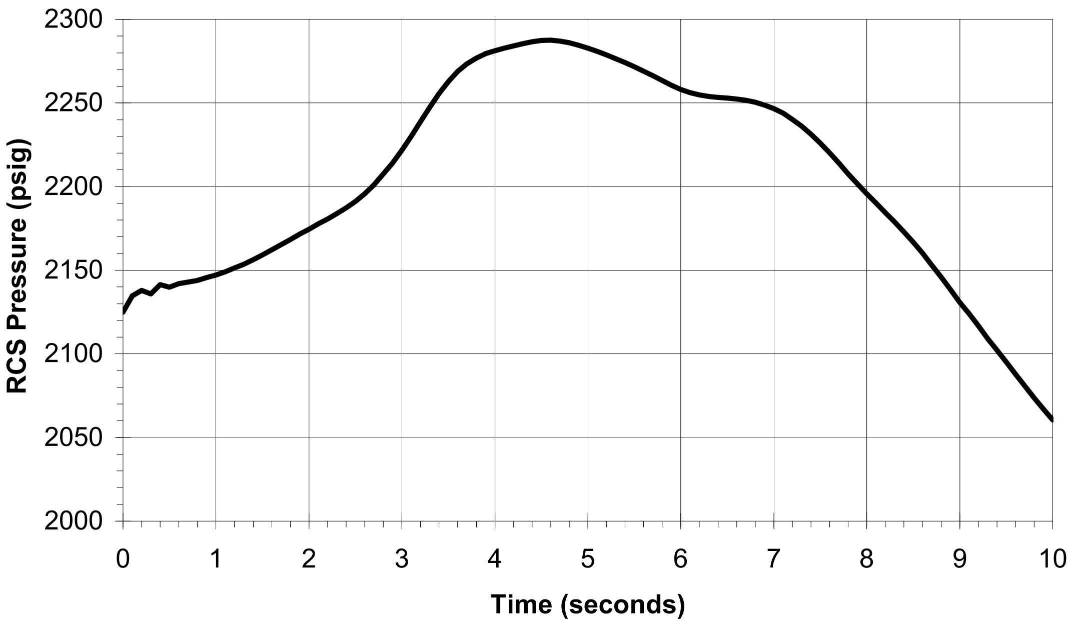

Figure 15-135. Loss of Coolant Flow Accidents - Locked Rotor From Four RCP Initial Conditions Analysis - DNBR

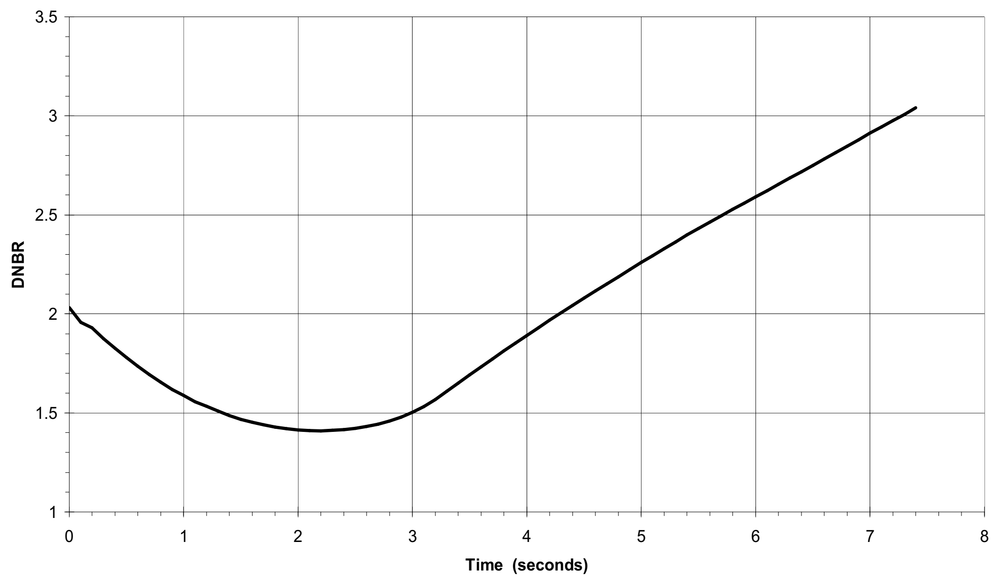

Figure 15-136. Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - RCS Flow

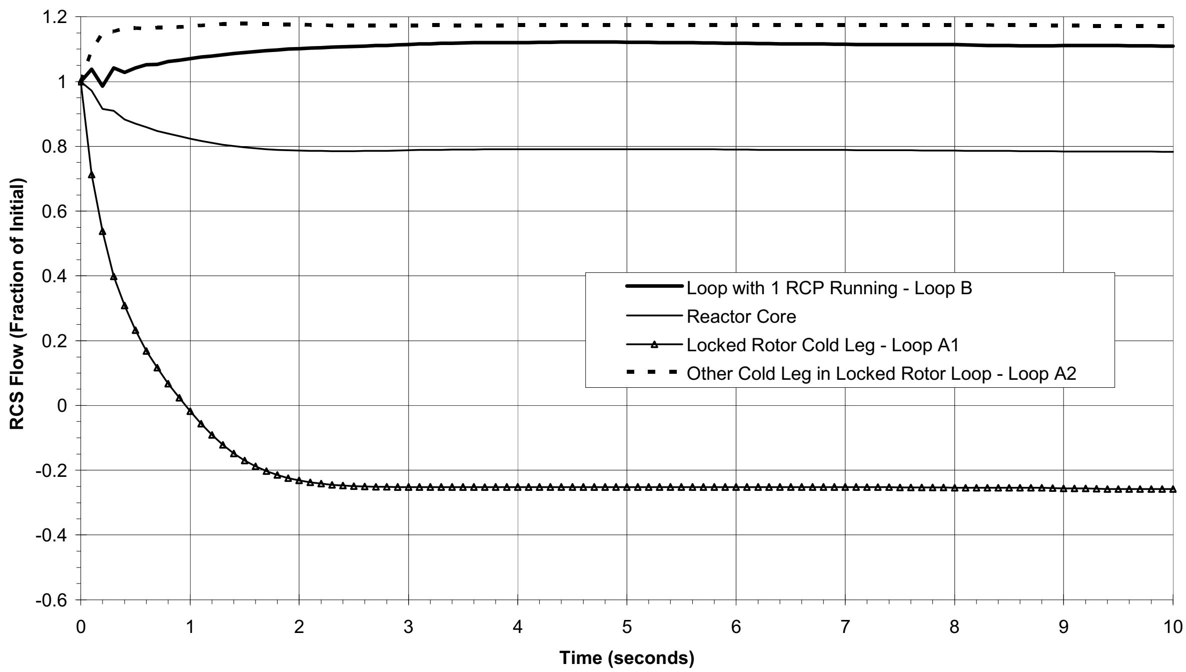

Figure 15-137. Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - Power

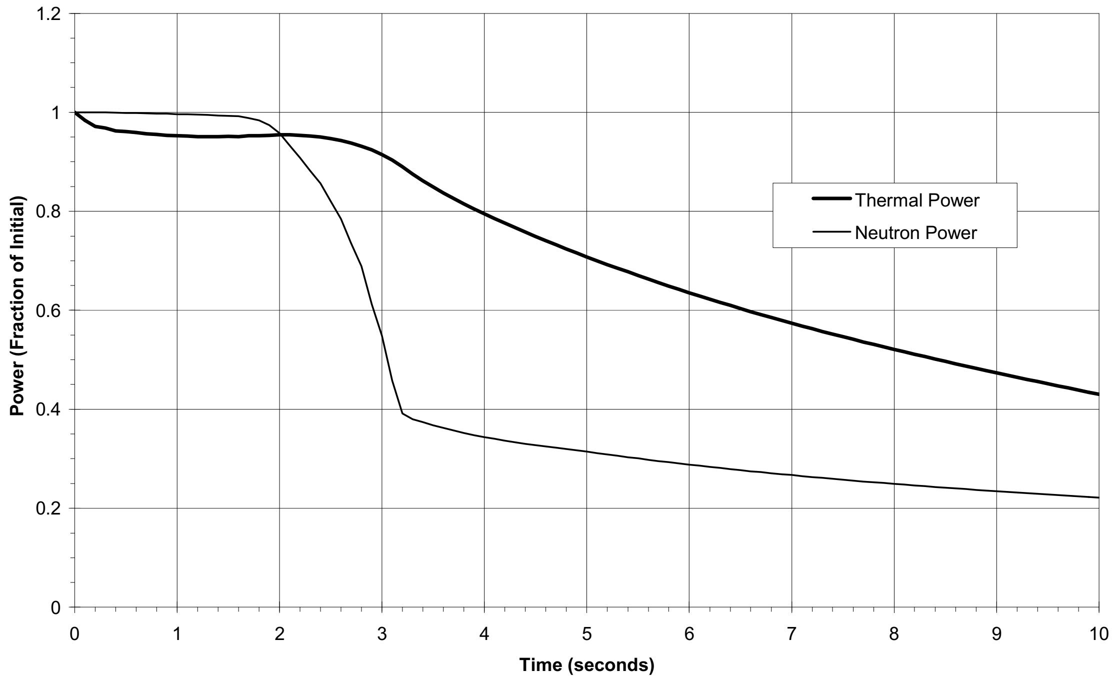

Figure 15-138. Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - RCS Temperatures

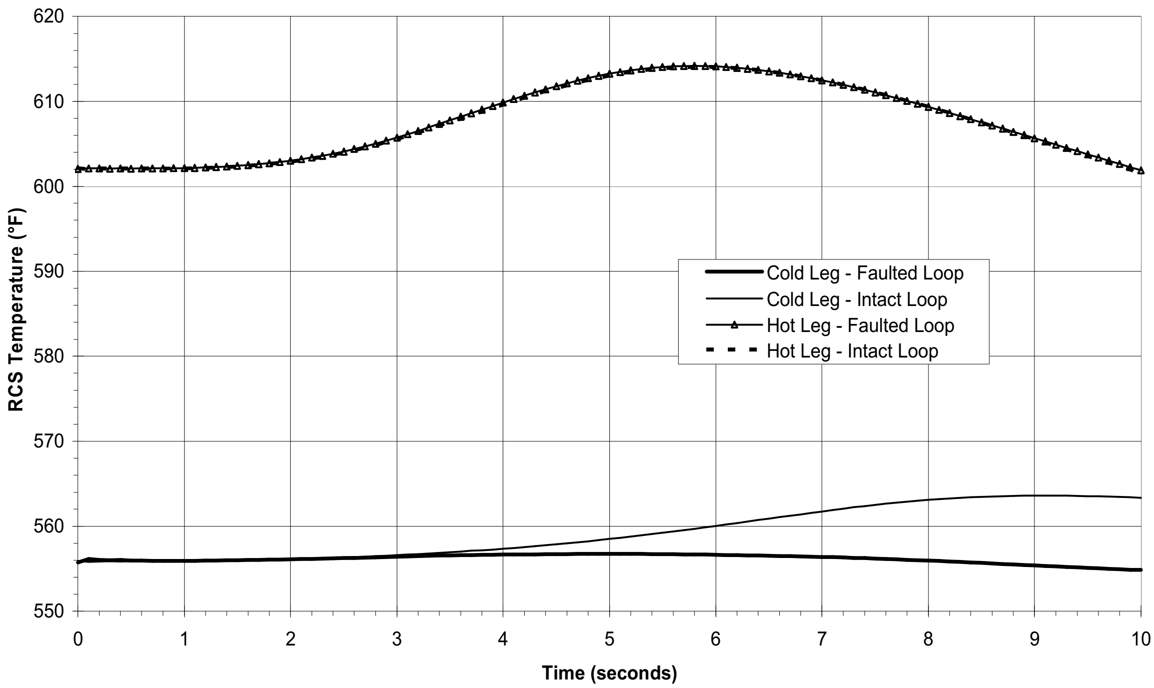

Figure 15-139. Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - Pressurizer Level

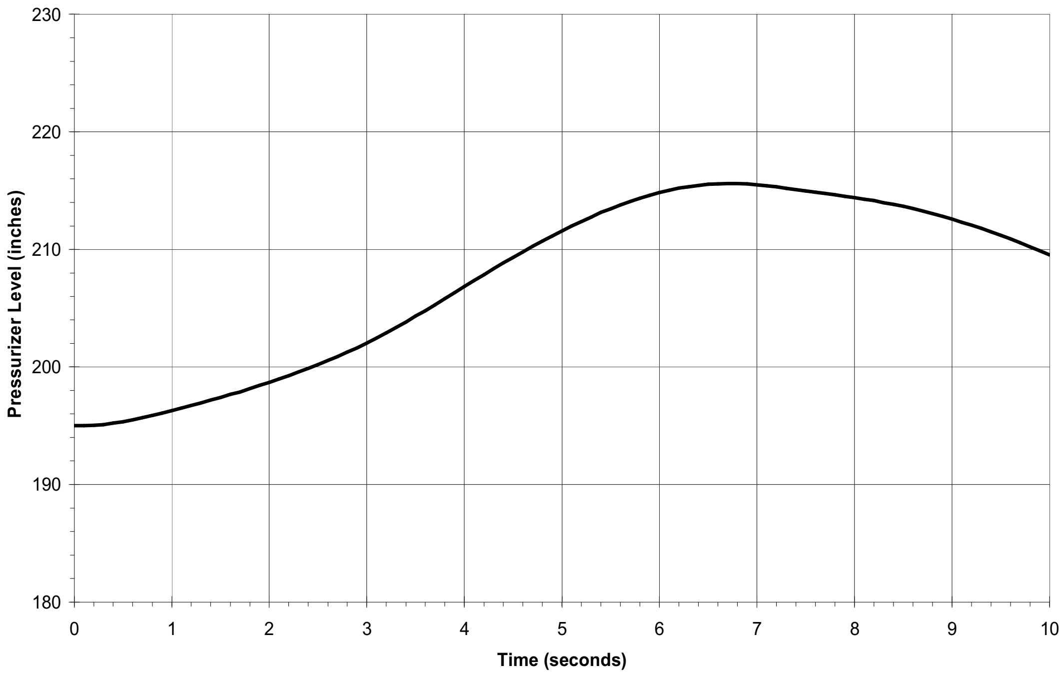

Figure 15-140. Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - RCS Pressure

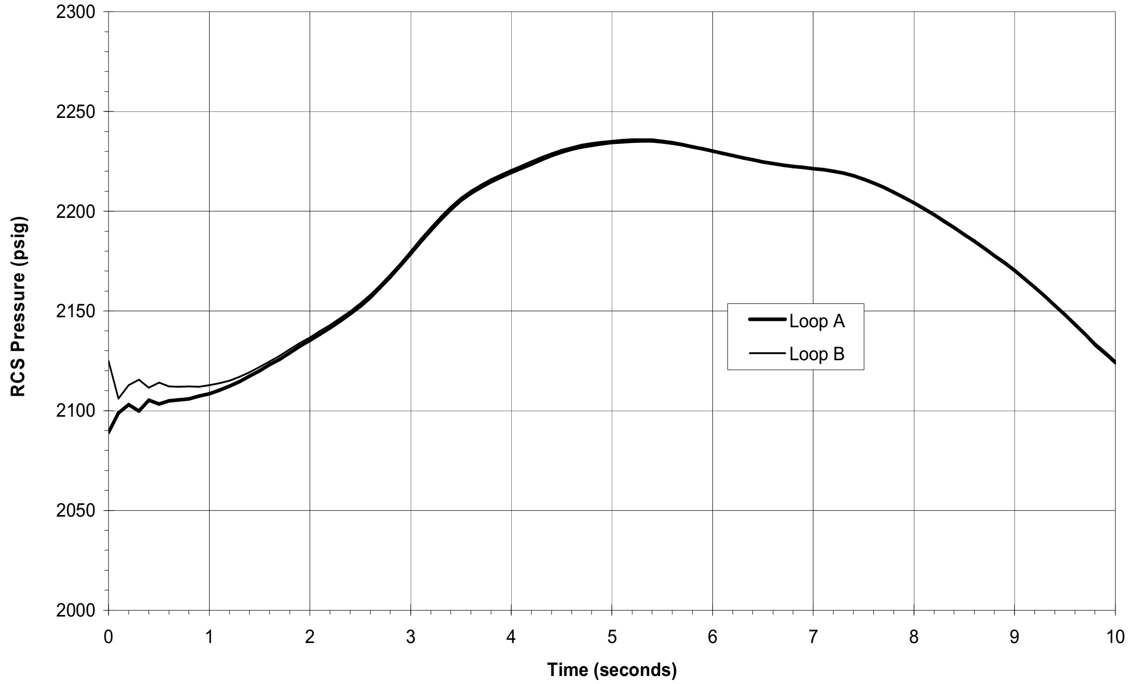

Figure 15-141. Loss of Coolant Flow Accidents - Locked Rotor From Three RCP Initial Conditions Analysis - DNBR

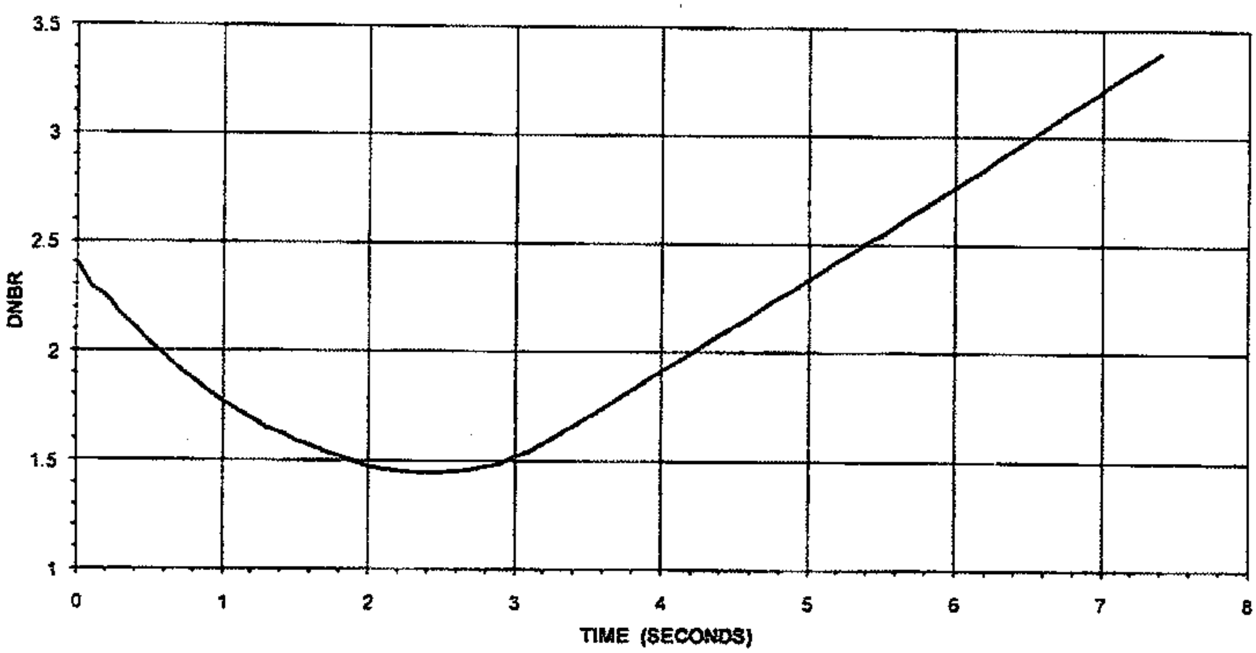

Figure 15-142. Intentionally Blank

Intentionally Blank

Figure 15-143. Control Rod Misalignment Accidents - Dropped Rod - RCS Pressure

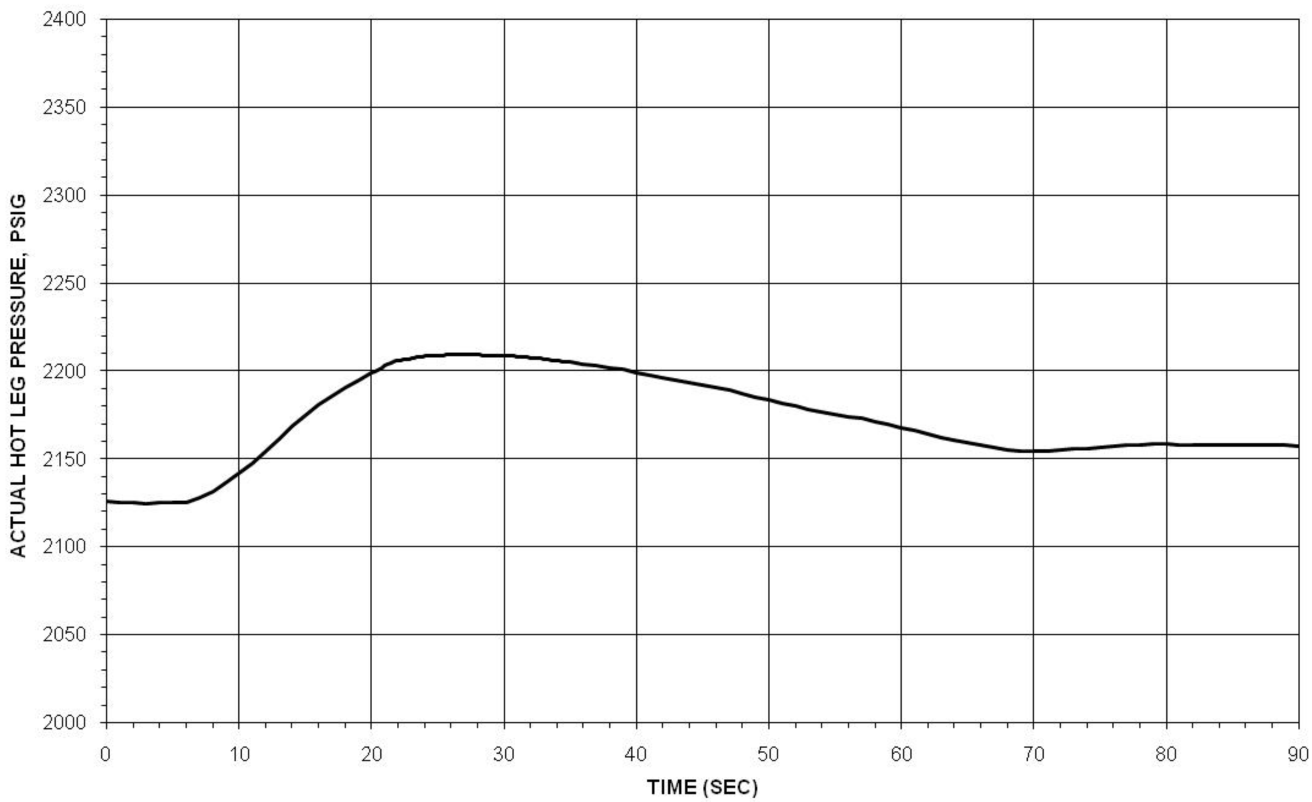

Figure 15-144. Control Rod Misalignment Accidents - Dropped Rod - DNBR

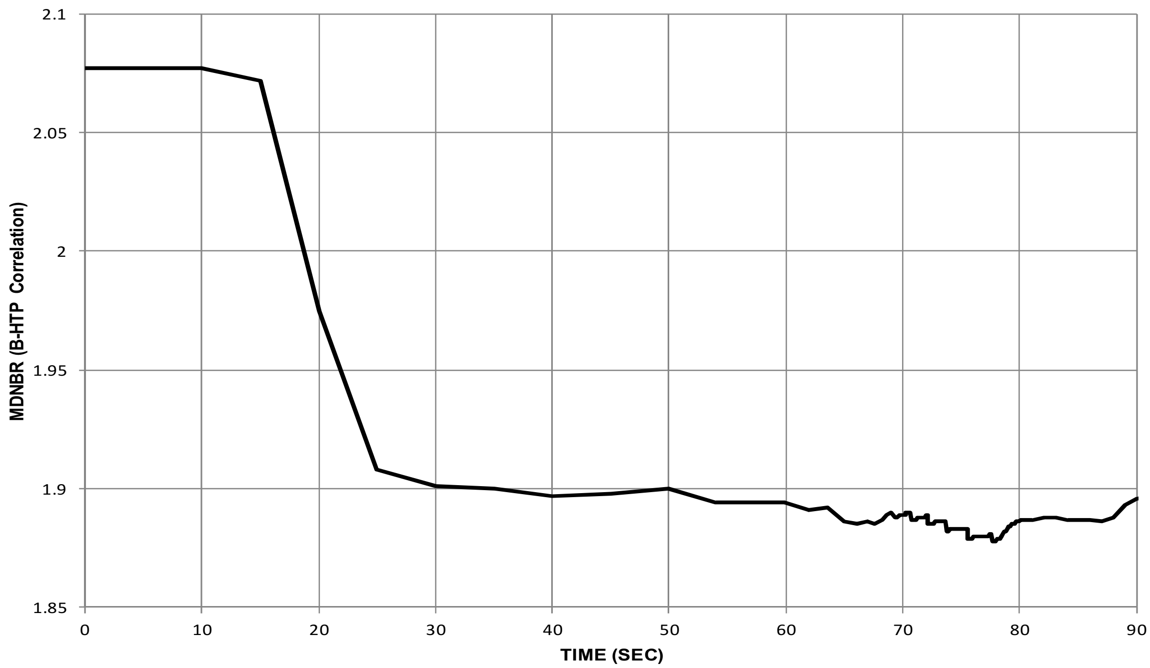

Figure 15-145. Turbine Trip Accident - Steam Generator Pressure

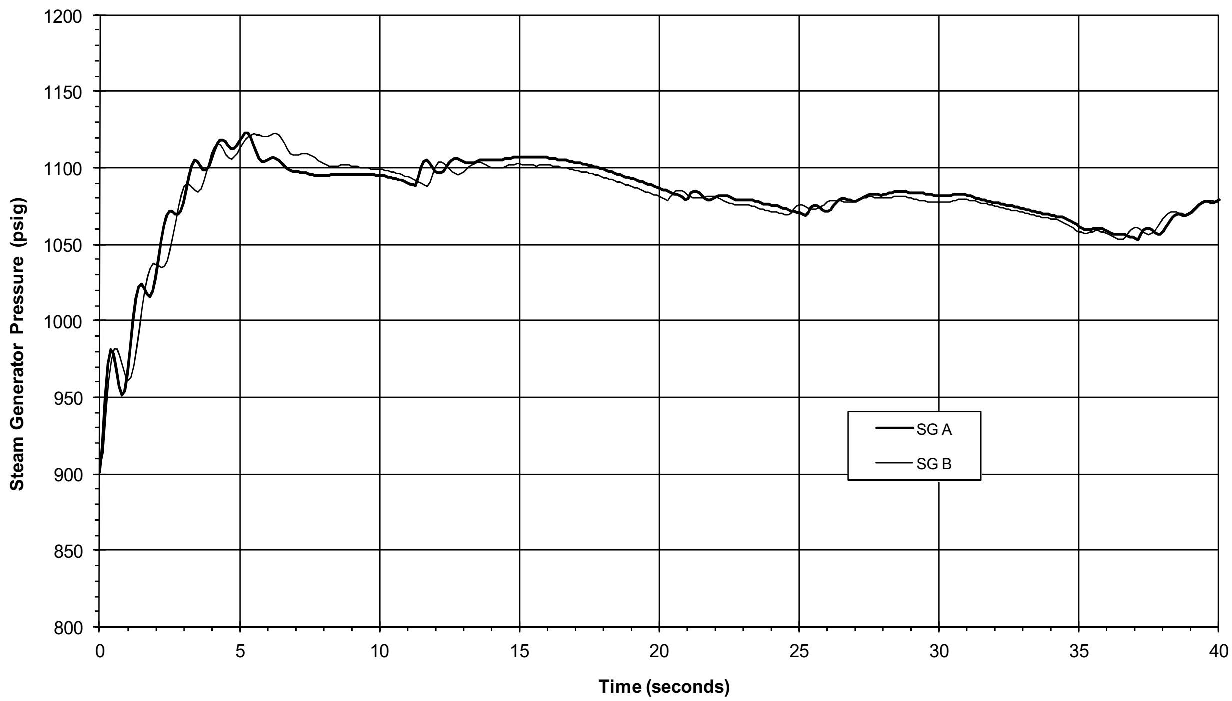

Figure 15-146. Turbine Trip Accident - RCS Temperatures

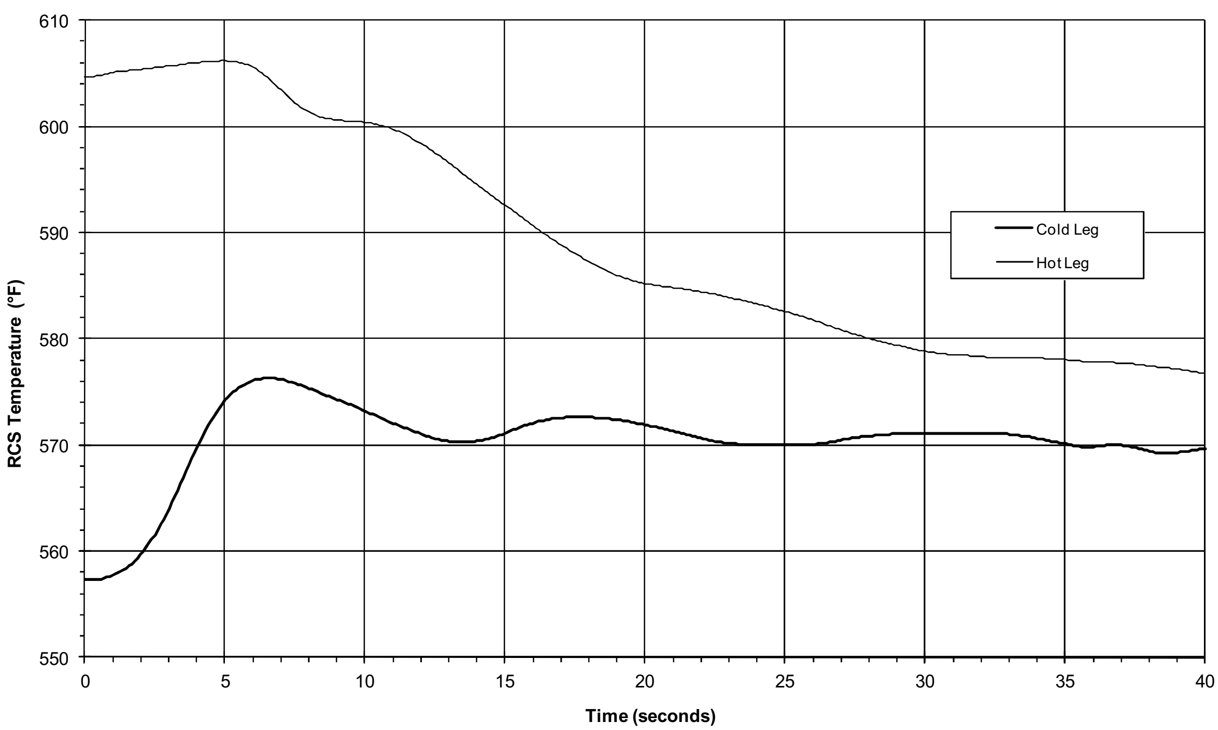

Figure 15-147. Turbine Trip Accident - Pressurizer Level

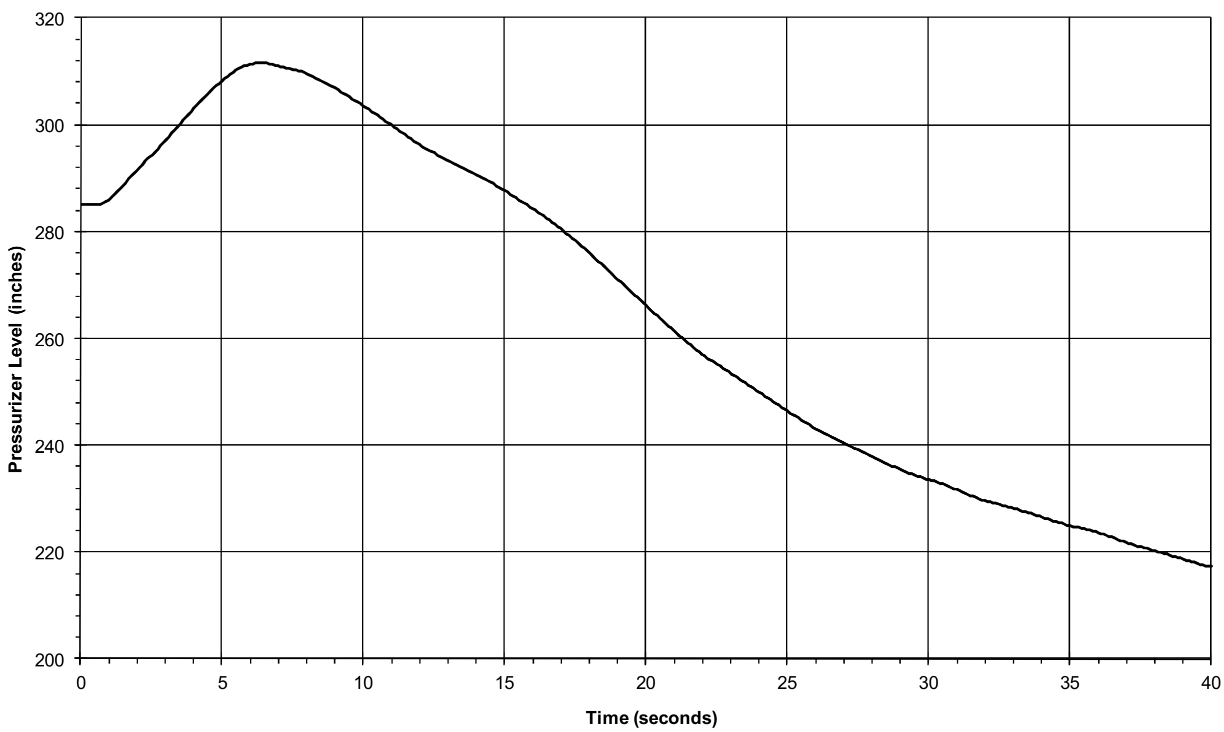

Figure 15-148. Turbine Trip Accident - RCS Pressure

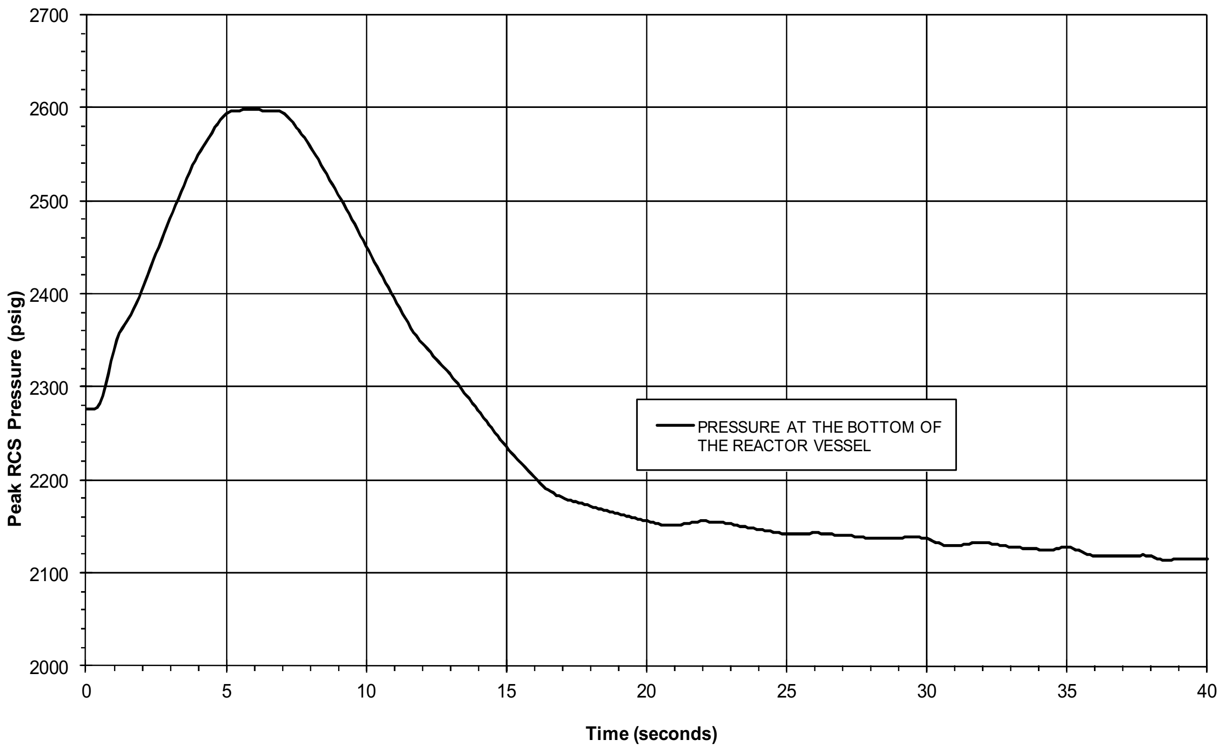

Figure 15-149. Turbine Trip Accident - Power

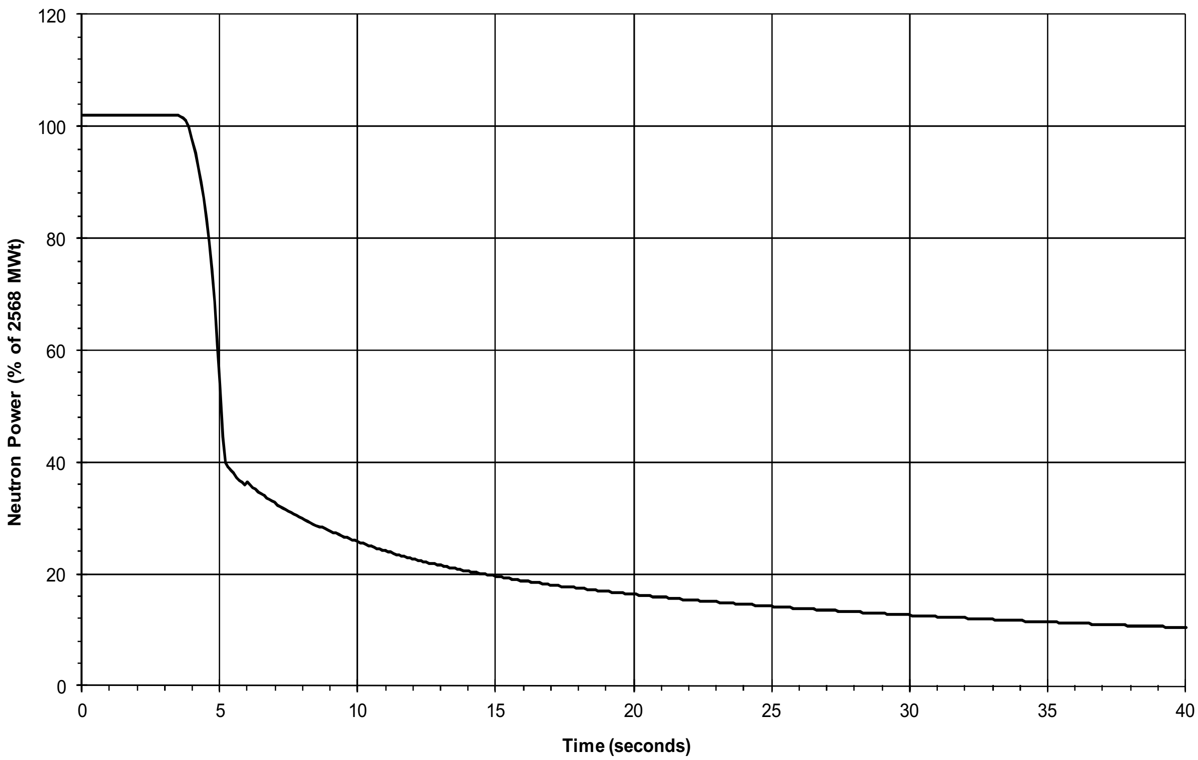

Figure 15-150. Steam Generator Tube Rupture - Power

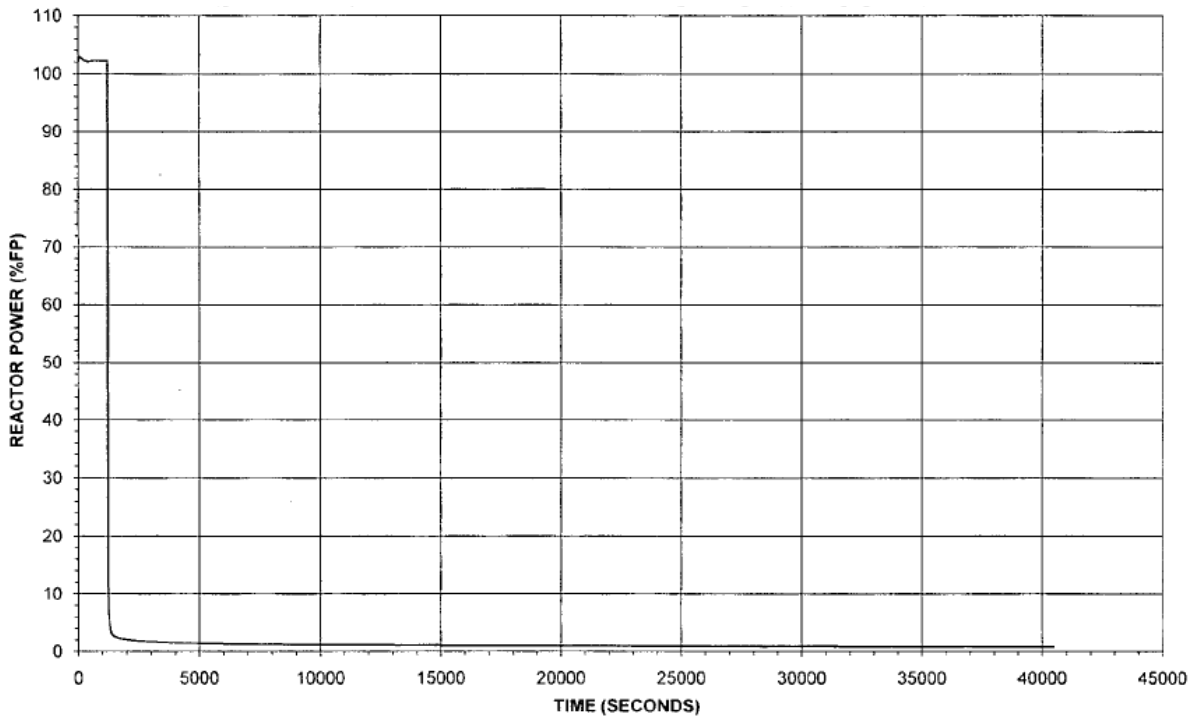

Figure 15-151. Steam Generator Tube Rupture - Break Flow

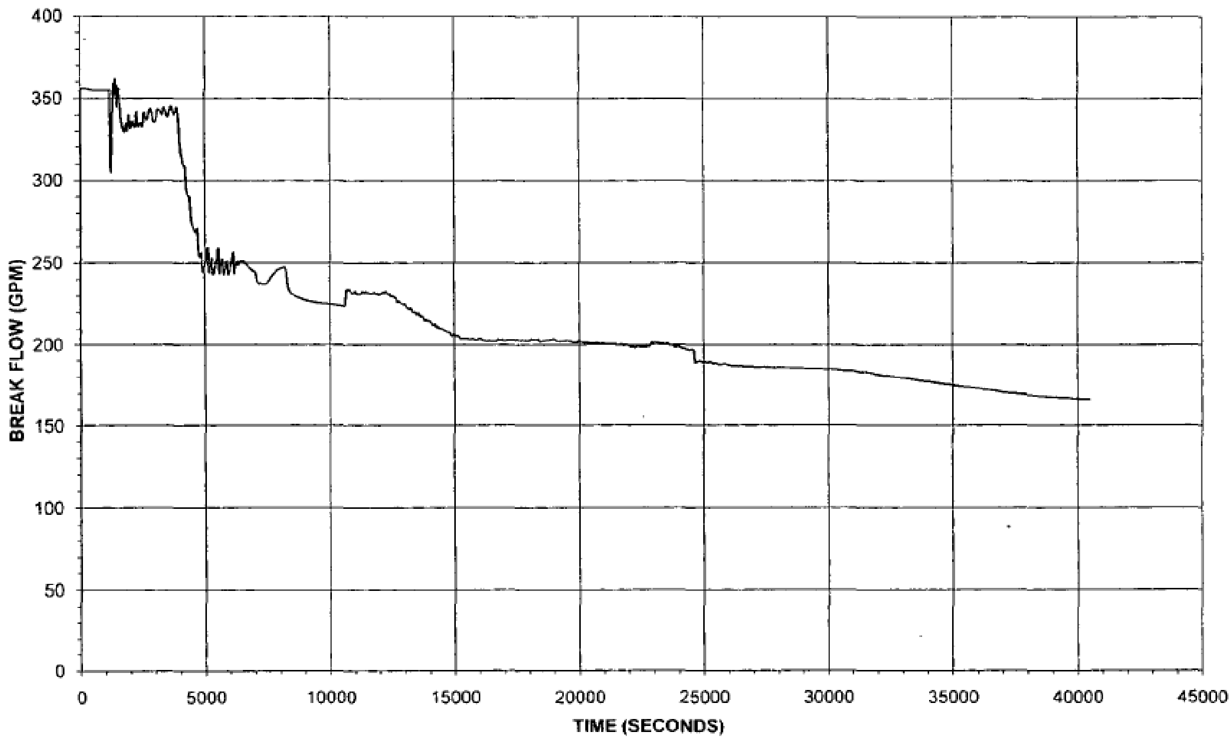

Figure 15-152. Steam Generator Tube Rupture - RCS Pressure

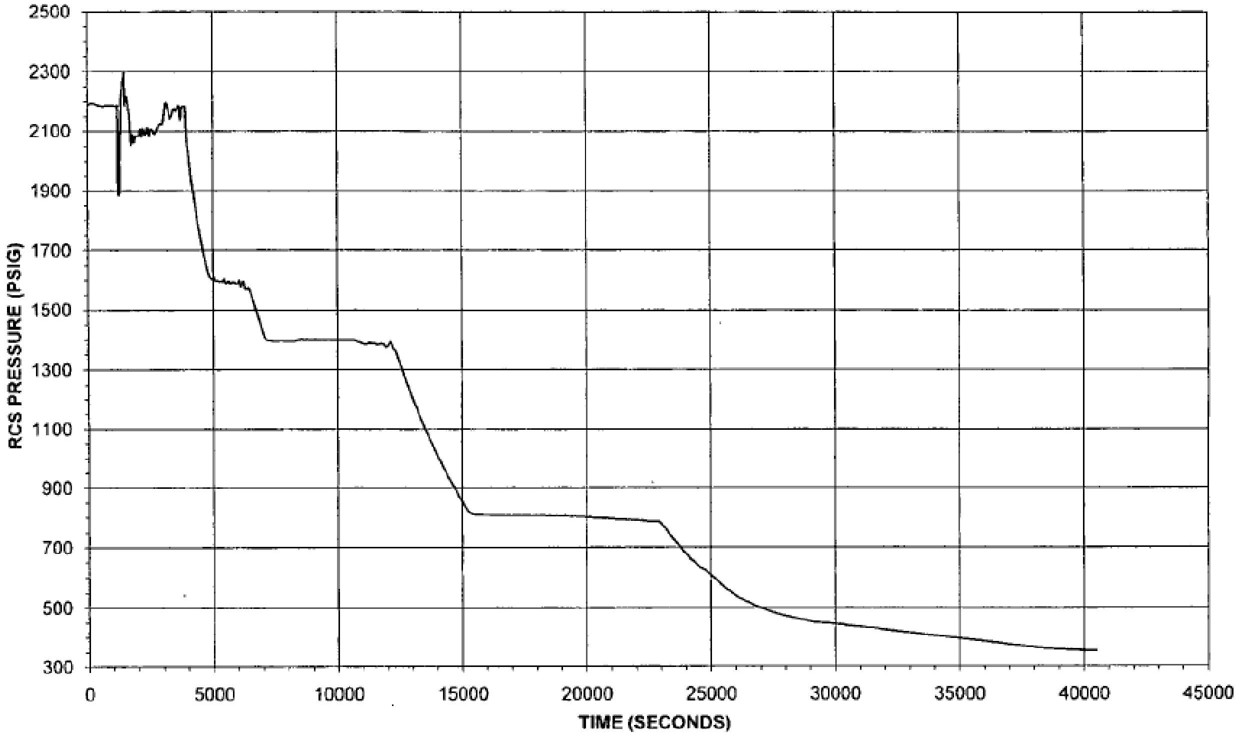

Figure 15-153. Steam Generator Tube Rupture - Pressurizer Level

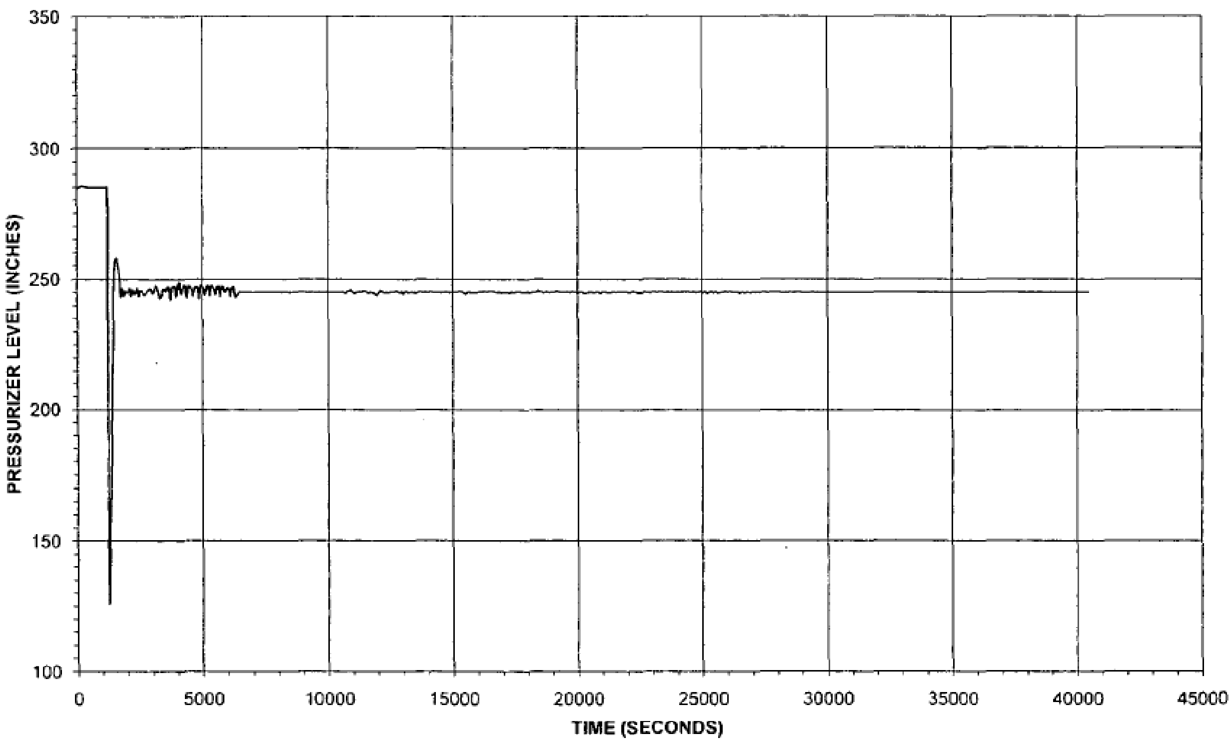

Figure 15-154. Steam Generator Tube Rupture - Steam Generator Pressure

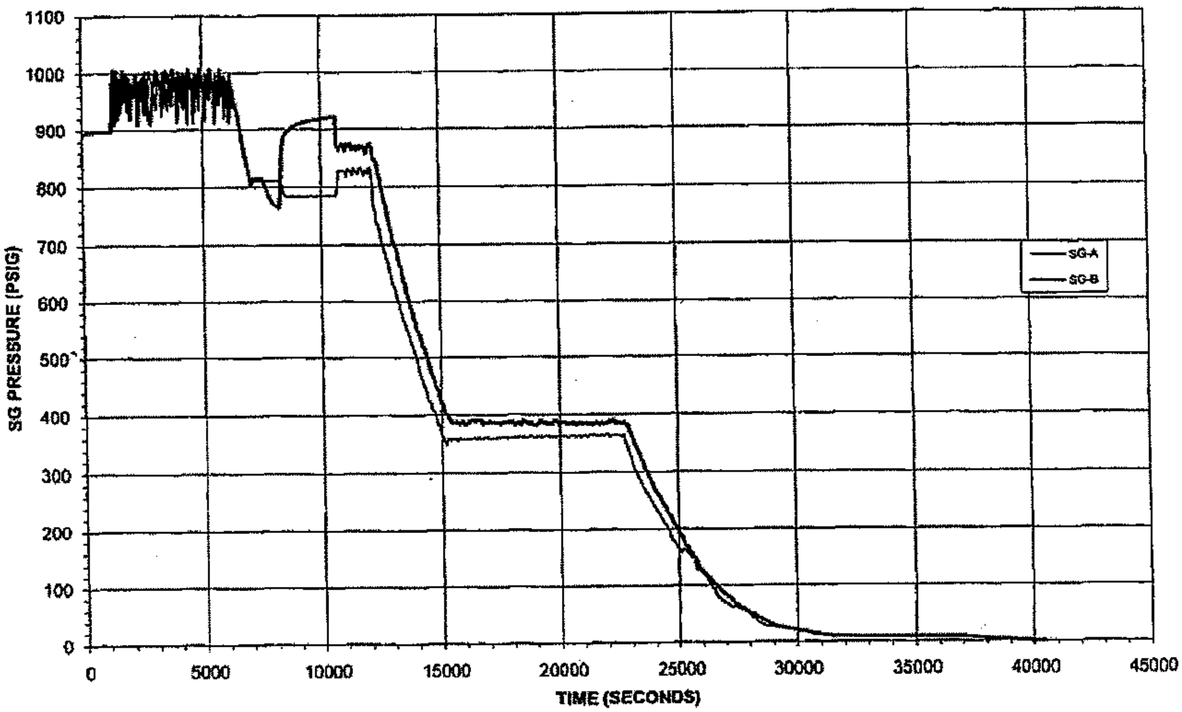

Figure 15-155. Steam Generator Tube Rupture - Steam Generator Level

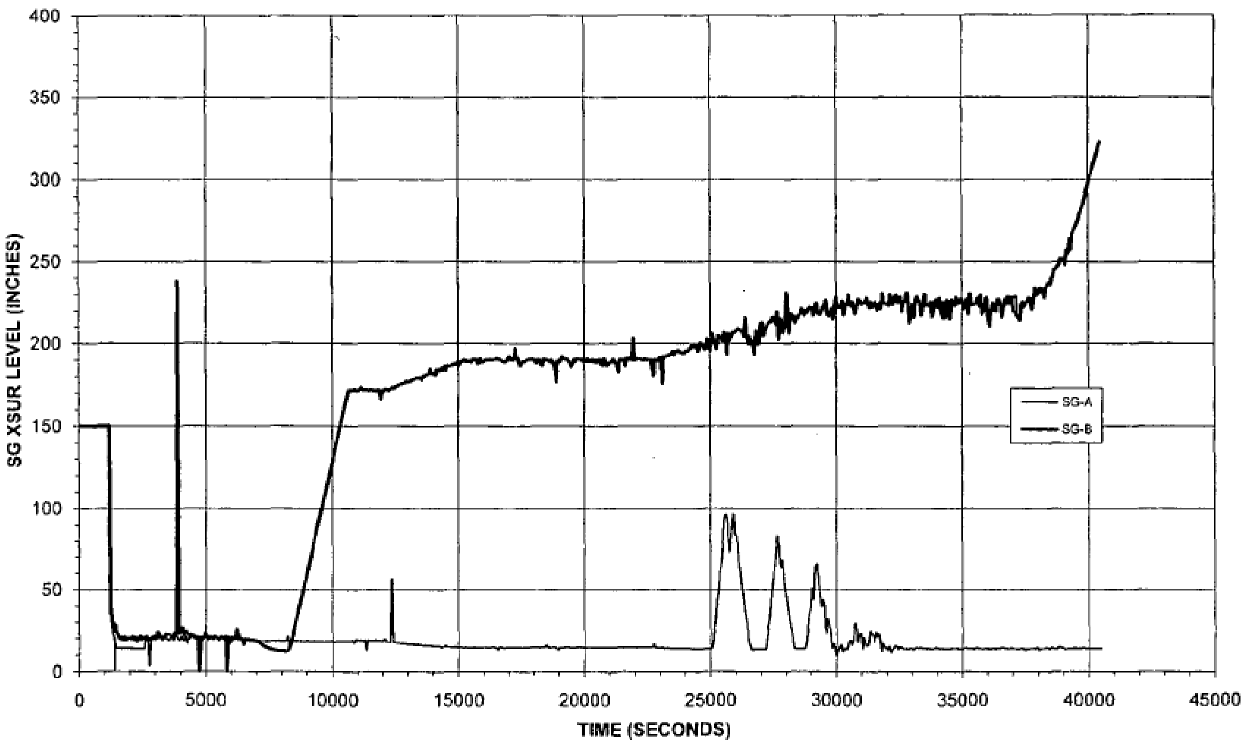

Figure 15-156. Steam Generator Tube Rupture - RCS Temperatures

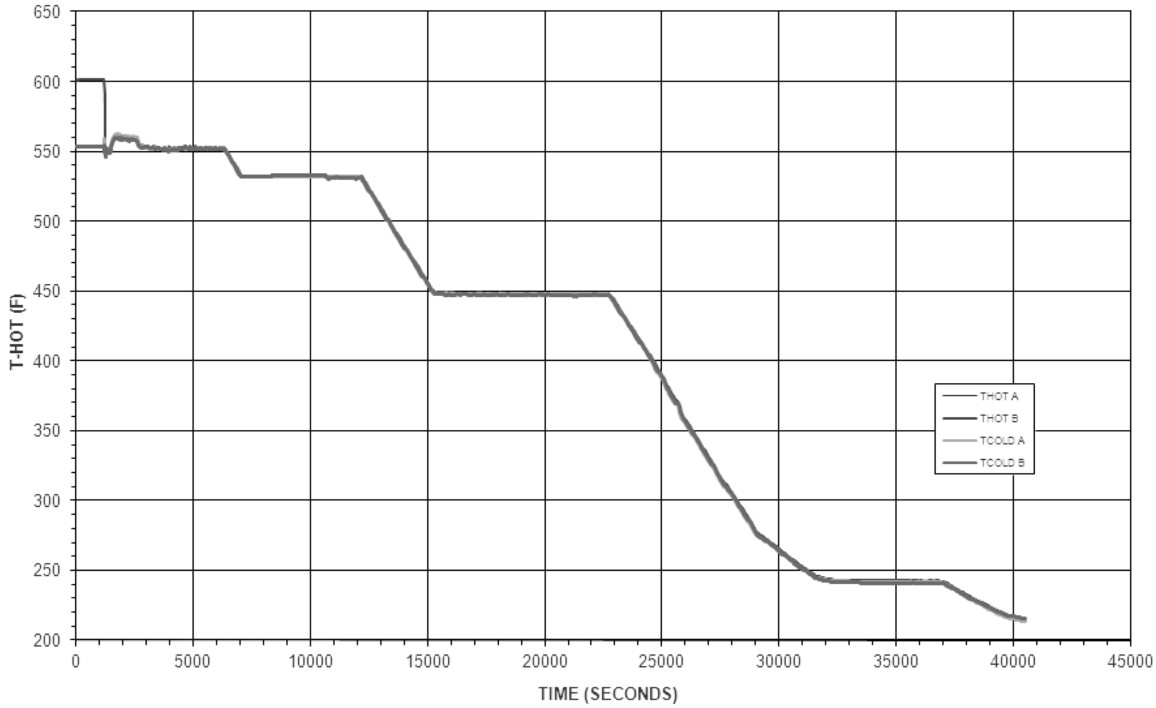

Figure 15-157. Steam Line Break Accident - With Offsite Power - Power

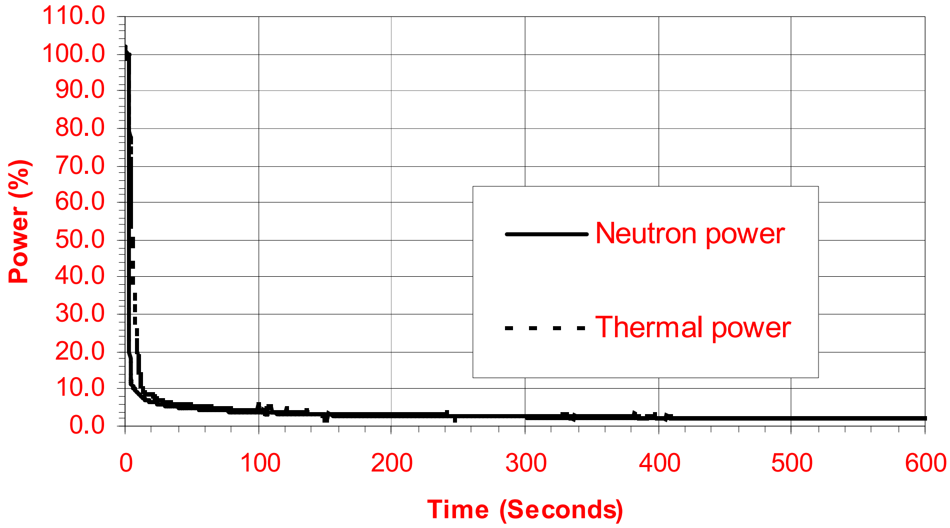

Figure 15-158. Steam Line Break Accident - With Offsite Power - RCS Pressure

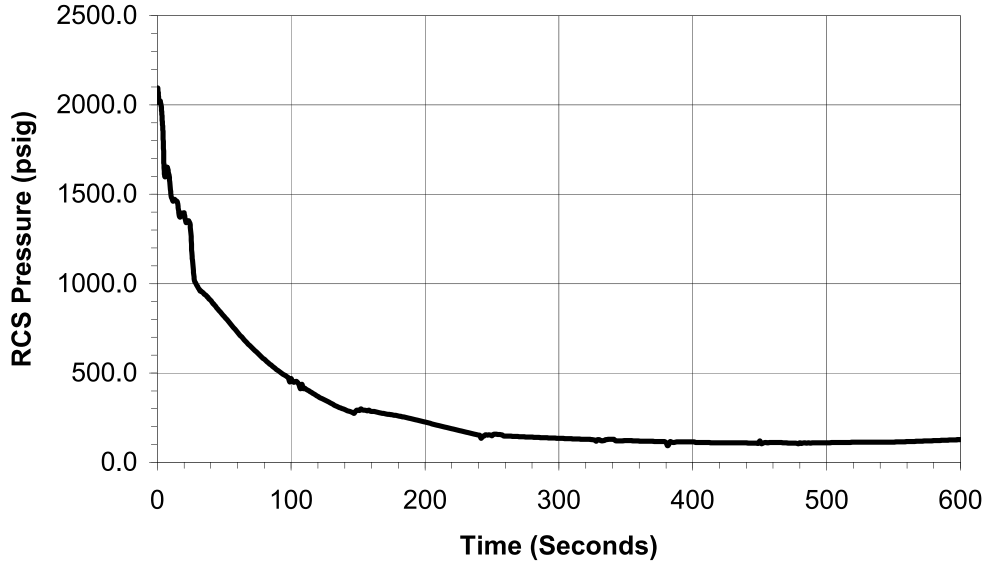

Figure 15-159. Steam Line Break Accident - With Offsite Power - Core Inlet Flow

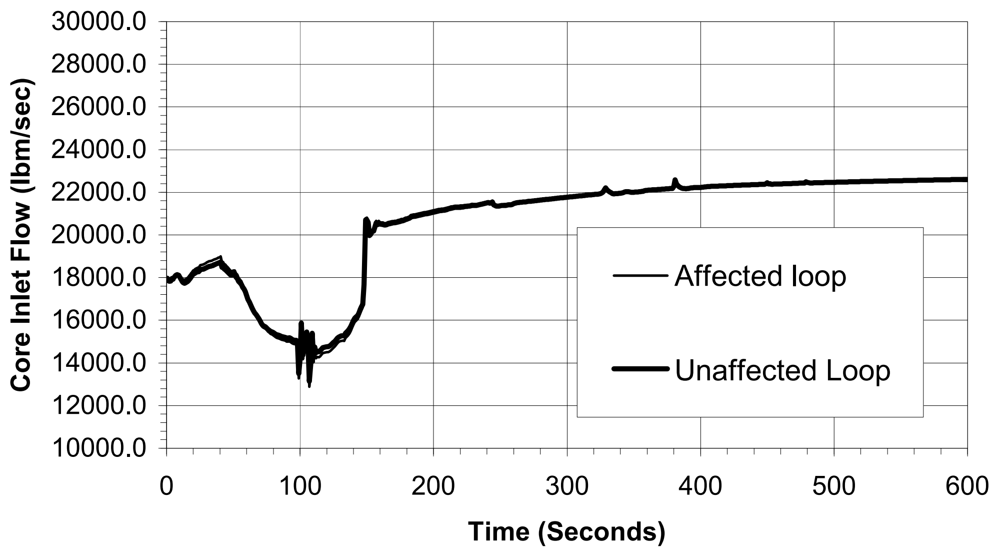

Figure 15-160. Deleted Per 2003 Update

Figure 15-161. Steam Line Break Accident - Without Offsite Power - Steam Line Pressure

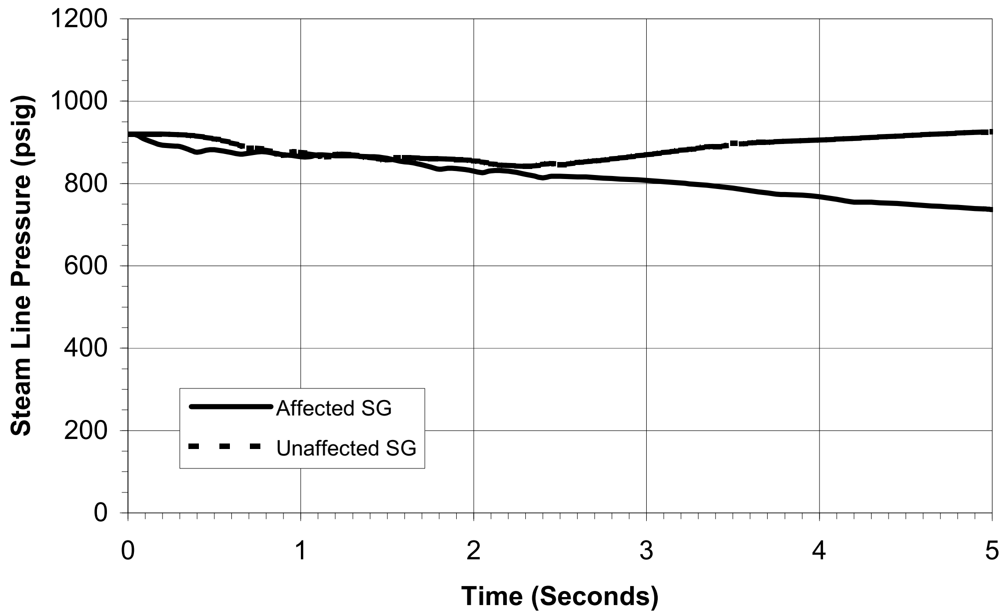

Figure 15-162. Steam Line Break Accident - Without Offsite Power - RCS Temperatures

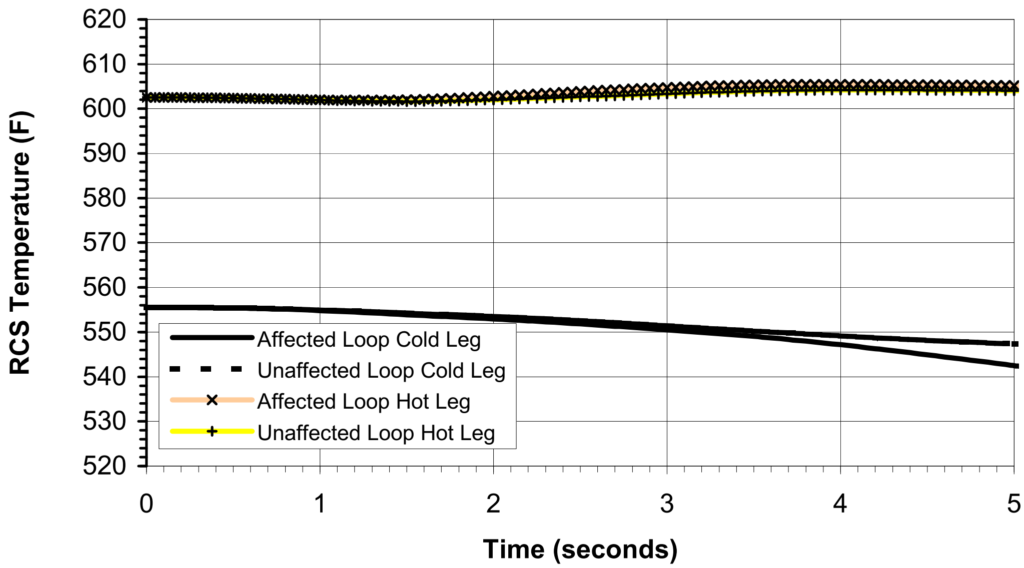

Figure 15-163. Steam Line Break Accident - Without Offsite Power - RCS Flow

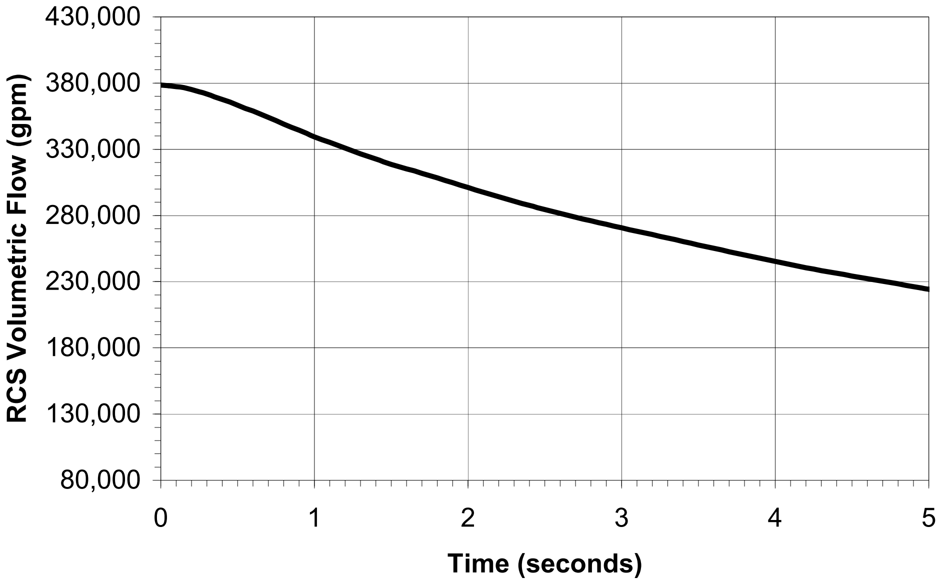

Figure 15-164. Steam Line Break Accident - Without Offsite Power - Reactivity

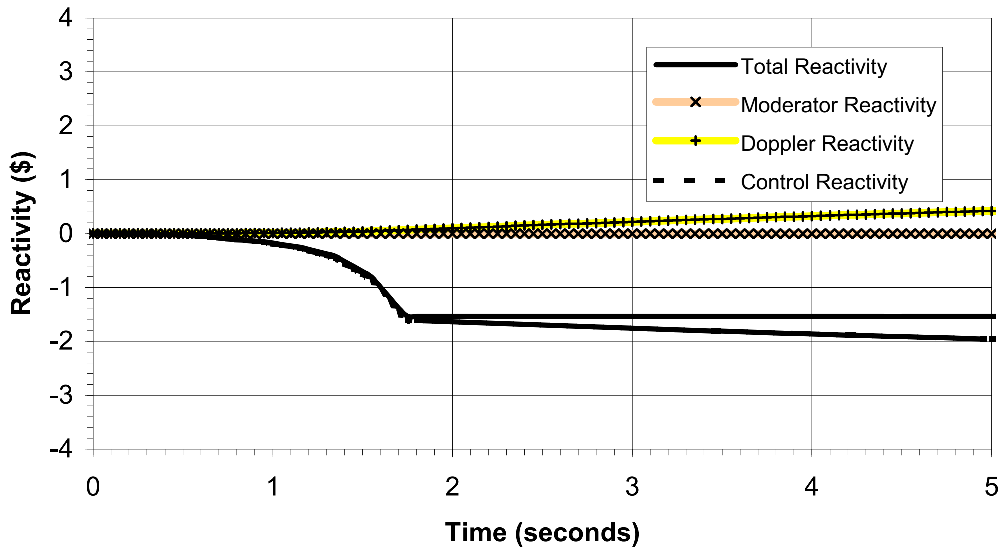

Figure 15-165. Steam Line Break Accident - Without Offsite Power – Power

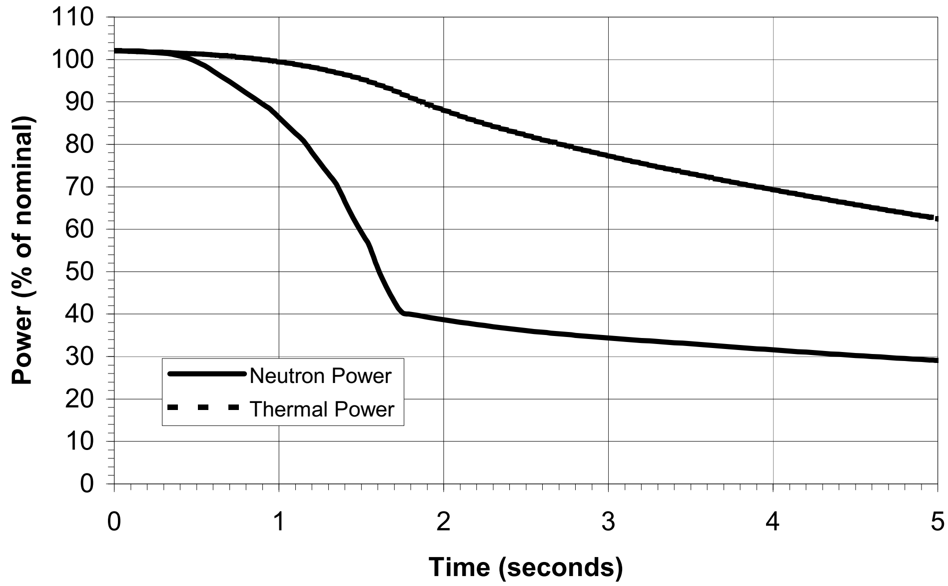

Figure 15-166. Steam Line Break Accident - Without Offsite Power - RCS Pressure

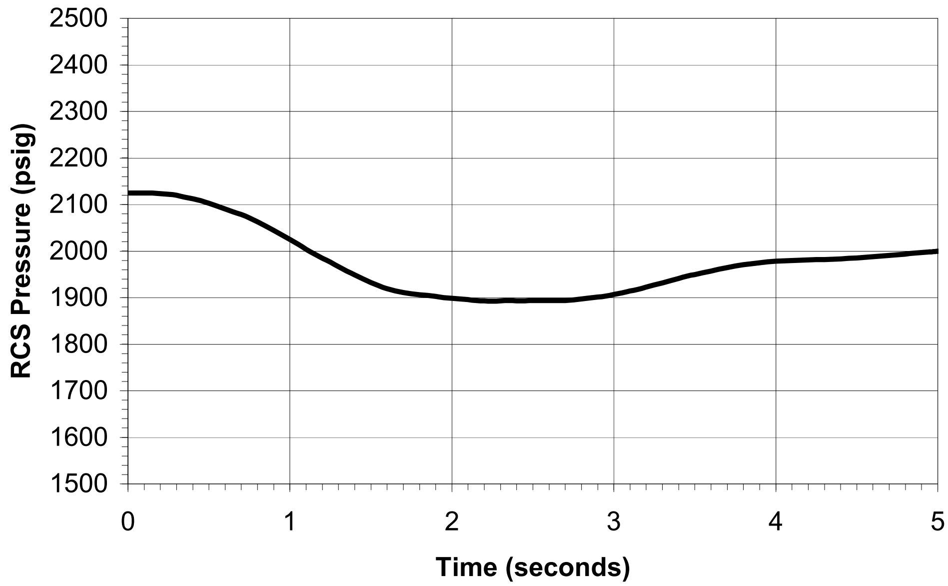

Figure 15-167. Steam Line Break Accident - Without Offsite Power - DNBR

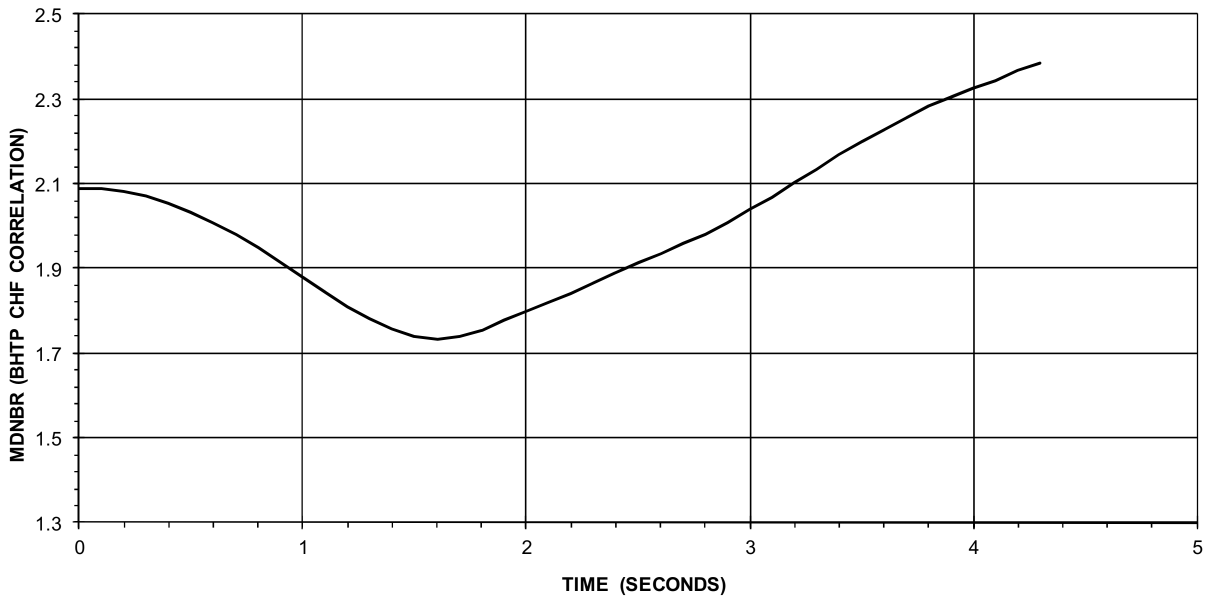

Figure 15-168. Small Steam Line Break - Steam Mass Flows

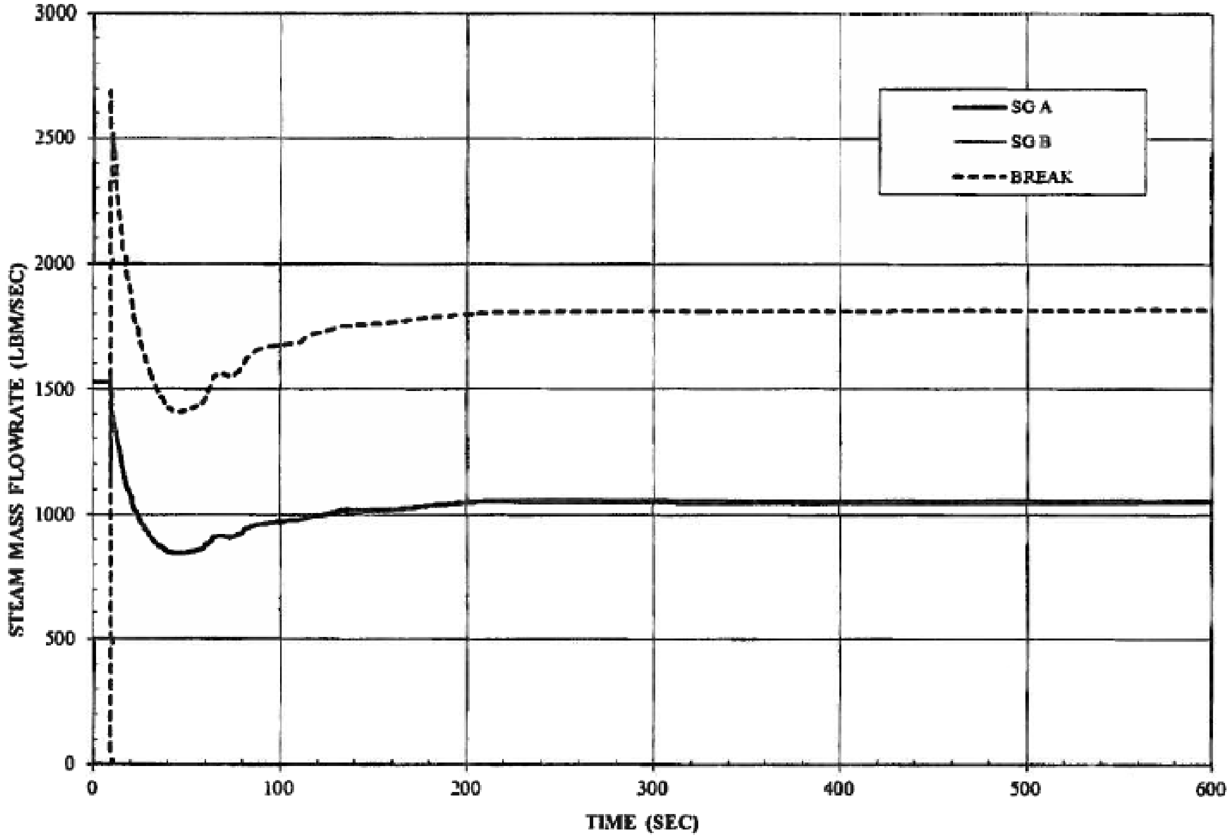

Figure 15-169. Small Steam Line Break - Steam Line Pressures

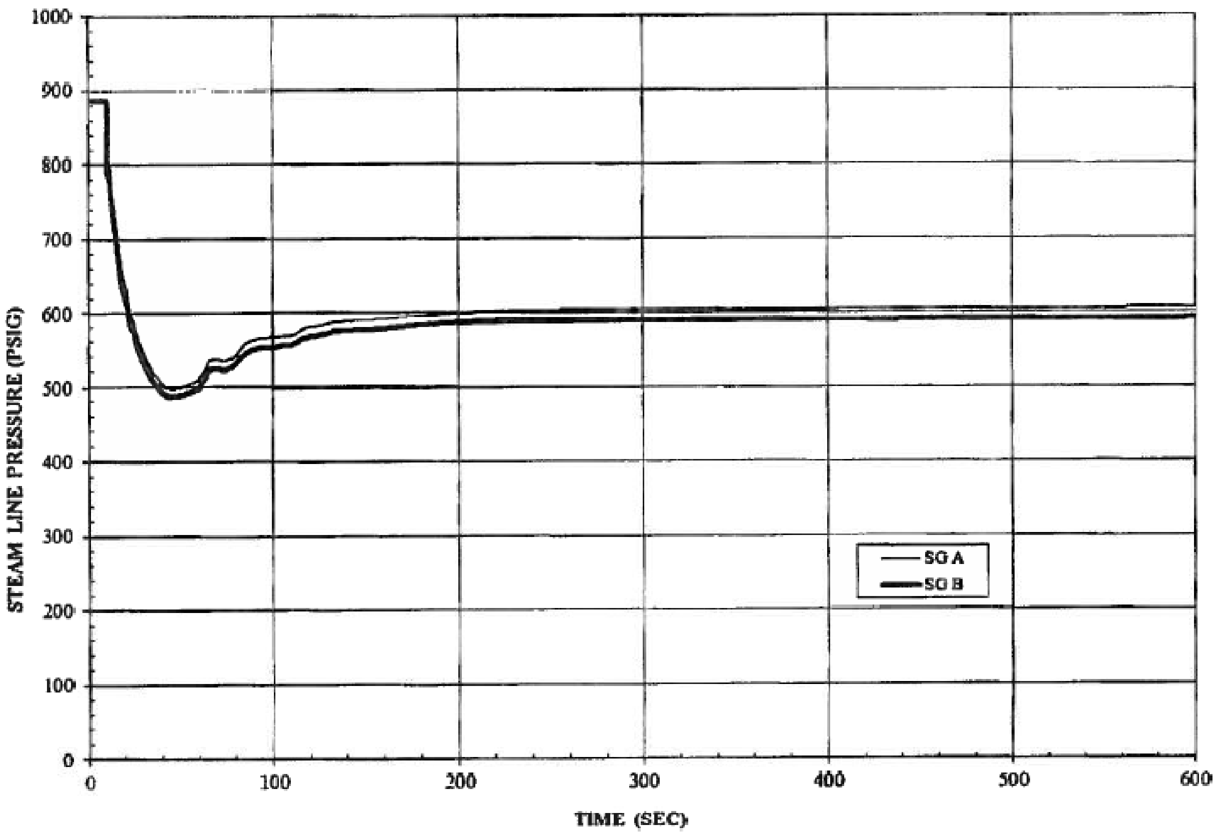

Figure 15-170. Small Steam Line Break - Main Feedwater Mass Flows

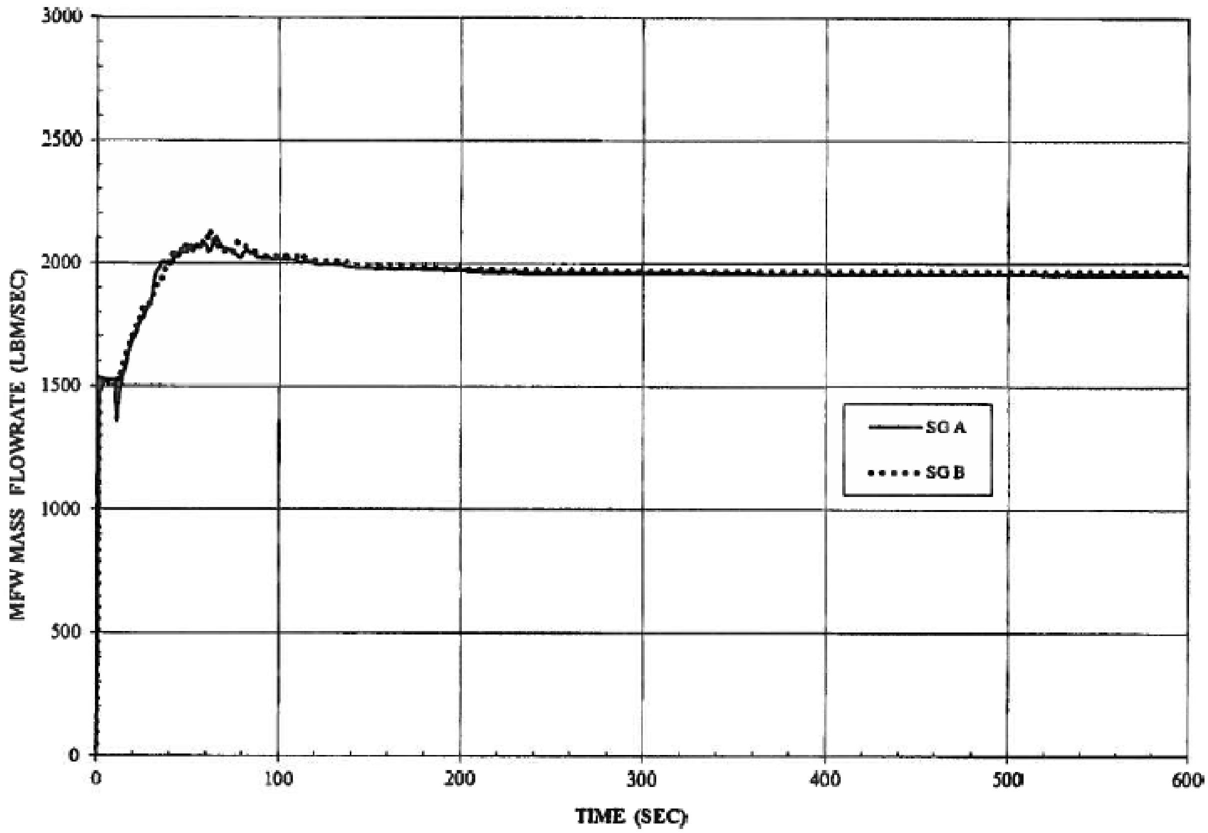

Figure 15-171. Small Steam Line Break – RCS Temperatures

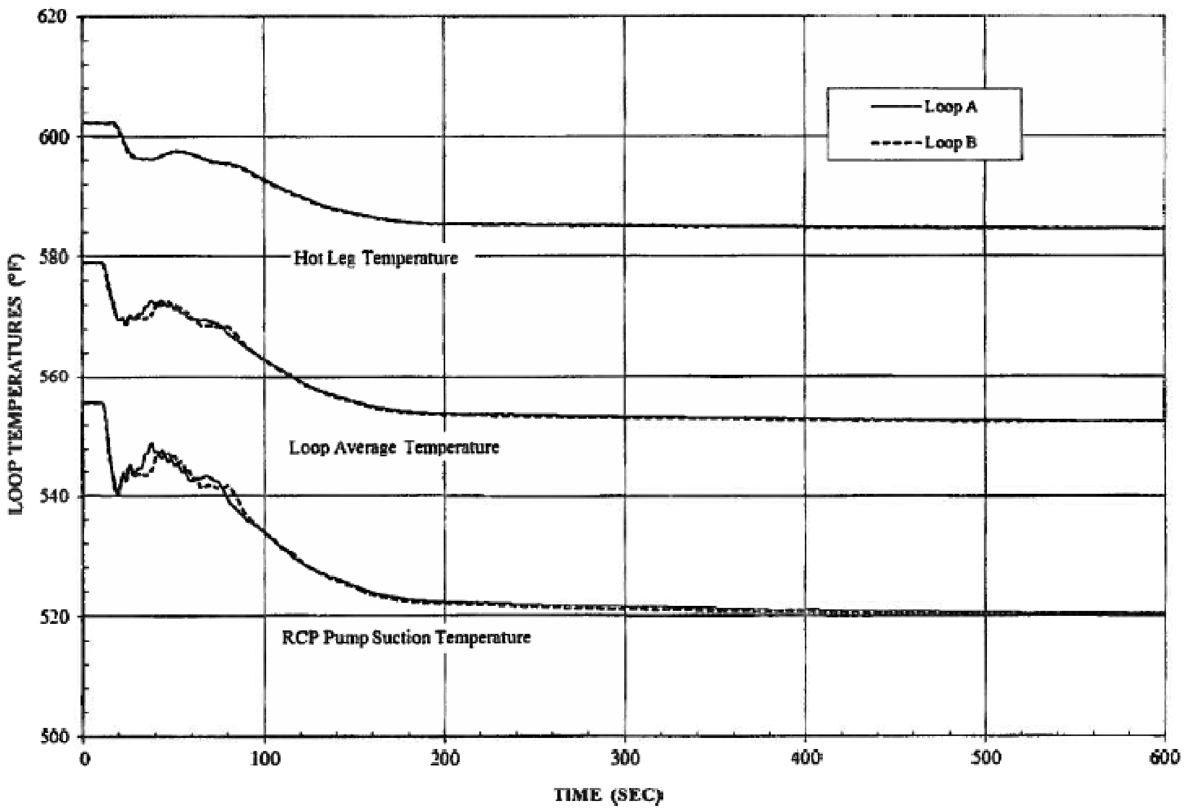

Figure 15-172. Small Steam Line Break – Core Average Power

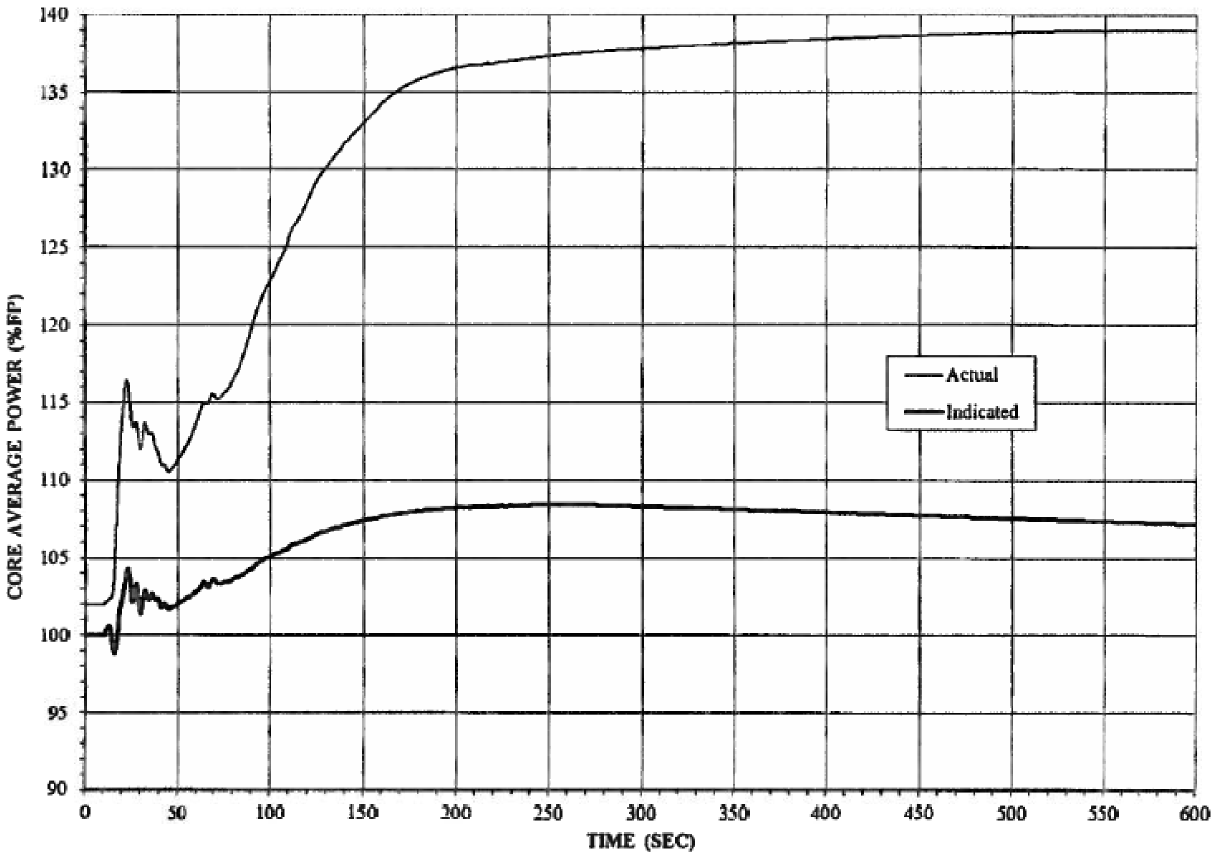

Figure 15-173. Small Steam Line Break - RCS Hot Leg Pressure

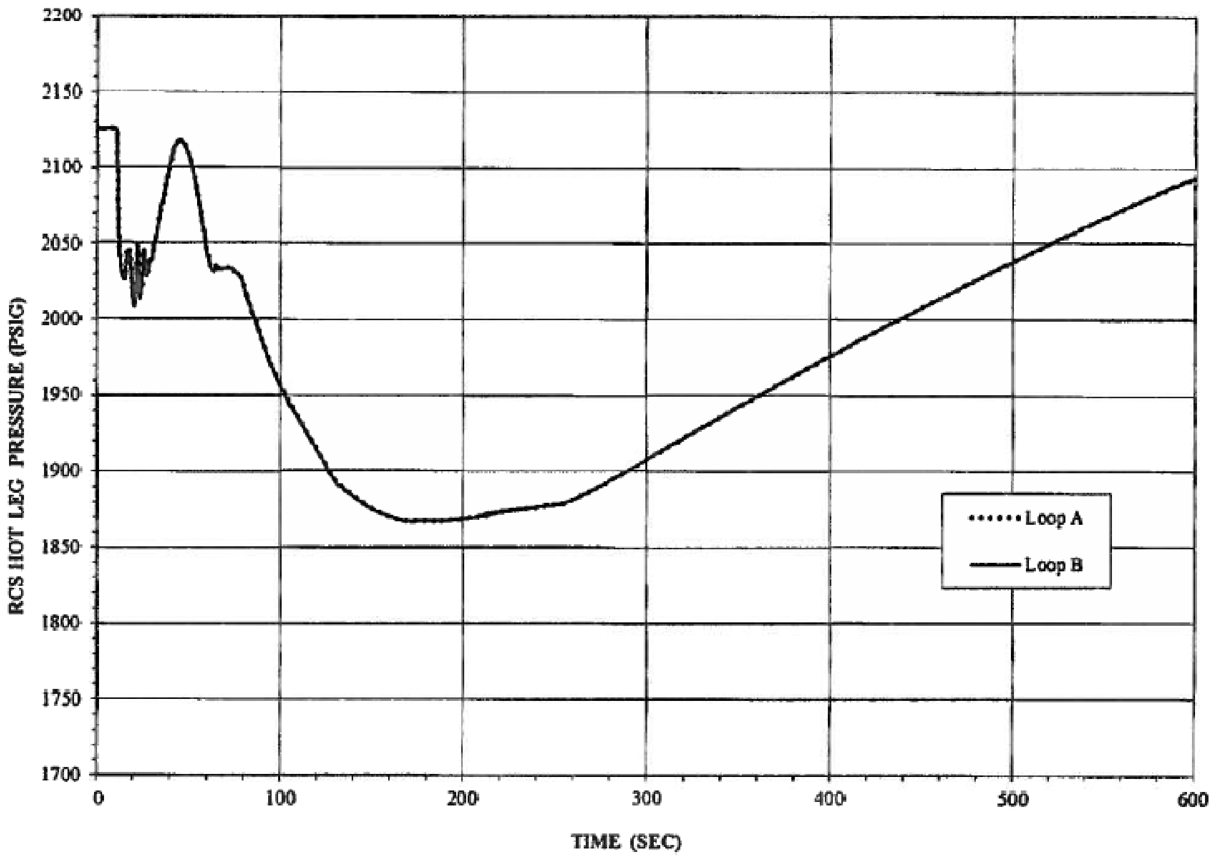

Figure 15-174. Deleted Per 2014 Update

Figure 15-175. Oconee - No CHRS Flow

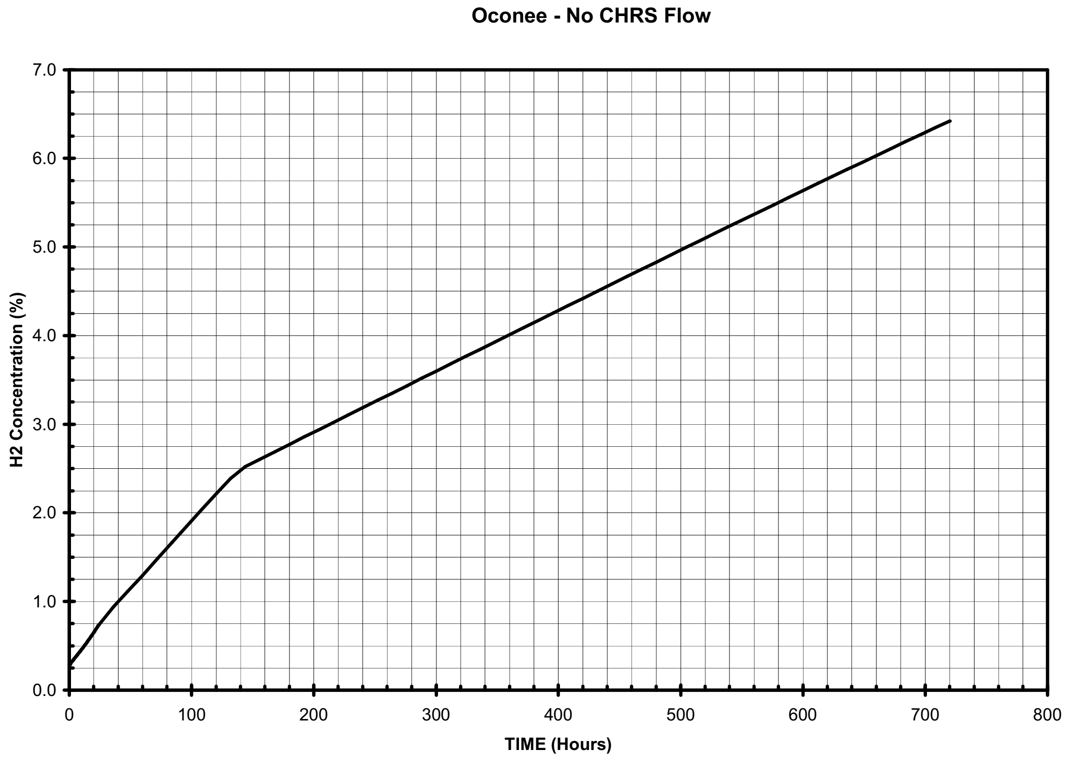

Figure 15-176. Deleted per 2001 Update

Figure 15-177. Lower Bound Containment Pressure Used in Large Break LOCA

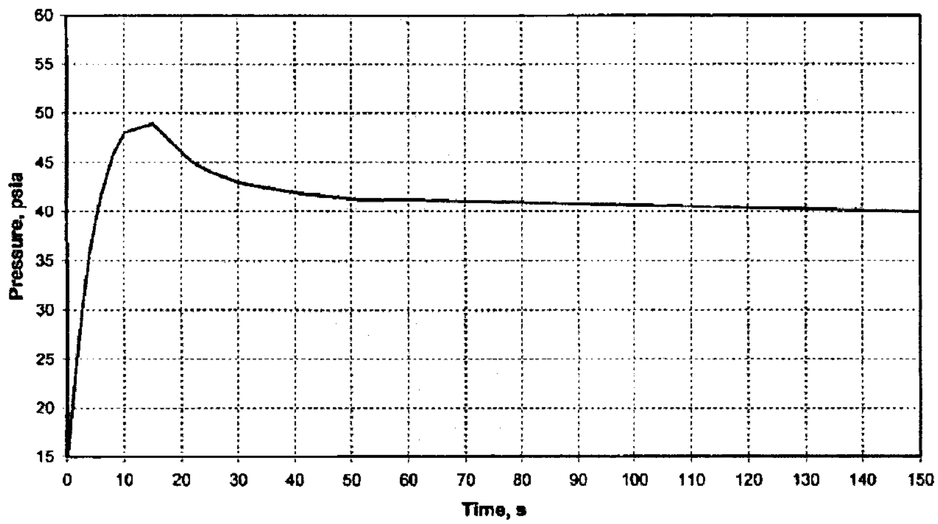

Figure 15-178. Deleted Per 2014 Update

Figure 15-179. Deleted Per 2014 Update

Figure 15-180. Deleted Per 2014 Update

Figure 15-181. Deleted Per 2014 Update

Figure 15-182. Deleted Per 2014 Update

Figure 15-183. Deleted Per 2014 Update

Figure 15-184. Deleted Per 2014 Update

Figure 15-185. Deleted Per 2014 Update

Figure 15-186. Deleted Per 2014 Update

Figure 15-187. Deleted Per 2014 Update

Figure 15-188. Deleted Per 2014 Update

Figure 15-189. Deleted Per 2014 Update

Figure 15-190. Deleted Per 2014 Update

Figure 15-191. Deleted Per 2014 Update

Figure 15-192. Deleted Per 2014 Update

Figure 15-193. Deleted Per 2014 Update

Figure 15-194. Deleted Per 2014 Update

Figure 15-195. Deleted Per 2014 Update

Figure 15-196. Deleted Per 2014 Update

Figure 15-197. Deleted Per 2014 Update

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Figure 15-199. Deleted Per 2014 Update

Figure 15-200. Deleted Per 2014 Update

Figure 15-201. Deleted Per 2014 Update

Figure 15-202. Deleted Per 2014 Update

Figure 15-203. Deleted Per 2014 Update

Figure 15-204. Deleted Per 2014 Update

Figure 15-205. Deleted Per 2014 Update

Figure 15-206. Deleted Per 2014 Update

Figure 15-207. Deleted Per 2014 Update

Figure 15-208. Deleted Per 2014 Update

Figure 15-209. Deleted Per 2014 Update

Figure 15-210. Deleted Per 2014 Update

Figure 15-211. Deleted Per 2014 Update

Figure 15-212. Deleted Per 2014 Update

Figure 15-213. 52% of 2568 MWt, Full Core Mark-B-HTP SBLOCA Break Spectrum Analysis

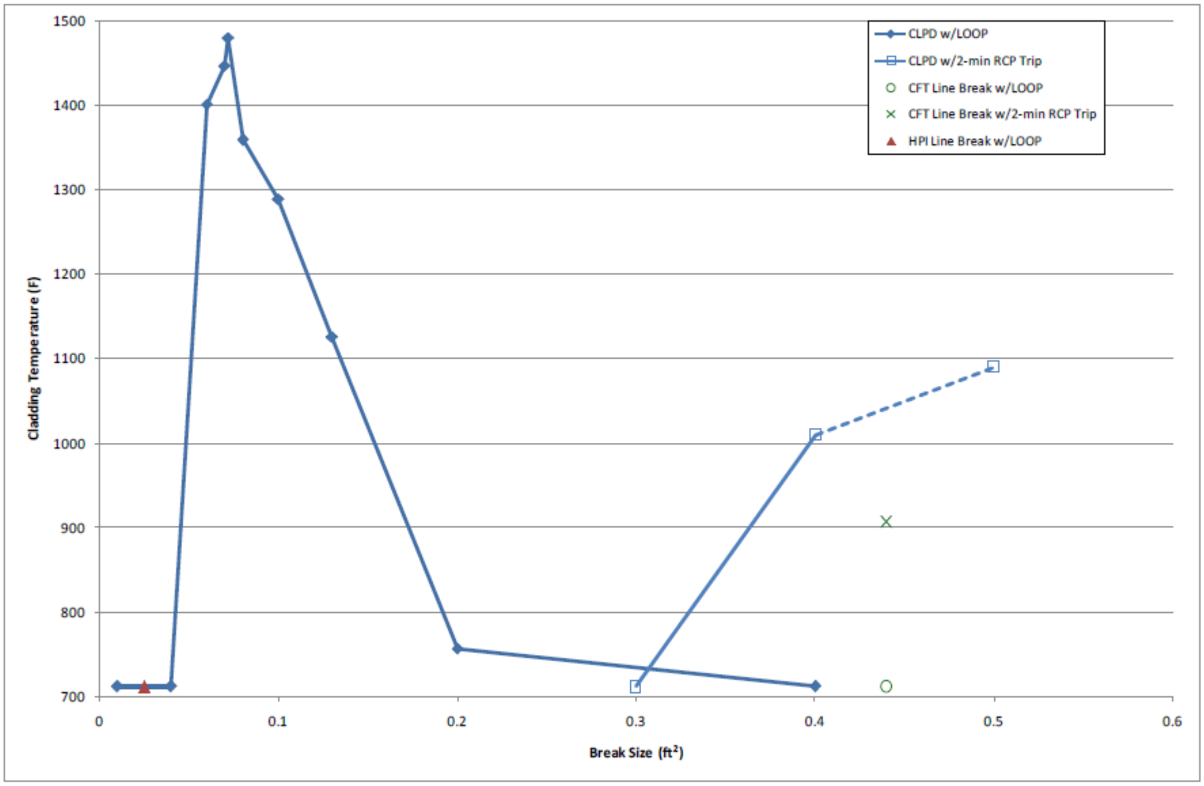

Figure 15-214. 0.072 ft^2 CLPD, 52% of 2568 MWt, Full-Core Mark-B-HTP SBLOCA - Pressure

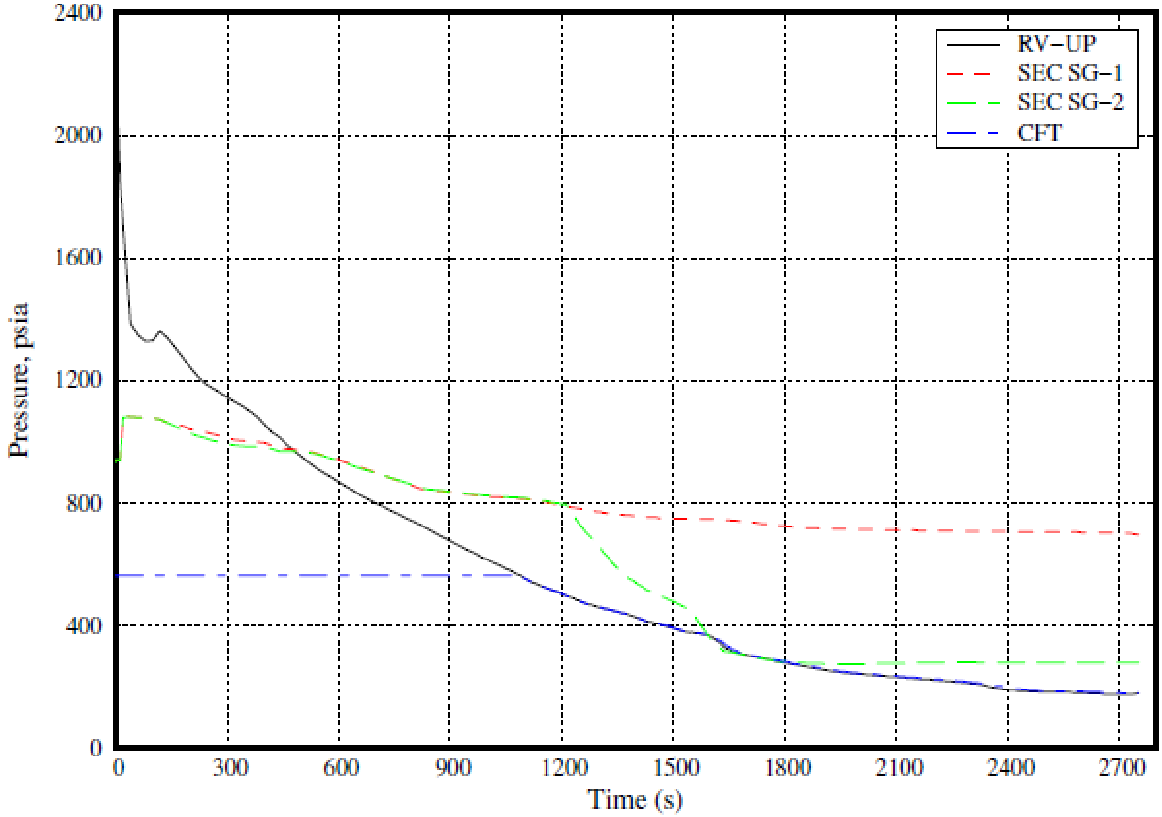

Figure 15-215. 0.072 ft^2 CLPD, 52% of 2568 MWt, Full Core Mark-B-HTP SBLOCA - Break and ECCS Mass Flow Rates

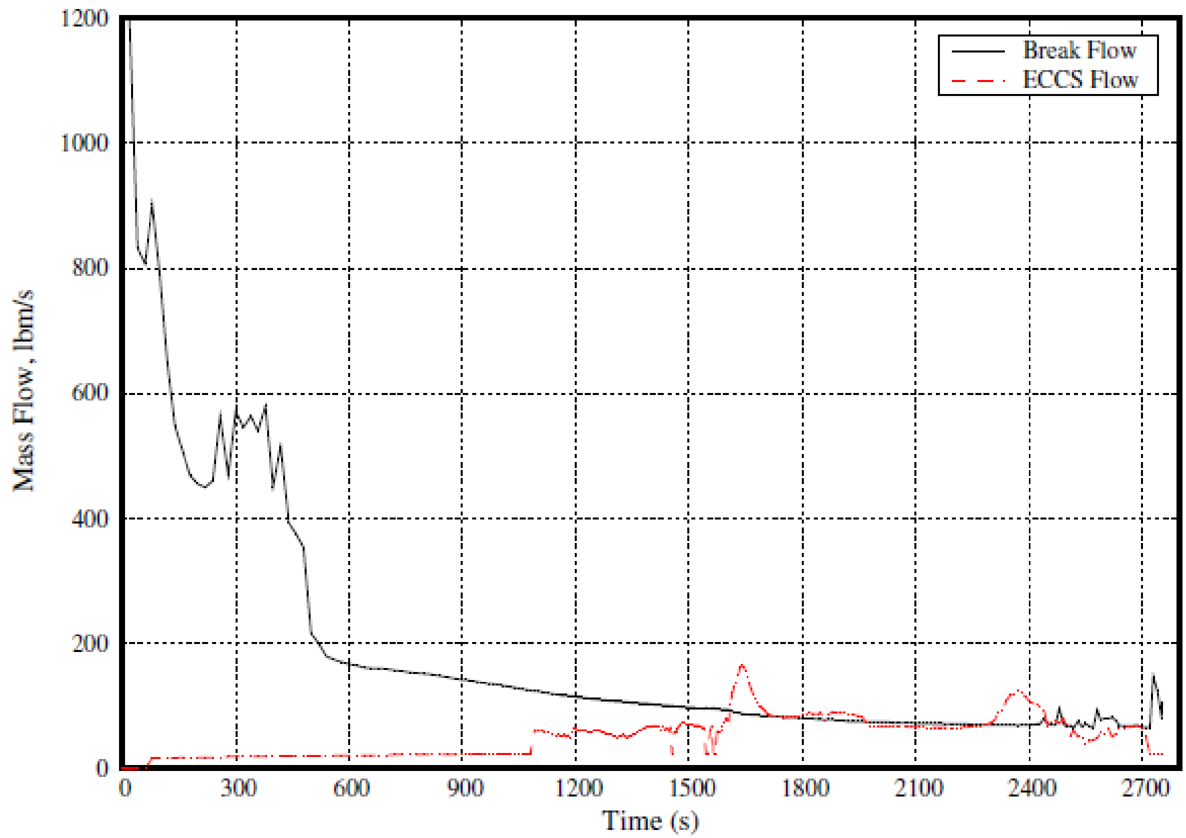

Figure 15-216. 0.072 ft^2 CLPD, 52% of 2568 MWt, Full Core Mark-B-HTP SBLOCA - RV Collapsed Liquid Level & Hot Channel Mixture Level

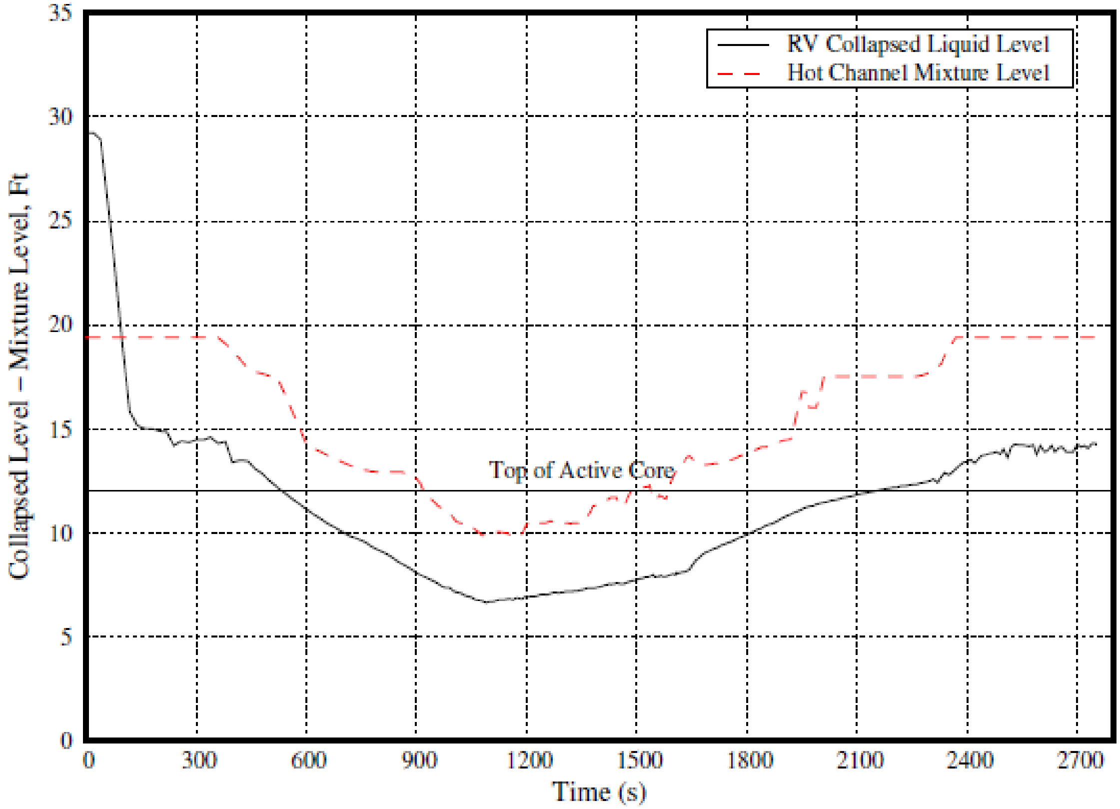

Figure 15-217. 0.072 ft^2 CLPD, 52% of 2568 MWt, Full Core Mark-B-HTP SBLOCA - Peak Cladding Temperature

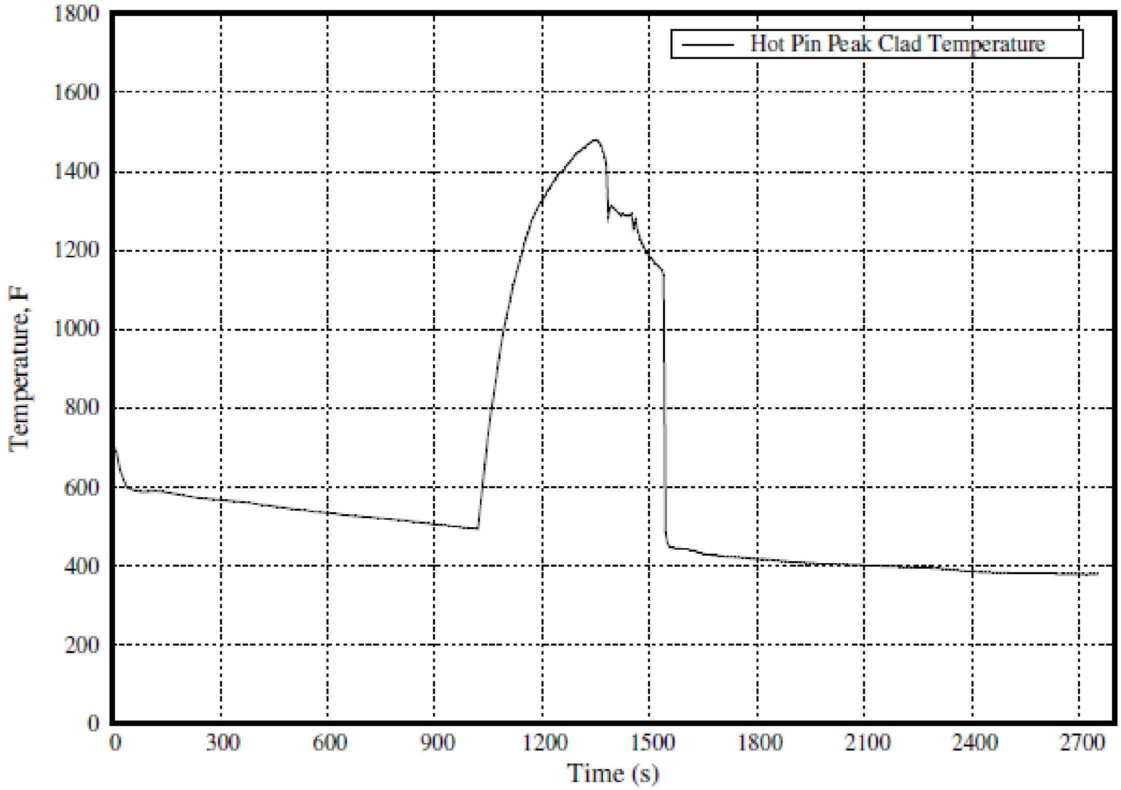

Figure 15-218. 0.072 ft^2 CLPD, 52% of 2568 MWt, Full Core Mark-B-HTP SBLOCA - Hot Channel Vapor Temperature at Core Exit

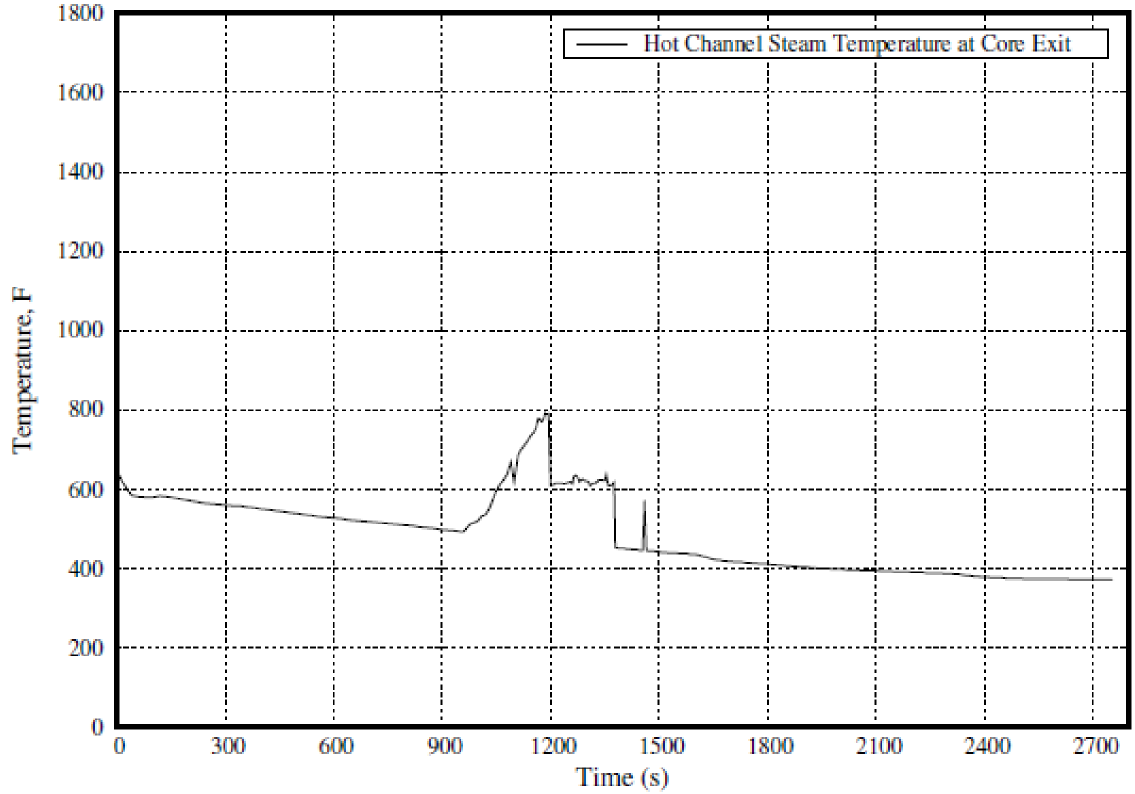

Figure 15-219. Mark-B-HTP Full-Core MOL LBLOCA – Reactor Vessel Upper Plenum Pressure

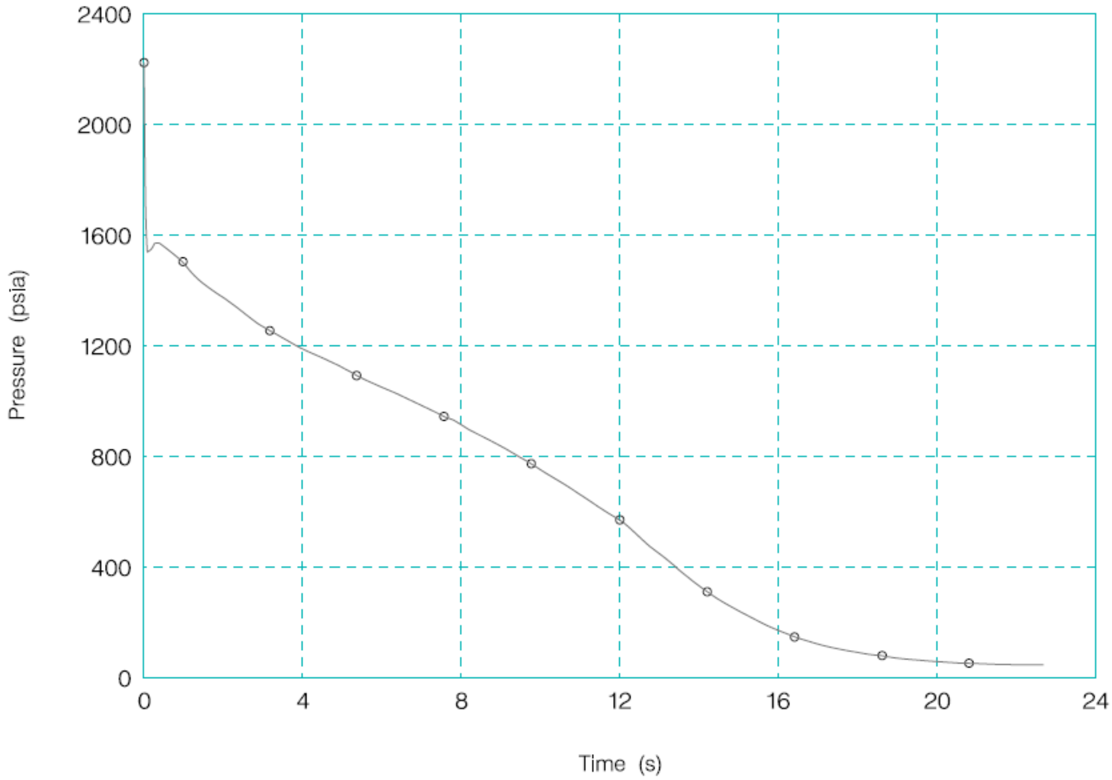

Figure 15-220. Mark-B-HTP Full-Core MOL LBLOCA – Break Mass Flow Rates

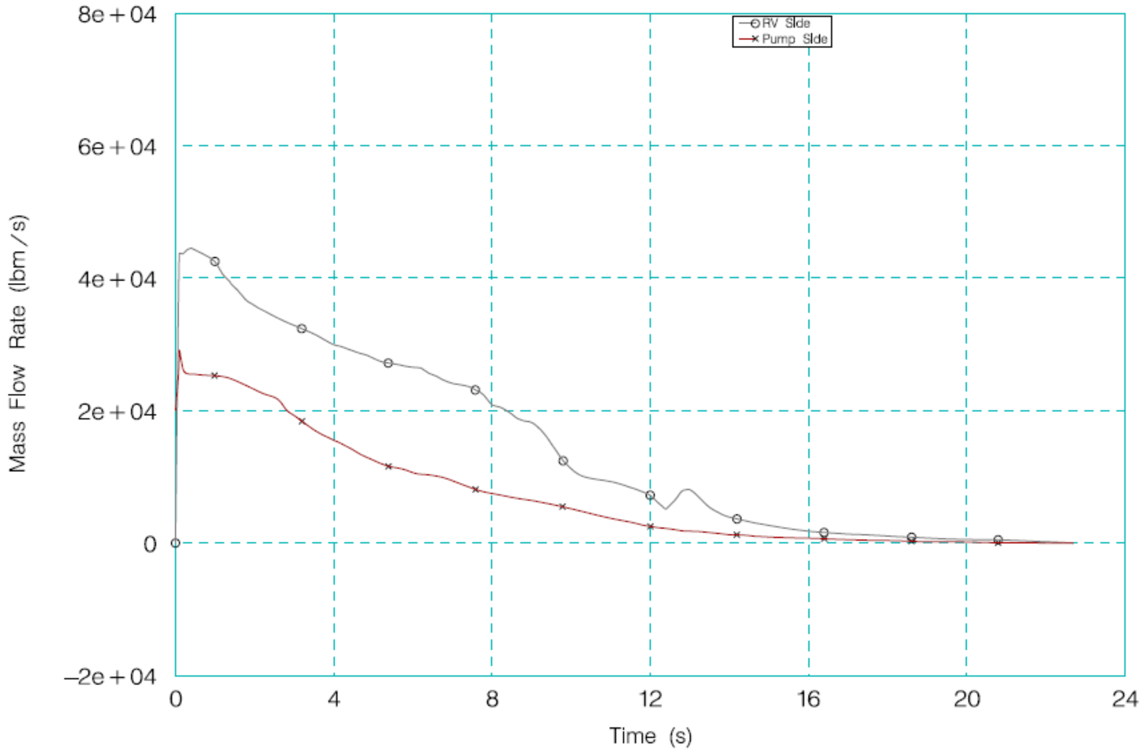

Figure 15-221. Mark-B-HTP Full-Core MOL LBLOCA – Hot Channel Mass Flow Rates

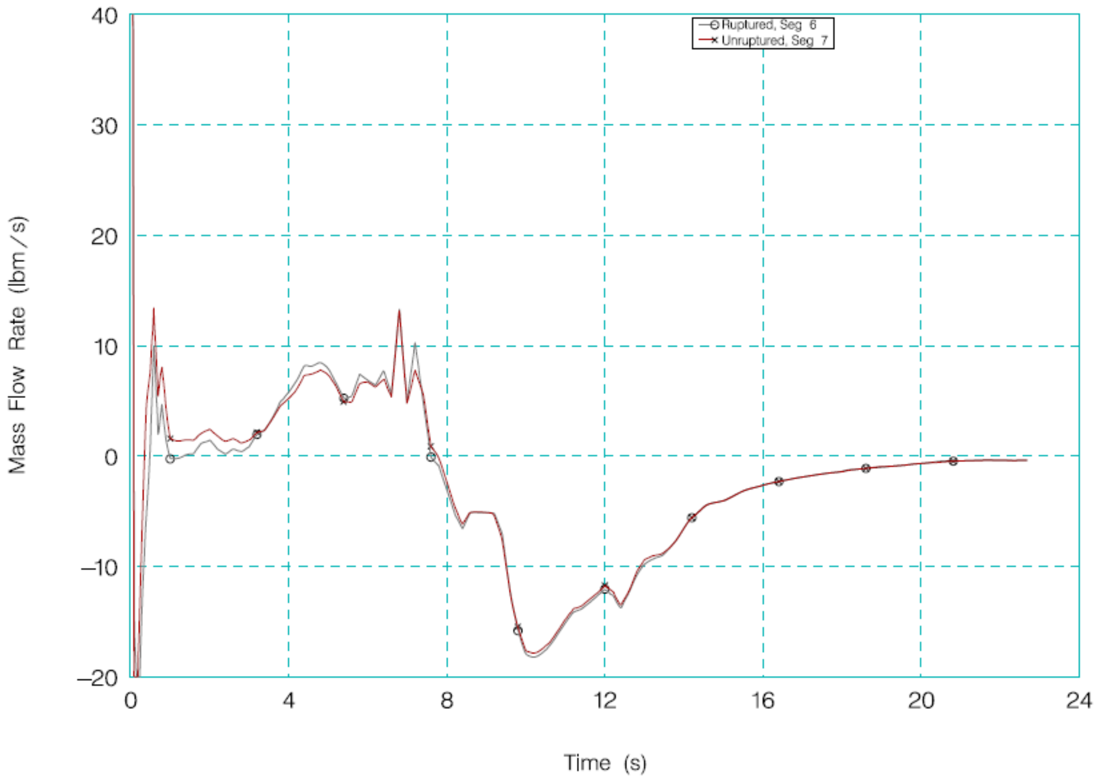

Figure 15-222. Mark-B-HTP Full-Core MOL LBLOCA – Core Flooding Rates

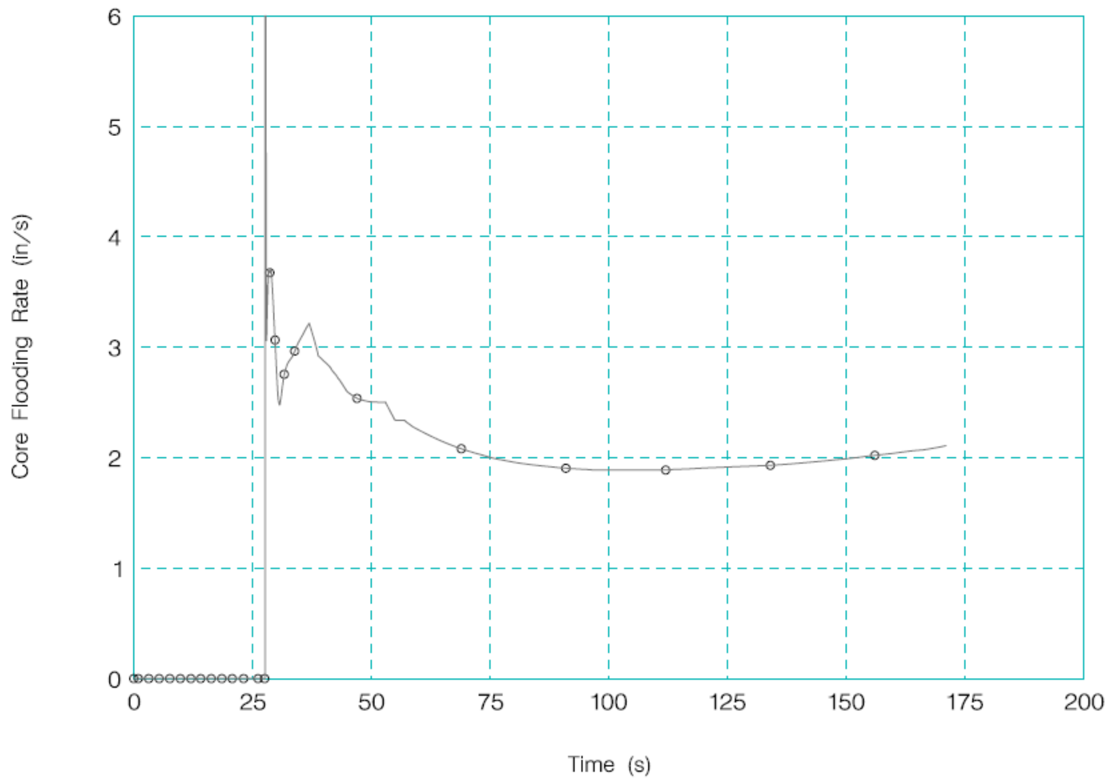

Figure 15-223. Mark-B-HTP Full-Core MOL LBLOCA – Hot Pin Fuel & Clad Temperatures at Ruptured Location

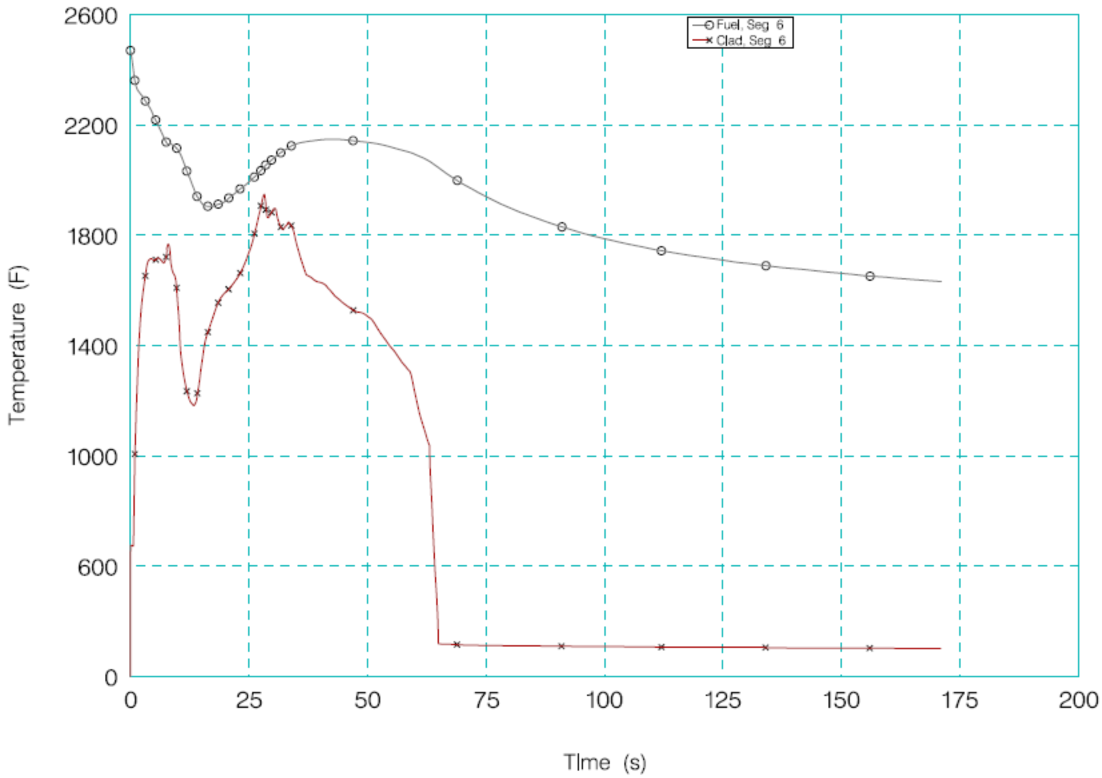

Figure 15-224. Mark-B-HTP Full-Core MOL LBLOCA – Hot Pin Fuel & Clad Temperatures at Unruptured Location

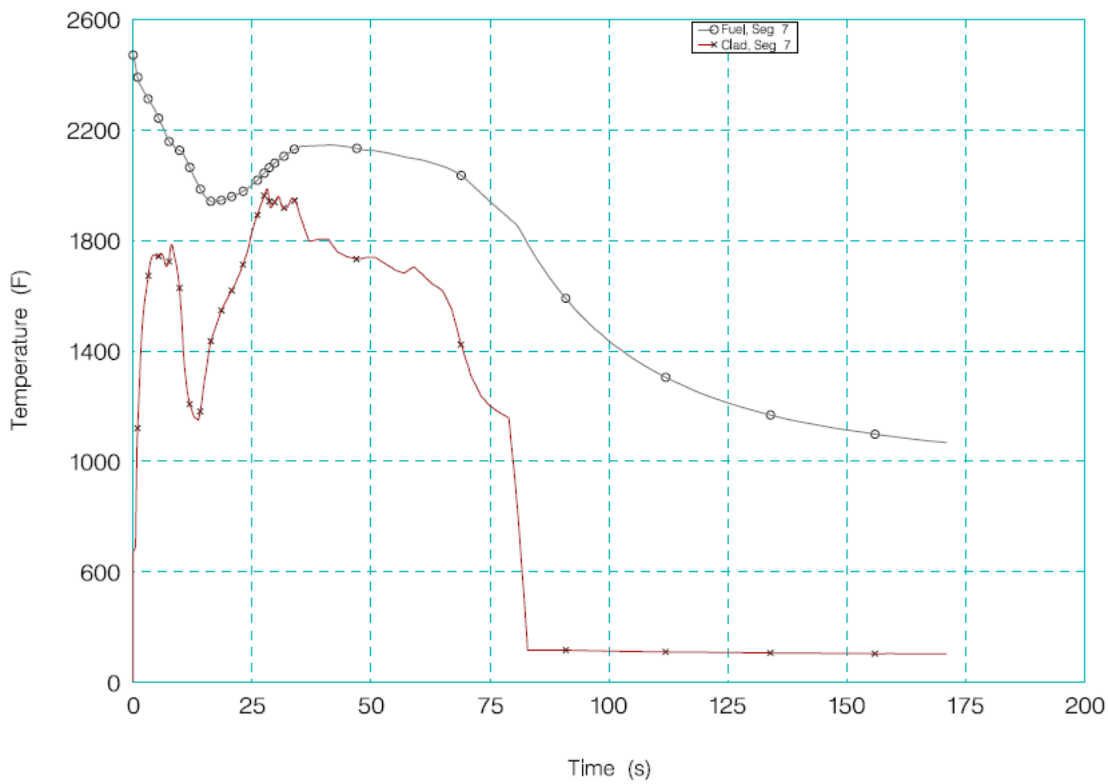

Figure 15-225. Mark-B-HTP Full-Core MOL LBLOCA – Quench Front Advancement

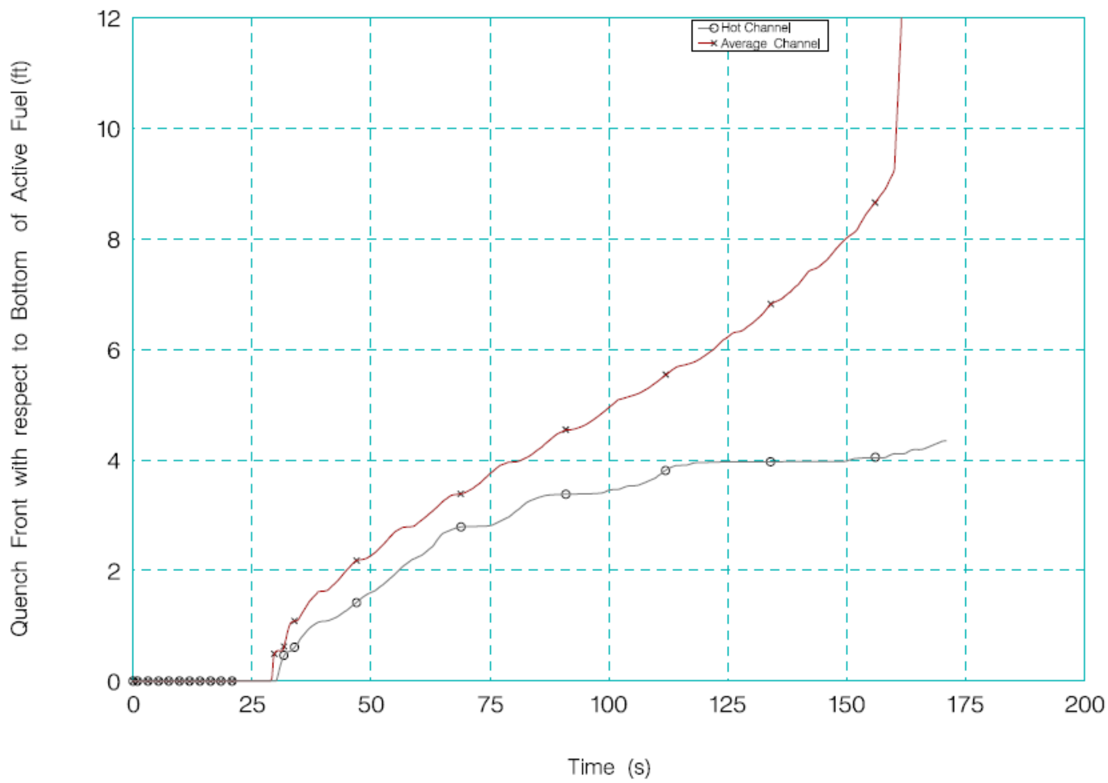

Figure 15-226. Mark-B-HTP Full-Core MOL LBLOCA – Hot Pin Heat Transfer Coefficients

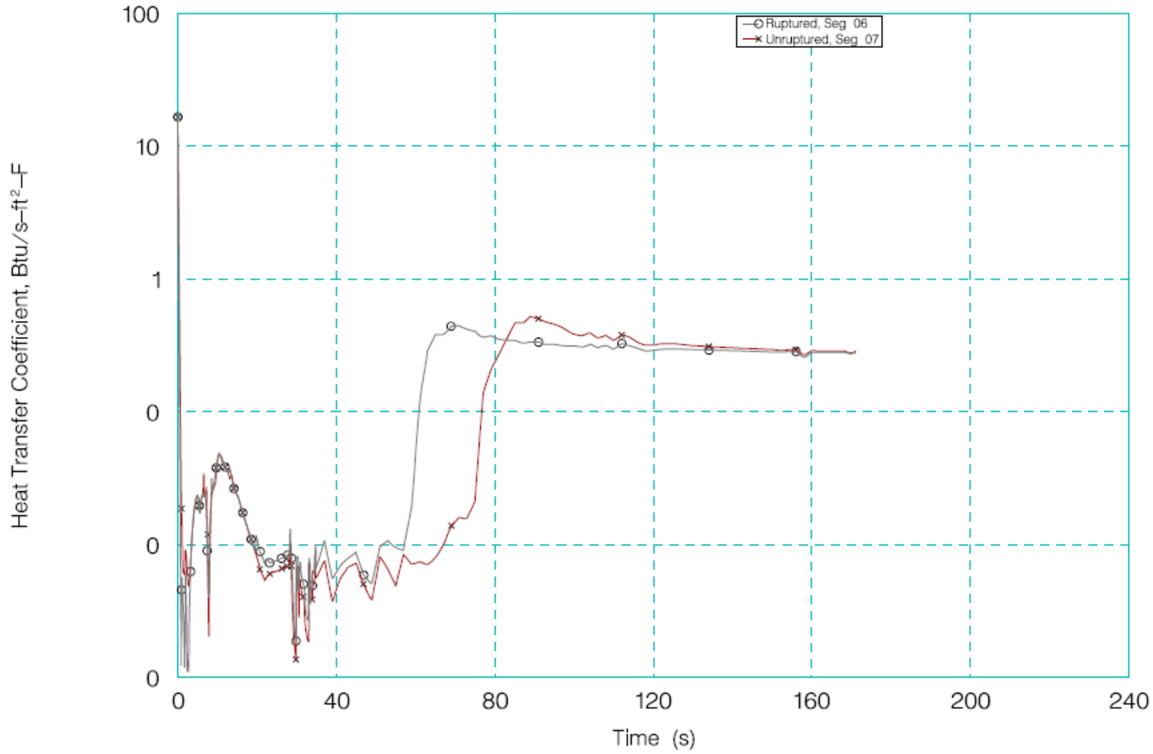

Figure 15-227. 102% of 2568 MWt, Full Core Mark-B-HTP SBLOCA Break Spectrum Analysis

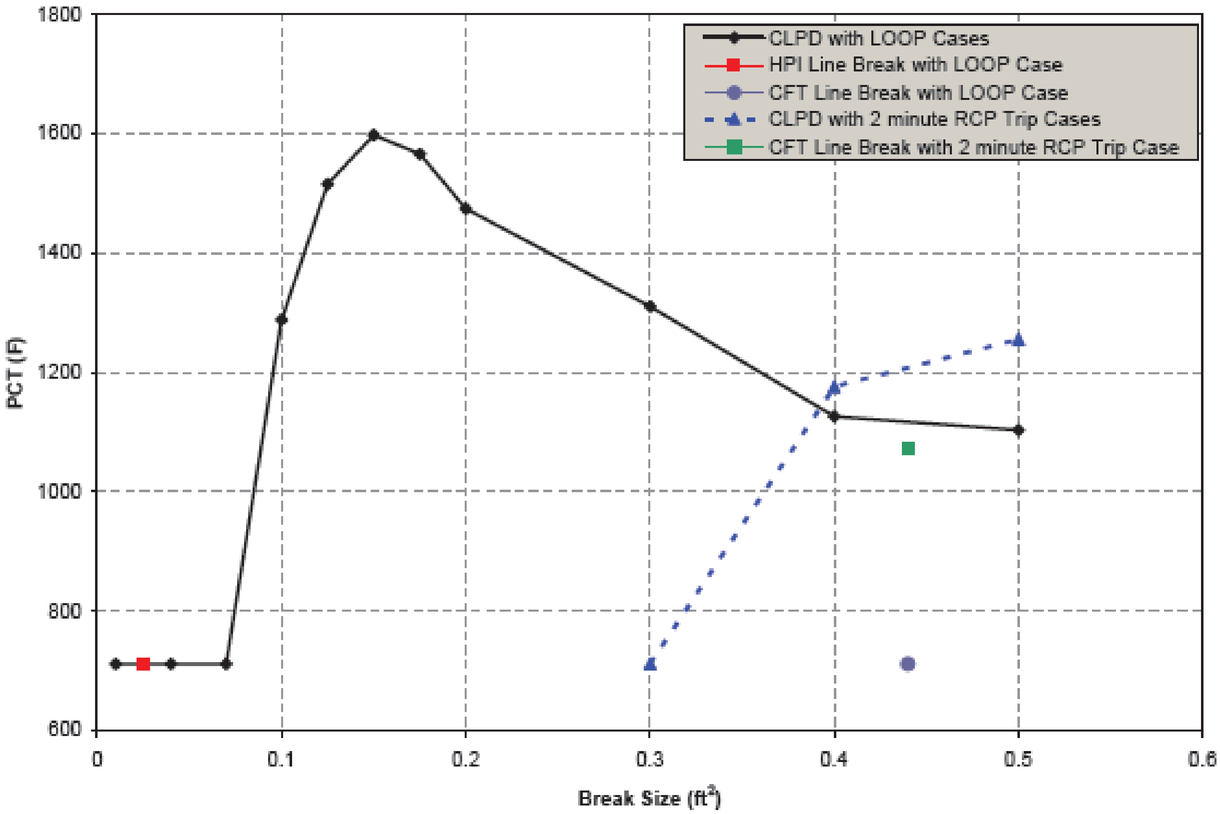

Figure 15-228. 0.15 ft^2 CLPD, 102% of 2568 MWt, Full Core Mark-B-HTP SBLOCA - Pressure

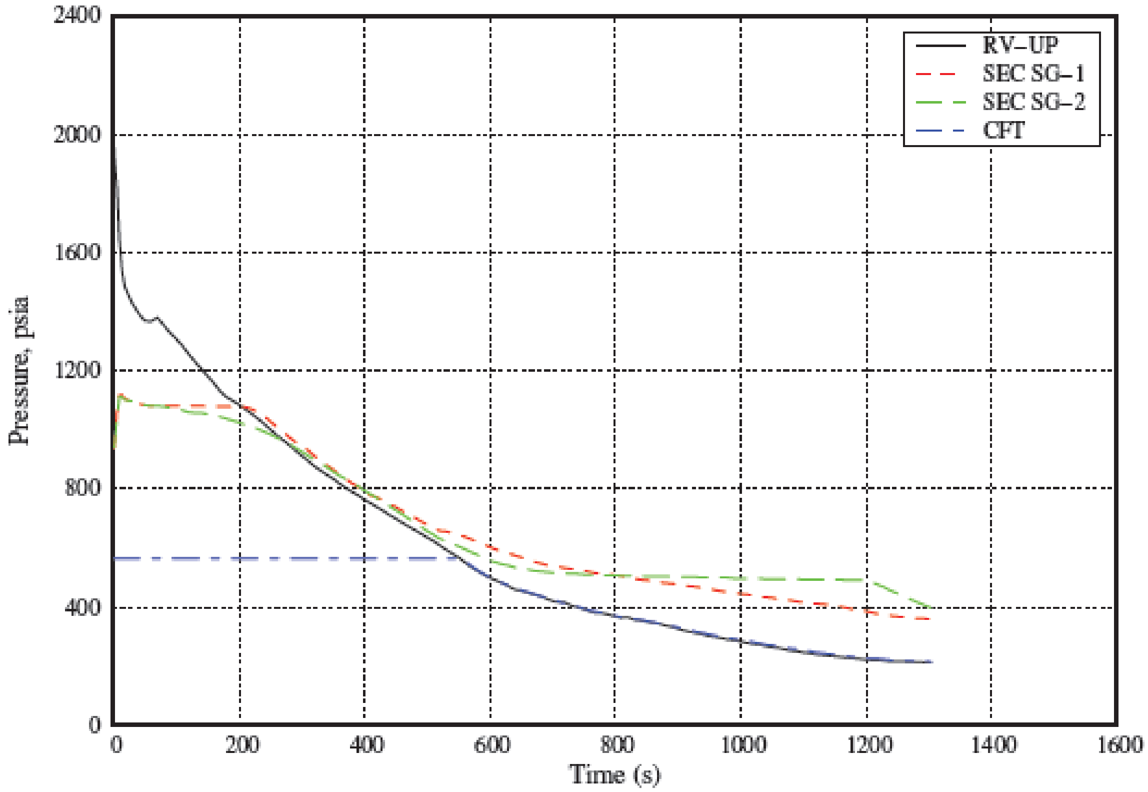

Figure 15-229. 0.15 ft^2 CLPD, 102% of 2568 MWt, Full Core Mark-B-HTP SBLOCA – Break and ECCS Mass Flow Rates

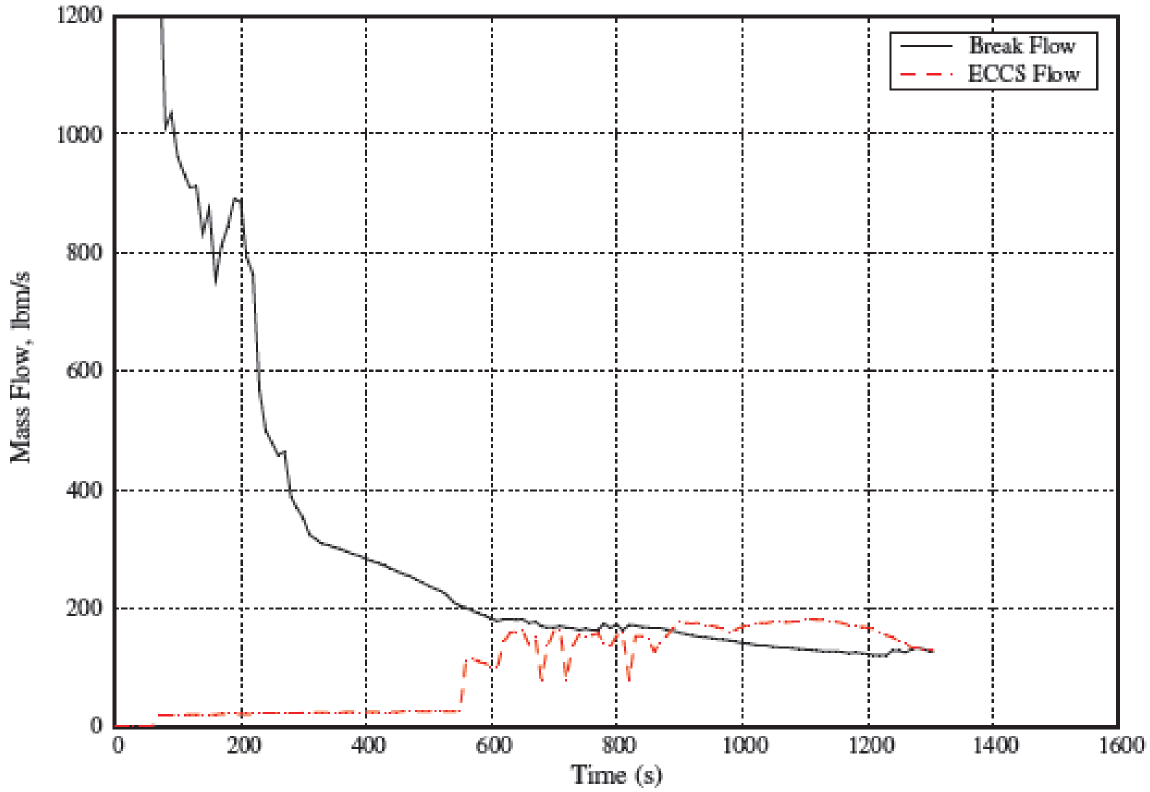

Figure 15-230. 0.15 ft^2 CLPD, 102% of 2568 MWt, Full Core Mark-B-HTP SBLOCA – RVCollapsed Liquid Level & Hot Channel Mixture Level

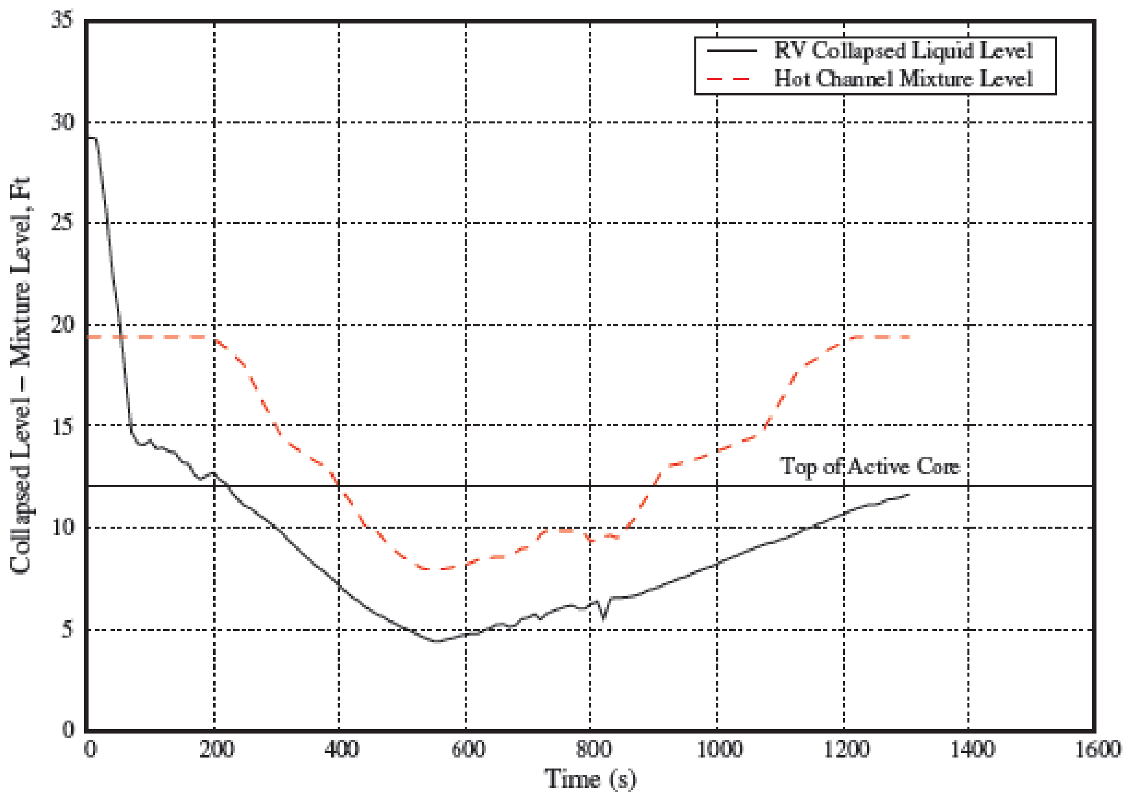

Figure 15-231. 0.15 ft^2 CLPD, 102% of 2568 MWt, Full Core Mark-B-HTP SBLOCA – HotPin Peak Clad Temperature

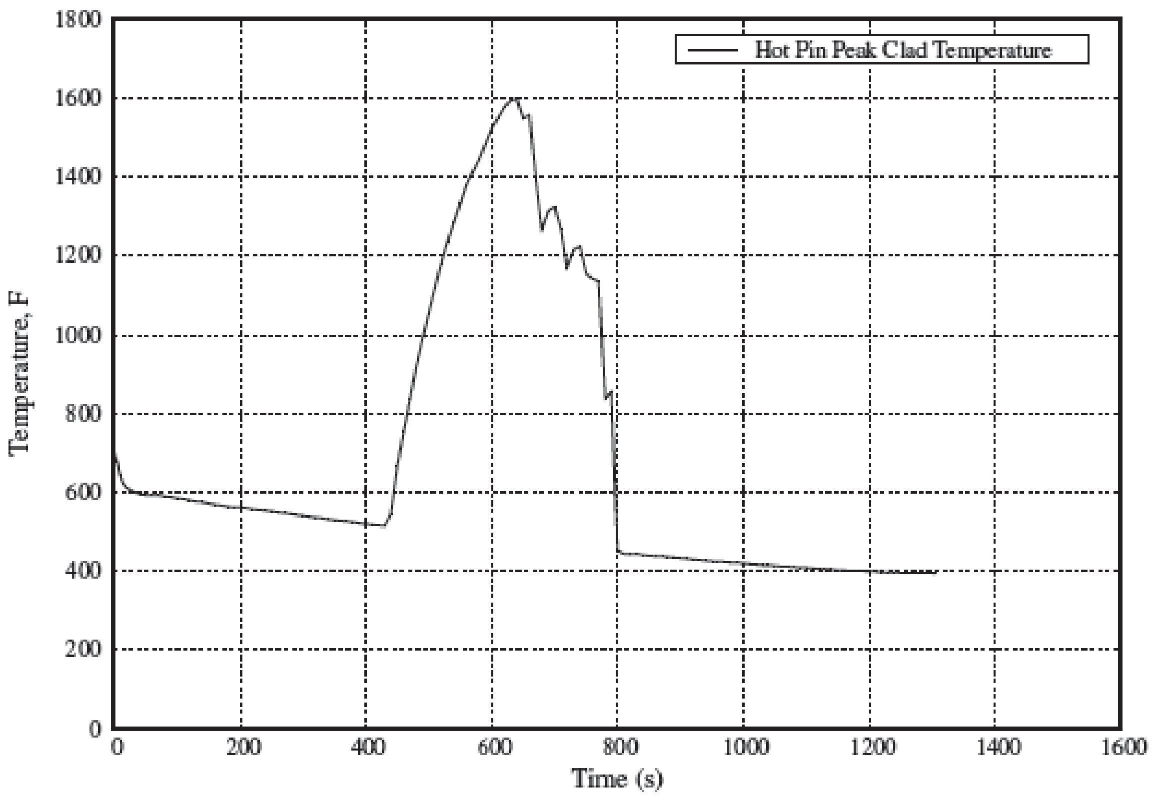

Figure 15-232. 0.15 ft^2 CLPD, 102% of 2568 MWt, Full Core Mark-B-HTP SBLOCA – HotChannel Vapor Temperature at Core Exit

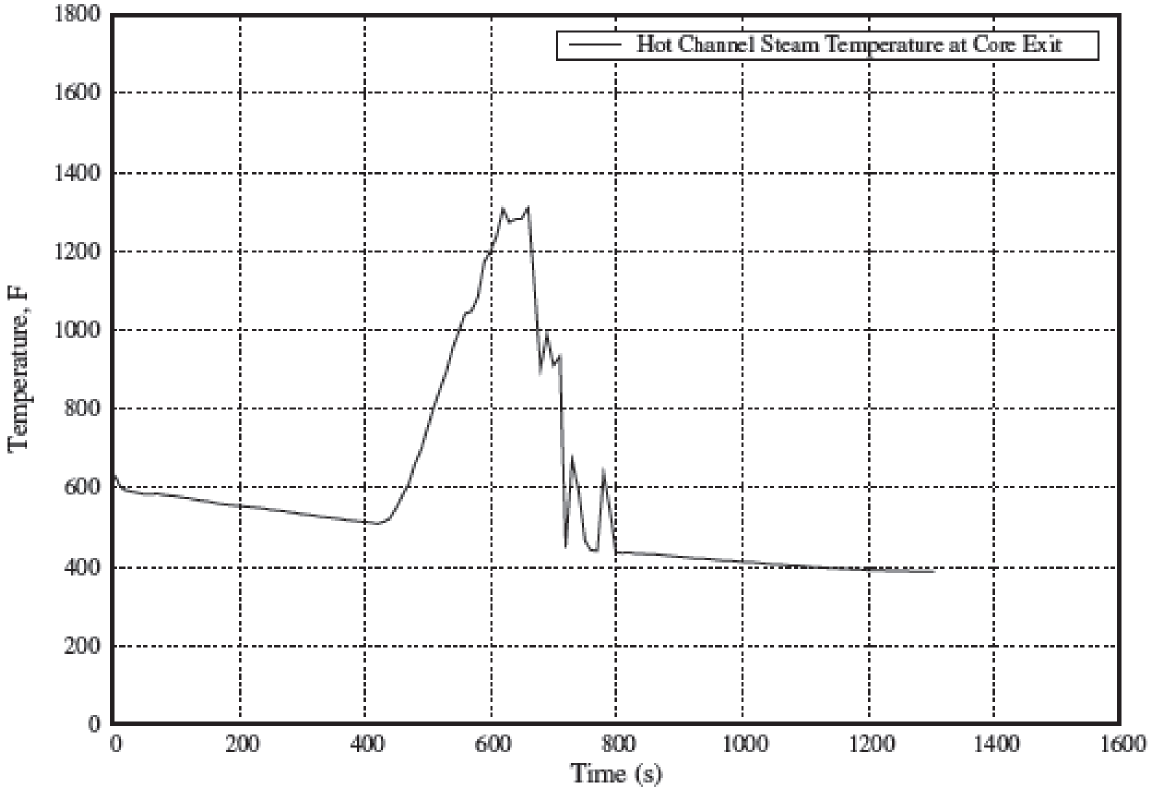

Table of Contents

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16.0 Selected Licensee Commitments

Note: CONTAINED IN A SEPARATE HARDCOPY MANUAL ONLY

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Table of Contents

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17.0 Quality Assurance

The description of the Quality Assurance Program is contained in the Duke Energy Corporation Topical Report Quality Assurance Program Description Operating Fleet, DUKE-QAPD-001-A. That Topical Report follows the format and content guidance of NUREG-0800, Section 17.3, except it is based on ANSI N18.7-1976 in lieu of ANSI/ASME NQA-1 and NQA-2.

Topical Report DUKE-QAPD-001-A is incorporated by reference into the UFSAR.

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Table of Contents

List of Tables

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18.0 Aging Management Programs and Activities

Paragraph(s) Deleted Per 2000 Update.

Aging Management Programs and Activities are being implemented as of July 1, 2001.

Paragraph(s) Deleted Per 2000 Update.

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18.1 Introduction

As the current operating license holder for Oconee Nuclear Station, Duke Energy Corporation prepared an Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3 (Application) [Reference 1]. The application, including information provided in additional correspondence, provided sufficient information for the NRC to complete their technical and environmental reviews and provided the basis for the NRC to make the findings required by Section 54.29 (Final Safety Evaluation Report - Final SER) [Reference 2]. Pursuant to the requirements of Section 54.21(d), the UFSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation determined by Section 54.21 (a) and (c), respectively.

As an aid to the reader, Table 18-1 provides a summary listing of the programs, activities and time-limited aging analyses (TLAA) (topics) required for license renewal. The first column of Table 18-1 provides a listing of these topics. The second column of Table 18-1 indicates whether the topic is a Program/Activity or TLAA. The third column of Table 18-1 identifies where the description of the Program, Activity, or TLAA is located in either the Oconee UFSAR or in the Oconee Improved Technical Specifications (ITS).

Section 18.2 contains summary descriptions of the one-time inspections that have been committed to be performed prior to the period of extended operation. Section 18.3 contains summary descriptions of the aging management programs and periodic inspections that are ongoing through the duration of the operating licenses of Oconee Nuclear Station. Section 18.4 contains additional commitments that are not identified in the preceding sections of Chapter 18.

A grace period may be applied to the frequencies of inspections required by aging management programs that existed at the time of the NRC license renewal review as documented in the license renewal safety evaluation (NUREG 1723). The grace period must be consistent with what applied when the NRC reviewed and approved the program. The NRC's review, as documented in NUREG 1723, confirmed that existing programs and inspection frequencies were adequate based on operating experience; therefore, whatever grace period that applied during the NRC review can be applied going forward. A grace period may not be applied to the frequencies of inspections of new aging management programs until adequate operating experience is obtained.

Station documents will be established, implemented, and maintained to cover the aging management programs and activities described in Chapter 18.

18.1.1 References

1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, - 270, and -287.
2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station,* Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.

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18.2 One-Time Inspections for License Renewal

18.2.1 Cast Iron Selective Leaching Inspection

Purpose - The purpose of the Cast Iron Selective Leaching Inspection was to characterize loss of material due to selective leaching of cast iron components in Oconee raw water, treated water, and underground environments.

Scope - The results of this inspection apply to the cast iron components falling within the scope of license renewal. These components include pump casings in several systems along with piping, valves and other components. The Oconee raw and treated water systems containing cast iron components potentially susceptible to loss of material due to selective leaching are the Auxiliary Service Water System, the Low Pressure Service Water System, the Condenser Circulating Water System, the Service Water System (Keowee), the Chilled Water System, the Condensate System, and the High Pressure Service Water System. Note: The Auxiliary Service Water System has been replaced by the Protected Service Water System. The Auxiliary Service Water pump was one of the selected pumps inspected; hence, reference to the Auxiliary Service Water System is correct for this program.

Aging Effects - The inspection was performed to determine the existence of loss of material due to selective leaching, a form of galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function. Selective leaching is the dissolution of iron at the metal surface that leaves a weakened network of graphite and iron corrosion products.

Method - The Cast Iron Selective Leaching Inspection inspected a select set of cast iron pump casings to determine whether selective leaching of the iron has been occurring at Oconee and whether loss of material due to selective leaching will be an aging effect of concern for the period of extended operation. A Brinell Hardness check was performed on the inside surface of a select set of cast iron pump casings to determine if this phenomenon is occurring. The results of the Cast Iron Selective Leaching Inspection are applicable to all cast iron components within license renewal scope and installed in applicable environments.

Sample Size - A representative sample of six pump casings was inspected for evidence of selective leaching, one from each of the following systems on-site:

1. Auxiliary Service Water System
2. Chilled Water System
3. Low Pressure Service Water System
4. High Pressure Service Water System
5. Service Water System (Keowee)
6. Condensate System (one inspection location on any of the three Oconee Units.)

Industry Codes or Standards - No specific codes or standards exist to address this inspection.

Frequency - The Cast Iron Selective Leaching Inspection was a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to selective leaching as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Corrective Action - Any unacceptable loss of material due to selective leaching requires an engineering analysis be performed to determine potential impact on component intended function. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Cast Iron Selective Leaching Inspection.

Timing of New Program or Activity - The Cast Iron Selective Leaching Inspection was completed prior to February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion - One-time inspections performed for the Cast Iron Selective Leaching determined that no significant selective leaching had occurred at Oconee. An operating experience review performed prior to entering the initial period of extended operation also found no instances of selective leaching applicable to Oconee.

Since entering the initial period of extended operation, Oconee has identified the occurrence of significant selective leaching in cast iron components in a set of filters in Service Water applications. Corrective actions included the inspection of all such filters in the scope of license renewal in this set. An operating experience review in support of corrective actions found no other instances of selective leaching in other cast iron components, or in other materials (ductile iron, coper alloys) and environments (waste water, treated water, closed cooling water). To address this operating experience, Oconee has implemented the Cast Iron Selective Leaching Monitoring Program, a sampling based periodic inspection program to monitor for the occurrence of selective leaching of cast iron components in a raw water environment.

18.2.2 Galvanic Susceptibility Inspection

Purpose - The purpose of the Galvanic Susceptibility Inspection was to characterize the loss of material by galvanic corrosion in carbon steel - stainless steel couples in the Oconee raw water systems.

Scope - The results of this inspection apply to all galvanic couples with the focus on the carbon steel - stainless steel couples in the Oconee raw water systems falling within the scope of license renewal.

Aging Effects - The inspection was performed to determine the existence of loss of material due to galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function.

Method - A volumetric or destructive examination at the junction of the carbon steel - stainless steel components was performed at susceptible locations to determine material loss from the more anodic carbon steel.

Sample Size - A sentinel population of the more susceptible locations on all three Oconee units, Keowee, and Standby Shutdown Facility was selected for this inspection from the following raw water systems within the scope of license renewal.

1. Auxiliary Service Water System

   Note: The inspection of the Auxiliary Service Water System piping was completed prior to upgrading the system to the Protected Service Water System.

2. Chilled Water System (raw water portion of the chillers)
3. Component Cooling System (raw water portion of the Component Cooler)

4. Condensate System (raw water portions of the Condensate Cooler and Main Condenser within the scope of license renewal)
5. Condenser Circulating Water System
6. Diesel Jacket Water Cooling System (raw water portion of the jacket water heat exchanger)
7. High Pressure Service Water System
8. Low Pressure Injection (raw water portion of the Decay Heat Removal Cooler)
9. Low Pressure Service Water System
10. Service Water System (Keowee)
11. Standby Shutdown Facility Auxiliary Service Water System
12. Turbine Generator Cooling Water System (Keowee)
13. Turbine Sump Pump System (Keowee)

Areas of low flow to stagnant conditions in Oconee raw water systems which contain carbon steel - stainless steel couples are considered the most susceptible locations. Engineering practice at Duke has been to use stainless steel as a replacement material in raw water systems. Since these replacements affect the extent of galvanic couples, the size of the sentinel population is dependent on the number of susceptible locations at the time of the inspection.

Industry Codes or Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability was judged in accordance with the Oconee component design code of record.

Frequency - The Galvanic Susceptibility Inspection was a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to galvanic corrosion as determined by engineering analysis.

Corrective Action - Any unacceptable loss due of material due to galvanic corrosion requires that an engineering analysis be performed to determine potential impact on component intended function. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Galvanic Susceptibility Inspection.

Timing of New Program or Activity - The Galvanic Susceptibility Inspection was completed prior to February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion - One-time inspections performed for the Galvanic Susceptibility Inspection determined that galvanic corrosion was occurring in bimetallic welds, and that ongoing monitoring would be required. Inspection locations have been added to the Service Water Piping Corrosion Program [UFSAR Section 18.3.21] to monitor loss of material due to galvanic corrosion during the Period of Extended Operation.

18.2.3 Keowee Air and Gas Systems Inspection

Purpose - The purpose of the Keowee Air and Gas Systems Inspection was to characterize the loss of material due to general corrosion of the carbon steel components within the Carbon Dioxide, Depressing Air, and Governor Air Systems at Keowee that may be exposed to condensation.

Scope - The results of this inspection apply to the carbon steel components within the license renewal portion of the Carbon Dioxide, Depressing Air, and Governor Air Systems on each unit at Keowee.

Aging Effects - The inspection was performed to determine the existence of loss of material due to general corrosion of carbon steel components in the Carbon Dioxide, Depressing Air, and Governor Air Systems. The inspection assessed the likelihood of the impact of this aging effect on the component intended function.

Method - An inspection of selected portions of each system determined whether loss of material due to general corrosion would be an aging effect of concern for the period of extended operation. The results of the Keowee Air and Gas Systems Inspection determined the need for additional programmatic oversight to manage this aging effect.

For the Carbon Dioxide System, a volumetric examination was performed on a portion of carbon steel pipe in and around a low point in the system.

For the Depressing Air System, a volumetric examination was performed on a portion of piping between the control valves and the Keowee unit turbine head cover.

For the Governor Air System, a visual examination of the bottom half of the interior surface of the air receiver tanks was performed to determine the presence of corrosion. The visual examination also served to characterize any instance of corrosion. Piping between the air receiver tank and the governor oil pressure tank received a volumetric examination.

Sample Size - For the Carbon Dioxide System, the inspection included four feet of pipe around the system low elevation point (two feet upstream and downstream).

For the Depressing Air System, the inspection included one of the two four-foot sections of piping between the control valves and the Keowee unit headcover.

For the Governor Air System, the inspection included the lower half of each Air Receiver Tank and one of the two four-foot sections of the piping between the air receiver tanks and the governor oil pressure tanks.

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The Keowee Air and Gas Systems Inspection was a one-time inspection.

Acceptance Criteria or Standard - Any indication of loss of material is documented and the need for further analysis determined. No unacceptable loss of material is permitted, as determined by engineering analysis. Component wall thickness acceptability is judged in accordance with the component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to corrosion requires that an engineering analysis be performed to determine proper corrective action. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Keowee Air and Gas Systems Inspection.

Timing of New Program or Activity - The Keowee Air and Gas Systems Inspection was completed prior to February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion - One-time inspections performed for the Keowee Air and Gas Systems Inspection identified no significant corrosion in the Governor Air Tanks. However, corrosion was identified in Carbon Dioxide System and Governor Air System piping that required ongoing monitoring. These points have been added to the Service Water Piping

Corrosion Program [UFSAR Section 18.3.21] for continued monitoring during the Period of Extended Operation.

18.2.4 Once Through Steam Generator Upper Lateral Support Inspection

Purpose - The purpose of the OTSG Upper Lateral Support Inspection was to determine whether cracking of the OTSG upper lateral support lubrite pads has occurred and to evaluate the need for future inspections.

Scope - The results of this inspection apply to all thirty lubrite pads installed at Oconee (ten per unit). (All thirty lubrite pads were subsequently replaced as part of OTSG replacement. The inspection results are applied to the replacement pads, to determine the need for further inspections.)

Aging Effects - The potential aging effect addressed by this inspection is cracking of the lubrite pads by gamma irradiation.

Method - A visual inspection of the accessible surfaces of a sample population of lubrite pads was performed to determine if the pads are cracking.

Sample Size - The sample size was five lubrite pads on one OTSG upper lateral support. The OTSG containing these pads was randomly selected from the total population of six OTSG at Oconee.

Industry Codes or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The OTSG Upper Lateral Support Inspection was a one-time inspection.

Acceptance Criteria or Standard - No visible cracking in the lubrite pads.

Corrective Action – If there is any cracking of the lubrite pads, an engineering evaluation would determine the need for future inspections and their periodicity. Specific corrective actions and confirmation are implemented in accordance with the Corrective Action Program.

Timing of New Program or Activity – The OTSG Upper Lateral Support Inspection was completed prior to February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion – The OTSG Upper Lateral Support Inspection found no visible cracking or deficiencies in the sample population of lubrite pads. No further action was required.

18.2.5 Pressurizer Examinations

18.2.5.1 Pressurizer Cladding, Internal Spray Line, and Spray Head Examination

Purpose - The purpose of the Pressurizer Cladding, Internal Spray Line, and Spray Head Examination was to assess the condition of the pressurizer cladding, internal spray line, and spray head.

Scope - The results of the Oconee Unit 1 pressurizer inspection apply to the Oconee Unit 2 and Unit 3 pressurizers. The applicable components of the pressurizer include the following: internal spray line, spray line fasteners, spray head, pressurizer cladding, and attachment welds to the cladding.

Aging Effects - The aging effects of concern are cracking of cladding by thermal fatigue, which may propagate to the underlying ferritic steel. Cracking of the internal spray line by fatigue and cracking and loss of fracture toughness due to thermal embrittlement of the spray head [Reference 3] are also aging effects.

Method - Visual examination (VT-3) of the clad inside surfaces of the pressurizer (100% coverage of the accessible surface) including attachment welds to the pressurizer were performed. Historical data (Haddam Neck) indicates cracking may occur adjacent to the heater bundles, if at all. Therefore, the examination focused on cladding adjacent to the heater bundles. In addition, visual inspections have been shown to be adequate for detecting cracks in cladding at Haddam Neck; cracking that extended to underlying ferritic steel was found due to the observance of rust.

Visual examination (VT-3) of the internal spray line and spray head, including the fasteners that are used to attach the spray line to the internal surface of the pressurizer was also performed.

Sample Size - The examination was performed on the cladding (100% coverage of the accessible surface), spray head, and internal spray line of one pressurizer at Oconee.

Industry Code or Standards - ASME Section XI.

Frequency - The Pressurizer Cladding, Internal Spray Line, and Spray Head Examination was a one-time inspection.

Acceptance Criteria or Standard - Acceptance standards for visual examinations is in accordance with ASME Section XI VT-3 examinations.

Corrective Action - If cracks are detected in the cladding that extend to the underlying ferritic steel, acceptance standards for Examination Categories B-B and B-D may be applied to subsequent volumetric examination of ferritic steel.

If cracks are detected in the internal spray piping, acceptance standards for Examination Category B-J may be applied. If cracks are detected in the spray head, engineering analysis would determine corrective actions that could include replacement of the spray head.

The need for subsequent examinations would be determined after the results of the initial examination are available.

Specific corrective actions would be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - The VT-3 examinations for the Oconee Unit 1 pressurizer occurred in two phases. Phase one examinations consisted of VT-3 examinations of the internal spray line, spray line fasteners, spray head, accessible cladding, and attachment welds to the cladding, down to the pressurizer thermowell or 1 foot above the water level. The phase one examinations occurred during the 1EOC26 outage occurring in April 2011. The phase two examinations consisted of the cladding and attachment welds below the level inspected during the phase one examinations, and was performed during 1EOC28 in the fall of 2014.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion – No damage or degradation was observed in any of the cladding, attachment welds, or components inspected. No further action was required.

18.2.5.2 Pressurizer Heater Bundle Penetration Welds Examination

Purpose - The purpose of the Pressurizer Heater Bundle Penetration Welds Examination was to assess the condition of the Unit 1 pressurizer heater penetration welds.

Scope - The results of this examination apply to the heater sheath-to-sleeve and heater sleeve-to-diaphragm plate penetration welds for the pressurizer heater bundles of Oconee Unit 1 (Reference Figure 2-8 of BAW-2244A). Inspections of Unit 2 or Unit 3 heater bundle welds are not required. [Reference 4]

Aging Effects - The aging effect of concern is cracking at heater bundle penetration welds which may lead to coolant leakage.

Method - For the heater bundle that is removed, the inspection would consist of a surface examination of sixteen peripheral welds on one bundle. A visual examination (VT-3 or equivalent) of the remaining welds of the heater bundle would be performed.

Sample Size - The examination would include sixteen peripheral heater penetration welds on one heater bundle from Oconee Unit 1, whichever heater bundle is removed first. The examination would also include the heater sheath-to-sleeve and heater sleeve-to-diaphragm plate penetration welds of the sixteen peripheral heaters.

Industry Code or Standards - ASME Section XI.

Frequency - The Pressurizer Heater Bundle Penetration Welds Examination was a one-time inspection.

Acceptance Criteria or Standard - Acceptance standards for surface examinations and visual examination (VT-3) is in accordance with ASME Section XI.

Corrective Action - If the results of the inspection are not acceptable, then the results may be used as a baseline inspection for establishing a longer term programmatic action covering all Oconee pressurizer heater bundles.

Specific corrective actions would be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - The surface examinations of the sixteen peripheral heater penetration welds would be performed upon removal of a pressurizer heater bundle. The examination will provide insights into the condition of the other similarly constructed pressurizer heater bundles in Oconee Unit 1 [Reference 5]

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusions - Due to pressurizer heater bundle (PHB) seal weld leakage identified in 2003, TMI-1 replaced the affected PHB and an inspection of the removed heater bundle was performed by Exelon. There was no observed degradation due to primary water stress corrosion cracking (PWSCC) and the results of this examination are documented in a B&W Owners Group Report completed in the spring of 2005. Only TMI-1 and ONS-1 have PHBs with Alloy 600 components that are susceptible to PWSCC. This TMI-1 component examination met all the ONS UFSAR requirements for the ONS one-time LR examination for this component, and was credited for the ONS-1 license renewal examination for this identical component.

All three Unit 1 Alloy 600 pressurizer heater bundles were subsequently replaced during the fall 2014 1EOC28 outage with stainless pressurizer heater bundles. This modification eliminated the aging concern (i.e., PWSCC) associated with Alloy 600.

18.2.6 Reactor Building Spray System Inspection

Purpose - The purpose of Reactor Building Spray System Inspection was to characterize the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components within the Reactor Building Spray System periodically exposed to a borated water environment that is not monitored.

Scope - The results of this inspection apply to stainless steel piping and components downstream of the containment isolation valves BS-1 and BS-2 toward their respective spray headers, a total of two lines per Oconee unit. Because the piping is open to the Reactor Building environment, unmonitored conditions exist in any borated water, which may be entrapped downstream of these valves. Results of this inspection also apply to not only the Reactor Building Spray System, but also to the Nitrogen Purge and Blanketing System.

Aging Effects - The inspection was performed to determine the existence of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel piping due to the periodic presence of borated water in the Reactor Building Spray piping open to the Reactor Building environment. The inspection assessed the likelihood of the impact of these aging effects on the component intended function.

Method - An inspection of a select set of stainless steel piping locations was performed to determine whether loss of material due to pitting corrosion and cracking due to stress corrosion was occurring and whether further programmatic aging management would be required to manage these effects for license renewal. A volumetric examination of susceptible piping locations was conducted for this inspection. This examination included a stainless steel weld and heat affected zone, since this is a more likely location for stress corrosion cracking to occur.

Sample Size - The inspection included one of six susceptible locations. The inspection locations are the piping between valves BS-1 and BS-2 and the normally open drain valves BS-15 and BS-20. Some of the parameters Duke considered to select the most bounding inspection location are piping geometry, presence of weld and heat affected zone, accessibility of location and radiation exposure. [Reference 6]

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The Reactor Building Spray System Inspection was a one-time inspection.

Acceptance Criteria or Standard - No indication of cracking is permitted. Any indication of loss of material is documented and the need for further analysis determined. No unacceptable loss of material is permitted, as determined by engineering analysis. Component wall thickness acceptability is judged in accordance with the component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to pitting corrosion or cracking due to stress corrosion requires that an engineering analysis be performed to determine proper corrective action. Specific corrective actions are implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity – The Reactor Building Spray System Inspection was completed prior to February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion – The Reactor Building Spray System Inspection found no indication of cracking or unacceptable loss of material. No further action was required.

18.2.7 Reactor Coolant Pump Motor Oil Collection System Inspection

Purpose - The purpose of the Reactor Coolant Pump Motor Oil Collection System Inspection was to characterize the loss of material due to general and localized corrosion of the carbon steel, copper alloy and stainless steel components in the Reactor Coolant Pump Motor Oil Collection System that may periodically be exposed to water.

Scope - The results of this inspection apply to the components in the system, particularly the lower portions of the system, with the potential to be exposed to water. Each Oconee unit has four Reactor Coolant Pump Oil Collection Tanks for a total population of twelve at Oconee.

Aging Effects - The inspection was performed to determine the existence of loss of material due to general and galvanic corrosion for the carbon steel component materials and pitting and crevice corrosion for the carbon steel, copper alloys and stainless steel component materials as a result of periodic exposure to water.

Method - An inspection of the Reactor Coolant Pump Motor Oil Collection System Tanks was performed to determine whether loss of material due to general and localized corrosion will be an aging effect of concern for the period of extended operation. The evidence gained from the tank examination is indicative of the condition of all materials in the lower portion of the system.

A visual examination on the bottom half of the interior surface of the tank was performed to determine the presence of corrosion. The visual examination also served to characterize any instances of corrosion, both general and localized. A volumetric examination was then conducted on problematic areas, as applicable, to determine the condition of the lower portions of the tank that is a leading indicator of the other susceptible components.

Sample Size - The inspection included one of the twelve Reactor Coolant Pump Motor Oil Collection System Tanks. The collection tank was chosen for inspection based on any higher frequency that water has been observed in the oil as well as accessibility and radiological concerns. [Reference 7]

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The Reactor Coolant Pump Motor Oil Collection System Inspection was a one-time inspection.

Acceptance Criteria - Any indication of loss of material is documented and the need for further analysis determined. No unacceptable loss of material is permitted, as determined by engineering analysis. Component wall thickness acceptability is judged in accordance with the component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to various forms of corrosion will require that an engineering analysis be performed to determine proper corrective action. Specific corrective actions will be implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Reactor Coolant Pump Motor Oil Collection System Inspection.

Timing of New Program or Activity – The Reactor Coolant Pump Motor Oil Collection System Inspection was completed prior to February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion – Inspections of the bottom half of the RCP 3A1 & 2B2 Oil Collection Tanks were performed by the RCP Component Engineer. These inspections identified no loss of material was occurring. No further action was required.

18.2.8 Small Bore Piping Inspection

Purpose - The purpose of the Small Bore Piping Inspection was to validate that service-induced weld cracking is not occurring in the small bore Reactor Coolant System piping that does not receive a volumetric examination under ASME Section XI.

Scope - The scope of Small Bore Piping Inspection includes the Oconee inservice inspection Class A piping welds in lines less than 4 inch nominal pipe size including pipe, fittings, and branch connections.

Aging Effects - The aging effect being investigated is cracking of piping welds which may not be fully managed by the current ASME Section XI examinations. For Duke, these inspections were driven by the consequences of small bore piping failures rather than a lack of confidence in the current inservice inspection techniques to manage aging. In many instances, small bore piping cannot be isolated from the Reactor Coolant System and a leak could lead to a small break loss of coolant accident and plant shutdown.

Method - Selected inspection locations received either a destructive or non-destructive examination that permits inspection of the inside surface of the piping.

Sample Size - Pipe, fittings, and branch connections over the entire small bore size range was considered for inspection. The total population of welds was determined by summing the number of welds found in scope. To determine the inspection locations from this total population of welds, risk-informed approaches were used to identify locations most susceptible to cracking. Susceptibility was determined either qualitatively (i.e., based on site and industry experience, evaluation of current ASME Section XI inspection requirements and results, and any applicable regulatory initiatives) or quantitatively, or both. The consequences of weld failure, without respect to susceptibility, was also evaluated to identify the most safety significant piping welds. After the evaluation of susceptibility and consequences, a list of potential inspection locations was developed. Actual inspection locations were selected based on physical accessibility, exposure levels, and the likelihood of meaningful results if a non-destructive technique is employed.

Industry Code or Standards - No code or standard exists to guide or govern this inspection. ASME Section XI provides rules for this piping, but not for volumetric or destructive examination. Where destructive examinations were employed, the Section XI rules for Repair and Replacement were used to return piping to its original condition.

Frequency - The Small Bore Piping Inspection was a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of cracking of piping welds as determined by engineering analysis.

Corrective Action - Any unacceptable indication of cracking of piping welds requires an engineering analysis be performed to determine proper corrective action.

Specific corrective actions are implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity – The One-Time Small Bore Piping Inspection was completed prior to February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion – No unacceptable degradation was identified under the One-Time, Small Bore Piping Examinations. However, the Oconee Thermal Fatigue Management Program (TFMP), also a License Renewal Commitment, was used to address the significant OE degradation identified outside of the Small Bore Piping Examinations. Since the

TFMP is an active program for ONS within the Period of Extended Operation, no additional Programs or Activities are required to address the OE items documented under the Small Bore Piping Examinations.

18.2.9 Treated Water Systems Stainless Steel Inspection

Purpose - The purpose of the Treated Water Systems Stainless Steel Inspection was to characterize the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components that could be occurring within several Oconee treated water systems.

Scope - The results of this inspection applies to the stainless steel piping and valves in portions of several Oconee treated water systems which are exposed to treated or potable water falling under separate guidelines from the Chemistry Control Program and the state of South Carolina. The stainless steel components may experience aging that is not monitored by current plant programs. The focus on this inspection was on a representative sample from each of the two treated water groups. The results of the inspections in each group are an indicator of the condition of all of the stainless steel components in the systems within that group. The systems containing the stainless steel piping and valves under consideration are:

1. Chemical Addition System (caustic addition portion containing demineralized water)
2. Component Cooling System (the stainless steel Containment penetration portion on Unit 2 only containing demineralized water)
3. Chilled Water System (containing potable water)
4. Demineralized Water System (Containment penetration portion containing demineralized water)
5. Diesel Jacket Cooling Water System (containing demineralized water)
6. Liquid Waste Disposal System (Containment penetration portion containing demineralized water)
7. SSF Drinking Water System (containing potable water)
8. SSF Sanitary Lift System (containing potable water)

Aging Effects - The inspection was performed to determine the existence of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel piping and valves.

Method - A volumetric examination of a length of the susceptible piping locations was conducted for this inspection. This examination included a stainless steel weld and heat affected zone since this is a more likely location for stress corrosion cracking to occur. In addition to the volumetric examination, a visual examination of the interior of a valve was performed to determine the presence of pitting corrosion.

Sample Size - Portions of stainless steel piping and valves, as applicable, for each of the two groups of system components were inspected. In the Demineralized Water System, one of the three, 4-inches nominal pipe size, Containment penetrations was inspected. A stainless steel weld at one Containment isolation valve along with piping and weld between the isolation valve and the containment penetration schedule transition point was also volumetrically examined. In addition, one valve was disassembled for an internal visual examination.

In the SSF Drinking Water System, a one-foot section of 1-inch nominal pipe size piping was volumetrically examined upstream of valve PDW-72. In addition, one valve was disassembled in the license renewal portion of this system for an internal visual inspection.

Industry Code and Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability is judged in accordance with the Oconee component design code of record.

Frequency - The Treated Water Systems Stainless Steel Inspection was a one-time inspection.

Acceptance Criteria or Standards - No unacceptable indication of loss of material due to pitting corrosion or cracking due to stress corrosion as determined by engineering analysis.

Corrective Action - Any unacceptable loss of material due to of pitting corrosion or stress corrosion cracking requires an engineering analysis be performed to determine potential impact on component intended function. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Treated Water Systems Stainless Steel Inspection.

Timing of New Program or Activity – The Treated Water Systems Stainless Steel Inspection was completed prior to February 6, 2013 (the end of the initial license of Oconee Unit 1).

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

One-Time Inspection Conclusion – One-time inspections were performed of stainless steel components in the scope of the Treated Water Systems Stainless Steel Inspection. These inspections identified no damage or age related degradation, and confirmed that there was no unacceptable loss of material or cracking occurring in the Treated Water Systems. No further action is required.

18.2.10 References

1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, - 270, and -287.
2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station,* Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.
3. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.4.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
4. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.6.2.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
5. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.4.3.3-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
6. M. S. Tuckman (Duke) letter dated May 10, 1999 to Document Control Desk (NRC), Attachment 1, Response to Items 4.3.9-6, - 7, and -8, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
7. M. S. Tuckman (Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.6.2.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

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18.3 Aging Management Programs and Activities

18.3.1 Alloy 600 Aging Management Program

The original Alloy 600 Aging`Management Review was proposed during the license renewal review process for Oconee Nuclear Station, and incorporated into the current licensing basis with the issuance of a renewed operating license on May 23, 2000. The original program description is being revised to reflect requirements imposed and commitments made subsequent to issuance of the renewed operating license. Unless otherwise noted, the intent of the original Alloy 600 Aging Management Review is met by the more comprehensive Alloy 600 Aging Management Program.

The purpose of the Alloy 600 Aging Management Program is to ensure that Alloy 600/82/182 high strength nickel alloy materials used in pressure boundary applications are adequately examined, mitigated, or replaced on a selective basis prioritized utilizing operating experience, examination requirements, and a temperature based susceptibility ranking. The program will facilitate the oversight and management of degradation due to Primary Water Stress Corrosion Cracking (PWCSS).

Consideration of industry operating experience is part of the Alloy 600 Aging Management Program. The ONS Augmented In-Service Inspection (AISI) Program was developed after the license renewal process to identify, schedule and track industry required and regulatory committed examinations. The in-service ONS Alloy 600 components and their respective examination requirements are included within and managed by the ONS AISI Program.

The NRC staff issued multiple generic communications regarding degradation of Alloy 600/82/182 materials. These communications imposed inspection requirements on specific Alloy 600 components in the Reactor Coolant System. These Alloy 600 component examination requirements were later included into three ASME Code Cases: N-722 (Reference 47), N-729 (Reference 46) and N-770 (Reference 55). The examination requirements of these Code Cases, and their revisions, including conditions specified in 10 CFR 50.55a, are managed under the ONS AISI Program.

Deleted Paragraphs Per 2016 Update.

The reactor vessel closure head penetration and pressurizer examination activities are described in Sections 18.3.1.2 and 18.3.1.3, respectively. The susceptibility ranking used in the original Alloy 600 Aging Management Review has been updated as described in Section 18.3.1.1

Specific corrective actions are implemented in accordance with the Duke Energy Quality Assurance Program.

18.3.1.1 Susceptibility Ranking

The original Alloy 600 Aging Management Review identified all Alloy 600/82/182 locations and performed a qualitative temperature based susceptibility ranking of these components for use in determining an adequate aging management inspection program. The initial inspections were to be completed before 2/6/2013, the end of the initial license term for Oconee Unit 1. As of the end of 2014, all Alloy 600 materials in the reactor vessel clousre heads, the steam generators, the pressurizers, and the hot leg decay heat nozzels for all three Oconee units have been either mitigated by full structural weld overlay or replaced with Alloy 690/52/152 or stainless steel materials. The current Alloy 600 Program also continues to identify the locations of Alloy 690/52/152 components.

The Alloy 600 Program change from a susceptibility based inspection regime to an active mitigation and examination strategy is based on industry Operational Experience (OE). Starting in 2000, it became apparent that an inspection schedule based on a susceptibility ranking of Alloy 600/82/182 components could not account for the PWSCC identified by OE within the nuclear industry. Therefore, Oconee updated the Alloy 600 Program to preemptively replace or mitigate the Alloy 600/82/182 components with PWSCC resistant materials (Alloys 690/52/152 or stainless steel). The mitigation priority was based on the component operating temperature combined with the component's ability to be volumetrically examined for PWSCC.

When the EPRI Materials' Reliability Program published MRP-139 (Reference 49), those volumetric examination requirements were integrated into the Alloy 600 Program. The inspection requirements of MRP-139 were subsequently replaced with ASME Code Cases N-770 (volumetric examination), Code Case N-722 (visual examination) and Code Case N-729 (for PWR reactor vessel closure heads having pressure retaining partial penetration welds). All the Code Cases were conditioned by 10 CFR 50.55a. Therefore, Oconee chose to prioritize mitigation of the Alloy 600/82/182 components based on a combination of temperature and susceptibility and the ability to implement examination requirements in lieu of strictly using the Alloy 600/82/182 PWSCC susceptibility models developed in the late 1990s. The Code Case examination requirements are all included and managed under the ONS AISI Program.

18.3.1.2 Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspection

The original Oconee RPV closure heads were replaced after the renewed licenses were issued and are composed of PWSCC resistant material. The RPV closure head inspections consist of visual, volumetric, and/or surface examinations. All the Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspections are managed under the ONS AISI Program.

18.3.1.3 Pressurizer Inspection

The original scope of the Pressurizer Inspection includes pressurizer connections containing Alloy 600/82/182 materials. These inspections verified that commitments made in response to NRC Bulletin 2004-01 remained satisfied by Section XI of the ASME Code including applicable Code Cases and the associated conditions imposed by 10 CFR 50.55a. As of the end of 2014, there are no unmitigated pressure boundary Alloy 600/82/182 materials remaining on the Oconee Units 1, 2, or 3 pressurizers.

18.3.2 Chemistry Control Program

The primary objective of the Oconee Chemistry Control Program is to protect the integrity, reliability, and availability of plant equipment and components by minimizing corrosion in fluid systems. To ensure the best protection is provided, reactor coolant water quality specifications are based upon the current revision of the EPRI PWR Primary Water Chemistry Guidelines and vendor recommendations as appropriate [UFSAR Section 5.2.1.7]. Secondary chemistry specifications are based upon the recommendations in the current revision of the EPRI PWR Secondary Water Chemistry Guidelines.

For the Component Cooling System (CC), the Recirculating Cooling Water System (RCW) the Chilled Water System (WC), and the SSF Diesel Generator Jacket Cooling Water System (DJW), Oconee utilizes chemistry control specifications that are consistent with the EPRI Closed

Cooling Water Chemistry Guideline. Oconee utilizes an industry-standard approved corrosion inhibitor to control corrosion in the SSF Diesel Jacket Water Cooling System.

The Oconee SSF Fuel Oil surveillances are governed by Oconee Technical Specifications [ITS SR 3.10.1.8 and ITS 5.5.14]. The applicable ASTM standard is ASTM D975 Standard, "Standard Specification for Diesel Fuel Oils."

Acceptance criteria for each monitored parameter have been established and are described in the applicable section of site specific or fleet documents. In the event the acceptance criteria are not met, then specific corrective actions will be implemented in accordance with the Corrective Action Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.3 Containment Inservice Inspection Plan

The Containment Inservice Inspection Plan was developed to implement applicable requirements of 10 CFR 50.55a. Section 50.55a(g)(4) requires that throughout the service life of nuclear power plants, components which are classified as either Class MC or Class CC pressure retaining components and their integral attachments must meet the requirements, except design and access provisions and preservice examination requirements, set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in §50.55a(b).

Furthermore, §50.55a(g)(4)(v)(B) and (C) require that metallic shell and penetration liners which are pressure retaining components and their integral attachments in concrete containments must meet the inservice inspection, repair, and replacement requirements applicable to components which are classified as ASME Code Class MC; and that concrete containment pressure retaining components and their integral attachments, and the post-tensioning systems of concrete containments must meet the inservice inspection, repair, and replacement requirements applicable to components which are classified as ASME Code Class CC.

These requirements are subject to the limitation listed in paragraph (b)(2)(vi) and the modifications listed in paragraphs (b)(2)(viii) and (b)(2)(ix) of §50.55a, to the extent practical within the limitations of design, geometry and materials of construction of the components.

Specific corrective actions are implemented in accordance with the Duke Energy Quality Assurance Program.

18.3.4 Deleted Per 2004 Update

This section has been relocated to Section 18.3.1.2.

18.3.5 Crane Inspection Program

Purpose - The purpose of the Crane Inspection Program is to provide periodic inspections and preventive maintenance on Oconee cranes and hoists. A subset of the many inspection activities performed under the auspices of the Crane Inspection Program is the inspection of the structural components.

Scope - Structural components associated with the following cranes and hoists are included in the Crane Inspection Program for license renewal:

Building	Crane
Auxiliary Building	Spent Fuel Bay Crane
	Spent Fuel Pool Fuel Handling Crane
	Hoists located over safety-related equipment
Keowee	270 Ton Crane
	Intake Hoist
	Hoists located over safety-related equipment
Reactor Building	Polar Crane
	2 Ton CRDM Service Crane
	Main Fuel Handling Bridge
	Equipment Hatch Hoist
	Hoists located over safety-related equipment
Turbine Building	Pump Aisle Crane
	Turbine Aisle Crane
	Turbine Aisle Auxiliary Crane
	Heater Bay Crane
	Hoists located over safety-related equipment
Standby Shutdown Facility	Hoists located over safety-related equipment

A complete list of cranes and hoists located over safety-related equipment is maintained at Oconee.

Aging Effects - The applicable aging effect is loss of material due to corrosion of the steel components.

Method - The program requires visual inspections of cranes and hoists within the scope.

Industry Code or Standard - ANSI B30.2.0 [Reference 6] for cranes and ANSI B30.16 [Reference 7] for hoists.

Frequency - Each crane and hoist is subject to several inspections. The inspection frequencies for the cranes are based on the guidance provided by ANSI B30.2.0. The inspection frequencies for hoists are based on guidance provided by ANSI B30.16. However, each crane or hoist over safety-related equipment and outside of the Reactor Building shall be inspected at least once a year independent of the status of the crane or hoist.

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material as determined by the accountable engineer.

Corrective Action - Items which do not meet the acceptance criteria are repaired or replaced. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - 29 CFR Chapter XVII, Section 1910.179 [Reference 8], Application [Reference 1] and Final SER [Reference 2].

18.3.6 Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances

Purpose - The purpose of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances is to inspect the structural integrity of the Keowee intake structure, spillway, and powerhouse.

Scope - The scope of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances includes:

1. Keowee Intake - trashracks, support steel and concrete
2. Spillway - concrete
3. Powerhouse - concrete

Aging Effects - The applicable aging effects include loss of material due to corrosion for steel components and loss of material, cracking, and change in material properties of concrete components.

Method - The program requires visual examinations of external surfaces. The examination of external surfaces covers the Keowee Intake, Spillway, and Powerhouse concrete surfaces exposed to water. The concrete structures are inspected from the foundation to the free water surface. [Reference 9]

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - Inspections are performed once every five years. The inspection frequency is consistent with the periodicity of inspections performed by Duke Energy in accordance with FERC requirements for maintaining other components of the structures. (See Section 18.3.8).

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material, cracking, or change in material properties as determined by the accountable engineer.

Corrective Action - Areas which do not meet the acceptance criteria are evaluated by the accountable engineer. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances.

Regulatory Basis - 18 CFR Part 12, Safety of Water Power Project and Project Works, Application [Reference 1] and Final SER [Reference 2].

18.3.7 Elevated Water Storage Tank Civil Inspection

Purpose - The purpose of the Elevated Water Storage Tank Civil Inspection is to provide a visual examination of the interior surfaces of the tank and associated components to ensure their structural integrity.

Scope - The scope of the program includes the interior surfaces of the Elevated Water Storage Tank and associated components.

Aging Effects - The applicable aging effect is loss of material due to corrosion.

Method - The program requires visual examinations of internal surfaces in accordance with station procedures. The inspection covers 100% of the interior tank surfaces. [Reference 9]

Industry Code or Standard - NFPA 25, Standard for the Inspection, Testing, and Maintenance of Water- Based Fire Protection Systems.

Frequency - Inspections are performed once every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material due to corrosion as determined by the accountable engineer.

Corrective Action - Items that do not meet the acceptance criteria are evaluated for continued service, monitored, or corrected. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.8 Federal Energy Regulatory Commission (FERC) Five Year Inspections

Inspections of the Keowee River Dam; Little River Dam; Little River Dikes A, B, C, and D; Oconee Intake Canal Dike; Keowee Spillway and Left Abutment, Keowee Intake and Powerhouse are performed in accordance with the requirements contained in 18 CFR Part 12, Safety of Water Power Projects and Project Works [Reference 10]. Specific corrective actions and confirmation are implemented in accordance with the Corrective Action Program.

18.3.9 Flow Accelerated Corrosion Program

Purpose - The purpose of the Flow Accelerated Corrosion Program is to manage loss of material for the component locations in the Feedwater System and Main Steam System that have been identified as being susceptible to flow accelerated corrosion.

Scope - The portion of the overall program credited for license renewal includes the components in the Feedwater System between the main control valves, bypass block valves, and the steam generator, and a small section of Main Steam System piping downstream of the Emergency Feedwater pump turbine steam supply control valve.

Aging Effects - The aging effect of concern is loss of material of carbon steel components due to flow accelerated corrosion under certain relevant conditions. Relevant conditions include physical parameters such as fluid temperature, fluid (steam) quality, fluid velocity, fluid pH, mechanical component geometry and piping configuration. An analytical review process is used to determine susceptible locations based on these types of relevant conditions.

Method - The focus of the program is on the carbon steel components in the more susceptible locations within these systems. Over seventy total inspection locations exist for the three units' Feedwater Systems and ten separate inspection locations exist for the three units' Main Steam Systems. Inspection methods for susceptible component locations include use of volumetric examinations using ultrasonic testing and radiography. Also visual examination is used when access to interior surfaces is allowed by component design.

Industry Codes and Standards - No code or standard exists to guide or govern this inspection. However, the program follows the basic guidelines or recommendations provided by EPRI Document NSAC- 202L. Component wall thickness acceptability is judged in accordance with the Oconee component design code of record.

Frequency - Inspection frequency varies for each location, depending on previous inspection results, calculated rate of material loss, analytical model review, changes in operating or chemistry conditions, pertinent industry events, and plant operating experiences.

Acceptance Criteria - Using inspection results and including a safety margin, the projected component wall thickness at the time of the next plant outage must be greater than the allowable minimum wall thickness under the component design code of record.

Corrective Action - If the calculated component wall thickness at the time of the next outage is projected to be less than the allowable minimum wall thickness with safety margin under the component design code of record, then the component will be repaired or replaced prior to system start-up. The as-inspected component can also be justified for continued service through additional detailed engineering analysis. Specific corrective actions are implemented in accordance with approved station processes, including work orders, modifications and the Corrective Action Program.

Regulatory Basis - Duke response to Bulletin 87-01 [References 11 and 12] and Duke response to Generic Letter 89-08 [References 13 and 14], Application [Reference 1] and Final SER [Reference 2].

18.3.10 Boric Acid Corrosion Control Program

Purpose - The purpose of the Boric Acid Corrosion Control Program is to ensure identification of leaks followed by timely investigation and repair. When boric acid leakage is involved, this program describes activities to identify the source of leakage and to evaluate subsequent corrosion degradation of associated piping, structures and components. This program includes focus on small leaks that generally occur below technical specification limits for operational leakage.

Scope - The results of the program are applicable to mechanical components and structural components fabricated from aluminum, brass, bronze, copper, galvanized steel, carbon steel and low alloy steel that are located in proximity to borated systems. Electrical equipment located in proximity to borated systems is also included. This program addresses equipment both inside and outside the Reactor Building. Bolted closures such as manways and flanged connections of systems containing dissolved boric acid are also included.

Aging Effects - Two of the conditions evaluated by the Boric Acid Corrosion Control Program are loss of material from components due to boric acid corrosion of the carbon steel and low alloy steel and boric acid intrusion into electrical equipment.

Method - Visual inspections are performed on external surfaces in accordance with plant procedures. Plant personnel look for leakage from both insulated and uninsulated components, as well as general corrosion of a component that may result from leakage. Plant personnel look for borated water leakage indicators such as discoloration or accumulated residue on surfaces such as insulation materials or floors. Possible intrusion of boric acid into electrical equipment is evaluated.

Industry Code or Standard - ASME Section XI and Generic Letter 88-05 [Reference 15].

Frequency - Reactor Building inspections are performed each refueling outage or every 24 months. Inspections of the Auxiliary Building are performed at a minimum as frequently as the Reactor Building is inspected. [Reference 16]

Acceptance Criteria or Standard - The Boric Acid Corrosion Control Program defines actions to achieve the following acceptance criteria:

1. Insulated, non-insulated or inaccessible components within borated water systems will not have external leakage, and
2. Components within scope with degradation resulting from external leakage from borated water systems will be evaluated by engineering.

Corrective Action - When the programmatic activities described in the Boric Acid Corrosion Control Program lead to detection of an unacceptable condition, the following corrective actions are required:

1. Locate leak source and areas of general corrosion.
2. Evaluate pressure-retaining components suffering wall loss for continued service or replacement.
3. Evaluate other affected components such as supports and other structural members for continued service, repair or replacement.

Specific corrective actions are implemented in accordance with the Boric Acid Corrosion Control Program or the Corrective Action Program. These programs apply to all structures and components within the scope of the Boric Acid Corrosion Control Program.

Regulatory Basis - ASME Section XI, Examination Category B-P, All Pressure Retaining Components, Examination Category C-H, All Pressure Retaining Components; Examination Category D-A, Systems in Support of Reactor Shutdown Function; Examination Category D-B, Systems in Support of Emergency Core Cooling, Containment Heat Removal, Atmospheric Cleanup, and Reactor Residual Heat Removal and Examination Category D-C, Systems in Support of Residual Heat Removal from Spent Fuel Storage Pool; Duke commitments in response to NRC Generic Letter 88-05 [Reference 17], Application [Reference 1], Final SER [Reference 2], and Duke letter [Reference 18].

18.3.11 Heat Exchanger Performance Testing Activities

The following heat exchangers in the scope of license renewal have heat transfer as a component intended function that could be impacted by fouling. Each of these heat exchangers has raw water from the Low Pressure Service Water System or the Standby Shutdown Facility Auxiliary Service Water System:

1. the decay heat removal coolers in the Low Pressure Injection System,
2. the Reactor Building cooling units in the Reactor Building Cooling System, and
3. the component coolers in the Component Cooling System
4. the Standby Shutdown Facility HVAC coolers in the Standby Shutdown Facility Auxiliary Service Water System.

Periodic testing is completed each refueling outage or every 24 months for the decay heat removal coolers and for the Reactor Building cooling units. Performance testing for these heat exchangers will provide assurance that the components are capable of adequate heat transfer required to meet system and accident load demands. Heat removal capacity is determined and compared to test acceptance criteria established by the accountable engineer and to previous test results for the decay heat removal coolers and the Reactor Building cooling units. If an adverse trend in heat removal is found, then corrective actions will be taken.

The Standby Shutdown Facility HVAC coolers are normally in service because they are required for SSF system operability per TS 3.10.1.D. The component coolers are normally in service because they are required to support normal plant operation. Accident load demands for these coolers are not greater than normal operation. Thus, heat removal capacity calculations are not performed for these coolers. Rather, flowrates through these coolers are monitored on a periodic basis. The Standby Shutdown Facility HVAC cooler flowrate is monitored twice per day. The component cooler flowrate is recorded on a refueling basis during performance testing. If an adverse trend in flowrate is found, then corrective actions will be taken.

If the heat exchangers fail to perform adequately, then corrective actions such as cleaning are undertaken. Specific corrective actions are implemented in accordance with the Corrective Action Program. This program applies to all structures and components within the scope of the Heat Exchanger Performance Testing Activities.

The continued implementation of the Heat Exchanger Performance Testing Activities provides reasonable assurance that the heat exchangers will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2]. Also, the activities credited here for license renewal for the SSF HVAC coolers, Decay Heat Removal coolers and the Reactor Building cooling Units are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 19, 20, 21, 22, and 23].

18.3.12 Inservice Inspection Plan

The Oconee Inservice Inspection Plan, implements the requirements of 10 CFR 50.55a for Class 1, 2, and 3 components and Class 1, 2, 3, and MC component supports. The examinations are performed to the extent practicable within the limitations of design, geometry and materials of construction of the component. The period of extended operation for Oconee will contain the 5th and 6th ten-year inservice inspection intervals. The Oconee Inservice Inspection Plan for each of these two inservice inspection intervals will:

1. Include compliance with Appendix VII, Qualification of Nondestructive Examination Personnel for Ultrasonic Examination;
2. Include compliance with Appendix VIII, Performance Demonstration for Ultrasonic Examination Systems;
3. Implement the Subsection IWB examination requirements of either (a) the 1989 Edition of ASME Section XI, or (b) the edition of the ASME Section XI Code required by Section 50.55a(b), or (c) another edition of ASME Section XI provided an appropriate evaluation is performed;
4. Comply with Section 50.55a except that if an examination required by the Code or Addenda is determined to be impractical, then a relief request will be submitted to the Commission in accordance with the requirements contained in Section 50.55a, for Commission evaluation; and
5. Include examination of pressurizer heater bundle welds in accordance with Examination Category B-E (or equivalent).

The Inservice Inspection Plan is credited for license renewal with managing certain aging effects associated with Reactor Coolant System pressure retaining components, their integral attachments, and other structural components within the jurisdiction of ASME Section XI. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

In addition, for Cast Austenitic Stainless Steel (CASS) Class 1 components when conditions are detected during these inservice inspections that exceed the allowable limits of ASME Section

XI, engineering evaluations of either detected or postulated flaws shall be carried out using material properties and acceptance criteria applicable to the evaluation procedures presented in IWB-3640. More favorable material properties and acceptance criteria may be used, if justified, on a case-by-case basis [Reference 1, Volume III, Exhibit A, Chapter 4, and Reference 2].

18.3.13 Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components is intended to meet the requirements of 10 CFR 50.65, Requirements for monitoring the effectiveness of maintenance at nuclear power plants (the Maintenance Rule). This program:

1. monitors and assesses mechanical components, civil structures and components and their condition in order to provide reasonable assurance that they are capable of performing their intended functions in accordance with the current licensing basis;
2. monitors degradation of caulking, sealants and waterstops in the Auxiliary Building and Standby Shutdown Facility, as well as the Fiber-reinforced polymer system on the Auxiliary Building, which may include but is not limited to water in-leakage, leaching, peeling paint, or discoloration of the concrete, debonding, blistering, cracking, crazing, deflections; and
3. includes nuclear safety-related structures which enclose, support, or protect nuclear safety-related systems and components and non-safety related structures whose failure may prevent a nuclear safety-related system or component from fulfilling its intended function.

NEI 96-03, Industry Guideline for Monitoring the Condition of Structures at Nuclear Power Plants, has been used as guidance in the preparation of the Inspection Program for Civil Engineering Structures and Components.

Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Inspection Program for Civil Engineering Structures and Components.

18.3.14 Insulated Cables and Connections Aging Management Program

Purpose - The purpose of the Insulated Cables and Connections Aging Management Program is to provide reasonable assurance that the license renewal intended functions of insulated cables and connections will be maintained consistent with the current licensing basis through the period of extended operation.

Scope - The Insulated Cables and Connections Aging Management Program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the Reactor Buildings, Auxiliary Buildings, Turbine Buildings, Standby Shutdown Facility, Keowee, in conduit and direct-buried, which could be subject to applicable aging effects from heat, radiation or moisture. This program does not include insulated cables and connections that are in the Environmental Qualification program. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment. An applicable aging effect is an aging effect that, if left unmanaged, could result in the loss of a component's license renewal intended function in the period of extended operation.

Aging Effects - Change in material properties of the conductor insulation is the applicable aging effect. The changes in material properties managed by this program are those caused by severe heat, radiation or moisture - conditions that establish an adverse, localized environment, which include energized medium-voltage cables exposed to significant moisture.

Method - The methods used are different for accessible insulated cables and connections and for inaccessible or direct-buried medium-voltage cables, which cannot be visually inspected.

Accessible insulated cables and connections installed in adverse, localized environments will be visually inspected for jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Surface anomalies are indications that can be visually monitored to preclude the conductor insulation applicable aging effect. In addition, water collection in manholes containing in-scope, medium-voltage cables will be monitored to prevent the cables from being exposed to significant moisture.

Inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage will be tested. The specific type of test performed will be determined prior to each test. Significant moisture exposure is defined as periodic exposures to moisture that last more than a few days (e.g., cable in standing water). Periodic exposures to moisture that last less than a few days (i.e., normal rain and drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. These definitions apply to cables for which no specific design characteristics are known. The moisture and voltage exposures described as significant in these definitions are not significant for medium-voltage cables that are designed for these conditions.

Sample Size - Samples may be used for this program. If used, an appropriate sample size will be determined prior to the inspection or test.

Industry Codes and Standards - EPRI TR-109619, Guideline for the Management of Adverse Localized Equipment Environments will be used as guidance in implementing this program.

Frequency - Accessible insulated cables and connections including Protected Service Water (PSW) 13.8kV cables installed in adverse, localized environments will be inspected at least once every 10 years. Water collection in manholes containing in-scope, medium-voltage cables will be monitored at a frequency adequate to prevent the cables from being exposed to significant moisture. The PSW drainage system of the trenches and manholes containing the PSW 13.8 kV cables shall be inspected annually to detect exposure of these cables to significant moisture and shall include video imaging of the drainage systems of the trench and manholes. If significant moisture is detected, actions shall be taken to correct this condition.

Inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage will be tested at least once every 10 years. The PSW System inaccessible 13.8 kV insulated power cables from the Keowee Hydroelectric station to the PSW Building and from the PSW substation to the PSW Building (Fant Line) shall be periodically electrically tested. The initial PSW 13.8 kV cable testing shall be performed prior to declaring the entire PSW System operable and thereafter at a 6 year frequency. The electrical tests shall follow the cable condition monitoring methods and testing techniques provided in Regulatory Guide 1.218 (April 2012).

Acceptance Criteria or Standard - The acceptance criteria is different for accessible insulated cables and connections and for inaccessible or direct-buried medium-voltage cables.

For accessible insulated cables and connections installed in adverse, localized environments, the acceptance criteria is no unacceptable, visual indications of jacket surface anomalies, which suggest that conductor insulation applicable aging effect may exist, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the license renewal intended function. In-scope, medium-voltage cables in manholes found to be exposed to significant moisture will be tested as described for inaccessible cables under Method, Frequency and Acceptance Criteria of this program.

For inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage, the acceptance criteria for the test will be defined by the specific type of test to be performed and the specific cable to be tested.

Corrective Action - Further investigation by engineering will be performed on accessible and inaccessible insulated cables and connections when the acceptance criteria is not met in order to ensure that the license renewal intended functions will be maintained consistent with the current licensing basis. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, relocating or replacement. Specific corrective actions will be implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Insulated Cables and Connections Aging Management Program. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible cables and connections.

Timing of New Program or Activity - Following issuance of a renewed operating licenses for Oconee Nuclear Station, the initial inspections and tests will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis - Duke response to SER Open Item 3.9.3 [Reference 24] and Final SER [Reference 2].

18.3.15 Keowee Oil Sampling Program

Purpose - The purpose of the Keowee Oil Sampling Program is to monitor and control the water contamination levels in the Governor Oil System to preclude loss of material for the carbon steel and stainless steel components in the scope of license renewal. In addition, the Keowee Oil Sampling Program manages loss of material of the stainless steel subcomponents in the Turbine Guide Bearing Oil System by monitoring the Turbine Guide Bearing Oil System for water contamination.

Scope - The scope of the Keowee Oil Sampling Program includes all carbon steel and stainless steel components within the scope of license renewal in the Governor Oil System and the turbine guide bearing oil coolers, the only stainless steel component of concern in the Turbine Guide Bearing Oil System. This program contains elements that cover all four Keowee oil systems and, as such, is intended to cover a broader scope than is being credited for license renewal.

Aging Effects - Water contamination in the Governor Oil System can expose the carbon steel and stainless steel components to conditions conducive to loss of material due to various forms of corrosion. Water contamination in the Turbine Guide Bearing Oil System is evidence of leakage of the Turbine Guide Bearing Oil Cooler from loss of material due to microbiologically influenced corrosion of the stainless steel components in the raw water environment of the shell side of the cooler. Monitoring and controlling water contamination precludes this applicable aging effect in the Governor Oil System and manages this applicable aging effect in the Turbine Guide Bearing Oil Coolers.

Method - The Keowee Oil Sampling Program requires that the Governor Oil System Sump and Turbine Guide Bearing Oil System reservoirs be sampled for the presence of water contamination. Results of the analysis are monitored and trended.

Industry Codes or Standards - ASTM D7416-08 or ASTM D6304 provides guidance for the testing of the oil sample.

Frequency - Oil samples are taken and analyzed every six months.

Acceptance Criteria or Standard - No water contamination in excess of 0.1% water by volume is the limit for water contamination in the Governor Oil System and Turbine Guide Bearing Oil System.

Corrective Action - If water contamination levels exceed the acceptance criteria, the accountable engineer will be notified and the source of the water contamination will be located and corrected. The contaminated oil will be sent to the plant oil purifier to remove the water and returned to the system. Specific corrective actions are made in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.16 Penstock Inspection

Purpose - The purpose of the Penstock Inspection is to ensure that the structural integrity of the Keowee Penstock will be maintained.

Scope - The scope of the Penstock Inspection includes both the steel lined and unreinforced concrete lined sections of the Keowee Penstock.

Aging Effects - The applicable aging effects include loss of material, cracking, and change in material properties for the unreinforced concrete lined section and loss of material for the steel lined section of the Keowee Penstock.

Method - The Penstock Inspection requires visual examination of the interior surface of the Keowee Penstock.

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - Inspections are performed when the Keowee Penstock is dewatered during outages, which is at least every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of aging effects as identified by the accountable engineer.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated by the accountable engineer for continued service or corrected by repair or replacement. Specific corrective actions will be implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Penstock Inspection.

Regulatory Basis - 18 CFR Part 12, Safety of Water Power Projects and Project Work.

18.3.17 Preventive Maintenance Activities

18.3.17.1 Borated Water Storage Tank Internal Coatings Inspection

A visual inspection of the internal coating of the tank will be performed every third refueling outage or every 6 years with the borated water removed from the tank. The acceptance criterion is no visual indications of coating defects that have exposed the base metal. Engineering evaluation is performed to determine whether coating and base metal continue to be acceptable. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Borated Water Storage Tank Internal Coating Inspection.

18.3.17.2 Chilled Water Refrigeration Unit Preventive Maintenance Activity

The chilled water refrigeration unit condensers are cleaned and eddy current tested once every four years to provide evidence of loss of material. System parameters of the entire refrigeration unit are monitored during operation to provide evidence of fouling. Parameters monitored are monitored quarterly and include inlet and outlet temperatures along with refrigerant pressures. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Chilled Water System Refrigeration Unit Preventive Maintenance Activity.

18.3.17.3 Component Cooler Tubing Examination

Eddy current testing of component cooler tubing is performed approximately every two years. Approximately 100% of the in-service tubes are examined. The acceptance criterion for the inspection is that all tube wall loss indications shall be less than 60% through wall. Tubes with wall loss indications greater than or equal to 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Component Cooler Tubing Examination.

18.3.17.4 Condensate Cooler Tubing Examination

Eddy current testing of condensate cooler tubing is performed every 54 months. The most susceptible tubes, those along the perimeter and those at the baffle regions that will experience turbulence due to the baffle geometry (approximately 25% of the tubes), are tested. The acceptance criterion for the inspection is that all wall loss indications must be less than 60% through wall. Tubes with wall loss indications greater than or equal to 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Condensate Cooler Tubing Examination.

18.3.17.5 Condenser Circulating Water System Internal Coatings Inspection

A visual inspection of the interior surfaces of the underground portions of the Condenser Circulating Water System intake and discharge piping is performed every third refueling outage or every 6 years. The acceptance criterion is no visual indications of coating defects that have exposed the base metal. Engineering evaluation is performed to determine whether coating and base metal continue to be acceptable. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Condenser Circulating Water System Internal Coatings Inspection.

18.3.17.6 Control Room Pressurization and Filtration System Examination

A visual inspection of the exterior surfaces of the Control Room Pressurization and Filtration System components, including seals, sealants, rubber boots, and flexible collars is performed quarterly. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Control Room Pressurization and Filtration System Examination.

18.3.17.7 Decay Heat Cooler Tubing Examination

Eddy current testing of the Decay Heat Cooler tubing is performed every 9 years. All of the inservice stainless steel heat exchanger tubes are examined. The acceptance criterion for the inspection is that all wall loss indications are less than 60% through wall. All tubes with wall loss indications greater than or equal to 60% through wall are plugged. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Decay Heat Cooler Tubing Examination.

18.3.17.8 Fire Hydrant Flow Test

Fire Hydrant Flow Test is an activity within the Fire Protection Program that was credited in license renewal. (Selected Licensee Commitments apply to other credited portions of the Fire Protection Program.) A flow test of fire hydrants is performed periodically. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all license- renewal related components within the scope of the Fire Hydrant Flow Test.

18.3.17.9 Jacket Water Heat Exchanger Preventive Maintenance Activity

System parameters of the entire Diesel Jacket Water Cooling System (i.e., system operating temperatures, pressures, and expansion tank levels) are monitored during diesel engine operation. Frequency of diesel engine operation is determined by Technical Specification Surveillance Requirement 3.10.1.9. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Jacket Water Heat Exchanger Preventive Maintenance Activity.

18.3.17.10 Keowee Turbine Generator Cooling Water System Strainer Inspection

A visual inspection of the strainer is performed semi-annually on the turbine packing box cooler water strainer and bimonthly on the main inlet strainer. Any noticeable sign of loss of material is documented. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Keowee Turbine Generator Cooling Water System Strainer Inspection.

18.3.17.11 Main Condenser Tubing Examination

Eddy current testing is performed on ten percent of the tubes in one-half of the condenser each refueling outage or every 24 months. Tubes in each half of the condenser are examined every other refueling outage or every 48 months. The acceptance criterion for the examination is that all tubing wall loss indications will be less than 60% through wall. Tubes with wall loss indications greater than or equal to 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Main Condenser Tubing Examination.

18.3.17.12 Deleted Per Rev. 29 Update

18.3.17.13 Reactor Building Cooling Unit Tubing Inspection

As required by periodic performance testing, tubes are rodded out and eddy current tested. In addition, the fins are cleaned and visually inspected. The acceptance criterion is any indication of loss of material will be documented and the need for further analysis or visual inspection determined. No unacceptable loss of material will be permitted, as determined by engineering analysis. Visual inspection of the ductwork and internal supports is performed on the frequency of the performance testing. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Reactor Building Cooling Unit Inspection.

18.3.17.14 Standby Shutdown Facility Diesel Fuel Oil StorageTank Inspection

A visual inspection of the interior surface of the tank is performed every ten years to monitor evidence of external corrosion due to voids in the external coating. The fuel oil is removed from the tank to perform this inspection. The acceptance criterion is no visual indications of loss of material as determined by Engineering. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Standby Shutdown Facility (SSF) Diesel Fuel Oil Storage Tank Inspection.

18.3.17.15 Standby Shutdown Facility HVAC Coolers Preventive Maintenance Activity

Inlet and outlet temperatures of both coolers as well as refrigerant conditions are monitored every six months. A visual inspection of the copper fins on the air cooling coils is performed every six months. For the water-cooled SSF HVAC condensers, cooling water and air operating temperatures will be within appropriate operating range and refrigerant will be within appropriate specifications. For the air cooling coil, the acceptance criterion is no indications of loss of material of the copper fins. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the SSF HVAC Coolers Preventive Maintenance Activity.

18.3.17.16 Standby Shutdown Facility HVAC Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Standby Shutdown Facility HVAC Inspection.

18.3.17.17 Reactor Building Cooling System Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Reactor Building Cooling System Inspection.

18.3.17.18 Auxiliary Building Ventilation Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Auxiliary Building Ventilation Inspection.

18.3.17.19 Control Room Pressurization and Filtration Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Control Room Pressurization and Filtration Inspection.

18.3.17.20 Penetration Room Ventilation System Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Penetration Room Ventilation System Inspection.

18.3.17.21 Reactor Building Purge System Inspection

A visual inspection of the internal/external surfaces of fan and damper housings, metallic piping and piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, or condensation is performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. These inspections are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason. For certain materials, such as polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Reactor Building Purge System Inspection.

18.3.17.22 Keowee Turbine Guide Bearing Oil Cooler Examination

An examination of the internal and external surfaces of each of the Keowee Turbine Guide Bearing Oil Coolers is performed every three years. This Preventive Maintenance Activity inspects, cleans, flushes (shell side) and performs both pressure and Eddy Current testing on each of the heat exchangers including functional verification. If any Asiatic clams are identified, the amount and location are reported. The acceptance criterion is stated in station procedures such that flow will be established for tubes and shell of heat exchanger and the heat exchanger will be free of any leaks. Specific corrective actions are implemented in accordance with Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Keowee Turbine Guide Bearing Oil Cooler Examination.

18.3.17.23 Generator Stator Water Cooler Inspection

The generator stator water coolers are cleaned and inspected (eddy current testing) as defined by the station PM program. The PM requires each cooler to be disassembled, cleaned, and reassembled. Any abnormal conditions identified during cleaning are recorded and evaluated before reassembly occurs. The subsequent eddy current test results are reviewed by engineering to determine whether any tube plugging is required prior to returning the cooler to service. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Generator Stator Water Cooler Inspection.

18.3.17.24 Instrument Air System Inspection

A preventive maintenance activity will manage internal surfaces of Instrument Air System piping components exposed to moist air / raw water. This activity will periodically inspect portions of the system ahead of the instrument air dryers for evidence of age related degradation, including loss of material and accumulation of corrosion products that could lead to fouling or affect the operation of downstream components. The activity will include inspection of internal surfaces of the instrument air receivers for corrosion. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Instrument Air System Inspection.

Regulatory Bases for the preceding Preventive Maintenance Activities:

1. Application [Reference 1].
2. W. R. McCollum Jr., (Duke) letter dated December 14, 1998, to Document Control Desk (NRC), Response to NRC letter dated October 29, 1998, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
3. M. S. Tuckman (Duke) letter dated September 30, 1999, to Document Control Desk (NRC), Amendment 1 - CLB Changes for 1999, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4. M. S. Tuckman (Duke) letter dated October 15, 1999, to Document Control Desk (NRC), Safety Evaluation Report, Comments and Responses to Open Items and Confirmatory Items, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
5. Final SER [Reference 2].

18.3.18 Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System

Purpose - The purpose of the Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System is to manage the tightness of the interface between the HPI nozzle thermal sleeves and safe ends and to manage the cracking of the piping welds in the normal and emergency HPI portions of the Reactor Coolant System branch lines. This program satisfies the requirements of previous Oconee inspection commitments to the NRC for Generic Letter 85-20 [Reference 25] and IE Bulletin 88-08 [Reference 26], as well as some key ASME Section XI requirements and simplifies the programmatic oversight of these risk-significant welds in the Reactor Coolant System.

Scope - The scope of this program includes the HPI nozzles on the reactor coolant loops and attached Reactor Coolant System piping. The program also applies to the thermal sleeves within the nozzles. It encompasses all Oconee System Piping Class A (not ISI Class A) HPI piping and components with the additions of some welds within Oconee System Piping Class B boundaries (still within ISI Class A scope) being examined in accordance with IE Bulletin 88-08 commitments.

The commitments of Oconee letter from Mr. W. R. McCollum, Jr. to U.S. Nuclear Regulatory Commission of January 7, 1998 on Oconee Nuclear Site, Docket Nos. 50-269, -270, -287, Inservice Inspection Program, Third Yen-Year ISI Interval, GL 85-20 Supplemental Information in answer to the NRC letter from David E. LaBarge to Mr. W. R. McCollum of October 23, 1997, High Pressure Injection System Augmented Inservice Inspection Program - Oconee Nuclear Station Units 1, 2, and 3 (TAC No. M98454) will continue to apply.

Aging Effects - Two aging effects are addressed by this program. The first aging effect is the cracking of the base metal or weld metal which could result in a non-isolable Reactor Coolant System Piping leak.

The second aging effect is the initiation and growth of gaps between the protective thermal sleeve and the nozzle safe end.

Method - This program includes the inspection techniques for these locations defined from ASME Section XI, Subsection IWB defined in the Oconee Inservice Inspection Plan. Additional augmented inspections are done using ultrasonic (UT) and dye- penetrant (PT) inspections of the components of the nozzles and piping to detect cracks, and radiographic (RT) inspections to verify no gaps are growing between the thermal sleeve and the safe end.

The thermal fatigue ultrasonic inspections referenced in this UFSAR Section meet or exceed the requirements of the 1992 Edition, 1993 Addenda of the ASME Code, Section XI, in use during the 3rd In-Service Inspection (ISI) Interval at Oconee. Future Intervals use inspection requirements from Editions/Addenda of the Section XI ASME Code that comply with applicable requirements of 10 CFR 50.55a.

Industry Code or Standard - ASME Section XI for the detection and engineering evaluation of flaws in the welds.

Frequency - The frequency of actions under this program are component location-specific. The frequencies are established for each component location by considering the ASME Section XI inspection frequencies in IWB-2400 as well as the frequencies established by Duke regulatory commitments for Generic Letter 85-20 and IE Bulletin 88-08.

Acceptance Criteria or Standard - For the base metal or weld metal, the acceptance criteria are no flaws in welds and base metal in accordance with ASME Section XI acceptance criteria and no flaws in the nozzle inner radius base metal (which is not required to be inspected under ASME Section XI criteria but which is being inspected under Generic Letter 85-20 commitments in accordance with standards established as a part of the Duke commitment to Generic Letter 85-20).

For the protective thermal sleeve and the nozzle safe end, the acceptance criterion is no increase in size of the gaps between the thermal sleeve and safe end.

Corrective Action - Flaws that can be justified for continued service become time-limited aging analyses and are addressed by the Oconee Thermal Fatigue Management Program. Flaws in weld or base metal that cannot be accepted based on either the geometry screening or the Fracture Mechanics Analysis methods of ASME Section XI are corrected by repair or replacement activities. Unacceptable gaps detected by sleeve RT are corrected by repair or replacement activities. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2]. Specific Duke-NRC communications with regard to NRC Generic Letter 85-20, IE Bulletin 88-08 and Oconee Inservice Inspection Plan provide the regulatory basis for this program. They are:

1. W. R. McCollum, Jr., (Duke) letter dated August 6, 1997 to Document Control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287, Inservice Inspection Plan, Third Ten-Year Inservice Inspection Interval, Generic Letter 85-20 Supplemental Information.
2. W. R. McCollum, Jr., (Duke) letter dated September 10, 1997 to Document control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287, Inservice Inspection Plan, Third Ten-Year Inservice Inspection Interval, Generic Letter 85-20 Supplemental Information.
3. H. B. Tucker (Duke) letter dated December 29, 1989 to Document Control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, -287, Thermal Stresses in Piping Connected to Reactor Coolant System (NRC Bulletin 88-08).

18.3.19 Reactor Vessel Integrity Program

The Oconee Nuclear Station (ONS) Reactor Vessel Integrity Program (RVIP) manages the fracture toughness reduction of the reactor vessel beltline materials for all three Oconee units due to neutron irradiation. The RVIP provides assurance that the Time Limited Aging Analyses (TLAAs) remain valid for the period of extended operation. The major components of the RVIP are the Master Integrated Reactor Vessel Surveillance Program (MIRVP) and the cavity dosimetry and fluence calculations used to establish Pressure Temperature (P-T) and pressurized thermal shock (PTS or RT_{PTS}) limits.

ONS participates in the Master Integrated Reactor Vessel Surveillance Program (MIRVP), which is an NRC approved program [Reference 27] that complies with requirements for an integrated surveillance program in accordance with 10 CFR 50, Appendix H, Paragraph III.C. The purpose of the MIRVP is to provide a method to monitor reactor pressure vessel beltline materials to determine the reduction of material toughness by neutron irradiation embrittlement. The MIRVP includes base and weld material from the beltline region of the Oconee reactor vessels. The

MIRVP provides data for reference temperature (RT) shift calculations used in 10 CFR 50 Appendix G and 10 CFR 50.61, and upper-shelf toughness decrease used in 10 CFR 50 Appendix G and ASME Section XI Appendix K.

ONS also utilizes cavity dosimetry as a continuous fluence monitoring device. Cavity dosimetry measurements are used to verify the accuracy of fluence calculations and to determine fluence uncertainty values.

Scope of Program

ONS's MIRVP and the RVIP fluence calculations are used to monitor embrittlement of beltline materials in all three ONS reactor vessels through the period of extended operation.

A description of the MIRVP is provided in BAW-1543 [Reference 28] and in BAW-2251A [Reference 29]. Specimens primarily have been irradiated in two B&W reactor vessels (Davis-Besse and Crystal River-3) with some additional irradiations in participating Westinghouse reactor vessels. The fracture toughness specimens are tested in accordance with applicable ASTM standards as identified in Appendix C of BAW-1543.

MIRVP provides reactor vessel material fracture toughness data for the following TLAAs:

- Charpy Upper-Shelf Energy (USE),
- Pressurized Thermal Shock (PTS),
- Reduced Fracture Toughness of RV Materials and Pressure-Temperature (P-T) Limits
- Under clad cracking.

Preventive Actions

The MIRVP and cavity dosimetry are condition monitoring programs and do not rely on preventive actions. However, all modifications to design and operation are reviewed to ensure that any significant changes that affect fluence projections are taken into account, in order to maintain compliance with 10 CFR 50.60, 10 CFR 50 Appendix G, 10 CFR 50 Appendix H, and 10 CFR 50.61.

Parameters Monitored/Inspected

The Cavity Dosimetry exchange is an ONS on-site method to continuously monitor the reactor vessel beltline region neutron fluence which is used in determining the reduction of material toughness. Cavity dosimetry measurements are used to verify the accuracy of fluence calculations and to determine fluence uncertainty values. Cavity dosimetry is changed out on an as needed basis. Examples of when the cavity dosimetry exchange may be needed are changes in fuel type, pressure-temperature limit updates, and significant changes in fuel loading pattern.

Only the ONS Unit 2 reactor vessel has installed cavity dosimetry. However, the ONS Unit 1 and ONS Unit 3 reactor vessel fluence uncertainty values are based on Oconee Unit 2 cavity dosimetry results due to similar design, fabrication, operation, and fuel loading patterns. The use of the ONS Unit 2 cavity dosimetry for Oconee Unit 1 and Oconee Unit 3 was approved by the NRC in a letter to Duke Power Company dated December 5, 1988 [Reference 53]. Dosimeters are irradiated in the cavity region outside of the ONS Unit 2 reactor vessel. Cavity dosimetry has been irradiated at ONS Unit 2 since cycle 9. The cavity dosimeters are measured to determine the activity resulting from the fast fluence irradiation. In addition, calculations of the dosimetry activities are performed using operational data. The calculations are compared to the measurements to verify the accuracy and the uncertainty in the calculated fluence. The cavity dosimeters are measured within a frequency such that the fluence uncertainty is kept within the guidance of Regulatory Guide 1.190 [Reference 35].

If modifications to design and operation result in significant changes to neutron energy spectrum, irradiation dose rate, or irradiation temperature (reactor inlet temperature) relative to that discussed in BAW-1543, then the NRC will be notified and a program to determine impact will be proposed.

Detection of Aging Effects

The applicable aging effect is the reduction of material toughness by neutron irradiation embrittlement. These effects are detected by the MIRVP and the cavity dosimetry used for the fluence calculations. The MIRVP meets the requirements of 10 CFR 50, Appendix H, with regard to integrated surveillance programs (Paragraph III.C) and is also an NRC accepted program. The capsule withdrawal schedules are presented in BAW-1543, Supplement 6-A [Reference 32].

MIRVP irradiated material specimen data is used to support reference temperature shift calculations and pressurized thermal shock requirements in accordance with Section 50.61 for the life of the plants.

The reactor vessel fluence and uncertainty calculations provide an accurate prediction of the actual reactor vessel accumulated fast neutron fluence values. The reactor vessel fluence and uncertainty calculations are used as inputs to the pressure-temperature limit curves, upper-shelf energy evaluations, and pressurized thermal shock calculations as well as the surveillance capsule analyses. The cavity dosimetry exchange yields irradiated dosimeters that are analyzed based on Oconee specific geometry models (i.e., fuel, reactor vessel, dosimetry capsule holder, and concrete structures), macroscopic cross sections, cycle-specific sources using the DORT and GIP computer codes, and a reference set of microscopic cross sections (BUGLE Series). Specific attention is made to target fluence values for limiting reactor vessel beltline weld material locations. Fluence and uncertainty calculations typically follow each cavity dosimetry analysis depending on the need. The frequency of updating fluence and uncertainty calculations change as additional data are obtained.

Monitoring and Trending

The applicable specimens removed from the MIRVP surveillance capsules are utilized to determine the adjusted reference temperature for the pressure-temperature limits (10 CFR 50, Appendix G, Section IV.A), and RT_{PTS} values (10 CFR 50.61(c)(2)). Applicable reactor vessel fracture toughness data is assessed and MIRVP TLAAs updated when required.

The USE and PTS TLAAs include for end-of-license fluence projections obtained from irradiated material properties. However, P-T limits are updated prior to exceeding the calculated time period (based on projected fluence values) and may be developed for less than the end-of-life. TLAAs are valid for periods of time expressed in effective full power years (EFPY). Periodically they may require updating based on changes to assumptions used in the analysis (e.g., revised accumulated fluence projections, significant operational changes such as uprates, and to incorporate methodology or regulatory changes). The rules and guidance governing TLAA inputs are contained in 10 CFR 50 Appendix G, 10 CFR 50 Appendix H, 10 CFR 50.61, Regulatory Guide 1.99 Rev. 2 [Reference 31], Regulatory Guide 1.190, ASME Section XI Appendix K, ASME Section XI Appendix G [Reference 37], ASME Section XI Appendix E, and ASTM E185-82 [Reference 30].

The ONS TLAA for upper shelf energy (USE) was performed using Reg. Guide 1.99 Rev. 2 Position 1.2 and predicted that the Charpy USE values fell below 50 ft-lbs for all Oconee beltline welds on each unit except for one weld on Unit 1. An equivalent margin analysis (EMA) was performed in BAW-2275A [Reference 54] per ASME Section XI Appendix K demonstrating a margin of safety against fracture that is equivalent to those required by Appendix G of ASME Section XI.

Acceptance Criteria

The data from MIRVP are used for RV embrittlement projections to comply with 10 CFR 50, Appendix G requirements and 10 CFR 50.61 limits through the period of extended operation.

The results of the fluence uncertainty values are to be within the NRC-recommended limit of ± 20%. Calculated fluence values for fluence levels greater than 1.0 MeV are compared with measurement values from the cavity dosimetry to determine if calculations contain any unexplained deviations. This methodology represents a continuous validation process to ensure that no unexplained deviations have been introduced, and that the uncertainties remain comparable to the reference benchmarks.

Modifications to core design and operation that result in significant changes to the neutron energy spectrum, gamma heating, or reactor vessel inlet temperature discussed in BAW-1543 [Reference 28] will be evaluated prior to implementation as part of the modification process. Any subsequent impact on the applicable embrittlement evaluations will be assessed, and changes to the TLAAs will be submitted to the NRC using the appropriate licensing process.

Pressure-temperature limit curves are generated in accordance with the requirements of 10 CFR 50, Appendix G. NRC approved pressure-temperature limit curves must be in place for continued plant operation.

Calculations of RT for pressurized thermal shock (RT_{PTS}) should be below the screening criteria of 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds, respectively, in accordance with 10 CFR 50.61.

Corrective Actions

If the MIRVP provides data that affects ONS's TLAA in meeting 10 CFR 50 Appendix G and 10 CFR 50.61 requirements, specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program (QAP).

As additional cavity dosimetry is withdrawn and tested, cavity dosimetry exchange frequency may be adjusted, as appropriate. If the comparison of calculations to measurements of the Unit 2 multiple dosimeters fail to meet ± 20%, measurements and calculations will be reviewed to locate the discrepancy.

As additional cavity dosimetry is withdrawn and tested, fluence and uncertainty calculations will be revised and updated accordingly. If comparisons of the dosimetry calculations to measurements are not within acceptance standards, then specific corrective actions will be implemented in accordance with the Duke QAP.

Oconee Improved Technical Specifications (ITS) 3.4.3, RCS Pressure and Temperature (P/T) Limits, require valid pressure-temperature limits prior to and during plant operations. Actions to be taken if the pressure-temperature limits are exceeded are specified in Oconee ITS 3.4.3, specific corrective actions will be implemented in accordance with the Duke QAP.

Confirmation Process and Administrative Controls

ONS has an established 10 CFR 50, Appendix B Program described in Duke Energy Topical Report Duke-1-A, "Quality Assurance Program" which addresses the elements of corrective actions, confirmation process, and administrative controls. Quality Assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B.

Operating Experience

Applicable operating experience is reviewed in accordance with the Duke Energy Operating Experience Program. Relevant operating experience will be entered into the Corrective Action Program to evaluate and address potential changes. This ongoing operating experience evaluation process helps ensure Reactor Vessel Integrity Program effectiveness.

18.3.19.1 Deleted Per 2014 Update

18.3.19.2 Deleted Per 2014 Update

18.3.19.3 Deleted Per 2014 Update

18.3.19.4 Deleted Per 2014 Update

18.3.19.5 Deleted Per 2014 Update

18.3.20 Reactor Vessel Internals Inspection Program

Purpose - The purpose of the Reactor Vessel Internals (RVI) Inspection Program is to manage the effects of age-related degradation mechanisms applicable to Pressurized Water Reactor (PWR) RVI components in order to assure that the applicable aging effects will not result in loss of the intended functions of the RVI during the period of extended operation.

Scope - The scope of this Program consists of the RVI components identified within Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) Report No. 3002017168, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," (MRP-227, Revision 1-A) [Reference 39].

The scope of components considered for inspection in MRP-227, Revision 1-A includes core support structures, those RVI components that serve an intended license renewal safety function pursuant to criteria in 10 CFR 54.4(a)(1), and other RVI components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a) (1)(i), (ii), or (iii). ASME Code, Section XI also includes inspection requirements for PWR removable core support structures in Table IWB-2500-1, Examination Category B-N-3, which are in addition to any inspections that are implemented in accordance with MRP-227, Revision 1-A.

Aging Effects - The aging effects managed by this Program include; (a) cracking, including stress-corrosion cracking (SCC), primary water stress-corrosion cracking (PWSCC), irradiated-assisted stress-corrosion cracking (IASCC), and cracking due to fatigue/cyclical loading; (b) loss of material induced by wear; (c) loss of fracture toughness due to either thermal aging or neutron irradiation embrittlement; (d) changes in dimension due to void swelling or distortion; and (e) loss of preload due to thermal and irradiation-enhanced stress relaxation or creep.

Method – The inspection methods are defined and established in Section 4 of MRP-227, Revision 1-A. Standards for implementing the inspection methods are defined and established in the Inspection Standard for Pressurized Water Reactor Internals, MRP-228 [Reference 56]. In all cases, well-established inspection methods are selected. These methods include volumetric UT examination methods for detecting flaws in bolting and various visual (VT-3, VT-1 and EVT-1) examinations for detecting effects ranging from general conditions to detection and sizing of surface-breaking discontinuities. Surface examinations may also be used as an alternative to visual examinations for detection and sizing of surface breaking discontinuities. In some cases, physical measurements are used to identify and manage degradation due to wear, stress relaxation or void swelling.

Sample Size - The sample size for the inspection of each Oconee unit is determined as dictated by MRP-227, Revision 1-A Primary and Expansion items. The MRP-227, Revision 1-A guidance for selecting RVI components for inclusion in the inspection sample is based on a four-step ranking process. Through this process, the B&W PWR designed RVI were assigned to one of the following four groups: “Primary,” “Expansion,” “Existing Programs,” and “No Additional Measures”.

The “Primary” internals component locations are inspected because they are expected to show the leading indications of degradation effects, with another set of “Expansion” internals component locations that are specified to expand the sample should the indications be more severe than anticipated. The degradation effects in a third set of internals locations are deemed to be adequately managed by “Existing Programs,” such as American Society of Mechanical Engineers (ASME) Code, Section XI, Examination Category B-N-3, examinations of core support structures. A Fourth set of internals locations are deemed to require no additional measures, as described by the title.

Industry Codes or Standards – The industry standards documented in MRP-227, Revision 1-A and MRP-228 are used for the ONS RVI Inspection Program. Additional inspection requirements are taken from ASME Code, Section XI.

Frequency - The RVI inspections are performed consistent with the inspection frequency and sampling bases for “Primary” components and “Expansion” components in MRP-227, Revision 1-A. The baseline RVI inspections at Oconee Units 1, 2, and 3 were performed in accordance with MRP-227-A during the 4th In-Service Inspection Interval, prior to entering the period of extended operation. RVI exams performed through December 2021 are conducted in accordance with MRP-227-A and after December 2021 are conducted in accordance with MRP-227, Revision 1-A.

Acceptance Criteria or Standard - Section 5 of MRP-227, Revision 1-A, which includes Table 5-1 for B&W-designed RVIs, provides specific examination and flaw evaluation acceptance criteria for the “Primary” and “Expansion” RVI component examination methods. For RVI components addressed by examinations performed in accordance with the ASME Section XI Code, the acceptance criteria in IWB-3500 are applicable. As applicable, the program establishes acceptance criteria for any visual, volumetric or physical measurement monitoring methods that are credited for aging management of specific RVI components.

Corrective Action - Any detected conditions that do not satisfy the examination acceptance criteria are required to be dispositioned through the plant corrective action program, which may require repair, replacement, or analytical evaluation for continued service until the next inspection. In accordance with MRP-227, Revision 1-A, engineering evaluations used to disposition an examination result that does not meet the examination acceptance criteria will be conducted in accordance with NRC-approved evaluation methods.

Regulatory Basis – Oconee Nuclear Station had a license renewal commitment to submit a RVI inspection plan to the NRC two years prior to the first RVI inspection. License Amendment Request for the Reactor Vessel Internals Inspection Plan (LAR 2010-06) [Reference 58] was submitted to the NRC on November 8, 2010 along with several later Supplements. On June 19, 2015 in response to LAR 2010-06, a letter [Reference 57] was received from the NRC issuing amendments that revised the UFSAR and licensing basis for Oconee Nuclear Station to approve the use of NRC staff-approved topical report MRP-227-A. The NRC Safety Evaluation

[Reference 59] documents the approval of the MRP-227-A requirements for Licensing use at Oconee Nuclear Station. RVI exams performed through December 2021 are conducted in accordance with MRP-227-A.

In December 2019, MRP-227, Revision 1-A was issued to incorporate generic improvements to PWR Vessel Internals Program methodologies. In its safety evaluation for this revision, the NRC concluded that MRP-227, Revision 1-A provides an acceptable means for managing aging of PWR reactor vessel internals, and satisfies the requirements of 10 CFR 54.21(a)(3) for demonstrating that the effects of aging on the RVI components within the scope of MRP-227, Revision 1, will be acceptably managed. Accordingly, ONS confirmed the applicability guidelines in Section 2.4 of MRP-227, Revision 1-A were met and transitioned the Reactor Vessel Internals Inspection aging management program to meet the requirements of MRP-227, Revision 1-A. RVI exams performed after December 2021 are conducted in accordance with MRP-227, Revision 1-A.

All documents referenced in Section 18.3.20 are “general references” and are not “Incorporated by reference” as stated in NEI 98-03 Revision 1.

18.3.21 Service Water Piping Corrosion Program

Purpose - The purpose of the Service Water Piping Corrosion Program is to assess and manage loss of material due to corrosion for the various component materials in Oconee, Keowee and Standby Shutdown Facility raw water systems and selected Keowee air and gas systems that may challenge the component intended function of pressure boundary. The following raw water and air and gas systems within the scope of license renewal are within the scope of the Service Water Piping Corrosion Program:

1. Protected Service Water System (refers to that portion of the system that was formerly the Auxiliary Service Water System),
2. Chilled Water System (raw water portion of the coolers),
3. Component Cooling System (raw water side of the component coolers),
4. Condenser Circulating Water System,
5. Diesel Jacket Water Cooling System (raw water side of the heat exchangers),
6. Essential Siphon Vacuum System,
7. High Pressure Service Water System,
8. Keowee Service Water System,
9. Keowee Turbine Generator Cooling Water System,
10. Keowee Turbine Sump Pump System,
11. Keowee Vacuum Break System,
12. Low Pressure Injection System (for the raw water side of the Decay Heat Cooler),
13. Low Pressure Service Water System,
14. Siphon Seal Water System,
15. SSF Auxiliary Service Water System,
16. Keowee Carbon Dioxide System,
17. Keowee Governor Air System,

18. Condensate System (raw water portions of the Condensate Cooler and Main Condenser within the scope of license renewal).

Scope - The Service Water Piping Corrosion Program is credited for license renewal for managing loss of material of copper, brass, bronze, carbon steel, cast iron and stainless steel components in the license renewal portions of the systems listed in the Purpose. The program includes the inspection of carbon steel and brass piping components exposed to raw water which are more susceptible to general corrosion and which serve as a leading indicator of the general material condition of the system components. The program was expanded as a result of One-Time Inspection activities during License Renewal Implementation to include loss of material in the Keowee Air and Gas Systems [UFSAR Section 18.2.3], and loss of material due to galvanic corrosion in the systems subject to the Galvanic Susceptibility Inspection [UFSAR Section 18.2.2].

Over 30 different carbon steel piping component inspection locations have been established throughout the applicable systems based on the understanding that fluid flow rates are a prime contributor to the conditions conducive to corrosion. The Service Water Piping Corrosion Program is not focused on components within each specific system, but is more broadly focused across all of the system components within license renewal that are susceptible to the various corrosion mechanisms. The intent of the Service Water Piping Corrosion Program is to inspect a number of locations with conditions that are characteristic of the conditions found throughout the raw water systems above. The results of these inspection locations are then extrapolated to similar locations throughout all the raw water systems within the scope of license renewal. This characteristic-based approach recognizes the commonality among the component materials of construction and the environment to which they are exposed. In this way components within the raw water systems at Keowee are linked to the results of the inspections of other raw water systems at Oconee and the Standby Shutdown Facility.

As an example, the inspection results of a carbon steel pipe in a stagnant location in the Low Pressure Service Water System at Oconee would be indicative of the condition of a carbon steel pipe in a stagnant location in the Turbine Generator Cooling Water System at Keowee. Both systems have carbon steel pipe in a stagnant location exposed to raw water from Lake Keowee. Both have operated a similar length of time under similar conditions. Therefore, the inspection results of the carbon steel pipe in the Low Pressure Service Water System will be characteristic of the condition of the carbon steel pipe in the Turbine Generator Cooling Water System at Keowee.

This characteristic-based approach to managing aging effects is also used for materials that behave similarly, but are not constructed from the same material specification. For example, due to the similarity between cast iron and carbon steel, operating experience has shown that the corrosion performance of cast irons and carbon steels is very similar. Monitoring of carbon steel piping for loss of material would serve as an indicator of the condition of the cast iron components in the raw water systems. Corroded carbon steel piping would be an indicator of corroded cast iron components.

Another example of materials that will behave similarly when exposed to raw water are copper, brass and bronze. Since copper and bronze are, in general, more corrosion resistatnt than brass to natural waters, an inspection location in brass piping in Keowee raw water systems will serve as an indicator of the condition of brass, bronze, and copper components exposed to raw water in other systems at Keowee, Oconee and the Standby Shutdown Facility.

Aging Effects - The aging effects of concern in raw water systems are loss of material due to general corrosion of copper, bronze, brass, carbon steel, and cast iron components, loss of material due to galvanic corrosion at the junction of carbon steel and stainless steel components, and loss of material due to localized corrosion for copper, bronze, brass, carbon steel, cast iron and stainless steel that may reveal itself in the raw water systems within the scope of license renewal. For the Keowee Carbon Dioxide and Keowee Governor Air systems, the aging effect is loss of material due to general corrosion of carbon steel components.

Method - Inspection methods for susceptible component locations include use of volumetric examinations using ultrasonic testing. Also, visual examination is used as a general characterization tool in conjunction with ultrasonic testing when access to interior surfaces is allowed such as during plant modifications.

Industry Codes and Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability is judged in accordance with the component design code of record.

Frequency - Because the corrosion phenomena is slow-acting, inspection frequency varies for each location with a periodicity on the order of five to ten years. The frequency of re-inspection depends on previous inspection results, calculated rate of material loss, piping analysis review, pertinent industry events and plant operating experiences.

Acceptance Criteria - No inspection locations falling below the minimum pipe wall thickness values for the inspection locations as defined in the program. These minimum values have been determined based on design pressure or structural loading using the piping design code of record and then applying additional conservatism.

Corrective Action - Inspection locations that fall below the acceptance criteria are repaired or replaced prior to the system returning to service unless an engineering analysis allows further operation. In the cases where a component may be allowed to continue in service, a re-inspection interval is established in the program. Inspection results at sentinel locations are applied to similar locations in other systems and components managed by the program to address extent of condition.

Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the Service Water Piping Corrosion Program.

Regulatory Basis - The Service Water Piping Corrosion Program is a formalization of a portion of the commitments made in response to GL 89-13, primarily those associated with component pressure boundary maintenance [References 19, 20, 21, 22, and 23]; Application [Reference 1] and Final SER [Reference 2].

18.3.22 System Performance Testing Activities

The following raw water systems have been identified as containing smaller diameter piping that could be affected by fouling and will be managed by System Performance Testing Activities:

1. Protected Service Water System,
2. Keowee Turbine Generator Cooling Water System,
3. Keowee Turbine Sump Pump System,
4. Low Pressure Service Water System,
5. Siphon Seal Water System, and
6. SSF Auxiliary Service Water System.
7. Essential Siphon Vacuum System.

Performance testing for these systems will provide assurance that the components are capable of delivering adequate flow at a sufficient pressure as required to meet system and accident load demands. Performance testing includes other alternate techniques, for example, periodic monitoring of system operating parameters, for those systems whose design or operation renders conventional testing techniques unfeasible. For the Keowee Turbine Generator Cooling Water system, monitoring or bearing temperatures is acceptable.

Periodic operation, inspections and testing are completed for the above systems at a range of frequencies. The Turbine Generator Cooling Water System is operated at design conditions every time the Keowee units operate with bearing temperatures monitored during operations. For other systems, periodic testing frequencies range from quarterly to every third refueling outage, depending on the system. Fouling is not a concern in the Essential Siphon Vacuum System since the system is primarily an air system, and any raw water intrusion is insufficient to allow for fouling.

System performance is determined and compared to test acceptance criteria established by engineering. The results of visual inspections are evaluated by engineering. If the results of the tests and inspections do not meet acceptance criteria, then corrective actions, which could require piping replacement, are undertaken. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the System Performance Testing Activities.

The activities credited here for license renewal are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 19, 20, 21, 22 and 23].

The continued implementation of the System Performance Testing Activities provides reasonable assurance that the aging effects will be managed such that mechanical components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.23 Tendon - Secondary Shield Wall - Surveillance Program

Purpose - The purpose of the Tendon - Secondary Shield Wall - Surveillance Program is to inspect the Secondary Shield Wall Post-Tension Tendon System to ensure that the quality and structural performance of the secondary shield wall is consistent with the licensing basis.

Scope - The scope of this program includes the tendon wires and tendon anchorage hardware, including bearing plates, anchorheads, bushing, buttonheads, and shims of the Units 1, 2, and 3 Secondary Shield Wall Tendons.

Aging Effects - The applicable aging effects include loss of material due to corrosion and cracking of tendon anchorage; wire force relaxation; loss of material due to corrosion and breakage of wires; loss of material due to corrosion and cracking of bearing plate; cracked, split, and broken buttonheads; cracking and loss of material due to corrosion of shims.

Method - Lift-off tests and visual inspections are performed on three randomly selected horizontal tendons.

Industry Code or Standard - No code or standard exists to guide or govern this program.

Frequency - Lift-off tests and visual inspections are performed on three randomly selected horizontal tendons every other refueling outage or every 48 months.

Acceptance Criteria or Standard - No unacceptable visual indication of moisture, discoloration, foreign matter, rust, corrosion, splits or cracks in the buttonheads, broken or missing wires, and other obvious damage as identified by the accountable engineer. Lift-off forces are measured and compared to established acceptance criteria. The minimum required forces for the tendon groups range from 390 kips to 560 kips depending on the location of the group.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by replacement. Specific corrective actions are implemented in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Application [Reference 1] and Final SER [Reference 2].

18.3.24 230 kV Keowee Transmission Line Inspection

Purpose - The purpose of the 230 kV Keowee Transmission Line Inspection is to maintain the structural integrity of the 230 kV Keowee transmission line structures.

Scope - The 230 kV Keowee Transmission Line Inspection includes steel towers, concrete foundations, and hardware within the 230 kV Keowee transmission line.

Aging Effects - The applicable aging effects of concern include loss of material due to corrosion of the steel structures and loss of material due to spalling or scaling for concrete components.

Method - The inspection requires a visual examination of the towers.

Industry Code or Standard - National Electric Safety Code, Part 2, Safety Rules for Overhead Lines; Rule 214 Inspection and Tests of Lines and Equipment.

Frequency - The inspections are performed once every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of aging effects as evaluated by the inspector.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by repair or replacement. Specific corrective actions are implemented in accordance with the Corrective Action Program. The Corrective Action Program applies to all structures and components within the scope of the 230 kV Keowee Transmission Line Inspection.

Regulatory Basis - National Electric Safety Code, Part 2, Safety Rules for Overhead Lines, Rule 214 Inspection and Tests of Lines and Equipment, Application [Reference 1] and Final SER [Reference 2].

18.3.25 Reactor Coolant Pump Flywheel Inspection Program

The program shall provide for the inspection of each reactor coolant pump flywheel per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975.

In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals. Results of the examinations will be evaluated by the original acceptance criteria and compared with the original examination data to assure the absence of unacceptable defects.

18.3.26 Battery Rack Inspections

Purpose - The purpose of the Battery Rack Inspections is to ensure that the structural integrity of the battery racks is maintained.

Scope - The scope of the Battery Rack Inspections include racks for 125 VDC instrumentation and control batteries at Keowee, 125 VDC 230 kV switchyard batteries, 125 VDC instrument and control batteries in the Auxiliary buildings, and 125 VDC instrument and control batteries in the SSF.

Aging Effect - Battery racks are inspected for physical damage or abnormal deterioration, including loss of material due to corrosion.

Method - The inspection requires a visual inspection of the surfaces of the battery racks.

Industry Code or Standard - NUREG-1430, Standard Technical Specifications-Babcock and Wilcox Plants, Revision 1, April 1995; IEEE450, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations.

Frequency - The inspection is performed annually as required by the Oconee Improved Technical Specifications. This surveillance frequency is consistent with the recommendation to check the structural integrity of the battery rack on a yearly basis per IEEE-450.

Acceptance Criteria or Standard - No visual indication of loss of material due to corrosion. The presence of physical damage or deterioration does not necessarily represent a failure, provided an evaluation determines that the physical damage or deterioration does not affect the ability of the battery to perform its function.

Corrective Action - Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by repair or replacement. Specific corrective actions are implemented by the Corrective Action Program and in accordance with the Duke Quality Assurance Program.

Regulatory Basis - Oconee improved Technical Specifications SR 3.8.1.11, AC Sources Operating, SR 3.8.3.3, DC Sources Operating and SR 3.10.1.10, Standby Shutdown Facility.

18.3.27 Steam Generator (SG) Program

The purpose of the Steam Generator (SG) Program is to provide comprehensive examinations of the steam generator tubes to ensure that degradation of the tubes is identified and corrective actions taken prior to exceeding allowable limits. The scope of the Steam Generator (SG) Program includes all steam generator tubes in each steam generator. The aging effects managed by the Steam Generator (SG) Program include loss of material, cracking, and mechanical distortion. The method of examination is specified in Oconee TS 5.5.10 Steam Generator (SG) Program. The Steam Generator (SG) Program complies with the guidance provided in NEI 97-06, Steam Generator Program Guidelines, and its referenced industry guideline documents for inspections, personnel qualification, and technique qualification. The frequency of examinations is specified in Oconee TS 5.5.10, Steam Generator (SG) Program. Acceptance criteria are specified in Oconee TS 5.5.10, Steam Generator (SG) Program. The Duke Energy Steam Generator Management Program Manual provides corrective action directions. Specific corrective actions will be implemented in accordance with the Duke Energy Quality Assurance Program. The Steam Generator (SG) Program is implemented by written procedures as required by Oconee TS 5.4 and the Duke Energy Quality Assurance Program. The regulatory basis for the Steam Generator (SG) Program is Oconee TS 5.5.10.

18.3.28 Cast Iron Selective Leaching Monitoring Program

Purpose – The purpose of the Cast Iron Selective Leaching Monitoring Program is to monitor for the presence of selective leaching of cast iron components in Oconee raw water.

Scope - The results of this inspection apply to the cast iron components falling within the scope of license renewal in a raw water environment. These components include pump casings, valve bodies, strainer housings, and other piping components. The Oconee raw water systems containing cast iron components potentially susceptible to loss of material due to selective leaching are the Auxiliary Service Water System, the Low Pressure Service Water System, the Condenser Circulating Water System, the Service Water System (Keowee), and the High Pressure Service Water System. Note: The Auxiliary Service Water System has been replaced by the Protected Service Water System. The Auxiliary Service Water System in this context is that portion of the Protected Service Water System that was formerly part of the Auxiliary Service Water System, and is in the scope of initial license renewal.

Aging Effects – Inspections are performed to determine the existence of loss of material due to selective leaching, a form of galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function. Selective leaching is the dissolution of iron at the metal surface that leaves a weakened network of graphite and iron corrosion products.

Method – The Cast Iron Selective Leaching Monitoring Program will inspect a sample of cast iron components in a raw water environment to determine whether selective leaching of the iron has been occurring at Oconee and whether loss of material due to selective leaching is an aging effect of concern for the period of extended operation. Inspections and examinations consist of the following:

- Visual inspections of all accessible surfaces. Note that graphitized cast iron cannot be reliably identified through visual examination, as the appearance of the graphite surface layer created by selective leaching does not always differ appreciably from the typical cast iron surface.
- Mechanical examination techniques, such as chipping and scraping, augment visual inspections for gray cast iron components.
- Destructive examinations are used to determine the presence of and depth of dealloying through-wall thickness of components.

Sample Size – The Oconee Cast Iron Selective Leaching Monitoring Program is an ongoing program that will perform seven visual and mechanical, and one destructive examination of cast iron components in each unit, in each program interval. Representative samples will be selected from each of the following systems:

- Auxiliary Service Water System
- Low Pressure Service Water System
- High Pressure Service Water System
- Condenser Circulating Water System
- Service Water System (Keowee)

Industry Codes or Standards – No specific codes or standards exist to address this inspection.

Frequency – The initial program interval is taken to be that period between the establishment of the program and the end of the current period of extended operation for Unit 1 (February 6, 2033), a period of approximately 11 years. Subsequent inspection intervals will be performed on a ten year basis, as applicable, subject to modification by approved aging management programs associated with the Subsequent License Renewal Application.

Acceptance Criteria or Standard – No unacceptable indication of loss of material due to selective leaching as determined by engineering analysis. Component wall thickness acceptability is judged in accordance with the Oconee component design code of record.

Corrective Action – Any unacceptable loss of material due to selective leaching requires an engineering analysis be performed to determine potential impact on component intended function. Specific corrective actions will be implemented in accordance with the Corrective Action Program.

Regulatory Basis – Application [Reference 1].

18.3.29 References

1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, - 270, and -287.
2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station,* Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.
3. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999 to Document Control Desk (NRC), Attachment 1, Pages 43-48, Response to Requests for Additional Information, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
4. W. T. Russell (NRC) letter dated November 19, 1993 to W. H. Rasin (NUMARC, now NEI).
5. M. S. Tuckman (Duke) letter dated July 30, 1997 to Document Control Desk (NRC), Oconee Nuclear Station - Response to Generic Letter 97-01: *Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,* Docket Nos. 50-269, -270, and -287.
6. ANSI B30.2.0, "Overhead and Gantry Cranes", American National Standard, Section 2-2, *Safety Standards for Cableways, Cranes, Derricks, Hoists, Hooks, Jacks and Slings,* The American Society of Mechanical Engineers, New York.
7. ANSI B30.16, "Overhead Hoists (Underhung)", The American Society of Mechanical Engineers, New York.
8. 29 CFR Chapter XVII, 1910.179, *Occupational Safety and Health Administration, Overhead and Gantry Cranes.*
9. W. R. McCollum, Jr. (Duke) letter dated February 8, 1999 to Document Control Desk (NRC), Response to Requests for Additional Information (RAI), Attachment 1, Response to RAI 4.12-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
10. 18 CFR Part 12 - *Safety of Water Power Projects and Project Works,* 59 FR 54815, Nov. 2, 1994.
11. IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants.*
12. H. B. Tucker (Duke) letter dated September 14, 1987 to Document Control Desk (NRC), Response to IE Bulletin 87-01, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
13. Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning.*

14. H. B. Tucker (Duke) letter dated July 21, 1989, Response to Generic Letter 89 08, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
15. Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,* dated March 17, 1988.
16. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999 to Document Control Desk (NRC), Response to Requests for Additional Information Attachment 7, Commitment #1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
17. H. B. Tucker (Duke) letter dated August 1, 1988 to Document Control Desk (NRC), *Response to Generic Letter 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,* Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.
18. M. S. Tuckman (Duke) letter dated December 17, 1999, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Response to SER Open Item 3.9.3-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
19. H. B. Tucker (Duke) letter dated January 26, 1990 to the Document Control Desk (NRC), *Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
20. H. B. Tucker (Duke) letter dated May 31, 1990 to the Document Control Desk (NRC), *Supplemental Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
21. J. W. Hampton (Duke) letter dated December 10, 1992 to the Document Control Desk (NRC), *Confirmation of Implementation of Recommended Action Related to Generic Letter 89-13,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, - 270, and -287.
22. J. W. Hampton (Duke) letter dated September 1, 1994 to the Document Control Desk (NRC), *Follow Up to a Deviation Notice in NRC Inspection Report 93-25 to Revise Response to 89-13,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and - 287.
23. J. W. Hampton (Duke) letter dated April 4, 1995 to Document Control Desk (NRC), *Supplemental Response #3 to Generic Letter 89-13,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
24. M. S. Tuckman (Duke) letter dated January 12, 2000, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Revised Response to SER Open Item 3.9.3-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
25. Generic Letter 85-20, *Resolution of Generic Issue 69: High Pressure Injection/Make-up Nozzle Cracking in Babcock and Wilcox Plants.*
26. IE Bulletin 88-08, *Thermal Stresses in Piping Connected to the Reactor Coolant System.*
27. D. B. Matthews (NRC) letter dated July 11, 1997 to J. H. Taylor (FTI), Babcock & Wilcox Owners Group (B&WOG) Reactor Vessel Working Group Report BAW-1543, Revision 4, Supplement 2, Supplement to the Master Integrated Reactor Vessel Surveillance Program, TAC No. M98089.
28. BAW-1543, Revision 4, *Master Integrated Reactor Vessel Surveillance Program,* prepared for B&W Owners Group by B&W Nuclear Technologies, Inc., February 1993.

29. BAW-2251A, *Demonstration of the Management of Aging Effects for the Reactor Vessel, The B&W Owners Group Generic License Renewal Program*, August 1999.
30. ASTM E 185, *Standard Practice for Conducting Surveillance Test for Light-Water Cooled Nuclear Power Reactor Vessels.*
31. Regulatory Guide 1.99, Revision 2, NRC, *Radiation Embrittlement of Reactor Vessel Materials,* May 1998.
32. BAW-1543(NP), Revision 4, Supplement 6A, *Supplement to the Master Integrated Reactor Vessel Surveillance Program,* AREVA NP, Inc., June 2007.
33. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999, Response to Request For Additional Information, Attachment 1, Response to RAI 3.4.5-2 pages 24 and 25, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
34. M. S. Tuckman (Duke) letter dated May 10, 1999, to Document Control Desk (NRC), Response to Requests for Additional Information, Attachment 1, Response to Potential Open Item 3.4.5-9, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
35. Regulatory Guide – 1.190, *Calculational and Dosimetry Method for Determining Pressure Vessel Neutron Fluence,* March 2001.
36. BAW-2241P, *Fluence and Uncertainty Methodologies,* April 1997 (under NRC review as of June 1998).
37. ASME Section XI, Appendix G for Nuclear Power Plants, Division 1, *Protection Against Non-Ductile Failure.*
38. ASME Code Case N-514, *Low Temperature Overpressure Protection,* Section XI, Division 1.
39. *Materials Reliability Program: Pressurized Water Reactors Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A)*. EPRI, Palo Alto, CA: 2019. 3002017168.
40. NRC Bulletin 2003-02, "Leakage from Reactor Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," August 21, 2003.
41. NRC Order EA-03-009, "Issuance of first revised NRC Order (EA-03-009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," February 20, 2004.
42. NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRS," May 28, 2004.
43. Barron, Henry B. (Duke) to U. S. Nuclear Regulatory Commission, Duke Response to NRC Bulletin 2004-01, July 27, 2004.
44. McCollum, William R. (Duke) to U. S. Nuclear Regulatory Commission, Supplement to Response to NRC Bulletin 2004-01, September 21, 2004.
45. Barret, R. (NRC) to Marion, A. (NEI), Flaw Evaluation Guidelines, April 11, 2003.
46. ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Code Case N-729, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzle Having Pressure Retaining Partial-Penetration Welds."
47. ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Code Case N-722, "Additional Examinations for PWR Pressure Retaining Welds in Class 1 Components Fabricated With Alloy 600/82/182 Materials."

48. Federal Register 10CFR Part 50, “Industry Codes and Standards; Amended Requirements; Final Rule, Wednesday September 10, 2008 – pages 52742 and 52749.”
49. Material Reliability Program: Primary System Piping Butt Weld Inspection and Evaluation Guideline (MRP-139), EPRI Report 1010087, Revision 1, December 2008.
50. License Amendment No. 373, 375, and 374 for Units 1, 2, and 3 respectively (date of issuance June 27, 2011) - Use of Fiber Reinforced polymer on masonry brick walls for the mitigation of differential pressure created by highwinds.
51. PD-EG-PWR-1611, Boric Acid Corrosion Control Program (Program Description), Rev. 0.
52. AD-EG-PWR-1611, Boric Acid Corrosion Control Program - Implementation (Administrative Procedure), Rev. 0.
53. D. B. Matthews (NRC) letter dated December 5, 1988 to H.B. Tucker (Duke), Subject: "Cavity Dosimetry Program", Oconee Nuclear Station Units 1, 2, and 3 (TAC 65759, 65760, 65761), Docket Nos. 50-269, 50-270, 50-287.
54. BAW-2275A, "Low Upper-Shelf Toughness Fracture Mechanics Analsyis of B&W Designed Reactor Vessels for 48 EFPY", August 1999.
55. ASME Boiler and Pressure Vessel Code, Section XI, Division 1, Code Case N-770, "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzel Butt Welds Fabricated With UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities."
56. EPRI 1025147, *Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals – 2015 Update (MRP-228 Revision 2)*, Electric Power Research Institute, Palo Alto, CA, 2015, EPRI Document 3002005386.
57. NRC Letter to Scott Batson, Subject: Oconee Nuclear Station, Units 1, 2, and 3, Issuance of Amendments Regarding Inspection Plan for Reactor Vessel Internals, TAC Nos. ME9024, ME9025, and ME9026 (ADAMS Accession No. ML15050A671).
58. License Amendment Request for the Reactor Vessel Internals Inspection Plan (LAR 2010-06) was submitted to the NRC on November 8, 2010 (ADAMS Accession No. ML103140599).
59. NRC Safety Evaluation documented in Enclosure 4 (Non-Proprietary) to NRC Letter dated June 19, 2015, Reference ADAMS Accession No. ML15050A671.
60. OSC 10773 Fiber Reinforced Polymer (FRP) Inspection Units 1, 2, 3 Appendix M Technical Justification for an Alternate Inspection of the Bottom Edge of Some U1 Fiber Reinforced Polymer (FRP) Masonry Wall Panels.

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18.4 Additional Commitments

The following are additional commitments that are not identified in the preceding sections of Chapter 18.

"HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED"

1. *A plant-specific analysis will be performed to demonstrate that, under loss-of-coolant-accident (LOCA) and seismic loading, the internals have adequate ductility to absorb local strain at the regions of maximum stress intensity and that irradiation accumulated at the expiration of the renewal license will not adversely affect deformation limits. Data will be developed to demonstrate that the internals will meet the deformation limits at the expiration of the renewal license. (Reference: Duke letter to the NRC dated December 17, 1999, Attachment 1, page 8)*

   Duke submitted the plant-specific time limited aging analysis (ML 12053A332) to the NRC for review on February 20, 2012 and received a Safety Evaluation (ML 13045A489) from the NRC on February 19, 2013. During NRC evaluation there was a request for additional information (RAI) from the NRC and a teleconference was held between the NRC and Duke Energy. The response to the RAI is documented in ML 12333A317 and a summary of the teleconference is contained in ML 13024A265.

2. For the Steam Generator (SG) Program see Section 18.3.27.

3. Table 5-24, Table 5-25, Table 5-26, Table 5-27, Table 5-28, and Table 5-29 of the UFSAR contain reactor vessel materials data. These tables will be revised to include the current data from BAW-2325 (Revision 1 or the most current revision available) by July 1, 2001. (Reference: Duke letter to NRC dated March 27, 2000, Submittal of UFSAR Supplement, March 2000)

4. The Oconee Thermal Fatigue Management Program will be modified to incorporate a plant-specific resolution of Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life." Plant-specific actions will be taken either in the manner that was described in Duke letter to the NRC dated October 15, 1999, "Safety Evaluation Report - Oconee Nuclear Station License Renewal Application, Comments and Responses to Open Items and Confirmatory Items, Response to Open Item 4.2.3-2," or by using another approach that is acceptable to the NRC staff. (Reference: Duke letter to NRC dated October 15, 1999, Attachment 2, page 111)

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Appendix 18A. Tables

Table 18-1. Summary Listing of the Programs, Activities and TLAA

Topic	Program/Activity or TLAA	UFSAR/ITS/SLC Location
Alloy 600 Aging Management Program	Program/Activity	18.3.1
Auxiliary Building Ventilation Inspection	Program/Activity	18.3.17.18
Battery Rack Inspections	Program/Activity	ITS: SR 3.8.1.11, SR3.8.3.3, SR 3.10.1.10 18.3.26
Boric Acid Corrosion Control Program	Program/Activity	18.3.10
Cast Iron Selective Leaching Inspection	Program/Activity	18.2.1
Cast Iron Selective Leaching Monitoring Program	Program/Activity	18.3.28
Chemistry Control Program	Program/Activity	18.3.2 ITS 5.5.14 ITS 3.10.1.8
Chilled Water Refrigeration Unit PM	Program/Activity	18.3.17.2
Coatings Program	Program/Activity	3.8.1.1.1 6.2.1.6 18.3.17.1 18.3.17.5
Containment Inservice Inspection Plan	Program/Activity	18.3.3 ITS 3.6.1 B3.6.1 5.5.7 SLC 16.6.2
Containment Leak Rate Testing Program	Program/Activity	ITS 5.5.2 3.6.1 B3.6.1 SLC 16.6.1
Containment Liner Plate and Penetrations - Thermal Cycles	TLAA	3.8.1.5.3
Containment Post-Tensioning System - Prestress Loss	TLAA	3.8.1.5.2 16.6.2 18.3.3
Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program	Program/Activity	18.3.1.2
Control Room Pressurization & Filtration Inspection	Program/Activity	18.3.17.19

Topic	Program/Activity or TLAA	UFSAR/ITS/SLC Location
Control Room Ventilation System Examination	Program/Activity	18.3.17.6
Crane Inspection Program	Program/Activity	18.3.5
Cranes and Control of Heavy Loads	TLAA	3.12
Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances	Program/Activity	18.3.6
Elevated Water Storage Tank Inspection	Program/Activity	18.3.7
Environmental Qualification of Electrical Equipment	TLAA	3.11
Federal Energy Regulatory Commission (FERC) Five Year Inspections	Program/Activity	18.3.8
Fire Protection Program	Program/Activity	16.9.1, 16.9.2, 16.9.4, 16.9.5, 18.3.17.8
Flow Accelerated Corrosion Program	Program/Activity	18.3.9
Deleted Row per 2012 Update		
Galvanic Susceptibility Inspection	Program/Activity	18.2.2, 18.3.21
Generator Stator Water Cooler Inspection	Program/Activity	18.3.17.23
Heat Exchangers	Program/Activity	18.3.11 18.3.17.3 18.3.17.4 18.3.17.7 18.3.17.9 18.3.17.11 18.317.12 18.3.17.13 18.3.17.15
Inservice Inspection Plan	Program/Activity	18.3.12 5.2.3.12.4 SLC 16.9.18
Inspection Program for Civil Engineering Structures and Components	Program/Activity	18.3.13
Insulated Cables and Connections Aging Management Program	Program/Activity	18.3.14
Keowee Air and Gas Systems Inspection	Program/Activity	18.2.3, 18.3.21
Keowee Oil Sampling Program	Program/Activity	18.3.15

Topic	Program/Activity or TLAA	UFSAR/ITS/SLC Location
Keowee Turbine Generator Cooling Water Strainer PM	Program/Activity	18.3.17.10
Keowee Turbine Guide Bearing Oil Cooler Examination	Program/Activity	18.3.17.22
Keowee 230 kV Transmission Line Inspections	Program/Activity	18.3.24
Non-Class 1 Piping - Thermal Cycles	TLAA	3.2.2.2
Once Through Steam Generator Upper Lateral Support Inspection	Program/Activity	18.2.4
Penetration Room Ventilation System Inspection	Program/Activity	18.3.17.20
Penstock Inspection	Program/Activity	18.3.16
Pressurizer Examinations and Inspections	Program/Activity	18.2.5 18.2.5.1 18.2.5.2 18.3.1.3
Preventive Maintenance Activities	Program/Activity	18.3.17
Program to Inspect High Pressure Injection Connections to the Reactor Coolant System	Program/Activity	18.3.18
Reactor Building Cooling System Inspection	Program/Activity	18.3.17.17
Reactor Building Purge System Inspection	Program/Activity	18.3.17.21
Reactor Building Spray System Inspection	Program/Activity	18.2.6
Reactor Coolant Pump Flywheel Inspection Program	Program/Activity	ITS 5.5.8 5.4.4.3.2 18.3.25
Reactor Coolant Pump Motor Oil Collection System Inspection	Program/Activity	18.2.7
Reactor Coolant System and Class 1 Components (include leak-before-break) (Oconee Thermal Fatigue Management Program)	TLAA	5.2.1.4 18.4
Reactor Coolant System Operational Leakage Monitoring	Program/Activity	ITS 3.4.13 ITS 3.4.15 SLC 16.11.3

Topic	Program/Activity or TLAA	UFSAR/ITS/SLC Location
Reactor Vessel Integrity Program	TLAA Program/Activity	5.2.3.3.2 5.2.3.3.3 5.2.3.3.4 5.2.3.3.5 5.2.3.3.6 5.2.3.3.10 5.2.3.3.11 18.3.19 18.4
Reactor Vessel Internals	TLAA	4.5.1.2 18.4
Reactor Vessel Internals Inspection	Program/Activity	18.3.20
Service Water Piping Corrosion Program	Program/Activity	18.3.21, 18.2.2, 18.2.3
Small Bore Piping Inspection	Program/Activity	18.2.8
Spent Fuel Rack Boraflex	None	9.1.2.5
SSF - Diesel Fuel Oil Storage Tank Inspection	Program/Activity	18.3.17.14
Standby Shutdown Facility HVAC Inspection	Program/Activity	18.3.17.16
Steam Generator (SG) Program	Program/Activity	ITS 5.5.10 ITS 3.4.16 18.3.27
System Performance Testing Activities	Program/Activity	18.3.22
Tendon - Secondary Shield Wall - Surveillance Program	Program/Activity	18.3.23 ITS 5.5.7
Treated Water Systems Stainless Steel Inspection	Program/Activity	18.2.9