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Technical Requirements Manual

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1.2.5.7 Nuclear System Process Control

1.2.5.7.1 Reactor Manual Control System

The reactor manual control system provides the means by which control rods are manipulated from the control room for gross power control. The system controls valves in the CRD hydraulic system. Only one control rod can be manipulated at a time. The reactor manual control system includes the controls that restrict control rod movement (rod block) under certain conditions as a backup to procedural controls. (Section 7.7)

1.2.5.7.2 Recirculation Flow Control System

The recirculation flow control system controls the speed of the reactor recirculation pumps. Adjusting the pump speed changes the coolant flow rate through the core. This affects changes in core power level. The system is arranged to adjust reactor power output to the load demand by adjusting the frequency of the electrical power supply for the reactor recirculation pumps. (Section 7.7)

1.2.5.7.3 Neutron Monitoring System

The neutron monitoring system is a system of incore neutron detectors and out-of-core electronic monitoring equipment. The system provides an indication of neutron flux, which can be correlated to thermal power level, for the entire range of flux conditions that may exist in the core. The source range monitors and the intermediate range monitors provide flux level indications during reactor startup and low-power operation. The local power range monitors and average power range monitors allow the assessment of local and overall flux conditions during power range operation. Rod block monitors are provided to prevent rod withdrawal when the change in reactor power would exceed a predetermined value that is based on the original power level. The rod block monitors prevent local fuel damage as a backup to procedural power flow restrictions. The flux mapping and calibration subsystem provides a means to calibrate individual monitors with traveling incore probes. (Section 7.6)

1.2.5.7.4 Refueling Interlocks

A system of interlocks that restrict the movements of refueling equipment and control rods when the reactor is in the refuel mode is provided to prevent an inadvertent criticality during refueling operations. The interlocks backup procedural controls that have the same objective. The interlocks affect the refueling bridge, the refueling bridge hoists, the fuel grapple, control rods, and the service platform hoist. (Section 7.6)

1.2.5.7.5 Reactor Vessel Instrumentation

In addition to instrumentation provided for the nuclear safety systems and engineered safeguards, instrumentation is provided to monitor and transmit information that can be used to assess conditions existing inside the reactor vessel and the physical condition of the vessel itself. The instrumentation provided monitors reactor vessel pressure, water level, surface temperature, internal differential pressures and coolant flow rates, and top head flange leakage. (Section 7-6)

1.2.5.7.6 Plant Process Computer System

An online plant process computer is provided to monitor and log process variables, and to make certain analytical computations. The plant process computer provides core fuel performance analysis and display, and display of plant data in remote locations. (Section 7.7)

1.2.5.7.7 Rod Worth Minimizer System

The rod worth minimizer is implemented on a stand-alone microcomputer system that interfaces to the plant process computer. The rod worth minimizer functions to prevent rod withdrawal if the rod to be withdrawn is not in accordance with a preplanned pattern. The effect of the rod block is to limit the reactivity worth of the control rods by enforcing adherence to the preplanned rod pattern.
(Section 7.7).

1.2.5.8 Power Conversion System Process Control

1.2.5.8.1 Pressure Regulator and Turbine-Generator Control

The pressure regulator and the integrated turbine-generator control system work together to allow proper generator and reactor response to load demand changes. The pressure regulator maintains nuclear system pressure essentially constant eliminating the possibility of pressure-induced core reactivity changes. The pressure regulator adjusts turbine control valves or turbine bypass valves while the turbine-generator controls maintain a constant turbine speed. The speed and load controls initiate rapid closure of the turbine control valves and fast opening of the bypass valves in case of loss of generator electrical load. (Section 7.7)

1.2.5.8.2 Feedwater System Control

A three-element controller is used to regulate the feedwater system so that proper water level is maintained in the reactor vessel. The controller uses main steam flow, reactor vessel water level, and feedwater flow to control feedwater. (Section 7.7)

Table 1.6-1

DAEC TOPICAL REPORTS SUBMITTED TO THE NRC

GENERAL ELECTRIC REPORT NO.	TITLE	UFSAR SECTION
APED-4784	Design and Operating Experience of the ESADA Vallecitos Experimental Experimental Superheat Reactor (EVESR) (February 1965)	15.0
APED-4827	Maximum Two-Phase Vessel Blowdown from Pipes (1965)	5.2.5.2.3
APED-5177	Liquid/Vapor Action in a Vessel During Blowdown (June 1966)	15.0
APED-5286	Design Basis for Critical Heat Flux in Boiling Water Reactors (September 1966)	
APED-5296	RIP-2, A Computer Program for Calculation of Reactor Internal Pressure During Accident Conditions (1966)	3.9.5.2.1
APED-5446	Control Rod Velocity Limiter (March 1967)	4.6.1.2.5.3
APED-5447	Depressurization Performance of the General Electric Boiling Water Reactor High-Pressure Coolant Injection System (June 1969)	6.2.1.3.3.5
APED-5448	Analysis Methods of Hypothetical Super-Prompt Critical Reactivity Transients in Large Power Reactors (April 1968)	
APED-5449	Control Rod Worth Minimizer (March 1967)	
APED-5453	Vibration Analysis and Testing of Reactor Internals (April 1967)	
APED-5454	Metal Water Reactions - Effects on Core Standby Cooling and Containment (March 1968)	
APED-5455	The Mechanical Effects of Reactivity Transients (January 1968)	
APED-5458	Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors (March 1968)	
APED-5460	Design and Performance of General Electric Boiling Water Reactor Jet Pumps (September 1968)	5.4.1
APED-5528	Nuclear Excursion Technology (August 1967)	
APED-5555	Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RDB144A (November 1967)	4.6.2.2
APED-5608	General Electric Company Analytical and Experimental Program for Resolution of ACRS Safety Concerns (April 1968) (Not Class I)	
APED-5640	Xenon Considerations in Design of Large Boiling Water Reactors (June 1968)	4.3.2.7.1

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DAEC TOPICAL REPORTS SUBMITTED TO THE NRC

GENERAL ELECTRIC REPORT NO.	TITLE	UFSAR SECTION
APED-5652	Stability and Dynamic Performance of the General Electric Boiling Water Reactor (April 1969)	
APED-5654	Considerations Pertaining to Containment Inerting (August 1968)	
APED-5696	Tornado Protection for the Spent Fuel Storage Pool (November 1968)	1.8.13
APED-5698	Summary of Results Obtained from a Typical Startup and Power Test Program for a General Electric Boiling Water Reactor (February 1969)	14.2.1.3
APED-5703	Design and Analysis of Control Rod Drive Reactor Vessel Penetrations (November 1968)	
APED-5706	In-Core Neutron Monitoring System for General Electric Boiling Water Reactors, Revision 1 (April 1969)	
APED-5736	Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards (April 1969)	
APED-5750	Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves (March 1969)	5.4.5.4
APED-5756	Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor (March 1969)	15.0
NEDC-20989	Mark I Containment - Short Term Program Report (1975)	6.2.1.6.1
NEDC-20989	Addendum 1, Mark I Containment - Short Term Program Report (December 1975)	6.2.1.6.1
NEDC-22082-P	Duane Arnold Energy Center Suppression Pool Temperature Response (March 1982)	6.2.1.3.3.3, 9.2.3.2.1
NEDC-22204	Evaluation of Mark I S/RV Load Cases C-3.1, C-3.2, C-3.3, for the DAEC (September 1982)	5.4.13.2
NEDC-23677	Duane Arnold Feedwater Nozzle Temperature Cycling (1977)	5.4.9.2.3
NEDC-30603-P-1	Duane Arnold Energy Center Power Uprate (December 1984)	
NEDC-30626	General Electric Boiling Water Reactor Extended Load Line Limit Analyses for Duane Arnold Energy Center, Cycle 8	4.4.3.3, 15.0.10

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DAEC TOPICAL REPORTS SUBMITTED TO THE NRC

GENERAL ELECTRIC REPORT NO.	TITLE	UFSAR SECTION
NEDC-30813-P	Average Power Range Monitor, Rod Block Monitor and Technical Specification Improvement (ARTS) Program for the DAEC (December 1984)	7.6.1.8.3, 7.6.1.8.4
NEDC-30839	DAEC Reactor Pressure Vessel Fracture Toughness Analysis to 10 CFR 50, Appendix G (May 1983)	5.3.2.1
NEDE-20566-P-A	General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K (November 1975)	Superceded by NEDC-23785-P-A
NEDE-20606-P-A	Creep Collapse Analysis of BWR Fuel Using SAFE-COLAPS Model (August 1976)	4.2.1.2.2
NEDE-21354-P	BWR Fuel Channel Mechanical Design and Deflection (September 1976)	4.2.1.1.5, 4.2.2
NEDE-21480	BWR Feedwater Nozzle/Sparger Interim Program Report (July 1977)	5.4.9.2.3
NEDE-21855-P	FSCRD Manufacturing Qualification Test Final Report (August 1978)	6.2.1.6.2.2
NEDE-21864-P	In-Plant Testing of T-Quencher Device at Monticello Nuclear Generating Plant (July 1978)	6.2.1.6.2.2
NEDE-23898-P	Analytical Model for Computing Water Rise in a Safety/Relief Valve Discharge Line Following Valve Closure	5.4.13.2
NEDE-24011-P-A	General Electric Standard Application for Reactor Fuel (latest appicable version)	4.2, 4.3, 4.4
NEDE-24284-P	Assessment of Fuel Rod Bowing in GE BWRs (December 1980)	4.2.3.1.5
NEDE-24343-P	Experience with BWR Fuel Through January 1981 (September 1976)	4.2.4
NEDE-24988-P	BWR Owners Group SRV Test Program (October 1981)	5.4.13.4
NEDE-30021-P	Low-Low Set Relief Logic System and Lower MSIV Water Level Trip for the Duane Arnold Energy Center (January 1983)	5.4.13.2, 15.0
NEDE-30051	Analysis of Reduced RHR Service Water Flow at the DAEC (January 1983)	9.2.3.2.1
NEDO-10017	Field Testing Requirements for Fuel, Curtains, and Control Rods (June 1969)	
NEDE-32417	GE12 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR-II)	4.2.3, 4.3.2, 15.4

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DAEC TOPICAL REPORTS SUBMITTED TO THE NRC

GENERAL ELECTRIC REPORT NO.	TITLE	UFSAR SECTION
NEDO-10029	An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design-Basis Accident (July 1969)	5.3.1.5
NEDO-10045	Consequences of a Steam Line Break for a General Electric Boiling Water Reactor (October 1969)	5.4.5.3
NEDO-10115	Mechanical Property Surveillance of General Electric BWR Vessels (July 1969)	5.3.1.6, 5.3.2.1, 5.3.3.1
NEDO-10139	Compliance of Protection Systems to Industry Criteria; GE BWR NSSS (June 1970)	1.8.22, 6.3.5.4, 7.2.1.2.4
NEDO-10173	Current State of Knowledge - High Performance BWR Zircaloy- Clad UO_2 Fuel (May 1970)	
NEDO-10174	Consequences of a Postulated Flow Blockage Incident in a Boiling Water Reactor (May 1970)	
NEDO-10179	Effects of Cladding Temperature and Material on ECCS Performance (June 1970)	
NEDO-10189	An Analysis of Functional Common-Mode Failures in General Electric BWR Protection and Control Instrumentation (July 1970)	
NEDO-10208	Effects of Fuel Rod Failure on ECCS Performance (August 1970)	
NEDO-10299	Core Flow Distribution in a Modern BWR as Measured at Monticello (1971)	3.9.4.3.2
NEDO-10320	General Electric Pressure Suppression Containment Analytical Model (April 1971)	3.1.2.5.1, 6.2.1.3.3.1, 15.0
NEDO-10329	Loss-of-Coolant Accident and Emergency Core Cooling Models for General Electric Boiling Water Reactors (April 1971)	3.9.1.2
NEDO-10349	Analysis of Anticipated Transients without Scram (March 1971)	4.6.2.1
NEDO-10527	Rod Drop Accident Analysis for Large Boiling Water Reactors (March 1972 and supplements)	4.2.1.2.6, 4.6.3.1.1, 4.6.2.4
NEDO-10677	Analysis of Recirculation Pump Overspeed in a Typical General Electric BWR (October 30, 1972)	7.7.5.4.4

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DAEC TOPICAL REPORTS SUBMITTED TO THE NRC

GENERAL ELECTRIC REPORT NO.	TITLE	UFSAR SECTION
NEDO-10739	Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems (January 1973)	6.3.4.2.1
NEDO-10801-A	Core Spray and Bottom Flooding Effectiveness in the BWR-6 (February 1977)	6.3.4.1.1
NEDO-20377	8 x 8 Fuel Development Support (February 1975)	4.2.3.1.3, 4.2.3.1.5
NEDO-20566-A	General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K (August 1975)	Superceded by NEDC-23785-P-A
NEDO-20606-A	General Electric Creep Collapse Analysis for BWR Fuel Using SAFE-COLARS Model (1976)	4.2.1.2.2
NEDO-21052	Maximum Discharge Rate of Liquid-Vapor Mixtures From Vessels (March 1982)	6.2.1.3.3.3
NEDO-21082-03	Loss-of-Coolant Accident Analysis Report for Duane Arnold Energy Center (Lead Plant) (June 1984)	
NEDO-21082-03	Appendix A, Loss-of-Coolant Accident Analysis Report for Duane Arnold Energy Center (Lead Plant) (June 1984)	
NEDO-21354	BWR Fuel Channel Mechanical Design and Deflection (1976)	4.2.1.1.5, 4.2.2
NEDO-21888	Mark I Containment Program Load Definition Report (November 1981)	3.1.2.5.1 6.2.1.3.3.3
NEDO-22082-P	DAEC Suppression Pool Temperature Response (March 1982)	6.2.1.3.3.3
NEDO-22155	Generation and Mitigation of Combustible Gas Mixtures in Inerted BWR Mark I Containments (August 1982)	6.2.5.1
NEDO-24011-P-A-US	General Electric Standard Application for Reactor Fuel - United States Supplement (latest approved revision)	6.3.1.2, 6.3.3, 15.0
NEDO-24087-3	General Electric Boiling Water Reactor Reload 3 (Cycle 4) Licensing Amendment for Duane Arnold Energy Center, Supplement 3: Application of Measured Scram Insertion Times (June 1978)	

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GENERAL ELECTRIC REPORT NO.	TITLE	UFSAR SECTION
NEDO-24087-6	General Electric Boiling Water Reactor Reload 3 Cycle 4) Licensing Amendment for Duane Arnold Energy Center, Supplement 6: Load Line Limit Analysis (September 1978)	4.4.3.3, 15.0
NEDO-24134-1	General Electric Process Specification for Heat Sink Welding of Austenitic Stainless Steel (1978)	5.2.3.4
NEDO-24220	Basis for Installation of Recirculation Pump Trip System (September 1979)	7.2.1.2.3
NEDO-24226	Evaluation of Control Blade Lifetime with Potential Loss of B_4C (December 1979)	4.2.1.1.8
NEDO-24232	Control Blade Lifetime Evaluation Accounting for Potential Loss of B_4C (1980)	4.6.1.2.5, 4.6.1.2.5.2
NEDO-24272[1]	Duane Arnold Energy Center Single-Loop Operation (July 1980)	4.4, 5.4.3.3, 15.0
NEDO-24571	Mark I Containment Program Plant Unique Load Definition, Duane Arnold Energy Center, Unit 1 (March 1982)	6.2.1.3.3.3
NEDO-24708a	Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors (Rev 1, December 1980)	15.0
NEDO-30603-P	General Electric Company, Duane Arnold Energy Center Power Uprate (May 1984)	6.2.1.3.3.3
NEDO-30603-1	General Electric Company, Duane Arnold Energy Center Power Uprate (Revision 1) December 1984	5.2.2.2.6 6.2.1.3.3.3
NEDO-30606	General Electric Company Safety Relief Valve Simmer Margin Analysis for the Duane Arnold Energy Center (May 1984)	5.4.13.3

[1] This report has been supplemented by MDL# APED LI2-003 [DAEC Supplement to NEDC-32915P, Duane Arnold Energy Center GE12 Fuel Upgrade Project, Rev. 0, March 2000], which was not submitted to the NRC, but done as part of the Core Modification Package for Cycle 17.

Table 1.6-1

DAEC TOPICAL REPORTS SUBMITTED TO THE NRC

GENERAL ELECTRIC REPORT NO.	TITLE	UFSAR SECTION
NEDO-30813	General Electric BWR Licensing Report: Average Power Range Monitor, Rod Block Monitor, and Technical Specification Improvement (ARTS) Program for the Duane Arnold Energy Center (March 1985)	4.4.3.3
NEDO-31908	General Electric Report, Licensing Criteria for Fuel Designs (Amendment 22 to NEDE-24011-P-A and Corresponding NRC Staff Safety Evaluation (January 1991).	4.2.1, 4.3.2
NEDC-31310-P	Duane Arnold Energy Center, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis (August 1986)	4.2.3.2.8, 4.2.3.3.3, 6.3.3, 15.0
NEDC-31310-P Supplement 1, Revision 1	Duane Arnold Energy Center, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis (September 1993)	4.2.3.2.8, 4.2.3.3.3, 6.3.3, 15.0
NEDC-32721P	General Electric Licensing Topical Report: Application Methodology for GE Stacked Disc ECCS Suction Strainer (November 1997)	1.8.1, Figure 5.4-15, 6.2.1.6.2.5, 6.3.2.2, 6.3.2.2.8, Table 6.3-3, Table 6.3-4
NEDO-32686-A	General Electric BWROG Topical Report: Utility Resolution Guide for ECCS Suction Strainer Blockage (October 1998)	1.8.1, Figure 5.4-15, 6.2.1.6.2.5, 6.3.2.2, 6.3.2.2.8, Table 6.3-3, Table 6.3-4

1.8 CONFORMANCE TO NRC REGULATORY GUIDES

The information in this section represents either the original or an updated Iowa Electric (now IES Utilities Inc.) position with respect to AEC Safety Guides, which have since been redesignated as NRC Regulatory Guides. Where the original DAEC position has been updated, that fact is so noted.

Only those guides addressed in the original FSAR are included in this section of the updated FSAR. Guides published after the original FSAR was written may in some cases be addressed elsewhere in the updated FSAR.

1.8.1 SAFETY GUIDE 1 (REGULATORY GUIDE 1.1), NET POSITIVE SUCTION HEAD FOR EMERGENCY CORE COOLING AND CONTAINMENT HEAT REMOVAL SYSTEM PUMPS

This Section has been updated since the initial submittal of the DAEC FSAR.

Regulatory Position

Emergency core cooling and containment heat removal systems should be designed so that adequate net positive suction head (NPSH) is provided to system pumps assuming maximum expected temperatures of pumped fluids and no increase in containment pressure from that present prior to postulated LOCAs.

Response

The emergency core cooling and containment heat removal functions are accomplished by the emergency core cooling systems. The entire spectrum of possible operating modes of the emergency core cooling systems has been examined for adequacy with regard to net positive suction head at the residual heat removal (RHR), core spray, and high pressure coolant injection (HPCI) pumps. Under no circumstance would there be insufficient net positive suction head at any of the pumps at any time.

These pumps are located below the water level of the suppression pool and/or condensate storage tanks. To demonstrate that net positive suction head would be available at all times, the various modes of operation were examined, and the most limiting for NPSH requirements was determined to occur during the long term transient following a design basis LOCA when core spray and one RHR pump will be running continuously. In this operating condition, the NPSH requirements for the core spray pump are most limiting.

The analysis of this situation demonstrated that available containment pressure was greater than the containment pressure required for adequate net positive suction head to the core spray pump, even though assumptions were used to minimize the containment pressure and maximize the temperature of the suppression pool water. Figure 5.4-15 indicates the margin available between actual suppression pool pressure and that pressure required for adequate core spray and RHR pump net positive suction head. The major assumptions are listed below:

1. Offsite power is assumed lost at the time of the accident and is not restored.

2. One of the onsite diesel-generators fails to start and remains out of service during the entire transient.

3. The service water temperature remains at the Technical Specification limit of 95°F throughout the transient. Normally, service water temperature would be at least 10°F less than this value.

4. The service water flow to the RHR heat exchanger is assumed to be maximized so the containment spray water temperature is lowered; this minimizes the containment pressure.

5. Before the accident, the Technical Specification temperature limit of 135°F exists in the drywell together with 100% humidity. Normal operating conditions would typically be 125° F with 20% humidity.

6. The minimum preaccident containment pressure is 0.5 psig (nominal value); normal operating pressure is typically ≈ 1.0 psig.

7. A containment gas leakage rate of 5.0% per day; this is 2.5 times the maximum allowable leakage rate (L_a) of 2.0% per day incorporated in the Technical Specifications.

8. The discharge of the RHR pump(s) is directed to the containment atmosphere via the broken recirculation loop (short-term), and via the drywell and torus sprays (long-term); this minimizes the containment pressure.

Although the safety guide requirement of no increase in containment pressure is not met exactly, the use of the pressure within the containment to provide additional suction head to the pumps is not unreasonable. This factor would exist in reality and would be greater than calculated due to the conservatism of the analysis.

1.8.2 SAFETY GUIDE 2 (REGULATORY GUIDE 1.2), THERMAL SHOCK TO REACTOR PRESSURE VESSELS

This Section has been updated since the initial submittal of the DAEC FSAR. This Regulatory Guide was withdrawn by the NRC in July 1991.

system and start standby gas treatment system may be tested by the operation of simulated process signals directly to the sensing section of the instrument. All of the above instruments except the reactor water cleanup system have integrally mounted trip units that provide the associated trips. The latter sensing section (flow transmitters) send analog signals through signal-conditioning equipment (flow comparators) to remote trip units that trip at some preset analog signal level.

In addition, all of the differential pressure indicating switches have a very fine control vent bleed valve installed on the high and low sides of the pressure sensing body to provide the capability for online testing of the instruments. The switch trip signals may be tested while the instrument is removed from service by venting either side of the pressure body depending on the direction the indicator is required to move for the operation of the trip point under test.

The following is a list of typical functions that have this type of testing capability:

1. Reactor vessel level switches.

2. Main steam line high flow switches.

3. Recirculation pumps differential pressure switches (used for RHR loop selection).

4. Jet pump riser differential pressure switches (used for RHR loop selection).

5. Core spray differential pressure from spray ring to core plate.

6. HPCI steam line high flow switches.

7. HPCI pump flow switches.

8. RCIC steam line high flow switches.

9. RCIC pump flow switches.

10. RHR pump flow switches.

The temperature sensors that provide signals for the leak detection systems for HPCI, RCIC, and reactor water cleanup isolation (as described in Chapter 7) are accessible during reactor operation. These sensors and the isolation circuits that they feed are testable during normal plant operation in accordance with paragraphs 4.9(3) and 4.10 of IEEE 279-1971. Each of these temperature sensors consists of dual thermocouple elements that supply analog signals to a control room vertical board. The analog signal from one thermocouple element drives the temperature switch that feeds the isolation logic while the redundant element is available for comparison testing against the active element. The leak detection temperature sensors are sufficient in quantity so that failed sensors may be jumpered-out as permitted by Technical Specifications and replaced later during plant shutdown.

Each temperature sensing loop in the main steam line temperature sensing system consists of a resistance temperature detector wired to:

1. A remotely-located temperature indicator, and

2. A remotely-located temperature switch (electronic type).

The main steam line low-pressure switches that trip the main steam line isolation valves at low reactor pressure when the reactor is in the "Run" mode are accessible for calibration and test during operation, as they are located outside the shielding wall and are provided with instrument valves that allow isolation for testing purposes.

The main steam line radiation sensors cannot be checked during reactor operation because of the high radiation from N-16 activity with steam.

There are four steam line radiation sensors, and each sensor provides a signal for its own independent radiation monitor/trip unit. Each monitor has a radiation indicator. Two of the monitors may be selected for recording.

The radiation sensors are located in very nearly equal radiation source zones. The indicators all show nearly equal readings and the readings vary in proportion to reactor power level.

Any monitor whose indicated radiation level deviates from the average of the other three at steady-state operation or fails to respond properly whenever the reactor power level is varied will immediately be suspect and subjected to test.

Testing will be done by introducing a simulated current signal into the sensor input terminals to check monitor response. A suspect monitor that responds properly to the simulated test will show that the sensor was the cause of the suspected reading. The Technical Specifications specify the minimum number of operable instrument channels per trip system and the required action if the minimum is not available.

The circuit accommodation for and the method of periodic testing of the emergency core cooling systems and automatic depressurization system control logic and trip logic circuit is described in Chapter 7. The general bases for the design and testability of the emergency core cooling system are also presented in Chapter 7.

The discussions show that all active components of the emergency core cooling systems can be tested and calibrated during plant operation. The active components include the initiating logics, the actuation logics, and the actuators actuating devices as well as valves (actuated devices).

quality water. There are no plans to develop the Jordan aquifer as a primary water supply for the plant since the Jordan aquifer is a sandstone aquifer which cannot tolerate excessive pumping; alternate wet and dry conditions would lead to ultimate crumbling and collapse.

2. Shallow Aquifers

Many adequate supplies of good water are obtained from sand and gravel aquifers in the surficial deposits that overlie the bedrock. These are replenished by direct precipitation, periodic flooding, and, where adequate underground hydraulic connections with streambeds exist, by river recharge.

Borings indicate that two aquifers underlie most of the site area, an upper water table aquifer composed of fine to medium sand, and a lower artesian-type aquifer in weathered rock. The two aquifers are separated by 10 to 60 ft of relatively impervious clayey material. Boring logs and water-level measurements indicate that this clay aquiclude is probably continuous over most of the site area. This clay extends above and below river bottom elevation at most boring locations.

Ground-water measurements indicate that flows in the upper aquifer are toward the river in a general southeasterly direction across the site. Pressure surface contours indicate that flows in the lower aquifer are also in this same general direction.

Since the aquifer below the clay is under considerable pressure in the natural state, any ground-water transfer between the two aquifers would be from the lower into the upper aquifer. With the production wells operating, the lower aquifer pressure could be lower than the surface water table in the immediate vicinity of these wells. Under this circumstance, ground-water transfer could possibly be reversed over a long period of time.

During production well tests and subsequent production well operation, no interference of the upper aquifer has been noted.

Gradients causing flow are quite steep in both aquifers. Information collected on domestic wells within a 1-mile radius of the plant indicates that all domestic wells west and north of the plant are up the ground-water slope from the plant; that is, ground water flows past these wells toward the plant or along some other path directly toward the river. Domestic wells southwest and south of the plant are approximately 1 mile away and are not in the line of ground-water flow past the plant.

Should the area be inundated by a Cedar River flood, infiltration would temporarily raise the general ground-water table. Some domestic wells south of the plant would be flooded. Those on higher ground would maintain their same relative positions on the general water table slope.

In the Village of Palo, 2.5 miles south-southwest of the plant, the water table stands approximately 12 ft below average ground-surface elevation 745, or at elevation 733. Ground-water flow is in an easterly direction toward the river.

A comprehensive subsurface exploration program was performed to establish the adequacy and quality of water available for plant use. Two production wells were drilled into the lower artesian aquifer in weathered rock, and a yield of 750 gpm for each well, pumping concurrently, was established. Test reports of water analysis indicated a good mineral quality.

2.4.13.2 Sources

There are no potable water supplies taken from the Cedar River surface water downstream of the DAEC. Irrigation uses are presented in Section 2.4.1. No permit is required nor is there any restriction on the withdrawal of water from the river for livestock watering, and no records are available.

The primary user of water that could originate from the river is the City of Cedar Rapids. Some of the recharge for the city wells comes from the river at normal withdrawal, and under periods of no or low withdrawal no recharge comes from the river.

In 1981, the average city water consumption was about 22.6 million gal per day (mgd) with a peak day consumption of approximately 33.8 million gal. It has been estimated that this will increase 2% to 5% per year. This system is expected to have an ultimate capacity of 42 mgd. Total storage capacity within the city system is approximately 16.3 million gal. All of the city water was supplied by wells located adjacent to the Cedar River. Because of this location, a large portion of the water withdrawn from these wells was recharged from the river. In addition, the city has an emergency standby system capable of withdrawing 24 mgd directly from the river.

Within a 1.5-mile radius of the plant, there were 14 property owners having 1 or more wells. The use of these wells extended beyond potable supply to such items as swimming pools, livestock watering, and irrigation.

Major industrial water use, within 50 miles downstream of the plant, is concentrated in the Cedar Rapids area. Primary uses of river water include condenser cooling and process water.

Agricultural withdrawals are made at a few locations for irrigation purposes. In addition, limited recreational use is made of the river, particularly above the power plant dams in Cedar Rapids, and in the headwater area recreational lakes. The operation of the plant does not affect these activities.

Chapter 3: DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

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3. Emergency Core Cooling System 6.3

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3.1.2.4.5 Criterion 34 - Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to ensure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

EVALUATION AGAINST CRITERION 34

The RHR system provides the means to

1. Remove decay heat and residual heat from the nuclear system so that refueling and nuclear system servicing can be performed.

2. Supplement the fuel pool cooling system capacity during shutdown to provide additional cooling capacity.

The major equipment of the RHR system consists of two heat exchangers, four main system pumps, and four service water pumps. The equipment is connected by associated valves and piping, and the controls and instrumentation are provided for proper system operation. The main system pumps are sized on the basis of the flow required during the LPCI mode of operation, which is the mode requiring the maximum flow rate. The heat exchangers are sized on the basis of the required duty for the shutdown cooling function, which is the mode requiring the maximum heat exchanger capacity.

One loop, consisting of a heat exchanger, two main system pumps in parallel, and associated piping, is located in one area of the reactor building. The other heat exchanger, pumps, and piping, forming a second loop, are located in another area of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system. The two loops of the RHR system are cross connected by a single header (with the exception of a small line connecting the loops and the Shutdown Cooling Suction Piping in order to create a differential pressure across the LPCI Inject Check Valves), making it possible to supply either loop from the pumps in the other loop.

The RHR system is designed for the following modes of operation:

1. Shutdown cooling.

2. Containment cooling.

3. Low-pressure coolant injection.

Both normal ac power and auxiliary onsite power systems provide enough power to operate all the auxiliary loads necessary for plant operation. The power sources for the plant auxiliary power system are sufficient in number, and of such electrical and physical independence, that no single probable event could interrupt all auxiliary power at one time.

The plant auxiliary buses supplying power to engineered safety features and reactor protection systems and those auxiliaries required for safe shutdown are connected by appropriate switching to either of two standby diesel-driven generators located in the plant. Each power source, up to the point of its connection to the auxiliary power buses, is capable of complete and rapid isolation from any other source.

Loads important to plant operation and safety are split and diversified between switchgear sections, and means are provided for the detection and isolation of system faults.

The plant layout is designed to effect the physical separation of essential bus sections, standby generators, switchgear, interconnections, feeders, power center, motor control centers, and other system components.

Two full-capacity 2850-kW standby diesel-generators are provided to supply a source of electric power that is self-contained within the plant and is not dependent on external sources of supply. The standby generators produce ac power at a voltage and frequency compatible with the normal bus requirements for essential equipment within the plant. Each of the diesel-generators has sufficient capacity to start and carry the essential loads it is expected to drive. All of the auxiliary loads required for safe and orderly shutdown including components of the RHR system are duplicated and connected to separate buses.

The RHR systems are adequate to remove residual heat from the reactor core to ensure that fuel and reactor coolant pressure boundary design limits are not exceeded. Redundant offsite and onsite electric power systems are provided. The design of the RHR system, including the power supply, meets the requirements of Criterion 34.

For further discussion, see the following sections:

1. Residual Heat Removal System 5.4.7

2. Emergency Core Cooling System 6.3

3.2 CLASSIFICATION OF STRUCTURES, SYSTEMS AND COMPONENTS

3.2.0 Structures, Systems, and Components Important to Safety

Certain structures, systems, and components of the nuclear plant are considered important to safety because they perform safety actions required to avoid or mitigate the consequences of abnormal operational transients or accidents. The ways in which structures, systems, and components important to safety work together to avoid the unacceptable results associated with the consequences of various extreme plant events is explained in the IE Nuclear Safety Operational Analysis (NSOA). The purpose of this section is to classify structures, systems, and components according to the importance of the safety function they perform. In addition, design requirements are placed upon such equipment to assure the proper performance of safety actions, when required.

In order to establish the loadings and loading combinations for which each individual structure and system is to be designed, buildings and their contained systems are separated into the seismic or nonseismic categories with respect to seismic design requirements.

3.2.1 Seismic Classifications

3.2.1.1 Seismic Structures, Systems, and Components

Those structures, systems, and components important to safety that are designed to withstand the effects of a safe shutdown earthquake (SSE) and remain functional are designated as Seismic Category 1. Tables 3.2-1 and 3.2-3 provide lists of Seismic Classification of Structures, Systems, and Components. Table 3.2-5 shows the relationship between Seismic Classification, Quality Group classification, and Safety Class.

Seismic Qualification Utility Group (SQUG) Methodology was used to verify the seismic adequacy of certain equipment as detailed in Reference 1. The SQUG's Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment provides methodology that relies primarily on the use of earthquake and test experience data to verify the seismic adequacy of generic classes of equipment. The NRC's Supplemental Safety Evaluation Report No. 2 (SSER No. 2) on the GIP, Revision 2, Corrected February 14, 1992 (GIP-2) found the GIP-2 methodology to be an acceptable evaluation method for the USI A-46 plants to verify the seismic adequacy of safe-shutdown equipment and to satisfy the pertinent equipment seismic requirements of General Design Criterion 2 and the purpose of the NRC regulations relevant to equipment seismic adequacy including 10 CFR Part 100.

IES committed to the use of SQUG methodology as documented in the GIP-2, to resolve Unresolved Safety Issue (USI) A-46, Seismic Qualification of Equipment in Operating Plants, at the DAEC. The NRC safety evaluation on the resolution of USI A-46 at the DAEC states that the DAEC's A-46 implementation program has, in general, met the purpose and intent of the criteria in GIP-2 and the NRC's SSER No. 2 for the resolution of USI A-46.

Seismic Category "A", The Main Steam Isolation Valve - Leakage Treatment System (MSIV-LTS) is seismically adequate to withstand the DAEC safe shutdown earthquake and maintain its functionality, and hence, meets the requirements of GDC-2 of Appendix A to 10CFR Part 50. A experience-based methodology was utilized to classify the MSIV Leakage Treatment System as seismically adequate. This seismic classification in Table 3.2-1 is denoted by an "A" in the column marked "Seismic Category". The experience-based methodology is restricted to its application for ensuring the pressure boundary integrity and functionality of the main steam drain path associated with the MSIV leakage treatment system. The methodology for this application is not an endorsement for the use of the experience-based methodology for other applications at the Duane Arnold Energy Center.

3.2.1.2 <u>Nonseismic Structures, Systems, and Components</u>

Nonseismic structures, systems, and components are those whose failure would not result in the release of significant radioactivity and would not prevent reactor shutdown. All structures, systems, and components not specifically listed as Seismic Category 1 are included in the nonseismic category. The failure of nonseismic structures, systems, or components may interrupt power generation.

Seismic, and nonseismic structures, systems and components are listed in Tables 3.2-1 and 3.2-3.

The equipment and piping classifications meet the general requirements given in Sections 3.2.2 and 5.2.1. They also meet the additional seismic requirements listed in Section 3.7 ("Seismic Design").

3.2.2 System Quality Group Classification

System quality group classifications have been determined for each component of (a) those applicable fluid systems relied upon to prevent or mitigate the consequences of accidents and malfunctions originating within the reactor coolant pressure boundary, or to permit shutdown of the reactor and maintenance in the safe shutdown condition, and (b) other associated safety related systems. A tabulation of quality group classification for each component so defined is shown in Table 3.2-1 under the heading "Quality Group Class."

Regulatory Guide 1.26 provides for the use of appropriate construction codes and standards which should be used for Quality Groups A through D. Figure 3.2-1 depicts the relative location of major components and the appropriate DAEC code of construction for these DAEC systems, as well as others, which are listed on Table 3.2-1 or Table 3.2-2. Table 3.2-5 compares the AEC (now NRC) Quality Group classification, Seismic Category and Quality Assurance requirements.

3.2.3 Conditions for Design

Two major categories of conditions might occur at the facility which must be appropriately considered in the design. These include (a) the plant process conditions as may be encountered during normal operation, anticipated operational occurrences, or postulated accidents; and (b) the conditions as may be imposed on the plant from the effects of natural phenomena. This subsection combines the plant process conditions (3.2.3.1) with the safe shutdown earthquake (SSE) and correlates these with design condition categories (normal, upset, emergency, and faulted) for structures within the Reactor Coolant Pressure Boundary (RCPB).

3.2.3.1 Plant Process Conditions (PPC) Considered in Design

The full spectrum of plant process conditions (PPC) are divided into four categories in accordance with their anticipated frequency of occurrence. The four categories of PPC are normal, frequent, infrequent, and limiting. These PPC are defined below and examples of representative process conditions are given.

3.2.3.1.1 Normal PPC

Normal PPC include process conditions which are expected to occur normally or regularly in the course of planned plant operation. Examples of normal PPC include the following:

(1) Refueling;

(2) Startup;

(3) Power Operation;

(4) Hot standby;

(5) Shutdown; and

(6) Routine testing and maintenance of components and systems during any of the above.

3.2.3.1.2 Frequent PPC

Frequent PPC are those incidents which are anticipated to occur occasionally during the life of the plant. Examples of frequent PPC include the following:

(1) Generator trip;

(2) Turbine trip;

(3) Isolation of any or all main steam lines;

(4) Loss of condenser cooling;

(5) Loss of feedwater heating;

(6) Inadvertent moderator cooldown;

(7) Control rod withdrawal error;

(8) Loss of feedwater flow;

(9) Total loss of offsite a-c power;

(10) Trip of any or all recirculation pumps;

(11) Inadvertent pump start in a hot recirculation loop;

(12) Inadvertent opening of a safety/safety relief valve;

(13) Single failure of a control component or an active component such as:

a. Turbine pressure regulator failure

b. Feedwater controller failure

c. Recirculation flow control failure

(14) Single failure in the electrical system; and

(15) Minor reactor coolant system leak which requires plant shutdown.

3.2.3.1.3 Infrequent PPC

Infrequent PPC are those which might occur infrequently during the life of the plant. Examples of infrequent PPC include the following:

(1) Blowdown of reactor coolant through multiple safety or relief valves; loss of reactor coolant from a break or crack which does not depressurize the reactor system, but which requires the safety functions of isolation or containment, emergency core cooling, and reactor shutdown;

(2) Improper assembly of core during refueling;

(3) Seizure of one recirculation pump;

(4) Startup of an idle recirculation pump in a cold loop;

(5) Reactor overpressure with delayed scram; and

(6) Release of radioactive material resulting from radwaste equipment failure.

GL 87-11's applicability to DAEC is determined on a per system basis; where the system is defined as a section of piping between two anchors. Where GL 87-11 is utilized to eliminate the requirements for arbitrary intermediate pipe ruptures, the basis for such a relaxation will be incorporated into this section.

Stress analyses based on the 1986 Edition of the ASME Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components," were performed on the following lines:

- the HPCI Steam Supply Line,
- the RCIC Steam Supply Line, and
- the RWCU return line from the 1E214A regenerative heat exchanger to the feed water piping.

GL 87-11 was found applicable to each of these lines, the intent of the letter has been met via the stress analyses conclusions and the system design bases. Therefore, GL 87-11 has been incorporated for eliminating the arbitrary pipe breaks in these lines.

REFERENCES FOR SECTION 3.2

1. R. Laufer (NRC) letter, to L. Liu (IES), Safety Evaluation on the Resolution of USI A-46 at the DAEC, July 29, 1998.

Table 3.2-1
DAEC Classification of Components in Systems

Principle Component		Scope of Supply (a)	Safety Class (b)	Code Class	Construction Code (c)	Quality Group Class	Quality Assurance Req. (d)	Seismic Catagory (e)(f)	PO Date (g)	Footnotes	Comments (h)
1	Condensate storage tank	B	Other	-	API-650 plus augmented NDE of welds	D+QA	-	NA	07/30/70	1i	Yes
2	Piping and valves	B	Other	-	USAS B31.1.0	D	D	NA	-	1f,1q	No
3	Other components	B	Other	-	-	D	D	NA	-	1q	No
XXXV	Auxiliary a-c Power System	R20, R22-24									
1	All components with safety function	B	2	-	-	-	B	I	-	-	Yes
XXXVI	125/250 Volt d-c Power System	R42									
1	All components with safety function	B	2	-	-	-	B	I	-	-	No
XXXVII	River Water Supply	W10									
1	Piping, pumps and valves	B	3	-	ANSI B31.1.0	D+QA	B	I	-	1f	Yes
2	Intake traveling screen, trash rakes	B	3	-	-	-	B	I	-	-	No
3	Pump motors	B	3	-	-	-	B	I	-	-	No
XXXVIII	Not Used										
									-	-	No
XXXIX	HVAC										
1	Control room	-	3	-	-	-	B	I	-	-	No
2	Pump house	-	3	-	-	-	B	I	-	-	No
3	Emergency diesel generator room	-	3	-	-	-	B	I	-	-	No
4	Reactor building secondary containment isolation dampers	-	3	-	-	-	B	I	-	-	No
5	Battery rooms	-	3	-	-	-	B	I	-	-	No
6	Intake structure	-	3	-	-	-	B	I	-	-	No
7	Essential switchgear rooms	-	3	-	-	-	B	I	-	-	No
XXXX	Miscellaneous Components										
1	Reactor Building Crane	B	3	-	-	-	B	I	-	-	No
2	Containment Penetrations for Process Piping and Electrical	B	2	-	-	-	B	I	-	-	No
General	General	n/a									
											Yes

Table 3.2-1
DAEC Classification of Components in Systems
Footnotes

Footnote#	Footnote	Systems
a	GE = General Electric; B = Bechtel; C = CB&I; IE = Iowa Electric(=DAEC); DAEC = Duane Arnold Energy Center	
b	1, 2, 3, "other" = safety classes defined in Section 3.2.4; "unc" = unclassified as defined in Section 3.2.4.	
c	The equipment shall be constructed in accordance with the codes listed in Table 3.2-2, if no Code of Construction is provided in this table. The term "construction", as used in this UFSAR, includes provisions for design, materials, fabrication, erection, testing and inspection.	
d	B = The equipment shall meet the quality assurance requirements of 10CFR50, Appendix B, in accordance with the quality assurance program described in Chapter 17. D = The equipment shall be constructed in accordance with the quality assurance requirements consistent with the good practices for steam power plants.	
e	I = The equipment shall be constructed in accordance with the seismic requirements for the safe shutdown earthquake, as described in Section 3.7, Seismic Design. Seismic adequacy of certain equipment was verified by Seismic Qualification Utility Group (SQUG) methodology. The NRC issued a Safety Evaluation on the resolution of USI A-46 at the DAEC on July 29, 1998. NA = The seismic requirements for the safe shutdown earthquake are not applicable to the equipment. A = Seismic Adequate for MSIV-LTS.	
f	Portions of 'non-seismic category I' piping (seismic category NA) passing through rooms containing safeguard equipment are seismically supported as seismic category I.	
g	Date on the purchase order for the component. Where provided, this can be used to establish the code edition and addenda in effect for the component.	
h	A "yes" in this column signifies there is a comment regarding the item at the end of Table 3.2-1.	
1a	The following items are applicable to instrument, sampling or small bore (3/4" NPS and smaller), as noted: **(1)Lines 3/4" and smaller which are part of the reactor coolant boundary shall be Safety Class 2. **(2)All instrument lines which are connected to the reactor coolant pressure boundary and are utilized to actuate safety systems shall be Safety Class 2 from the outer isolation valve or the process shutoff valve (root valve) to the sensing instrument. **(3)All instrument lines which are connected to the reactor coolant pressure boundary and are not utilized to actuate safety systems shall be Quality Group D from the outer isolation valve or the process shutoff valve (root valve) to the sensing instrumentation. **(4)All other instrument lines through the root valve shall be of the same classification as the system to which they are attached, except those lines that contain an excess flow check valve (EFCV) are classified as Quality Group D beyond the EFCV. See Figure 3.2-2. **(5) All other instrument lines beyond the root valve, if used to actuate a safety system, shall be the same classification as the system to which they are attached. **(6)All other instrument lines beyond the root valve, if not used to actuate a safety system, shall be Quality Group D. **(7)All sample lines from the outer isolation valve or the process root valve through the remainder of the sampling system shall be Quality Group D.	I-10, II-7, II-8, II-13, II-4, III-1, IV-4, IV-8, V-7, V-8, VI-1, IX-3, IX-4, X-1, X-3, X-2, XI-1, XI-3, XI-2, XI-7, XII-2, XII-7, XII-1, XII-3, XVIII-4, XVIII-3, XIX-4, XIX-3, XX-5, XXXIII-4, XXXIII-1, XXXIII-3, XXXIII-2,
1b	ANSI B31, Code Case 78 applies for B31.7 Class 1 and Class 2 pipe and fittings 3/4" nominal pipe size (NPS) and smaller.	I-10, II-7, II-8, II-13, II-4, III-1, IV-8, V-8, V-7, VI-1, IX-4, IX-3, X-2, X-3, X-1, XI-2, XI-3, XI-7, XI-1, XII-3, XII-1, XII-7, XII-2, XVIII-3, XVIII-4, XIX-3, XIX-4, XXVIII-3, XXXIII-3,
1c	A module is an assembly of interconnected components which constitute an identifiable device or piece of equipment. For example, electrical modules include sensors, power supplies, and signal processors. Mechanical modules include turbines, strainers, ane orifices.	II-14, II-15, III-7, IV-10, V-9, VI-3, VII-1, VIII-1, IX-10, IX-11, X-9, XI-10, XII-10, XVIII-8, XIX-8, XXI-1, XXII-1, XXIII-7, XXIV-5, XXV-5, XXIX-6,
1d	GE Specification 21A1100AS (Ref. 243) adds the following code requirements to the Reactor Vessel: The Winter 1967 Addenda to the ASME Code Section III is not to be included as a basis for purchase of this vessel, except as follows: 1)Charpy impact tests per N-331.2 of the Winter 1967 Addenda will be furnished; 2)Welds are to be ultrasonically examined using the angle beam method described by N-625 of Winter 1967 Addenda; 3)The changes to Article 4-Design By the Winter 1967 Addenda are included; 4)The addition of Appendix IX - Quality Control and Nondestructive Examination Methods in included.	I-1, I-2, I-3, I-5, I-9,

3.4 WATER LEVEL (FLOOD) DESIGN

3.4.1 FLOOD PROTECTION

3.4.1.1 Flood Protection Measures for Seismic Category I and Nonseismic Structures

3.4.1.1.1 Introduction

All Seismic Category I structures and Nonseismic structures housing Seismic Category I equipment are designed to withstand the hydraulic head resulting from the "maximum probable flood" to which the site could be subjected. Under this condition, the water level may reach an elevation of 764.1 ft msl. Allowing for wave action and free board of 2.9 ft, the design floodwater is at elevation 767.0 ft msl. There will be a 6.4-day period before the flood peak during which to prepare.

Major equipment penetrations in the exterior walls are located above elevation 767.0 ft. Openings below the flood level are either watertight or are provided with means to control the inflow of water in order to ensure that a safe shutdown can be achieved and maintained.

As an additional safety factor, consideration has been given to providing temporary protection for openings in the exterior walls up to flood levels of 769 ft msl.

3.4.1.1.2 Waterproofing

The waterproofing system used on the exterior surfaces of all Seismic Category I structures below grade requiring protection is "Thio-Deck," as manufactured by Toch Brothers Division, Carboline Company. The system is a polyurethane-bitumen, fluid-applied, elastometric membrane that was applied to a minimum dry film thickness of 50 mils on vertical wall surfaces below grade. The membrane bonds tightly to the concrete surface to which it is applied, thus preventing lateral migration of water between the membrane and concrete surface in the event it is punctured. Thus, in the event a leak is detected within the structure, only local repair procedures in the area of the leak would be required and the integrity of the entire system would not be jeopardized. The membrane surface was protected from puncture by the placement of celotex boards against the walls before backfill placement.

Joints between adjacent structures were protected by the embedment of a 6-in. center bulb-type water stop that was run continuously below grade. The Thio-Deck membrane was applied up to and across the water stop on both structures. All exterior wall surfaces of the reactor building were protected to just below grade with Thio-Deck membrane. In addition to the 6-in. center bulb water stop between structures, a 1-in. minimum silicon rubber base sealant, General Electric, No. 1300, was applied as a secondary backup protection system. The integrity of the watertightness in this area may be checked by vertical access from above.

Pipe and conduit penetrations through the exterior walls below elevation 757 ft 0 in. were coated with the Thio-Deck membrane system for a distance of 1 ft from the structure. At all pipe conduit and concrete construction joints, the minimum dry film thickness was increased to 100 mils for a distance of 1 ft from the joint.

3.4.1.1.3 Design Criteria

The following criteria were investigated in order to establish flood protection methods to be applied to all structures housing Seismic Category I equipment in the event of a maximum probable flood.

1. The structural safety of all buildings for the resulting hydrostatic loading.

2. An inventory of all openings in the buildings below elevation 769.0 ft.

3. Modifications to buildings required to withstand the hydrostatic loading and/or methods for closing openings below elevation 769.0 ft.

Flood data were obtained from a report prepared by Commonwealth Associates, Inc., Jackson, Michigan, on the probable maximum flood of the Cedar River near Palo, Iowa (Appendix H of the DAEC PSAR). The probable maximum flood discharge was determined to be 316,000 cfs and to have a corresponding peak stage of elevation 764.1 ft msl. The flood would result from meteorological conditions that could occur during late winter or early spring and would reach maximum river level in about 6.4 days after the beginning of the storm. The maximum flood of record at the site occurred in 1961 and rose to elevation 746.5 ft. The "Standard Project Flood" as determined by the U.S. Army Corps of Engineers would flood the plant site to elevation 754.5 ft.

The site natural grade level in the vicinity of the plant varies from about elevation 746.0 ft to elevation 750.0 ft. As a consequence of the "Standard Project Flood," the plant site finished grade is at elevation 757.0 ft.

Major equipment penetrations in the exterior walls are located above elevation 767 ft. Personnel doors and railroad and truck openings at or near grade would require protection in the event of a flood above elevation 757.0 ft. All structures have been designed in accordance with the provision for Ultimate Strength Design ACI-318-63 to withstand the hydrostatic loadings resulting from the flood conditions. The hydrostatic load was treated as a dead load using the following load factors:

1.5 x OL for high water level at elevation 757.0 ft
1.0 x OL for high water level at elevation 767.0 ft

All buildings were also checked against uplift (buoyancy) for a flood level at elevation 767.0 ft, and the minimum factor of safety used was 1.2.

3.4.1.1.4 Plant Structures

The plant buildings that were reviewed for the maximum probable flood of elevation 767.0 ft are the following:

1. Reactor building (including HPCI structure).
2. Turbine building.
3. Intake structure.
4. Control building.
5. Radwaste building.
6. Pump house.
7. Recombiner room.
8. Low-level Radwaste Processing and Storage Facility (Storage Portion).

The arrangement of the structures on the site is shown in Figure 1.2-1.

All stoplogs, caulking, and bracing required are maintained at the site. As approximately 6.4 days exist from the start of the storm to maximum flood stage, enough time exists to make all flood preparations.

3.4.1.1.4.1 Reactor Building

This building is a reinforced-concrete structure from the foundation at elevation 716 ft 9 in. to the operating floor at elevation 855 ft 0 in. Grade around the building is generally at elevation 757.0 ft. The building has a factor of safety against buoyancy (considering dead loads and equipment loads only) of 2.0.

There are no openings below elevation 757 ft 6 in. that require protection against flooding. The following access doors require protection against flooding:

1. Door No. 225 on column line 11.1 between column lines F and G access to administration building.

2. Door No. 231 on column line 11.1 between column lines H and J access into airlock leading to turbine building.

3. Railroad door on column line 5.2 between column lines D and E access into railroad airlock.

Door No. 225 and the railroad door will be provided with stoplogs to prevent the flooding of the structure. Additional caulking and temporary bracing of gap material will be provided because of the 1-in. gap between structures adjoining the reactor building. A waterstop is installed in the reactor and turbine buildings' foundation walls, which will prevent water from entering the gap between the two buildings. There are no ducts that exit the structure below elevation 767.0 ft. Piping penetrating the exterior walls below elevation 757.0 ft is embedded in the concrete with a ring plate that ensures against water seepage. Above elevation 757.0 ft, all piping is caulked in the wall and some minor seepage may be expected. Minor seepage from both piping and at doors may be easily controlled by sump pumps at the mat elevation and through the use of additional portable water pumps. Typical stoplog arrangements are shown in Figure 3.4-1.

3.4.1.1.4.2 Turbine Building

The substructure of this building is of reinforced concrete from the mat at elevation 734 ft 0 in. to elevation 757 ft 6 in., and precast concrete panels above grade to the operating floor at elevation 780 ft 0 in. The building has a factor of safety against buoyancy (considering dead loads and equipment loads only) of 1.3.

There are no openings below elevation 757 ft 6 in. that would require protection against flooding. The following access doors require protection against flooding:

1. Door No. 124 on column line 14.0 between column lines M and N access into yard.

2. Door No. 136 on column line 4.0 between column lines M and N access into yard.

3. Door No. 121 on column line K between column lines 13 and 14 access into control building.

4. Door No. 122 on column line K between column lines 12 and 13 access into control building.

5. Railroad door on column line 4.0 between column lines L and N access into yard.

6. Door No. 229 on column line K between column lines 12 and 13 access into reactor building through airlock.

7. Door No. 154 on column line 14 between column lines L and M access into turbine building.

Door No. 136, Door No. 124, and the railroad door opening will be provided with stoplogs to prevent the flooding of the building. Door Nos. 121, 122, and 229 will be provided with additional caulking and temporary bracing of gap material between the

3.4.1.1.4.9 Low-level Radwaste Processing and Storage Facility (FFRPSF)

The storage section of the LLRPSF is a reinforced concrete structure with top of mat elevation at 757 ft 6 in and extends to elevation 812 ft 8 in. To prevent possible contamination of flood waters, this portion of the facility is protected against the maximum probable flood. The stresses in the walls resulting from hydrostatic loading are very low, and this section of the building has a factor of safety against buoyancy of 2.6.

The following doors have been provided with steel stoplogs to prevent flooding of this section of the facility:

1. Door No. 846 (on column line 10.06, between column lines A and B_L) which accesses the yard;

2. Door No. 805 (on column line J_J, between column lines 6.8 and 6.06) which accesses the yard; and

3. Door No. 806 (on column line 6.06 between column lines D_L and J_J) which accesses the processing section of the LLRPSF.

Minor seepage into the facility will be detected and monitored by the sump system located in this portion of the facility.

A waterproof membrane is installed for all exterior wall construction joints and at all corners below elevation 767'-6". In addition, a continuous waterstop to provide a watertight boundary between the existing radwaste building and the storage portion of the facility has been installed below elevation 767'-6". Finally, the gap between the storage section and the existing radwaste building is filled with ethafoam.

Protection against the maximum probable flood is not considered necessary for the processing section of the LLRPSF. There will be a 6.4-day period before flood peak. This will provide time to move contaminated laundry and unpackaged DAW from the processing section of the LLRPSF into an area protected against the maximum probable flood.

3.4.1.1.5 Roof Structures

In the event of rains as severe as those that could cause a local probable maximum flood, some local flooding could occur because of the fact that the site storm drainage system is designed to accommodate the runoff from a 10-yr storm, but this flooding will have no adverse effect on any safety-related structures or equipment.

A review of the DAEC structural design has shown that all safety-related structures are capable of supporting a water accumulation on their roofs to the depth of the parapet without failure. Above this depth, the water will spill over the parapet and down the side of the building.

All roof penetrations on all plant safety-related structures extend above the roof to a height greater than the height of the parapet, thus precluding any flooding of the interior of any building from excessive precipitation. Therefore, it may be concluded that the probable maximum precipitation storm will not cause the failure of any safety-related structures or equipment.

The emergency diesel-generator air intakes are located on the turbine building roof. This roof has two 4 by 12 in. scuppers on the west side of the north and south walls of the turbine building. The east wall of the turbine building parapet has six 4 by 12 in. scuppers. These scuppers are watertight at the penetrations and they ensure that water will not accumulate on the roof and flood the emergency diesel-generator air intakes.

3.4.1.1.6 Emergency Procedures

Emergency measures to be taken to protect safety-related structures and equipment from the consequences of a probable maximum flood and coincident wave action are discussed in Section 3.4.1.1.4.

To eliminate possible leakage at plant access openings during periods when flood protection is required, sheet plastic held in place with sandbags will be used in addition to the stoplogs shown in Figure 3.4-1.

The Technical Requirements Manual includes the requirement to begin plant shutdown when, under severe flood conditions, the stillwater level reaches elevation 757 ft (plant grade).

It should be noted, however, that the plant, including its safety-related components, is in fact protected to an elevation of 769 ft. In view of this fact, DAEC will consult with the NRC before any required shutdown to determine whether shutdown should be implemented, considering all relevant circumstances, including the need for power, which may be created by the emergency itself.

3.4.1.2 <u>Permanent Dewatering System</u>

The DAEC does not have a permanent dewatering system.

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the allowable stress intensity of S_m = 26,700 psi. The maximum primary local membrane stress intensity, P_L, is 13,142 psi in the cross section 7-8 compared with the allowable stress intensity of 1.5 S_m = 40,050 psi. The maximum range of the primary plus secondary stress intensity range, $P_L + P_b + Q$, is 23,483 psi at point 7 compared with the allowable limit of 3 S_m = 80,100 psi.

In the nozzle safe end and sleeve, the maximum primary membrane stress intensity is 13,473 psi in the cross section 23-24 compared with the allowable S_m = 23,300 psi. The maximum primary local membrane stress intensity is 21,167 psi in the cross section 23-24 compared with the allowable 1.5 S_m = 34,950 psi. The maximum range of the primary plus secondary stress intensity range is 68,626 psi at point 13, between zero stress state and cooldown transient 1, compared with the allowable limit of 3 S_m = 69,900 psi.

In accordance with the plastic fatigue analysis, the maximum cumulative usage factor in the component beyond the immediate vicinity of the opening is 0.438, which is less than unity.

3.7.3.8.4 Equivalent Dynamic Analysis

There are two types of analysis in this category, as follows:

1. Analysis using first mode greater than the peak value.

2. Analysis using a modified spectrum curve.

Both of these approaches result in charts and tables showing span lengths and restraint forces for various building elevations.

3.7.3.8.4.1 First Mode Greater than Spectrum Peak

A piping system may be considered seismically acceptable if it can be divided into a series of simple spans. These spans are limited by guides that are specified in the form of vertical and lateral restraints at each change of direction, at all concentrated masses (e.g., valves), at all extended masses, at each tee, and at a maximum spacing on straight runs of piping defined by the following criteria. The fundamental frequency of multispan piping systems supported as stated above is greater than or equal to the fundamental frequency of a simple beam of maximum seismic span that is calculated using

$$f = \frac{\pi}{2}\sqrt{\frac{EI}{mL^4}} \qquad (3.7\text{-}28)$$

where

f	= fundamental frequency
E	= modulus of elasticity
I	= moment of inertia
m	= mass per unit length
L	= maximum seismic span (maximum distance between two seismic guides)

The frequency is chosen so that it is 20% larger than the frequency that defines the rigid side of the spectrum curve as shown in Figure 3.7-10. This is done on a case basis for each elevation. The simple beam formula can be used for the static equivalent load analysis with the peak value and at the spectrum curve and yields conservative results. A static load is then applied to the span to determine the maximum displacement, moment, and restraint force, which is calculated by

$$V = \frac{5}{384}\frac{mL^4 Sa}{EI} \qquad (3.7\text{-}29)$$

$$M = 0.125mL^2 Sa \qquad (3.7\text{-}30)$$

$$R = mL^2 Sa \qquad (3.7\text{-}31)$$

where

S_a	= the peak value of spectrum curve
V	= maximum displacement
M	= maximum moment
R	= maximum restraint force

Even though restraints are specified to ensure that the system will be on the rigid side of the curve, the spectral acceleration associated with the peak of the curve is used to obtain restraint loading and piping stresses.

A dynamic analysis was performed to verify the conservatism of the approach.

The piping system chosen for analysis was a general model that included various piping configurations. The model and results are given in Section 3.7.3.8.4.5. A sample chart of limiting span is shown in Table 3.7-28.

3.8.2.3.3 Loading Using Higher Limits

The Seismic Category I structures are in general proportioned to maintain elastic behavior when subjected to various combinations of dead loads, thermal loads, seismic loads, and accident loads. The upper limit of elastic behavior is considered to be the yield strength of the effective load-carrying structural materials. The yield strength, F_y, for steel (including reinforcing steel) is considered to be the guaranteed minimum given in appropriate ASTM specifications. The yield strength for reinforced-concrete structures is considered to be the ultimate resisting capacity as calculated from the ultimate strength design portion of ACI 318-63.

Concrete

Concrete structures are designed to satisfy the most severe of the following loading combinations:

$$U = 1.0\,D + 1.0\,L + 1.0\,E' + 1.0\,T_A + 1.25\,H_A = 1.0\,R$$

$$U = 1.0\,D + 1.0\,L + 1.0\,E' + 1.0\,T_o + 1.0\,H_o = 1.0\,R$$

$$U = 1.0\,D + 1.0\,L + 1.0\,A + 1.0\,T_o + 1.25\,H_o$$

$$U = 1.0\,D + 1.0\,L + 1.0\,W' + 1.0\,T_o + 1.25\,H_o$$

$$U = 0.95\,D + 1.25\,E + 1.0\,T_A + 1.0\,H_A + 1.0\,R$$

$$U = 1.05\,D + 1.05\,L + 1.25\,E + 1.0\,T_A + 1.0\,H_A + 1.0\,R$$

Structural Steel

Steel structures are designed to satisfy the most severe of the following loading combinations without exceeding the specified stresses:

$D + L + R + T_o + H_o + E'$ - stress limit* = $1.5\,f_s$

$D + L + R + T_A + H_A + E'$ - stress limit* = $1.5\,f_s$

$D + L + A + T_o + H_o$ -stress limit* = $1.5\,f_s$

$D + L + T_o + H_o + W'$ - stress limi*t = $1.5\,f_s$

*Maximum allowable stress in bending and tension is 0.9 F_y. Maximum allowable stress in shear is 0.5F_y

Concrete structures are designed using the ultimate strength design method and allowable stresses in accordance with ACI 318-63. In no case did the actual design stresses for the DAEC exceed the ACI allowable stresses. The only modification to the ACI provision is in the assignment of load factors as indicated in Section 3.8.2.4. The conservative choice of loading conditions justifies the use of this modification.

Concentrated loads were provided for by the addition of special restraining systems.

3.8.2.3.4 Pipe Jet Effects

The primary containment system is designed to withstand forces imposed by an earthquake that occurs simultaneously with a LOCA. In addition to the pressure and the thermal loading condition described in Section 6.2.1, the primary containment is designed to withstand the jet forces shown below at the locations indicated from any direction within the drywell:

Location	Jet Force (maximum)	Interior Area Subjected to Jet Forces
Spherical part of drywell	393,000 lb	2.19 ft^2
Cylinder and sphere to cylinder transition	325, 000 lb	1.80 ft^2
Suppression chamber	21,000 lb	Each pipe

These forces are described in Section 3.6.2

To provide a housing support structure that absorbs as much energy as practical without yielding, the allowable tension and bending stresses were taken as 90% of yield, and the shear stress as 60% of yield. These are 1.5 times the corresponding AISC allowable stresses of 60% and 40% of yield. This stress criterion is considered desirable for this application and adequate for the "once in a lifetime" loading condition.

For mechanical design purposes, the postulated failure resulting in the highest forces is an instantaneous circumferential separation of the CRD housing from the reactor vessel, with an internal pressure of 1250 psig (reactor vessel design pressure) acting on the area of the separated housing. The weight of the separated housing, control rod drive, and blade, plus the pressure force, is approximately 35,000 lb. This force is multiplied by a factor of three for impact, conservatively assuming the housing travels through a 1-in. gap before contacting the supports. The total force (10^5 lb) is then treated as a static load in design formulas.

Safety Evaluation

The downward travel of CRD housing and its control rod following the postulated housing failure is the sum of the compression of the disk springs under dynamic loading and the initial gap between the grid and the bottom contact surface of the CRD flange. If the reactor were cold and pressurized, the downward motion of the control rod would be limited to the approximate 2-in. spring compression plus approximately a 1-in. gap. If the reactor were hot and pressurized, the gap would be approximately 0.25 in. and the spring compression slightly less than in the cold condition. In either case, the control rod movement following a housing failure is limited substantially below one drive "notch" movement (6 in.). The nuclear transient from sudden withdrawal of any control rod through a distance of one drive notch at any position in the core does not result in a transient sufficient to cause damage to any radioactive material barrier.

The CRD housing supports are in place any time the reactor is to be operated. The housing supports may be removed when the reactor is in the shutdown condition even when the reactor is pressurized, because all control rods are then inserted. Even if a control rod is ejected under the shutdown condition, the reactor remains subcritical, because it is designed to remain subcritical with any one control rod fully withdrawn at any time.

At plant operating temperature, a gap of approximately 0.25 in. is maintained between the CRD housing and the supports; at lower temperatures the gap is greater. Because the supports do not come in contact with any of the CRD housing, except during the postulated accident condition, vertical contact stresses are prevented.

Inspection and Testing

When the reactor is in the shutdown mode, the CRD housing supports may be removed to permit inspection and maintenance of the control rod drives. When the support structure is reinstalled, it is inspected for proper assembly, particular attention being given to ensure that the correct gap between the CRD flange lower contact surface and the grid is maintained.

3.9.4.2 Applicable Control Rod Drive System Design Specifications

As discussed in Section 3.9.5.1.3, the guide tubes are designed as lateral guides for the control rods and as vertical support for a fuel support casting and four fuel assemblies. The 89 guide tubes are made of Type 304 stainless steel. The guide tubes are straight cylindrical tubes whose nominal dimensions are as follows:

Inside diameter, 10.420 in.
Wall thickness, 0.165 in.
Length, 159 in.

Significant limits are as follows:

Minimum wall thickness, 0.144 in.
Circular within, 0.030 in.

The guide tube can be subjected to any or all of the following loads:

1. Inward load due to pressure differential.
2. Lateral loads due to flow across the guide tube.
3. Deadweight.
4. Seismic.

3.9.4.3 Design Loads, Stress Limits, and Allowable Deformations

3.9.4.3.1 Pressure Differential Loading

The question of the analytical models used to evaluate the control rod guide tube loading and the degree of conservatism in the calculated peak loadings is discussed extensively in the Enrico Fermi Unit 2 (Docket 50-341) Amendment 11, Question 5.4.3; Amendment 12, Question 5.4.1; and Amendment 15, Question 5.4.4. The DAEC has the same guide tube design as the Enrico Fermi Unit 2, and the guide tube loadings imposed by both the steam-line break and the recirculation-line break would be similar for both plants. Thus, it can be concluded that the considerable margin demonstrated to exist for the Enrico Fermi reactor will be present in the DAEC.

A brief description of the analytical model used by GE to evaluate the maximum pressure differentials that occur across the internal structures of a BWR is given in Section 3.9.5.2. A much more detailed description is given on pages R-9.0-1 to R-9.0-23 of Amendment 3 to the Vermont Yankee Preliminary Safety Analysis Report, AEC Docket No. 50-271, April 1967. The description includes comparisons of the model predictions with data obtained by both GE and the LOFT program. The comparisons show that the model adequately predicts blowdown forces.

When using the analytical model described in the above reference, the following assumptions are made as to the response of the reactor to the accident. (All are conservative assumptions in that they maximize the guide tube and core plate maximum pressure differentials.)

1. Following a steam-line break, there is no level rise and no two-phase blowdown associated with the accident. This maximizes the vessel depressurization rate and thus the guide tube loading. (Note: Level rise is assumed when evaluating dryer loads.)

2. During the period when the maximum guide tube loading would be occurring, it is assumed that the drive pumps continue to operate at 100% speed, and that their performance is not affected by cavitation effects. This maintains lower plenum pressure and thus inward loading of the guide tubes.

3. Feedwater flow is assumed to continue at 100%; this contributes to maximizing the depressurization rate.

4. Break flow is defined by frictionless Moody critical flow.

This represents a theoretical maximum flow rate and gives the fastest depressurization rate.

When applying the nodalized analytical model to a particular reactor, it is not always possible (because of modeling limitations) to exactly account for all the fluid within the reactor pressure vessel. The guide tube maximum loading of 32 psi is based on an analysis that assumed all the fluid within the guide tubes is in fact outside the guide tubes and that the inner pressure is the same as the pressure in the region above the core. To demonstrate the conservatism in this assumption, the loadings on the CRD guide tubes have been evaluated with the more refined blowdown analytical model that is used to evaluate the ECCS capabilities.

Assumptions 1 through 4 listed above were used in the analysis. Because of the more detailed reactor modeling used in the ECCS code, the fluid in the guide tube region is properly distributed with respect to the guide tube walls; in addition, the pressure changes due to elevation effects are accounted for. Following a steam-line break, the

ECCS model predicts that the peak loading across the guide tubes would be 26 psi; the model used to evaluate component loadings predicts 32 psi. This comparison is presented for illustrative purposes only and is intended to give an indication of the conservatism associated with the above assumption as to fluid distribution within the guide tube region. The design-basis peak guide tube loading is 32 psi.

Because of the proven capability of the analytical model to simulate experimental results and because of the conservative assumptions delineated above, it is concluded that the guide tube loading following an instantaneous steam-line break will not exceed 32 psi. There is no credible accident that would result in guide tube loadings greater than those given by a steam-line break.

An additional assessment was performed in 1999. The purpose of this assessment was to demonstrate the structural integrity of the reactor internal components in support of the GE 12 fuel upgrade. The changes in the applicable loading conditions as a result of the GE12 fuel change are reconciled against the pre-GE12 design basis conditions. The assessment demonstrates that the structural integrity of the internal components is maintained in the GE12 fuel upgraded condition, consistent with the existing design basis. More information on the details and assumptions of this assessment are found in Reference 6.

Steam-line Break Analysis

When the reactor is operating normally, there is an inward-acting pressure differential across the guide tube walls. Figure 3.9-10 demonstrates the source of this differential as follows: The guide tubes are located in the lower plenum of the reactor so the pressure on the outside surface is the jet pump discharge pressure. The volume inside of the guide tubes communicates directly with the region between the fuel assemblies (the leakage region). Because the flow rate in this region is only approximately 10% of the total recirculation flow, the pressure losses are small and the pressure in the leakage region is essentially the same as the pressure in the reactor discharge plenum. Thus, the steady-state inward pressure differential across the guide tube walls is the same as the core pressure drop (i.e., approximately 19 psi).

Any reactor transient that increases the pressure differential between the lower plenum and the discharge plenum will produce an inward loading on the guide tubes greater than the steady-state value of 19 psi. The entire spectrum of possible abnormal transients and accidents has been examined, and it has been determined that the maximum inward pressure differential on the guide tubes occurs during a guillotine break of a main steam line upstream of the flow limiter when the reactor is operating at 20% rated power and 110% rated recirculation flow.

3.9.5.1.8 Differential Pressure and Standby Liquid Control Line

The differential pressure and standby liquid control line serves a dual function within the reactor vessel--to inject liquid control solution into the coolant stream (see Section 9.3.4) and to sense the differential pressure across the core support assembly (described in Section 5.3). This line enters the reactor vessel at a point below the core shroud as two concentric pipes. In the lower plenum, the two pipes separate. The inner pipe terminates near the lower shroud with a perforated length below the core support assembly. It is used to sense the pressure below the core support during normal operation and to inject liquid control solution when required. This location facilitates good mixing and dispersion. The inner pipe also reduces thermal shock to the vessel nozzle should the standby liquid control system be actuated. The outer pipe terminates immediately above the core support and senses the pressure in the region outside the fuel assembly channels.

3.9.5.1.9 Incore Flux Monitor Guide Tubes

The incore flux monitor guide tubes extend from the top of the incore flux monitor housings (see Section 5.3) in the lower plenum to the top guide. The power range detectors for the power range monitoring units and the dry tubes for the source range monitoring and intermediate range monitoring (SRM/IRM) detectors are inserted through the guide tubes. The guide tubes are held in place below the top guide by spring tension. A latticework of clamps, tie bars, and spacers gives lateral support and rigidity to the guide tubes. The bolts and clamps are welded, after assembly, to prevent loosening during reactor operation.

3.9.5.1.10 Initial Startup Neutron Sources

Each initial startup source consists of two irradiated antimony rods within a single beryllium cylinder. The antimony-beryllium cylinder assemblies are further encased in stainless steel tubes. These tubes have fitted nosepieces on one end and axial spring-loaded detent pins on the other end. The nosepieces and detent pins mate, respectively, with notches in the top of the core support plate and the bottom of the top guide to position the startup sources securely in the vertical position. The design provides a sufficient source of neutrons in the core to ensure that the core neutron flux monitors are operating and that significant changes in core reactivity can be readily detected by the installed neutron flux instrumentation (see Section 7.6.1).

3.9.5.1.11 Surveillance Sample Holders

The surveillance sample holders are welded baskets containing impact and tensile specimen capsules (see Section 5.3). The baskets hang from brackets that are attached to the inside wall of the reactor vessel and extend to mid-height of the active core. The radial positions are chosen to expose the specimens to the same environment and maximum neutron fluxes experienced by the reactor vessel itself while avoiding jet pump removal interference or damage.

3.9.5.2 Loading Conditions

3.9.5.2.1 Evaluation Methods

To determine that the safety design bases are satisfied, responses of the reactor vessel internals to loads imposed during normal, upset, emergency, and faulted conditions were examined. The effects on the ability to insert control rods, cool the core, and flood the inner volume of the reactor vessel were determined.

The ASME Code, Section III, for Class A vessels was used as a guide to determine limiting stress intensities and cyclic loadings for the reactor vessel internals. When buckling was not a possible failure mode and stresses were within those stated in the ASME Code, either the elastic stability of the structure or the resulting deformation was examined to determine whether the safety design bases were satisfied.

An additional assessment was performed in 1999 for the introduction of GE12 fuel. More information on this analysis is located in Section 3.9.4.3.1

Events To Be Evaluated

The examination of the spectrum of conditions for which the safety design bases must be satisfied reveals three significant events:

1. LOCA: A break in a recirculation line. The accident results in pressure differentials, across some of the reactor vessel internals, that exceed normal loads.

2. Steam-line break accident: A break in one main steam line between the reactor vessel and the flow restrictor. The accident results in significant pressure differentials across some of the reactor vessel internals.

3. Earthquake: This condition subjects the reactor vessel internals to significant forces as a result of ground motion.

The analysis of other conditions existing during normal operation, abnormal operational transients, and accidents shows that the loads affecting the reactor vessel internals are less severe than the design-basis postulated events.

The recirculation-line break is analyzed at the case 1 initial conditions. Note that a steam-line break at low reactor power would impose less severe requirements on the emergency core cooling system, because there would be less stored heat in the core. The assumed initial conditions of case 2 represent the most severe possible situation. If a steam-line break accident occurred during a reactor startup (at low power and natural recirculation flow), the resulting loads would be similar but less severe.

The maximum differential pressures across the reactor assembly internals resulting from the postulated accidents are shown in Table 3.9-7. Figures 3.9-26 and 3.9-27 show the differential pressures for various internals as a function of time.

An additional assessment was performed in 1999 for the introduction of GE12 fuel. More information on this analysis is located in Section 3.9.4.3.1.

Response of Reactor Internals to Pressure Differences

The maximum differential pressures are used, in combination with other structural loads, to determine the total loading on the various reactor vessel internals. The internals are then evaluated to assess the extent of deformation and collapse, if any. Of particular interest are (1) the responses of the guide tubes and the metal channels around the fuel bundles and (2) the potential leakage around the jet pump joints.

The guide tube was evaluated for collapse caused by externally applied pressure, as discussed in Section 3.9.4.3.1.

The fuel channel load resulting from an internally applied pressure is evaluated, using a fixed-beam analytical model under a uniform load. Tests to verify the applicability of the analytical model indicate that the model is conservative. The fuel channels may deform sufficiently outward to cause some interference with movement of the control rod blade. There are approximately 15 factors, such as fuel channel deformation, core support hole tolerance, and top fuel guide beam location, that determine the clearance between the control rod blade and fuel channel. If each tolerance factor is assumed to be at the worst extreme of the tolerance range, then a slight interference would develop under an 18-psi pressure difference across the channel wall. However, the maximum calculated pressure differential is only 13 psi. A roller, at the top of the control rod, guides the blade as it is inserted. The clearance between channels is 70 mils less than the diameter of the roller, causing it to slide or skid instead of roll. As the rod is inserted approximately halfway, the control rod sheath tends to push inward on the channel and cause the control rod surface to contract the channel surface. A "worst-case" study indicates the possibility of a 50-mil interference.

The possibility of a worst case developing is extremely remote. A statistical analysis using a normal distribution of each of the 15 variables indicates that no interference occurs with 3σ limits, where σ is the standard deviation in a point distribution of events (3σ lies in the 0.995 percentile of probability of nonoccurrence). However, even if interference occurs, the result is negligible. About 1 lb of lateral force is required to deflect the channel inboard 1 mil. The friction force developed is an extremely small percentage of the total force available to the control rod drives.

The previous discussion presupposes that the control rod has not moved when the fuel channel experiences the largest magnitude of pressure drop. Analysis indicates that the rod is about 70% to 90% inserted. If the rod is beyond 70% inserted, then no interference is likely to develop because all the channel deformation is in the lower portion of the fuel channel, whereas the roller is at the top of the rod. It is concluded that the main steam line break accident can pose no significant interference to the movement of control rods.

Additional analysis indicates that no fuel pins will come in contact with the fuel element channels as the result of the DBE concurrent with rapid depressurization of the reactor core.

Jet Pump Joints: An analysis has been performed to evaluate the potential leakage from within the floodable inner volume of the reactor vessel during the recirculation-line break and subsequent LPCI reflooding. The two possible sources of leakage are the following:

1. Jet pump throat to diffuser joint.

2. Jet pump nozzle to riser joint.

The jet pump to shroud support joint is welded and therefore is not a potential source of leakage. The slip joints for all jet pumps leak no more than a total of 225 gpm. The jet pump bolted joint, by analysis, is shown to leak no more than 542 gpm for the pumps through which the vessel is being flooded.

The summary of maximum leakage is as follows:

Total leakage through all throat to diffuser joints	225 gpm
Total leakage through all nozzle to riser joints	542 gpm
Total maximum rate	767 gpm

3.9.5.3.3 Power Generation Design Bases

The reactor vessel internals are designed to meet the following power generation design bases:

1. They provide the proper coolant distribution during all anticipated normal operating conditions to allow power operation of the core without fuel damage.

2. They are arranged to facilitate refueling operations.

3. They are designed to facilitate inspection.

3.9.6 INSERVICE TESTING OF PUMPS AND VALVES

An inservice testing program for pumps and valves has been prepared. This program is revised as required for each 120-month inspection interval to incorporate the latest applicable addenda to ASME Code, Section XI.

Inservice testing of pumps and valves complies with the requirements of Subsections IWP and IWV of ASME Code, Section XI, respectively.

3.9.6.1 Relief Requests

When compliance with ASME Code, Section XI, is impractical for specific items, relief is requested from the NRC in compliance with 10CFR50.55a(g)(5).

3.9.6.2 Inservice Testing Program

The inservice testing program for the DAEC third 10-year Inservice Testing interval commenced February 1, 1995. The current revised program has been prepared and implemented according to the 1989 Edition of Section XI of the ASME Code, which refers to implementing the requirements of ASME/ANSI OM-6 and OM-10. In this regard, the DAEC IST program is based on the applicable requirements set forth in ASME/ANSI OM-1987 including ASME/ANSI OMa-1988 Addenda.

In response to NRC Generic Letter 87-06, a list of all pressure isolation valves along with information on periodic tests was submitted in Reference 4.

REFERENCES FOR SECTION 3.9

1. U.S. Nuclear Regulatory Commission, Failure of Control Rods to Insert During a Scram at a BWR, IE Bulletin 80-17 (series), 1980-1981.

2. H. T. Kim, Core Flow Distribution in a Modern BWR as Measured at Monticello, NEDO-10299, 1971.

3. D. A. Rockwell, RIP-2, A Computer Program for Calculation of Reactor Internal Pressures During Accident Conditions, APED-5296, General Electric Company, Atomic Power Equipment Department, 1966.

4. Letter from R. McGaughy (Iowa Electric) to T. Murley (NRC), Subject: Periodic Testing of Leak Tight Integrity of Pressure Isolation Valves (Generic Letter 87-06), dated June 11, 1987 (NG-87-1881).

5. J. G. Erbes, Safety Evaluation of the Jet Pump Sensing Line Clamp and Beam Assembly Duane Arnold, RDE #04-387, General Electric Company, March 1987.

6. General Electric Company, Duane Arnold Energy Center GE12 Fuel Upgrade Project NEDC-32915P, Revision 0, November, 1999.

CHAPTER 4: REACTOR

LIST OF FIGURES

Important features of the reactor core arrangement are as follows:

1. The bottom-entry cruciform control rods consist of boron carbide in stainless steel tubes surrounded by a stainless steel sheath. Rods of this design have accumulated thousands of hours of service in operating BWRs without significant failure. Beginning with Cycle 9 operation, some replacement rods utilize a new design which increases both the mechanical and nuclear lifetimes. This is the Hybrid I Control Rod Assembly. Beginning with Cycle 11, some controls rods were replaced with the G.E. Duralife D-230 control rod assemblies. These assemblies are described in Section 4.6.1.2.5.

2. The fixed incore fission chambers provide continuous power range neutron flux monitoring. A guide tube in incore assemblies provides for a traversing ion chamber for calibration and axial detail. One incore assembly does not have a guide tube for a traversing ion chamber. Modeling techniques in the three dimensional core simulator are used to provide information for calibration and axial detail. This assembly was modified to accommodate monitoring equipment for Noble metals injection and coating. Source and intermediate range detectors are located in the core and are axially retractable. The incore location of the startup and source range instruments provides the coverage of the large reactor core and provides an acceptable signal-to-noise ratio and neutron-to-gamma ratio. All incore instrument leads enter from the bottom and the instruments are in service during refueling. Incore instrumentation is further discussed in Section 7.7.

3. Experience has shown that the operator, rising the incore flux monitoring system, can maintain the desired power distribution within a large core by proper control rod scheduling.

4. The Zircaloy-2 channels provide a fixed flow path for the boiling coolant, serve as a guiding surface for the control rods, and protect the fuel during handling operations.

5. Mechanical reactivity control permits criticality checks during refueling and provides maximum plant safety. The core is designed to be subcritical at any time in its operating history, with any one control rod fully withdrawn.

6. The selected control rod pitch represents a practical value of individual control rod reactivity worth, and allows adequate clearance below the pressure vessel, between CRD mechanisms, for ease of maintenance and removal.

4.1.2.1.2 Core Configuration

The reactor core is arranged as an upright circular cylinder containing a large number of fuel cells and is located in the reactor vessel. The coolant flows upward through the core.

4.1.2.1.3 Fuel Assembly Description

The BWR core is composed essentially of two components: fuel assemblies and control rods. The fuel assembly and control rod-mechanical configurations are basically the same as used in Dresden 1 and in all subsequent GE BWRs. Further discussion is contained in Sections 4.2 and 4.3.

4.1.2.1.3.1 Fuel Rod

A fuel rod consists of uranium dioxide pellets and a Zircaloy-2 cladding tube. For the barrier fuel design, the cladding consists of the same zircaloy base material with the innermost part of the cladding replaced by a thin zirconium liner. This liner is mechanically bonded to the base zircaloy material during manufacture. The purpose of the zirconium liner is to improve stress resistance in pellet clad interaction. A fuel rod is made by stacking pellets into the cladding tube, which is evacuated and backfilled with helium and sealed by welding zircaloy end plugs in each end of the tube. The ASME Boiler and Pressure Vessel Code, Section III, is used as a guide in the mechanical design and stress analysis of the fuel rod. The fuel rod is designed to withstand applied loads, both external and internal. The fuel pellet is sized to provide sufficient clearance within the cladding tube and to accommodate axial and radial differential expansion between fuel and clad. Overall fuel rod design is conservative in its accommodation of the mechanisms affecting fuel in a BWR environment.

4.1.2.1.3.2 Fuel Bundle

Each fuel bundle contains fuel rods and water rods, which are spaced and supported in a square array (e.g., 8 x 8, 10 x 10, etc.) by spacers and a lower and upper tie plate. The fuel bundle has two important design features as follows:

1. Each fuel rod is free to expand in the axial direction.

2. The structural design permits the removal and replacement of individual fuel rods if required.

4.2 FUEL SYSTEM DESIGN

The format of this section corresponds to Standard Review Plan 4.2 in NUREG - 0800. Most of the information presented will be by reference to the approved General Electric (GE) report.[1]

4.2.1 DESIGN BASES

The fuel assembly must be designed to ensure that possible fuel damage would not result in the release of radioactive materials in excess of applicable regulations. The adequacy of the fuel assembly is demonstrated if it is shown to provide substantial fission product retention capability during all potential operational modes and sufficient structural integrity to prevent operational impairment of any reactor safety equipment. The fuel assembly and its components are designed to withstand the loadings documented in Section 2.2 of Reference 1. Specific criteria and limits that ensure that these bases are met are given below. In addition, for advanced fuel designs, specific licensing criteria are applied (Reference 15).

4.2.1.1 Fuel System Damage Limits

4.2.1.1.1 Stress-Strain Limits

Stress and equivalent strain limits for normal and abnormal operational transient loads on the fuel rod and other bundle component analyses are documented in Subsection 2.2.1.1 of Reference 1.

4.2.1.1.2 Fatigue Limits

Stress/cycle limits for fatigue analyses are given in Subsection 2.2.1.2 of Reference 1.

4.2.1.1.3 Fretting Wear Limits

Per Section 2.2.1.3 of Reference 1, the fuel assembly is evaluated to ensure that fuel will not fail due to fretting wear of the assembly components

4.2.1.1.4 Oxidation, Hydriding, and Corrosion Limits

There are design limits for cladding oxidation, hydriding, or corrosion. Oxidation and corrosion are considered in the mechanical design analyses. Criteria for these analyses are given in Subsection 2.2.1.4 of Reference 1. Hydriding is controlled through the use of a specification limit of the amount of hydrogen permitted in a manufactured fuel rod.

4.2.1.1.5 Dimensional Change Limits

Rod-to-rod and rod-to-channel deflection limits are given in Subsection 2.2.1.5 of Reference 1. Manufacturing tolerances, axial load and thermal effects are included in the fuel design and thermal and mechanical analyzes. Maximum allowable control blade-to-channel clearance is given in Reference 2.

4.2.1.1.6 Internal Gas Pressure Limits

The internal gas pressure within the fuel rod is limited so that the cladding creepout rate is not expected to exceed the instantaneous fuel swelling rate. The internal gas pressure as a function of exposure is an input to the fuel rod mechanical design analyses. Criteria for these analyses are given in Subsection 2.2.1.6 of Reference 1.

4.2.1.1.7 Hydraulic Load Limits

The fuel assembly is evaluated to ensure that vertical liftoff forces are not sufficient to unseat the bundle to a degree that the bundle could interfere with control blade insertion. Normal operational hydraulic loads are conservatively bounded by the combined loss-of-coolant accident (LOCA) plus safe shutdown earthquake (SSE) loading. Design limits for this faulted condition are given in Subsection 2.2.1.7 of Reference 1.

4.2.1.1.8 Control Rod Reactivity Limits

Sections in 4.3.1 and 4.3.2.4 provides the control rod reactivity basis. An evaluation of control blade lifetime as provided by nuclear and mechanical lifetime limits is given in Reference 3.

4.2.1.2 <u>Fuel Rod Failure Limits</u>

4.2.1.2.1 Hydriding Limits

Hydriding limits are discussed in Section 4.2.1.1.4.

4.2.1.2.2 Cladding Collapse Limits

If axial gaps in the fuel pellet column occur from densification, the cladding has the potential of collapsing into a gap. To preclude collapse, the criterion provided in Section 8 of Reference 4 is met.

4.2.1.2.3 Fretting Wear Limits

These limits are addressed in Section 4.2.1.1.3

4.2.1.2.4 Overheating of Cladding Limits

The fuel cladding integrity safety limit for the minimum critical power ratio (MCPR) (Subsection 2.2.2.4 and Subsection 4.3.1 of Reference 1) ensures that overheating of the cladding does not occur.

4.2.1.2.5 Overheating of Pellet Limits

No fuel centermelt occurs for normal operation and whole core anticipated operational occurrences as documented in Subsection 2.2.2.5 of Reference 1. A small amount of fuel centerline melt is calculated to possibly occur on a localized basis during the rod withdrawal error transient, but cladding damage and subsequent fission product release is limited by the 1% plastic strain criterion.

4.2.1.2.6 Excessive Fuel Enthalpy Limits

Clad failure threshold is 170 cal/g. This limit is identified in Amendment 7 to Reference 1.

4.2.1.2.7 Pellet-Cladding Interaction Limits

The fuel rods are evaluated to ensure that fuel rod failure due to pellet-clad mechanical interaction will not occur, i.e. the 1% plastic strain criterion is not exceeded. These limits are given in Subsection 2.2.2.7 of Reference 1.

4.2.1.2.8 Bursting Limits

Section 1.B of Appendix K to 10 CFR 50 specifies that each LOCA evaluation model shall include a provision for predicting cladding swelling and rupture due to axial temperature distribution and differential pressure between inside and outside cladding, (Ref. NUREG-0630). This specification is met as documented in Volume II of Reference 6.

4.2.1.2.9 Mechanical Fracturing Limits

Mechanical breaking under normal and abnormal operational transients is bounded by the combined LOCA plus SSE loading. Limits for this faulted condition are given in Subsection 2.2.2.9 of Reference 1.

4.2.1.3 Fuel Coolability Limits

4.2.1.3.1 Cladding Embrittlement Limits

Peak clad temperature and maximum cladding oxidation limits documented in 10 CFR 50.46 ensure that cladding embrittlement does not occur. Conformance to these limits is given in Volume III of Reference 6.

4.2.1.3.2 Violent Expulsion of Fuel Limits

The limit for severe reactivity accidents is 280 cal/g. This limit is documented in Amendment 7 to Reference 1.

4.2.1.3.3 Generalized Cladding Melt Limits

As documented in the Standard Review Plan, the generalized cladding melt limit is bounded by the cladding embrittlement limit given in Section 4.2.1.3.1.

4.2.1.3.4 Fuel Rod Ballooning Limits

Criteria for fuel rod ballooning are given in Section 4.2.1.2.8.

4.2.1.3.5 Structural Deformation Limits

Faulted limits for the DBE plus LOCA analysis are given in Section 4.2.1.2.9.

4.2.2 DESCRIPTION AND DESIGN DRAWINGS

The fuel assembly consists of a fuel bundle and a channel that surrounds it. The DAEC has an evolution of fuel designs in the core. The reference core-loading pattern for each cycle of operation is documented in Section 4.3. A description and drawings of each fuel type and other bundle components for the current core are given in Reference 14. The channel is described and analyzed in Reference 2. The reactivity control assembly is described in Section 4.6.

4.2.3 DESIGN EVALUATION

The following sections document that the design bases described in Section 4.2.1 are met. Methods used to demonstrate this compliance are operating experience, prototype testing, and analytical predictions. Most of these methods are documented in other approved reports, which are referenced in the following sections. As stated in Section 4.2.1, specific licensing criteria are applied to advanced fuel designs (Ref. 15). For the GE12 fuel design introduced during Cycle 17, this compliance is demonstrated in Reference 16.

4.2.3.1 Fuel System Damage Evaluation

4.2.3.1.1 Stress-Strain Evaluation

Analyses of the mechanical integrity of the fuel bundle demonstrate that the design bases are met. Analytical methods and results are documented in Section 2.2.1.1 of Reference 1.

4.2.3.1.2 Fatigue Evaluation

The analysis of the cumulative fatigue damage on key components shows that the design bases are met. Analytical methods and results are documented in Section 2.2.1.2 of Reference 1.

4.2.3.1.3 Fretting Wear Evaluation

Extensive out-of-reactor and in-reactor testing and surveillance verify that fretting wear is not a problem with the current fuel design. Details of the tests are given in Section 2.2.1.3 of Reference 1. Additional information is given in Section VII of Reference 8.

4.2.3.1.4 Oxidation, Hydriding, and Corrosion Evaluation

Oxidation, Hydriding and Corrosion Products are discussed in Section 2.2.1.4 of Reference 1.

4.2.3.1.5 Dimensional Change Evaluation

Fuel rod deflection analysis results show that the design bases are met. Analytical methods and results are provided in Subsection 2.2.1.5 of Reference 1. Fuel rod bowing is addressed separately in Reference 9. Channel deflection analysis is given in Reference 2.

4.2.3.1.6 Internal Gas Pressure Evaluation

Results of the analysis for end-of-life internal gas pressure is provided in Section 2.2.1.6 of Reference 1.

4.2.3.1.7 Hydraulic Load Evaluation

Fuel rod vibration analysis is provided in Section 2.2.1.7 of Reference 1. A conservative evaluation showing there is no potential for fuel bundle lift was provided in Reference 10.

4.2.3.1.8 Control Rod Reactivity Evaluation

The control rod reactivity evaluation is documented in Section 4.3.

4.2.3.2 Fuel Rod Failure Evaluation

4.2.3.2.1 Hydriding Evaluation

The evaluation of hydriding is given in Section 4.2.3.1.4

4.2.3.2.2 Cladding Collapse Evaluation

Cladding collapse is not calculated to occur in General Electric fuels documented in Section 2.2.2.2 of Reference 1.

4.2.3.2.3 Fretting Wear Evaluation

The evaluation of fretting wear is given in Section 4.2.3.1.3.

4.2.3.2.4 Overheating of Cladding Evaluation

Subsection 4.3.1 of Reference 1 describes the basis for the operating MCPR limit calculation. This cycle-dependent limit ensures that the MCPR fuel cladding integrity safety limit is not exceeded during abnormal operational transients.

4.2.3.2.5 Pellet Overheating Evaluation

Per Section 2.2.2.5.1 of Reference 1, the fuel rod is evaluated to ensure that fuel melting during normal steady state operation and whole core anticipated operational occurrences is not expected to occur. For local anticipated operational occurrences such as the rod withdrawal error, a small amount of calculated fuel pellet center melting may occur but is limited by 1% cladding circumferential plastic strain criterion.

4.2.3.2.6 Excessive Fuel Enthalpy Evaluation

The evaluation of reactivity events is given in Chapter 15.

4.2.3.2.7 Pellet-Cladding Interaction Evaluation

Transient analyses documented in Chapter 15 do not exceed the design basis of 1% plastic strain or MCPR fuel cladding integrity safety limits.

4.2.3.2.8 Bursting Evaluation

In accordance with Appendix K to 10 CFR 50, temperature and time of rupture at key exposures are given in References 11 and 17 (the plant specific ECCS analysis).

4.2.3.2.9 Mechanical Fracturing Evaluation

Per Section 2.2.2.9 of Reference 1, the fuel assembly is evaluated under Safety Shutdown Earthquake and LOCA loading conditions to ensure that loss of fuel assembly coolability, and interference to the degree that control blade insertion is prevented, will not occur.

4.2.3.3 <u>Fuel Coolability Evaluation</u>

4.2.3.3.1 Cladding Embrittlement Evaluation

Precluding cladding embrittlement is demonstrated in the LOCA analysis provided in Section 6.3.

4.2.3.3.2 Violent Expulsion of Fuel Evaluation

The DAEC has adapted a control rod withdrawal sequence which has been shown statistically to result in rod worths below those needed to exceed the peak fuel enthalpy limit of 280 cal/gm for fuel expulsion.

4.2.3.3.3 Generalized Cladding Melt Evaluation

The LOCA analysis documented in References 11, 13 and 17 are bounding for this evaluation.

4.2.3.3.4 Fuel Rod Ballooning Evaluation

Fuel rod ballooning is addressed in Section 4.2.3.2.8.

4.2.3.3.5 Structural Deformation Evaluation

Results of the SSE plus LOCA analysis are documented in Subsection 2.2.2.9 of Reference 1.

4.2.4 TESTING, INSPECTION, AND SURVEILLANCE PLANS

Fuel assembly testing and inspection are documented in Section 2.3.1 of Reference 1.

REFERENCES FOR SECTION 4.2

1. General Electric Company, General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest NRC approved revision).

2. General Electric Company, BWR Fuel Channel Mechanical Design and Deflection, NEDE-21354-P (proprietary) and NEDO-21354, 1976.

3. General Electric Company, GE BWR Control Rod Lifetime, NEDE-30931-4-P, Rev. 4, May, 1996.

4. General Electric Company, Creep Collapse Analysis of BWR Fuel Using SAFE-COLAPS Model, NEDE-20606-P-A (proprietary) and NEDO-20606-A, 1976.

5. C. J. Paone, et al., Rod Drop Accident Analysis for Large BWR's, NEDO-10527, 1972.

6. General Electric Company, The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident, NEDE-23785-P (proprietary), January 1985.

7. R. H. Buchholz (General Electric) letter MFN-097-81 to L. S. Rubsenstein (NRC), General Electric Fuel Clad Swelling and Rupture Model, May 15, 1981.

8. General Electric Company, 8 x 8 Fuel Development Support, NEDO-20377, 1975.

9. General Electric Company, Assessment of Fuel Rod Bowing in GE BWR's, NEDE-24284-P, 1980.

10. R. L. Gridley (General Electric) letter MFN-266-77 to D. G. Eisenhut (NRC), Evaluation of Potential Fuel Bundle Lift at Operating Reactors, July 11, 1977.

11. General Electric Company , Duane Arnold Energy Center, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, NEDE-31310-P, August, 1986 and Supplement 1, August, 1993.

12 General Electric Company, Experience with BWR Fuel Through January 1981, NEDE-24343-P, 1976.

13. General Electric Company, Safety Evaluation of the General Electric Hybrid I Control Rod Assembly, NEDE-22290-A, September 1983.

14. General Electric Company, GE Fuel Bundle Designs, NEDE-31152P, (latest NRC approved version).

15. General Electric Company, Licensing Criteria for Fuel Designs (Amendment 22 to NEDE-24011-P-A and Corresponding NRC Staff Safety Evaluation), NEDO-31908, January 1991.

16. General Electric Company, GE12 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR-II), NEDE-32417P, December 1994.

17. General Electric Company, Duane Arnold Energy Center GE12 Fuel Upgrade Project, NEDC-32915P, November 1999.

4.3 NUCLEAR DESIGN

The nuclear core design presented here is based on the D lattice fuel documented in Sections 1 and 2 of Reference 1. Specific core-loading patterns for the DAEC are given in the references in Table 4.3-1.

4.3.1 DESIGN BASES

The nuclear design bases are divided into two specific categories: (1) the safety design bases are those that are required for the plant to operate from safety considerations and (2) the plant performance design bases are those that are required to meet the objective of producing power in an efficient manner.

4.3.1.1 Safety Design Bases

The safety design bases are requirements that protect the nuclear fuel from a violation of the design integrity limits. In general, the safety bases fall into two categories: (1) the reactivity basis, which prevents an uncontrolled positive reactivity excursion, and (2) the overpower bases, which prevent the core from operating beyond the fuel integrity limits.

4.3.1.1.1 Reactivity Basis

The nuclear design shall meet the following basis: The core shall be capable of being rendered subcritical at any time or at any core conditions with the highest worth control rod fully withdrawn.

4.3.1.1.2 Overpower Bases

The limits on LHGR, MCPR, and the maximum average planar linear heat generation rate (MAPLHGR) as presented in the Core Operating Limits Report shall not be exceeded during steady-state operation.

4.3.1.2. Plant Performance Design Bases

The nuclear design shall meet the following bases:

1. The design shall provide adequate hot excess reactivity to attain the desired cycle length.

2. The design shall be capable of operating at rated conditions without exceeding the Technical Specification limits.

3. The nuclear design and reactivity control system shall allow continuous, stable regulation of reactivity.

4. The nuclear design shall have adequate reactivity feedback to facilitate normal operation.

Core nuclear design analyses results are used as inputs to the core transient and stability analyses and do not have separate limits.

4.3.2 DESCRIPTION

The BWR core design uses a light-water-moderated reactor, fueled with slightly enriched uranium dioxide. The use of water as a moderator produces a neutron energy spectrum in which fissions are caused principally by thermal neutrons. At normal operating conditions, the moderator boils, producing a spatially variable distribution of steam voids in the core. The BWR design provides a system for which reactivity changes are inversely proportional to the steam void content in the moderator. This void feedback effect is one of the inherent safety features of the BWR system. Any system input that increases reactor power, either in a local or gross sense, produces additional steam voids that reduce reactivity and thereby reduce power.

4.3.2.1 Nuclear Design Description

The reference core-loading pattern is the basis for all fuel licensing. The bundle and lattice designations for D lattice fuel enrichments are given in Reference 3. Uranium dioxide and gadolinia distributions for each bundle enrichment and typical lattice nuclear characteristics are given in Reference 3. In addition, specific licensing criteria are applied to advanced fuel designs (Ref. 4). For the GE12 fuel design introduced during Cycle 17, this compliance is demonstrated in Reference 5. Steady-state core characteristics are also discussed. The reference core-loading pattern for each reload cycle is given in the references listed in Table 4.3-1.

4.3.2.2 Power Distribution

The core power distribution is a function of fuel bundle design, core loading, control rod pattern, core exposure distributions, and core coolant flow rate. The thermal performance parameters, MAPLHGR and MCPR (defined in Table 3-1 of Reference 1) limit unacceptable core power distribution.

4.3.2.3 Reactivity Coefficients

Reactivity coefficients are discussed in Section 3.2.3 of Reference 1.

4.3.2.4 Control Requirements

The nuclear design, in conjunction with the reactivity control system, provides an inherently stable system for BWRs.

The control rod system is designed to provide adequate control of the maximum excess reactivity expected during cycle operation. Because fuel reactivity is a maximum and control is a minimum at ambient temperature, the shutdown capability is evaluated assuming a cold, xenon-free core. The safety design basis requires that the core, in its maximum reactivity condition, be subcritical with the control rod of the highest worth fully withdrawn and all others fully inserted.

4.3.2.4.1 Shutdown Reactivity

To ensure that the safety design basis for shutdown is satisfied, an additional design margin is adopted: the reactor is subcritical with the control rod of highest worth fully withdrawn. A confirmation of this is provided in the supplemental reload licensing report for each cycle. A listing of these submittals is given in Table 4.3-1.

4.3.2.4.2 Reactivity Variations

The excess reactivity designed into the core is controlled by the control rod system supplemented by gadolinia-urania fuel rods. Gadolinia and enrichment distributions for these rods are given in Reference 3. Control rods are used during the cycle partly to compensate for burnup and partly to flatten the power distribution.

4.3.2.5 Control Rod Patterns and Reactivity Worths

For BWR plants, control rod patterns are not uniquely specified in advance; rather, during normal operation, the control rod patterns are selected from the measured core power distributions, within the constraints imposed by the rod worth minimizer described in Section 7.7.7. Control Requirements are discussed in Section 3.2.4 of Reference 1.

4.3.2.6 Shutdown of Reactor During Refueling

The maximum allowable value of k_{eff} is less than 1.0 at any time during refueling. Cycle-specific analyses are performed as described in Subsection 3.4 of Reference 1.

4.3.2.7 Stability

4.3.2.7.1 Xenon Transients

BWRs do not have instability problems due to xenon. This has been demonstrated by operating BWRs for which xenon instabilities have never been observed. Such instabilities would readily be detected by the local power range monitors, by special tests that have been conducted on operating BWRs in an attempt to force the reactor into xenon instability, and by calculations. All of these indicators have proved that xenon transients are highly damped in a BWR because of the large negative power coefficient.

Analyses and experiments conducted in this area are reported in Reference 2.

4.3.2.7.2 Thermal-Hydraulic Stability

This subject is covered in Section 4.4.

4.3.2.8 Vessel Irradiations

The nil ductility transition temperature increases as a function of neutron exposure at integrated neutron exposures greater than about 1 x 10^{17} nvt with neutrons of energies in excess of 1 MeV. The coolant annulus between the vessel and core shroud and the core location in the vessel limit the integrated neutron exposure of reactor vessel material to less than 1.42 x 10^{18} nvt from neutrons with energy levels greater than 1 MeV within the 40-year design lifetime of the vessel. This is a model exposure value that can be demonstrated to be safe and practical.

4.3.3 ANALYTICAL METHODS

The analytical methods and nuclear data used to determine the nuclear characteristics are provided in Section 3 of Reference 1 and Reference 5. The qualification of these models is also noted in Reference 1 and Reference 5.

4.3.4 CHANGES

General Electric fuel design philosophy is based on three principles: standardization, evolution, and testing before use. This process has resulted in a series of 8 x 8 and 10 x 10 fuel designs. Details of these designs are provided in References 3, 4, and 5.

REFERENCES FOR SECTION 4.3

1. General Electric Company, General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest NRC approved version).

2. R. L. Crowther, Xenon Considerations in Design of Boiling Water Reactors, APED-5640, 1968.

3. General Electric Company, GE Fuel Bundle Designs, NEDE-31152P (latest NRC approved version).

4. General Electric Company, Licensing Criteria for Fuel Designs (Amendment 22 to NEDE-24011-P-A and Corresponding NRC Safety Evaluation), NEDO-31908, January 1991.

5. General Electric Company, GE12 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR-II), NEDE-32417P, December 1994.

Table 4.3-1

Reload	Reference
1	General Electric Boiling Water Reactor Reload 1 Licensing Submittal, Duane Arnold Energy Center, NEDO-21082, November 1975. General Electric Boiling Water Reactor Reload 1 Licensing Submittal, Bypass Flow Holes Plugged, Duane Arnold Energy Center, NEDO-21082-01, January 1976.
2	General Electric Boiling Water Reactor Reload Number 2 Licensing Submittal, Duane Arnold Energy Center, NEDO-21082-02, 1977. General Electric Boiling Water Reactor Reload Number 2 Licensing Submittal Supplement 1, Partially Drilled Core, Duane Arnold Energy Center, NEDO-21082-02-1, 1977.
3	Boiling Water Reactor Reload 3 Licensing Amendment for Duane Arnold Atomic Energy Center, NEDO-24087, December 1977.
4	Supplemental Reload Licensing Submittal for Duane Arnold Atomic Energy Center Reload 4, NEDO-24234, January 1980.
5	Supplemental Reload Licensing Submittal for Duane Arnold Atomic Energy Center Reload 5, Y1003J01A18, January 1981.
6	Supplemental Reload Licensing Submittal for Duane Arnold Atomic Energy Center Reload 6, Y1003J01A46, March 1983.
7	Supplemental Reload Licensing Submittal for Duane Arnold Atomic Energy Center Reload 7, 23A1739, Revision 1, December 1984.
8	Supplemental Reload Licensing Submittal for Duane Arnold Atomic Energy Center Reload 8, 23A4812, Revision 0, September 1986.
9	Supplemental Reload Licensing Submittal for Duane Arnold Energy Center, Unit 1, Reload 9, Cycle 10, 23A5906, Revision 0, June 1988.
10	Supplemental Reload Licensing Submittal for Duane Arnold Energy Center, Reload 10, Cycle 11, 23A6450, Revision 1, August 1990.
11	Supplemental Reload Licensing Submittal for Duane Arnold Energy Center, Reload 11, Cycle 12, 23A7143, Rev. 0, February, 1992.
12	Supplemental Reload Licensing Submittal for Duane Arnold Energy Center, Reload 12, Cycle 13, 23A7210, Rev. 0, June, 1993.
13	Supplemental Reload Licensing Submittal for Duane Arnold Energy Center, Reload 13, Cycle 14, 24A5171, Rev. 1, August, 1995.
14	Supplemental Reload Licensing Report for Duane Arnold Energy Center, Reload 14, Cycle 15, 24A5369, Rev. 0, September 1996
15	Supplemental Reload Licensing Report for Duane Arnold Energy Center, Reload 15, Cycle 16, 24A5410, Rev. 0, March 1998
16	Supplemental Reload Licensing Report for Duane Arnold Energy Center, Reload 16, Cycle 17, J11-03517, SRLR, Rev. 0, October 1999.

4.4 THERMAL-HYDRAULIC DESIGN

4.4.1 DESIGN BASIS

4.4.1.1 Safety Design Bases

Thermal-hydraulic design of the core shall establish the following:

1. Actuation limits for the devices of the nuclear safety systems such that no fuel safety limit is calculated to be exceeded as a result of analyzed abnormal operational transient events.

2. The safety limits for use in evaluating the safety margin relating the consequences of fuel barrier failure to public safety.

3. That the nuclear system exhibits no inherent tendency toward divergent or limit cycle oscillations that would compromise the integrity of the fuel or nuclear system process barrier.

4.4.1.2. Power Generation Design Bases

The thermal-hydraulic design of the core shall provide the following operational characteristics:

1. The ability to achieve rated core power output throughout the design life of the fuel.

2. The flexibility to adjust core output over the range of plant load and load-maneuvering requirements in a stable, predictable manner without sustaining fuel damage.

4.4.1.3 Requirements for Steady-State Conditions

For purposes of maintaining adequate thermal margin during normal steady-state operation, the MCPR must not be less than the required MCPR operating limit, and the MLHGR must be maintained below the design LHGR for the plant. This does not specify the operating power nor does it specify peaking factors. These parameters are determined subject to a number of constraints, including the thermal limits given previously. The core and fuel design bases for steady-state operation (that is, MCPR and LHGR limits) have been defined to provide a margin between the steady-state operating conditions and any fuel damage condition to accommodate uncertainties and to ensure that no fuel damage results even during the worst anticipated transient condition at any time during plant life.

The design steady-state MCPR operating limit and the peak LHGR are given in the Core Operating Limits Report. Modifications for one recirculation loop operation are documented in Reference 2, as supplemented by Reference 9.

4.4.1.4 Requirements for Transient Conditions

The MCPR and MAPLHGR limits are established such that no safety limit is expected to be exceeded during the most severe moderate frequency Anticipated Operational Occurrences (AOO) event as defined in Reference 1.

4.4.1.5 Summary of Design Bases

The steady state operating limits have been established to assure that the design bases are satisfied for the most severe moderate frequency AOO. Demonstration that the steady state MCPR and MAPLHGR limits are not exceeded is sufficient to conclude that the design bases are satisfied .

4.4.2 DESCRIPTION OF THERMAL-HYDRAULIC DESIGN OF THE REACTOR CORE

4.4.2.1 Summary Comparison

An evaluation of plant performance from a thermal-hydraulic standpoint is provided in Section 4.4.3.

Cycle-specific parameters are provided in the supplemental reload licensing reports listed in Table 4.3-1.

4.4.2.2 Critical Power Ratio

A description of the critical power ratio and the model used to calculate this ratio is provided in Section 4.3.1 of Reference 1. Values of the fuel cladding integrity safety limit are given in Subsection 4.3.1.1 of Reference 1; operating MCPR limits are provided in the supplemental reload licensing reports listed in Table 4.3-1. Modifications of these limits for one recirculation pump operation is given in Reference 2, as supplemented by Reference 9. Operating MCPR limits for two recirculation loop and single loop operations are included in the Core Operating Limits Report.

4.4.2.3 MAPLHGR Limits

The models used to determine the MAPLHGR limits are described in Section 2.2 and S.2.2.3.2.1 of Reference 1.

4.4.2.4 Void Fraction Distribution

The void fraction is calculated each cycle. The value used in relatively slow transient analyses is provided in supplemental reload licensing reports listed in Table 4.3-1. This value is calculated within the transient code for rapid pressurization events and is not reported separately but is reflected in the plot of void reactivity in the figures given for these events in the supplemental reload licensing reports.

4.4.2.5 Core Coolant Flow Distribution

Hydraulic models and the core coolant flow distribution between the area inside the channel and the bypass region are given in Section 4.2 of Reference 1.

4.4.2.6 Core Pressure Drops and Hydraulic Loads

Models for core pressure drop are given in Section 4.2.4 of Reference 1.

4.4.2.7 Correlation and Physical Data

General Electric has obtained substantial amounts of physical data in support of the pressure drop and thermal-hydraulic loads. This information is given in Section 4.2.4 of Reference 1. Models used to calculate the heat-transfer coefficient are referenced in Section 4.2.5.3 of Reference 1.

4.4.2.8 Thermal Effects of Operational Transients

The evaluation of the core's capability to withstand the thermal effects resulting from anticipated operational transients is discussed in Chapter 15.

4.4.2.9 Uncertainties in Estimates

Uncertainties in thermal-hydraulic parameters considered in the statistical analysis that is performed to establish the fuel cladding integrity safety limits are documented in Amendment 25 to Reference 1.

4.4.2.10 Flux Tilt Considerations

The inherent design characteristics of the BWR are particularly well suited to handle perturbations due to flux tilt. The stabilizing nature of the moderator void coefficient effectively damps oscillations in the power distribution. In addition to this damping, the incore instrumentation system and the associated on-line computer provide the operator with prompt and readily available power distribution information. Thus, the operator can readily use control rods or other means to effectively limit the undesirable effects of flux tilting. Because of these features and capabilities, it is not necessary to allocate a specific peaking factor margin to account for flux tilt. If for some reason the power distribution could not be maintained within normal limits using control rods, then the operating power limits would have to be reduced as described in the plant Core Operating Limits Report.

4.4.3 DESCRIPTION OF THERMAL-HYDRAULIC DESIGN OF THE REACTOR COOLANT SYSTEM

The thermal-hydraulic design of the reactor coolant system is described in this section.

4.4.3.1 Plant Configuration Data

The reactor coolant system is described in Chapter 5. Values from the reactor heat balance used in the safety limit analyses are given in Table S-8 of Reference 1.

4.4.3.2 Operating Restrictions on Pumps

Section 4.4.3.3 gives the operating limits imposed on the recirculation pumps by cavitation, pump loads, bearing design flow starvation, and pump speed.

4.4.3.3 Power-Flow Operating Map

A BWR must operate with certain restrictions because of pump net positive suction head (NPSH), overall plant control characteristics, core thermal power limits, etc. The latest power flow map is included in the Core Operating Limits Report. The operating envelope includes the region bounded by the 108% average power range monitor (APRM) rod block line, the rated power line, and the rated load line. Reference 4 provides the analytical bases for operation of the DAEC under this operating envelope, which is validated as part of the cycle-dependent reload analysis. The average power range monitor, rod block monitor, and Technical Specification improvement (ARTS) program provided the system and instrumentation improvements and operating procedure changes which permit steady-state operation in the region of the power flow map above the 100% load lines. The nuclear system equipment, nuclear instrumentation, and the reactor protection system, in conjunction with operating procedures, maintain operations within the area of this map for normal operating conditions. The boundaries of this map are as follows:

1. Natural Circulation Line

   The operating state of the reactor moves along this line for the normal control rod withdrawal sequence in the absence of recirculation pump operation.

2. Minimum Pump Speed Line

   Startup operations of the plant are normally carried out with the recirculation pumps operating at approximately 20% speed. The operating state for the reactor follows this line for the normal control rod withdrawal sequence.

3. Operational Upper Loadline Limit

   This is a power-flow line that is bounded by the 108% rod block line up to 100% rated power/87% rated flow.

4. Low Feedwater Protection Line

   This line results from the recirculation pump and jet pump NPSH requirements. When feedwater flow drops below 20% of rated flow, the recirculation pumps are automatically tripped to 20% speed.

5. Exclusion Zone

   The exclusion zone is defined in Reference 6 and in the supplemental reload submittals listed in Table 4.3-1. The DAEC shall not have a planned entry into this area of the power/flow map due to the reduced margin to thermal hydraulic instability.

6. Buffer Zone

   The buffer zone is defined in the Core Operating Limits Report. Planned entry into the buffer zone is allowed if acceptable results are demonstrated from the stability monitor in use at the DAEC.

4.4.3.4 Temperature-Power Operating Map

Not applicable to the DAEC (applies to pressurized-water reactors).

4.4.3.5 Thermal-Hydraulic Characteristics Summary Table

The thermal-hydraulic characteristics used in the safety analyses are given in Table 3-1 of Reference 7 and in the supplemental reload submittals listed in Table 4.3-1.

4.4.4 EVALUATION

The design basis employed for the thermal-hydraulic characteristics incorporated in the core design, in conjunction with the plant equipment characteristics, nuclear instrumentation, and the reactor protection system, is to require that no fuel damage occurs during normal operation or during abnormal operational transients. Analyses have demonstrated that the applicable thermal-hydraulic limits are not exceeded.

4.4.4.1 Critical Power

The GEXL critical power correlation used in thermal-hydraulic evaluations is discussed in Section S.2 of Reference 1.

4.4.4.2 Core Hydraulics

Core hydraulic models and correlations are discussed in Section 4.0 of Reference 1.

4.4.4.3 Influence of Power Distributions

The influence of power distributions on the thermal-hydraulic design is discussed in Section S.2 of Reference 1.

4.4.4.4 Core Thermal Response

The thermal response of the core for accidents and expected transient conditions is discussed in Chapter 15.

4.4.4.5 Analytical Methods

The analytical methods, thermodynamic data, and hydrodynamic data used in determining the thermal-hydraulic characteristics of the core are documented in Section 4.0 and Subsection S.2 of Reference 1.

4.4.4.6 Thermal-Hydraulic Stability Analysis

The original Option I-D DAEC Specific thermal-hydraulic stability analysis is given in Reference 6. This analysis was then updated in accordance with Reference 8.

4.4.5 TESTING AND VERIFICATION

The testing and verification techniques used to ensure that the planned thermal-hydraulic design characteristics of the core will remain within required limits throughout the life of the core are discussed in Chapter 14 and in the Technical Specifications.

4.4.6 INSTRUMENTATION REQUIREMENTS

The reactor vessel instrumentation monitors the key reactor vessel operating parameters during planned operations. This ensures sufficient control of the parameters. The reactor vessel sensors are discussed in Section 7.6.4.

REFERENCES FOR SECTION 4.4

1. General Electric Company, General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest NRC approved version).

2. General Electric Company, Duane Arnold Energy Center Single-Loop Operation, NEDO-24272, 1980.

3. General Electric Company, General Electric Boiling Water Reactor Extended Load Line Limit Analysis for Duane Arnold Energy Center, Cycle 8, NEDC-30626, May 1984.

4. General Electric Company, General Electric BWR Licensing Report: Average Power Range Monitor, Rod Block Monitor and Technical Specification Improvement (ARTS) Program for the Duane Arnold Energy Center, NEDO-30813, March 1985.

5. General Electric Company, Service Information Letter (SIL) No. 380, Revision 1, February 10, 1984.

6. Application of the "Regional Exclusion with Flow-Biased APRM Neutron Flux Scram", Stability Solution (Option I-D) to the Duane Arnold Energy Center, GENE-A00-04021-01, September, 1995.

7. General Electric Company, GE Fuel Bundle Designs, NEDE-31152P (latest approved version).

8. General Electric Company, Duane Arnold Energy Center GE12 Fuel Upgrade Project, NEDC-32915P, Revision 0, November, 1999.

9. MDL#APED LI2-003, DAEC Supplement to NEDC-32915P, Duane Arnold Energy Center GE12 Fuel Upgrade Project, Rev. 0, March 2000.

The control rods are 9.75 in. in total span and are separated uniformly throughout the core on a 12-in. pitch. Each control rod is surrounded by four fuel assemblies (see Section 4.2).

Beginning cycle 11, some control rods were replaced with the G.E. Duralife D-230 control rod assemblies. These assemblies are described in Reference 9, which has been accepted by the NRC in license applications (Reference 10). Extended lifetime in the D-230 is achieved by replacing the top 6 inches of the absorber tubes with a hafnium plate and increasing the overall thickness of the absorber tubes (to add more boron carbide powder).

The main structural member of a control rod is made of Type 304 stainless steel and consists of a top handle, a bottom casting with a velocity limiter and CRD coupling, a vertical cruciform center post, and four U-shaped absorber tube sheaths. The top handle, bottom casting, and center post are welded into a single skeletal structure. The U-shaped sheaths are resistance welded to the center post, handle, and castings to form a rigid housing to contain the absorber rods filled with boron carbide. Rollers at the top and bottom of the control rod guide the control rod as it is inserted and withdrawn from the core. The control rods are cooled by the core bypass flow. The U-shaped sheaths are perforated to allow the coolant to circulate freely about the absorber tubes. Operating experience has shown that control rods constructed as described above are not susceptible to dimensional distortions.

The boron carbide powder in the absorber tubes is compacted to about 70% of its theoretical density. The boron carbide contains a minimum of 76.5% by weight natural boron. The boron-10 minimum content of the boron is 18.0% by weight. Absorber tubes are made of Type 304 stainless steel. Each absorber tube is 0.188 inch outside diameter and has a 0.025 inch wall thickness, except the D-230 which has a 0.220 inch outside diameter and a 0.020 inch wall thickness. Even though the D-230 is 0.016 inch thicker than the original control rod, a comparison study performed by General Electric shows that the D-230 will operate with no increase in the probability of fuel channel interference. Absorber tubes are sealed by a plug welded into each end. The boron carbide is longitudinally separated into individual compartments by stainless steel balls at approximately 16-in. intervals. The steel balls are held in place by a slight crimp of the tube. Should boron carbide tend to compact further in service, the steel balls will distribute the resulting voids over the length of the absorber tube.

NEDO-24232[1] contains a discussion of various mechanical and nuclear design considerations that define the life-limiting mechanism for control blades. The mechanical evaluations performed consist of control blade bending, twist, binding, internal gas pressure, wear, fatigue, and seismic test. Presently, none of these considerations limits the useful life of the control blade. Nuclear evaluations include boron depletion and boron loss due to a manufacturing flaw, internal gas pressure, and boron carbide swelling. A typical control blade is shown in Figure 4.6-2.

Boron loss due to a manufacturing flaw is a random low-frequency occurrence and, therefore, was not considered in determining control blade lifetime. Boron loss due to overpressurization is avoided by designing the absorber tube with end-of-life structural capability in excess of the expected stresses due to end-of-life internal pressure. The life-limiting mechanism for control blades is the combination of boron depletion and boron loss resulting from tube cracking. The criterion defining the end of control blade life is a loss of total reactivity equal to 10% of the associated initial control blade worth.

Some of the quality control tests performed on the control rod absorber tubes are the following:

1. Material integrity of the tubing and end plug is verified by ultrasonic inspection.

2. Boron-10 fraction of the boron content of each lot of boron carbide is verified.

3. Weld integrity of the finished absorber tubes is verified by helium leak testing.

4.6.1.2.5.1 Test Program

Numerous testing programs have been developed to verify the adequacy of the control blade design.

Mechanical Tests

Various mechanical tests have been performed to determine the structural capabilities of the control blade design. These tests included seismic testing, bent-beam testing, twist testing, and scram testing. The control blade was also tested under simulated operating conditions in facilities outside the reactor core for its capabilities in actual operation to withstand blade movements, such as jogs and scrams, in excess of the number expected during the life of a plant.

Nuclear Tests

Reactivity measurements have been taken at various operating reactors by performing blade substitution tests. Results of these tests have indicated that the control blades lose nuclear control strength at a slightly slower rate than experimental and analytical techniques predict.

Neutron transmission tests have also been performed. The neutron transmission device cannot be used to detect the loss of boron carbide from absorber tube cracking. The device can readily find areas of missing boron carbide if the tube being measured does not contain water; however, once water has entered the tube and if the water has some boron carbide in the solution, neutron transmission cannot differentiate between the boron carbide water mixture and solid boron carbide. In addition, the areas of loss are at the tip of the control blade and located at the outer edge (Figures 4.6-3 and 4.6-4). These conditions make it very difficult for the detection equipment to find missing boron carbide. Also, a layer of boron carbide often adheres to the walls

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The program included induction heating stress improvement (IHSI) of welds in the recirculation system large diameter piping (10 in. or greater). As a result of ultrasonic inspections performed before and after IHSI, 11 code reportable indications were found in the recirculation system welds. Ten welds had reportable IGSCC-like indications. One weld had an indication not associated with IGSCC. The 11 welds were repaired by full structural weld overlays.[5]

IGSCC is controlled by a hydrogen water chemistry system, described in Section 9.3.5, which injects hydrogen into the feedwater. The hydrogen is carried into the reactor, where it reduces the concentration of dissolved oxygen in the reactor coolant. To satisfy the requirements of NRC Generic Letter 88-01, an augmented IGSCC examination program is in effect for austenitic stainless piping welds.

5.2.4 INSERVICE INSPECTION AND TESTING OF REACTOR COOLANT PRESSURE BOUNDARY

5.2.4.1 Introduction

A preservice inspection of Nuclear Class 1 components was conducted to ensure freedom from defects greater than code allowance; in addition, this served as a reference base for future inspections. Prior to operation, the reactor coolant system as described in Article IS-120 of Section XI of the ASME Code was inspected to ensure that the system was free of gross defects. In addition, the facility was designed such that gross defects should not occur throughout the life of the plant. The preservice inspection program was based on the 1971 Section XI of the ASME Code for inservice inspection. This inspection plan was designed to reveal problem areas (should they occur) before a leak in the coolant system could develop. The program was established to provide reasonable assurance that no LOCA would occur at the DAEC as a result of leakage or breach of pressure-containing components and piping of the reactor coolant system, portions of the emergency core cooling systems, and portions of the auxiliary systems-associated with the reactor coolant system.

The engineering and design effort associated with the DAEC predates the availability of the ASME Inspection Code. However, this code, including subsequent Addenda through the Winter 1972 Addendum, dated December 31, 1972, was used as a guide in the preparation of the initial DAEC inservice inspection plan for Nuclear Class 1 components, and maximum access has been provided within the limits of drywell design.

The inspection interval for the examination program is 10 years. The extent of Nuclear Class 1 examinations at periods of 3-1/3 years and intervals of 10 years is tabulated in the DAEC Inservice Inspection Program. The extent of Nuclear Class 2 examinations during the first 10-yr interval and during the service lifetime of the plant is as indicated in Section 6.6. The actual individual inspections are generally performed during refueling outages and are adjusted to the load factor of the unit to minimize outage time directly required for inspection.

The examination program for Nuclear Class 1 components includes those portions of the pressure-containing components up to and including the outermost containment isolation valve that could isolate the primary systems in the event of a LOCA. The examination program assumes that examinations can be performed without the necessity of unloading the reactor core solely for the purpose of conducting examinations.

The first 10-yr program interval and the first 40-month inspection period began February 1, 1975. The second 40-month inspection period began June 1, 1978. The second inspection period was actually 49 months long because it was extended to cover a 9-month outage for replacement of recirculation system inlet nozzle safe-ends. The third 40-month inspection period began July 1, 1982, and it, and the 10-year program, ended on October 31, 1985.

The DAEC Inservice Inspection Program for the second and third inspection periods conformed to the requirements of ASME Code Section XI, 1974 Edition, with Addenda through Summer 1975.

The DAEC Inservice Inspection Program for the second 10-yr interval addressed the requirements of ASME Code, Section XI, 1980 Edition, with Addenda through Winter 1981, subject to limitations and modifications as stated in 10CFR50.55a(b)(2). This second 10-yr interval began November 1, 1985, and was divided into three inspection periods: (Note the second ten year interval was extended 1 year as permitted by IWA 2430(d) of the ASME Section XI, 1989 Edition and the revised rulemaking of 10CFR50.55a(g)(6)(A)(3)(v).

Period 1	November 1, 1985-March 1, 1989
Period 2	March 1, 1989-July 1, 1992
Period 3	July 1, 1992-November 1, 1996

The DAEC Inservice Inspection Program for the third 10-yr interval addresses the requirements of ASME Code, Section XI, 1989 Edition, subject to limitations and modifications as stated in 10CFR50.55a(b)(2). This third 10-yr interval began November 1, 1996. Results of inservice inspections and exceptions to the ASME Code are summarized in References 10 through 19.

When it is impossible or impractical to meet certain requirements of ASME Code, Section XI, requests for relief from the requirements are made pursuant to 10 CFR 50.55a(g)(5)(iii).

Visual inspection for leaks will be made periodically on ASME Section XI, Class 1, 2 and 3 systems. The specified inspection program encompasses the major areas of the vessel and piping systems within the ASME Section XI boundaries. The inspection period is based on the observed rate of growth of defects from fatigue studies sponsored by the NRC and is delineated by Section XI of the ASME Code. These studies show that it requires thousands of stress cycles at stresses beyond those expected to occur in a reactor system to propagate a crack. The test frequency established is at intervals such that, in comparison to study results, only a small number of stress cycles will occur at values below limits. On this basis, it is considered that the test frequencies are adequate.

The type of examinations planned for each component depends on location, accessibility, and type of expected defect. Direct visual examination is proposed wherever possible since it is fast and reliable. Surface examinations are planned where practical and where added sensitivity is required. Ultrasonic testing or radiography will be used where defects can occur in concealed surfaces. The type of examination will comply with ASME Section XI requirements for the particular item.

Records and documentation of all information and inspection results are retained by the DAEC for the active lifetime of the plant. The records provide the basis for the evaluation of the preservice examination and facilitate its comparison with results from subsequent inspections.

5.2.4.2 Program Purpose and Objectives

The inservice inspection program for the DAEC complies with the principles and intent of the ASME Inservice Inspection Code to the extent that current design and radiation levels permit. The program is established to provide reasonable assurance that no LOCA occurs at the DAEC as a result of leakage or rupture of pressure-containing components and piping of the reactor coolant system, portions of the emergency core cooling systems, and portions of the auxiliary systems associated with the reactor coolant system.

The required ensurance is provided by conducting the following:

1. A preservice examination of all components and piping within the scope of Section XI (July 1, 1971 edition) of the ASME Code against which future examination determinations can be compared.

2. Systematic volumetric, visual, and surface examinations of systems and components during refueling outages to confirm that the structural integrity of these systems and components has not changed from their preoperational condition or that any observed changed conditions are acceptable for continued plant operation.

3. System pressure tests and leakage inspections for Nuclear Class 1 components on a periodic basis.

4. An Inservice Testing Program for pumps and valves as described in Section 3.9.6.

5. Feedwater Nozzle inspections and Control Rod Drive Return Line Nozzle inspections are discussed in the DAEC augmented examination program.

5.2.4.3 Examination Techniques

5.2.4.3.1 Nondestructive Examination

The examination procedures used for preservice and inservice inspection employ ultrasonic, surface, and visual techniques. All examinations are conducted in accordance with the applicable edition of the ASME Code, Section XI.

The major emphasis of Section XI is on volumetric examination, which may be accomplished by either ultrasonic or radiographic techniques. Because of the buildup of background radiation from plant operation, the ultrasonic technique is considered the most practical method for volumetric examination. This type of examination may be done rapidly and in certain instances remotely, the components examined may be filled with water, and access to the work area while examinations are being conducted is not restricted.

Ultrasonic testing is utilized at the DAEC for volumetric examination. If interpretation of ultrasonic results warrant, radiographic techniques may also be applied. To meet the ASME Code, certain components and supports receive surface examinations utilizing dye penetrate or magnetic particle techniques. Systems and components also receive visual examinations prior to other techniques being employed.

Visual examinations provide a report of the general condition of the part, component, or surface examined, including such conditions as scratches, wear, cracks, corrosion, erosion, or evidence of leakage.

The method used in the examination of each component is delineated in the DAEC Third 10-Year Inservice Inspection Plan. Presently known instances where radiation levels, plant design, and/or materials make it impractical to adhere to the ASME Code are discussed in the Inservice Inspection Plan and Section 5.2.4.5.

5.2.4.3.2 Pressure Tests for Nuclear Class 1 Components

Components within the reactor coolant pressure boundary are pressure tested before startup following each reactor refueling outage and near the end of each inspection interval in accordance with the Inservice Inspection Plan. During the pressure test, components are inspected for leakage without the removal of insulation.

5.2.4.4 Nondestructive Testing (NDT) Operator Qualification

The nondestructive examinations are performed by personnel qualified in accordance with the guidelines of ASME Section XI (IWA-2300) which endorses SNT-TC-1A. Examiners are certified in accordance with the contractor's written practice which conforms to the guidelines of SNT-TC-lA.

f. Pump Supports and Hangers

Examinations are conducted in accordance with the Inservice Inspection Plan.

4. Valve Pressure Boundary

a. Valve Body Welds

There are no valves in this system with pressure-containing welds.

b. Valve Bodies

Examinations are conducted in accordance with the Inservice Inspection Plan.

c. Valve-to-Safe-End (Dissimilar Metal) Welds

There are no valves in the system with dissimilar metal welds.

d. Pressure-Retaining Bolting Larger than 2 in.

There are no valves with bolting 2 in. or larger in the system.

e. Pressure-Retaining Bolting Under 2 in.

All valves in the system have bolts under 2 in. in diameter. Examinations are conducted in accordance with the Inservice Inspection Plan.

f. Valve Supports and Hangers

There are no valves within the system with integrally welded supports. Examinations of nonintegrally welded supports and hangers are conducted in accordance with the Inservice Inspection Plan.

5.2.4.7 Nuclear Class 1 Preoperational Examinations

Before initial plant startup, a preoperational examination of Nuclear Class 1 components was performed to establish a preservice record against which future inservice inspection results can be compared to determine the integrity of various included items throughout their lifetime.

The preoperational examinations were performed on all welds and components within the specified boundaries of the reactor coolant system, the auxiliary system associated with the reactor coolant system, and the emergency core cooling system as defined in Sections 5.2.4.5.1, 5.2.4.5.2, and 5.2.4.5.3.

5.2.4.8 Inservice Inspection of Shock Suppressors (Snubbers)

All safety-related snubbers are subject to an augmented inservice inspection program which is described in the Technical Requirements Manual.

5.2.4.9 Documentation and Records

Documentation and records of examination procedures, schedules, and inspection reports concerned with preoperational and inservice inspection are compiled and maintained by the DAEC throughout the life of the plant.

The minimum requirements for documentation by the DAEC are those referenced in ASME Code, Section XI, and include full documentation of all the preservice base examination data and inservice inspection records of tests performed. Comparative analysis reports form part of the documentary effort, in addition corrective action reports and repair procedures where required. Originals of all inservice inspection records are maintained in a central location.

5.2.5 DETECTION OF LEAKAGE THROUGH REACTOR COOLANT PRESSURE BOUNDARY

Reliable means are provided to detect leakage from the nuclear system barrier inside the drywell. Nuclear system leakage rate limits are established so that appropriate action can be taken before the integrity of the nuclear system process barrier is unduly compromised.

5.2.5.1 Safety Design Bases

The nuclear system leakage rate limits are set such that corrective action can be taken before one of the following occurs:

1. A threat of significant compromise to the nuclear system process barrier.

2. A leakage rate in excess of the coolant makeup capability to the reactor vessel.

3. A leakage rate in excess of the removal capability of the drywell sump pumps.

The nuclear system leakage detection system employs diverse methods to indicate leakage within the drywell.

The lengths of through-wall cracks that would leak at the rate of 5 gpm given as a function of wall thickness and nominal

Nominal Pipe Size	Wall Thickness (in.)	Crack Length l (in.) Steam Line	Water Line
4 in., Schedule 80	0.337	7.15	4.91
12 in., Schedule 80	0.687	8.46	4.76
20 in., main steam	0.758	7.39	--
22 in., recirculation	0.975	--	4.39

The ratios of crack length l to the critical crack length l_c as a function of nominal pipe size are

Nominal Pipe Size	Ratio l/l_c Steam Line	Water Line
4 in., Schedule 80	0.745	0.510
12 in., Schedule 80	0.432	0.243
20 in., main steam	0.342	--
22 in., recirculation	--	0.158

It is important to recognize that the failure of ductile piping with a long, through-wall crack is characterized by large crack-opening displacements that precede unstable rupture. Judging from observed crack behavior in the GE and BMI experimental programs involving both circumferential and axial cracks, it is estimated that leak rates of hundreds of gpm will precede crack instability. Measured crack-opening displacements for the BMI experiments were in the range of 0.1 to 0.2 in. at the time of incipient rupture, corresponding to leaks of the order of 1 in^2. in size for plain carbon steel piping. For austenitic stainless steel piping, even larger leaks are expected to precede crack instability, although there is insufficient data to permit quantitative prediction.

The results given are for a longitudinally oriented flaw at normal operating hoop stress. A circumferentially oriented flaw could be subjected to stress as high as the 550°F yield stress, assuming that high thermal expansion stresses exist. A good mathematical model that is well supported by test data is not available for the circumferential crack. Therefore, it is assumed that the longitudinal crack, subject to a stress as high as 30,000 psi, constitutes a "worst case" with regard to leak rate versus critical size relationships. Given the same stress level, differences between the circumferential and longitudinal orientations are not expected to be significant in this comparison.

5.2.5.2.3.1 Equipment Drain and Floor Drain Sumps

The equipment drain sump system is actually composed of two sumps: the equipment drain sump is located beneath the reactor inside the reactor vessel pedestal and is directly joined to the equipment drain pump sump located inside the drywell but outside the pedestal. These two sumps will be generally referred to as the equipment drain sump.

The equipment drain sump level is used to control the drain pumps and provide alarms to control room personnel.

The pump control and alarm function is as follows.

At the lowest of the high water level settings, the preferred pump is automatically started. If the water level continues to rise, a higher water level setting starts the standby pump and actuates an alarm in the control room. When the water level decreases to a low water level setting, the pumps are stopped and the automatic pump selector switch reverses the roles of the preferred and standby pumps.

As the water that has collected in the sump is pumped out, the discharge flow is monitored. The flow rate is continually plotted on a recorder in the control room. The total volume pumped is indicated in the control room. The sump pump discharge flow duration, the frequency of pump operation, and the volume pumped can be used to provide a measure of the leakage rate.

Excessive leak rates are indicated by a control room alarm. This alarm is actuated by either of two timed conditions: the pump starting at shorter intervals than would be required if the alarm setpoint leak rate existed, or the pump running longer than would be required to lower the level to the shutoff point.

The drywell floor drain sump system is monitored and controlled in the same manner as the drywell equipment drain sump.

5.2.5.2.3.2 Drywell Ventilation

The drywell ventilation system is a water-cooled, forced-air system, using well water as the cooling medium. In this system, the temperature of the gas entering and leaving the cooler and the outlet temperature of the well water are monitored. Once steady-state operation is established, variations of these parameters can indicate possible leaks. Since the inlet water has an essentially constant temperature, a rise in outlet temperature indicates additional heat load on the cooling coils and could be indicative of a leak. With the exception of the single fan units, high air or water outlet temperature will actuate an alarm.

5.2.5.2.3.3 Drywell Pressure, Temperature and Radioactivity

The drywell temperature and pressure are monitored, indicated, and recorded in the control room. The sample points and instrumentation are indicated in Figure 6.2-44.

16. Letter from J. Franz, Iowa Electric, to T. Murley, NRC, Subject: DAEC Inservice Inspection Report, dated January 11, 1994 (NG-93-5376).

17. Letter from J. Franz, IES Utilities, to W. Russell, NRC, Subject: DAEC Third 10-year Inservice Inspection Plan, dated April 26, 1996, (NG-96-0809).

18. Letter from K. Young, IES Utilities, to W. Russell, NRC, Subject: DAEC Inservice Inspection Report, dated July 18, 1995, (NG-95-2142).

19. Letter from K. Peveler, IES Utlitites, to NRC, Subject: DAEC Inservice Inspection Report, dated February 14, 1997, (NG-97-0327).

According to tests made on the original safe-end material, the average Charpy energy values at the temperatures of primary concern are the following:

Test Temperature (°F)	Energy (ft-lb)
40	33
10	20

The 40°F water steady-state 200 gpm per nozzle flow case analysis indicated that the limiting temperature is 68°F in the 1-in. length of the original safe-end material. The 58°F margin between the 68°F steady-state metal temperature and the 10°F 20-ft-lb temperature is considered to be technically adequate for this abnormal condition. Therefore, RCIC injection to the vessel through the feedwater nozzle is appropriate.

After the consideration of several alternatives, the feedwater thermal sleeve detail was changed by welding the thermal sleeve directly to the safe end. This detail prevents the flow of cold water behind the thermal sleeve, and therefore the nozzle forging temperature is maintained above 100°F for turbine roll. The original safe ends except for a short length (approximately 1 in.) adjacent to each nozzle have been removed.

In addition, a portion of the safe-end that could be exposed to the 90°F water flow was replaced with a new safe end that has a minimum of 20 ft-lb Charpy V-notch impact properties at -20°F.

With these changes in the feedwater safe-end detail, the 90°F steady-state flow case will still govern the lowest service metal temperature of the nozzle and remaining portion of the original safe end. The 1-in. length of original safe-end material and the nozzle forging have Charpy impact tests made at +40°F. With the design change, the lowest calculated temperatures are 118°F in the nozzle forging and 108°F in the 1-in. portion of the original safe end. This exceeds the requirements of the code.

After these changes were made, the feedwater nozzles were hydrostatically tested and the vessel was ASME Code stamped. The feedwater nozzle thermal sleeve design is shown in Figure 5.3-4.

The vessel top head nozzles have flanges with small-groove facing. The drain nozzle is of the full-penetration weld design and extends 16 in. below the bottom outside surface of the vessel. The recirculation inlet nozzles located as shown in Figure 5.3-3, feedwater inlet nozzles and core spray inlet nozzles have thermal sleeves similar to those shown in the detail of Figure 5.3-4.

Nozzles connecting to stainless steel piping are clad on the interior to a minimum thickness of 0.125 in. with stainless steel weld overlay equivalent to that used in the vessel. Nozzles for connecting carbon steel piping are clad through at least the thickness of the vessel wall or one-half the diameter of the nozzle bore, whichever is less.

The nozzle for the core differential pressure and liquid control pipe is designed with a transition so that the stainless steel outer pipe of the differential pressure and liquid control line can be socket welded to the inner end of the nozzle and so that the inner pipe passes through the nozzle. This design provides an annular region between the nozzle and the inner liquid control line to minimize thermal shock effects on the reactor vessel in the event that the use of the standby liquid control system is required.

The jet pump instrumentation penetration seal is welded directly to the outer end of the jet pump instrumentation nozzle. The stainless steel recirculation loop piping is welded to the outer end of the recirculation outlet and inlet nozzles. The main steam line piping is welded to the outer end of the steam outlet nozzle.

The piping attached to the vessel nozzle is designed, installed, and tested in accordance with the requirements of the ASME Code.

Thermocouple pads are located on the exterior of the vessel (see Table 5.3-6 and Figure 5.3-5). At each thermocouple location, two pads are provided--an end pad to hold the end of a 3/16-in.-diameter thermocouple and a clamp pad equipped with a set screw to secure the thermocouple.

5.3.3.2.1 Shroud Support

The reactor vessel shroud support is a cylindrical shell that surrounds the reactor core assembly and is designed so that stresses due to reactions at the shroud support are within limits given in Chapter 3. The design pressure differential across the shroud support is 100 psi (higher pressure under the support) occurring at the vessel design temperature. The design of the shroud support also takes into account the restraining effect of the components attached to the support and weight and earthquake loadings. The vessel shroud support and other internal attachments (jet pump riser support pads, guide rod brackets, steam dryer support brackets, dryer holddown brackets, feedwater sparger brackets, surveillance specimen brackets, and core spray brackets) are as shown in Figure 5.3-6 and Table 5.3-6.

5.3.3.2.2 Reactor Vessel Support Assembly

The reactor vessel is laterally and vertically supported and braced to make it as rigid as possible without impairing the movements required for thermal expansion. Where thermal requirements prohibit the use of rigid supports, spring anchors are employed to resist earthquake forces while allowing sufficient flexibility for thermal expansion.

The reactor vessel is supported on a steel cylinder that is welded to the bottom of the reactor vessel and extends down and through the drywell shell and is embedded in the reactor building mat. After the erection of the reactor vessel, a concrete pedestal is added, which is constructed monolithically with the steel support cylinder.

3. Results:

   a. Natural frequencies

Fundamental of system	0.868 cps
Second	8.308 cps
Third	12.039 cps
Fourth	28.050 cps

   b. Peak deflection is 0.0002 at 8.308 cps.

   c. Maximum vibration, induced stress is 30 psi.

The maximum stress level of 30 psi is very low. A two-dimensional model of the reactor coolant recirculation system loop piping neglects the torsional modes of vibration. The first torsional natural frequency is usually slightly higher than the lateral fundamental frequency. The second, third, and fourth torsional frequencies increase in the same fashion as the translational natural frequencies. It is reasoned that if a torsional mode with a natural frequency near the pump speed exists, it will be one of the higher harmonics of the torsional fundamental frequencies. Hence, if it is excited, the deflections will be similar to those obtained from the lateral vibrational analysis.

This insignificant stress level precludes the need for a more refined model and includes all possible sources of internal excitation.

5.4.3.2.2 Method of Vibration Control

1. Sway braces are installed on suction and discharge lines in order to dampen the possible induced vibrations. The sway braces are installed after the verification of the accuracy of the analysis cited above is proved in an actual operating facility.

2. The normally planned startup procedures include tests for loop vibrations to verify the actual installation and design principles.

5.4.3.2.3 Reactor Coolant System Venting

Adequate reactor coolant system venting is provided by existing plant designs.

The DAEC has four power-operated safety-grade relief valves (automatic depressurization system (ADS) valves) remotely operable from the main control room (Section 5.4.13). These valves vent the reactor coolant system of noncondensible gases (post-accident and in emergency conditions) and discharge to the suppression pool. (Reference 7, NUREG-0737, item II.B.1)

Procedures have been provided to govern the operator's use of the relief valves for venting the reactor pressure vessel.

A description of the construction, location, size, and power supply for these valves is provided in Sections 5.2.2 and 5.4.13. An analysis of a more severe LOCA is contained in Section 15.6.6.

As a backup to ADS valve operation, the reactor vessel can also be vented by the reactor pressure vessel head vent line, which contains two nitrogen-operated valves in series that are remotely operable from the control room. These valves are normally closed with solenoids that are normally deenergized. These valves, while not environmentally qualified, are powered from an emergency power source. The reactor pressure vessel head vent line discharges to the drywell equipment drain sump. In addition, the reactor vessel is vented to a main steam line through a normally open, manually operated valve.

Venting is also provided by the main-steam-driven turbines of the HPCI and RCIC systems, which exhaust to the suppression pool.

5.4.3.3 Safety Evaluation

Reactor recirculation system malfunctions that pose threats of damage to the fuel barrier are described and evaluated in Chapter 15. It is shown that none of the malfunctions result in fuel damage; thus, the recirculation system has sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients. The core flooding capability that is provided by a jet pump design plant is shown in Figure 5.4-6. There is no recirculation-line break that can prevent the reflooding of the core to the level of the jet pump suction inlet. The core flooding capability of a jet pump design plant is discussed in detail in Chapter 6.

The DAEC is licensed to operate with one recirculation loop not in operation (single-loop operation). Single-loop operation has been analyzed and found to be acceptable for the DAEC (References 1b and 21). Single-loop operation primarily affects the probability of an inadvertent startup of an idle recirculation pump transient evaluated in Chapter 15. As specified in plant procedures, the idle loop is required to be electrically isolated prior to continued single-loop operation in order to minimize the probability of such an event. The water temperature and chemistry in the inactive loop are maintained by leaving the suction and discharge (or bypass) valves open. The LPCI loop selection logic will close these valves during a LOCA in order to prevent degradation in LPCI flow. Analyses have been performed (References 17 and 21) that demonstrate that the acceptance criteria of 10CFR50.46 are still met if the recirculation discharge bypass valve remains open in the selected loop.

If for any reason the RCIC system is incapable of supplying sufficient flow for core cooling, the emergency core cooling systems are actuated to provide the required boundary protection.

The RCIC piping within the drywell up to and including the outer isolation valve is designed in accordance with ANSI B31, Class 1. Other piping is designed in accordance with ANSI B31.7, Class 2. The RCIC turbine exhaust line to the suppression pool is equipped with a vacuum breaker system as described in Section 6.3 and shown in Figure 5.4-9, Sheet 1.

The RCIC turbine is provided with a turbine trip on high exhaust pressure in the pipe to the suppression chamber so that if the cause of the high pressure can be found and corrected, the system can be quickly restored to service. The turbine exhaust pressure trip is set at a nominal 50 psig. This level is high enough to permit RCIC operation during a hypothetical small break LOCA when high pressures could exist in the primary containment, yet low enough to limit RCIC turbine gland seal leakage and its associated radiological effects at elevated back pressures.

5.4.6.3 Safety Evaluation

To provide a high degree of assurance that the RCIC system shall operate when necessary and in time to prevent inadequate core cooling, the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given in the capability for periodic testing during station operation.

The potential for steam void formation (which could cause water hammer) due to leakage through the system discharge valves has been considered. During the normal plant operation, any back leakage of reactor coolant into the RCIC system cannot cause significant steam void formation in the discharge piping. Thus, there is no significant potential for water hammer upon RCIC system startup.

5.4.6.4 Inspection and Testing

A design flow functional test of the RCIC system is performed during plant operation by taking suction from the condensate storage tank and discharging through the full-flow test return line back to the condensate storage tank. The discharge valve to the feed line remains closed during the test, and reactor operation is undisturbed. The operation of the pump discharge valve is accomplished by first shutting the upstream discharge valve. The operability of the pump discharge check valve is verified using either non-intrusive diagnostic techniques, direct visual inspection following disassembly, or by other techniques as described in the Inservice Testing Program (Reference 3.9.6.2). Control system design provides automatic return from test to operating mode if system initiation is required during testing. The frequency and scope of periodic inspections and maintenance of the turbine-pump unit are carried out in accordance with normal plant practices, manufacturers recommendations and operating history. Valve position indication as well as instrumentation alarms are displayed in the control room (see Figure 5.4-11).

The procedure used to calibrate the elbow taps that measure the RCIC and HPCI steam flows involves an initial calibration using a formula supplied by the elbow tap manufacturer:

$$h = \frac{(Q_s)^2\ V}{12.9 \times 10^4 \times (R)}$$

where

h	=	differential pressure at the elbow taps (inches of water)
Q_S	=	maximum steam flow possible (lb/hr)
V	=	specific volume of steam at flowing conditions (ft^3/lb)
R	=	pipe constant

Final verification of the steam flow as determined by the elbow taps is made during startup testing when the turbine is running at rated, steady-state condition. At this point, the steady-state steam flow is recorded, and the isolation trip signal setpoint is set at three times this observed flow via the equation given below:

$$\Delta P_t = 9\left(\Delta P_m\right)\left[\frac{W_{max}}{W_{test}}\right]^2$$

where

ΔP_t	=	trip setpoint required
ΔP_m	=	measured ΔP (steady state)
9	=	ΔP change corresponding to 300% flow
W_{max}	=	maximum steam flow required in any mode per process diagrams
W_{test}	=	steam flow required in test mode per process diagrams

General Electric Service Information Letter (GE SIL) 475 Revision 2 provided an additional equation to utilize for determining the Analytic Limit for HPCI and RCIC high steam flow. This equation can be used to adjust plants existing instrument setpoints. The plant conditions for taking data are the same as the conditions used to do the final verification. The equation is as follows:

$$\Delta P_{max} = 9\left(\Delta P_{test}\right)\left(\frac{\rho_{test}}{\rho_{max}}\right)\left(\frac{W_{max}}{W_{test}}\right)$$

In which:

ΔP_{max}	=	Analytical limit required for 300% steam flow
ΔP_{test}	=	Differential pressure measured during steady state testing
ρ_{max}	=	Steam density for process diagram Mode A conditions
ρ_{test}	=	Steam density for measured reactor pressure
W_{max}	=	Maximum steam flow (Mode A of system process diagram)
W_{test}	=	Steam flow from test mode of system process diagram

Removable spool pieces are provided for temporary connection of the plant heating steam to the RCIC system as shown in Figure 5.4-9. The connection permits the use of clean (nonradioactive) steam for preoperational testing of the RCIC turbine during initial startup or after extensive maintenance. The RCIC spool piece is 9 ft of 3-in. pipe with flanges. Blind flanges are provided for isolation when the spool piece is not in use.

In response to IE Bulletin 85-03 and Generic Letter 89-10, the capability of certain motor-operated valves to open and close under conditions of maximum-expected differential pressures has been verified (References 15 and 16).

5.4.7 RESIDUAL HEAT REMOVAL SYSTEM

5.4.7.1 Design Bases

The objective of the RHR system is to restore and maintain the coolant inventory in the reactor vessel so that the core is adequately cooled after a LOCA. The RHR system also provides for containment cooling so that the condensation of the steam resulting from the blowdown due to the design-basis LOCA is ensured. Containment cooling is discussed in Section 6.2.2.

The RHR system provides the means to meet the following operational objectives:

1. Remove decay heat and residual heat from the nuclear system so that refueling and nuclear system servicing can be performed.

2. Supplement the fuel pool cooling system capacity when necessary to provide additional cooling capacity.

The safety design bases are as follows:

1. The RHR system acts automatically, in combination with other emergency core cooling systems, to restore and maintain the coolant inventory in the reactor vessel such that the core is adequately cooled to preclude excessive fuel clad temperature following a design-basis LOCA.

2. The RHR system, in conjunction with other emergency core cooling systems, has such diversity and redundancy that only a highly improbable combination of events could result in their inability to provide adequate core cooling.

3. The source of water for the restoration of reactor vessel coolant inventory is located within the primary containment in such a manner that a closed cooling water path is established.

4. To provide a high degree of assurance that the RHR system operates satisfactorily during a LOCA, each active component is capable of being tested during the operation of the nuclear system.

The power generation design bases are as follows:

1. An additional source of water for postaccident containment flooding is provided by a crosstie between the service water system and RHR system.

2. The RHR system is designed with enough capacity that service water outlet temperature can be limited during shutdown conditions to minimize fouling.

5.4.7.2 Description

5.4.7.2.1 General

The RHR system may operate functionally in four major subsystems and four minor subsystems.

The major subsystems are:

1. Low Pressure Coolant Injection (LPCI).

2. Containment spray.

3. Suppression pool cooling.

4. Shutdown cooling.

Each of these subsystems is discussed separately. A fifth major subsystem, RHR steam condensing, has been disabled.

The minor functional subsystems are:

1. Fuel pool cooling.

2. Reactor vessel draining.

3. Suppression pool draining.

4. Reactor or containment flood with RHR service water.

There is also a test mode, to allow the RHR system to be periodically tested.

The major equipment of the RHR system consists of two heat exchangers, four main system pumps, and four RHR service water pumps. The equipment is connected by associated valves and piping, and controls and instrumentation are provided for proper system operation. A schematic diagram of the RHR system is shown in Figure 5.4-12. Cooling water for the RHR heat exchangers is supplied by the RHR Service Water System, described in Section 9.2.3.2.1. A description of the controls and instrumentation for the LPCI mode of operation is presented in Section 7.3. Chapter 6 describes how the operation of the equipment in the RHR system, in conjunction with other emergency core cooling systems, protects the core in case of a LOCA.

The main system pumps are sized on the basis of the flow required during the LPCI mode of operation, which is the mode requiring the maximum flow rate. The service water pumps are sized to cause the pressure at the cooling water outlet of the RHR system heat exchangers to be greater than the pressure of the reactor coolant at the inlet of the heat exchangers during the shutdown cooling mode of operation. This criterion ensures that in case of a leak in the tubes of the heat exchanger, the radioactive coolant does not leak into the service water.

The heat exchangers are sized on the basis of their required duty for the shutdown cooling function. A summary of the design requirement of the main system pumps and the heat exchangers is presented in Table 5.4-4.

Figure 5.4-12 indicates that RHR heat exchanger duties for the principal modes of operation are as follows:

Post-LOCA 51.3×10^6 Btu/hr

Shutdown cooling 98.5×10^6 Btu/hr

As can be seen, the most limiting duty is that associated with the normal shutdown cooling mode. The performance of this type of heat exchanger operating in this mode (water to water) is well established by operating BWR facilities.

A plot of heat exchanger capability as a function of suppression pool temperature is provided in Figure 5.4-13.

A blind flange connection is provided on the shutdown cooling piping circuit for making connection to the fuel pool system (see Figure 5.4-14) so that the RHR system heat exchangers may be used to assist in cooling the fuel pool. The spool piece may be installed or removed as desired. The RHR system is seismically qualified with or without the spool piece installed. (see Section 9.1.3).

One loop, consisting of a heat exchanger, two main system pumps in parallel, and associated piping, is located in one area of the reactor building. The other heat exchanger, pumps, and piping, forming a second loop, are located in another area of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system. The two loops of the RHR system are cross-connected by a single header (with the exception of a small line connecting the loops and the Shutdown Cooling Suction Piping in order to create a differential pressure across the LPCI Inject Check Valves), making it possible to supply either loop from the pumps in the other loop. Each loop has a separate minimum flow bypass valve and bypass valve controls.

Maintaining the core spray and RHR pump discharge lines downstream of the pump discharge check valves full of water is important, as possible water hammer and consequent damage to the piping system may result if these lines are not full of water. An RHR/core spray fill pump shown in Figure 5.4-14 is provided for this purpose. In the process of circulating water from and back to the suppression pool via the RHR pump suction line and the RHR minimum flow bypass line, this fill pump maintains water pressure in the discharge lines. Each discharge line is monitored by a low-pressure switch and alarm, which ensures the operator that the lines are full. The pressure switches which monitor the LPCI and core spray lines to ensure they are full shall be functionally tested quarterly and calibrated once per operating cycle. The possibility of defeating the Automatic Depressurization System low-pressure core cooling interlock by manner to that made for the core spray pumps. The results of this analysis are shown in Figure 5.4-15.

A minimum flow bypass line runs from the discharge of each RHR pump to the test line, which returns the flow from two RHR pumps and one core spray pump to the suppression pool. In response to NRC Bulletin 88-04, it was shown that there is no potential for dead-heading a pump, even with all three pumps discharging from their minimum flow lines into the shared line. Flow resistance calculations show that most of the pressure drop in the minimum flow lines is in the orifices in the individual minimum flow lines. These relatively large pressure drops, along with the relatively large downstream common lines, negate the effects of pump-to-pump interaction. A special test (SpTP-152) also demonstrated that dead-heading of a pump is likely not to occur, even when all three pumps on a common minimum flow line were run simultaneously.

5.4.7.4 Inspection and Testing

A design flow functional test of the RHR system main system pumps is performed for each pair of pumps during normal plant operation by taking suction from the suppression pool and discharging through the test lines back to the suppression pool. The discharge valves to the reactor recirculation loops remain closed during this test, and reactor operation is undisturbed. An operational test of these discharge valves is performed by shutting the downstream valve after it has been satisfactorily tested and then operating the discharge valve. The discharge valves to the containment spray headers are checked in a similar manner by operating the upstream and downstream valves individually. All these valves can be actuated from the control room using remote manual switches. Control system design provides automatic return from test to operating mode if LPCI initiation is required during testing.

Testing the sequencing of the LPCI mode of operation is performed after the reactor is shut down and the RHR system has been drained and flushed (if necessary to prevent injection of low purity water). Testing the operation of the valves required for the remaining modes of operation of the RHR system is performed at this time.

The frequency and scope of periodic inspection and maintenance of the main system pumps, pump motors, and heat exchangers are carried out in accordance with normal plant practices, manufacturer's recommendations and operating history.

Chapter 6 presents a discussion of the availability of engineered safeguards and frequency of testing of equipment.

5.4.8 REACTOR WATER CLEANUP SYSTEM

5.4.8.1 Design Bases

The RWCU system maintains high reactor water purity to limit chemical and corrosive action, thereby limiting fouling and deposition on heat-transfer surfaces. The RWCU system also removes corrosion products to limit impurities available for activation by neutron flux and resultant radiation from the deposition of corrosion products.

The power generation design bases are as follows:

1. Provision is made for the discharge of reactor water in order to control reactor water level during startup and shutdown.

2. Provision is made to limit the heat loss and the fluid loss from the nuclear system.

5.4.8.2 Description

The RWCU system provides continuous purification of a portion of the recirculation flow. The processed fluid is returned to the reactor via the feedwater line or to storage. Regenerative heat exchangers are provided to limit heat loss from the nuclear system. The system can be operated at any time during normal operations.

The equipment of the RWCU system is located in the reactor building and the radwaste building and consists of two pumps, regenerative and nonregenerative heat exchangers and two filter-demineralizers with supporting equipment. The entire system is connected by associated valves and piping, and controls and instrumentation are provided for proper system operation. Design data for the major pieces of equipment are presented in Table 5.4-6.

Reactor coolant is removed from the reactor coolant recirculation system, cooled in the regenerative and nonregenerative heat exchangers, filtered and demineralized, and returned to the feedwater system through the shell side of the regenerative heat exchanger. A schematic diagram of the RWCU system is shown in Figure 5.4-16.

Because the filter-demineralizer units are temperature limited (Table 5.4-6), the reactor coolant must be cooled prior to processing in the filter-demineralizer units. The regenerative heat exchanger transfers heat from the influent water to the effluent water. The effluent returns to the feedwater system. The nonregenerative heat exchanger cools the influent water further by transferring heat to the reactor building closed cooling water system. The nonregenerative heat exchanger is designed to maintain the lower temperature even when the effectiveness of the regenerative heat exchanger is reduced. The thermal effectiveness of the regenerative heat exchanger is reduced when excess water is being removed from the reactor vessel via the RWCU system. A part of the flow from the filter-demineralizer may be directed either to the main condenser or to the radwaste system and is returned to storage instead of returning to the regenerative heat exchanger.

5. The surface of the water becomes more regular as the water moves through the straight pipe and the effective heat-transfer coefficient and consequent condensation rate are reduced. As air approaches the steam-water interface, the condensation rate rapidly decreases because of the reduced partial pressure of steam relative to the total gas pressure and the inhibiting effect of the noncondensible air. The air entering the discharge line causes the pressure in the pipe to increase. This, combined with the increased elevation of the gas-water interface, starts to slow the water column rise. (The model is currently qualified only for an air atmosphere in the drywell.)

6. When the difference in pressure between the outside and the inside of the pipe is less than some minimum value, the vacuum breaker closes. The water continues to rise, compressing the gas, and eventually the rise stops.

In some cases, the vacuum breaker may not close because of its small size or because of continued condensation in the pipe. In either situation, the water oscillates up and down in the pipe for one or more cycles before the vacuum breaker closes. In some cases, the vacuum breaker may close but open again at a later time.

The analytical model that predicts the reflooding of a discharge line after a safety/relief valve closes, as described in Reference 8, includes models of gas and water flow within the discharge line, considers steam condensation at the gas-water interface and at the inside pipe wall, and allows a vacuum breaker to be placed anywhere in the line. The gas in the line can be either steam alone or a steam-air mixture. The inhibiting effect of noncondensible air on the condensation of steam at the gas-water interface is taken into account.

The model is verified with predictions of an ideal, frictionless case and of Monticello test data from ramshead and T-quencher tests. The comparisons of model predictions to the exact case are excellent, within 0.2%. For the comparisons to both the ramshead and T-quencher test data, an accurate prediction of the first rise height is obtained when the steam condensation at the gas-water interface is assumed to cease after the discharge devices are filled with water. This is physically justifiable because the flow is expected to be very turbulent when filling the discharge device, and thus the gas-water interface will be highly irregular. Once inside the discharge line, the flow will become more even.

After the first peak, the predictions show higher subsequent peaks than the data, and in the T-quencher case, lower line pressures. This difference can be explained by the vaporizing of a film of water left on the inside of the hot pipe as the water level drops after the first rise. This vaporization would increase the line pressure and lessen the heights of subsequent peaks. The overprediction of subsequent peaks is not important, however, since the first peak is the highest and therefore represents the design base.

Measured and predicted pressure differences across the vacuum breaker for the ramshead test are also in good agreement, as are the final air masses in the discharge line for the T-quencher test.

As part of the Mark I containment modification program, a low-low set (LLS) function has been added to the safety/relief valve system. The LLS function provides automatic relief mode setpoints on the two non-ADS safety/relief valves. The LLS function lowers the opening and closing setpoints after any safety/relief valve has opened at its normal steam pilot setpoint when a concurrent high reactor vessel steam dome pressure scram signal is present. The purpose of the LLS is to mitigate the induced high frequency loads on the containment and thrust loads on the safety/relief valve discharge lines by increasing the time between safety/relief valve actuations. The LLS function increases the amount of reactor depressurization during a safety/relief valve blowdown because the lowered LLS setpoints keep the two LLS safety/relief valves open for a longer time. In this way, the frequency and magnitude of the containment blowdown duty cycle is substantially reduced. The LLS logic results from the evaluation of Mark I safety/relief valve loads performed by General Electric and documented in General Electric Report NEDC-22204.[9] Plant specific analysis of LLS function for the DAEC is contained in General Electric Report NEDE-30021-P.[10] The safety/relief valve setpoints for the LLS function are contained in Table 5.2-1. The LLS logic is discussed in Section 7.6.5.

Main steam safety/relief valve open/closed indication is provided in the control room by three pressure switches located on each main steam safety/relief valve discharge piping. The three pressure switches are arranged in a two-out-of-three logic to provide control room indication of an open safety/relief valve as well as provide an input to the low-low-set logic. Backup main steam safety/relief valve open/close indication is provided by a temperature element installed in a thermowell in the safety/relief valve discharge piping several feet from the valve body. The temperature elements are connected to dual pen recorders in the main control room to provide a means of detecting relief valve leakage during plant operation.

The safety/relief valves are nitrogen operated. The solenoids controlling the nitrogen supply are powered from the 120-V instrument ac bus. On loss of power from one bus, the load can be manually transferred to the alternate essential bus. On the receipt of a containment isolation signal, the nitrogen supply isolation valves close and the basic valve logic does not permit reopening until the isolation signal is cleared. To defeat the isolation logic and provide safety-grade power to the isolation valves in order to allow opening, isolation override circuitry and separate control switches for the isolation valves have been provided.

5.4.13.3 Safety Evaluation

The ASME Code requires overpressure protection for each vessel designed to meet Code Section III. The code permits a peak allowable pressure of 110% of vessel design pressure (1375 psig for a 1250-psig vessel). The code specifications for safety valves additionally require that the lowest safety valve setpoint be at or below vessel design pressure (1250 psig) and the highest safety valve setpoint be at or below 105% of vessel design pressure (1313 psig). The safety/relief valves are set to open by self-actuation (overpressure safety function) in the range from 1110 to 1140 psig, and the safety valves are set to operate at 1240 psig. These settings satisfy the ASME Code specifications for the setpoints of the safety valves.

There are two major pressure transients, the closure of all main steam line isolation valves and a turbine trip with a coincident closure of the turbine steam bypass system valves, that represent the most severe abnormal operational transients resulting in a nuclear system pressure rise.

For the DAEC plant, the transient produced by the closure of all main steam line isolation valves represents the most severe abnormal operational transient resulting in a nuclear system pressure rise when direct scrams are ignored. The required safety valve capacity is determined by analyzing the pressure rise from such a transient. The plant is assumed to be operating at the turbine-generator design conditions at a maximum vessel dome pressure of 1025 psig. The analysis hypothetically assumes the failure of the direct isolation valve position scram. The reactor is shut down by the backup, indirect, high-neutron-flux scram. For the analysis, the self-actuated setpoints (safety function) of the safety/relief valves are assumed to be in the range from 1121 to 1151 psig, and the safety valves are assumed to operate at 1252 psig (setpoints + 1%)*. The safety/relief and safety valves open to limit the nuclear system pressure rise to 1275 psig. The analysis indicates that the design valve capacities (see Table 5.2-1) are capable of maintaining adequate margin (100 psi) below the peak ASME Code allowable pressure in the nuclear system (1375 psig). The safety valve capacity in conjunction with safety/relief valve capacity limits the peak nuclear system pressure at the bottom of the vessel. The resulting margin to the ASME Code limit ensures adequate protection against excessive overpressurization of the nuclear system process barrier even for this hypothetical reactor isolation event (Reference 11). Figure 5.4-18 graphically shows typical results produced by this simulated analysis.

The sequence of events assumed in the analysis was investigated to show conformance to code requirements and to evaluate the pressure relief system exclusively. System malfunctions that pose threats to the radioactive material containment barriers are presented in Chapter 15.

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* The MSIV closure event was analyzed using the NRC staff-approved model ODYN with 3% setpoint tolerance. This analysis shows that the maximum vessel pressure (bottom head) is 1282 psig for MSIV closure with flux scram. This value is 93 psig less than the vessel design pressure of 1375 psig (References 19 and 20).

The automatic depressurization capability of the nuclear pressure relief system is evaluated in Sections 6.3 and 7.3. The relief valve discharge piping is designed, installed, and tested in accordance with ANSI B31.7.0 plus additional requirements as outlined in Section 3.2.2.

The pressure relief valves used on BWRs have a long history of successful operation on conventional plants. Such operation for the BWR is well within the state of the art and with a very moderate environment.

At this point, a credible common failure mode in the "failure to open" direction has not been identified. The good operational history through years of application of these pressure relief valves continues to be the most convincing evidence of integrity.

Although no common failure mode has been identified that would prevent the pressure relief valves from opening during plant transient events, such a case is presented in the Enrico Fermi Unit 2 FSAR. It was shown that for the plant safety/relief and safety valve arrangement at Fermi Unit 2 the ASME Code limit for the reactor coolant pressure boundary would not be exceeded.

The DAEC safety/relief and safety valve arrangement and sizing analysis is discussed in Section 5.2.2, as confirmed in the DAEC Overpressure Protection Report prepared in accordance with the requirements of N910.3 of ASME Code, Section III.

Typical safety/relief valve characteristics are shown in Figure 5.2-1. Typical safety valve characteristics are shown in Figure 5.2-2.

The safety/relief valves are designed to relieve energy from the nuclear system rapidly enough to prevent the operation of the safety valves during pressure transients that are reasonably expected to occur during the lifetime of the plant. The relief valve capacity is determined by analyzing the pressure rise accompanying the transients produced by a turbine trip without bypass and a load rejection without bypass initiated from turbine-generator design conditions with a maximum vessel dome pressure of 1025 psig.

The analysis that forms the basis for the evaluation of the pressure relief function of the nuclear pressure relief system appears in Chapter 15. The setpoints of the safety/relief valves are assumed to operate in the range from 1110 to 1140 psig and the reactor is shut down by the normal trip scram (turbine stop valve closure scram).

5.4.13.4 <u>Inspection and Testing</u>

The safety and safety/relief valves are tested in accordance with the manufacturer's quality control procedures to detect defects and prove operability before installation. The following tests are witnessed by a representative of the purchaser:

11. General Electric Company, Safety Relief Valve Simmer Margin Analysis for the Duane Arnold Energy Center, NEDO-30606, May 1984.

12. Letter from D. B. Waters, BWR Owners Group, to R. H. Vollmer, NRC, Subject: BWR Owners Group SRV Test Program, dated September 17, 1980.

13. General Electric Company, BWR Owners Group SRV Test Program, NEDE-24988-P, October 1981.

14. Letter from L. D. Root, Iowa Electric, to H. R. Denton, NRC, Subject: DAEC NUREG-0737, Item II.D.1, Request for Additional Information, dated December 14, 1982.

15. Letter from W. C. Rothert, Iowa Electric, to A. Bert Davis, NRC, Subject: Final Report Pursuant to IE Bulletin 85-03, dated January 15, 1988 (NG-88-0001).

16. NRC Inspection Report 50-331/95-011, dated January 25, 1996.

17. General Electric Company, Duane Arnold Energy Center SAFER/GESTR-LOCA Loss of Coolant Accident Analysis, NEDO-31310, 1986 and Supplement 1, 1993.

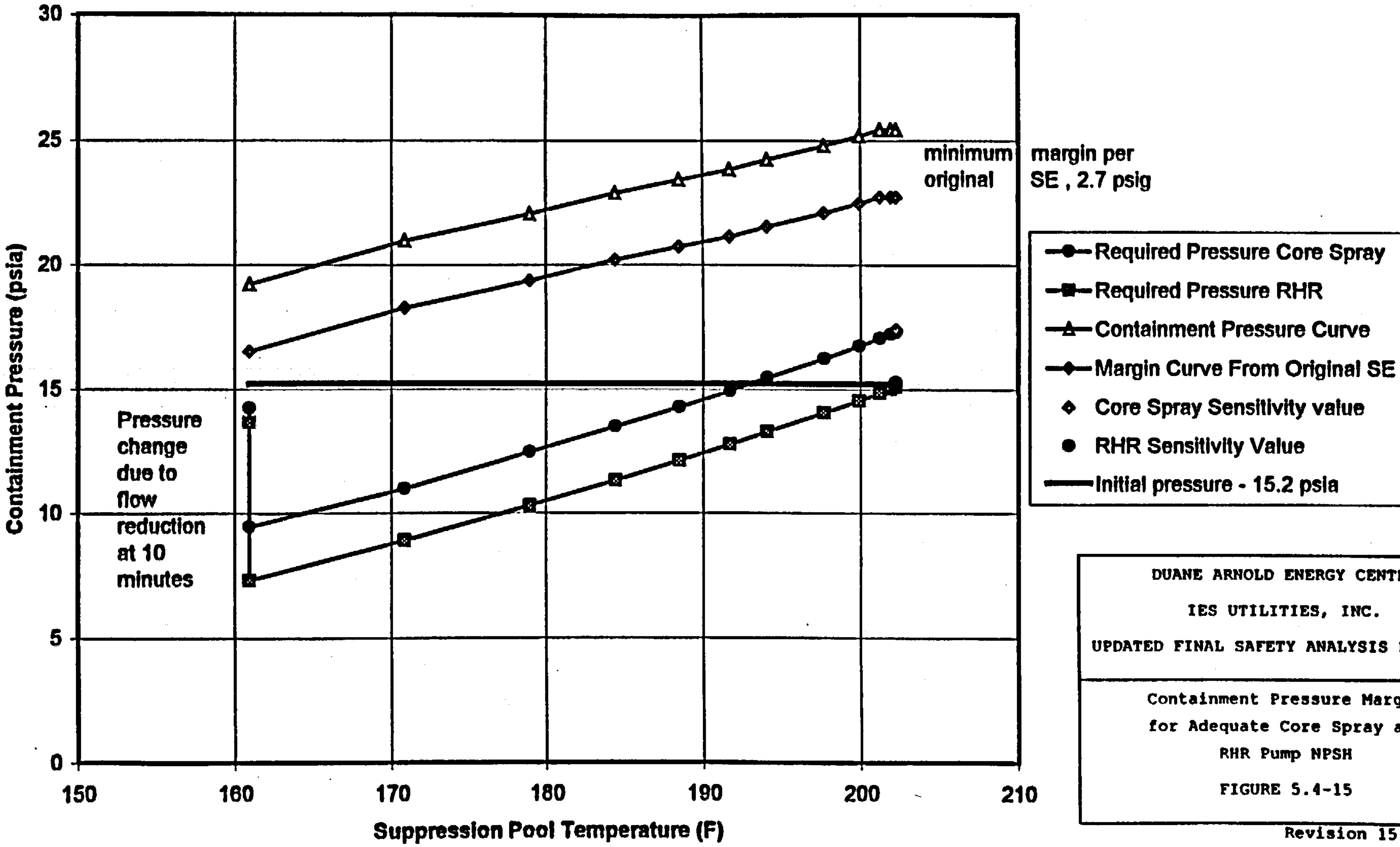
18. Letter from C.M. Craig, NRC, to E. Protsch, IES, dated November 19, 1999, Alternative to the ASME B&PV Code Repair Requirements for the Recirculation Line for the DAEC.

19. NRC Safety Evaluation Related to Amendment 228, Safety Relief Valve Setpoint Tolerance, dated September 22, 1999.

20. Technical Specification Change Request (TSCR-009), Revision to Safety Relief Valve Setpoint Tolerance (±3%), NG-99-0598, dated April 30, 1999.

21. MDL# LI2-003, DAEC Supplement to NEDC-32915P, Duane Arnold Energy Center GE12 Fuel Upgrade Project, Rev. 0, March 2000.

Containment Pressure Margin for Adequate Core Spray and RHR Pump NPSH



DUANE ARNOLD ENERGY CENTER IES UTILITIES, INC. UPDATED FINAL SAFETY ANALYSIS REPORT
Containment Pressure Margin for Adequate Core Spray and RHR Pump NPSH FIGURE 5.4-15

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The studs were checked for average stress on the cross section and maximum stress at the periphery (resulting from direct tension plus bending but neglecting stress concentrations). It was found that the highest stud stresses occur at 270 min into the startup transient when the average stud temperature is 333°F. The average stud stress at that time is 45,445 psi, and the maximum stress is 92,090 psi. According to Paragraph N-416 of Section III of the ASME Code, the allowable average stress is 2 S_m at temperature, and the allowable maximum stress range is 2.7 S_m at temperature if the higher of the two fatigue curves in Figure N-416 is used. Based on the above code rules, the allowable average stress in this case is 79,480 psi, and the allowable maximum stress range is 107,298 psi.

The maintenance of a tight head closure seal was checked in accordance with the GE specification.

The investigation of eight different loading conditions, including the design hydrotest, showed that a tight seal will be maintained in all cases.

The maximum gasket relief occurs at 250.6 min into the shutdown transient and amounts to 0.00037 in. This compares very favorably with the guaranteed gasket springback of 0.012 in.

The bearing stress in the flange base metal under the flange contact surface is 29,306 psi during the rapid cooldown transient when the average flange temperature is 404°F. The allowable bearing stress at this temperature is 44,450 psi.

The maximum bearing stress in the base metal under the spherical washers occurs during the startup transient. The flange temperature at that point is 412°F, and the bearing stress is 37,556 psi. The allowable bearing stress at 412°F is 44,345 psi.

The fatigue analysis of the main closure flanges and studs was performed per the GE specification and Article 4 of Section III, ASME Code, 1968 Edition.

The stud fatigue analysis was done using the method of Paragraph N-415.2 of ASME Code, Section III, 1965 Edition, and the higher of the two fatigue design curves in Figure N-416. This could be done because the requirements of Paragraph N-416.2(b) were satisfied. The stud cyclic loading was obtained from GE Specification Drawing 729E762, with additional cycles being added because of boltup-unbolt operations. The cumulative usage factor for the studs was found to be 0.882, which is within the allowable value of 1.

It was found that a fatigue analysis for the flanges was not required because all the requirements of Paragraph N-415.1 could be satisfied.

5A.5.3 SUMMARY OF RESULTS - SUPPORT SKIRT (See Figure 5A.5-1)

The design of the skirt to bottom head junction was found to be adequate in accordance with Article 4, Section III of the ASME Code.

The maximum general primary membrane stress intensity P_m is 18,320 psi at points 21 and 22. This is less than the allowable of 26,700 psi, which is the value of S_m for SA-533. In the skirt section where the carbon steel is of the SA-516 type, the P_m stress intensity is 6649 psi. This is below the SA-516 allowable of 22,500 psi.

The maximum range of primary plus secondary stress intensity in the shell and skirt made of SA-533 steel is 57,250 psi, under the 3 S_m allowable of 80,100 psi. The maximum range occurs at point 5 between zero case and maximum seismic plus jet at 180°F. For the SA-516 carbon steel section of the skirt, the maximum range of primary plus secondary stress intensity is 51,370 psi under the 3 S_m allowable of 67,500 psi. The maximum range occurs at point 3 between the zero and maximum seismic plus jet at 180°F case.

The fatigue usage factor has been calculated to be 0.0337; this is below the allowable value of 1.

5A.5.4 SUMMARY OF RESULTS - SHROUD SUPPORT (See Figure 5A.5-1)

The maximum primary general membrane stress intensity for the low-alloy steel vessel wall is 22,330 psi for points 11 and 12. This compares with the 26,700 psi allowable for the SA-533, Grade B, Class 1 material at 575°F. For the SB-168 Inconel material, the highest primary general membrane stress is 21,344 psi at points 31 and 32. The code allowable is 23,300 psi at 575°F.

The maximum local membrane plus primary bending stress intensity for the Inconel shroud is 25,785 psi at point 33 for Θ180°. This is less than the code allowable of 1.5 S_m 34,950 psi.

The maximum range of primary plus secondary stress intensity for the low-alloy vessel shell is 89,764 psi (at point 21) for the improper start and loss of feedwater transients. The code allowable of 1.5 S_m is 80,100 psi. At the junction to the vessel wall and the shroud support cylinder, the range of stress intensity for the Inconel baffle plate is 73,160 psi (at point 16) and 86,354 (at point 19), respectively, for the loss of feedwater and improper startup transients; the 3 S_m allowable is 69,900 psi.

An elastic-plastic fatigue analysis has been performed for the shroud support configuration. The maximum usage factor is 0.773 (at point 21) for low-alloy portion and 0.320 (at point 42) for the Inconel portion of the shroud support. These are less than the code allowable of 1.

5A.5.5 SUMMARY OF RESULTS - FEEDWATER NOZZLE

Area replacement requirements of ASME Code, Section III have been satisfied. The maximum primary local stress intensity is 24,700 psi, where the allowable is 26,550 psi. The maximum range of primary plus secondary stress intensity was found to be 46,029 psi where the 3 S_m allowable is 53,100 psi.

The maximum value of the fatigue usage factor has conservatively been calculated to be 0.778, which is less than the code allowable of 1.

5A.5.6 SUMMARY OF RESULTS - CONTROL ROD DRIVE PENETRATIONS (See Figure 5A.5-2)

Based on the stress analysis and the fatigue considerations, the CRD penetrations meet the requirements of Article 4 of Section III of the ASME Code.

The maximum primary general membrane stress intensity in the stainless steel housing (9533 psi) occurs at sections 11 and 12 on the outermost penetration, against an allowable of S_m (15,800 psi). For the Inconel stub tube, the maximum value (7966 psi) is at sections 19 and 20 on the outermost penetration, against an allowable of S_m (20,000 psi).

The maximum primary local membrane stress intensity in the stainless steel housing (11,213 psi) occurs at sections 9 and 10 on the center penetration, against an allowable of 1.5 S_m (23,700 psi). For the Inconel stub tube, the maximum value (24,749 psi) is at sections 23 and 24 on the outermost penetration, against an allowable of 1.5 S_m (30,000 psi).

The maximum primary plus secondary stress intensity in the stainless steel housing (36,278 psi) occurs at point 7 on the center penetration, against an allowable of 3 S_m (48,096 psi). For the Inconel stub tube, the maximum value (56,196 psi) is at point 25 on the outermost penetration, against an allowable of 3 S_m (60,000 psi).

A fatigue exemption in accordance with the rules of Paragraph N-415.1 of ASME Code, Section III is also verified.

5A.5.7 SUMMARY OF RESULTS - CONTROL ROD DRIVE NOZZLE

Calculations are made to ensure compliance with area replacement requirements of Section III of the ASME Code. Stresses in the shell at nozzle attachment have been calculated and the maximum found to be 905 psi. The nozzle has been checked for external loading and pressure, the maximum stress intensity being 14,754 psi versus an allowable of 1.5 S_m of 19,725 psi for the stainless steel at design temperature.

The maximum range of primary plus secondary stresses is found to be 32,257 psi for the stainless steel material (with allowable of 39,550 psi) and 28,774 psi for the low-alloy steel material (with allowable of 80,000 psi).

Originally, the water discharged from a control rod drive (CRD) during normal rod positioning flowed back to the reactor vessel through the CRD return line. In 1983, a blind (spectacle) flange was installed on the CRD return line to eliminate the potential for thermal fatigue of the CRD return line nozzle at the reactor vessel.

5A.5.8 SUMMARY OF RESULTS - CORE SPRAY NOZZLE

Calculations are made to ensure compliance with area replacement requirements of Section III. Stresses in the shell at nozzle attachment have been calculated and the maximum found to be 5894 psi. The nozzle has been checked for external loading and pressure, the maximum stress intensity being 22,085 psi versus an allowable stress of 34,950 psi. The maximum range of primary plus secondary stresses is found to be 37,569 psi, well within the 3 S_m allowable of 70,000 psi.

The above value of stresses do not include the stresses due to thermal sleeve reactions. The sleeve reaction stresses have been calculated. These results indicate that the maximum additional stress is about 3000 psi. With the margin indicated above, this additional 3000 psi increase will not be critical.

The highest amplitude of peak stress is found to occur on the inside face of the cladding and to be 138,500 psi. This would result in code allowable cycles of about 1100. The total number of cycles affecting the nozzle is the sum of startup-shutdown, design hydrotest, and emergency core flooding cycles, which total 260. This, therefore, indicates a usage factor of about 0.735.

5A.5.9 SUMMARY OF RESULTS - RECIRCULATION INLET NOZZLE (See Figure 5A.5-3)

The recirculation inlet nozzle design was found adequate in accordance with the requirements of the ASME Code, Section III and of the GE specification.

The requirements for the area of compensation were satisfied for the nozzle opening, and it had also been shown that the analysis for cyclic operation was not required for the entire nozzle as well as nozzle sleeve. Thus, in the immediate vicinity of the nozzle opening, the general primary membrane stress intensity, P_m, the local primary membrane stress intensity, P_L, primary membrane plus primary bending stress intensity, $P_L + P_b$, and primary plus secondary stress intensity, $P_L + P_b + Q$, are all within the allowable stress intensity limits.

In the nozzle beyond the immediate vicinity of the opening, the maximum primary membrane stress intensity, P_m, is 7628 psi in the cross-section 7-8 comparing with the allowable stress intensity of S_m = 26,700 psi. The maximum primary local membrane stress intensity, P_L, is 13,142 psi in the cross-section 7-8 comparing with the allowable stress intensity of 1.5 S_m = 40,050 psi. The maximum range of the primary plus secondary stress intensity range, $P_L + P_b + Q$, is 23,483 psi at point 7 comparing with the allowable limit of 3 S_m = 80,100 psi.

In the nozzle safe end and sleeve, the maximum primary membrane stress intensity is 13,473 psi in the cross-section 23-24 comparing with the allowable S_m = 23,300 psi. The maximum primary local membrane stress intensity is 21,167 psi in the cross-section 23-24 comparing with the allowable 1.5 S_m = 34,950 psi. The maximum range of the primary plus secondary stress intensity range is 68,626 psi at point 13, between zero stress state and cooldown transient 1, comparing with the allowable limit of 3 S_m = 69,900 psi.

In accordance with the plastic fatigue analysis, the maximum cumulative usage factor in the component beyond the intermediate vicinity of the opening is 0.438, which is less than the allowable of 1.

5A.5.10 SUMMARY OF RESULTS - RECIRCULATION OUTLET NOZZLE (See Figure 5A.5-4)

The recirculation outlet nozzle design was found adequate in accordance with the requirements of the ASME Code, Section III and of the GE specification.

The requirements for the area of compensation were satisfied for the nozzle opening, and it had also been shown that the analysis for cyclic operation was not required for the entire nozzle as well as nozzle safe end. Thus, in the immediate vicinity of the nozzle opening, the general primary membrane stress intensity , P_m, the local primary membrane stress intensity, P_L, primary membrane plus primary bending stress intensity, $P_L + P_b$, and primary plus secondary stress intensity, $P_L + P_b + Q$, are all within the allowable stress intensity limits.

In the nozzle beyond the immediate vicinity of the opening, the maximum primary membrane stress intensity, P_m, is 9687 psi in the cross-section 9-10 comparing with the allowable stress intensity of S_m = 26,700 psi. The maximum local primary membrane stress intensity, P_L, is 11,809 psi in the cross-section 9-10 comparing with the allowable stress intensity of 1.5 S_m = 40,050 psi. The maximum range of the primary plus secondary stress intensity, $P_L + P_b + Q$, is 34,848 psi at point 9 comparing with the allowable limit of 3 S_m = 80,100 psi.

In the nozzle safe end, the maximum primary membrane stress intensity is 12,205 psi in the cross-section 1-2 comparing with the allowable S_m = 13,150 psi. The maximum local primary membrane stress intensity is 14,961 psi in the cross-section 1-2 comparing with the allowable 1.5 S_m = 19,725 psi. The maximum range of the primary plus secondary stress intensity is 21,195 psi at point 4 comparing with the allowable limit of 3 S_m 40,350 psi.

In accordance with the plastic fatigue analysis, the maximum cumulative usage factor in the component beyond the immediate vicinity of the opening is 0.975, which is less than the allowable of 1.

5A.5.11 SUMMARY OF RESULTS - STEAM OUTLET NOZZLE (See Figure 5A.5-5)

The steam outlet nozzle design was found adequate in accordance with the requirements of the ASME Code, Section III and of the GE specification.

The requirements for the area of compensation were satisfied for the nozzle opening, and it had also been shown that the analysis for cyclic operation was not required for the entire nozzle as well as nozzle safe end. Thus, in the immediate vicinity of the nozzle opening, the general primary membrane stress intensity, P_m, the local primary membrane stress intensity, P_L, primary membrane plus primary bending stress intensity, $P_L + P_b$, and primary plus secondary stress intensity, $P_L + P_b + Q$, are all within the allowable stress intensity limits.

In the nozzle beyond the immediate vicinity of the opening, the maximum primary membrane stress intensity , P_m, is 8820 psi in the cross-section 5-6 comparing with the allowable stress intensity of $S_m = 26{,}700$ psi. The maximum local primary membrane stress intensity, P_L, is 22,004 psi in the cross-section 5-6 comparing with the allowable stress intensity of 1.5 S_m = 40,050 psi. The maximum range of the primary plus secondary stress intensity is 28,088 psi at point 3 comparing with the allowable limit of 3 S_m = 80,100 psi.

In the nozzle safe end, the maximum primary membrane stress intensity is 13,690 psi in the cross-section 11-12 comparing with the allowable S_m = 18,100 psi. The maximum local primary membrane stress intensity is 19,537 psi in the cross-section 11-12 comparing with the allowable 1.5 S_m = 27,150 psi. The maximum range of the primary plus secondary stress intensity is 25,490 psi at point 12 comparing with the allowable limit of 3 S_m 54,300 psi.

Fatigue requirements have been satisfied by means of Paragraph N415.1 of the ASME Code.

5A.5.12 SUMMARY OF RESULTS - MISCELLANEOUS NOZZLES (See Figure 5A.5-6)

The design of the miscellaneous nozzles was found to be adequate in accordance with Article 4, Section III of the ASME Code.

The area replacement calculations and nozzle load calculations for nozzles N-10, N-6, N-7, N-11, N-12, N-16, N-8, and N-15 are performed and presented in the certified stress report. Designation for nozzles is taken from GE Drawing 921D217, Sheet 1 (N-6, 6"Ø; N-7; N-8, 4"Ø; N-10; N-11; N-12; N-15; N-16,~2"Ø). The maximum stress intensity due to specified nozzle loads for the miscellaneous nozzles is 14,709 psi in the stainless steel safe ends for the 2 in. in diameter instrumentation nozzles. This is less than the code allowable of 1.5 S_m = 19,725 for the SA-182, Type 304L material.

As noted in the introduction to this section, a detailed analysis was performed for nozzle N-10 only. N-10 is the nozzle for liquid control line and core differential pressure line. The maximum general membrane stress intensity for N-10 is P_m = 6403 psi at points 1 and 2. This is less than the allowable of 13,150 psi for the SA-182, Type 304L material.

The maximum range of primary plus secondary stress intensity in the shell is 43,478 psi, under the 3.S_m allowable of 80,100 psi. The maximum range occurs at point 13 for the steady state and liquid control at 90-min transients.

The area replacement calculations for nozzle N-10 are performed, and code requirements are ensured. In accordance with Paragraph N-451(a) of Section III, the area replacement calculations are sufficient to meet the requirements of Paragraphs N-414.1, General Primary Membrane Stress Intensity; N-414.2, Local Membrane Stress Intensity; N-414.3, Primary Membrane Plus Primary Bending Stress Intensity; and N-414.4, Primary Plus Secondary Stress Intensity within the reinforcing area boundaries. The satisfaction of the requirements of Paragraph N-414.4 is contingent on meeting the requirements of Paragraph N-415.1, Vessels Not Requiring Analysis for Cyclic Operation.

For areas beyond the limits of reinforcing, a stress analysis has been made with the KALNINS program,[1] which is used to analyze elastic shell of revolution. The maximum primary bending stress intensity due to specified loads and pressure in the stainless steel safe end is 14,709 psi. This is less than the allowable stress intensity for the SA-182, Type 304L material 1.5 S_m 19,725 psi at the design temperature of 575°F.

The stresses in the vessel wall at the junction with the nozzle have been calculated using the methods of W.R.C. Bulletin 107[2] and CB&I Computer Code 6-20.[3] The maximum stress intensity thus compared is 512 psi for nozzle N-10. Fatigue requirements have been satisfied by means of Paragraph N415.1 of the ASME Code.

5A.5.13 SUMMARY OF RESULTS - REFUELING BELLOWS

The refueling bellows support design is found adequate in accordance with the requirements of the ASME Code, Section III and the GE specification.

The maximum general primary membrane stress intensity is 3722 psi against the allowable S_m of 19,150 psi. The maximum range of the primary plus secondary stress intensity is 39,872 psi comparing with the allowable 3 S_m of 69,300 psi. The maximum bellows support rotation under loadings is 0.241 degrees comparing with allowable limit of 0.3 degrees. The structure is also found safe against structural instability.

The maximum possible cumulative usage factor of the structure is 0.580, which is well below the allowable limit of 1.

REFERENCES FOR SECTION 5A.5

1. A. Kalnins, "Analysis of Shells of Revolution Subjected to Symmetrical and Nonsymmetrical Loads," Journal of Applied Mechanics, Vol. 31, 1964, pp. 467-476, Chicago Bridge & Iron Computer Program 7-81.

2. K. R. Wichman, A. G. Hooper, and J. L. Mershon, "Local Stresses in Spherical and Cylindrical Shells due to External Loadings," Welding Research Council Bulletin 107, 1965.

3. Chicago Bridge & Iron Computer Program 6-20. This program is named "Cookbook" and is based on the data presented in Reference 2.

4. CAL-M97-015, Revision 1, Reassessment of Duane Arnold RPV Fatigue Usage.

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Technical Requirements Manual
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T 1.0 USE AND APPLICATION

The Technical Requirements Manual (TRM) contains TRM Limiting Conditions for Operation (TLCOs) and operational conveniences, such as lists, cross references, acceptance criteria, and drawings.

The TLCOs are contained in Section 3.0 and include operational requirements, TRM Surveillance Requirements (TSRs), and Required Actions for inoperable equipment. Instructions for the use and application of TLCOs are included in Section 1.0.

Operational conveniences provide a ready reference to lists and other helpful tools described in plant procedures and programs.

Other plant documents, such as the Core Operating Limits Report, are not considered to be part of the TRM, but are included in the TRM as Appendices, and either contain their own rules of usage or are governed by other plant documents.

The TRM is a licensing document and changes to this manual are governed by Administrative Control Procedure ACP-102.19, Preparation, Revision, and Processing of Technical Requirements Manual Change Requests. While the TLCOs are to be treated like Technical Specifications from an implementation viewpoint, the TLCOs are essentially procedures. Therefore, unless specifically stated in the TLCO, entry into or violation of a TRM Required Action, or violation of a TRM Surveillance Requirement is not specifically reportable per 10 CFR 50.72 or 10 CFR 50.73. Likewise, power reductions and/or plant shutdowns required to comply with TRM ACTIONS are not specifically reportable per 10 CFR 50.72(b)(1)(i)(A) or 10 CFR 50.73(a)(2)(i)(A)or (a)(2)(i)(B). Failure to comply with TLCO requirements shall be treated as a failure to follow procedure and entered into the Action Request (AR) system, as appropriate.

(continued)

T 1.1 Definitions

---------------------------------NOTE---------------------------------
The defined terms of this section appear in capitalized type and are applicable throughout these TLCOs and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a TRM Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, display, and trip functions, and shall include the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with Resistance Temperature Detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps so that the entire channel is calibrated.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.
CHANNEL FUNCTIONAL TEST	A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY, including required alarm, interlock, display, and trip functions, and channel failure trips. The CHANNEL FUNCTIONAL TEST may be performed by means of any series of sequential,

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6.2.1.6.2.4 Containment Hard Vent Modification

The containment hard vent system is an 8.0 inch line that connects the torus vent line to the offgas system downstream of the steam packing exhauster. An 8" outboard primary containment isolation valve, CV-4357, is included in this line. The hard vent system will facilitate the venting of primary containment when the primary containment pressure limit (PCPL) is threatened by directly venting to the offgas stack bypassing the standby gas treatment system.

An 8" rupture disk, PSE-4357, installed in the NE corner room in-line with the hard vent piping and downstream of the outboard primary containment isolation valve, CV-4357, will serve two specific purposes with respect to the hard vent design: (1) The rupture disk will prevent the opening of a vent path from the primary containment directly to the environment unless the PCPL is threatened and (2) during a design basis accident, the rupture disk will provide a zero-leakage barrier between the primary containment and the environment to prevent any small amount of leakage past CV-4300, CV-4309 and CV-4357 from bypassing the secondary containment.

The basis for the containment hard vent system is NRC Generic Letter 89-16 which requested that each licensee with a Mark I containment install a hardened wetwell vent under the provisions of 10 CFR 50.59. The DAEC voluntarily agreed to the installation of such a vent by the transmittal of letter NG-89-2886. The purpose of the modification is to protect and preserve containment integrity that may be threatened due to overpressurization during special events or severe accidents that are beyond the postulated events discussed in Chapter 15. Relief and control of containment pressure by the use of the hard vent is preferable to the uncontrolled release of radioactivity to the environment that could result following the rupture of the primary containment due to overpressurization.

The DAEC Emergency Operating Procedures will control the use of the containment hard vent system in response to primary containment threatening events.

6.2.1.6.2.5 Containment Debris Generation Post LOCA

In accordance with NRC Generic Letter 85-22 "Potential Loss of Post LOCA Recirculation Capability Due to Insulation Debris Blockage" the DAEC evaluated the quantity of destroyed insulation in the drywell and the transport of the material to the torus and ultimately to the Core Spray and RHR pump suction strainers. This analysis determined that the quantities of material and the rate of transport resulted in no adverse impact on the NPSH requirements for the RHR and core spray pumps.

NRC Bulletin 96-03 was prepared in response to a strainer blockage issue following an inadvertent safety valve release into the containment at a Swedish facility. An evaluation of the assumptions used during the previous work resulted in the preparation of NEDO-32686 "Utility Resolution Guidelines for ECCS Suction Strainer Blockage". The DAEC used the guidance of NEDO-32686 to evaluate the quantity of debris that would be present on the ECCS strainers following a large break LOCA. In addition, NPSH calculations have been performed to verify that adequate minimum NPSH is maintained for core spray and LPCI injection modes of RHR.

6.2.2 PRIMARY CONTAINMENT HEAT REMOVAL SYSTEMS

The following systems, some of which are parts of larger systems, are available under various conditions for the removal of heat from the primary containment:

1. Suppression pool cooling system.

2. Containment spray system.

3. Primary containment cooling system.

Each of these systems is discussed in the following sections.

6.2.2.1 Design Basis

The suppression pool cooling system and containment spray system are the containment cooling subsystems of the RHR system. The design bases for the RHR system including the containment cooling subsystems are contained in Section 5.4.7.1. The primary containment cooling system design parameters are given in Table 6.2-18.

6.2.2.2 System Description

6.2.2.2.1 Suppression Pool Cooling Subsystem

The suppression pool cooling subsystem is an integral part of the RHR system and is placed in operation to limit the temperature of the water in the suppression pool so that, immediately after the design-basis LOCA has occurred, pool temperature does not exceed 170°F. The selection of 170°F is based on tests that showed that at this temperature complete condensation of blowdown steam from the design-basis LOCA can be expected. Although complete condensation is expected at higher suppression pool temperatures, there are no test data available for any higher temperature.

This 170°F temperature in conjunction with the Technical Specification suppression pool temperature of 120°F and minimum suppression pool volume dictates a permissible 50°F temperature rise for the LOCA energy addition. The energy transferred to the pool during the blowdown includes the following:

1. All the primary system steam and liquid mass minus the steam stored in the drywell at the end of blowdown.

2. All of the stored heat in the fuel and reactor internals plus the integrated decay heat during the blowdown duration.

3. Approximately 15% of the stored heat in the RPV body not including the head.

The energy of the steam in the drywell and the residual vessel energy is added to the pool following the blowdown.

With a minimum suppression pool water volume of approximately 58,900 ft^3, the calculated design-basis LOCA temperature rise during blowdown is 50°F (see Table 6.2-1). The Technical Specifications limit the maximum suppression pool water temperature during normal operations to 95°F and require reactor shutdown if the pool water temperature exceeds 110°F. Should the temperature of the pool exceed 120°F, the DAEC Technical Specifications require depressurizing the reactor to less than 200 psig within 12 hours. An external visual inspection of the suppression pool will be conducted if the pool temperature reaches 200°F or more with indication of relief valve operation.

With the RHR system in the suppression pool cooling mode of operation, the RHR main system pumps are aligned to pump water from the suppression pool through the RHR system heat exchangers where cooling takes place by transferring heat to the service water. The flow returns to the suppression pool via the full-flow test line (see Figure 5.4-14, Sheet 1).

6.2.2.2.2 Containment Spray Subsystem

The containment cooling subsystem provides containment spray capability as an alternative method of reducing containment pressure following a LOCA. The water pumped through the RHR system heat exchangers may be diverted to two spray headers in the drywell and one above the suppression pool. The spray headers in the drywell condense any steam that may exist in the drywell thereby lowering containment pressure. The spray collects in the bottom of the drywell until the water level rises to the level of the pressure suppression vent lines where it overflows and drains back to the suppression pool. Approximately 5% of this flow may be directed to the suppression chamber spray ring to cool any noncondensible gases collected in the free volume above the suppression pool. Containment spray operation is not required from the standpoint of reactor safety. If spray operations are considered by the operator to be desirable, the procedures set forth in Sections 6.2.2.2.2.2 and 6.2.2.2.2.3 can be utilized.

The spray headers of the RHR system cannot be placed in operation unless the core-cooling requirements of the LPCI subsystem have been satisfied. These requirements may be bypassed by the operator using a key-lock switch in the control room (see Section 7.4).

6.2.2.2.2.1 Design Standards

Figure 3.2-1 shows that the containment spray subsystem piping is designed to ANSI B31.7, Class II. Table 3.2-3 shows that the valves in the containment spray subsystem are Type B, and the applicable codes for Type B valves are shown in Table 3.2-4.

6.2.2.2.2.2 Design Basis Procedure for Use of Containment Spray Following a Loss-of-Coolant Accident

Although the instructions for the use of containment spray are contained in the Emergency Operating Procedures (EOPs) and in the Residual Heat Removal System Operating Instructions, the procedure used for the original design basis scenario for containment spray is provided.

Assumptions

1. High drywell pressure has tripped (containment pressure greater than 2 psig). Reactor vessel water level may or may not have tripped at the low-low-low level depending on break size.

2. All RHR pumps are running. All RHR service water system pumps are stopped by automatic action on the initiation of the RHR system.

3. If reactor vessel pressure is greater than 450 psig, LPCI and core spray injection valves remain closed and RHR and core spray pumps are delivering flow through minimum flow bypass to torus. When reactor pressure drops to 450 psig, the RHR and core spray injection valves open. Water starts injecting into the core at a reactor pressure of about 240 psig when pump head overcomes reactor vessel pressure.

4. Offsite power is available, or it is assumed that if offsite power is not available only one diesel-generator is operating.

5. At least one core spray system is delivering water to the reactor core or through minimum flow bypass to the torus (see 3 above).

6. High-pressure coolant injection and reactor core isolation cooling may or may not be in operation.

Operating Procedure

1. Verify that reactor vessel water level is near the two-thirds core level trip point.

   Note: If LPCI trip has occurred and this condition does not exist, interlocks prevent opening the containment spray valves.

2. Verify that at least one core spray pump is delivering water to the reactor core, or to the torus, through its minimum flow bypass line.

3. Energize the containment spray valves (torus and drywell) in either LPCI loop.

4. If operating on only one diesel-generator, stop one of the two RHR pumps to permit the addition of RHR service water pumps to the diesel-generator load.

5. Place one RHR heat exchanger into operation by establishing RHR service water system cooling. (Use two RHR service water pumps.)

6. Open the drywell spray valves in either LPCI loop and close the selected LPCI injection valves.

7. Open the suppression pool spray valve.

8. Close the selected heat exchanger bypass valve in the spray loop.

9. Continue the containment spray until the pressure decreases to 2 psig, and verify that containment spray valves automatically close.

6.2.2.2.2.3 Design Basis Procedure for Use of Containment Spray Following a Small Pressure Boundary Leak Inside Containment

Although the instructions for the use of containment spray are confined in the Emergency Operating Procedures (EOPs) and in the Residual Heat Removal System Operating Instructions, the procedure used for the original design basis scenario for containment spray is provided.

Assumptions

1. High drywell pressure has tripped (containment pressure greater than 2 psig). Reactor vessel water level is above low-low-low level.

2. All RHR pumps are running. All RHR service water system pumps are stopped by automatic action on the initiation of the RHR system.

3. Reactor vessel pressure remains above LPCI or core spray injection pressure.

4. Containment pressure has exceeded 10 psig for 30 min and drywell atmosphere exceeds 281°F.

5. Offsite power is available, or it is assumed that if offsite power is not available only one diesel-generator is operating.

6. At least one core spray system is running and recirculating water from the core spray pump to the torus.

7. The HPCI system has been initiated and is providing water to the reactor vessel. (HPCI operation may or may not be on a continuous basis.)

Operating Procedure

1. Verify that reactor vessel water level is being maintained and that the HPCI system is operating.

2. Energize the containment spray valves (torus and drywell) in either LPCI loop.

3. If operating on only one diesel-generator, stop one of the two RHR pumps to permit the addition of RHR service water pumps to the diesel-generator load.

4. Place one RHR heat exchanger for the containment spray loop into operation by establishing RHR service water system cooling. (Use two pumps.)

5. Open the drywell spray valves in either LPCI loop.

6. Open the suppression pool spray valve.

7. Close the selected heat exchanger bypass valve in the spray loop.

8. Continue the containment spray until the pressure decreases to 2 psig, and verify that containment spray valves automatically close.

9. Continue with other emergency procedures for small leaks inside containment as required.

6.2.2.2.3 Primary Containment Cooling System

The primary containment cooling system is designed to cool and circulate the drywell atmosphere during normal plant operating modes. It maintains temperature within normal operating limits for the components in the drywell. Temperatures, heat loads, and other system design data are given in Table 6.2-18.

A study of the containment cooling system was undertaken as a result of Phase II of the DAEC Power Uprate Program Balance of Plant Study. High ambient temperatures in the upper elevations of the drywell were determined to be due to higher than anticipated heatloads and air stratification. Two cooling units were added to the drywell to provide additional cooling capacity and improved air circulation. The units were designed to provide a volumetric average drywell temperature of 135°F with a maximum of 150°F during normal operation.

The primary containment cooling system uses eight fan-coil units at various locations in the drywell (See Figures 6.2-59 and 6.2-60). Six of these units are original plant equipment, while the other two units were added during the cycle 8/9 refuel outage, as discussed above. Each of the six original fan-coil units (which are not all of the same size) consists of two cooling coils and two motor-driven vane axial fans. Either fan can be used with either cooling coil. The two additional units each have a single cooling coil and a single direct-connected motor driven vane axial fan. Each cooling coil is connected to the well water system cooling water supply and return piping inside the drywell (see Figure 6.2-60). Technical Specifications limit Drywell average air temperature to ≤ 135 °F whenever the reactor is critical or when reactor temperature is above 212 °F and fuel is in the reactor vessel.

Two fan-coil units circulate cooled drywell atmosphere through each of the following equipments or areas: the recirculating pump motors (one unit for each motor), the control rod drive area, and the annular space between the reactor pressure vessel and the sacrificial reactor shield. Cooled gas is also circulated from two of the units through the reactor vessel head area, the space immediately above the refueling bellows bulkhead plate, and the relief valve area (see Figure 6.2-59).

Each of the original fan-coil units has provisions for installing dust filters, which were employed only during construction and were removed before plant operation.

Each fan is started from the control room by using ON-OFF switches. For the dual-fan units, one fan is started by switching to ON, and the other fan switch may be placed in the OFF position. During normal operation, both of the single fan units are switched to ON. If the normal operating fan on any of the dual-fan units fails, a high-temperature alarm will annunciate in the control room, and the second fan is started by the operator.

Cooling unit discharge air/N_2 temperature is sensed by a temperature element and indicated in the control room. Upon high temperature due to scram, any fans that are in standby of the fan-coil units in the control rod drive area are placed in service automatically to provide additional cooling. All fan-coil units are operated from the essential electric buses.

6.2.2.3 Design Evaluation

The evaluation of the suppression pool cooling system and containment spray system in conjunction with the other emergency core cooling systems to satisfy their safety objectives is contained in Section 6.3.

The torus, which is in a Seismic Category I structure, provides a sufficient supply of water for the containment spray subsystem.

The protection of containment spray subsystem components against missiles is discussed in Section 3.5.3.

Containment spray piping is designed to Seismic Category I criteria as discussed in Section 3.8.

The containment spray system is a manually initiated system that is not required from the standpoint of nuclear safety. Although the capability of withstanding a single failure is not necessary for the initiation of this system, redundant drywell spray loops ensure spray availability in the event of a single failure.

The reliability of the containment spray system is ensured by all of the features of the system as discussed above.

6.2.2.3.1 Bases for and Acceptability of Operator To Limit Temperature Rise of the Containment

A postulated condition where containment sprays may be desirable is in the case of a small steam leak in the drywell. The consequence of such an occurrence, assuming no corrective spray action is taken, is the possibility of the containment atmosphere exceeding the containment design temperature due to superheating, thus presenting the potential to exceed the design temperature of the drywell vessel.

An analysis conducted for a similar drywell structure (Dresden 2 - Supplement to Special Report of the June 5, 1970 incident) demonstrates that the higher temperature (340°F) can be tolerated with no significant compromise to the original design margins (based on a design temperature of 281°F). It is concluded, therefore, that from a safety standpoint the drywell sprays are not necessary. To avoid any concern of the drywell wall exceeding the design temperature, the operator will be instructed to initiate the containment sprays if containment pressure exceeds 10 psig for longer than 30 min and if a drywell atmosphere temperature in excess of 281°F persists. This procedure will ensure that the containment wall never exceeds 281°F. The following paragraphs discuss the analysis and assumptions used in determining this time period.

When a postulated leak occurs inside the drywell, the pressure and temperature rise, but the time response is different for every postulated steam or liquid leak depending on leak size, reactor pressure, heat transfer to the containment structure, etc.

If the leak is very small, the drywell fan coolers will remove the additional sensible and latent heat caused by the leak with only a slight increase in pressure and temperature. If the leak is large enough such that the pressure in the drywell rises above that necessary to clear the wetwell downcomers, venting from the drywell to wetwell will result. As the mixture of noncondensibles and steam is purged to the wetwell, the steam is condensed in the pool and the noncondensibles are stored in the wetwell gas volume. The containment pressure will continue to increase to the point where essentially all of the noncondensibles in the drywell are "washed" over to the wetwell. The larger the leak, the more rapid the pressure rise. However, the maximum pressure will always correspond to all the noncondensibles initially in the drywell stored in the wetwell gas volume.

The containment atmosphere temperature response is largely a function of this containment pressure. In the case of liquid or mixture leaks, the maximum temperature at any time is upper-bounded by the saturation temperature corresponding to the containment pressure at that time. The peak atmosphere temperature corresponds to the containment pressure when all the drywell noncondensibles are transferred to the wetwell.

In the case of a steam leak, the peak atmosphere temperature is upper-bounded by the maximum superheat temperature. This temperature is a function of both the source pressure (RPV) and the receiver pressure (drywell) and is a maximum when the RPV pressure is between 400 and 600 psi and the containment pressure is at its peak.

Since the containment pressure and temperature response will vary for every postulated size steam leak, a spectrum of leak sizes was analyzed to determine the temperature-time response of the drywell wall.

This analysis assumes the reactor initially at near rated conditions. The leak occurs and the reactor is scrammed on high drywell pressure, and high-pressure coolant injection is available to add water to the reactor vessel. A simultaneous loss of offsite ac power is also assumed along with no operator action. The reactor pressure stabilizes out at the pressure where the latent energy leaving the vessel equals the decay heat.

Containment pressure and temperature increase at a rate dependent on the size of the steam leak and the reactor pressure. The containment shell temperature rises as steam condenses on the relatively cool wall. The containment pressure likewise rises, and the peak pressure occurs at a value corresponding to all the noncondensible gases initially in the drywell being washed over to the wetwell. When the drywell shell temperature reaches the saturated temperature dictated by this containment pressure, steam condensation is terminated, and the only energy available to further increase the wall temperature is the superheat energy. The result is a decrease in the rate of temperature rise in the containment wall and an increase in the bulk atmosphere temperature of the drywell.

The drywell wall is assumed to be insulated at the back face and is taken to be the only capacitor in the drywell. A film coefficient of h = 1000 Btu/hr-ft^2-°F was used during the condensing portion of the transient. After the wall reaches saturation temperature, no condensation takes place and the vapor merely loses some of its superheat. The heat-transfer mechanism for this portion is the same as for cooling a noncondensible gas, and a film coefficient of h = 5 Btu/hr-ft^2-°F was used.

For the complete spectrum of steam leaks, the time for the containment wall to reach the design temperature of 281°F is greater than 2000 sec. It is evident from these results that sufficient time is available for the operator to limit the drywell wall temperature to less than the design temperature.

The activation of one of the two containment sprays any time before the wall temperature reaches 281°F will be effective in terminating the temperature rise because the superheat will be quickly removed from the atmosphere. The spray nozzles are designed to give a small particle size, and the heat transfer to the subcooled spray is very effective.

To terminate the wall temperature increase, it is necessary to remove only the superheat energy.

The instructions to manually initiate containment sprays are contained in the Emergency Operating Procedures (EOPs). Since the EOPs are revised as-needed to implement the proper guidance (i.e., in accordance with the Emergency Procedure Guidelines/Severe Accident Guidelines (EPGs/SAGs), as implemented at the DAEC under administrative controls) for initiating containment sprays, the specific instructions are not identified here in the UFSAR. However, at the time of the original FSAR, a combination of temperature and pressure was selected as the basis for determining when to turn on the spray, with the objective to prevent average containment wall temperatures from exceeding 281°F for any steam leak. A pressure of 10 psig with a time delay of 30 min. for operator action was selected on the basis that the time required to reach the pressure setting is small relative to the time required for the average wall temperature to reach 281°F. This selection also ensured that there would be no conflicting demands for the RHR pumps since the short-term ECCS function will always be completed prior to any need for operator action for containment spray. For small leaks, the drywell coolers may preclude the need for containment spray initiation. Pressure above 10 psig might occur simultaneously with temperature less than 281°F when the coolers are available. Drywell atmosphere temperatures are indicated in the control room, and the reading of any two separated sensors can be used to determine the drywell temperature to circumvent the problem of local variations. Therefore, the operator was instructed to turn on the sprays, after waiting 30 min. from the time 10 psig is reached, if a drywell atmospheric temperature in excess of 281°F persisted. This ensured that the wall never exceeded 281°F.

It should also be pointed out that analysis on a similar type of containment vessel (Dresden 2 - Supplement to Special Report of June 5, 1970 incident) demonstrates that even if a higher temperature condition (340°F rather than 281°F) were to exist, it would impose no significant compromise on the design margins that were originally based on the design temperature condition of 281°F.

Although spray is not required for plant safety since stress analysis shows ample design margin, sprays would be used to limit temperature to 281°F. Furthermore, ample time is available for operator action. However, in the event of a Station Blackout, when sprays are not available, drywell temperature is allowed to rise above 281°F prior to Emergency Depressurization (if required) in order to preserve HPCI and/or RCIC as sources for reactor coolant makeup.

In the event of a small steam leak condition where the drywell spray may be required, it is highly unlikely that the core would uncover. However, if such an event is postulated, triple low-level and high drywell pressure will initiate the automatic depressurization system. The reactor pressure vessel will depressurize in a matter of minutes to a point where the low-pressure ECCS are activated.

The level will be rapidly restored and continue above the two-thirds core height. Therefore, if the level does drop below the interlock setting, it will be for only a very short time and long before the minimum spray initiation time of at least 30 min.

6.2.2.3.2 Relation of Operator Capabilities and/or Actions to Containment Performance Analysis

The 10-min spray activation time used for the containment analysis given in Chapter 15, although arbitrary, was selected based on the requirement of no operator action for 10 min following the design-basis accident. The spray may be activated any time after the core is flooded to the two-thirds height. However, there is no requirement to activate the spray at any given time following the design-basis accident. The effect on the containment response with and without spray is demonstrated in Figures 6.2-45 through 6.2-47.

6.2.2.4 Tests and Inspections

See Sections 5.4.7.4 and 6.3.

The operation of the discharge valves to the containment spray headers is tested as described in Section 5.4.7.4. Air and smoke testing of the containment spray spargers and bench testing of the spray nozzles is discussed in Section 14.2.12.5. During each 5-yr period, an air test is performed on the drywell spray headers and nozzles.

See also Section 1.8, Safety Guide 22, for a discussion of periodic testing of the reactor emergency core cooling systems.

6.2.2.5 Instrumentation Requirements

See Chapter 7.

6.2.3 SECONDARY CONTAINMENT SYSTEM FUNCTIONAL DESIGN

The functional description of this system for normal operation is given in Section 9.4 under reactor building heating, ventilation, and air conditioning (HVAC). Only emergency operation is discussed in this section.

6.2.3.1 Design Bases

6.2.3.1.1 Safety Objective

The safety objective of the secondary containment system in conjunction with other engineered safeguards and nuclear safety systems is to limit the release to the environs of radioactive materials so that offsite doses from a postulated design-basis accident will be below the guideline values of 10 CFR 100.

6.2.3.1.2 Safety Design Bases

The safety design bases of the secondary containment system are as follows:

1. The secondary containment system is designed to provide secondary containment when the primary containment is operable and when the primary containment is open.

2. The secondary containment system is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective.

3. The secondary containment system is designed in accordance with Seismic Category I design criteria.

4. The secondary containment is designed to provide a filtered, elevated release of airborne radioactive materials so that offsite doses from a design-basis fuel-handling accident or LOCA will be below the guideline values stated in 10 CFR 100.

5. The reactor building is designed to contain a positive internal pressure of at least 7 in. of water.

6. The secondary containment system is designed to be sufficiently leaktight to allow the standby gas treatment system (SGTS) to maintain the reactor building pressure at a subatmospheric pressure of 0.25 in. of water when the standby gas treatment system is exhausting reactor building atmosphere.

7. The reactor building isolation and control system is designed to isolate the reactor building fast enough to prevent fission products from the postulated fuel-handling accident from being released to the environs through the normal discharge path.

8. The secondary containment system is provided with means to conduct periodic tests to verify system performance.

9. The secondary containment meets the applicable codes as described in Section 6.2.1.

6.2.3.2 System Description

6.2.3.2.1 General Description

The secondary containment system consists of four subsystems, which are the reactor building, the reactor building isolation and control system, the standby gas treatment system, and the offgas stack. The secondary containment system surrounds the primary containment system and is designed to provide secondary containment for the postulated LOCA. The secondary containment system also surrounds the refueling facilities and is designed to provide primary containment for the postulated refueling accident.

The secondary containment system uses four different features to mitigate the consequences of a postulated LOCA (pipe break inside the drywell) and the refueling accident (fuel-handling accident). The first feature is a negative pressure barrier that minimizes the ground-level release of fission products by ensuring that all leakage relative to the environment is into the secondary containment. The second feature is a low-leakage containment volume that provides a holdup time for fission product decay before release. The third feature is the removal of particulates and iodines by filtration before release, and the fourth feature is the exhausting of the secondary containment atmosphere through an elevated release point, which aids in the dispersion of the effluent by atmospheric diffusion. Each of the features is provided by a different combination of subsystems: the first by the reactor building, the reactor building isolation and control system, and the standby gas treatment exhaust system; the second by the reactor building and the reactor building isolation and control system; the third by the standby gas treatment system filters; and the fourth by the offgas stack.

6.2.3.2.2 Reactor Building

The reactor building completely encloses the reactor and its pressure suppression primary containment system. The reactor building houses the refueling and reactor servicing equipment, new- and spent-fuel storage facilities, and other reactor auxiliary and service equipment. Also housed within the reactor building are the emergency core cooling systems, reactor cleanup filter-demineralizer system, RCIC system, ventilation and exhaust systems, standby liquid control system, CRD system, reactor protection system, and electrical equipment components.

The structural design features of the reactor building are described in Chapter 3, which also includes discussions of the Seismic Category I design. The reactor building is designed to meet the shielding requirements discussed in Section 12.3.2.

As indicated in Section 3.3.1 the reactor building is designed to withstand a wind pressure of 31 psf or 5.9 in. H_2O. An analysis has been made using the inherent building leakage resistance characteristics which shows that the pressure differential during the operation of the standby gas treatment system will not exceed 5 in. H_2O, which is less than the design capability of the structure. Thus the standby gas treatment system cannot create building pressure differentials exceeding the reactor building structural design limits.

6.2.3.2.3 Reactor Building Isolation and Control System

The reactor building isolation and control system serves to trip the reactor building supply and exhaust fans, isolate the normal ventilation system, and provide the starting signals for the standby gas treatment system in the event of the postulated LOCA inside the drywell or the postulated fuel-handling accident in the reactor building. Five signals will automatically initiate the secondary containment system. Two signals, high drywell pressure and low reactor water level, indicate a LOCA inside the drywell. Radiation monitors in the reactor building vent shaft, fuel pool exhaust, and offgas vent pipe, can initiate the secondary containment system. Secondary containment can also be initiated manually from the control room.

Normally open air-operated isolation dampers are provided on the discharge side of the reactor building and operating floor supply fans. Similar isolation dampers are located in the intakes to the operating floor ventilation exhaust fans and to the contaminated area exhaust fans. Two dampers in series are provided throughout the isolation system to provide the required redundancy. Both dampers fail closed on a loss of power to the solenoids, or on a loss of instrument air to the dampers. The isolation dampers are spring operated and designed to close before fission products from the design-basis refueling accident can travel the distance between radiation monitors and the isolation dampers.

Penetrations of the secondary containment are designed to have leakage characteristics consistent with secondary containment leakage limitations. Electrical penetrations in the reactor building are designed to withstand environmental conditions and to retain their integrity during the postulated fuel-handling accident and the LOCA inside the drywell. The interlock function of the two doors that provide equipment/personnel access throughout the plant is Quality Level II - requiring the interlock function to be tested on a routine basis to ensure that building access cannot interfere with maintaining the secondary containment integrity. All normally open drains that are open both to the secondary containment and outside atmosphere are provided with water seals to maintain containment integrity. The Standby Gas Treatment System drains shall be inspected quarterly for adequate water level in loop seals.

6.2.3.2.4 Standby Gas Treatment System

The standby gas treatment system is a subsystem of the secondary containment and is shown in Figure 6.2-61. The system is described in Section 6.5.3.3 as a subsystem of the DAEC fission product control systems.

6.2.3.2.5 Offgas Stack

The location of the offgas stack is shown in Figure 1.2-1. The top of the stack is 100 m above plant grade. The structural design of the stack is discussed in Section 3.8.4.1.

6.2.3.3 Safety Evaluation

The secondary containment system provides the principal mechanisms for the mitigation of the consequences of an accident in the reactor building. The primary and secondary containment act together to provide the principal mechanisms for the mitigation of the consequences of an accident in the drywell. If the leakage rate of the building is low, and the leakage air is filtered and discharged to the elevated release point (using the standby gas treatment system and the offgas stack), the offsite radiation doses that result from postulated accidents are reduced significantly. The reactor building is a Seismic Category I structure designed as described in Chapter 3. The design reactor building inleakage rate is 100% of reactor building volume per day at a building subatmospheric pressure of 0.25 in. of water at normal atmospheric conditions. The actual inleakage rate corresponding to a building subatmospheric pressure of 0.25 in. of water was established during preoperational testing.

In the event of a pipe break inside the primary containment or a fuel-handling accident, reactor building isolation will be effected, and the standby gas treatment system will be initiated. For a discussion on high-energy line breaks see Section 3.6.1.2. Both SGTS trains will start automatically. When system flow has been verified, one train is stopped and placed in a standby condition, and the remaining train exhausts the reactor building to the main stack. With the reactor building isolated, the standby gas treatment system has the capability to hold the building at a subatmospheric pressure of 0.25 in. of water. Automatic exhaust fan inlet vane controls on each fan are provided to maintain the required flow rate.

The reactor building isolation and control system performs the required isolation actions of the secondary containment system following the receipt of the appropriate initiation signals. Following initiation, the reactor building ventilation isolation dampers close, the reactor building supply and exhaust fans automatically trip, and the standby gas treatment system starts.

The fuel pool exhaust system is designed so that it takes longer for fission products released in any postulated fuel-handling accident to travel from the operating (refueling) floor ventilation exhaust radiation monitors to the isolation dampers than for the isolation dampers to close. Thus, no significant release of fission products to the environment is possible.

The standby gas treatment system exhausts air from the reactor building and discharges the processed air to the offgas stack. The system filters particulates and iodine from the air stream to reduce the level of airborne contamination released to the environs via the offgas stack.

The offgas stack provides an elevated release point for airborne activity during the postulated loss-of-coolant and refueling accidents. The release of activity to the environs from the secondary containment system is analyzed in detail in Chapter 15.

Instrument Line Break

An analysis was made to determine the effect of an instrument line break on the secondary containment. The results of this analysis are shown in Figure 6.2-62, which shows that after 3.5 hr (the duration of the detection and cooldown sequence) of continuous blowdown, the temperature and pressure in the reactor building are 110°F and 0.94 in. H_2O, respectively.

The model used to calculate the pressure and temperature response consisted of a volume, assumed to be the total free volume of the reactor building, into which reactor water is blown down from reactor temperature and pressure to atmospheric pressure. Mass and energy are removed from the volume by the standby gas treatment system and by leakage.

For purposes of analysis, it was assumed that the standby gas treatment system starts automatically on high reactor building ventilation activity. This is conservative in that if normal building ventilation is considered to be operating, the equilibrium reactor building pressure would be lower because of the greater steam removal rate.

Mass balance equations were written for the mass of vapor and mass of air in the building atmosphere. A heat balance equation was written for the atmosphere to calculate temperature, and the pressure was calculated from the mass inventory, leakage, temperature, and volume. The simultaneous, nonlinear differential equations were solved using the MIMIC computer code subject to the following assumptions and initial conditions:

Assumptions

1. Leakage is proportional to the square root of pressure differential (1263 cfm at 1/4 in. H_2O).

2. No heat transfer to building.

3. No friction losses in instrument lines.

4. Blowdown flow rate is the maximum for a two-phase mixture according to Moody (8000 lbm water/sec-ft^2 at 1050 psia).

5. Instrument lines have 0.25 in. orifices.

6. Reactor pressure is 1050 psia throughout the calculation.

7. Building pressure is atmospheric at the beginning of the transient.

8. Quality of blowdown is assumed constant at 0.38, calculated from an energy balance.

Initial Conditions

Mass flow rate of vapor from blowdown (constant).	62.5 lbm/min
Mass of air in the building	1.285×10^5 lbm
Mass of vapor in the building at 50% r.h.	1938 lbm
Atmospheric (exterior) pressure (constant)	2120 lb/ft^2
SGTS flow rate (constant)	1263 ft^3/min
Total building free volume	1.82×10^6 ft^3
Temperature of air in building	90°F
Leakage at 0.25 in. H_2O	1263 ft^3/min
Blowdown flow rate (vapor + water)	164 lbm/min
Quality of blowdown (constant)	0.38

From the results of this analysis, it is seen that the structural integrity of the building is ensured in that the building is designed to withstand a pressure of 7 in. H_2O.

6.2.3.4 Inspection and Testing

The secondary containment leakage rate is determined in the following manner. The reactor building is isolated and the standby gas treatment system is started with one treatment train and its associated exhaust fan. The exhaust flow rate is controlled by the fan inlet vane control position as determined by flow rate measurements in the SGTS exhaust duct. The fan inlet vane positioner is used to control the exhaust flow rate to produce a reactor building subatmospheric pressure greater than or equal to 0.25 in. of water (with normal atmospheric conditions at the site), thus verifying the safety design basis leaktightness with respect to inleakage.

Tests of the ability of the various isolation initiation signals to automatically render the reactor building isolated, to trip the supply and exhaust fans, and to start the standby gas treatment system can be conducted by simulating the isolation signals.

Provisions are made for periodic tests of each filter unit. These tests include determinations of differential pressure across each filter and of filter efficiency. Connections for testing, such as injection and sampling, are located to provide adequate mixing of the injected fluid and representative sampling and monitoring so that test results are indicative of performance. The (HEPA) filters are tested with dioctylphthalate (DOP) smoke. The charcoal filters can be tested for bypass with freon.

6.2.4 CONTAINMENT ISOLATION SYSTEM

6.2.4.1 Design Bases

6.2.4.1.1 Safety Objective

See Section 6.2.1.1.1.

The safety objective of the primary containment system is to provide the capability in conjunction with other safeguard features, including the containment isolation system, to limit the release of fission products in the event of a postulated design-basis accident so that offsite doses are held to a practical minimum and do not exceed the guideline values set forth in 10 CFR 100.

6.2.4.1.2 Safety Design Bases

See Section 6.2.1.1.2. The primary containment system has the capability to reliably isolate all pipes necessary to establish the primary containment barrier. See also Section 7.3.1.2.1.

6.2.4.2 System Design

See Section 7.3.1.1.1 for a discussion of the lines that penetrate the primary containment, the type and locations of valves installed in each line, the valve closing devices and circuits, and their isolation functions and settings.

6.2.4.2.1 Process Lines

6.2.4.2.1.1 General

Lines that penetrate the primary containment fall into the following three basic groups.

1. Type A: Lines that communicate directly with the reactor vessel.

2. Type B: Lines that communicate with the primary containment free space.

3. Type C: Lines that neither communicate with the reactor vessel, with the primary containment free space, or with the environs.

The primary containment isolation valves and their arrangement differ according to the above groups of lines that penetrate the containment. The three general groups are discussed in the following paragraphs and exceptions are discussed in subsequent sections.

Type A isolation valves are on process lines that communicate directly with the reactor vessel and penetrate the primary containment. These lines, except as noted in Sections 6.2.4.2.1.4 and 6.2.4.2.7, have two valves in series: one inside the primary containment and one outside the primary containment.

Type B isolation valves are on process lines that do not communicate directly with the reactor vessel, but penetrate the primary containment and communicate with the primary containment free space. These lines have two valves in series, both located outside the primary containment and as close to the primary containment boundary as practical. Lines that communicate with the suppression pool have at least one isolation valve external to and as close as possible to the primary containment.

Type C isolation valves are on process lines that penetrate the primary containment, but do not communicate directly with the reactor vessel, with the primary containment free space, or with the environs. These lines require only one valve located outside the primary containment.

The containment isolation valves are listed in Section 7.3.1.1.1. That section provides drywell penetrations, valve types, valve group, valve locations, isolation signals, and normal status. Section 3.2.2 discusses valve and process line groupings and classifications.

6.2.4.2.1.2 Closure of Type A and Type B Automatic Valves

Air-operated, motor-operated, and solenoid-operated valves in lines that communicate with the reactor or drywell receive automatic isolation signals, unless such a line is required to mitigate the casualty. In lines that contain two isolation valves, both valves receive a closure signal even if normally closed during reactor operation.

The feedwater lines each have a motor-operated stop check valve and a check valve which serve as isolation valves. The stop check valves are used in the feedwater lines outside containment and provide positive closure of the lines should it be required. These valves do not receive an isolation signal but can be closed remotely. The valves inside containment are simple check valves and close automatically when flow stops or reverses.

Effluent lines, such as main steam lines, that connect to the reactor vessel or open to the primary containment have air-operated valves. This arrangement provides the ability for a given valve to fail either open or shut as required by safety considerations. If the operation of a system may be required after an accident, the valves are either motor operated or are equipped with gas accumulators.

6.2.4.2.1.3 Closure of Type C Automatic Valves

Valves in lines that neither communicate directly with the reactor or drywell generally do not receive an automatic isolation signal. However, the reactor building closed cooling water and drywell cooling water systems are provided with single automatic isolation valves.

6.2.4.2.1.4 Closure of Check Valves

Automatic isolation valves, in the usual sense, are not used on the inlet lines of the emergency core cooling systems, reactor feedwater system, and other systems that can add water inventory or liquid poison because the operation of these systems mitigates the consequences of a LOCA. Because normal flow of water in these systems is inward to the reactor vessel or to the primary containment, check valves located in the lines will provide automatic isolation if necessary.

6.2.4.2.1.5 Motive and Control Power

Motive and control power for the valves on process lines that require two valves have physically independent sources, except as indicated in Section 6.2.4.2.7, to provide a high probability that no single accidental event could interrupt motive power to both closure devices.

6.2.4.2.2 Traversing Incore Probe System

TIP system guide tubes are provided with an isolation valve that closes automatically on the receipt of an isolation signal and after the TIP cable and fission chamber have been retracted. In series with this isolation valve, an additional or backup isolation shear valve is included.

Both valves are located outside the drywell. The function of the shear valve is to ensure the integrity of the containment in the unlikely event that the other isolation valve should fail to close or the chamber drive cable should fail to retract if it should be extended in the guide tube during the time that containment isolation is required. This valve is designed to shear the cable and seal the guide tube on the receipt of a manually initiated signal. Valve position (full open or full closed) of the automatic closing valves is indicated in the control room. Each shear valve must be operated independently. The valve is an explosive-type valve and each actuating circuit is monitored. In the event of a containment isolation signal, the TIP system receives a command to retract the traversing probes. On full retraction, each isolation valve closes automatically. If a traversing probe were jammed in the tube run such that it could not be retracted, instruments would supply this information to the operator, who, in turn, would investigate to determine whether the shear valve should be operated.

6.2.4.2.3 Control Rod Drive Hydraulic System Isolation

No automatic isolation valves are provided on the CRD system hydraulic lines for insert, withdraw, or water return. These lines are isolated by the normally closed directional control and scram valves in the CRD hydraulic control units. The cooling water header is protected by a check valve in the hydraulic control unit, and the water return line is provided with a check valve outside the drywell and a check valve inside the drywell. A ball check valve that comprises an internal portion of each CRD mechanism prevents the reactor from blowing down into the drywell should a rupture of the insert lines occur.

6.2.4.2.4 Instrument Line Isolation

Instrument sensing lines and the ability to isolate them have been designed to meet the intent of AEC Safety Guide 11, "Instrument Lines Penetrating Primary Reactor Containment."

Instrument lines that penetrate the drywell and are part of the reactor coolant pressure boundary are provided with an excess flow check valve external and adjacent to the drywell. The excess flow check valves are held open by a spring. If the sensing line ruptures downstream of the excess flow check valves, these valves will shut and prevent uncontrolled release of reactor coolant. A differential of 10 psid is sufficient to cause automatic valve closure. Leakage past the seat with 1100 psid across the valve is less than 2 cm^3/hr-in. of poppet diameter. When line integrity has been restored, a solenoid-operated bypass valve permits the operator in the control room to reset the check valve. Valve position is indicated in the control room.

Instrument lines that penetrate the containment and are part of the reactor coolant pressure boundary are provided with orifices inside the drywell. The orifices are sized in accordance with Safety Guide 11 such that coolant loss through the postulated line rupture is within the capability of the reactor coolant make-up systems. The valves and orifices are designed or sized to restrict flow to no more than a 0.25 in. sharp-edged orifice. Since the average time constant to a step level change for a 0.25 in. orifice is 0.72 sec, the instrument response time is not unacceptably degraded by the inclusion of an orifice. These instrument lines are provided with manual root valves outside the containment upstream of the excess flow check valve to permit the removal of instruments from service for maintenance. Individual instruments have their own isolation valves, usually located close to the instrument.

Instrument process lines that penetrate the drywell and communicate with the drywell atmosphere are provided with manual isolation valves located outside and close to the drywell. These lines are designed and built to the same criteria as those which connect to the reactor coolant pressure boundary but are exposed to significantly lower pressures during both normal operation and accident conditions.

Piping classification of instrument lines is discussed in Section 3.2.2 and seismic classification is discussed in Section 3.2.1.

An instrument line which penetrates the drywell at penetration X37B utilizes a different configuration. A 1/8" capillary tube is routed from a load frame (outside primary containment), through the primary containment at X37B, connects to a modified LPRM assembly at core location 16-41, and terminates internal to the LPRM at a bellows assembly. The tube and bellows is a closed system, and is filled with demineralized water. Normal system operation has no direct safety function. Based on design function and size, the tube is classified as an instrument line. The design, which is based on configuration specified in Design Safety Standard 16 (reference DBD-A61-001), utilizes a single outboard manual isolation valve and a .069" orifice (inherent to the tube inside diameter), but does not utilize an excess flow check valve. Use of a standard design detail specified in the Design safety Standards is acceptable, meets original plant design and licensing criteria, and ensures that nuclear safety is maintained. The instrument line break analysis in Section 6.2.3 adequately bounds the design of the capillary tube.

6.2.4.2.5 Containment Purge and Vent Valves

6.2.4.2.5.1 <u>Description</u>

The containment purge and vent isolation valves are closed except while purging. Purging operations are limited to only those required for plant maintenance and surveillance procedures (see Section 6.2.5).

The DAEC containment purge and vent isolation system contains nine valves arranged in three groups of three valves each. Each grouping consists of an outboard isolation valve and two inboard isolation valves. One group provides containment isolation of the purge supply line, one group isolates the drywell ventilation exhaust line, and one group isolates the suppression pool exhaust line. The outboard valves are isolated by electrical Division 2 isolation circuitry, whereas the inboard valves are associated with Division 1 isolation circuits. The purge and vent valves automatically isolate on any one of the following plant conditions:

1. High drywell pressure.

2. Low reactor vessel level.

3. High fuel pool exhaust radiation.

4. High reactor building ventilation radiation.

5. High-high offgas stack radiation level.

Seismic Category I debris screens have been added to the drywell penetrations to protect the isolation valves from being blocked open by debris. The containment purge isolation valves have been restricted to opening no more than 30 degrees of their full-open 90-degree disk rotation. The limitation on valve travel to 30-degrees open ensures closure capability under worst-case dynamic loading, without valve damage. Flow forces will tend to close the valve, and thereby assist, rather than hinder, valve closure.

Periodic containment venting is necessary during reactor heatup and cooldown to properly control N_2 pressure in the inerted containment. Maintaining the subject valves closed would preclude proper maintenance of the inert environment.

The containment isolation logic for these valves provides individual override capability of each isolation parameter without the bypassing of the remaining parameters, such that the valves will isolate if any nonoverridden isolation parameter is exceeded. With this design, the purge and vent valves have the ability to reisolate following an isolation/override/reopen valve sequence occurrence of a second (or third, fourth, or fifth) trip parameter.

Key-lock switches are provided for enabling the override function. The switches are GE Model CR2940, Form UN200D. The switch action of this model is a two-position (NORM or NORMAL and BYPASS) key switch with the key being removable only in the left (counterclockwise) position. The purge and vent valve isolation override switches enable the override function in the right (clockwise) position. Therefore, the key cannot be removed from the switch while the switch is in the override position, which enhances the administrative control aspects of the override feature. All keys required for deliberate override or manual bypassing safety systems are under the direct control of the Operations Shift Supervisor. The preceding controls are supplemented by alarm and annunciation of the override condition.

Keylock switches are provided for enabling the override of High Drywell Pressure and Low Reactor Water Level Signals for Group 3 isolation valves (one for the inboard logic and one for the outboard logic) as required by the Emergency Operating Procedure (EOPs). The EOPs direct the plant operators to restore secondary containment ventilation provided a radiation problem does not exist. By bypassing the High Drywell Pressure and Low Reactor Water Level Signals, the Group 3 isolation valves can be reopened following an isolation provided the three radiation isolation signals are not present.

Two additional keylock switches are provided for enabling the override of all Group 3 isolation signals. This action is only required as a last resort to allow venting and purging of the Drywell or Torus regardless of the radioactive release in support of Primary Containment Pressure and Hydrogen Control actions directed in EOPs. The locking brass handle switches are unique from others at DAEC and are only used for override functions associated with the EOPs. These switches are similar to other brass handled keylock switches, but have a longer handle and are keyed differently. This provides additional administrative controls over their use. The switch action of this model is a two-position key switch with the key being removable only in the left (counterclockwise) position. The override function is enabled only in the right (clockwise) position. Therefore, the key cannot be removed from the switch while the switch is in the override position, which enhances the administrative control aspects of the override feature. Each switch lights an amber light directly above the switch and is annunciated on the front panel when taken to override. All keys required for deliberate override of safety systems are under the direct control of the Operations Shift Supervisor.

With the following exceptions, the operator cannot reopen an isolation valve until the conditions that tripped the isolation system have cleared or have been overridden as described above (see Section 7.3.1.1.1). The four valves in the primary containment purge and vent system that can be reopened following manual override of a containment isolation signal, are the torus inboard bypass and outboard vent valves, and the drywell inboard bypass and outboard vent valves. Two of these four valves are provided with a key-bypass permissive switch in addition to each individual manual override switch that is administratively controlled and annunciated in the control room. The bypass function of the vent bypass valves is unique in that it requires two deliberate operator actions: (1) the operator must select the drywell or torus override and (2) the operator must bypass the individual valve.

For the other two vent valves(drywell and torus inboard), administrative controls are used to ensure that the isolation signal is bypassed only if that isolation signal (high containment pressure and/or low reactor water level) has been tripped.

The containment purge and vent valves are pneumatically operated, with a fail-close actuator. The isolation signal causes the air supply solenoid to deenergize, which vents air from the actuator and allows actuator spring force to close the valve.

6.2.4.2.5.2 Design Criteria

The circuitry for the DAEC primary containment isolation system was designed and manufactured by GE as the NSSS supplier. The governing design standard for the system was IEEE 279-1968. The equipment in use at the DAEC is similar to equipment supplied to other BWR/4 plants and is qualified to operate over for the 40-year life of the plant in the benign environment of the control room.

The diversity of containment ventilation system isolation parameters is satisfied by the five isolation parameters listed in Section 6.2.4.2.5.1. The instrumentation and control logic providing the isolation signals for the inboard division and their power sources are physically and electrically separated from those of the outboard division, to satisfy redundancy and electrical separation criteria.

As described in Section 7.3, the instrumentation and control system that initiates containment isolation is designed to meet the criteria of IEEE 279, which in turn requires that nuclear power plant protection systems be designed and qualified as safety-grade equipment.

The debris screens on the drywell purge supply and exhaust lines are designed to protect the drywell purge isolation valves from debris which may become entrained in the exhaust stream generated by a postulated LOCA while purging. The screens are designed as Seismic Category I to remain functional after a design-basis earthquake and to withstand the differential pressure from a postulated LOCA (56 psig), assuming they are completely clogged.

6.2.4.2.5.3 Evaluation

Sufficient physical features in the key-lock switches are provided to facilitate adequate administrative control of the containment purge override function.

Each individual override switch provides one contact, which lights an amber lamp in the control room when the switch is placed in the override position to display the bypass condition for each individual trip parameter to the operator. The five override switches in each division of isolation logic are ganged to a common annunciator window in the control room, such that any one of the five key switches placed in the override position results in an alarm that requires operator acknowledgment.

Following either override or reset of the isolation signal(s), the operator must manipulate the control switch for each purge and vent valve individually to reopen the valve.

Provisions were made to ensure that isolation valve closure will not be prevented by debris which could potentially become entrained in the escaping air/steam mixture following a LOCA during purging. Based on the close proximity of the valves to the penetration, it was determined that additional protection against debris is desirable for drywell purge connections. It was also determined that additional protection against debris is not necessary for the torus purge exhaust and torus purge supply connections. This determination was based on the location of the connections (vertical takeoffs near the top of the torus) and the lack of debris in the torus.

The DAEC conducted a design review program to verify that the DAEC purge and vent valves are operable under design-basis LOCA conditions. The results of that design review program verified that, with the DAEC purge and vent valves limited to a maximum of 30 degrees open:

1. The valves have the capability to close and seal against worst case (design-basis LOCA) differential pressure.

2. The valves and their operators are capable of performing their intended function during and following a postulated seismic DBE.

3. The valves are capable of closing within the time required against worst case (design-basis LOCA) differential pressure.

4. The valve seal material is capable of functioning as intended under worst case (design-basis LOCA) conditions.

The DAEC performed an analysis of the potential consequences of a design-basis LOCA occurring during containment purge system operation. The analysis included determination of the airborne radiation and the mass of air/steam released through all purge lines prior to full closure of the 18-in. purge line isolation valves. The results of this analysis demonstrated that the potential airborne radiation released to the environment as a result of this accident scenario is well below the guidelines of 10 CFR 100.11. The thyroid dose rate at the exclusion area boundary due to airborne radiation released via purge lines (drywell and torus supply and exhaust) prior to isolation would be 3 mrem.

6.2.4.2.6 Compliance with Containment Isolation Provisions of NUREG-0578, Section 2.1.4

The DAEC is in compliance with the provisions of NUREG-0578, Section 2.1.4, [26,27] as follows:

1. The DAEC has identified which systems are considered essential and which are considered nonessential for safety.

2. All nonessential systems are isolated by automatic, diverse, safety-grade isolation signals, except that certain valves that are part of a closed system do not have diverse signals.

3. Resetting of the containment isolation signals will not result in the automatic reopening of nonessential containment isolation valves.

The following criteria are used in identifying essential and nonessential lines penetrating containment:

1. If a fluid line does not have a postaccident function, the line is nonessential and requires isolation following an accident.

2. If a fluid line provides an engineered safety feature function or engineered safety feature related system function, it is essential, and the isolation valves in the lines may remain open or be opened following an accident.

3. Engineering judgment was used to apply these criteria to each line in light of the system requirements as interpreted from the FSAR and piping and instrumentation diagrams.

6.2.4.2.7 Postaccident Sampling, Reactor Sample Lines

The reactor liquid sample lines for the postaccident sampling system connect to jet pump flow-sensing instrument lines outside of the drywell. Both sample lines have been provided with two automatic isolation valves in series located outside of the drywell. The isolation valves are solenoid valves which fail closed on loss of power, and are closed except during sampling. Both valves on each sample line are powered from the same division to provide the capability to obtain a jet pump sample following a loss of power in one division. However, the isolation signal for each of the two valves in each line is derived from separate divisions to ensure that at least one of the valves in each line will close or remain closed when the containment is isolated. The reactor liquid sample return line to the suppression pool is equipped with two automatic solenoid isolation valves. The isolation valves for both samples lines and the return line have been provided with key-lock handswitches for override of the containment isolation signal to enable sampling with the containment isolated. Override of the isolation signal to any of the valves lights an amber light adjacent to the handswitches on 1C-29 panel. Valve position is also indicated on the containment isolation benchboard 1C-03 in the control room.

The reactor recirculation system process sample line (not part of the postaccident sampling system) also has postaccident liquid sample capabilities that could be used as a backup. See Section 9.3.2 for a discussion of the process sampling system.

6.2.4.3 Design Evaluation

One of the basic purposes of the primary containment system is to provide a minimum of one protective barrier between the reactor core and the environmental surroundings subsequent to an accident involving the failure of the piping components of the reactor primary system. To fulfill its role as a barrier, the primary containment is designed to remain intact before, during, and after any design-basis accident of the process system installed either inside or outside the primary containment. The process system and the primary containment are considered as separate systems, but where process lines penetrate the containment, the penetration design has the same integrity as the primary containment structure itself. The process line isolation valves are designed to achieve the containment function inside the process lines when required.

Since a potential pipe failure must be analyzed considering an additional single active component failure, two isolation valves in series are generally required. Exceptions to this criterion are discussed in the preceding section. The use of two isolation valves in series optimizes the plant's ability to isolate the rupture from the reactor or to isolate the drywell from the outside environment. To maximize the independence of the two series valves, each is provided with an independent power source, and, for lines which connect directly to the reactor, the valves are placed on opposite sides of the drywell wall.

The isolation signals are different for each valve and are described in detail in Section 7.3.1.1. When an isolation signal occurs, both valves in series receive a "close" signal even if they are initially closed.

It is not necessary, nor desirable, that every isolation valve close simultaneously with a common isolation signal. For example, if a process pipe were to rupture in the drywell, it would be important to close all lines that are open to the drywell, and some effluent process lines such as the main steam lines. However, under these conditions, it is essential that containment and core cooling systems be operable. For this reason, specific signals are used for the isolation of the various process and safeguards systems.

Isolation valves must be closed before significant amounts of fission products are released from the reactor core under design-basis accident conditions. Because the amount of radioactive materials in the reactor coolant is small, a sufficient limitation of fission product release will be accomplished if the isolation valves are closed before the coolant drops below the top of the core.

See also Section 7.3.4.1.

6.2.4.4 Tests and Inspections

See Section 6.2.6.3.

Surveillance requirements for the primary containment power-operated isolation valves are contained in the Technical Specifications.

The primary containment isolation system is testable during reactor operation. Isolation valves can be tested to ensure that they are capable of closing by operating manual switches in the main control room and observing the position lights and any associated process effects. The channel and trip system responses can be functionally tested by applying test signals to each channel and observing the trip system response.

6.2.5 CONTAINMENT ATMOSPHERE CONTROL SYSTEM

The system is depicted in Figure 6.2-44 and includes the following subsystems:

1. Primary containment purge system.

2. Primary containment nitrogen inerting system.

3. Containment atmosphere dilution (CAD) system.

The primary containment purge system provides the means to introduce to and exhaust air from the drywell and the pressure suppression chamber. Clean reactor building air is supplied to the drywell for purge and ventilation purposes during the reactor shutdown and refueling periods to permit personnel access and occupancy. The containment can be vented during reactor heatup as necessary to eliminate a pressure buildup. It can be periodically vented thereafter to maintain pressure within operating limits during plant operations. The venting portion of the system is used as a backup to the CAD system for combustible gas control following a LOCA.

The primary containment nitrogen inerting system provides the means of introducing gaseous nitrogen into the drywell, thus reducing the oxygen content of the primary containment atmosphere to less than 4% and maintaining it at below 4% by volume during normal operation.

The CAD system is the principal DAEC combustible gas control system. It operates on the principle of limiting the oxygen concentration in the containment, following a LOCA, by adding nitrogen to the containment atmosphere, thus diluting the oxygen concentration to less than the flammability limit of 5% by volume. The system has been designed and evaluated in accordance with Safety Guide 7 assumptions. The adherence to that guide is discussed in Section 1.8.7.

Backup means for combustible gas control is provided by the ability to purge the containment through the standby gas treatment system, which is discussed in Section 6.5.3.

The drywell purge and vent valves are equipped with an inflatable T-ring seal system to provide leak tight seating for the valve discs. The T-ring seals are made of Dupont Nordel-Ethylene Propylene Elastomer (EPDM). The seal systems are pressurized from the Control Building HVAC instrument air system which contains normal atmospheric concentrations of oxygen. The T-ring seal material is qualified for the post-LOCA environment and the seals are replaced periodically to prevent seal failure which could result in oxygen inleakage into containment. The T-seals are replaced at intervals not exceeding 7.5 years. A pressure indicator is installed on each of the valves and can be used to locate seal leakage. In the event of leakage, operators will have sufficient time to detect leakage, identify the source and correct the problem before containment oxygen concentration would reach 5%. Further discussion is provided in Section 6.2.5.3.

The control valves in the Torus to Reactor Building vacuum breaker system are also equipped with T-ring seals. The seals are made of the same qualified material and are replaced at intervals not exceeding 7.5 years. These seals are pressurized from the same pneumatic supply as the valve operator, i.e., Control Building Compressed Air System, which also contains normal atmospheric concentrations of oxygen. In addition to the pressure indicator on the valve seal, each vacuum breaker line is equipped with a differential pressure indicator. The pressure drop in these lines is monitored once a day to check for seal leakage. If leakage is detected, a nitrogen supply may be temporarily connected to pressurize the T-ring seals. Operators will have sufficient time to detect leakage, identify the source and correct the problem before the containment O_2 concentration can exceed the 5% limit. Further discussion is provided in Section 6.2.5.3.

6.2.5.1 Design Bases

Following a LOCA, hydrogen and oxygen will be evolved within the primary containment from postulated metal-water reactions and from radiolysis. The guidelines and assumptions for the calculation of the combustible gas production are contained in Safety Guide 7. This guide specifies the flammability limit for hydrogen and oxygen as 4% and 5% by volume, respectively. That is, the hydrogen concentration should not exceed 4% by volume if more than 5% by volume of oxygen is present, and the oxygen concentration should not exceed 5% by volume if more than 4% by volume of hydrogen is present.

The containment inerting system maintains the containment during normal operation at an atmosphere oxygen level of 4% by volume and the CAD system prevents that level from reaching the flammability concentration level of 5% following a LOCA by adding nitrogen to the containment to dilute the oxygen concentration. The assumptions for the calculation of the combustible gas production are in Safety Guide 7 and are shown in Table 6.2-19.

Uniform mixing of the generated oxygen within the containment atmosphere is ensured by diffusion and other driving forces such as natural and forced convection. The one driving force of mixing that can be precisely calculated (i.e., diffusion) is sufficient to ensure that the maximum volume with oxygen concentration more than 0.1% oxygen greater than the average oxygen concentration is less than 10 ft^3.

The system provides continuous indication of hydrogen and oxygen content as well as failure alarms. The monitoring system of containment atmosphere dilution is designed to be capable of manual initiation from the control room. The monitoring system is redundant and testable. The redundant systems are supplied by separate power sources.

A Seismic Category I nitrogen source of sufficient capacity to ensure dilution nitrogen requirements through the 7th day after a postulated design-basis LOCA is provided. Beyond the 7-day period, nitrogen from a readily available source will be brought to the site, if necessary, to ensure that dilution requirements are satisfied. There is additional Nonseismic storage on the site. The Nonseismic CAD system charging compressor can take a suction from this Nonseismic storage tank and charge the CAD system.

No special control actions are expected to be required of the operator to adjust the pressure level of containment during CAD system operation. Normal containment leakage is expected to offset nitrogen additions such that containment design pressure will not be reached, as is shown in Figure 6.2-63.

Containment hydrogen and oxygen concentrations are monitored by redundant detector systems. Nitrogen will be added to dilute the combustible containment gases in a stepwise fashion as required to maintain oxygen levels below the 5% concentration limit of Safety Guide 7.

CAD system operation will result only in containment pressure increases over and above the pressure ranges described in Chapter 15. Minimum net positive suction head (NPSH) requirements of the vital core and containment cooling pumps are already maintained for postaccident conditions without CAD system operation. Thus, NPSH requirements will also be met during CAD system operation.

The high-pressure storage portion of the CAD system is per ASME Code, Section III, Class 2 up to the isolation valves at the drywell, with the exception of the nitrogen storage tanks, which will be per ASME Codes Section VIII "U"-stamped forged steel vessels. The isolation valves and penetrations are per ASME Code, Section III, Class MC.

The drywell atmosphere monitoring system is designed to the requirements of the ASME Pump and Valve Code, ANSI B31.1.

The entire CAD system required for postaccident operation is designed to Seismic Category I criteria with quality assurance documentation and to the criteria of IEEE 279.

All piping and valves up to the high-pressure nitrogen storage tanks and pressure-reducing valves are designed for the same peak pressure and temperature as the drywell. The high-pressure storage vessels and associated pressure-reducing valves are designed for the same pressure and temperature as the storage vessels.

The venting portion of the containment purging system provides the capability for purging the containment through the standby gas treatment system with final discharge through the main stack, thus limiting the potential release of radioactive iodine and other radioactive materials to the environment. The operation of the standby gas treatment system during the postaccident period has been specifically discussed with respect to flow, rate efficiency, and conditions of operation in Sections 6.2.3 and 6.5. Containment purge through the standby gas treatment system for post-LOCA combustible gas control is available as the backup control system to the CAD system per Regulatory Position 3 of Safety Guide 7.

The CAD system, including its nitrogen dilution and monitoring functions, is designed as an engineered safety feature, meeting the redundancy and seismic requirements of such systems and also the requirements of IEEE 279. Thus, the DAEC considers that total failure of the CAD system is incredible and that containment purge through the standby gas treatment system would never be necessary. The Nonseismic nitrogen charging compressor interfaces with the safety-related system through Seismic Category I valves and piping.

The BWR Owners Group evaluation[28] for participating utilities has concluded that neither recombiners nor containment venting is required to control combustible gas concentrations below the Regulatory Guide 1.7 (Safety Guide 7) allowable limits for the Mark I plants with inerted containments. These plants include the DAEC.

6.2.5.2 <u>System Design</u>

The containment atmosphere control system is shown in Figure 6.2-44.

6.2.5.2.1 Containment Purge System

The containment purge system introduces air to the drywell and pressure suppression chamber by a common fan that supplies 6000 cfm of air to two ducts leading to each area. The exhaust from each area is routed to a common header that permits sending the exhaust through the standby gas treatment system to the offgas stack. The vent path depends on the level of activity present in the gases.

The ventilation lines supplying air to the primary containment are provided with two fast-acting, pneumatic cylinder-operated butterfly valves in series for isolation purposes. These valves are normally closed during plant operation. The exhaust lines are also provided with the same type valves, which are normally closed during plant operation. The drywell and suppression pool chambers can be vented separately.

If the purge system is used for purging following a LOCA, the outboard normal containment isolation purge valve is opened to allow a flow path to the standby gas treatment system.

Procedures for normal primary containment venting and purging are established such that gaseous effluent releases from the station remain within the normal release limits. Purge or vent exhausts are directed to the outside atmosphere via the standby gas treatment system and the offgas stack. The primary containment purge and vent isolation valves are closed automatically on reactor building ventilation high radiation, fuel pool exhaust high radiation, drywell high pressure, reactor water low water level, and offgas stack high-high radiation. Override of containment isolation signals are provided by key-locked switches.

Drywell and torus purging will normally be conducted to facilitate personnel access subsequent to periods of operation with the primary containment inerted. Primary containment purge operations would normally release on the order of 1 million scf of gas. Drywell and torus venting is required during reactor startups to maintain normal operational primary containment pressure control as heat loads increase drywell atmosphere temperatures. The volume of gas released during venting operations is expected to be small compared to purge volumes.

Torus venting may also be used during a severe accident where structural failure of the containment due to overpressurization appears to be inevitable. The torus can be directly vented to the offgas stack bypassing the standby gas treatment system via the containment hard vent system. Venting will only be an option when the primary containment pressure limit (PCPL) is threatened or to maintain hydrogen and oxygen concentrations below the deflagration limits and will be administratively controlled by DAEC Emergency Operating Procedures.

Before purging or venting the containment, airborne contamination levels will be determined and estimates made of expected gaseous activity releases. The selection of release routes and release rates will be made so as to ensure compliance with the Technical Specifications. No special area controls or monitoring procedures are imposed during primary containment purging or venting operations. Primary containment venting by the use of the containment hard vent system will occur when directed by DAEC Emergency Operating Procedures, irrespective of radioactive releases, to maintain the containment pressure below the primary containment pressure limit (PCPL).

The drywell will be vented through the standby gas treatment system as required to maintain the post-LOCA repressurization pressure at or below 30 psig. The time required for the drywell pressure to reach 30 psig is a function of the containment leak rate. Assuming 0% leak rate, approximately 35 days are required to reach 30 psig using conservative Safety Guide 7 assumptions. However, the maximum drywell leak rate of 2% per day will prevent the drywell pressure from exceeding a peak value of 18 psig after approximately 40 days, at which time the pressure starts to decay slowly for the duration of the accident. Therefore, the actual purge initiation time must be determined following the accident by continuously monitoring the drywell pressure. Since this pressure buildup is slow and continuous, the operators will have sufficient time to ensure appropriate operator action.

The purge rate will be fixed by the system resistance of the 2-in. bypass around the inboard purge valve. This resistance has been selected so that with the bypass valve in the wide-open position and a containment pressure of 30 psig the purge rate will exceed the sum of the radiolytic formation rate and nitrogen addition rate by an appropriate margin. This will ensure a net decrease in containment pressure with time.

6.2.5.2.2 Containment Nitrogen Inerting System

The containment nitrogen inerting system is sized to allow the inerting of the drywell in a 4-hr period. The inerting equipment converts liquid nitrogen into gaseous nitrogen. Gaseous nitrogen is introduced into the primary containment through the containment purge system ventilation lines for the torus and drywell.

The nitrogen supply for initial inerting is from the normal nitrogen supply, which includes a large nonseismic liquid nitrogen storage tank (8 ft in diameter by 40 ft long). After initial inerting, containment atmosphere control at 4% oxygen by volume is maintained by the nitrogen inerting system.

Containment atmosphere control following a LOCA through the addition of nitrogen is accomplished by the CAD system described in Section 6.2.5.2.3.

6.2.5.2.3 Containment Atmosphere Dilution System

Figure 6.2-44 shows the containment atmospheric control system, which includes the CAD, inerting, and normal nitrogen makeup systems. The Seismic Category I compressed nitrogen storage for the CAD system, consisting of ten approximately 7735 scf tanks and associated valve manifold, is external to the reactor building and ties into the normal N_2 makeup system.

The nitrogen cylinders and header up to the first normally closed valve in each of the redundant supply lines constitute a "passive" system and, accordingly, are not subject to the single-failure criterion that applies only to "active" components. Therefore, it is not necessary that the CAD nitrogen source be redundant.

The compressed nitrogen is stored at 2400 psig. Thus, there are no limitations on this system functioning against containment pressure. Whenever the reactor is in power operation, the Post-LOCA Containment Atmosphere Dilution System shall contain a minimum of 50,000 scf of N_2 as determined by pressure and temperature measurements.

The CAD system includes a nitrogen compressor that takes a suction from the normal nitrogen supply system and charges the CAD nitrogen cylinders.

As a result of structural analyses performed in conjunction with a generic review of pressure suppression pool dynamic loads for the GE BWR Mark I containments, it was determined that if pool dynamic loads resulting from a postulated LOCA are considered, the margin of safety in the containment design for the DAEC was lower than originally intended. Thus, as a short term improvement, the DAEC installed a differential-pressure control system to mitigate the pool dynamic loads and thereby restore the margin of safety in the containment design. The differential-pressure control system maintained a positive differential pressure between the drywell and torus regions of the containment. This reduced the height of the water leg in the downcomers and subsequently would reduce the LOCA hydrodynamic loads.

The inclusion of a positive differential pressure between the drywell and torus resulted in a loss of nitrogen from the drywell to the torus airspace from leakage through the vacuum breakers on the vent headers. To minimize the loss of nitrogen from the system, the DAEC installed a recirculation system that collects the nitrogen in the torus and returns it to the drywell.

Two screw-type pump-back compressors and associated equipment are used to draw nitrogen from the torus and discharge it to the drywell (see Figure 6.2-44). These compressors take suction downstream of the drywell and torus purge fan discharge (reversing the flow in its discharge line) and discharge at a location near the suction of the nitrogen compressor (1K-14).

During the long term improvement program, all of the containment modifications were based on loadings assuming a zero differential pressure between the drywell and the torus. Thus, after all long term program modifications were completed, the differential pressure control system was no longer required and has been removed from the DAEC Technical Specifications.

However, the pump-back system has been retained as an operations aid for primary containment atmosphere control.

Two redundant oxygen-hydrogen analyzers are provided for monitoring the containment atmosphere. The Safety Guide 7 assumptions concerning the hydrogen generation rate from a metal-water reaction are extremely conservative. Consequently, an indication of the hydrogen concentration is required to determine whether or not the flammability limit for hydrogen is exceeded, and the dilution system is required to control the oxygen concentration. There are sample points in the torus and the drywell. The two analyzers are completely redundant and designed to withstand the effects associated with the DBE without a loss of function.

The analyzers are mounted on a control panel and located within the reactor building. The readouts are in the main control room. See Section 6.2.5.5.2.

6.2.5.3 <u>Design Evaluation</u>

The initial oxygen content in the containment before the occurrence of the postulated LOCA that was used in the CAD system analysis for the DAEC was 5% by volume. Because of the steam dilution effect resulting from a LOCA, the oxygen content volume is immediately reduced as indicated in Figure 6.2-64. The limiting condition for operation with respect to oxygen concentration in containment is 4.0% by volume as stated in the Technical Specifications.

Figure 6.2-63 plots the containment pressure response using the realistic assumptions of initial hydrogen release and subsequent gas releases from radiolysis shown in Figure 6.2-64.

In addition to oxygen evolving from metal-water reactions and from radiolysis, there are two additional sources of oxygen known at present in the BWR/containment system at the DAEC. First, the water and steam in the reactor itself will contain a small amount of dissolved and free oxygen. Following the LOCA, most of this water and steam will be released to the primary containment. If it is conservatively assumed that all of the dissolved oxygen would be released, there would be about 0.03 lb-moles of oxygen added to the primary containment. When this is compared to the 25 lb-moles of oxygen initially present (assuming containment inerted to 5% of oxygen) or the 1.1 lb-moles of oxygen generated by radiolysis (Safety Guide 7 assumptions) in the first hour after the LOCA, it can be seen that the oxygen in the primary system can be considered an insignificant amount.

Second, during review of NRC Generic Letter 84-09 regarding potential sources of oxygen inleakage into the primary containment, it was determined that the inflatable T-ring seals in the Torus-Reactor Building vacuum breakers and primary containment purge and vent valves use normal air as their working fluid. Further evaluation revealed that under a worst case failure of one of these seals, the oxygen level within primary containment could exceed the 5% limit after approximately three (3) days.

Therefore, the torus to reactor building vacuum breakers T-ring seals' pneumatic supply is monitored for signs of leakage on a daily basis to ensure that corrective action, if required, can be initiated prior to exceeding the 5% limit (see Section 6.2.5).

All remaining gaseous pneumatic systems in the drywell/torus use nitrogen as the working fluid; therefore, any inleakage from these systems is of no concern from a viewpoint of flammability control.

Zinc-bearing primers were used to prime the concrete surfaces of the drywell and torus for the DAEC. Limited experimental work performed at Oak Ridge National Laboratory has shown that the potential does exist for hydrogen offgassing as a result of a steam reaction with both top-coated and untop-coated zinc-bearing primers. However, the CAD system is designed to control oxygen concentrations in the inerted containment, not hydrogen concentrations.

The oxygen concentration in the primary containment will be maintained at less than 4% by adding nitrogen as a dilution gas. This approach is the result of the Safety Guide 7 assumption of 5% metal-water reaction, which results in hydrogen concentrations that rapidly exceed the specified 4% flammability limit.

Hydrogen gas additions due to zinc-steam reactions or any other postulated minor chemical sources are expected to contribute only a small fraction of the amount postulated for the metal-water and radiolysis mechanisms, and, in any case, these additions only serve to further dilute the oxygen concentration, thus delaying the need for nitrogen addition.

Corrosive containment sprays and emergency cooling solutions are not used in the DAEC. Emergency cooling water is expected to maintain a relatively neutral pH even following the postulated LOCA. Hydrogen, in addition to that produced by a postulated metal-water reaction and radiolysis, may be produced by a steam reaction with zinc-bearing containment coatings. However, noncombustible or combustible gas production due to corrosive reactions with suppression pool water are expected to be negligible because of its neutral condition.

The post-LOCA containment atmosphere will be monitored for combustible gas accumulation by redundant hydrogen-oxygen monitoring systems for the drywell and torus. Based on the conservative hydrogen and oxygen production assumptions of Safety Guide 7, Figure 6.2-64 traces the buildup of combustible gases following the postulated LOCA. It is shown that the oxygen flammability limit of 5% will be reached after approximately 3.5 days at the earliest. Manual override of system isolation and initiation of nitrogen addition will take place from the control room at or before this time to ensure a nonflammable containment atmosphere.

The sample time response of the hydrogen and oxygen analyzers is adequate to allow the operator time to act. The nitrogen addition will be done on a step basis. Redundant containment pressure gauges and oxygen and hydrogen sensors are available to continuously monitor containment conditions.

The only operator action required to operate the CAD system is to open the isolation valves and manually modulate one valve in each of the loops to the containment and torus. This can be done in a matter of minutes by operators in the main control room. Hydrogen and oxygen concentrations are monitored in the drywell and torus to provide indication so that the operators will know whether or not the system is functioning properly.

The hydrogen-oxygen analyzers are each 100% redundant including sampling points, analyzers, power supply, and remote-control capability (see Figure 6.2-65). Each of the redundant analyzers shown in Figure 6.2-65 can take a sample from either the torus or the drywell and return the sample to its source. The drywell penetrations serving the respective analyzer systems are approximately 180 degrees apart to ensure system redundancy (see Figure 6.2-44). The analyzer racks are 180 degrees apart, near their respective penetrations.

Atmospheric mixing in the containment is a complex function of diffusion and natural and induced convection. Largely because of the complex geometry of the containment, detailed and rigorous calculations of convection flow paths are impractical. However, a number of solutions of the diffusion equation for specific geometries and boundary conditions are available in the literature. Furthermore, by noting the similarities between the phenomena and equations governing mass and heat transfer, experimental heat-transfer data and their correlations can be used to predict the effect of convection on mass transfer.

This mass/heat transfer analogy was used to make a conservative prediction of the concentration gradients for oxygen and hydrogen in the suppression chamber. The results of this analysis are summarized in Figure 6.2-66, which shows a maximum oxygen concentration of 5.10% at the suppression pool surface for an average concentration of 5%. Because of its higher diffusivity, the concentration gradients for hydrogen are even less. Using less conservative assumptions with respect to natural convection, heat-transfer coefficients would result in a maximum oxygen concentration of only 5.015% at the pool surface.

Concentration gradients in the drywell were not specifically calculated. However, the existence of strong convection-inducing forces such as the high temperature differential between the reactor vessel and the drywell atmosphere, flow out of the broken pipe, and the drywell sprays would result in the calculation of smaller concentration gradients than were calculated for the relatively quiescent suppression chamber.

Given the conservatism of the Safety Guide 7 assumptions and the results of this analysis, the overall conclusion is that the assumption of uniform concentration in the containment is reasonable for performing calculations related to the CAD operation.

Analysis

The general diffusion equation (one dimension) is as follows:

$$\frac{dv_1}{dt} = \frac{K\delta^2 v_1}{\delta x^2}$$

This equation describes the transport of V_1 as a function of a "concentration" gradient, dv/dt. In the heat-induction problem, v is temperature and k is k/pc, where k is the thermal conductivity. In the mass-diffusion problem, v is the molecular density of the diffusing component and K is the coefficient of diffusion. Since the heat-transfer problem is more generally encountered, a large number of solutions of the diffusion equation for various boundary and initial conditions can be found in many textbooks and reference manuals.

Two particularly useful solutions that can be applied to the problem of radiolysis in the suppression chamber can be found in Carslaw and Jaeger[29] and in Schneider.[30] The Carslaw and Jaeger solution is for a slab with a constant flux at one surface, and is written as (for mass diffusion)

$$V = \frac{F_o t}{\ell} - \frac{F_o l}{K}\left[\frac{3x^2 - \ell^2}{6\ell^2} - \frac{2}{\pi}\sum_{n=1}^{\infty}\frac{(-1)^n}{n^2} e^{-kn^2\pi^2 t/\ell^2} \cos(n\pi X/\ell)\right]$$

where F_o is the flux.

Carslaw and Jaeger plot the solutions of this equation for various values of X/ℓ (normalized distance) and the dimensionless ratio, Kt/ℓ^2.

Schneider's solution is for essentially the same boundary conditions as Carslaw and Jaeger's except that flux is not a constant but linearly decreases with time. The solution is also plotted as a function of Kt/ℓ^2. Therefore, it can be seen that the problem is essentially one of evaluating the dimensionless ratio, Kt/ℓ^2. Previous analyses of the hydrogen problem have shown that no flammable condition exists until a number of days after the LOCA has occurred.

Furthermore, the height of the top of the suppression chamber above the pool surface is on the order of 500 cm. Therefore, the ratio of t/ℓ^2 (in sec/cm^2) is on the order of unity.

The values of K used in the analysis were evaluated from the coefficients of diffusion for hydrogen and oxygen and analogy between heat and mass-transfer coefficients. Kays[31] discusses the analogy between heat and mass transfer. He states that experimental heat-transfer data, expressed in terms of the Nusselt number, can be used to determine an equivalent mass-transfer coefficient. Noting that the Nusselt number is the ratio of convective to conductive heat transfer and that pure molecular diffusion is equivalent to heat conduction, the following relationship for a mass-transfer coefficient was developed:

$$K_{\text{convective mass transfer}} = Nu_{\text{heat transfer}} \times D$$

where Nu is the Nusselt number from experimental heat-transfer data and D is the classical molecular coefficient of diffusion. Values for the coefficient of diffusion can be found in various sources.[32, 33] The values selected for calculational purposes were D = 0.76 cm^2/sec for hydrogen and D = 0.2 cm^2/sec for oxygen.

Small variations in these values because of temperature and concentration changes are of second-order importance when compared to the order of magnitude of the convective term or the Nusselt number.

McAdams[34] is the most general reference source for experimental mental heat-transfer correlations. Using the correlations presented in the chapter on natural convection, Nusselt numbers from 25 $\Delta t^{1/4}$ to 150 $\Delta t^{1/4}$ (Δt is a temperature differential) can be calculated depending on what geometric assumptions are used. The temperature differential describes the buoyancy term that is the natural convection driving force. It can be seen that for even very small Δt's, the Nusselt number ranges from about 25 to 150.

Conservatively selecting the lowest Nusselt number of 25, the mass-transfer coefficient (K) used in the calculations was thus 19 for hydrogen and 5 for oxygen. Selecting 3 days (the time at which oxygen concentration reaches 5%) after the LOCA as t, Kt/ℓ^2 was 19.6 for hydrogen and 5.2 for oxygen.

Using these values for Kt/ℓ^2 in the Carslaw and Jaeger solution (constant flux) resulted in the concentration gradients shown in Figure 6.2-66. Only that portion of the total oxygen concentration that was a result of radiolysis (about 30%) was subject to the gradient calculation. The remaining oxygen was part of the original inventory, hence it does not have a gradient associated with it. All of the hydrogen was assumed to be subject to the gradient, even though a small part of it was from the hydrogen resulting from the metal-water reaction.

The Schneider solution, for a linearly decreasing flux, results in even smaller gradients than the constant flux solution. The actual flux is not decreasing linearly, of course; however, the Schneider solution does show that the assumption of constant flux is conservative.

If a Nusselt number of 150 had been used, the Carslaw and Jaeger solution would have yielded a maximum oxygen concentration of only 5.015% at the pool surface. The Schneider solution would have resulted in an even lower concentration.

The calculations of the maximum oxygen concentration that could occur in the containment were based on a conservative application of convective mixing forces to the basic diffusion equation. With the known conservatisms in the Safety Guide 7 assumptions relative to metal-water reaction and radiolysis (the need for actuation of the CAD system would probably never occur), the relative nonuniformity in the calculated concentrations was of such small magnitude that the need for a prescribed method of mixing the containment atmosphere was not considered necessary.

However, if it is required, periodic actuation of the containment sprays during the postaccident period may be used to further promote atmospheric mixing.

The concentration of steam at any time following the LOCA was calculated from the reasonable assumption that the drywell and suppression chamber gas spaces were at 100% relative humidity. Therefore, the concentration of steam was simply the ratio of the partial pressure of the water vapor to the total pressure of the containment. The partial pressure of the water vapor was obtained from standard steam tables as a function of temperature. The temperature used was from the standard post-LOCA containment response analysis as presented in Chapter 15.

The range of steam concentrations can vary from 100% in the drywell immediately following the blowdown down to practically zero. Choosing the zero leakage case for illustration, Figure 6.2-67 shows the steam concentration versus time in the drywell and suppression chamber following the LOCA.

Pressure in the containment, both short and long term, was calculated using the ideal gas equation of state and the partial pressure of water

$$P = \frac{nR_oT}{V} + P_{H_2O/T}$$

where

n = moles of noncondensible gases
R_o = ideal gas constant
T = gas temperature
V = volume
$P_{H_2O/T}$ = partial pressure of water at T

The temperatures and volumes (drywell and suppression chamber) are input values. The noncondensible gas inventory was continuously uprated accounting for leakage, nitrogen additions, radiolysis and metal-water reactions, and gas transfers between chambers.

The long-term pressure transient calculations were conservative because the use of the highest post-LOCA calculated temperature (i.e., minimum cooling, no sprays) from Chapter 15 results in a calculation of the peak containment pressure even after considering the additional amount of nitrogen that would be required at lower temperatures to compensate for the lower water vapor concentration. Figure 6.2-68 shows that for a constant oxygen concentration of 5%, pressure continually increases with increasing temperature. Therefore, the use of the highest temperature is conservative from a pressure viewpoint. Secondly, if some condition other than 100% relative humidity were assumed at the same temperature, the same total pressure would still result for CAD operation. This is because any loss in water vapor would have to be made up by an equal amount (moles) of nitrogen. Thus, at a given temperature, the total number of moles, hence pressure, would remain the same.

From the viewpoint of nitrogen makeup requirements, the long-term cumulative nitrogen makeup requirements are only slightly affected by variations in water vapor concentration. Figure 6.2-69 shows the relatively small effect of water vapor concentration on the total nitrogen requirements between the two extremes of 100% and 0% relative humidity. From a practical viewpoint, this means that total nitrogen supply requirements can be reasonably determined without too much concern about containment atmospheric conditions.

The analyses done for the DAEC were in strict accordance with Safety Guide 7. Therefore, the "entrained fission products" are accounted for in the assumption that 50% of the core halogens and 1% of the solids are intimately mixed with the coolant water. The reactor core was treated as a separate radiolysis source. The radiolysis rates from each of these sources (i.e., entrained fission products and the reactor core region) were calculated per the recommended assumptions in Safety Guide 7.

The drywell and suppression chamber were treated as separate volumes in the analysis. Hydrogen and oxygen generation in the drywell was based on radiolysis in the core region. Generation in the suppression chamber was based on radiolysis due to the entrained fission products. Communication between the two chambers via the vents and vacuum breakers was also accounted for in the calculations.

The selection of 30 days after the postulated design-basis LOCA for the evaluation of containment venting was arbitrarily selected to facilitate an incremental radiological exposure comparison with the 30-day LOCA exposures at the LPZ boundary. As stated in Safety Guide 7, venting is not required at that time for pressure control based on evaluations made in accordance with the parameters specified in Table 6.2-19.

The operation of the standby gas treatment system during the postaccident period has been specifically discussed with respect to flow rate, efficiency, and conditions of operation in Sections 6.2.3 and 6.5.3. Containment purge through the standby gas treatment system for post-LOCA combustible gas control is available as the backup control system to the CAD system as recommended in Regulatory Position 3 of Safety Guide 7.

The CAD system, including its nitrogen dilution and monitoring functions, is designed as an engineered safety feature, meeting the redundancy and seismic requirements of such systems and also the requirements of IEEE 279. Thus, the DAEC considers that total failure of the CAD system is incredible and that containment purge through the standby gas treatment system would never be necessary.

In the unlikely event that the standby gas treatment system should be used for containment purge, either to control combustible gas concentrations or containment pressure buildup (because of CAD system operation), no effects detrimental to standby gas treatment system operation or efficiency are expected. The maximum required purge flow rates of less than 100 scfm are well within the flow rate capability of the standby gas treatment system. Moisture or steam additions to the air stream will be controlled by an upstream moisture eliminator and preheater combination that maintains a downstream relative humidity (at the HEPA and deep-bed charcoal filters) of 70% or less. The deep-bed carbon filter has been sized to accommodate 25% of the equilibrium core mass inventory of iodine, and the overall system is capable of operating under the predicted range of temperature conditions for primary containment gases that could exist from 3.5 days after the postulated LOCA. (Three-and-one-half days after a LOCA is the shortest calculated time period after which combustible gas control could become necessary for the DAEC under the assumptions of Safety Guide 7 and assuming an initial containment oxygen level of 4%.)

Nitrogen concentrations either higher or lower than normal air concentrations will have no effect on standby gas treatment system operation or efficiency.

Stratification of hydrogen leakage from the drywell into the reactor building or compartments is not a problem at the DAEC because in areas where there are potential ignition sources, adequate purging and mixing due to convection and the high diffusion rate of hydrogen, respectively, prevent the formation of localized combustible gas mixtures. The only area having a significant potential for the formation of localized combustible gas mixtures is considered to be the personnel access room, where a significant portion of the total drywell leakage is expected to occur. Ventilation openings are provided such that a continuous purge, due to convection, caused by the temperature differential between the suppression chamber area (below the personnel access room) and the area above the personnel access room, will maintain the concentration of hydrogen in the personnel access room at less than 4% by volume.

The leaktightness of the main steam isolation valve is maintained within the Technical Specification limit through regular testing and maintenance. Once the main steam isolation valve is closed, there is nothing that can degrade the seal leakage capability over a prolonged period so long as the seat loading force is maintained. The seat loading force comes from the annular spring and the pressure of the Class 1 nitrogen supply system.

The remaining isolation valves are periodically tested to ensure that Technical Specification leakage is not exceeded and that isolation valve leakage remains at an acceptable level. Once an isolation valve is closed, there is nothing to degrade the seat and thereby increase drywell leakage.

Any long-range postaccident pressure transient is below the drywell bellows and drywell penetration design values. For this reason, no degradation is expected during an extended pressure-temperature transient due to a LOCA and subsequent repressurization by the CAD system.

Structures within the primary containment are designed to withstand the long-term effects of a postulated LOCA.

6.2.5.4 Tests and Inspections

Surveillance requirements for the containment purge system, CAD system, CAD nitrogen storage and CAD system hydrogen-oxygen analyzers are contained in the Technical Specifications.

The post-LOCA Containment Atmosphere Dilution System shall be functionally tested annually.

6.2.5.5 Instrumentation Requirements

6.2.5.5.1 Containment Atmosphere Monitoring System

To provide the operator with essential information, the following containment parameters are monitored by instruments shown in Figure 6.2-44:

1. Temperature (drywell and torus).

2. Pressure (drywell and torus).

3. Humidity (drywell).

4. Radioactive particulate, halogen, and gaseous activities (drywell and torus

5. Oxygen concentration (drywell and torus).

6. Hydrogen concentration (drywell and torus).

Containment temperature, pressure, and radioactive particulate, halogen and noble gas activities are continuously indicated and recorded in the main control room. The drywell temperature, pressure, and atmosphere radioactivity monitoring systems are used for the drywell nuclear system leak detection as discussed in Section 5.2.5.3.4.

The containment pressure monitor system consists of two low-pressure channels with a range of -5 to +5 psig, two high-pressure channels with a range of 0 to 250 psig, and two intermediate range channels measure drywell pressure with a range of -10 to +90 psig. The containment pressure monitor system channels have indicator and recorder readouts in the control room. The low-pressure indicator loop has a system accuracy of 1.9% and the reactor loop has a system accuracy of 0.9%. The high-pressure recorder loop has a system accuracy of 0.9%. New digital indicating recorders were installed during the Cycle 9/10 Refueling Outage and have a recorder accuracy better than those they replaced. The two high-pressure channels do not have separate indicators, but use the digital indicators of the recorders. Both indicator loops have a response time of 0.3 sec. and both recorder loops have a system response time which varies between 0.3 and 3.8 sec, increasing with a magnitude of the pressure transient. The containment pressure monitor system satisfies the requirements of NUREG-0737, Item II.F.1.4. Drywell pressure is also provided on two redundant 0 to 100 psig indicators on panel 1C03. Indication of torus pressure is provided on panel 1C03 on two redundant 0-100 psig indicators.

Containment temperature is monitored from resistance temperature detectors located in eight positions in the drywell and four positions above the water level in the suppression chamber. The instrument range is 0 to 350°F for the drywell and 0 to 300°F for the torus. The accuracy is ± 1% of the range. Two of the drywell temperatures are averaged and displayed on panel 1C03 in the Control room (for EOP use).

Humidity within the primary containment is indicated locally from 0 to 100% relative humidity. See Section 7.5.1.7.

The containment hydrogen monitoring system has an indicator accuracy of 3.9% of full scale and a recorder accuracy of 2.8% of full scale. Full scale is 0 to 10% or 0 to 20% by volume hydrogen. There are two hydrogen sample ports in the suppression pool and four ports within the drywell for detection of hydrogen escaping from the pressure vessel. The sample lines from the sample ports can be operator-selected by handswitches on the control room hydrogen-oxygen monitor panel. The containment hydrogen monitoring system satisfies the requirements of NUREG-0737, Item II.F.1.6.

Containment oxygen is monitored in conjunction with the nitrogen inerting system. Oxygen is sampled from several locations within the containment to determine when the oxygen concentration is below the value required for plant operation or to determine when oxygen concentration is high enough to permit access by personnel.

Containment oxygen and hydrogen are monitored following a LOCA in conjunction with the CAD system for post-LOCA combustible gas control. See Section 6.2.5.5.2.

6.2.5.5.2 Postaccident Containment Atmosphere Monitoring

The DAEC containment atmosphere monitoring system has provisions for postaccident containment atmosphere monitoring. The system contains redundant hydrogen, oxygen, and radioactive particulate, halogen and noble gas analyzers that are located on opposite sides of the containment in the reactor building. Each analyzer is provided with redundant pumps that permit containment atmosphere monitoring when the containment is at negative or positive pressure. The hydrogen-oxygen analyzers are designed to operate under post-LOCA conditions. The readout for all of the analyzers is in the main control room. Although the lines from the containment to the analyzers isolate with a containment isolation signal, the isolation valve switches on the control panel are provided with a key-locked override feature, which will permit the opening of the Drywell and Torus Sample Lines valves with PCIS Group 3 isolation signal present. This allows the H_2 and O_2 Analyzers to be restored to Service as directed by Emergency Operating Procedures.

The hydrogen-oxygen analyzer systems are designed to operate under the following containment sampling conditions:

Nitrogen	32 to 98%
Oxygen	0 to 25%
Hydrogen	0 to 10%
Steam	0 to 67%

Relative humidity	100%
Pressure	-2 to 56 psig
Temperature	100 to 300°F*
Radiation background	1.5×10^4 rad/hr (decaying to 4.1×10^3/hr after 1 month)

The hydrogen analyzers and recorders have two scales, 0 to 10% and 0 to 20% by volume hydrogen. The oxygen analyzers and recorders have two scales, 0 to 10% and 0 to 25% by volume oxygen. The analyzer systems are designed to collect and condition gas samples for introduction to the analyzers for analysis for hydrogen and oxygen content.

The radioactive particulate, halogen and noble gaseous activity analyzers are not designed for postaccident radioactivity levels, and therefore, cannot be used for monitoring postaccident containment atmosphere radioactivity. However, grab samples can be obtained from valved sample points at the analyzers, so that the containment atmosphere radioactivity can be analyzed at the postaccident sampling analysis laboratory described in Section 12.3.4.2.6.

6.2.5.5.3 Drywell/Torus Differential Pressure

The instrumentation used to control the drywell/torus differential pressure is shown in Figure 6.2-44. The two functions provided by the instrumentation are control of CV4316 and the alarm. There is a single channel provided for the instrumentation functions. The alarm location is panel 1C35 in the control room.

Direct pressure readout instrumentation is used to monitor the drywell/torus differential pressure. After completion of the long term program modifications, the differential pressure was no longer required, but has been retained in the plant as an operations aid.

* At high containment temperatures, the analyzer systems may not provide accurate indication. However, after 30 minutes have passed from safety injection, and containment temperature has decreased, the indications will be within the accuracy required by Reg Guide 1.97.

6.2.6 CONTAINMENT LEAKAGE TESTING

The DAEC has implemented a Primary Containment Leakage Rate Testing Program (Reference 39).

6.2.6.1 Containment Integrated Leakage Rate Test

6.2.6.1.1 Primary Containment Integrity and Leaktightness

Fabrication procedures, nondestructive testing, and sample coupon tests were made in accordance with the ASME B&PV Code, Section III, Subsection B. The integrity of the primary containment system was verified by a pneumatic test of the drywell and suppression chamber at 1.25 times their design pressure of 56 psig in accordance with code requirements.

6.2.6.1.2 Primary Containment Leak Testing

After the completion of the construction of the primary reactor containment and the installation of all systems penetrating the containment pressure boundary, the vessel was pressurized to the calculated peak containment internal pressure as determined by the containment response analysis (Chapter 15) for the design-basis accident. This initial test verified that the integrated leakage rate did not exceed the design-basis accident leakage rate used in Chapter 15 to calculate the radiological consequences of the design-basis accident. Since both the drywell and suppression chamber are designed for the same pressure, it was possible to test the entire primary containment at the same time without the necessity of providing temporary closures to isolate the suppression chamber from the drywell. The necessary instrumentation was installed in the vessel to provide the data required to calculate and verify the leakage rate. Provisions were made to permit periodic leakage rate retests. Periodic primary containment integrated leakage rate tests are conducted in accordance with the Primary Containment Leakage Rate Testing Program.

6.2.6.2 Penetration Leakage Rate Tests

Pipe penetrations that must accommodate thermal movement are provided with two-ply expansion bellows, such as the penetration shown in Figure 6.2-4. By the use of the pressure test tap, a gas can be injected into the annulus between the two-ply bellows, and by soap film, pressure decay, or other means, leakage can be detected and measured during shutdown without pressurizing the entire primary containment system. The test tap will be plugged during normal operation to prevent leakage through the test tap plug in the event of a leak within the penetration.

Electrical penetrations are also provided with double seals and are also separately testable. The test taps and seals will be located so that the tests of the electrical penetrations can be conducted without entering or pressurizing the drywell or suppression chamber.

All containment closure covers that are fitted with resilient seals are separately testable. The covers on flanged closures, such as the equipment access hatch cover, the drywell head, the access manholes, CRD removal hatch, torus manholes, and TIP penetrations are provided with double seals and with a test tap that allows the pressurization of the space between the seals without pressurizing the entire containment system. The personnel airlock doors are tested by pressurizing the airlock itself through test connections provided on the exterior bulkhead.

6.2.6.3 Isolation Valve Leakage Rate Tests

The test capabilities that are incorporated in the primary containment system to permit leak detection testing of containment isolation valves are different for valves in category A and B lines.

The first category consists of those valves in lines that open into the containment and are not connected to the reactor vessel (category B). In lines that contain two power-operated isolation valves in series, a test tap is provided between the valves, which permits leakage monitoring of the first valve when the containment is pressurized. The test tap can also be used to pressurize between the valves to permit leakage testing of both valves simultaneously.

The second category consists of those valves in lines that are connected to the reactor vessel (category A). In lines that contain two power-operated valves in series, except for the reactor sample lines for the postaccident sampling system, a test tap is provided between the valves, which permits leakage monitoring of the first valve when the reactor vessel is pressurized. The test tap can also be used to pressurize between the valves to permit leakage testing of both valves simultaneously when the reactor vessel is not pressurized. In lines that contain an inboard check valve in addition to the outboard power-operated valves, mentioned above, leakage through the inboard check valve can be monitored through the test tap. The test taps for the isolation valves on the reactor sample lines are located upstream of the inboard valves.

Isolation valve closing time was determined during the functional performance test before reactor startup.

6.2.6.3.1 Reactor Feedwater and CRD Hydraulic Lines

A test connection is located between the series check valves in each of the reactor feedwater lines. With the reactor pressurized, leakage past the inboard check valve could be detected at the test connection. With the gate valve on the reactor side of the inboard stop check valve closed and the line pressurized, a pressure loss could be detected at the test connection. This would indicate leakage past the outer check valve.

The same arrangement also exists in the CRD system hydraulic lines except that check valves are employed.

6.2.6.3.2 Vacuum Relief Valves/Lines

A test connection is provided between the two valves in the reactor building-to-torus vacuum relief lines. With the inner air-operated valve held shut, leakage past the outer check valve will be measured. Each of the two parallel lines would be tested individually. Thus, if the plant were in operation during the tests, the vacuum-breaking capability would still be effective.

6.2.6.3.3 Valves in Instrument Sensing Lines

A representative sample of the instrument line excess flow check valves are checked during every operating cycle (such that all valves are tested within 10 years). Functional testing of the valve is accomplished by venting the instrument side of the tube. The resultant increase in flow imposes a differential pressure across the poppet, which compresses the spring and decreases flow through the valve.

Excess flow check valves will be exercised at the frequency specified in the Technical Specifications. The remote position indication will be verified in the closed direction at the same frequency as the exercise test. After the close position test, the valves will be reset, and the remote open position indication will be verified. The DAEC verifies the excess flow check valves indicate open in the control room at a frequency greater than once every 2 years.

Valves will be accepted if

1. A marked decrease in flow rate is observed.

2. The operator observes a change of valve plug position.

In the event any valve does not meet the acceptance criteria, it will be replaced or repaired.

6.2.6.3.4 Drywell Head Seal Leak Detection Line

The drywell head seal leak detection line cannot be tested in the same manner as the instrument sensing valve lines (Section 6.2.6.3.3). This valve will not be exposed to primary system pressure except under unlikely conditions of seal failure where it could be partially pressurized to reactor pressure. Any leakage path is restricted at the source and therefore this valve need not be tested. This valve is in a sensing line that is not safety related.

6.2.6.3.5 Drywell Vent System Leak Testing

6.2.6.3.5.1 General

The DAEC conducted a leak test of the drywell vent system (vent pipes, headers, downcomers, and vacuum breakers) and has been conducting the same test at the end of each regularly scheduled refueling outage before the pressurization of the primary system.

The test involved pressurizing the drywell by approximately 1 psi with respect to the wetwell; the subsequent wetwell pressure transient was then monitored. The leak test is described below. This test has also been performed once every month during commercial operation of the DAEC.

6.2.6.3.5.2 Maximum Acceptable Leakage

Chapter 15 discusses the maximum allowable bypass leakage for the DAEC containment in detail. It is shown there that the maximum allowable leakage area is approximately 0.2 ft^2 ($A/\sqrt{K} = 0.11$ ft^2). This corresponds to the area of a 6-in. pipe.

6.2.6.3.5.3 Test Description

Objective

The objective of the routine leak testing is to detect flow paths between the drywell and the wetwell whose total capacity is equal to or greater than the capacity of a plate orifice 1 in. in diameter.

A 1-in. pipe is the smallest pipe in the vent system whose failure could result in drywell-to-wetwell leakage. There are eight of these 1-in. lines, which serve as drain lines for the vent headers.

A 1-in. plate orifice has an $A\sqrt{K}$ of approximately 0.0033 ft^2. The maximum leakage capacity that the DAEC primary containment can tolerate, assuming a 10-min operator delay, is $A\sqrt{K} = 0.11$ ft^2. Thus, the leakage test has the capability to detect a leak whose capacity is only 3% of the maximum allowable.

Test Procedure

The drywell pressure was increased by approximately 1 psi with respect to the wetwell pressure and held constant. The 2-psig scram setpoint was not exceeded. The subsequent wetwell pressure transient was monitored with a precision pressure gauge capable of detecting a small pressure increase. When the drywell pressure cannot be increased by 1 psi over the wetwell pressure, a significant leak path exists; in this case the leakage source is identified and eliminated before primary system pressurization. The occurrence of leakage in excess of the Technical Specification limit also calls for the identification and elimination of the leakage source before primary system pressurization. The same procedure has been followed in subsequent tests.

Acceptability

With a differential pressure of greater than 1 psi, the rate of change of the wetwell pressure must be such that the corresponding calculated bypass area is less than that of an equivalent 1-in. orifice. In the event that the rate of change exceeds this value, than the source of leakage will be identified and eliminated before power operation. Figure 6.2-70 shows the drywell and wetwell pressure transients assuming leakage through a 1-in. orifice and assuming that the drywell pressure is increased 1.25 psi in a 5-min period. Figure 6.2-71 shows the associated pressure differential between the drywell and the wetwell. It can be seen that there is a 20-min period during which the differential pressure would be greater than 1 psi; thus, there is ample time to conduct a 10-min test.

Test Schedule

The drywell-to-wetwell test has been performed at the end of each regularly scheduled refueling outage and before the pressurization of the primary system.

Boundary Conditions

During the test period there was no operation of the following equipment:

1. The RHR system in either the containment spray or pool cooling mode.

2. The RCIC system.

3. The HPCI system.

4. The relief valves.

The objective of these restrictions was to prevent temperature variations in either the pool or the suppression chamber airspace during the test.

The leakage test has been conducted at the end of each refueling outage; during this time, there were no energy dumps to the pool, and a constant temperature situation existed in the suppression chamber at the time of the test.

6.2.6.4 Scheduling of Periodic Tests

Periodic leak rate tests will be conducted in accordance with the Primary Containment Leakage Rate Testing Program.

6.2.6.5 Special Testing Requirements

See Section 6.2.3.4 for test procedures for the secondary containment leakage rate.

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PRIMARY CONTAINMENT SYSTEM DESIGN

Principal Design Parameters and Characteristics

Drywell (ASME modified)	- internal design pressure	56 psig
	- external design pressure	2 psig
Design temperature of drywell		281°F
Pressure suppression chamber (ASME modified)	- internal design pressure	56 psig
	- external design pressure	2 psig
Design temperature of pressure suppression chamber		281°F
Drywell free volume, including vent system		130,000 ft^3 (approx.)
Drywell vessel gross volume		157,700 ft^3 (approx.)
Pressure suppression chamber free volume	- minimum	94,070 ft^3 (approx.)
	- gross	155,570 ft^3 (approx.)
Pressure suppression pool water volume	- minimum	58,900 ft^3
	- maximum	61,500 ft^3
Pool water depth	@ min. pool volume	10 ft 1-5/16 in. (approx.)
	@ max. pool volume	10 ft 5-5/16 in. (approx.)
Pool cross-sectional area	- minimum	190 ft^2 (approx.)

Vent/Downcomer System

Number of vents		8
Nominal vent inside diameter		4 ft 9 in.
Total vent area		142 ft^2 (approx.)
Number of downcomers		48
Nominal downcomer inside diameter		23.5 in.
Submergence of downcomer below pressure suppression pool surface	@min. pool volume	3 ft 0-5/16 in.
	@max. pool volume	3 ft 4-5/16 in.
Vent system flow path loss coefficient		4.65

Table 6.2-1

PRIMARY CONTAINMENT SYSTEM DESIGN

Design-Basis Accident Initial Conditions and Calculated Results - Original Analysis

Effective break area		2.75 ft^2
Break area/total vent area		0.0194
Nuclear steam supply system[a] - volume of water in vessel		6,187 ft^3
- volume of steam in vessel		4,215
- volume of water in recirculation loops		625
	Total	11,027 ft^3
Reactor power level		1658 MWt
Reactor pressure		1035 psia
Containment heat removal capability per loop, using 95°F service water and 165°F pool temperature; two RHR pumps and two RHR service water pumps		36.6 x 10^6 Btu/hr
Calculated peak pressure during blowdown (no prepurge)		
Drywell		54 psig
Pressure suppression chamber		25 psig
Design initial pressure suppression chamber temperature rise		50°F

[a] Does not include main steam, feedwater or other piping connected to reactor vessel except for recirculation piping.

Table 6.2-6

PRIMARY CONTAINMENT DIMENSIONS

Drywell	
Cylindrical section - internal diameter	32 ft 0 in.
- height	27 ft 6-1/2 in.
Spherical section - internal diameter	63 ft 0 in.
- height	48 ft 1/2 in.
Spherical shell to cylindrical neck - height	5 ft 7-1/2 in.
Wall Plate Thickness	
Spherical shell	3/4 to 1-1/2 in.
Spherical shell to cylindrical neck	2-1/2 in.
Cylindrical neck	3/4 to 1-3/8 in. (varies)
Top head	1-3/8 in.
Pressure Suppression Chamber (Torus)	
Torus internal diameter	25 ft 8 in.
Torus major diameter	98 ft 8 in.

Table 6.2-7

DRYWELL LOADING COMBINATIONS

CB&I Case Number

Loads	(1) Overload Test	(2) Final Test	(3) Construction	(4) Normal Operating		(5) Refueling	(6) Accident		(7) Flooding	Load Symbol[a]
Dead load, vessel and attachments	X	X	X	X	X	X	X	X	X	D
Pressure (psi)										
Positive	70	56		2			56			R
Negative					2	2		2		R
Contained air	X	X								D
Lateral load, seismic or wind	X	X	X	X	X	X	X	X	X	E or E'
Vertical load, seismic	X	X	X	X	X	X	X	X	X	E or E'
Vent thrusts	X	X		X	X					R
Equipment support loads		X		X	X	X	X	X	X	D
Personnel lock										
Dead load	X	X	X	X	X	X	X	X	X	D
Live load				X	X	X	X	X	X	D
Equipment hatches										
Dead load	X	X	X	X	X	X	X	X	X	D
Live load				X	X	X	X	X	X	D
Refueling seal loads				X	X					D
Water on refueling seals						X				D
Jet forces							X	X		R
Hydrostatic pressure due to flooding									X	Flood

[a] Used to indicate load combinations in Tables 6.2-9 through 6.2-14.

6.3 EMERGENCY CORE COOLING SYSTEMS

6.3.1 DESIGN BASES AND SUMMARY DESCRIPTION

This section provides the design bases for the emergency core cooling systems (ECCS), formerly the core standby cooling systems (CSCS), and a summary description of these systems as an introduction to the more detailed design descriptions provided in Section 6.3.2 and to the performance analysis provided in Section 6.3.3.

6.3.1.1 Design Bases

6.3.1.1.1 Performance and Functional Requirements

The ECCS is designed to provide protection against the postulated LOCA caused by ruptures in the primary system piping. The functional requirements (i.e., coolant delivery rates) specified in detail in Table 6.3-1 are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of 10CFR50.46. (Note: These are the original design values. Sensitivity studies have been performed (Reference 12) that demonstrate that margin is available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. Actual relaxation of these performance requirements will be evaluated on a case-by-case basis.) These requirements, the most important of which is that the post-LOCA peak cladding temperature (PCT) be limited to 2200°F, are summarized in Section 6.3.3. In addition, the ECCS is designed to provide the following:

1. Protection is provided for any primary system line break up to and including the double-ended break of the largest line.

2. Two independent phenomenological cooling methods (flooding and spraying) are provided to cool the core.

3. One high pressure cooling system is provided, which is capable of maintaining the water level above the top of the core and preventing automatic depressurization system (ADS) actuation for small breaks.

4. Automatic actuation is provided such that no operator action is required until 10 min after an accident, to allow for operator assessment and decision.

5. The ECCS is designed to satisfy all criteria specified in this section for any normal mode of reactor operation.

6. A sufficient water source and the necessary piping, pumps, and other hardware are provided so that the containment and reactor core can be flooded for possible core heat removal following a LOCA.

6.3.1.1.2 Reliability Requirements

The following reliability requirements apply:

1. The ECCS conforms to all applicable requirements for redundancy and separation.

2. To meet the above requirements, the ECCS network has built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. As a minimum, the following equipment makes up this system:

    a. One high-pressure coolant injection (HPCI) system.

    b. Two core spray (CS) systems.

    c. One low-pressure coolant injection (LPCI) system.

    d. One automatic depressurization system (ADS).

3. The system is designed so that a single active component failure, including power buses, electrical and mechanical parts, cabinets, and wiring, cannot disable the automatic depressurization system.

4. If there is a break in a pipe that is not a part of the ECCS, no single component failure in the system prevents automatic initiation and successful operation of less than one of the following combinations of ECCS equipment:

    a. Two LPCI pumps, one core spray loop, the automatic depressurization system, and the HPCI system (i.e., single diesel-generator failure).

    b. Two LPCI pumps, one core spray loop and the automatic depressurization system (i.e., Division II 125V battery failure).

    c. Four LPCI pumps, two core spray loops, and the automatic depressurization system (i.e., HPCI failure).

    d. Two core spray loops, the HPCI system, and the automatic depressurization system (i.e., LPCI injection valve failure).

5. If there is a break in a pipe that is a part of the ECCS, no single component failure in the system prevents automatic initiation and successful operation of less than one of the following combinations of ECCS equipment:

   a. Two LPCI pumps, the HPCI system, and the automatic depressurization system (core spray break with a concurrent diesel-generator failure).

   b. Two LPCI pumps and the automatic depressurization system (core spray break with a concurrent Division II 125V battery failure).

   c. One core spray, HPCI system, and automatic depressurization system (core spray, LPCI injection valve failure).

   d. Two LPCI pumps, one core spray loop, and automatic depressurization system (HPCI break with a concurrent diesel-generator failure or HPCI break with a concurrent single 125V battery failure).

   e. Two core spray loops and automatic depressurization system (HPCI break, LPCI injection valve failure).

   These are the minimum ECCS combinations that result after assuming any failure (from item 4 above), and assuming that the ECCS line break disables the affected system.

6. Long-term (10 min after initiation signal) cooling requirements call for the removal of decay heat via the service water system. In addition to the break that initiated the loss-of-coolant event, the system can sustain one active failure and still have at least one RHR pump with a heat exchanger, and 100% service water flow to the heat exchanger operating for heat removal. For the LOCA analysis of Reference 4b, long-term core cooling requires core reflood above the top of the active fuel (TAF) OR core reflood to top of the jet pump and one core spray operating.

7. Offsite ac power is the preferred source of ac power for the ECCS network, and every reasonable precaution is made to ensure its high availability. However, onsite ac power has sufficient diversity and capacity to meet all the above requirements, even if offsite ac power is not available.

8. Each system of the ECCS network, including flow rate and sensing networks, is capable of being tested during shutdown. All active components (except those that could impact on plant operation) are capable of being tested during plant operation, including logic required to automatically initiate component action.

9. Provisions for testing the ECCS network components (electronic, mechanical, hydraulic and pneumatic, as applicable) are installed in such a manner that they are an integral and nonseparable part of the design.

6.3.1.1.3 ECCS Requirements for Protection from Physical Damage

The ECCS piping and components are protected against damage from the effects of movement, thermal stresses, the effects of the LOCA, and the design-basis earthquake (DBE).

The ECCS is protected against the effects of pipe whip, which might result from piping failures up to, and including, the design-basis LOCA. This protection is provided by separation, pipe whip restraints, or energy-absorbing materials if required. One of these three methods is applied to provide protection against damage to piping and components of the ECCS, which otherwise could reduce ECCS effectiveness to an unacceptable level.

For the purpose of mechanical separation ECCS components are in two divisions. The Division 1 ECCS components include the following:

1. Core spray loop A.

2. RHR pumps A and C.

3. Automatic Depressurization System.

The Division 2 ECCS components include the following:

1. Core spray loop B.

2. RHR pumps B and D.

3. High-pressure coolant injection.

Two RHR pumps and one core spray pump in each division are in a common compartment (the HPCI pump is in its own compartment). This compartmentalization ensures that environmental disturbances such as fire, pipe rupture, flooding, etc., affecting one division does not affect the remaining division. For ECCS mechanical components outside the pump compartments, such as the outboard containment isolation valves, separation between the different divisions is provided by distance or by locating the components in different compartments.

Electrical separation is described in Section 8.3.

6.3.1.1.4 ECCS Environmental Design Basis

Each system of the ECCS injection network, except the HPCI system, has a safety-related injection/isolation check valve located in piping within the drywell. The HPCI system injects through the feedwater system, and the (non-ECCS) RCIC system injects through the other feedwater system. However, both systems have isolation valves in the drywell portion of their steam supply piping. No portion of the ECCS and RCIC piping is subject to drywell flooding, since water drains into the suppression chamber through the downcomers.

6.3.1.2 Summary Descriptions of ECCS

The ECCS injection network comprises an HPCI system, a low-pressure core spray system, and the LPCI mode of the RHR system. These systems are briefly described here as an introduction to the more detailed system design descriptions provided in Section 6.3.2. The automatic depressurization system, which assists the injection network under certain conditions, is also briefly described. Boiling-water reactors (BWRs) with the same ECCS design are listed in Reference 1.

6.3.1.2.1 High-Pressure Coolant Injection System

The HPCI system pumps water through one of the feedwater spargers. The primary purpose of the HPCI system is to maintain the reactor vessel water inventory after small breaks that do not depressurize the reactor vessel.

6.3.1.2.2 Core Spray System

The two core spray system loops pump water into peripheral ring spray spargers, mounted above the reactor core. The primary purposes of the core spray are to provide inventory makeup and spray cooling during large breaks in which the core is calculated to uncover. Following ADS initiation, the core spray provides inventory makeup following a small break.

6.3.1.2.3 Low-Pressure Coolant Injection

Low-pressure coolant injection is an operating mode of the RHR system. Four pumps deliver water from the suppression pool to the selected recirculation loop, which discharges inside the core shroud region. The primary purpose of low-pressure coolant injection is to provide vessel inventory makeup following large pipe breaks. Following ADS initiation, low-pressure coolant injection provides inventory makeup following a small break.

6.3.1.2.4 Automatic Depressurization System

The automatic depressurization system uses a number of the reactor safety relief valves to reduce reactor pressure during small breaks, in the event of HPCI failure. When the vessel pressure is reduced to within the design of the low-pressure systems (core spray and low-pressure coolant injection), these systems provide inventory makeup so that acceptable postaccident temperatures are maintained.

6.3.2 SYSTEM DESIGN

More detailed descriptions of the individual systems, including individual design characteristics of the systems, are covered in detail in Sections 6.3.2.2.1 through 6.3.2.2.4. The following discussion provides details of the combined systems, and in particular, those design features and characteristics that are common to all systems.

6.3.2.1 Piping and Instrumentation and Process Diagrams

The piping and instrumentation diagrams for the ECCS and the process diagrams that identify the various operating modes of each system are identified in Section 6.3.2.2.

6.3.2.2 Equipment and Component Descriptions

The starting signal for the ECCS comes from at least two independent and redundant sensors of high drywell pressure and low reactor water level. The ECCS is actuated automatically and is designed to require no operator action during the first 10 min following the accident. A time sequence for starting the systems is provided in Table 6.3-2. (Note: These are the original design values. Sensitivity studies have been performed (Reference 12) that demonstrate that margin is available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. Actual relaxation of these performance requirements will be evaluated on a case-by-case basis.)

Electric power for operating the ECCS (except the dc-powered HPCI and automatic depressurization system) is from the preferred offsite ac power supply. Upon loss of the preferred source, operation is from the onsite standby diesel-generators. Chapter 8 contains a more detailed description of the power supplies for the ECCS.

The DAEC design requires containment pressure for adequate ECCS net positive suction head (NPSH) following a DBA LOCA at elevated suppression pool temperatures. Clarification of these system requirements are identified in Section 1.8.1 and in Figure 5.4-15.

HPCI system initiation automatically actuates the following valves:

1. HPCI system pump discharge test bypass valves.
2. HPCI system pump suction shutoff valve.
3. HPCI system pump discharge shutoff valve.
4. HPCI system steam supply shutoff valve.
5. HPCI system turbine stop valve.
6. HPCI system turbine control valve.
7. HPCI system steam supply line drain isolation valves.
8. HPCI system condensate drain isolation valves.
9. HPCI system steam supply isolation valves.
10. HPCI system cooling water supply valve.

The hydraulic oil pump must be started and the hydraulic control system must be functioning properly before the turbine valves can be opened. The barometric condenser components must be operating to prevent outleakage from the turbine shaft seals. The startup of the equipment is automatic, but its failure does not prevent the HPCI system from fulfilling its core-cooling objective. This is because even with steam leakage past the turbine shaft seals and valve stems into the room, no system operational limits or radiological limits are exceeded. Before startup, the control governor may be anywhere between its high-speed and low-speed stop positions. On the receipt of an initiating signal, the flow control signal automatically runs the control governor toward its high-speed stop. (The maximum demand signal is received from the flow controller.) The same initiating signal automatically starts the hydraulic oil pump, and when enough oil pressure is developed, both the turbine stop valve and the control valves open simultaneously and the turbine accelerates to the speed setting of either the control governor or the speed governor, whichever is lower. When rated flow is established, the flow controller signal adjusts the setting of the control governor to maintain rated flow as nuclear system pressure decreases.

A minimum flow bypass is provided for pump protection and to help prevent an overspeed trip that might otherwise occur if the system were started with no discharge path available. The bypass valve automatically opens on a low-flow signal, and automatically closes on a high-flow signal. When the bypass is open, flow is directed to the suppression pool. A system test line provides recirculation to the condensate storage tank during system test. Shutoff valves are provided with proper interlocks that automatically close the test line on the receipt of an HPCI system initiation signal.

Initial preoperational testing of the HPCI and RCIC systems at several BWRs revealed varying degrees of water hammer and check valve slamming that are undesirable. Preliminary testing of these systems at the DAEC (using house boiler steam) revealed a tendency for check valve noise plus the potential for water hammer, even with the improved piping layout incorporated in the DAEC design. A 2-in. vacuum breaker that allows the torus atmosphere to communicate with the HPCI/RCIC exhaust piping during turbine operation was added to mitigate these dynamic conditions.

The modification consisted of vacuum breakers to ensure that during HPCI/RCIC system operation and subsequent shutdown, check valve slamming or water hammer on the exhaust line is mitigated (a later modification relocated check valve V22-0016 closer to V22-0017 to provide added assurance).

Following system shutdown after LOCA, a closure of the motor-operated isolation valves in the vacuum breaker lines results in torus pressure forcing water to the exhaust line check valves, precluding gaseous outleakage through this path.

During normal operation, both motor-operated valves are in the open position to ensure vacuum breaker availability should the HPCI or RCIC systems operate. The fact that either of these valves has left the full-open position is annunciated in the control room. Isolation valve closure is initiated by concurrent signals of reactor pressure vessel low pressure (the sensors used will be those which secure the HPCI/RCIC turbine on low pressure) and drywell high pressure.

This logic selection ensures the availability of the vacuum breaker feature following shutdown from "normal" HPCI/RCIC operation while at the same time providing the desired containment isolation capability following a design-basis LOCA. Isolation valve power and control logic shall meet the separation requirements applied to other containment isolation valves.

The vacuum breaker arrangement incorporates series check valves that preclude inadvertent pressurization of the torus gas space in the event of a single failure of one check valve to close.

Manual maintenance valves are provided in each leg of the vacuum breaker piping to allow the isolation of check valves for maintenance.

Test connections across the check valves allow proper valve functioning to be ascertained.

6.3.2.2.2 Automatic Depressurization System

The automatic depressurization system provides automatic nuclear system depressurization for small breaks assuming failure of the HPCI system so that low-pressure coolant injection and the core spray system can operate. The relief capacity of the automatic depressurization system is based on the time required after its initiation to depressurize the nuclear system so that the core can be cooled by the core spray and the LPCI systems and meet the requirements of 10 CFR 50.46.

The automatic depressurization system uses four of the nuclear system pressure relief valves to relieve the high-pressure steam to the suppression pool. The design, description, and evaluation of the pressure relief valves are discussed in detail in Section 5.2.2.

The pressure relief valves open automatically after receiving reactor vessel low water level signals and discharge pressure indications from any low-pressure cooling system pump (LPCI or core spray) and after a 2-min delay. The delay provides time for the operator to manually inhibit the automatic depressurization system actuation if control room information indicates the signals are false or actuation is not needed.

Each of the four automatic depressurization system safety relief valves is equipped with a Seismic Category I 200 gal nitrogen accumulator. The accumulators receive their supply from the nonseismic normal primary containment nitrogen pneumatic supply system (Section 9.3.1.2). Each automatic depressurization system accumulator system has an inlet check valve at the boundary between the safety-grade accumulator system and the nonsafety drywell nitrogen supply system. The inlet check valves serve to minimize the loss of nitrogen from the automatic depressurization system accumulator systems in the event that the normal drywell nitrogen supply system should fail.

The inlet check valves are a soft-seated type which have significantly lower leakage rates than conventional hard-seated type check valves. In addition, leakage tests are performed during each refueling outage on the check valves and other system components to ensure that the leakage rates are at an acceptable level. The maximum acceptable leakage rate for the tests is 25 standard cm^3/min. The soft seat is replaceable.

Each ADS accumulator system has the capability to accommodate a nitrogen system leakage of 30 standard cm^3/min for up to 100 days without makeup and still provide five actuations of the ADS safety/relief valves. Thus the accumulators meet the requirement of NUREG-0737, Item II.K.3.28, which is to cycle the ADS valves open five times over a 100 day period following a design-basis LOCA.

6.3.2.2.3 Core Spray System

Figure 6.3-8 is the core spray system piping and instrumentation diagram.

The core spray system is provided to protect the core by removing decay heat following the postulated design-basis LOCA. The core spray system is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the core spray operates in conjunction with the automatic depressurization system, the effective core-cooling capability of the core spray is extended to all break sizes. This is because the automatic depressurization system rapidly reduces the reactor vessel pressure to the core spray operating range (see Figure 6.3-9). The system head flow characteristics assumed for LOCA analyses are shown in Tables 6.3-1 and 6.3-2. (Note: These are the original design values. Sensitivity studies have been performed (Reference 12) that demonstrate that margin is available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. Actual relaxation of these performance requirements will be evaluated on a case-by-case basis.)

The core spray system consists of two independent loops. Each loop includes one 100% capacity centrifugal water pump driven by an electric motor, a spray sparger in the reactor vessel above the core, piping and valves that convey water from the suppression pool to the sparger, and associated controls and instrumentation. Figure 6.3-2 is a schematic process diagram of the core spray system. Figure 7.3-12 is the flow control diagram.

The actuation of the core spray system results from low ("low-low-low") water level in the reactor vessel or high pressure in the drywell. When reactor vessel pressure is low enough, the core spray system automatically sprays water onto the top of the fuel assemblies to cool the core. (The same signals start the low-pressure coolant injection, which operates independently to flood the reactor vessel and achieve the same objective.)

The core spray pumps receive power from the 4160-V ac emergency auxiliary buses. Each core spray pump motor and the associated automatic motor-operated valves receive ac power from a different bus. Similarly, the control power for each loop of the core spray system comes from different dc buses (see Chapters 7 and 8).

The core spray pumps and all automatic valves can be operated individually by manual switches in the main control room.

Pressure indicators, flow meters, and indicator lights provide operating information in the main control room.

The following paragraphs describe the major equipment for one of two identical loops.

When the system is actuated, water is taken from the suppression pool. Flow then passes through two motor-operated gate valves that are normally open, but that can be closed by a remote manual key-lock switch from the main control room. Closure isolates the system from the suppression pool in the case of core spray system leakage. One valve is located in the core spray pump suction line, as close to the suppression pool as practical; the other valve is located toward the pump suction nozzle just upstream of the condensate storage line intertie.

A local pressure gauge for each pump indicates the presence of a suction head for the pump. The core spray pumps are located in the reactor building below the water level in the suppression pool. Separation of the pumps, piping, controls, and instrumentation of each loop is such that any single physical event cannot make both core spray loops inoperable. The switchgear for each loop is located in a separate room for the same reason.

A low-flow bypass line runs from the pump discharge to a test line, shared with the RHR system, which directs the flow into the suppression pool (below the normal water level). The bypass line shutoff valve opens automatically on a low-flow signal and closes automatically on a high-flow signal. The bypass flow is required to prevent the pump from overheating when pumping occurs against a closed discharge valve. An orifice limits the bypass flow. In response to NRC Bulletin 88-04, it has been shown by calculation and by special test that dead-heading of pumps is not likely to occur with 2 RHR pumps and a Core Spray pump discharging from their minimum flow lines into the shared line. Additional information is given in Section 5.4.7.3.

A relief valve protects the core spray system upstream of the outboard shutoff valve from reactor pressure. The relief valve discharges to the suppression pool.

A full-flow test line allows water to be circulated to the suppression pool for system testing during normal plant operations. A remote manual switch in the main control room operates a motor-operated valve in the line that is normally closed. Partial opening of the valve in the test line provides rated core spray flow at a pressure drop equivalent to that of the discharge into the reactor vessel. A loop flow indicator is located in the main control room.

Both injection lines are provided with two isolation valves. One of these valves is a check valve located inside the drywell, as close as practical to the reactor vessel. Core spray injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during the LOCA). If the core spray line should break outside the containment, the check valve in the line inside the drywell prevents the loss of reactor water. To facilitate operation and maintenance, two motor-operated valves are installed outside the drywell; however, they are placed as close to the drywell as practical to limit the length of line exposed to reactor pressure. The valve nearer the containment is normally closed to back up the inside check valve for containment purposes. The outboard valve is normally open to limit the equipment needed to operate in an accident condition. When the outboard valve is closed, the inboard valve can be operated for testing with the reactor vessel pressurized. A vent line is provided between the two motor-operated valves that can be used to measure leakage through the inside check valve or the inboard motor-operated valve. On the vent line between the two isolation valves (i.e., the check valve and the inboard motor-operated valve) the inboard vent line valve is used to ensure containment integrity and reactor coolant pressure boundary integrity (the inject line check valve is the inboard isolation valve). The vent line is normally closed with two valves, and a pipe cap.

A check valve in each core spray line just inside the primary containment prevents the loss of reactor coolant outside the containment in case the core spray line breaks. A manual valve, which is normally locked open, is provided downstream of the inside check valve. The valve shuts off the core spray system from the reactor during shutdown to permit maintenance of the upstream valves. The two pipes in the core spray system enter the reactor vessel through nozzles located 180 degrees apart. Each internal pipe then divides into a semicircular header, with a downcomer at each end that turns through the shroud near the top. A semicircular sparger is attached to each of the four outlets to form two circles, one above the other and both essentially complete. Short elbow nozzles are spaced around the spargers to spray the water radially onto the tops of the fuel assemblies.

Core spray piping upstream of the outboard shutoff valve is designed for the lower pressure and temperature of the core spray pump discharge. The outboard valve and piping downstream are designed for reactor vessel pressure and temperature. All piping and pump casings are designed in accordance with the criteria presented in Chapter 3.

The RHR/core spray fill pump maintains system piping filled with water to prevent the potential for water hammer as discussed in Section 5.4.7.2.1.

The core spray equipment, piping, and support structures are designed in accordance with Seismic Category I criteria to resist motion effected by the DBE at the installed location within the supporting building. For seismic analysis, the core spray system is assumed to be filled with water.

Low ("low-low-low") water level in the reactor or high pressure in the drywell signals the automatic controls to energize the core spray pumps and place system valves in the spray mode. When reactor pressure decreases, the core spray shutoff valves are signaled to open. Flow to the sparger begins when the pressure differential opens the inside check valve. Section 7.3.1.1.2 gives further details and evaluation.

6.3.2.2.4 Low-Pressure Coolant Injection

The LPCI system is an operating mode of the RHR system. The LPCI system is automatically actuated by low water level in the reactor and/or high pressure in the drywell. It uses four motor-driven RHR pumps to draw suction from the suppression pool and inject cooling water into the reactor core.

The LPCI system, like the core spray system, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCI system operates in conjunction with the automatic depressurization system, the effective core-cooling capability of the LPCI system is extended to all break sizes because the automatic depressurization system rapidly reduces the reactor vessel pressure to the LPCI operating range.

Figure 6.3-3 is a schematic process diagram of low-pressure coolant injection. LPCI operation is based on using three of the four ac motor-driven centrifugal pumps that take water from the suppression pool and pump it into one of the two recirculation loops. The water enters the reactor through jet pumps and restores the water level in the reactor vessel. Figure 7.3-13, Sheets 1 through 3A, is the flow control diagram for the RHR system including the LPCI system.

Because the motor-operators to the recirculation discharge bypass valves may not be qualified for all postulated operating environments, analyses have been performed (References 4 and 13) that demonstrate that the acceptance criteria of 10 CFR 50.46 are met if these valves remain open during the LOCA and allow a portion of the injected flow to be lost out of the break.

The RHR/core spray fill pump maintains system piping filled with water to prevent the potential for water hammer, as discussed in Section 5.4.7.2.1.

The LPCI pumps receive power from the 4160-V ac emergency auxiliary buses. For each loop, the LPCI pump motors and associated automatic motor-operated valves receive ac power from different buses.

LPCI pumps and piping equipment are described in detail in Section 5.4.7. Also described are other functions served by the same pumps if they are not needed for the LPCI function. Portions of the RHR system required for accident protection are designed in accordance with Seismic Category I criteria.

6.3.2.2.5 HPCI, Core Spray, and LPCI Pump Curves

Curves showing head, horsepower, net positive suction head versus flow, and efficiency for the HPCI, Core Spray, and RHR (LPCI) pumps are presented as Figures 6.3-4, 6.3-5, and 6.3-6. Specific speed for each pump is also indicated in these figures.

6.3.2.2.6 ECCS Principal Design Parameters

Table 6.3-1 summarizes the principal design parameters such as cooling capacity, flow, pressure, and backup systems of the emergency core cooling system. (Note: These are the original design values. Sensitivity studies have been performed (Reference 12) that demonstrate that margin is available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. Actual relaxation of these performance requirements will be evaluated on a case-by-case basis.)

6.3.2.2.7 ECCS Actuation Parameters

Table 6.3-2 lists initiating signals and variable setpoints for ECCS actuation. (Note: These are the original design values. Sensitivity studies have been performed (Reference 12) that demonstrate that margin is available to relax these performance requirements while still meeting the acceptance criteria of 10 CFR50.46. Actual relaxation of these performance requirements will be evaluated on a case-by-case basis.)

6.3.2.2.8 Evaluation of RHR(LPCI) Pump Runout Conditions

Pump runout conditions during the first ten minutes following a LOCA could occur in certain situations where the RHR (LPCI) pumps discharge to flow paths with too little system flow resistance. The operation of the RHR (LPCI) pumps under this condition could result in damage to the pumps from cavitation and/or motor overload. The DAEC is in the category of BWR/3 and BWR/4 plants with loop selection logic systems (LSLS). The following situations could potentially result in RHR (LPCI) pump runout conditions and a subsequent reduction or loss of long-term heat removal capability following a postulated LOCA for this category of plant:

1. Four LPCI pumps injecting into a broken recirculation loop from a single LSLS failure.

2. Four LPCI pumps injecting into both recirculation loops simultaneously, with one loop broken, from a single LSLS failure.

3. Operation with three pumps providing flow (one pump inoperable as allowed per the Technical Specifications) to the unbroken loop, with the single failure of a recirculation loop discharge valve to close.

4. Three LPCI pumps injecting into the broken loop, with one loop broken.

An evaluation was performed on the DAEC RHR system to determine possible effects on long-term heat removal capabilities. With respect to the above potential RHR runout conditions, no other situations were found to be more severe than conditions 1 through 4 above.

Resistance calculations were performed on the RHR-recirculation piping network to determine the loop with the highest RHR pump runout potential. The following network configurations were evaluated with respect to their associated potential RHR runout conditions:

1. Condition 1

    a. RHR pumps A, B, C, and D operating.

    b. Recirculation loop B broken.

    c. All RHR pumps injecting into recirculation loop B.

2. Condition 2

    a. RHR pumps A, B, C, and D operating.

    b. Recirculation loop B broken.

    c. All four RHR pumps simultaneously injecting into recirculation loops A and B (cross-tie open).

3. Condition 3

    a. RHR pumps A, B, and D operating.

    b. Recirculation loop B broken.

    c. RHR pumps A, B, and D injecting into intact recirculation loop A.

    d. Recirculation loop A discharge valve fails to close.

After selecting the piping configuration presenting the greatest potential for runout, the potential for cavitation was evaluated for each RHR pump with respect to conditions 1 through 3 above. The calculated net positive suction head for each case is listed in Table 6.3-3 along with RHR pump requirements. These calculations were performed in accordance with Regulatory Guide 1.1. In each of the above cases listed in Table 6.3-3, adequate net positive suction head was maintained for each RHR pump precluding cavitation.

Each RHR pump was evaluated for potential motor overload for the three conditions listed above. For these conditions, the maximum calculated values for motor current and allowable times at current are summarized below:

Maximum Motor Current	Maximum Allowable Time at Maximum Motor Current
<1.20 of rated	25 min

The worst case of motor current occurs in condition 2. The motor current will remain less than 1.20 times rated. The continuous motor service factor is 1.15. Design motor data allow the motor to remain at the 1.20 value for 25 min before corrective action is necessary. Motor current loads for conditions 1 and 3 are less severe.

In the above evaluation summary of potential RHR (LPCI) pump runout conditions, it was found that adequate available net positive suction head was maintained to preclude pump cavitation. It was also determined that RHR (LPCI) pump motor current would not exceed design limits for 25 min allowing sufficient time for an operator to take corrective action. Therefore, it has been determined that the long-term cooling potential for the DAEC will not be lost or decreased from potential RHR pump runout conditions following a postulated LOCA. This conclusion is based on a set of conservative assumptions that were used in the evaluation.

The potential runout with three pumps operating rather than four and a double-ended line break on the recirculation pump A discharge pipe has been evaluated. The same conservatisms that were used to perform previous analyses were also used in evaluating the three-pump case. The results of the evaluation (Table 6.3-3) indicate that the RHR pumps will remain functional with three pumps operating. During runout conditions, the limiting pump (pump B), would have 1.2 ft of available net positive suction head above the approximately 14 ft that it requires. Hence, there would be no pump cavitation. The pump B motor current would be less than 120% of rated.

The increase in motor current would result in increased diesel-generator loading. However, the increase would not exceed 10.5% (55 KW) per pump. This is below the 100 KW per pump increase used to evaluate the four-pump case. Therefore, the load summary previously submitted is still applicable and the diesel-generators would remain within rated conditions.

6.3.2.3 Applicable Codes and Classifications

Analytical methods, design criteria, and applicable codes and standards used for safety-related valves and pumps located outside of the reactor coolant pressure boundary are given in Sections 3.2, 3.6, and 3.7. References for analytical methods outlined in Section 3.7 for the above safety-related items are as follows:

1. RCIC Pump

   a. For closure bolting and wall thickness see Table 3.7-13.

   b. Nozzle Loads - Stress limits are determined from ASME, Section VIII, for normal and upset conditions and are set at 1.5 times allowable stress for emergency conditions. Pressure stresses are then deducted from allowable stress limits to yield net remaining allowable stresses. This net remaining stress is then equal to F/A + M/Z (giving a super position of axial and bending stresses from elementary engineering mechanics), and the relationship is rearranged and solved for F in terms of M and the appropriate constants.

2. HPCI Pump

    a. For closure bolting and wall thickness see Table 3.7-15.

    b. Nozzle Loads - Method of analysis follows same procedure used for preceding item 1.b.

3. RHR Pump

    a. For closure bolting and wall thickness see Table 3.7-9.

    b. Nozzle Loads - Method of analysis follows same procedure used for preceding item 1.b.

4. Core Spray Pump

    a. For closure bolting and wall thickness see Table 3.7-11.

    b. Nozzle Loads - Method of analysis follows same procedure used for preceding item 1.b.

6.3.2.4 Material Specifications

The DAEC emergency core cooling systems have been designed with adequate margin for the expected maximum temperature, pH, and radioactivity (based on the source suggested in TID-14844) and its treatment within the containment and for degeneration of items such as filters, pump impellers, and seals that could affect the postaccident cooling system integrity. With regard to materials, special attention has been paid in the specifications to employing compatible materials, to considering possible interaction of dissimilar metals, and to ensuring that only acceptable materials have been selected.

For further information regarding the detailed design of the emergency core cooling system, refer to Sections 7.3 and 5.4.

6.3.2.5 System Reliability

6.3.2.5.1 General

Adequate emergency cooling capability is necessary whenever irradiated fuel is in the reactor vessel. For this reason, the reliability of all emergency core cooling systems components must be very high to support high availability for core cooling. To ensure that the systems will start when needed and will deliver the required quantity of coolant within specified log times, the

As described in Section 5.4.7, the core spray and RHR pump discharge piping is maintained completely full of water by a pump that takes suction from and recirculates to the suppression pool. Accordingly, hydraulic forces resulting from system initiation with the pump discharge lines not completely filled with fluid are avoided.

In addition, control room display of ECCS pump suction pressure, pump discharge flow rate, and torus water level would allow the operator to become aware of any significant leakage into the ECCS pump compartment at which time remote isolation of torus suction valves in the defective loop and startup of the other redundant RHR/core spray loop could be affected.

6.3.2.7 Provisions for Performance Testing

Periodic system and component testing provisions for the ECCS are described in Section 6.3.2.2 as part of the individual system descriptions.

The core spray system includes a low-flow bypass line to prevent the pump from overheating when pumping against a closed discharge valve and a full-flow test line that permits circulating water to the suppression pool for testing the system during normal plant operations. A normally locked-open manual valve is used to close the bypass line for maintenance. A normally closed, motor-operated valve in the test line is controlled by a remote manual switch in the control room. The full-flow test line is not in operation when the core spray system is functioning after an accident. Both lines are designed for full core spray system pressure and are an extension of the primary containment when the core spray system is operating. The lines have a water seal and contain the same fluid on both sides of their respective valves.

6.3.2.8 Manual Actions

Following a postulated LOCA, an operator would have LPCI pump flow indication in the control room on the control panel 1C-04, flow indicators FI-1971 A and B. An operator may take manual control action as necessary prior to or after the first 10 min following a postulated LOCA (although, per the ECCS design basis, no operator action is required until 10 min. after an accident), but must act in accordance with prescribed emergency procedures.

As stated in Section 6.3.2.2.5, the analysis has shown that the LPCI pumps at the DAEC will not experience pump cavitation or pump runout following a postulated LOCA. However, flow in the RHR system can be throttled from the control room.

6.3.3 PERFORMANCE EVALUATION

To achieve reliability, each emergency core cooling system uses the minimum feasible number of components that are required to actuate. All equipment is testable during operation. Two different cooling methods--spraying and flooding--provide diversity.

The evaluation of ECCS controls and instrumentation for reliability and redundancy shows that a failure of any single initiating sensor cannot prevent or falsely start the initiation of these cooling systems. No single control failure can prevent the combined cooling systems from adequately cooling the core. The controls and instrumentation can be calibrated and tested to ensure adequate response to conditions representative of accident situations.

The performance of the ECCS is determined through the application of the 10 CFR 50, Appendix K evaluation models, and by conformance to the acceptance criteria of 10 CFR 50.46. NEDC-23785-P (Reference 3) provides a complete description of the methods used to perform the calculations.

The re-analysis of the plant LOCA was provided in accordance with NRC requirements and to demonstrate conformance with the ECCS acceptance criteria of 10 CFR 50.46.[4] The objective of the LOCA analysis contained therein was to provide assurance that the most limiting break size, break location, and single-failure combination had been considered for the plant.

Plant analyses for each reload are reported in the supplemental reload licensing submittal for the plant and the applicable version of Reference 1.

6.3.3.1 Individual System Adequacy

6.3.3.1.1 General

The manner in which the emergency core cooling systems operate to protect the core is a function of the rate at which coolant is lost from a break in the nuclear system process barrier. The HPCI system is designed to operate while the nuclear system is at high pressure. The core spray and LPCI systems are designed for low pressure operation only.

Nuclear system pressure is automatically reduced if a break has occurred and vessel water level is not maintained. Automatic depressurization of the nuclear system reduces the vessel pressure and permits flow from the core spray and low-pressure coolant injection to enter the vessel, thus limiting the core temperature rise.

The ECCS network provides two independent phenomenological cooling methods - flooding and spraying. The entire spectrum of liquid and steam-line breaks are covered by the high-pressure coolant injection, automatic depressurization system, core spray, and low-pressure coolant injection. High-pressure coolant injection or automatic depressurization system plus the core spray provide both spray and flooding. The high-pressure coolant injection plus low-pressure coolant injection or automatic depressurization system plus low-pressure coolant injection provide core flooding.

6.3.3.1.2 High-Pressure Coolant Injection System

See Sections 6.3.2.2.1 and 6.2.1.3.

6.3.3.1.3 Automatic Depressurization System

When the automatic depressurization system is actuated, the flow of steam through the valves provides a maximum energy removal rate while minimizing the corresponding fluid mass loss from the reactor vessel. Thus, the specific internal energy of the saturated fluid in the reactor vessel is rapidly decreased causing pressure reduction. The system provides backup for high-pressure coolant injection.

Actuation of the automatic depressurization function does not require any source of offsite or onsite AC power. The relief valves are controlled by DC power from the unit batteries and are operated by pneumatic power from accumulators. Each of the four automatic depressurization system safety/relief valves is equipped with a Seismic Category I nitrogen accumulator. The accumulators have sufficient capacity to cycle the automatic depressurization system valves five times at the DAEC containment design pressure.

6.3.3.1.4 Core Spray System

The core spray system is designed to provide continuous reactor core cooling for a LOCA. It provides adequate cooling for intermediate and large line break sizes up to, and including, the design-basis, double-ended, recirculation-line break, without assistance from any other emergency core cooling systems. The integrated performance of the core spray system in conjunction with other emergency core cooling systems is given in Section 6.3.2.2.3.

6.3.3.1.5 Low-Pressure Coolant Injection System

The low-pressure coolant injection (LPCI) system is provided to automatically reflood the reactor core in time to limit cladding temperatures after a nuclear system LOCA when the reactor vessel pressure is below the shutoff head of the pumps. Low-pressure coolant injection cools the core by flooding. With assistance of the automatic depressurization system or high-pressure coolant injection the low-pressure coolant injection can independently supply sufficient cooling to meet the safety objective for any rupture of the nuclear system boundary up to and including the design-basis accident.

The maximum flow capacity is determined by the design break (instantaneous break of a recirculation line). The pumps refill the inner plenum long before excessive cladding temperatures occur. The minimum allowable time in which this must be done occurs for the design break because the least core cooling during blowdown occurs for this break. Hence, it must be reflooded more quickly than for small breaks. However, for the design break the vessel depressurizes very quickly, improving the pump flow characteristics. Hence, a greater flow of water can be pumped into the vessel.

6.3.3.2 Integrated Operation of Emergency Core Cooling Systems

The previous discussion describes the individual performance and operation of each of the emergency core cooling systems. It has been demonstrated that two different methods and at least two independent core cooling systems are provided to limit fuel cladding temperature over the entire spectrum of postulated reactor primary system breaks as required by the design bases.

Sensitivity studies have been performed (References 13 and 14) that show how peak cladding temperature (PCT) varies with changes in ECCS flowrates for the Design Basis Accident (DBA).

For the DBA Suction Break, the HPCI and ADS systems do not have any significant effect on the overall ECCS performance. This is because the large breaks depressurize the reactor vessel before the steam-driven HPCI system has sufficient time to startup and inject coolant into the vessel (45 seconds) and the ADS time delay (125 seconds) has expired. The primary core cooling depends on the CS and LPCI systems for these breaks. In general, the time required to reflood the core and the lower plenum depends on the total ECCS flow (CS and LPCI). The peak in PCT occurs shortly after the core is reflooded with the predominantly liquid continuum. Figure 6.3-9 shows how both the peak PCT time (i.e., core reflood time) and the peak cladding temperature for the DBA increase as the total ECCS Flowrate decreases. When the time between ECCS initiation and core reflood is short, the PCT increase is small, since the hot bundle is continuously covered with a two-phase mixture, which provides good heat removal capability (curves 1-4). With only a single CS pump, a two-phase continuum in the hot bundle cannot be maintained and the resulting PCT increase is large (curve 5).

See Section 6.2.1.3 for a detailed discussion of the emergency core cooling systems performance evaluation on the Primary Containment response to a LOCA.

6.3.4 TESTS AND INSPECTIONS

Each active component of the emergency core cooling systems that is provided to operate in a design-basis accident is designed to be tested during normal operation of the nuclear system.

REFERENCES FOR SECTION 6.3

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

2. Letter from R. E. Engel, General Electric Company, to P. S. Check, NRC, Subject: DC Power Source Failure for BWR/III and IV, dated November 1, 1978.

3. General Electric Company, The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident, NEDC-23785-P, Volumes I, II, and III, January, 1985.

4a. General Electric Company, Duane Arnold Energy Center SAFER/GESTR-LOCA Loss of Coolant Accident Analysis, NEDO-31310, August 1986 and Supplement 1, Revision 1, September, 1993.

4b. General Electric Company, Duane Arnold Energy Center GE12 Fuel Upgrade Project, NEDC-32915P, Revision 0, November, 1999.

5. Letter from Darrell G. Eisenhut, NRC, to E. D. Fuller, General Electric, Subject: Documentation of the Reanalysis Results for the Loss-of-Coolant Accident (LOCA) of Lead and Non-Lead Plants, dated June 30, 1977 (Serial No. MFN-255-77).

6. General Electric, Core Spray and Bottom Flooding Effectiveness in the BWR-6, NEDO-10801-A, 1977.

7. H. M. Hirsch, Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems, NEDO-10739, 1973.

8. M. K. Hentschel et al., Compliance of Protection Systems to Industry Criteria: General Electric BWR Nuclear Steam System, NEDO-10139, 1970.

9. Letter from W. C. Rothert, Iowa Electric, to A. Bert Davis, NRC, Subject: Final Report Pursuant to IE Bulletin 85-03, dated January 15, 1988 (NG-88-0001).

10. Letter from D.L. Mineck, Iowa Electric, to Dr. T. E. Murley, NRC, Subject: Consideration of Postulated Electric Failure in 10CFR50.46 ECCS Analysis, dated June 26, 1989 (NG-89-1856).

11. NRC Inspection Report 50-331/95-011, dated January 25, 1996.

12. General Electric Company, Sensitivity of the Duane Arnold Center Safety Systems Performance to Fundamental System Parameters, MDE-282-1285, February, 1986.

13. General Electric Company, Duane Arnold Energy Center SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis Engineering Report, GENE-637-034-1093, October 1993.

14. General Electric Company, Duane Arnold Energy Center SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis Engineering Report, Addendum 1 (sensitivity cases), GENE-637-048-1293, December 1993.

Table 6.3-1
EMERGENCY CORE COOLING SYSTEMS EQUIPMENT DESIGN DATA SUMMARY[a]

Parameter	HPCI	ADS	Core Spray	LPCI
Number installed	1	4	2	4
Individual capacity	100%	33-1/3%	100%	33-1/3%
Design flow (each) (psid)[b]	3000 gpm at 150	800,000 lb/hr at 1125	3020 gpm at 113	4800 gpm at 20
Pressure range (psid)	1135 to 150	1125 to 50	264 to 0	197 to 0
Ac required for initiation	None	None	Normal aux. or standby diesel-generator	Normal aux. or standby diesel-generator
Source of water	Condensate storage tank or suppression pool	- -	Suppression pool	Suppression pool
Backup system	ADS + CS + LPCI	HPCI + remote manual relief valves	LPCI	CS

[a] Minimum performance criteria for satisfying 10CFR50.46 are specified in the Technical Specifications and Reference 4.
[b] psid = pounds per square inch differential between reactor vessel and primary containment or reactor vessel and pump suction.

Table 6.3-2

EMERGENCY CORE COOLING SYSTEMS ACTUATION PARAMETERS

Plant Name: Duane Arnold Energy Center

a. LPCI System

Variable	Value
Maximum vessel pressure at which pumps can inject flow (from preoperational test data)	197[a] psid (vessel to drywell)
Minimum rated flow at vessel pressure	14,400 gpm (three pumps) (20 psig)
Maximum allowable time delay from initiating signal to pumps at rated speed and injection valve open (assuming below noted permissive is always satisfied)	40 sec
Pressure at which injection valve may open (permissive)	<450 psig (vessel)
Maximum injection valve opening time	18 sec (original design basis) 28 sec (per current LOCA analysis)
Initiating signals Low water level or high drywell pressure and low reactor pressure	See the Technical Specifications

[a] Not verified.

Table 6.3-2 Sheet 4 of 4

EMERGENCY CORE COOLING SYSTEMS ACTUATION PARAMETERS

d. Automatic Depressurization System (ADS) Variable

	Value
Total number of relief valves with ADS function	4
Pressure at which below-listed flow capacity is quoted	1122.7 psig
Minimum flow rate with all valves open at above-listed pressure	3.584×10^6 lb/hr
Total number of relief valves with ADS function given the failure of highest capacity valve	3
Pressure at which below-listed flow capacity is quoted	1125 psig
Minimum flow rate at above-listed pressure with highest capacity valve shut	2.688×10^6 lb/hr
Delay time from all initiating signals completed to the time valves are open	$90 < T < 120$
Initiating signals	
Low reactor water level and	See the Technical Specifications
signal that at least 1 LPCI or 1 LPCS pump is running (pump discharge pressure)	145 ± 20 psig (LPCS) 125 ± 25 psig (LPCI)

Table 6.3-3

RHR (LPCI) PUMP NET POSITIVE SUCTION HEAD FOR CONDITIONS 1, 2, 3, AND 4

Parameter[a]	RHR Injection Pumps A	C	B	D	Comment
Condition 1					
Flow rate, gpm	6336	6340	6445	6449	No cavitation
Total head, ft	244	243	226	226	
Available NPSH, ft	15.7	15.8	15.0	15.2	
Required NPSH, ft	10.4	10.5	10.8	10.8	
Condition 2					
Flow rate, gpm	6621	6625	6665	6669	No cavitation
Total head, ft	197	196	189	189	
Available NPSH, ft	13.9	14.1	13.7	13.8	
Required NPSH, ft	11.4	11.4	11.6	11.6	
Condition 3					
Flow rate, gpm	6705	0	6407	6411	No cavitation
Total head, ft	182	N/A	233	232	
Available NPSH, ft	23.7	N/A	15.3	15.4	
Required NPSH, ft	11.7	N/A	10.7	10.7	
Condition 4					
Flowrate, gpm	7000	0	6756	6760	No cavitation
Total head, ft	126	N/A	173	173	
Available NPSH, ft	22.7	N/A	13.1	13.2	
Required NPSH, ft	12.8	N/A	11.9	11.9	

[a] Heads are in feet of water at 62.4 lb/ft^3.

Table 6.3-4

Not Used.

Table 6.3-5 Sheet 1 of 10

POWER SUPPLIES AFFECTING ECCS EQUIPMENT FOR CORE SPRAY, LOW-PRESSURE COOLANT INJECTION (RHR SYSTEM), AND AUTOMATIC DEPRESSURIZATION SYSTEM

Equipment Description	Equipment Number	Equipment Power		Control Power*	
		Division 1	Division 2	Division 1	Division 2
Auto depressurization valve	SV-4400	1D13 (dc)	1D23 (dc)	1D13 (dc)	1D23 (dc)
Auto depressurization valve	SV-4402	1D13 (dc)	1D23 (dc)	1D13 (dc)	1D23 (dc)
Auto depressurization valve	SV-4405	1D13 (dc)	1D23 (dc)	1D13 (dc)	1D23 (dc)
Auto depressurization valve	SV-4406	1D13 (dc)	1D23 (dc)	1D13 (dc)	1D23 (dc)
Core spray pump	1P-211A	1A3 (ac)		1D13 (dc) 1D11 (dc)	
Core spray pump	1P-211B		1A4 (ac)		1D23 (dc) 1D21 (dc)
Core spray system I suction valve	MO-2100	1B34 (ac)		1B34 (ac)	
Core spray system II suction valve	MO-2120		1B44 (ac)		1B44 (ac)
Core spray system I main isolation valve	MO-2147	1B34 (ac)		1B34 (ac)	
Core spray system II main isolation valve	MO-2146		1B44 (ac)		1B44 (ac)
Core spray system I inboard valve	MO-2117	1B34 (ac)		1D11 (dc)	
Core spray system II inboard valve	MO-2137		1B44 (ac)		1D21 (dc)
Core spray system I minimum flow bypass valve	MO-2104	1B34 (ac)		1B34 (ac)	
Core spray system II minimum flow bypass valve	MO-2124		1B44 (ac)		1B44 (ac)

* "Control Power" for this table and the power supplies listed are those which power various instruments and/or trip devices in the ECCS logic.

Table 6.3-5

POWER SUPPLIES AFFECTING ECCS EQUIPMENT FOR CORE SPRAY, LOW-PRESSURE COOLANT INJECTION (RHR SYSTEM), AND AUTOMATIC DEPRESSURIZATION SYSTEM

Equipment Description	Equipment Number	Equipment Power Division 1	Equipment Power Division 2	Control Power* Division 1	Control Power* Division 2
RHR pump	1P-229B		1A4 (ac)		1D23 (dc)
RHR pump	1P-229C	1A3 (ac)		1D13 (ac)	
RHR pump	1P-229D		1A4 (ac)		1D23 (dc)
RHR shutdown cooling isolation valve (inboard)	MO-1908	1B34 (ac)		1B34 (ac)	
RHR shutdown cooling isolation valve (outboard)	MO-1909		1D42 (dc)		1D42 (dc)
RHR discharge to radwaste isolation valve (outboard)	MO-1937		1D42 (dc)		1D42 (dc)
RHR discharge to radwaste isolation valve (inboard)	MO-1936	1B34 (ac)		1B34 (ac)	
RHR loop A minimum flow bypass valve	MO-1935		1B44 (ac)		1D23 (dc)
RHR loop B minimum flow bypass valve	MO-2009	1B34 (ac)		1D13 (dc)	
RHR sample line valve	SV-1972	RPS (ac)		RPS (ac)	
RHR sample line valve	SV-2051	RPS (ac)		RPS (ac)	
RHR sample line valve	SV-1973		RPS (ac)		RPS (ac)

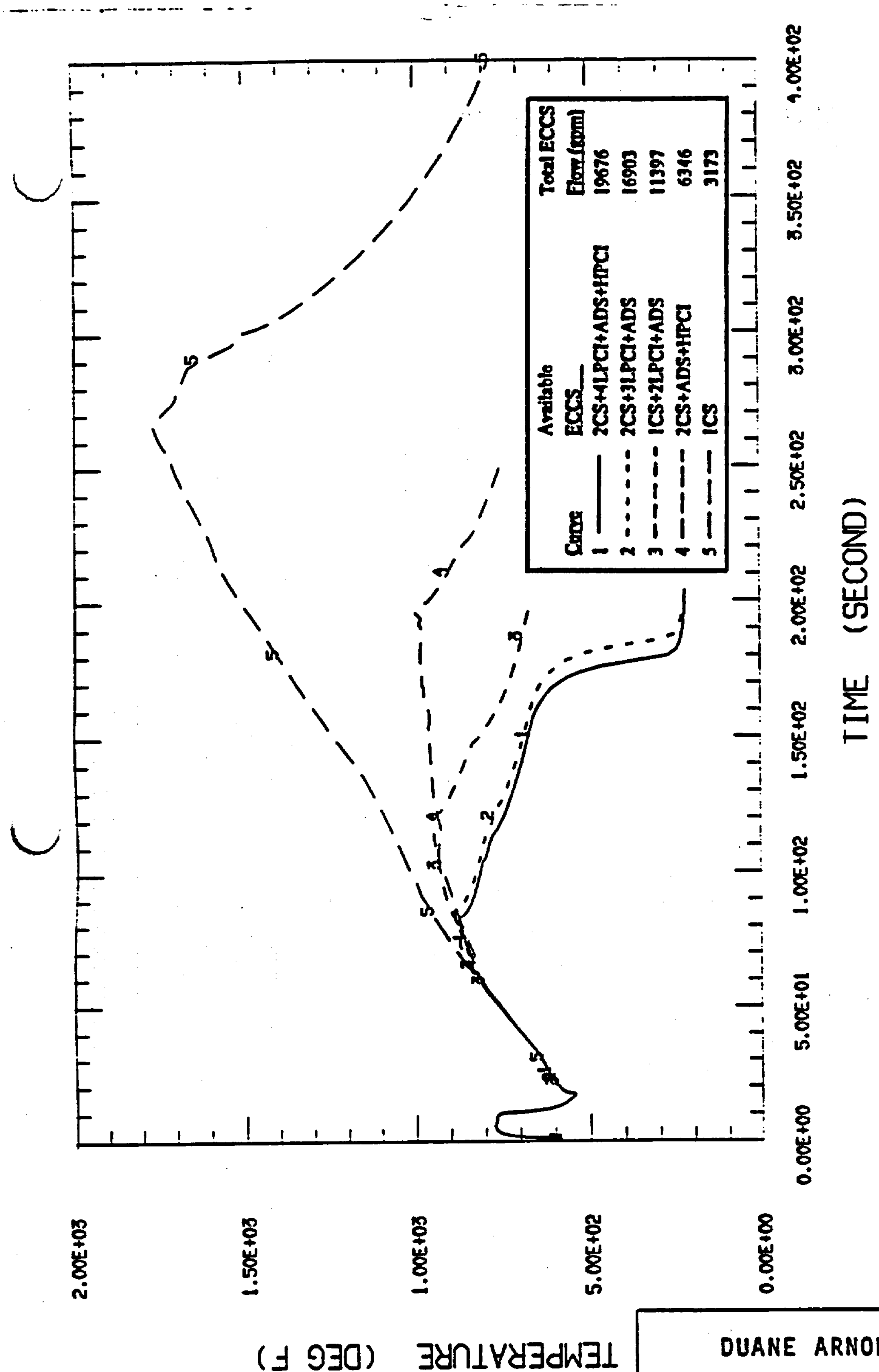
* "Control Power" for this table and the power supplies listed are those which power various instruments and/or trip devices in the ECCS logic.

Table 6.3-5

POWER SUPPLIES AFFECTING ECCS EQUIPMENT FOR CORE SPRAY, LOW-PRESSURE COOLANT INJECTION (RHR SYSTEM), AND AUTOMATIC DEPRESSURIZATION SYSTEM

Equipment Description	Equipment Number	Equipment Power Division 1	Equipment Power Division 2	Control Power* Division 1	Control Power* Division 2
RHR sample line valve	SV-2052		RPS (ac)		RPS (ac)
HPCI Inlet pressure control solenoid valve	SV-1963		1D23 (dc)		1D23 (dc)
HPCI Inlet pressure control solenoid valve	SV-1964		1D23 (dc)		1D23 (dc)
RHR to RCIC pressure cooling solenoid valve	SV-1966		1D23 (dc)		1D23 (dc)
HPCI Inlet pressure control solenoid valve	SV-2033	1D13 (dc)		1D13 (dc)	
HPCI Inlet pressure control solenoid valve	SV-2034	1D13 (dc)		1D13 (dc)	
RHR to RCIC pressure control solenoid valve	SV-2037	1D13 (dc)		1D13 (dc)	
RHR loop A containment cooling valve	MO-2000	1B34 (ac)		1D13 (dc)	
RHR loop B containment cooling valve	MO-1902		1B44 (ac)		1D23 (dc)
RHR loop A containment cooling regulator valve	MO-2001	1B34 (ac)		1D13 (dc)	
RHR loop B containment cooling regulator valve	MO-1903		1B44 (ac)		1D23 (dc)
RHR loop A discharge to LPCI valve (inboard)	MO-2003	1B34A (ac)	1B34A (ac)	1D13 (dc)	1D23 (dc)

* "Control Power" for this table and the power supplies listed are those which power various instruments and/or trip devices in the ECCS logic.



DUANE ARNOLD ENERGY CENTER
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UPDATED FINAL SAFETY ANALYSIS REPORT

Emergency Core Cooling Systems Performance Capability

Figure 6.3-9

6.4 HABITABILITY SYSTEMS

The Control Room habitability system is discussed in Sections 6.4.1 through 6.4.6. Section 6.4.7 discusses the Technical Support Center habitability systems.

6.4.1 DESIGN BASIS

The DAEC control room and control building designs were licensed before the issuance of NRC Standard Review Plan sections and Regulatory Guides dealing specifically with control room habitability criteria. The DAEC control room design was governed by General Design Criterion 19, "Control Room," which addresses radiation protection of control room personnel, but does not specifically address protection from hazardous-chemical releases.

A comparison of the DAEC design to the criteria found in Regulatory Guides 1.78 and 1.95 and Standard Review Plan Section 2.2 and 6.4 is described in Section 6.4.4.4. The comparison, originally submitted as Attachment 8 to Reference 3, revealed the following significant facts:

1. The DAEC control room is adequately designed to protect the control room occupants from radiological hazards. Automatic detection and filtration of airborne radioactivity is provided, and the control room is adequately shielded for design-basis accident conditions.

2. Chlorine was the only hazardous chemical stored within 5 miles of the plant site that presented a potential toxic threat to control room habitability.

3. Regulatory Guides 1.78 and 1.95 require that the detection of hazardous-chemical releases be followed by automatic initiation of systems designed for the protection of the control room. The DAEC control room/control building ventilation system is presently designed for manual initiation of an emergency filtration ventilation mode and relies on operator detection of hazardous-chemical releases.

4. Regulatory Guides 1.78 and 1.95 contain assumptions and analysis techniques for hazardous-chemical releases that are more conservative than the DAEC FSAR analysis for a chlorine release.

5. DAEC emergency procedures do not presently address hazardous-chemical- release conditions.

The overall conclusion of the above review was that design changes to the DAEC control room/control building ventilation system are needed to bring the DAEC design into conformance with the current NRC licensing requirements related to control room habitability under chlorine-release conditions.

The evaluation of DAEC control room habitability is discussed in Section 6.4.4, which contains the information to support the above conclusions. Also included in that section is an item-by-item response to the information requested in Attachment 1 to NUREG-0737,[1] Item III.D.3.4 (see Section 6.4.4.5).

The potential impact of a Cable Spreading Room Cardox actuation on Control Room Habitability has been analyzed. Analysis and testing were performed subsequent to the DAEC response to NUREG-0737. The evaluation was performed in response to a CARDOX System spurious actuation incident that occurred in the Cable Spreading Room in September, 1990 and the adverse impact it had on the Control Room habitability.

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of Control Room Envelope

The control room is located in the control building, which is adjacent to but physically separate from the reactor and turbine buildings. The control building houses the control room and associated auxiliaries, essential switchgear rooms, battery rooms, cable spreading room, computer room, and HVAC equipment room. The location of the control building is shown in the site plan, Figure 1.2-1. The control building arrangement is shown in the arrangement drawings: Figures 1.2-4, 1.2-5, 1.2-7, 1.2-8, 1.2-10, and 1.2-11.

6.4.2.2 Ventilation System Design

The DAEC control room is located in the control building at elevation 786 ft. The ventilation system that provides control room airflow also supplies the remainder of the control building, including the essential switchgear and battery rooms (elevation 757 ft 6 in.), the cable spreading areas above and below the control room, and the HVAC equipment room (elevation 800 ft 4 in.). Makeup air for the control building comes directly from the outside air. A diagram of the control building airflow is shown in Figure 9.4-7.

Because the source of control room air is presently common with the air distributed to the remainder of the control building, no special means of isolating just the control room is provided (see also Section 6.4.4.5, item 2a). The present design includes a HEPA and charcoal filtration train in the emergency makeup air duct through which emergency makeup air is automatically diverted when a predetermined level of airborne radioactivity is detected. The HEPA filters are discussed in Section 6.4.4.5, items 2e and 5b. This detection also isolates the normal control building makeup air supply and exhaust ducts. These actions of isolating the control building and filtration of the emergency makeup supply protect the control building inhabitants from high levels of airborne radioactivity.

6.4.2.3 Leaktightness

See Section 6.4.4.5, item 2d.

6.4.2.4 Shielding Design

The shielding of the main control room has been designed to limit the dose rate to operating personnel within the control room to less than 0.5 mrem/hr during normal plant operations.

In addition to normal operations, the radiation conditions resulting from the design-basis accidents have been evaluated. Adequate shielding has been provided to permit access and occupancy of the control room for a 30-day period without personnel receiving radiation exposures in excess of 5-rem whole body.

See also Section 6.4.4.5, item 2h, and Section 12.3.2.6.1.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

See Section 9.4.1 for a discussion of control room HVAC operations.

6.4.4 DESIGN EVALUATIONS

6.4.4.1 Radiological and Toxic Gas Protection

The evaluation of DAEC control room habitability during toxic-releases, radioactive-gas releases, and direct radiation resulting from design-basis accidents is discussed in this section. The evaluation was intended to satisfy the requirements for nuclear power plant control room habitability review found in Item III.D.3.4 of NUREG-0660.[2] This item of NUREG-0660 was implemented by the May 7, 1980, letter from D. Eisenhut of the NRC to all operating reactors. Further clarification of Item III.D.3.4 is presented in NUREG-0737. The response to the NRC request for specific information required for control room habitability evaluation found in Attachment 1 to NUREG-0737, Item III.D.3.4, is also included in Section 6.4.4.5. The DAEC responded to NUREG-0737, Item III.D.3.4, by submitting an evaluation of the DAEC control room habitability as Attachment 8 to Reference 3, and committed to eliminate the onsite storage of chlorine by Reference 4. By Reference 5 the NRC issued a Safety Evaluation which found that the DAEC design with the elimination of the chlorine storage meets the criteria identified in Item III.D.3.4 of NUREG-0737 and is acceptable.

An additional request for information from the NRC regarding Control Room Habitability was forwarded to the DAEC in Reference 6. DAEC's response to this request is documented in References 7 and 8.

Radiation protection for operating personnel in the control room under accident conditions is provided by the operation of either of two high-efficiency air filtration trains in conjunction with the installed control room shielding. Two 1000-cfm single-pass high-efficiency filter trains are provided in parallel with the normal outside air inlet duct. Each filter train consists of inlet and outlet isolation dampers, a heating coil, a prefilter, a HEPA filter, a charcoal filter (2-in. bed, tray type), and a final HEPA filter. Should fission products leaving the main stack reach ground level during a brief atmospheric fumigation, outside air radiation monitors will isolate the normal ventilation path and initiate high-efficiency filtration of incoming outside air. Control room air is recirculated through dust filters and heated or cooled as necessary to maintain comfortable working conditions. Power for the filtration-recirculation system may be supplied from the emergency bus. The filtration-recirculation system is Seismic Category I and is located in a Seismic Category I structure. See Section 9.4 for further description.

The control room design-basis dose criteria of 5-rem whole body or its equivalent to any part of the body resulting from access and occupancy for the duration of the accident condition are consistent with General Design Criterion 19.

The design of the main control room shielding and the main control room ventilation system has been evaluated using a hypothetical LOCA that results in the assumed release into the primary containment of 100% of the noble gases, 50% of the halogens, and 1% of the solids in the core fission product inventory (TID-14844 source). In addition, the thyroid and whole-body radiation exposures of control room personnel resulting from the periodic need for personnel to leave the main control room were evaluated.

The following radiation sources were considered when evaluating the whole-body dose received by control room personnel while in the control room and while traveling to and from the control room across the site:

1. Fission products in the primary containment.

2. Fission products external to the control room in the cloud leaving the main stack.

3. Fission products in the reactor building.

4. Cloud fission products taken into the control room.

The thyroid dose received by control room personnel was evaluated considering exposure while in the control room and while traveling to and from the control room in the fission product cloud released from the main stack.

Whole-body dose contributions from primary containment and reactor building shine were evaluated for the time-dependent fission-product source terms given in Table 15.7-2, assuming uniform mixing in the total available free volume, both 0.635% per day and 2.0% per day primary containment leak rates, and a reactor building ventilation rate of 100% per day. Fission-product cloud concentrations surrounding the control room and within it were determined from the atmospheric diffusion tables of Safety Guide 3 (including a 0.5-hr fumigation condition) for a 100-m stack, 200 m from the control room (see Section 1.8). No reactor building holdup (no mixing) was assumed when determining the time-dependent fission-product release rates from the main stack to the atmosphere.

Whole-body dose calculations were performed using a point kernal multienergy group shielding computer code for all radiation sources. The primary containment was represented by a concrete cylinder with walls that are 5 ft 8 in. thick. The reactor building was also described as a large, uniform cylindrical source with concrete walls that are 2 ft 6 in. thick, but with no credit taken for the concrete floors within. The control room was modeled to include the 2.5 ft concrete control room wall facing the reactor building and the 2-ft concrete ceiling and floor.

Thyroid doses were calculated using the breathing rate and energy-to-dose conversions of Safety Guide 3 (see Section 1.8), an iodine removal efficiency of 99% for the deep-bed charcoal filter of the standby gas treatment system, and an iodine removal efficiency of 90% for the control room high-efficiency filter train. Outside air was assumed to be continuously available to the control room.

Operators were assumed to be present in the control room on a normal rotating shift basis of 8 hr per day, 22 days per month.

The probable radiation exposure of personnel resulting from the periodic need of personnel to leave the control room and return was evaluated assuming normal rotation of operating shifts and allowing 10 min for the incoming or outgoing personnel to travel from the turbine building exit along the access road to the site boundary. Personnel were assumed to travel this route twice a day on each of 22 days per month. Exposure to the various radiation sources resulting from the release of the TID-14844 fission-product source term in the primary containment was assumed to be negligible along the route from the main control room to the turbine building exit because of the shielding provided by the surrounding concrete floors and walls and the short travel time in the structure. No credit was taken anywhere along the route to the site boundary for breathing apparatus or special whole-body shielding.

From the above assumptions and methods, the total whole-body and thyroid doses (from ingress, egress, and occupancy) to a control room operator were calculated, and these are given in Table 6.4-1. Skin doses to control room operators were calculated based on occupancy factors of 1.0 for the first 24 hours, 0.6 for the next 72 hours, and 0.4 for the interval from 96 hours to 30 days. The skin dose resulting from this exposure was calculated to be 8.6 rem.

The degree of compliance of the DAEC control room habitability design to the applicable NRC Standard Review Plan sections and Regulatory Guides listed in NUREG-0737 are discussed in Section 6.4.1. Included in Section 6.4.4.3 are the results of a survey of potential onsite and offsite sources of chemical hazards that could jeopardize control room habitability. Descriptions of modification options to improve the DAEC control room habitability were presented in Reference 3.

6.4.4.2 Control Room Radiological Analysis from the Main Steam Isolation Valve Leakage Treatment Path

As a resolution to the MSIV-LCS concerns, as described in Section 6.7, the BWROG proposed to use the main steam piping and main condenser as a method for MSIV leakage treatment. Based upon the studies and recommendations mentioned in that section, DAEC has chosen to eliminate the MSIV-LCS and take credit for MSIV leakage utilizing the main steam drain lines and the main condenser. The allowable MSIV leakage rate limit has been increased to 100 scfh per valve, 200 scfh total. The bases for this approach and guidelines for implementation are contained in NEDC-31858P, Revision 2, BWROG Report for Increasing MSIV Leakage Rate Limits and Elimination of Leakage Control Systems (Reference 1 to Section 6.7).

To demonstrate the adequacy of the DAEC engineered safety features, an assessment was performed of the offsite radiological consequences that could result from the occurrence of design-basis-accidents (DBAs) with a leakage rate of 100 scfh per MSIV with a total leakage rate of 200 scfh through four main steam lines and without the MSIV-LCS. The radiological dose methodology developed by GE for the BWROG is documented in Appendix C of Reference 1 to Section 6.7. This radiological analysis was used to calculate the effects of the allowable MSIV leakage rate in terms of control room doses. Table 6.7-1 shows the calculated control room doses for the BWROG radiological analysis for the DAEC. Regulatory limits and the calculated doses from radiological analysis, Table 6.4-1, are also included for comparison purposes. This analysis demonstrates that a leakage rate of 100 scfh per MSIV, with a maximum leakage rate of 200 scfh for all four main steam lines (with elimination of the LCS) results in an acceptable increase in the dose exposure previously calculated for the control room. The revised LOCA doses remain within the guidelines of 10CFR50, Appendix A, (General Design Criterion 19) for the control room.

6.4.4.3 Survey Results

The survey of chemicals stored in quantity on the DAEC plant site identified chlorine as the only chemical that presented a potential hazard to control room habitability. This potential hazard was eliminated in 1982 by eliminating the onsite storage of chlorine gas and using sodium hypochlorite to chlorinate the circulating and service water systems.

The survey of offsite chemical storage within a 5-mile radius of the DAEC site identified no additional chemicals that present a potential hazard to control room habitability. The survey also included a review of offsite fire and explosive hazards, and no hazards in this category were found. A more detailed discussion of the offsite survey results is provided in Section 6.4.4.3.2.

The effects on Control Room habitability from a carbon dioxide discharge into the Cable Spreading Room are discussed in Section 6.4.4.5.

6.4.4.3.1 Survey of Onsite Chemical Hazards

A survey of potentially toxic and explosive chemicals stored on the DAEC site in quantities exceeding 100 lb was conducted in 1980. The following chemicals in this category were identified:

1. Hydrogen.
2. Chlorine.
3. Nitrogen.
4. Carbon dioxide.
5. Sulfuric acid.
6. Circulating water treatment chemicals (three types).

The evaluation of the survey results is presented below.

1. Hydrogen can be both an ashphyxiant and explosive hazard. At the DAEC, hydrogen gas is used to cool the turbine-generator windings and is injected into each reactor feedpump suction line to aid in Intergranular Stress Corrosion Cracking (IGSCC) mitigation. The hydrogen is supplied from vendor supplied tube trailers. Tube trailer capacities are approximately 125,000 ft^3. The hydrogen tube trailer is utilized via a discharge stanchion at the compressed gas storage facility located approximately 550 feet east of the turbine building. Additionally, six hybrid tubes are permanently stored in the same location and represent approximately 51,000 ft^3 of reserve capacity. Because the density of hydrogen is less than 1/14 the density of air, the hydrogen cloud will rise and dissipate too rapidly to draw a combustible concentration (4% by volume in air is the hydrogen lower flammable limit) into the control building. Similarly, the hydrogen concentration will be too low to present an asphyxiation hazard.

2. Chlorine was judged to be a potential threat to control room habitability and had been identified in the FSAR as such. Chlorine was used as a biocide in the circulating and service water systems. The DAEC chlorine storage consisted of nine 1-ton tanks of liquefied chlorine in the pump house. The tanks were manifolded in three groups of three tanks each.

   An analysis of the three-chlorine-tank rupture accident was performed using Regulatory Guide 1.78, Appendix B criteria. A calculation of the maximum chlorine concentration that could exist inside the control room for this rupture size showed that a chlorine concentration exceeding 670 ppm (by volume in air) could occur. This calculation assumed that no operator action was taken to isolate the control building ventilation following operator detection of the chlorine gas and also assumed Regulatory Guide 1.78 criteria for meteorological assumptions.

On the basis of the calculated high concentration of chlorine that could occur in the control room under the existing DAEC design with no operator action, chlorine was evaluated as a potential threat to control room habitability. As a result, the system was replaced by a liquid sodium hypochlorite system in 1987.

3. Nitrogen is stored in liquid form in a 9300-gal cryogenic tank located outside the reactor building south wall (on the opposite side from the control building). The nitrogen is used principally for containment inserting. Pure nitrogen is an asphyxiant if allowed to displace the oxygen in the control room atmosphere. A puff release of nitrogen from the cryogenic tank could release an estimated 800,000 scf. An analysis of nitrogen-cloud dispersion around the reactor building was performed to determine if nitrogen storage represents a threat to control room habitability.

   The analysis concluded that the increase in nitrogen level within the control room as a result of the cryogenic tank rupture would be approximately 1.5% by volume in air. Because air is normally at a 79% nitrogen level, this increase in total nitrogen content is small. The nitrogen increase would cause a corresponding decrease in oxygen level from approximately 21% to 19.5%. The decrease in oxygen concentration will have no adverse effect on control room habitability for the duration of the nitrogen release condition.

4. Carbon dioxide is stored in a 10-ton tank inside the turbine building adjacent to the control building. The carbon dioxide is used for fire protection and as a purge for the turbine-generator hydrogen coolant. A rupture of the carbon dioxide tank could release a puff of approximately 186,000 scf. An analysis of the carbon dioxide tank rupture was conducted, and it was concluded that the increase in carbon dioxide level in the control room would not exceed the threshold limit value (9000 mg/m^3) because of this event. The turbine building would effectively dilute and contain most of the carbon dioxide release; in addition, the higher density of carbon dioxide relative to air would contribute to minimizing the amount reaching the control building air intake outside and 15 m above the release point in the turbine building. Therefore, carbon dioxide stored onsite does not represent a threat to control room habitability. The potential for intrusion of CO_2 into the Control Room via pathways other than the CO_2 tank rupture have been identified. These pathways include infiltration from the Cable Spreading Room penetrations and associated ductwork. Infiltration could occur due to a Cable Spreading Room CARDOX actuation. Details of this event and actions taken to mitigate the consequences are discussed in Section 6.4.4.5.

5. Sulfuric acid is used to treat the circulating and service water systems and is stored east of the pump house in a 20,000-gal tank. Sulfuric acid is a liquid at 100°F and has a vapor pressure of less than 10 torr. Regulatory Guide 1.78 states that any chemical that has a vapor pressure of less than 10 torr and is a liquid at a temperature of 100°F can be excluded from the control room habitability analysis. Therefore, the sulfuric acid storage at the DAEC is not a threat to control room habitability.

b. As in Regulatory Guides 1.78 and 1.95, the Standard Review Plan assumes that automatic isolation of the control room occurs on the detection of hazardous chemicals in the inlet air and evaluates a design according to infiltration rate and makeup airflow. The DAEC design does not presently meet the isolation requirement to satisfy this Standard Review Plan criterion.

5. Standard Review Plan Sections 2.2.1, 2.2.2, and 2.2.3 were used in the identification of potential offsite hazards discussed in Section 6.4.4.3.2.

6. The paper prepared by Murphy and Campe to address methodology for meeting General Design Criterion 19 control room ventilation design requirements was reviewed for applicability to the DAEC design. The paper presents a methodology for calculating control room radiation doses for particular plant geometries, source terms, meteorological conditions, etc. The calculations performed to support this control room habitability study employed calculational methods and assumptions consistent with the methodology promoted in the Murphy and Campe paper.

6.4.4.5 NRC-Requested Information Required for Control Room Habitability Evaluation

Regulatory Position Habitability Evaluation

The following information is listed in the same order as requested in Attachment 1 to NUREG-0737, Item III.D.3.4.

Item	Response
1	The control building ventilation system mode of operation for the detection of high airborne radioactivity is automatic isolation of the normal control building makeup and exhaust ducting and pressurization of the control building with once-through filtered makeup air through emergency charcoal filters. The control building ventilation system mode of operation for a hazardous-chemical release is operator detection followed by manual initiation of the same isolation and filter alignment described above for the radiological accident. Figure 9.4-7 shows the control building airflow.
2	a. The control room is supplied air from the ventilation system common to the entire control building. The air volume of the control building is 155,000 ft^3.

Item		Response
2 (cont.)	b.	The "control room emergency zone" at the DAEC envelopes the entire control building air space. This space includes the essential switchgear and battery rooms, the cable spreading room, the control room, and the HVAC equipment room.
	c.	Figure 9.4-7 shows normal and emergency airflow rates for the control building.
	d.	The control building air infiltration leakage rate has not been determined at the DAEC. The emergency filtration mode continues to supply outside makeup air to maintain a positive control building pressure such that infiltration is minimized.
	e.	The HEPA filters in the emergency filtration trains are rated at 99% efficiency in removing particulates. The charcoal filters in each emergency filtration train are rated at 90% efficiency for radioactive methyl iodide removal.
	f.	The control building air inlet is located 52 ft due north from the closest wall of the reactor building (secondary containment).
	g.	The site layout showing the location of the control building in relation to the reactor building, turbine building, and pump house is shown in Figure 1.2-1. The control room elevation of the control building is shown in Figure 6.4-1. The control building air intake location is shown in Figure 6.4-2.
	h.	The control room is shielded by concrete and high-density blockwall. The wall design and radiation dose rates under design-basis accident LOCA conditions are described in Section 12.3.2. No streaming of radiation will occur in the control room.
	i.	The control building isolation dampers are rectangular. The inlet dampers are approximately 38.5 by 68.5 in. OD (35.5 by 59.5 in. ID) ; the design leakage rate at a pressure differential of 0.5-in. water gauge is 67.5 scfm. The exhaust dampers are 40 by 46 in.; the design leakage rate at a pressure differential of 0.5-in. water gauge is 57 scfm. No periodic leakage testing is presently performed.
	j.	The DAEC design presently includes one detector for chlorine located in the chlorine storage area of the pump house. The detector is not safety grade and alarms on detection both locally and in the control room. No toxic gas detectors are provided to initiate control building isolation.

Item		Response
2 (cont.)	k.	Seven self-contained breathing apparatus units are provided in the DAEC control room.
	l.	Each self-contained breathing apparatus is provided with a 1-hr reserve of bottled air supply.
	m.	The DAEC control room is not presently provisioned with food for the operators and supervisor for a 5-day period. Adequate potable water and a medical kit are provided.
	n.	The control room personnel capacity is only limited to seven persons by the number of self-contained breathing apparatus units. If the control room air is breathable, the capacity is only limited by shift supervisor control of access to the room, as discussed in DAEC's response to NUREG-0578, Item 2.2.2.a.
	o.	Potassium iodide drugs are not presently available in the DAEC control room.
3	a.	The quantities and volumes of storage containers for potentially hazardous chemicals on the DAEC site are as follows:

Chemical	Quantity	Storage Container Size
Hydrogen	2 (tube trailers)	176,00 ft^3
Nitrogen	1	9300-gal cryogenic tank
Carbon dioxide	1	10-ton tank
Sulfuric acid	1	20,000-gal tank
Circulating water treatment chemicals (3)	2 1 1	2000-gal tank 2000-gal tank 1000-gal tank

The review of control room habitability has determined that, of the above chemicals, none represents a threat to control room habitability.

b. There is no onsite chlorine storage.

4 The survey of offsite manufacturing, storage, and transportation facilities of hazardous chemicals documented in Section 2.2 provides each of the requested items listed in NUREG-0737, Item III.D.3.4.

5 a. Because the DAEC design does not provide for a safety-grade chlorine detection/isolation system, no technical specifications exist to address chlorine detection.

b. The Technical Specifications for control building ventilation include surveillance testing to verify HEPA filter and charcoal adsorber bank efficiencies, to verify system flow isolation/filter system operability periodically and to verify system flow rate. Although there is no Technical Specification requirement to measure system isolation time, it is believed the intent of this requirement is met in that unusual damper closure time would be recorded as a problem in the Surveillance Test Procedure, reported as a deviation, and hence corrected via maintenance.

6 Carbon dioxide intrusion into the control room has the potential to impact control room habitability. CO_2 infiltration into the control room can occur during CARDOX discharge. Pathways into the control room include Cable Spreading Room-Control Room penetrations and HVAC ductwork. Modifications to the ventilation system have been performed and are discussed below.

The modifications included 1) the elimination of a direct vent path from the Cable Spreading Room to the control room area, 2) modifications to the Cable Spreading Room exhaust damper to provide for better venting and limit the internal pressure buildup of the Cable Spreading Room, 3) the addition of secondary Cable Spreading Room vent path, and 4) incorporation of a scent into the CARDOX system to alert control room personnel of any CO_2 intrusion.

The post-modification test results indicate that the cable spreading room is adequately vented during a CARDOX actuation which thereby limits CO_2 intrusion and maintains normal oxygen levels in the control room. A more detailed description of the modifications and test results are included in Reference 8.

6.4.5 TESTING AND INSPECTION

Section 9.4.4.4 contains inspection and testing requirements for the control room HVAC system, including, the control room ventilation HEPA filters and charcoal adsorbers.

6.4.6 INSTRUMENTATION REQUIREMENT

The control room habitability instrumentation and logic are discussed in detail in Section 6.4.4.4.

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The fourth test is the single-rod scram test that verifies the capability of each rod to scram. It is accomplished by the operation of toggle switches on the protection system operations panel. Timing traces can be made for each rod scrammed. Before the test, a physics review must be conducted to ensure that the rod pattern during scram testing does not create a rod of excessive reactivity worth.

The fifth test involves applying a test signal to each RPS channel in turn and observing that a logic trip results. This test also verifies the electrical independence of the channel circuitry. The test signals can be applied to the process-type sensing instruments (pressure and differential pressure) through calibration taps.

There are only two dc solenoid-operated backup scram valves, either of which can control the air to all scram valves for all control rods. Thus, the backup scram valves cannot be tested during reactor operation without tripping the reactor. The backup scram valves are tested during each refueling outage.

RPS response times were first verified during preoperational testing and may be verified thereafter by a similar test. The elapsed times from a sensor trip to each of the following events are measured:

1. Channel relay deenergized.

2. Trip actuators deenergized.

Surveillance requirements for the reactor protection system are specified in the Technical Specifications.

The Reactor Vessel Steam Dome Pressure-High Sensor Response time shall be < 0.5 seconds and the Reactor Trip System Response Time shall be ≤ 0.55 seconds.

The Reactor Water Level-Low Sensor Response time shall be < 1.0 seconds and the Reactor Trip System Response time shall be ≤ 1.05 seconds.

The designed system response times from the opening of the sensor contact up to and including the opening of the trip actuator contacts shall not exceed 50 milliseconds.

The alarm typewriter provided with the process computer verifies the proper operation of many sensors during plant startups and shutdowns. Main steam line isolation valve position switches and turbine stop valve position switches can be checked in this manner. The verification provided by the alarm typewriter is not considered in the selection of test and calibration frequencies and is not required for plant safety.

7.2.2 ANALYSIS

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. Chapter 15 identifies and evaluates events that challenge the fuel barrier and nuclear system process barrier. The methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are sought and identified, are presented in that chapter.

Design procedures have been to select tentative scram trip settings that are far enough above or below normal operating levels that spurious scrams and operating inconvenience are avoided; it is then verified by analysis that the reactor fuel and nuclear system process barriers are protected as is required by the basic objective. In all cases, the specific scram trip point selected is not the only value of the trip point that results in no damage to the fuel or nuclear system process barriers; trip setting selection is based on operating experience and constrained by the safety design basis.

The scrams initiated by neutron monitoring system variables, nuclear system high pressure, turbine stop valve closure, turbine control valve fast closure, and reactor vessel low water level are sufficient to prevent fuel damage following abnormal operational transients. Specifically, these scram functions initiate a scram in time to prevent the core from exceeding the thermal-hydraulic safety limit during abnormal operational transients.

The scram initiated by nuclear system high pressure, in conjunction with the pressure relief system, is sufficient to prevent damage to the nuclear system process barrier as a result of reactor pressure. For turbine-generator trips, the stop valve closure scram and turbine control valve fast closure scram provide a greater margin anticipatory to the nuclear system pressure safety limit than the high-pressure scram. Chapter 15 identifies and evaluates accidents and abnormal operational events that result in nuclear system pressure increases; in no case does pressure exceed the nuclear system safety limit.

The scram initiated by the neutron monitoring system, main steam isolation valve closure, and reactor vessel low water level satisfactorily limits the radiological consequences of gross failure of the nuclear system process barrier. Chapter 15 evaluates gross failures of the nuclear system process barrier; in no case does the release of radioactive material to the environs result in exposures that exceed the guideline values of published regulations.

Neutron flux (the neutron monitoring system variable) is the only essential variable of significant spatial dependence that provides inputs to the RPS. The basis for the number and locations of neutron flux detectors is discussed in Section 7.6.1. The other requirements are fulfilled through the combination of logic arrangement, channel redundancy, wiring scheme, physical isolation, power supply redundancy, and component environmental capabilities. The following discussion evaluates these subjects.

In terms of protection system nomenclature, the RPS is a one-out-of-two system used twice. Theoretically, its reliability is slightly higher than a two-out-of-three system and slightly lower than a one-out-of-two system. However, since the differences are slight, they can, in a practical sense, be neglected. The advantage of the dual-trip system arrangement is that it can be tested thoroughly during reactor operation without causing a scram. This capability for a thorough testing program, which contributes significantly to increased reliability, is not possible for a one-out-of-two system.

The use of an independent channel for each logic allows the system to sustain any channel failure without preventing other sensors monitoring the same variable from initiating a scram. A single sensor or channel failure will cause a single trip system trip and actuate alarms that identify the trip. The failure of two or more sensors or channels would cause either a single trip system trip if the failures were confined to one trip system, or a reactor scram if the failures occurred in different trip systems. Any intentional bypass, maintenance operation, calibration operation, or test, all of which result in a single trip system trip, leaves at least two channels per monitored variable capable of initiating a scram by causing a trip of the remaining trip system. The resistance to spurious scrams contributes to plant safety because unnecessary cycling of the reactor through its operating modes would increase the probability of error or actual failure.

An actual condition in which an essential monitored variable exceeds its scram trip point is sensed by at least two independent sensors in each trip system. Because only one channel must trip in each trip system to initiate a scram, the arrangement of two channels per monitored variable trip system provides assurance that a scram will occur as any monitored variable exceeds its scram setting.

Each control rod is controlled as an individual unit although the rods are scrammed in groups. A failure of the controls for one rod would not affect other rods. The backup scram valves provide a second method of venting the air pressure from the scram valves, even if either scram pilot valve solenoid for any control rod fails to deenergize when a scram is required.

Sensors, channels, and logics of the RPS are not used directly for automatic control of process systems. Therefore, failure in the controls and instrumentation of process systems cannot induce a failure of any portion of the protection system.

The failure of either RPS motor-generator set would result, at worst, in a single trip system trip. Alternate power is available to the RPS buses. A complete, sustained loss of electric power to both buses would result in a scram, delayed by the motor-generator set flywheel inertia.

The environmental conditions in which the instruments and equipment of the RPS must operate are considered in setting the environmental specifications. For the instruments located in the reactor or turbine buildings, the specifications are based on the worst expected ambient conditions in which the instruments must operate. The RPS components that are located inside the primary containment are the condensing chambers. Special precautions are taken to ensure satisfactory operability after the accident. The condensing chambers are similar to those that have successfully undergone qualification testing in connection with other projects. Additionally, a continous purge system has been installed to prevent the accumulation of non-condensible gases that could come out of solution following rapid depressurization and subsequently adversely affect level indication.

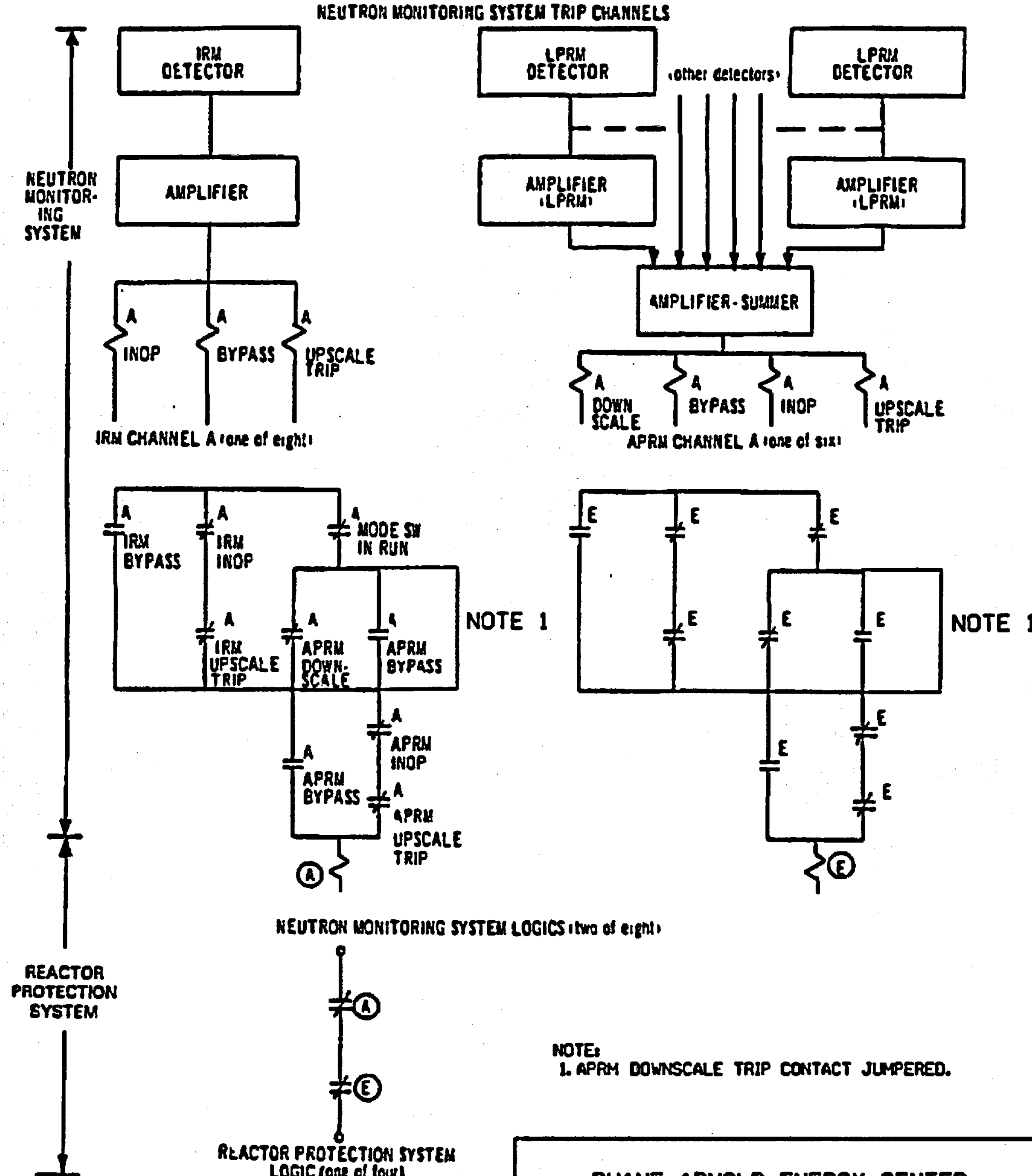
Safe shutdown of the reactor during earthquake ground motion is ensured by the Seismic Category I design of the system and the fail-safe characteristics of the system. The system only fails in a direction that causes a reactor scram when subjected to extremes of vibration and shock.

To ensure that the RPS remains functional, the number of operable trip channels for the essential monitored variables should be maintained at or above the minimums given in Technical Specifications Table 3.3.1.1-1. The minimums apply to any untripped trip system; a tripped trip system may have any number of inoperative channels. Because reactor protection requirements vary with the mode in which the reactor operates, the tables show different functional requirements for the RUN and STARTUP modes. These are the only modes where more than one control rod can be withdrawn from the fully inserted position.

Calibration and test controls for the neutron monitoring system are located in the main control room and are, because of their physical location, under direct physical control of the plant operator. Calibration and test controls for pressure switches, level switches, and valve position switches are located in the turbine building, reactor building, and primary containment. To gain access to the setting controls on each switch, a cover plate sealing device must be removed. The plant operator is responsible for granting access to the setting controls to properly qualified plant personnel for the purpose of testing or calibration adjustment.

7.2.3 ATWS-RPT/ARI

The NRC, in 10CFR50.62, requires that certain systems be provided to cope with anticipated transients without scram (ATWS). For BWRs, the required systems are the Standby Liquid Control System, the Alternate Rod Injection (ARI) System, and the Recirculation Pump Trip (RPT) system. The DAEC Standby Liquid Control system is described in Section 9.3.4, and the ARI-RPT system is described in the following sections, and in References 3 through 6.



NOTE:
1. APRM DOWNSCALE TRIP CONTACT JUMPERED.

DUANE ARNOLD ENERGY CENTER
IES UTILITIES
UPDATED FINAL SAFETY ANALYSIS REPORT

RELATIONSHIP BETWEEN NEUTRON MONITORING AND REACTOR PROTECTION SYSTEM

FIGURE 7.2-4

modification prevents the automatic opening of these valves with a potentially large differential pressure across the valves and subsequent damage to downstream components.

4. Drywell/Torus Vent and Purge Isolation Defeat

This defeat allows venting and purging of the Drywell or Torus regardless of the radioactive release in support of the Primary Containment Pressure and Hydrogen Control Sections of EOP-2 by bypassing all Group III isolations. Two key-lock switches are installed to override all isolation signals (one in each isolation channel). Each switch has an associated amber light and individually annunciates on front panel 1C-14 when taken to override.

This override utilizes locking brass handle switches which are unique from others at DAEC and are only used for override functions associated with the EOPs.

The torus vent and purge inboard isolation valve, CV-4300, is controlled by handswitch HS-4300 and a two-position keylock handswitch, HS-4300A. Spare contacts on HS-4300 have been utilized to provide the capability to operate SV-4300A with 125 Vdc power. When HS-4300A is in the NORMAL position, 125 Vdc power will not be available at HS-4300 for the operation of SV-4300A. The existing function and operation of CV-4300, including automatic primary containment isolation functions, will not be altered. In the OVERRIDE position, HS-4300A applies 125 Vdc power to contacts operated by HS-4300 and removes 120 Vac power from HS-4300, allowing operation of CV-4300 independent of AC power and overriding primary containment isolation functions associated with CV-4300. An amber indicating light above HS-4300A and an alarm will annunciate on front panel 1C-14 when HS-4300A is taken to the OVERRIDE position.

5. RHR Discharge to Radwaste Isolation Defeat

This defeat allows the RHR Discharge to Radwaste Valves to remain open with the presence of a Group II Isolation signal. This defeat is to support the Torus Level Control Section of EOP-2 by allowing the Torus to be drained via the Radwaste System. Two key-lock switches are installed to override all isolation signals (one for each valve). Each switch has an associated amber light and annunciates on front panel 1C-14 when taken to override.

6. RWCU RPV Low-Low Level & RWCU Area Temperature Isolation Defeat

This defeat permits RWCU isolation valves to be opened or to remain open in support of Alternate Boron Injection. This defeat also allows RWCU to be used to lower RPV level as directed in the Power/Level Control Section of EOP-ATWS. Two key-lock switches are installed to override the isolation signals (one for each isolation channel). Each switch has an associated amber light and annunciates on front panel 1C-14 when taken to override.

7. Drywell Cooling Isolation Defeats

Two key-lock switches allow drywell cooling to be re-established following an isolation signal and allow drywell cooling fans to run in fast speed with an isolation signal present. These switches also override the shift to slow speed of the drywell fans when a high drywell pressure signal is received, thus allowing the fans to run in fast speed. Each switch has an associated amber light and individually annunciates on front panel 1C-14 when taken to override.

A trip of an isolation control system channel (except Group 7) is annunciated in the main control room so that the operator is immediately informed of the condition. The response of isolation valves is indicated by "open-closed" lights. One set is located near the manual control switches for the control of each valve from the main control room panel. The positions of air-operated isolation valves are displayed in the same manner as motor-operated valves.

Input to annunciators, indicators, and the process computer are arranged so that no malfunction of the annunciating, indicating, or computing equipment can functionally disable the system. Signals directly from the isolation control system sensors are not used as inputs to annunciating or data logging equipment. Isolation is provided between the primary signal and the information output.

7.3.1.1.1.7 Isolation Valve Closing Devices and Circuits

Table 7.3-1 itemizes the closing device provided for each isolation valve used in automatic or remote manual isolation of the primary containment or reactor vessel. To meet the requirement that automatic Type A valves be fully closed in time to prevent the reactor vessel water level from falling below the top of the active fuel as a result of a break of the line that the valve isolates, the valve closing mechanisms are designed to give minimum closing rates. In many cases, a standard closing rate of 12 in./min is adequate to meet isolation requirements. Using the standard rate, a 12-in. valve is closed in 60 sec. Conversion to actual closing time can be made by using the size of the line to be isolated. Because of the relatively long time required for fission products to reach the containment atmosphere following a break in the nuclear system process barrier inside the primary containment, a standard closure rate (12 in./min) is adequate for the automatic closing devices on Type B isolation valves. The design maximum closure times for the various automatic isolation valves essential to reactor vessel isolation are as follows:

Valves	Design Maximum Closure Times (sec)	Line Nominal Size (in.)
Main steam line isolation valves	3-5	20
Main steam line drain isolation valves	15	3
Reactor core isolation cooling (RCIC) system steam line isolation valves	20	4
HPCI system steam line isolation valves	13	10
RHR system shutdown cooling supply isolation valves	22	18
RHR system shutdown cooling inboard discharge isolation valves (MO1905, MO2003)	25	20
RWCU system supply isolation valves	22	4
RWCU isolation valve (enters feedwater line outside primary containment	20	4

Motor operators for Type A and Type B isolation valves are selected with capabilities suitable to the physical and environmental requirements of service. The required valve closing rates were considered in specifying motor operators.

Torque and limit switches are used to ensure proper valve seating in accordance with GL 89-10. Handwheels, which are automatically disengaged from the motor operator when the motor is energized, are provided for local hand operation.

Direct solenoid-operated isolation valves and solenoid nitrogen pilot valves are chosen with electrical and mechanical characteristics that make them suitable for the service for which they are intended. Appropriate watertight or weathertight housings are used to ensure proper operation under accident conditions. (Note: air has been replaced by nitrogen as the fluid used to operate pneumatic actuators inside containment.)

The main steam isolation valves are spring/pneumatic-closing, electrical pneumatic-opening, piston-operated valves designed to close on loss of electrical power to both solenoid pilot valves or pneumatic pressure to the valve operator. This is a fail-safe design. The control arrangement is shown in Figure 7.3-6, Sheet 2, and Figure 7.3-7. Closure time for the valves is adjustable between 3 and 5 sec. Each valve is piloted by two 3-way, packless, direct-acting, solenoid-operated pilot valves, one powered by ac, the other by dc. An accumulator is located close to each isolation valve to provide pneumatic pressure for valve closing in the event of the failure of the normal non-safety nitrogen supply system. Control nitrogen to the inboard MSIVs is provided from each MSIV accumulator. Each control nitrogen line to each outboard MSIV contains an accumulator and check valve and is provided from the non-safety nitrogen supply system.

The main steam isolation valve characteristics used in the transient analysis (Chapter 15) are given in Figure 7.3-8.

The valve pilot system and the pneumatic lines, as shown in Figure 7.3-7, are arranged so that when one or both solenoid-operated pilot valves are energized normal nitrogen supply provides pneumatic pressure to the nitrogen-operated pilot valve to direct nitrogen pressure to the main valve pneumatic operator. This overcomes the closing force exerted by the spring to keep the main valve open. When both pilots are deenergized, as would be the result of both trip systems tripping or placing the manual switch in the closed position, the path through which nitrogen pressure acts is switched so that the opposite side of the valve operator is pressurized, thus assisting the spring in closing the valve. In the event of nitrogen supply failure, the loss of nitrogen pressure will cause the nitrogen-operated pilot valve to move by spring force to the position resulting in main valve closure. Main valve closure is then effected by means of the nitrogen stored in the accumulator and by the spring. However, the inboard MSIVs will be closed per plant operating procedures prior to nitrogen-operated pilot valve repositioning due to loss of nitrogen pressure.

Nitrogen pressure, acting alone, and the force exerted by the spring, acting alone, are each capable of independently closing the valve with the exception of the isolation valves inside the primary containment (inboard). These inboard valves are designed to close using both pneumatic

Three reactor vessel low-water-level isolation trip settings are used to complete the isolation of the primary containment and the reactor vessel. The first reactor vessel low-water-level isolation trip setting, which occurs at a higher water level than the second and third settings, initiates the closure of all Type A and Type B valves in major process lines except RWCU and the main steam lines. RWCU lines remain open in an effort to eliminate unnecessary isolations resulting from scrams not related to RPV low level. The main steam lines are left open to allow the removal of heat from the reactor core. The second and third reactor vessel low-water-level (low-low and low-low-low) isolation trip settings complete the isolation of the primary containment and reactor vessel by initiating the closure of the main steam isolation valves and any other Type A or Type B valves that must be shut to isolate minor process lines.

The first low-water-level setting, which is coincidentally the same as the reactor vessel low-water-level scram setting, was selected to initiate isolation at the earliest indication of a possible breach in the nuclear system process barrier, yet far enough below normal operational levels to avoid spurious isolation. The isolation of the following lines is initiated when reactor vessel low-water-level falls to this first setting (Table 7.3-1, Signal A):

a. RHR system reactor shutdown cooling supply.*

b. Deleted

c. RHR system LPCI to reactor.*

d. Deleted

e. Drywell equipment drain discharge.

f. Drywell floor drain discharge.

g. Containment purge inlet.*

h. Drywell air purge inlet.*

i. Drywell vent.*

j. Drywell vent valve bypass.*

---

*Closed during normal power operation.

k. Suppression chamber air purge inlet.*

l. Suppression chamber vent.*

m. Suppression chamber vent valve bypass.*

n. Reactor building - torus vacuum breaker.*

o. RHR discharge to radwaste.*

p. RHR sample.*

q. Makeup N_2.

r. Drywell N_2 makeup.*

s. Suppression chamber N_2 makeup.*

t. Traversing incore probe tubes.*

u. Traversing incore probe purge.*

v. Drywell atmosphere analyzer suction.

w. Drywell atmosphere analyzer return.

x. Torus atmosphere analyzer suction.

y. Torus atmosphere analyzer return.

z. Mini-purge to reactor recirculation pump seal.

aa. Deleted.

---

*Closed during normal power operation.

k. Drywell vent valve bypass.*

l. Suppression chamber air purge inlet.*

m. Suppression chamber vent.*

n. Suppression chamber vent valve bypass.*

o. Reactor building - torus vacuum breaker.*

p. RHR discharge to radwaste.*

q. RHR sample.*

r. Drywell N_2 makeup.*

s. Suppression chamber N_2 makeup.*

t. Makeup N_2.*

u. Containment N_2 compressor suction.

v. Instrument N_2 to drywell.

w. Drywell atmosphere analyzer suction.

x. Drywell atmosphere analyzer return.

y. Torus atmosphere analyzer suction.

z. Torus atmosphere analyzer return.

aa. HPCI/RCIC exhaust line vacuum breaker**.

ab. Mini-purge to reactor recirculation pump seal.

The primary containment high-pressure isolation setting was selected to be as low as possible without inducing spurious isolation trips.

* Closed during normal power operation
** Coincident with HPCI Steamline low pressure.

7. RCIC Equipment Room and Suppression Pool Area High Ambient Temperature and High Differential Temperature (Table 7.3-1, Signal K)

High ambient or differential temperature in the RCIC equipment room or in the suppression pool area could indicate a break in the RCIC steam line. The automatic closure of the RCIC steam-line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When any one of the following alarm conditions is sensed, an alarm is actuated in the main control room, and the RCIC steam-line valves are closed:

a. High differential temperature between the inlet and outlet ducts that ventilate the RCIC equipment room.

b. High differential temperature between the inlet and outlet ducts that ventilate the suppression pool area.

c. High ambient temperature in the suppression pool area.

d. High ambient temperature at the RCIC equipment room standby cooler.

If the high ambient or differential temperature in b and c above occurs, isolation does not occur immediately, but a timer is initiated and if the temperature is not reduced below the trip point before the time runs out, the RCIC steam line is isolated. The high ambient temperature and high differential temperature isolation settings were selected far enough above expected normal operational levels to avoid spurious operation, but low enough to provide timely detection of an RCIC turbine steam-line break.

8. RCIC Turbine High Steam Flow (Table 7.3-1, Signal K)

RCIC turbine high steam flow could indicate a large break in the RCIC turbine steam line. The automatic closure of the RCIC steam-line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier. The RCIC turbine high steam flow trip setting was selected high enough to avoid spurious isolation, that is, above the high steam flow rate encountered during turbine starts. The setting was selected low enough to provide timely detection of an RCIC turbine steam-line break.

Hydraulic snubbers have been added to the RCIC system to preclude spurious isolation of the system due to the pressure spikes that accompany startup steam-flow transients. These snubbers are located in the DP instrument lines of the steam supply line-break

The operating time is the time required for the valve to travel from the fully closed to the fully open position, or vice versa. Because the two HPCI system steam supply line isolation valves are normally open and because they are intended to isolate the HPCI system steam line in the event of a break in that line, the operating time requirements for them are based on isolation specifications. These are described in Section 7.3.1.1.1. A normally closed dc motor-operated isolation valve is located in the turbine steam supply line just upstream of the turbine stop valve. The control scheme for this valve is shown in Figure 7.3-10, Sheet 2. Upon the receipt of an HPCI system initiation signal, this valve opens and remains open until closed by operator action from the main control room.

Two normally open isolation valves are provided in the steam supply line to the turbine. The valve inside the drywell is controlled by an ac motor. The valve outside the drywell is controlled by a dc motor. The control diagram is shown in Figure 7.3-10, Sheet 1. Although these valves are normally open, an HPCI system initiating signal opens them if they are closed. However, the initiation signal is overridden, and the valves automatically close upon the receipt of HPCI system turbine steam line high-flow signals, HPCI turbine high exhaust diaphragm pressure signals, HPCI system turbine steam supply low-pressure signals, leak detection temperature or differential temperature signals, or high steam-line space temperature signals.

Key-lock switches are provided to enable the use of the HPCI steam line to depressurize the RPV via operation of the HPCI turbine. Turbine trips for Steam Line Pressure Low, High RPV Water Level and High Ambient/Differential Temperature are also defeated to allow the turbine to be reset under non-steam line break conditions. One of the switches also removes the auto open signal to MO-2238 and a separate switch removes the auto open signal to MO-2239. This allows manual throttling of the valves and thus provides steamline warmup. By warming the steam lines, possible damage is prevented to downstream components from opening the valves with a large differential pressure across the valves.

Separate key-lock switches are provided for RCIC to bypass its respective trips in a similar manner. These overrides are used as required by the Emergency Operating Procedures (EOPs).

Three pump suction shutoff valves are provided in the HPCI system. One valve provides pump suction from the condensate storage tank; the other two are in series and provide suction from the suppression pool. The condensate storage tank is the preferred source of water for the HPCI system. All three valves are operated by dc motors. The control arrangement is shown in Figure 7.3-10, Sheets 1 and 3. Although the condensate storage tank suction valve is normally open, an HPCI system initiation signal opens it if it is closed. If the water level in the condensate storage tank falls to a preselected level, the suppression pool suction valves automatically open. A time delay relay has been added to the HPCI/RCIC suction transfer on low CST level to prevent spurious signals from causing an unnecessary suction transfer from the CST to the suppression pool. The time delay is set at 2 seconds or less. With this time delay, an actual low level condition would remove an additional 115 gallons (maximum) from the CST with both systems pumping at rated flows prior to the start of the suction transfer. The low CST transfer setpoint corresponds to 10,000 gallons in the CST. The additional 115 gallons drawn from the CST during the time delay does not result in a noticeable decrease in suction pressure and therefore the consequences of the time delay are insignificant. The time delay relay is a highly reliable device procured as a class 1E relay. (See Table 7.3-3.) When the suppression pool valves are both fully open, the condensate storage tank suction valve automatically closes. Two level switches are used to detect the condensate storage tank low-water-level condition. Either switch can cause the suppression pool suction valves to open. The suppression pool suction valves also automatically open, and the condensate storage tank suction valve closes if the HPCI suction water level is reached in the suppression pool.

Two level switches monitor the water level in the suppression pool. Either switch can initiate the opening of the suppression pool suction valves. A keylock switch with an amber indicating light for overriding the HPCI Torus High Water Level Transfer is provided for operator actions which are required procedurally during Emergency Operating Procedure (EOP) actions. The override will: 1) remove the high suppression pool water level signal from opening the HPCI suppression pool suction valves, 2) remove the shut signal from the HPCI CST suction unless a CST low level signal is present, 3) light an amber light above the handswitch and 4) annunciate on front panel 1C-14 when in override.

With the handswitch in override, the logic configuration will provide for automatically closing the CST valve on a low CST level if both suppression pool suction valves are full open. With the handswitch in normal, the CST suction valve will close as originally designed, i.e., with both suppression pool suction valves full open. In override, the switch blocks the close signal to the CST suction valve unless the CST low level signal is present. Without this additional function, the CST suction valve would go shut as soon as it reached full open, provided the suppression pool suction valves were open. If open, the suppression pool suction valves automatically close upon the receipt of the signals that initiate HPCI system steam line isolation.

Two dc motor-operated valves in the pump discharge line are provided. The control schemes for these two valves are shown in Figure 7.3-10, Sheet 3. Both valves are arranged to open upon the receipt of the HPCI system initiation signal.

A pump discharge minimum flow bypass is provided to prevent damage by overheating at reduced HPCI system pump flow. The bypass is controlled by an automatic, dc motor-operated valve whose control scheme is shown in Figure 7.3-10, Sheet 3. At HPCI system high flow, the valve is closed; at low flow, the valve is opened except when the HPCI turbine is tripped. A flow switch measures the pressure difference across a flow element in the HPCI system pump discharge line to provide the closure signal for the valve. There is also an interlock

A two-position switch is provided in the main control room for the control of the relief valves. The two positions are "open" and "auto." In the open position, the switch energizes the solenoid-operated pilot valve, which allows pneumatic pressure to be applied to the piston actuator of the relief valve. This allows the plant operator to take action independent of the automatic system. The relief valves can be manually opened to provide a controlled nuclear system cooldown under conditions where the normal heat sink is not available. Manual reset circuits are provided for the automatic initiating signals. By manually resetting the initiating signals, the delay self-indicating timers are recycled. The operator can use the reset switch to delay or prevent automatic opening of the relief valves if such delay or prevention is prudent. Manual actuation of one ADS "Reset" button recycles the timer for its trip system. Both timers must be reset to prevent automatic depressurization. Automatic depressurization system initiation can also be prevented by placing the reset switch in the override position (See NUREG-0737, Item II.K.3.18). This will maintain the switch contacts open and prevent the ADS relays from being energized. Both reset switches must be in their override position to prevent ADS initiation.

The logic scheme used for initiating the system is shown in simplified form in Figure 7.3-11 and is a single trip system containing two logics. Each logic can initiate automatic depressurization. The trip system is powered by reliable dc buses. Instrument specifications and settings are listed in Table 7.3-4.

Two pressure switches on the discharge of each core spray and each LPCI pump are arranged to inhibit the automatic depressurization system unless at least one low-pressure cooling pump shows appropriate discharge pressure.

The reactor vessel low-water-level initiation setting for the automatic depressurization system is selected to open the relief valves to depressurize the reactor vessel in time to allow adequate cooling of the fuel by the core spray system and LPCI following a LOCA in which the other makeup systems (RCIC system, HPCI system) fail to maintain vessel water level. The second reactor vessel low-water-level initiation setting is selected to confirm that water level in the vessel is low to provide protection against inadvertent depressurization should an instrument line fail.

Initiation Instrumentation

The level switches used to initiate the automatic depressurization system are common to each relief valve control circuit. Reactor vessel low water level is detected by four switches that measure differential pressure. There are two additional reactor water level switches that perform a permissive function for ADS initiation. These two level switches are activated at a higher level and sense level from different references legs than the other four level switches and use different reference columns to verify a low water level. As shown in Figure 7.3-11, each switch actuates a contact in the control circuit such that a minimum of three water-level signals, and two pump-running signals are required to actuate each of the logic circuits.

The 120-sec (nominal) delay time setting of the self-indicating timers in the logic is chosen to be long enough so that the HPCI system has time to start, yet not so long that the core spray system and LPCI are unable to adequately cool the fuel if the HPCI system fails to start. An alarm in the main control room is annunciated every time either of the timers is running. The timers display the time remaining until ADS initiation. Resetting the ADS logic in the presence of tripped initiating signals recycles the timers. The requirement that at least one of the LPCI or core spray pumps be running before automatic depressurization starts ensures that cooling will be available to the core after the reactor system pressure is lowered. Also, an alarm in the main control room is annunciated when the ADS timers have been locked out.

Alarms

A temperature element is installed in a thermowell in the relief valve discharge piping several feet from the valve body. The temperature elements are connected to dual pen recorders in the main control room to provide a means of detecting relief valve leakage during plant operation. When the temperature in any relief valve discharge line exceeds a preset value, an alarm is sounded in the main control room. The alarm setting is selected far enough above normal ambient temperature at rated power to avoid spurious alarms, yet low enough to give early indication of relief valve leakage.

7.3.1.1.2.3 Core Spray System Instrumentation Control

Identification and Physical Arrangement

The core spray system consists of two independent spray loops as illustrated in Figure 6.3-8. Each loop is capable of supplying sufficient cooling water to the reactor vessel to adequately cool the core following a design-basis LOCA. The two spray loops are physically and electrically separated so that no single physical event makes both loops inoperable. Each loop includes an ac motor-driven pump, appropriate valves, and the piping to route water from the suppression pool to the reactor vessel. The controls and instrumentation for the core spray system include the sensors, relays, wiring, and valve operating mechanisms used to start, operate, and test the system. The sensors and valve closing mechanisms for the core spray system are located in the reactor building. Cables from the sensors are routed to the main control room where the control circuitry is assembled in electrical panels. Each core spray pump is powered from a different ac bus that is capable of receiving standby power. The power supply for automatic valves in each loop is the same as that used for the core spray pump in that loop. Control power for each of the core spray loops comes from separate dc buses. The electrical

A flow switch on the discharge of each set of pumps provides a signal to operate the minimum flow bypass line valve for each pump set. When the flow reaches the value required to prevent pump overheating, the bypass valves close directing all flow into the sparger.

Alarms and Indications

Core spray system pressure is monitored by a pressure switch to permit the detection of leakage from the nuclear system into the core spray system outside the primary containment. A detection system is also provided to continuously confirm the integrity of the core spray piping between the inside of the reactor vessel and the core shroud. A differential-pressure switch measures the pressure difference between the top of the core support plate and the inside of the core spray sparger pipe just outside the reactor vessel. Since both core spray spargers are located inside of the core shroud, differential pressure will essentially be due to elevation, provided that there is no piping break. If there is a core spray sparger piping break, this pressure difference will be the pressure drop across the core resulting from interchannel leakage. If integrity is lost, this pressure drop will include the steam separator pressure drop. A decrease in the normal pressure drop initiates an alarm in the main control room. Pressure in each core spray pump suction and discharge line is monitored by a locally mounted pressure indicator to permit the determination of suction head and pump performance.

Flow and pressure measuring instrumentation is connected in each of the core spray pump discharge lines. The instrumentation provides flow and pressure indication in the main control room.

7.3.1.1.2.4 LPCI System Instrumentation and Control

Identification and Physical Arrangement

The LPCI mode is an operating mode of the RHR system that uses pumps and piping that are parts of the RHR system. Because this mode is designed to provide cooling water to the reactor vessel following the design-basis LOCA, the controls and instrumentation for LPCI mode of operation are discussed here. Section 5.4.7 describes the RHR system. Figure 5.4-14 shows the entire RHR system, including the equipment used for LPCI operation. The following list itemizes the essential equipment for which control or instrumentation is required:

1. Four RHR system pumps.

2. Pump suction valves.

3. LPCI-to-recirculation loop injection valves.

The instrumentation for LPCI operation provides inputs to the control circuitry for other valves in the RHR system. This is necessary to ensure that the water pumped from the suppression chamber by the pumps is routed directly to a reactor recirculation loop. These interlocking features are described in this section. The actions of the reactor recirculation loop valves are described in this section because these actions are accomplished to facilitate LPCI operation.

LPCI operation uses two identical pump loops, each loop with two pumps in parallel. The two loops are arranged to discharge water into different reactor recirculation loops. A cross connection exists between the pump discharge lines of each loop to allow the water from one loop to be combined with the water from the other loop prior to being discharged into the recirculation loop and reactor vessel. Additionally, there is a small line, with minimal flow capacity, connecting the loops and the Shutdown Cooling Suction Piping in order to create a differential pressure across the LPCI Inject Check Valves. Figure 5.4-14 shows the locations of instruments, control equipment, and LPCI components relative to the primary containment. Except for the reactor recirculation loop pump valves, the components pertinent to LPCI operation are located outside the primary containment.

The power for the RHR pumps is supplied from ac buses that can receive standby ac power. Motive power for the injection valves used during LPCI operation comes from a common bus that can be automatically connected to alternate standby power sources. Logic power for the LPCI components comes from the dc buses. Redundant trip systems are powered from different dc buses. The use of common buses for some of the LPCI components is acceptable because the LPCI system is a single subsystem. As indicated in Chapter 8, the effect of a single dc power supply failure has been reviewed by the NRC. The NRC has concluded that Emergency Core Cooling System performance with a dc power supply failure is acceptable. Backup is provided by the core spray system since the operation of both the LPCI and core spray systems are arranged independently to accomplish the same objective, that is, provide adequate cooling for the fuel at low nuclear system pressure following a design-basis accident.

LPCI is arranged for automatic operation and for remote manual operation from the main control room. The equipment provided for manual operation of the system allows the operator to take action independent of the automatic controls in the event of a LOCA.

Initiation Signals and Logic

The overall operating sequence for LPCI following the receipt of an initiation signal (see Figure 7.3-13) is as follows:

1. If one of the reactor recirculation loops is ruptured, LPCI instrumentation identifies the damaged loop. (See Figure 7.3-13, Sheets 2 and 2A).

pairs of lines terminate outside the primary containment and inside the reactor building; they are physically separated from each other and tap off the reactor vessel at widely separated points. The reactor vessel low-water-level switches sense level from these lines. This arrangement ensures that no single physical event can prevent isolation. Cables from the level sensors are routed to the main control room. Temperature compensating columns are used to increase the accuracy of the level measurements (see Figure 5.1-1, Sheet 2).

Main steam line radiation is monitored by four radiation monitors, which are described in Chapter 11.

High flow in each main steam line is sensed by four indicating-type differential-pressure switches that sense the pressure difference across the flow restrictor in that line. Figure 7.3-16 illustrates how the 16 differential-pressure switches are combined to form four logic channels. Figure 7.3-17 shows a typical arrangement for main steam line break detection by flow measurement. Each main steam line isolation logic receives an input signal from each main steam line. (see Figure 7.3-6, Sheet 2).

High temperature in the vicinity of the main steam lines is detected by 16 resistance temperature detectors (RTD) located along the main steam lines in the main steam line tunnel, a thermocouple located in the main steam line tunnel high vent outlet, and two thermocouples, one each located in the main steam line tunnel high vent outlet and inlet. In addition, eight RTDs are located in the vicinity of the main steam lines outside the main steam tunnel, four near the turbine stop valves, and four near the steam tunnel. The detectors are located or shielded so that they are sensitive to air temperature and not the radiated heat from hot equipment. The temperature sensors located in the main steam line tunnel high vent outlet and inlet activate an alarm at high temperature and, upon loss of power, operate to give the alarm condition. The RTDs sense main steam line tunnel ambient temperatures and feed remotely located temperature transmitters, indicators, and electronic switches. The main steam lines are isolated on high ambient temperature in the main steam line tunnel or high ambient temperature in the turbine building in the vicinity of the main steam lines. The four instrument channels (RTDs) from each main steam line are combined into one logic channel. A total of four main steam line space high-temperature logic channels are provided.

Accessibility to these switches during plant operation permits periodic testing of the logic.

Main steam line low pressure is sensed by four force balance type pressure switches that sense pressure downstream of the outboard main steam isolation valves. The sensing point is located at the header that connects the four steam lines upstream of the turbine stop valves. Each switch is part of an independent channel and each channel provides a signal to one isolation logic.

Primary containment pressure is monitored by four nonindicating pressure switches that are mounted on instrument racks outside the drywell. Lines that terminate in the reactor building connect the switches with the drywell interior. Cables are routed from the switches to the main control room. The switches are grouped in pairs, physically separated, and electrically connected to the isolation control system so that no single event will prevent isolation due to primary containment pressure.

High differential temperature in the RCIC equipment room inlet/outlet ventilation ducts is sensed by two differential-temperature switches. High ambient temperature is also sensed at the standby cooler by two temperature switches. Each switch is arranged as one channel. One channel for the ventilation ducts and one channel for the standby cooler form a trip system. A trip of either channel will initiate an alarm in the main control room and will initiate RCIC steam line isolation. The two logic channels are not divisionalized. However, they are physically and electrically separated from the HPCI steam leak detection logic. As it is not practical to maintain both physical diversity between the HPCI and RCIC systems and physical diversity between Divisions I and II of the leak detection logic, maintaining physical diversity between HPCI and RCIC logics was judged to be preferable to maintaining physical diversity between the two divisions of RCIC logic. This configuration is permitted because the temperature sensors are equipped with burnout protection devices which activate the logic in an open circuit. Figure 7.3-20 illustrates the arrangement. All RCIC isolation functions and their arrangements are shown in detail in Figures 5.4-9 and 5.4-11.

High flow in the RCIC turbine steam line is sensed by two differential- pressure switches, each of which monitors the differential pressure across an elbow installed in the RCIC turbine steam supply line. The arrangement is illustrated in Figure 7.3-18. The tripping of either switch initiates the isolation of the RCIC turbine steam line.

Low pressure in the RCIC turbine steam line is sensed by four pressure switches from the RCIC turbine steam line upstream of the isolation valves. The switches are arranged as two trip systems, both of which must trip to initiate the isolation of the RCIC turbine steam line. Each trip system receives inputs from two pressure switches, either one of which can trip the trip system.

High pressure in the RCIC turbine exhaust diaphragm assembly is indicative of a degraded inner diaphragm boundary. A shutdown of the system automatically results to ensure the outer diaphragm is not significantly challenged to thermal/cyclic fatigue (see Figure 7.3-19). High pressure downstream from the rupture disk is sensed by four pressure switches. Each set is arranged as two trip systems. Each trip system receives input signals from two pressure trip channels, and both trip channels must trip to initiate isolation.

Table 7.3-1

Sheet 1 of 20

PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
Main steam (A-D)	X-7	AO globe	4412, 15, 18, 20	N_2 & ac, dc	A	Inside	N_2 & spring	G, D, P, X	Open	Notes 1, 19, 22
Main steam line (A-D)	X-7	AO globe	4413, 16, 19, 21	N_2 & ac, dc	A	Outside	N_2 & spring	G, D, P, X	Open	Notes 1, 19, 22
Main steam line drain	X-8	MO gate	4423	ac	A	Inside	ac	G, C, D, P, X	Open	Notes 19, 22
Main steam line drain	X-8	MO gate	4424	dc	A	Outside	dc	G, C, D, P, X	Open	Notes 19, 22
Feedwater (A, B)	X-9	Check	V-14-1, V-14-3	Fwd. flow	A	Inside	Process	Rev. flow	Open	
Feedwater (A, B)	X-9	MO stop check	4441, 42	ac	A	Outside	Process	Rev. flow	Open	Insure positive closure. Note 3 not essential ac power.
Reactor water sample	X-41	AO gate	4639	Air & ac	A	Inside	Spring	G, C, D, P, X	Open	Manual bypass Notes 19, 22
Reactor water sample	X-41	AO gate	4640	Air & ac	A	Outside	Spring	G, C, D, P, X	Open	Manual bypass Notes 19, 22
Mini purge	X-32	AO gate	1804A, B	Air & ac	B	Outside	Spring	A, G, F, Z	Open	Notes 20, 22
Mini purge	X-32	Check	V-17-83 V-17-96	Fwd. flow	B	Inside	Process	Rev. flow	Open	

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

Sheet 2 of 20

PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
CRD hydraulic ret	X-36	Check	V-17-52	Fwd. flow	A	Outside	Process	Rev. flow	Closed	
CRD hydraulic ret	X-36	Check	V-17-53	Fwd. flow	A	Inside	Process	Rev. flow	Closed	
CRD withdraw	X-38	SO globe	1852 (HCU 1)	ac	A	Outside	Spring			Note 4
CRD withdraw	X-38	SO globe	1854	ac	A	Outside	Spring			Note 4
CRD insert	X-37	SO globe	1851 (HCU 1)	ac	A	Outside	Spring			Note 4
CRD insert	X-37	SO globe	1853 (HCU 1)	ac	A	Outside	Spring			Note 4
Scram inlet	X-37	AO gate	1849 (HCU 1)	Spring	A	Outside	Air & ac			Note 4
Scram discharge	X-38	AO gate	1850 (HCU 1)	Spring	A	Outside	Air & ac			Note 4
RHR reactor shutdown cooling supply	X-12	MO gate	1909	dc	A	Outside	dc	A, F, U	Closed	Note 28
RHR reactor shutdown cooling supply	X-12	MO gate	1908	ac	A	Inside	ac	A, F, U	Closed	

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

Sheet 3 of 20

PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
MO 1908	N/A	Check	V19-0195	Fwd. flow	A	Inside	Process	Rev. flow	Closed	Ref. SE96-18
RHR supp. pool suct.	N225A, B	MO gate	1989/ 2069	ac	B	Outside (i)	ac	--	Open	
RHR pump suction	None	MO gate	1921, 13 2012, 15	ac	B	Outside (o)	ac	--	Open	Note 15
RHR disch. to supp. pool	N210, 211 (A, B)	MO gate	1932/ 2005	ac	B	Outside (o)	ac	G, S	Closed	Note 2
RHR to supp. spray	N-211 (A, B)	MO globe	1933/ 2006	ac	B	Outside (i)	ac	G, S	Closed	Throttling -type valve, Note 2
RHR test line to supp. pool	N-210 (A, B)	MO globe	1934/ 2007	ac	B	Outside (i)	ac	G, S	Closed	Throttling -type valve, Note 2
RHR containment spray	X-39 (A, B)	MO gate	1902/ 2000	ac	B	Outside (i)	ac	G, S	Closed	Note 2
RHR containment spray	X-39 (A, B)	MO globe	1903/ 2001	ac	B	Outside (o)	ac	G, S	Closed	Note 2

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

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PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
RHR LPCI to reactor	X-13 (A, B)	MO gate	1905/ 2003	ac	A	Outside (i)	ac	A, F, H	Closed	Note 10 Note 13 Note 28
RHR LPCI to reactor	X-13 (A, B)	MO globe	1904/ 2004	ac	A	Outside (o)	ac	H	Open	Throttling -type, Note 8
RHR LPCI to reactor	X-13 (A, B)	Check	V-19-149 V-20-82	Fwd. flow	A	Inside	Process	Rev. flow	Closed	
RHR min. pump flow	N-210 (A, B)	Check	V-19-16 V-19-14 V-20-06 V-20-08	Fwd. flow	B	Outside (o)	Process	Rev. flow	Closed	
RHR min. pump flow	N-210 (A, B)	MO gate	1935/ 2009	ac	B	Outside (i)	ac		Closed	
RHR discharge to radwaste	None	MO globe	1936	ac		Outside (o)	ac	F, A	Closed	Note 20
RHR discharge to radwaste	None	MO gate	1937	dc		Outside (i)	dc	F, A, U	Closed	Note 20
RHR sample	None	SO Gate	1972/ 2051	ac		Outside (o)	Spring	F, A	Closed	
RHR sample	None	SO Gate	1973/ 2052	ac		Outside (o)	Spring	F, A	Closed	

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

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PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
HPCI turbine steam	X-11	MO gate	2238	ac	A	Inside	ac	L, Q, AB	Open	Signal "B" or "F" opens valve Note 24
HPCI turbine steam	X-11	MO gate	2239	dc	A	Outside	dc	L, Q, AB	Open	Note 24
HPCI steam line drain	None	AO gate	2211	Air & dc		Outside (i)	Spring	B, E	Open	
HPCI steam line drain	None	AO gate	2212	Air & dc		Outside (o)	Spring	B, E	Open	
HPCI turbine exhaust	N-214	Check	V-22-16	High exh. pressure	B	Outside (o)	Process	Rev. flow	Closed	
HPCI turbine exhaust	N-214	Stop check	V-22-17	High exh. pressure	B	Outside (i)	Process	Rev. flow	Open	Note 14
HPCI pump suction (supp. pool)	N-226	MO gate	2321	dc	B	Outside (i)	dc	L, Q	Closed	Notes 14, 24
HPCI pump suction (supp. pool)	N-226	MO gate	2322	dc	B	Outside (o)	dc	L, Q	Closed	Notes 14, 24

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

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PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
GS cond. drain	None	AO gate	2234	Air & dc		Outside (i)	Spring	E	Open	
HPCI/RCIC exhaust vacuum	N-219	MO gate	2290 A, B	ac	B	Outside	ac	F + AB	Open	
GS cond. drain	None	AO gate	2235	Air & ac		Outside (o)	Spring	E	Closed	
HPCI min. pump flow	N-210	Check	V-23-14	Fwd. flow	B	Outside (o)	Process	Rev. flow	Closed	
HPCI min. pump flow	N-210	MO globe	2318	dc	B	Outside (i)	dc	V	Closed	Opens/ closes to maintain min. pump flow
TIP	X-35 (B-D)	SO shear	1S260A-shear 1S260B-shear 1S260C-shear		B	Outside (o)	dc	--	Open	One valve on each of three lines
TIP	X-35 (B-D)	SO ball	1S260A-ball 1S260B-ball 1S260C-ball	ac	B	Outside (i)	Spring	F, A	Closed*	One valve on each of three lines Note 12

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

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PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
TIP purge	X-35A	SO globe	SV4355	ac	B	Outside (o)	Spring	F, A	Closed	Note 12
TIP purge	X-35A	Check	V-43-503	Fwd. flow	B	Outside (i)	Process	Rev. flow	Closed	Note 12
Inst. Line-typical	--	Root globe	--	Hand	--	Outside	Hand	---	Open	See Chapter 5 for Instrument Line Isolation Discussion
	--- ---	EFCV Inst. globe	--- ---	Spring hand	--- ---	Outside Outside	Flow Hand	--- ---	Open	
Service air to drywell	X-21	Hand gate	V-30-287	hand	B	Outside (i)	Hand	---	Closed	
Service air to drywell	X-21	Check	V-30-286	Fwd. flow	B	Outside (o)	Process	Rev. flow	Closed	Line blind flanged inside drywell
Inst. N_2 to drywell	X-22	AO gate	4371A	Air & ac	B	Outside	Spring	A, F, Z	Open	Notes 20, 22
Inst. N_2 to drywell	X-22	Check	V-43-214	Fwd. flow	B	Inside	Process	Rev. flow	Open	
Inst. N_2 to torus	N-229A	AO gate	4371C	Air & ac	B	Outside	Spring	A, F, Z	Open	Notes 20, 22

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

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PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
Containment N_2 comp. suct.	X-32	AO gate	4378A, B	Air & ac	B	Outside	Spring	A, F, Z	Open	Notes 20, 22
Reac. bldg. cool wtr. in	X-55	MO gate	4841B	ac	C	Outside	ac	G	Open	
Reac. bldg.cool wtr. out	X-54	MO gate	4841A	ac	C	Outside	ac	G	Open	
Demin. service wtr. in.	X-20	Hand gate	V-09-65	Hand	C	Outside	Hand	--	Closed	
Demin. service wtr. in.	X-20	Hand gate	V-09-111	Hand	C	Inside	Hand	--	Closed	
Well water in	X-23 A, B	AO gate AO globe	5718A 5718 B	Spring	C	Outside (o)	Air & ac	G	Open	Contains two supply and two return lines Note 19
Well water in	X-23 A, B	Check	V-57-58 V-57-59	Fwd. flow	C	Outside (i)	Process	Rev. flow	Open	
Well water out	X-24 A, B	AO gate AO globe	5704A 5704B	Spring	C	Outside	Air & ac	G	Open	Note 19

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

Sheet 13 of 20

PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
Well water back flush inlet	X-24 A, B	Hand gate	V-57-75 V-57-76	Hand	C	Outside	Hand	G	Closed	Key locked
Well water back flush inlet	X-24 A, B	Check	V-57-60 V-57-61	Fwd. flow	C	Outside	Process	Rev. flow	Closed	-
Well water back flush outlet	X-23 A, B	Hand gate	V-57-77 V-57-78	Hand	C	Outside	Hand	G	Closed	Key locked
Vac brkr torus-drywell	N-202 A-G	Vac. brkr.	4327	Torus press.	B	In torus	Drywell press.	---	Closed	Has air-operated check open feature-4327 A-G excluding E. Notes 20, 22
Vac brkr actuating N_2	N-229 A	AO gate	4371A, C	Air & ac	B	Outside	Spring	RM	Open	Notes 20, 22
Vac brkr reac bldg-torus	N-231	AO btrfly	4304, 4305	Spring	B	Outside (i)	Air & ac	F, A, Z (7)	Closed	RB- torus differential pressure overrides isolation signal to open valves Notes 20, 22, 27

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.
[b] See key at the end of the notes to this table.

Table 7.3-1

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PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
Vac brkr reac bldg-torus	N-231	Check	V-43-168 V-43-169	R.B. Press	B	Outside (o)	Torus press.	---	Closed	
Purge Inlet	X-26, N-220	AO btrfly	4306	Air & ac	B	Outside (o)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22, 27
Drywell purge inlet	X-26	AO btrfly	4307	Air & ac	B	Outside (i)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22, 27
Torus purge inlet	N-220	AO btrfly	4308	Air & ac	B	Outside (i)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22, 27
Drywell vent	X-25	AO btrfly	4302	Air & ac	B	Outside (i)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22, 27
Drywell vent valve bypass	X-25	AO gate	4310	Air & ac	B	Outside (i)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22
Drywell vent	X-25	AO btrfly	4303	Air & ac	B	Outside (o)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22, 27
Torus vent	N-205	AO btrfly	4300	Air & ac, dc (26)	B	Outside (i)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22 26, 27
Torus vent valve bypass	N-205	AO btrfly	4309	Air & ac	B	Outside (i)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22
Torus vent	N-205	AO btrfly	4301	Air & ac	B	Outside (o)	Spring	F, A, Z (7)	Closed	(18) Notes 20, 22, 27

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

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PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
Torus vent	N-205	AO btrfly	4357	Air & dc	B	Outside (o)	Spring		Closed	Note 25
Drywell atm analyzer suction	X-50, X56	SO gate	8101 A, B 8102 A, B 8103 A, B 8104 A, B	dc	B	Outside (i) Outside (o) Outside (i) Outside (o)	Spring	F, A, Z (7)	Open	Manual override of all auto signals Notes 20, 22
Makeup N_2	X-26 N-220	AO gate	4311	Air & ac	B	Outside (o)	Spring	F, A, Z (7)	Open	Manual override of all auto signals Notes 20, 22
Makeup N_2-drywell	X-26	AO gate	4312	Air & ac	B	Outside (i)	Spring	F, A, Z (7)	Closed	Manual override of all auto signals Notes 20, 22
Makeup N_2-drywell	N-220	AO gate	4313	Air & ac	B	Outside (i)	Spring	F, A, Z (7)	Closed	Manual override of all auto signals Notes 20, 22
Drywell atm analyzer return	X-50, X-46	SO gate	8105 A, B 8106 A, B	dc	B	Outside (i) Outside (o)	Spring	F, A, Z (7)	Open	Notes 20, 22
Torus atm analyzer suction	X-229 B, G	SO gate	8107 A, B 8108 A, B	dc	B	Outside (i) Outside (o)	Spring	F, A, Z (7)	Open	Notes 20, 22

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

Table 7.3-1

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PROCESS PIPELINES PENETRATING PRIMARY CONTAINMENT[a]

Line Isolated	Drywell Penetration	Valve Type[b]	Valve Number	Power to Open (5) (6)	Grp. (16)	Location Ref. to Drywell[b]	Power to Close (5) (6)	Isolation Signal (17)	Normal Status (10)	Remarks and Exceptions
Torus atm analyzer suction	X-229 C, F	SO gate	8109 A, B 8110 A, B	dc	B	Outside (i) Outside (o)	Spring	F, A, Z (7)	Open	Notes 20, 22
Post accident liquid sample return	N-229G	SO globe	8772A 8772B	dc	B	Outside (i) Outside (o)	Spring	F, A, Z (7)	Closed	Key lock Notes 20, 22
CAD system isolation	N-211 A, B	SO gate	4333 A, B 4334 A, B	dc	---	Outside	Spring	---	Closed	Key lock
CAD system isolation	X-39 A, B	SO gate	4331 A, B 4332 A, B	dc	---	Outside	Spring	---	Closed	Key lock
Postaccident reactor liquid sample	X-40D X-40C	SO globe	4594 A, B 4595 A, B	dc	A	Outside (i) Outside (o)	Spring	F, A, Z (7)	Closed	Key lock Notes 20, 22
HPCI Exhaust Drain Pot	N-222	Stop Check	V-22-22	Fwd. flow	B	Outside (i)	Process	Rev. flow	Locked Open	Open
HPCI Exhaust Drain Pot	N-222	Check	V-22-21	Fwd. flow	B	Outside (o)	Process	Rev. flow	Closed	
RCIC exh vac bkr	N-212	Check	V-24-46 V-24-47	Fwd. flow	B	Outside (i) Outside (o)	Process	Rev. flow	Closed	
HPCI exh vac bkr	N-214	Check	V-22-63 V-22-64	Fwd. flow	B	Outside (i) Outside (o)	Process	Rev. flow	Closed	

[a] Numbers in parentheses are keyed to the notes at the end of this table, along with the signal codes.

[b] See key at the end of the notes to this table.

NOTES

These notes are keyed by number to correspond to numbers in parentheses, in Table 7.3-1:

1. Main steam isolation valves require that both solenoid pilots be deenergized to close valves. Accumulator nitrogen pressure plus spring act together to close valves when both pilots are deenergized. Voltage failure at only one pilot does not cause valve closure. The valves are designed to fully close in less than 10 sec, but in no less than 3 sec.

2. Drywell spray and suppression pool cooling valves have interlocks that allow them to by manually reopened after automatic closure to permit containment spray, for high drywell pressure conditions, and/or suppression water cooling. When signal (G) is present, valves may be opened if "Drywell pressure not low" and "Level inside RV shroud above low level trip" signals are present. If either signal of "S" is lost, the valves will close. When automatic signal (G) is not present, these valves may be opened for test or operating convenience.

3. The feedwater outboard stop check valve can be held shut.

4. Control rod hydraulic lines can be isolated by the solenoid valves outside the primary containment. Lines that extend outside the primary containment are small and terminate in a system that is designed to prevent out-leakage. Valves normally are closed, but they open on rod movement or during reactor scram.

5. Alternating current motor-operated valves are powered from the essential ac buses. Direct current operated isolation valves are powered from the plant batteries.

6. All motor-operated isolation valves remain in the last position upon failure of valve power. Air-operated valves fail into the position required to optimize plant safety on loss of motive air or loss of electric power to the solenoid pilot valve.

7. The following will provide the "Z" isolation signal: offgas stack high-high radiation on one of two channels, refuel pool ventilation exhaust high radiation on one of two channels or either channel out of operate mode, and reactor building ventilation exhaust high radiation or downscale on one of two channels.

8. Coincident low reactor water level or high drywell pressure signal "G" and low reactor pressure signal "T" open LPCI valves, except that recirculation line break signal "H" overrides to close LPCI valves on broken side and automatically opens the LPCI valves in the opposite loop. Timer interlocks prevent opening of closed loop inboard valve for 10 min. and closing of opened loop outboard valve for 5 min. Special interlocks permit testing these valves with manual switch during any mode of reactor operation except when coincident signals "G" and "T" are present.

9. Coincident signals "G" and "T" open valves. Special interlocks that allow manual opening of one valve at a time permit testing these valves by manual switch except when automatic signals are present.

10. Normal status position of valve (open or closed) is the position during normal power operation of the reactor (see "Normal Status" column).

NOTES

11. Both the drywell and torus vent bypass valves are operated by a single switch when the three-position key-lock permissive switch is in the "normal" position. The bypass valves may be operated individually by repositioning the permissive switch.

12. Signal "A" or "F" causes automatic withdrawal of TIP probe. When the probe is withdrawn, the ball valve automatically closes when the detector is housed in the chamber shield. TIP purge is secured by isolation signal. (Approval basis for this class of line isolation provisions is discussed in NEDC 22253).

13. Inboard injection valves close when RHR shutdown cooling supply valves (MO 1909 and 1908) are open and signal "A" or "F" are present and signal "U" is not present.

14. For HPCI the condensate storage suction valves open on initiation signal. When a low condensate storage tank level or high suppression pool level occurs, the suppression pool suction valves open. When the suppression pool suction valves are fully open, the condensate storage tank valves close.

15. A line break in RHR system piping (high temperature or high differential temperature in RHR equipment space) will alarm only; no auto closure is initiated.

16. Valve groups are those used in Chapter 7 and Section 6.2.

17. All regular group A, B, and C isolation valves are capable of remote manual operation from the control room.

18. Key-lock switch provided for override of each actuation signal.

19. Key-lock switches provided for override of low-low-low reactor water level signals.

20. Key-lock switches provided for override of low reactor water level and high drywell pressure signals.

21. Key-lock switches provided for override of all actuation signals <u>except</u> Low-Low-Low reactor water level signal.

22. Key-lock switches provided for override of ALL actuation signals.

23. Key-lock switches provided for override of ALL actuation signals except Hi flow and non-regenerative Hx high inlet temperature.

24. Key-lock switches provided for override of low steam pressure, high area temperatures and Hi RPV water level.

25. CV-4357 is a "sealed closed" primary containment isolation valve that is not subject to automatic primary containment isolation signals. Power will be prevented from energizing SV-4357 by reliance upon administrative control of the key for HS-4357 in conjunction with the removal of control power fuses. To open CV-4357, the key for HS-4357 must be obtained from the Operations Shift Supervisor, control power fuses installed, and HS-4357 placed in the "OPEN" position. The DAEC Emergency Operating Procedures will control the use of CV-4357 in response to containment threatening events.

26. In the "NORMAL" position of HS-4300A the AC solenoid logic will operate CV-4300. The "OVERRIDE" position of HS-4300A allows CV-4300 to be opened using the DC control logic independent of a primary containment isolation signal. In both modes of operation, opening and closing of CV-4300 is controlled by HS-4300.

27. Valves have T-ring seals.

28 This valve is the outboard isolation valve located on the process pipeline for this penetration. However, effectively, MO190[illegible] MO1909 and MO2003 are the combined outboard isolation valves for this penetration due to a small line which connects [illegible] process pipelines, between each of their inboard and outboard isolation valves, together.

Table 7.3-3

HIGH-PRESSURE COOLANT INJECTION SYSTEM INSTRUMENT TRIP SETTINGS

HPCI Function	Instrument	Nominal Setting
Reactor vessel high-water-level turbine trip	Level Switch	+211 in. Indicated level [a]
Turbine exhaust high pressure	Pressure switch	140 psig
HPCI system pump low suction pressure	Pressure switch	15 in. Hg vac.[b]
Reactor vessel low water level[b]	Level switch	+119.5 in. indicated level[a]
Primary containment (drywell) high pressure[c]	Pressure switch	2 psig
HPCI system steam supply low pressure	Pressure switch	< 100 psig reset > 50 psig trip
Condensate storage tank low level	Level switch	12 in. above tank bottom (10,000 gal)
Turbine overspeed	Centrifugal device	125% of rated speed
Suppression chamber high water level	Level switch	5 in. above nominal water level
urbine Exhaust Diaphragm High Pressure	Pressure switch	≤ 10 psig
HPCI Steam Line Flow-High HPCI Steam Line Flow-High	Pressure switch Pressure switch	≤ 103 In. H2O (out board) ≤ 386 In. H2O (In board)
HPCI Equipment Room Temperature-High	Temperature switch	≤ 175°F
HPCI Room Ventilation Differential Temperature-High	Differential Temperature switch	≤ Δ 50° F
HPCI Leak Detection Time Delay	Relay	≤ 15 minutes
Suppression Pool Area Ambient Temperature-High	Temperature switch	≤ 150° F
Suppression Pool Area Ventilation Differential Temperature-High	Differential Temperature switch	≤Δ 50° F

[a] Zero referenced to top of active fuel (344.5 in. above vessel zero).
[b] Approximate setting.
[c] Incident detection circuitry instrumentation.

Table 7.3-4

AUTOMATIC DEPRESSURIZATION SYSTEM INSTRUMENT TRIP SETTINGS

System Function	Instrument Type	Nominal Setting
Rector vessel low-low-low water level[a]	Level switch	+18.5 in. Indicated level [b]
Automatic depressurization time delay[a]	Self Indicating Timer	120 sec
LPCI pump discharge pressure[a]	Pressure switch	125 ±25 psig
Core spray pump discharge pressure[a]	Pressure switch	145 ±20 psig
Reactor vessel low water level "confirmed"	Level switch	+170 in indicated level[b]

[a] Incident detector circuitry instrumentation.

[b] Zero referenced to top of active fuel (344.5 in. above vessel zero).

PT4599B) generates an error signal lighting an amber indicating light between the respective indicators and recorders informing Operations personnel to perform the pressure compensation manually. These channels provide post-accident vessel level indication and continuously monitor vessel level in the cold shutdown condition.

d. Indication is provided for the channel which measures level above the reactor vessel flange. This channel is not density compensated, thus cannot provide an accurate measurement of level above ambient conditions. It does however, provide an indication of relative water level changes.

A full discussion of the ten separate reactor vessel level indicators that are provided in the reactor control room can be found in Section 7.6.4 and are shown in Figure 7.6-30.

2. Reactor Pressure

Reactor pressure is recorded in the control room by two recorders operating from separate pressure transmitters located outside the primary containment. Ranges of the two recorders are 0 to 1200 psig and 800 to 1100 psig, respectively, with an accuracy of ±1/2% of the range. In addition, there are two local 0 to 1500-psig gauges. Two separate channels with a range of 0-1500 psig, are recorded and indicated in the Control Room. Two separate channels with a range of 0-250 psig are also indicated in the Control Room, with an accuracy of ± 8.7%. Three channels of reactor pressure measurement with range 0 to 1200 psig are provided. Three pressure indicators are provided in the control room, one for each channel. One recorder, which may be manually switched between two of the channels is provided. The third channel cannot be connected to the recorder.

3. Primary Containment Pressure

Six channels provide drywell pressure indication and recording in the control room. Two channels have a range of -5 to +5 psig, two have a range of -10 to +90 psig, and two have a range of 0 to 250 psig. Two additional channels provide drywell pressure indication with a range of 0 to 100 psig.

All of the indicators are redundant class 1E instruments that meet seismic category 1 criteria, and meet the safety-grade criteria in effect at the time of their installation.

The range of 0 to 250 psig meets the NUREG-0737, Item II.F.1.4 requirement of 4 times design pressure (56 psig). The instrumentation meets design provisions of Regulatory Guide 1.97, including qualification, redundancy, and testability. Information on the accuracy of these channels is given in Section 6.2.5.5.1.

Two local indicators with range 0-100 psig are provided, one for drywell pressure, and one for torus pressure. Two separate channels provide Control Room indication of torus pressure with a range of 0-100 psig.

4. Primary Containment Temperature

Primary containment temperature is monitored in the control room on redundant recorders operating from resistance temperature detectors in the drywell and above the normal level in the suppression chamber. The range is 0 to 350▪F in the drywell and 0 to 300▪F in the torus. The accuracy is ±1% of the range. Eight detectors are located in the drywell and four detectors are located in the suppression pool. Average drywell air temperature is also indicated.

5. Primary Containment Environment

a. A postaccident sampling system has been installed to obtain representative liquid and gas samples from within the primary containment for radiological and chemical analyses in association with a postulated LOCA. See Section 12.3.4.

b. Oxygen analysis of the containment atmosphere is performed by a redundant oxygen analyzer system that is recorded in the control room. See Section 6.2.5.5.

c. Hydrogen instrumentation provides indication in the control room. The range is 0% to 20% H_2 by volume under both positive and negative ambient pressure. The instrumentation meets the design provisions of Regulatory Guide 1.97, including qualification, redundancy, and testability. See Section 6.2.5.5.

d. High-range containment radiation monitors have been installed in response to NUREG-0737 (Section II.F.1.3). They consist of four (two in the torus and two in the drywell) physically separated monitors designed and qualified to function in an accident environment with a maximum range of 10^7 rad/hr. They provide continuous indication and a recorder is also provided in the Control Room. See Section 12.3.3.3.

Table 7.6-3

LPRM TRIPS AND ALARMS

Trip Function	Setpoint	Trip Action
LPRM downscale	3/125	White light and annunciator.
LPRM upscale	100/125	Amber light and annuciator.
LPRM bypass	Manual switch	White light and APRM averaging compensation.

Table 7.6-4

APRM TRIPS AND ALARMS

Trip Function	Trip Point Range	Nominal Setpoint	Action
APRM downscale (RUN mode)	2% to full scale	≥ 5/125	Rod block, annunciator, white light.
APRM upscale (Hi) alarm (RUN mode)	Varied with flow, intercept, and slope adjustable.	Two Loop: ≤ 0.58 flow + 50% Single Loop: ≤ 0.58 flow + 46.5%	Rod block, annunciator, amber light.
APRM upscale (Hi-Hi) trip (RUN mode)	2% to full scale varied with flow intercept and slope adjustable.	0.58 flow + 62% 120/125 maximum (0.58 flow + 58.5% for SLO)	Scram, annunciator, red light.
APRM inoperative	Calibrate switch or too few inputs	Not in operate mode or if less than 13 LRPM inputs for APRMs E, F, or 9 for APRMs A, B, C, D	Scram, annunciator, red light, rod block.
APRM bypass	Manual switch	- -	White light
APRM upscale (Hi) alarm (not in RUN mode)	Up to 27% power (Startup)	≤ 12/125	Rod block, annunciator, amber light.
APRM upscale (Hi-Hi) trip (not in RUN mode).	Up to 30% power	15/125	Scram, annunciator, red light.

A separate four rod display includes the LPRM values for each of the detector arrays surrounding the rod selected (Figures 7.7-3 and 7.7-4). Since each detector array contains 4 sensors in a vertical column and there can be a maximum of 4 detector arrays surrounding a rod, 16 meters are installed. Between the LPRM indicators are four rod position modules. These four modules will display rod position in two digits and rod selected status (white light, off or on) for the four rods located within the LPRM detector arrays being displayed. The rod position digital range is from 00 to 48, with 00 representing the fully in position and 48, fully out; each even increment, for example, 00-02, equals six physical inches of rod movement. The four rod display allows the operator to easily focus his attention on the core volume of concern during rod movements.

Control rod position information is obtained from reed switches in the control rod drive that open or close during rod movement. Reed switches are provided at each 3-in. increment of piston travel. Since a notch is 6 in., indication is available for each half-notch of rod travel. The reed switches located at the half-notch positions for each rod are used to indicate rod drift. Both a rod selected for movement and the rods not selected for movement are monitored for drift. A drifting rod is indicated by an alarm and red light in the main control room. The rod drift condition is also monitored by the Plant Process Computer and Rod Worth Minimizer.

Reed switches are also provided at locations that are beyond the limits of normal rod movement. If the rod drive piston moves to these overtravel positions, an alarm is sounded in the control room. The overtravel alarm provides a means to verify that the drive-to-rod coupling is intact, because with the coupling in its normal condition, the drive cannot be physically withdrawn to the overtravel position. Coupling integrity can be checked by attempting to withdraw the drive to the overtravel position and observing that no over travel alarm occurs.

The Plant Process Computer system receives position indication from the Rod Worth Minimizer microcomputer and can display and print all rod positions in a prearranged sequence. The user may order a computer display or printout at any time. The display and printout depict the rod positions in an array corresponding to the other displays and actual core location . The display and printout are always in the same order; if there is an unavailable input, the display and printout will signify it by a -99; while a blank indicates the rod is fully withdrawn.

All displays are essentially independent of one another. Signals for the rod status display are hard wired from the rod position information system cabinet buffer outputs, so that a signal failure of other parts of the rod position information system cabinet will not affect this display. Likewise, the computer could conceivably fail and the rod status and rod position displays will continue to function normally.

The following control room lights are provided to allow the operator to know the conditions of the CRD hydraulic system and the control circuitry (Figure 7.7-2, Sheets 1 and 2):

1. Stabilizing valve selector switch position.
2. Insert bus energized.
3. Withdraw bus energized.
4. Settle bus energized.
5. Withdrawal not permissive.
6. Notch override.
7. Pressure control valve position.
8. Flow control valve position.
9. Drive water pump low suction pressure (alarm only).
10. Drive water filter high differential pressure (alarm only).
11. Charging water (to accumulator) low pressure (alarm only).
12. Control rod drive temperature.
13. Scram discharge volume not drained (alarm only).
14. Scram valve pilot air header low pressure (alarm only).

7.7.3.9 Safety Evaluation

The circuitry described for the reactor manual control system is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. The scram circuitry is discussed in Section 7.2. Because each control rod is controlled as an individual unit, a failure that results in the energizing of any of the insert or withdraw solenoid valves can affect only one control rod. The effectiveness of a reactor scram is not impaired by the malfunctioning of any one control rod. No single failure in the reactor manual control system can result in the prevention of a reactor scram. Repair, adjustment, or maintenance of reactor manual control system components does not affect the scram circuitry.

7.7.4.6.7 Isotopic Composition of Exposed Fuel

The computer provides online capability to determine monthly and on demand isotopic composition for each one-quarter length section of each fuel bundle in the core. This evaluation consists of computing the weight of one neptunium, three uranium, and five plutonium isotopes as well as the total uranium and total plutonium content. The isotopic composition is calculated for each one-quarter length of each fuel bundle and summed accordingly by bundles and batches. The method of analysis consists of relating the computed fuel exposure and average void fraction for the fuel to computer-stored isotopic characteristics applicable to the specific fuel type. The output is on punched paper tape and can be used in combination with the tape reader and I/O typewriter to obtain a printed record. Paper tape also permits flexibility in transmitting the data to other off line devices for additional data processing.

7.7.4.6.8 Stability Monitoring

In response to Generic Letter 94-02 (Reference 1), an on-line stability monitoring system was installed following Refuel Outage 14. This stability monitoring is accomplished via use of the SOLOMON system and provides operators with a means of detecting when stability margin is degrading. Per Reference 2, operation within the "buffer zone" as shown on the power flow map included in the Core Operating Limits Report (COLR) in not allowed when SOLOMON is inoperable.

7.7.4.7 <u>Plant Process Computer System Software</u>

7.7.4.7.1 Data Acquisition and Processing Software

The data acquisition and processing software is distributed between the data concentrator and the PPC VAX. The software on the data concentrator scans the plant instrumentation to gather data from plant data systems; supports signal processing such as ranging, span and zero adjustments; and makes the data available for subsequent data storage and processing by the PPC VAX.

The software controls the processing associated with the following types of field inputs/outputs;

1. Analog inputs

2. Digital inputs

3. Sequence-Of-Events (SOE) inputs

4. Pulse inputs

5. Digital outputs

6. Analog outputs

The software provides six different scan classes (i.e., scan frequencies) for assigning point scan/processing frequency for analog points. All digital points are in the one second scan class. Additionally, the software provides for alarming of analog and digital points, limit checking of values, and quality code determination.

The alarm CRT displays all analog point alarms generated by the system. The alarm list is divided into an unacknowledged alarm section and an acknowledged alarm section. A white line separates the two sections. Alarm lines in each area are sorted first by priority and then chronologically. When there are no unacknowledged alarms, the white line will not appear.

The alarm logs are hard-copy records of the alarm CRT displays and are typed by the alarm printer located underneath the common console in the main control room.

Alarm printouts are used to inform the operator of computer system malfunctions, plant system operation exceeding acceptable limits, and potentially off-normal, or failed input sensors.

7.7.4.7.2 Balance of Plant (BOP) Software

7.7.4.7.2.1 Man-Machine Interface (MMI)

The Balance Of Plant (BOP) Software provides a man-machine interface (MMI) to the Plant Process Computer programs and the process data base. The BOP software provides capability for data display, data storage, and report generation. The information is available through hierarchically structured menus and is designed to operate under all normal plant operating conditions. The user uses the following touchscreen menus for accessing the data display, storage, and reporting functions:

1. Master Menu

2. Plant Process Computer Operations Menu

3. Group Menu

4. DGS Demandable Function Menu

5. BOP Reporting Menu

6. Data Trending and Plotting Menu

7. Maintenance Menu

8. Utilities Menu

The log and reporting menus will provide capability for data display, data storage, and report generation. The information will be available through various Balance Of Plant software modules.

7.7.4.7.2.2 NSSS/BOP Post-Trip Logging

The Plant Process Computer (PPC) and the plant strip chart recorders support the reconstruction of the sequence of events following a reactor trip. The PPC software is capable of accessing 4096 analog and digital input points, many of which are time sequenced on the alarm printer. The alarm printer provides time signatures (typically 2 milliseconds) for important data points, depending on the alarm point priority, sequencing, and computer scan class. Low priority computer inputs are stored in the computer during periods of maximum printer demand and may be printed out at a later time.

The NSSS/BOP Post-trip Log consists of the following:

Values for the nuclear steam supply system variables are provided for several key parameters before and after a scram. These parameters include core thermal power, total core flow, reactor water level, reactor pressure, etc.

Values for the balance of plant variables are provided by the computer before and after a scram. The selected variables include turbine-generator parameters, feedwater system parameters, and condenser parameters.

The operator's choice for the sampling rate for the post-trip log is from one to sixty seconds in one second increments. The pre-trip time window is 0 to 20 minutes and the post-trip time window is 0 to 20 minutes with the restriction that the total time window for the NSSS/BOP Post-trip Log shall not be greater than 20 minutes.

The strip chart recorders provide a continuous, analog record of such information as neutron flux, recirculation pump flow, emergency core cooling system parameters, feedwater and condensate system parameters, containment parameters, radiation monitoring, ventilation system parameters, and turbine-generator variables.

7.7.4.8 Inspection and Testing

The process computer system is self checking. It performs diagnostic checks to determine the operability of certain portions of the system hardware, and it performs internal programming checks to verify that input signals and selected program computations are either within specific limits or within reasonable bounds.

7.7.5 RECIRCULATION FLOW CONTROL SYSTEM

7.7.5.1 Power Generation Objective

The power generation objective of the recirculation flow control system is to control reactor power level, over a limited range, by controlling the flow rate of the reactor recirculating water.

7.7.5.2 Power Generation Design Bases

1. The recirculation flow control system is designed to allow variation of the recirculation flow rate.

2. The recirculation flow control system is designed to allow manual recirculation flow adjustment, so that manual control of reactor power level and load following are possible.

7.7.5.3 Safety Design Bases

The recirculation flow control system functions so that no abnormal operational transient resulting from a malfunction in the recirculation flow control system can result in damaging the fuel or exceeding the nuclear system pressure limits.

7.7.5.4 System Description

7.7.5.4.1 General

Reactor recirculation flow is changed by adjusting the speed of the two reactor recirculation pumps. The recirculation flow control system controls the power supplied to the recirculation pump motors. By adjusting the frequency of the electrical power supplied to the recirculation pump motors, the recirculation flow control system can manually affect changes in reactor power level. The reactor recirculation flow control system can control recirculation flow between 20% to 102.5% of nominal rated speed. Minimum speed is set by the scoop tube positioner electrical stops and is 20-28% speed. When the reactor is operating in a desired control rod pattern, flow adjustments can smoothly change reactor power over a power range of about 50%, without movement of the control rods.

An increase in recirculation flow temporarily reduces the void content of the moderator by increasing the flow of coolant through the core. The additional neutron moderation increases the reactivity of the core, which causes the reactor power level to increase. The increased steam generation rate increases the steam volume in the core with a consequent negative reactivity effect, and a new steady-state power level is established. When recirculation flow is reduced, the power level is reduced in the reverse manner.

to assist the operator. The digital meter on the speed indicating controller can be used to display any of the variables: speed, setpoint and controller output.

Start-up Signal

The speed indicating controller generates a start-up signal that adjusts the variable speed converter so that a proper amount of power can be delivered from the M-G set to start and accelerate the pump motor to the minimum continuous operating speed.

Limiters

The speed indicating controller will 1imit the output if either the recirculation pump discharge valve is not fully open or total feedwater flow is less than 20% of rated. This limited output signal will reduce the generator speed to the minimum speed. This limiting action is to prevent pump overheating should the discharge valve be closed and protect the recirculation pump against possible cavitation due to low feed water flow.

The speed indicating controller will limit the output in the event of shutdown of any one feedwater pump and the reactor vessel level is below the point at which vessel low-level alarm is initiated. The limited signal will cause a reduction of generator and recirculation pump speed so that resultant reactor power reduction is within the capabilities of the feedwater system. This limiting actions is to prevent total reactor shutdown due to partial loss of feedwater flow.

Failure Alarm

If the speed indicating controller were to fail or upon loss of the feedback signal to the recirculationspeed controller, a normally energized contact in the speed indicating controller will actuate an alarm in the control room and acts to prevent any change of slip within the variable speed converter.

Generator Tachometer (one for each M-G set)

The generator tachometer is directly connected to the generator shaft and supplies the feedback signal to the V/I converter. The V/I converter supplies a feedback signal to the speed indicating controller.

Deviation Meter (one for each M-G set)

The Deviation Meter shows the deviation between the slip device controller's actual position and the demand signal to that device. If a large positive deviation is sensed at the positioner between demand and actual position, the brake will be engaged and lock the scoop tube. Together, this limits the amount of recirculation pump speed change can result from mismatches between the demanded speed signal and the actual slip device position.

7.7.5.4.4 Safety Evaluation

The recirculation flow control system is designed so that coupling is maintained between an M-G set drive motor and its generator even if the ac power or a speed controller signal fails. This ensures that the drive motor inertia contributes to power supplied to the recirculation pump during the coastdown of the M-G set after loss of ac power and that the generator continues to be driven if the speed controller signal is lost.

Transient analyses described in the Accident Analyses section (Chapter 15) show that no malfunction in the recirculation flow control system can cause a transient sufficient to damage the fuel barrier or exceed the nuclear system pressure limits, as required by the safety design basis.

A topical report, NEDO-10677, has been prepared by General Electric for the Enrico Fermi 2 and Browns Ferry class reactors describing the probable consequences from recirculation pump overspeed in a typical BWR. This report was submitted to the AEC in October 1972.

The report states basically that in the unlikely event that a break occurs in the recirculation line, the pump impeller may act as a hydraulic turbine causing the pump and motor to overspeed and become potential sources of missiles. See Section 3.5.1.2.1.

7.7.5.4.5 Inspection and Testing

The M-G set speed controller functions during normal power operation. Any abnormal operation of this component can be detected during operation. The components that do not continually function during normal operation can be tested and inspected for calibration and operability during scheduled plant shutdowns. All the recirculation flow control system components are tested and inspected according to normal plant practices, recommendations of the component manufacturers and operating history. This can be done during scheduled shutdowns.

7.7.6 SAFETY PARAMETER DISPLAY SYSTEM

7.7.6.1 <u>Power Generation Objective</u>

The objective of the safety parameter display system (SPDS) is to provide a concise display of critical plant variables to the control room personnel to aid them in rapidly and reliably determining the safety status of the plant. The SPDS will be operated during normal plant operations, as well as during abnormal and emergency conditions. The principal purpose and function of the SPDS is to aid the control room personnel during abnormal and emergency conditions in determining the safety status of the plant.

REFERENCES FOR SECTION 7.7

1. NRC Generic Letter 94-02, "Long-Term Solutions and Upgrades of Interim Operating Recommendations for Thermal-Hydraulic Instabilities in Boiling Water Reactors," dated July 11, 1994.

2. Amendment No. 215 to Facility Operating License No. DPR-49 Duane Arnold Energy Center, dated August 7, 1996.

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8.2 OFFSITE POWER SYSTEM

8.2.1 DESCRIPTION

8.2.1.1 Power Generation Objective

The power generation objective of the DAEC switchyard and offsite power transmission system is to supply power to the IES Utilities, Inc. transmission system, which in turn supplies offsite AC power for operating the essential AC buses, as well as startup and shutdown power for all AC buses in the plant.

8.2.1.2 Power Generation Design Basis

1. The offsite power system is designed to provide a high degree of reliability.

2. The offsite power system is designed to maintain the physical independence of the offsite sources of electric power.

3. Means are provided for the detection and isolation of system faults.

8.2.1.3 System Description

The electrical output of the DAEC feeds into the IES Utilities Inc. power transmission system which is interconnected with the Mid-America Interconnected Network (MAIN). MAIN requires reserve capacity for emergency conditions. MAIN is also interconnected to other regional power pools such as the Mid-Continent Area Power Pool (MAPP). Large blocks of power are available from these power pools in the event of an emergency in the IES Utilities Inc. system or to provide power for startup or shutdown of the DAEC.

8.2.1.3.1 DAEC Switchyard

The DAEC Switchyard (Figure 8.2-1)is a standard electric utility design which incorporates features that provide for continuous service capabilities. Equipment can be isolated for maintenance or replacement purposes without deenergizing large sections of the switchyard. The DAEC station switchyard consists of a 161 KV ring bus section, a 345 KV transmission section, a 36 KV site support power section, and a 34.5 KV site support power section. The preferred power source is taken from the 161 KV section through breakers 5550 or 5560, a single circuit 161 KV overhead transmission line, and the Startup transformer to the plant essential buses. The 161 KV section employs a breaker and a half scheme (three breakers for two points of connection) for all feeds except the 6th Street and Radwaste feeds, which provides for flexible operation, high reliability, and bus failure does not deenergize the preferred source connection. The alternate preferred power source is taken from a tertiary 34.5 KV winding on the 161 KV/345 KV 400 MVA autotransformer through breaker 8490, a single circuit 34.5 KV underground transmission line, and the Standby transformer to the plant essential buses. Additional site power for auxiliary buildings, radwaste, service air compressors, and the training center is supplied through the 36 KV substation section to the LLRPSF and site support transformers. In the event of the loss of the 36 KV substation section, alternate power is automatically provided through a recloser 5960 to the site loads. The electrical output of the main plant generator supplies the 161 KV substation through a main transformer (three single phase transformers with an installed spare) rated at 600 MVA. The plant auxiliary transformer is also connected to the plant main generator output 22 KV isolated phase bus. The plant auxiliary transformer does not power any loads required for safe shutdown of the plant.

8.2.1.3.2 Switchyard Protective Breakers and Relaying

The DAEC switchyard uses a combination of oil immersion, and sulfur hexafloride breakers. These breakers use permissive, transfer trip, breaker failure protection schemes consisting of two independent sets (primary, secondary) of protective relays.

The AC control power for the switchyard breakers is available from two sources, the 34.5 KV tertiary winding on the 161 KV/345 KV autotransformer and a 4.16 KV nonessential plant power bus. An automatic transfer switch is provided to transfer from one AC source to the other in case there is a loss of power on one of the sources. The DC control power for the switchyard breakers is supplied by one 125 VDC battery located in the switchyard control building. The generation output breakers and the plant preferred AC source breakers are equipped with dual trip coils, one of which is powered from one of the plant essential 125 VDC.

The plant preferred AC power breakers and the generator output breakers are supervised and operated remotely from the DAEC control room. However, one of the generator breakers can be remotely operated by the IES Utilities, Inc. System Dispatch Control Center. All the switchyard and line breakers may be operated locally from the breaker control cabinet on the breaker. Operational procedures exist to manually isolate faulted portions of the DAEC switchyard and restore offsite power to the DAEC.

Annunciators and event recorders located in the switchyard control building, have been provided for location of trouble or abnormal conditions, and for providing data for post trip root cause analysis. Two channels are provided on the supervisory control equipment to transmit to the IES Utilities, Inc. System Dispatch Control Center any abnormal condition indicated by the annunciators.

8.2.1.3.3 DAEC Transmission Lines

The DAEC substation is connected to the IES Utilities, Inc. power transmission system through four single circuit 161 KV overhead high voltage lines 10 to 20 miles in length and to the regional power pools through two 345 KV high voltage overhead lines 33 and 36 miles in length (Figure 8.2-1). All lines are designed to meet the requirements of the National Electric Safety Code (ANSI C2) Sixth Edition, "Heavy Loading Grade B Construction" and they have a performance of less than one outage per line per year. Of these electrical power sources, at least two divergent paths of transmission begin approximately 750 feet south of the DAEC switchyard and the DAEC is characterized as a multiple right of way transmission path site. Any one of these transmission lines has the capacity to supply electrical power to safely shutdown the DAEC.

8.2.2 ANALYSIS

8.2.2.1 General

The DAEC is a single unit nuclear power station that complies with the requirements of General Design Criterion 17 of 10CFR Part 50, Appendix A. Based on IES Utilities, Inc. review of (1) the DAEC electrical system design, (2) The related studies done for the DAEC response to (a) NRC Generic letter dated August 8, 1979 (Millstone incident, Reference 1) and (b) 10CFR50.63 (Station Blackout, Reference 3), (3) The preoperational startup tests, (4) surveillance tests, and (5) operational experience; sufficient capacity and capability of the offsite and the onsite electrical power systems exist to operate safely under all postulated events. The NRC SER issued by letter dated December 31, 1981, confirmed the adequacy of the station electric distribution system. The NRC SER issued by letter dated June 15, 1992, confirmed the adequacy of the station electric distribution system to cope with a Station Blackout. Additional studies of the plant electrical power distribution systems were completed in 1991 plant contolled documents APED-R20-003, APED-R20-004, APED-R20-005, APED-R20-006, and APED-R42-003 reflect these studies. Stability analyses of the interconnected power grid due to the loss of the DAEC generating capacity was submitted with the PSAR and updated stability analyses are performed by MAIN affiliates whenever significant power grid changes are made.

8.2.2.2 Offsite Power Grid Voltage Analysis

8.2.2.2.1 Introduction

The operation of the offsite power grid is based on recommendations and guidelines developed by the IES Utilities, Inc. planning department in conjunction with the Mid-America Interconnected Network (MAIN). Power grid low frequency limits are established at 59.3 Hz. with automatic load shedding trips initiated at this frequency. These trips reduce the grid load, isolate transmission systems, and prevent cascading generating plant trips. The DAEC generator protective relays alarm at 59.5 Hz and trip the generator after a three minute delay at 58.5 Hz or after a one-tenth second delay at 57 Hz . The recommended power grid operating voltage range is from 95% to 105% of nominal voltage. The power grid transmission voltage is normally maintained between 103% to 104%.

8.2.2.2.2 Steady State Loads

The DAEC electrical distribution system has been analyzed to determine if the voltage levels at the safety and nonsafety buses are within the range required for proper operation of the connected utilization equipment throughout the operating range of the offsite power grid. This analysis (APED-R20-003, APED-R20-004, APED-R20-005, APED-R20-006) considers the operating sequences and events given in the DAEC Nuclear Safety Operational Analysis (NSOA) which defines safety concerns and establishes the required systems to cope with events during each plant operational state. The following operating states and events were evaluated:

Shutdown Plant electrical loads supplied while the reactor is in cold shutdown such as during refueling outages. The electrical loads will be normally supplied by the startup transformer although the main generator transformers can be used occasionally. This analysis addresses concerns of overvoltage due to lightly loaded buses.

Plant Startup Plant electrical loads are supplied by the Startup Transformer prior to synchronizing the main generator to the offsite power grid.

Full Power Normal plant operation during full reactor power. Plant safety related electrical loads are supplied by the Startup Transformer and plant nonsafety electrical loads are supplied by the station auxiliary transformer. Loading may vary due to seasonal operation of equipment and testing of equipment.

Loss of Offsite Power Electrical loads utilized in the plant response to the loss of all offsite power during full reactor power are supplied by the emergency AC diesel generators.

Loss of Coolant Accident Electrical loads utilized in the plant response to the loss of coolant accident as defined in the UFSAR during full reactor power. Plant safety related and nonsafety electrical loads are supplied by the Startup Transformer.

Loss of Coolant Accident with Loss of Offsite Power Electrical loads utilized in the plant response to the loss of coolant accident concurrent with the loss of all offsite power during full reactor power as defined in the UFSAR are supplied by the emergency AC diesel generators.

This power system analysis examines the DAEC integrated AC electrical distribution systems using models for load flow and voltage drop. The analysis techniques employed consist of Thevenin Equivalent Circuits, Superposition Theory, and graphical plotting. The power system analysis inputs are obtained from the plant controlled documentation system. The individual calculations identify these inputs and their references.

To determine the most severe service for each model, the equipment operating sequences are examined, mutually exclusive sequences identified (e.g. shutdown loads and running loads are not energized at the same time),and all credible loads are totaled to produce the highest load current flows or the largest voltage drops.

8.2.2.2.3 Acceptance Criteria

The applied acceptance criteria is derived from the design basis requirements for the applicable utilization system. This translates to the proper currents and voltage levels for utilization devices. Safety related motors are capable of accelerating their loads at 70% of rated motor nameplate voltage (2912 VAC or 322 VAC). Motor operated valves are capable of required thrust at 80%* of rated nameplate voltage (368 VAC). Motor starters operate over a range of 67% to 110% of rated voltage (77.05 VAC to 126.5 VAC). All other safety related components are designed to operate over a voltage range greater than the full range of voltages at the safety related buses. Individual calculation results are listed in plant controlled MDL documents APED-A20-003, APED-R20-004, APED-R20-005, and APED-R20-006.

8.2.2.2.4 Conclusions

The DAEC AC electrical distribution system has been designed, constructed and maintained in a manner that supports the design objectives and requirements for the AC support system.

All bus voltage levels meet the criteria specified in Section 8.2.2.2.3. Buses supplying loads from lAl, 1A2, 1A3, 1A4 are above 70% of rated (2912 VAC) and below 110% (4400 VAC). Buses supplying nonsafety motor loads from 1B1, 1B2, 1B5, 1B6, 1B7, 1B8, are above 80% of rated (368 VAC) and below 110% (528 VAC). Buses supplying safety loads from 1B3, 1B4, 1B9, 1B20, are above the required 70% (322 VAC) or 80% (368 VAC) and below 110% (528 VAC).

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* This was an assumption for this study of the AC distribution system. Safety-related motor-operated valves are not required to have 80% terminal voltage available in order to perform their active safety functions. Refer to the Generic Letter 89-10 Program analyses for documentation of the ability of each safety-related MOV to operate under degraded voltage conditions.

REFERENCES FOR SECTION 8.2

1. Letter from L. Liu, Iowa Electric, to G. Lear, Operating Reactor Branch, NRC, dated October 9, 1976 (IE-76-1590).

2. Letter from NRC to all power reactor licensees, dated August 8, 1979.

3. Letter from NRC, Docket 50-331, Station Blackout Rule Conformance Evaluation dated June 15, 1992

The switchgear for the 4160 V bus is of the metal-clad indoor type. Circuit breakers are three-pole and are electrically operated from 125 V plant batteries. All 4160 V breakers have stored-energy closing mechanisms. The 4160 V auxiliary buses are in four separate sections. Nonessential buses 1A1 and 1A2 are located in the turbine building and essential buses 1A3 and 1A4 are located in the control building and are designed to meet Seismic Category I criteria.

Voltage sensors in the essential switchgear (1A3, 1A4) monitor the essential bus voltages. Separate voltage sensors in the essential switchgear monitor the startup and the standby transformer voltages. Upon low voltage (65% or less of nominal) from the startup transformer, the safety related loads are transferred to the standby transformer. Upon low voltage from both the startup transformer and the standby transformer or a low essential bus voltage, the diesel generators are started. Upon a loss of bus voltage (20% or less of nominal), the large motors on the bus are load-shed. Upon a coincident loss of coolant accident (LOCA), some bus loads are shed and are sequentially re-energized from the standby transformer or the diesel generators.

The undervoltage sensors are chosen so that potential transients on the transmission system and bus voltage dips due to the starting of large motors will not cause a spurious transfer from the offsite power source to the onsite power source.

Degraded voltage bus protection exists for the essential 4160 V buses. When a degraded voltage condition is experienced (65% or less of nominal), the degraded voltage relays will cause the essential 4160 V incoming breakers to trip resulting in the actions discussed above.

Indicating voltmeters that monitor bus voltage and loss of voltage annunciators are provided in the control room. The plant computer alarms upon a generator overvoltage or undervoltage, a 4160 V bus undervoltage, or a startup or standby transformer undervoltage. In addition to the control room voltage monitors and alarms, indicating voltmeters are available locally in the switchgear and load centers.

<u>480 V Distribution</u>

Load center unit substations are supplied to transform power from 4160 to 480 V and to provide protection and control for 480 V feeder circuits. These units consist of an incoming bus section (4160 V), a transformer, and a low Voltage section (480 V). The transformers between the 4160 V and 480 V systems are indoor air-cooled dry type. All load center connections are inside enclosures. Each load center is in self-supporting, metal-clad sections with continuous main buses having horizontal-drawout circuit breaker units that are replaceable under live bus conditions. This equipment is properly coordinated electrically to permit safe operation under normal and short circuit conditions. Compartmentation of major components in the low voltage section confines faults, if they should occur, and provides safety for operating personnel.

The 480 V motor control centers are located in areas of electric load concentration. Those associated with the turbine-generator auxiliary systems are located around the turbine generator operating floor. Those associated with other balance of plant equipment are located near the loads that they supply. Those associated with the nuclear steam supply system are located in Seismic Category I areas.

The 480 V motor control centers are of the indoor type, which, in addition to supplying the motors of 250 hp and below, also supply the stepdown transformers for lighting, instrumentation, and miscellaneous plant service loads.

Control and Instrumentation AC Power

Control and instrumentation power is taken from uninterruptible AC sources or the reactor protection system (RPS) AC as described below.

Uninterruptible AC

Loads that are not essential to plant safety but for which power interruption should be avoided are powered from a 120 V, single-phase, 60-Hz uninterruptible system.

Power is provided to the uninterruptible buses (1Y11, 1Y21, 1Y23) from three independent solid-state static inverter/regulating transformer systems (see Figure 8.3-2). Each inverter is energized from a battery charger and supplies regulated 120 VAC power to the load. If the battery charger fails or if a loss of the 480 VAC system supplying the charger occurs, the assigned station battery will automatically provide power to the inverter. The inverter output will stay within voltage and frequency specifications during transfer and retransfer between its two power sources (battery charger and battery). When power returns, the battery charger will resume supplying the inverter and recharge the assigned battery. The uninterruptible power buses may receive another source of 120 VAC power directly from a regulating transformer supplied from an essential 480 VAC Motor Control Center. The regulating transformer is connected to the uninterruptible power bus by an automatic solid-state static transfer switch. The static transfer switch senses load faults, over/under inverter voltage conditions, and frequency conditions which exceed limitations before completing an automatic transfer operation. Manual operation of the static switch allows the user to select either power source (inverter or transformer) and is used when performing maintenance on the inverter equipment. A separate manual transfer switch in parallel with the static switch permits maintenance on the inverter and the static switch.

For those trays to which fire protection material has been added, the dynamic loading (seismic event) design has been analyzed for the added weight of the fire protection material.

Loss of Auxiliary Nonessential Power.

Auxiliary power that supplies nonessential buses only is normally supplied by the auxiliary transformer, with the startup transformer as backup. It is improbable that both electric power sources would be lost simultaneously, because each is supplied from a different source. On loss of auxiliary transformer output, detected by undervoltage relays on buses 1A1 and 1A2, there will be an automatic transfer of these buses to the startup transformer if its undervoltage relays indicate available voltage.

Inspection and Testing.

Inspections and tests at vendor factories and during startup have demonstrated that the design and construction of the auxiliary AC systems have been properly implemented.

Operational testing of the normal and standby power systems is conducted under conditions that simulate the loss of offsite power. This testing demonstrates the following:

All essential loads can be operated in the proper sequence for each design-basis accident condition with normal power available for essential loads.

The relaying and control system can detect a loss of external power and, with the buses dead, start and load the standby power sources.

The standby power sources can provide sufficient power for an adequate time interval.

Each essential AC power circuit breaker shall be subject to inspection and preventive maintenance in accordance with procedures based on the manufacturer's recommendations and industry experience.

8.3.1.2 Standby AC Power System

8.3.1.2.1 Safety Objective

The safety objective of the standby AC power supply and distribution system is to provide power required to safely shutdown the plant and to protect against postulated accidents in the event of the loss of offsite power.

8.3.1.2.2 Safety Design Bases

The standby AC power supply consists of two separate divisions, each with a diesel-driven generator, essential 4160 V and 480 V buses, motor control centers, and a DC control power source. The two divisions are electrically and physically independent to ensure that no single event can cause the loss of both.

On a reactor low-low-low water level, drywell high pressure, loss of offsite power, or a degraded voltage condition, both diesel generators start automatically. When each diesel generator reaches operating voltage and frequency and there is no voltage on the corresponding emergency service bus, the diesel generator is automatically connected to its bus. To prevent an initial overload of the diesel generators, their selected loads are started in sequence. This loading sequence has been designed to provide maximum core cooling flow in the shortest practicable time.

Each diesel engine has two independent air start systems. Each starting air system has the capability of providing a minimum of five normal diesel starts per air receiver without recharging. A minimum of fifteen normal diesel starts are provided for each diesel engine. If the air start receivers are depleted and the normal air supply for recharging is not available, procedures and permanently installed emergency diesel driven compressors are available to directly recharge the receivers.

The fuel supply for the engines consists of one common underground fuel storage tank and a day tank for each engine. The diesel fuel storage tank is of sufficient capacity to meet the diesel generator fuel requirements for approximately 7 days. The day tank capacity meets the fuel requirement for approximately 4 hours.

The diesel generators are equipped for periodic manual starting to permit tests for readiness. In addition, load carrying capability may be demonstrated without interruption of normal plant operation.

8.3.1.2.3 Description of Standby AC Power Systems

<u>Emergency AC System</u>

The prime movers for the Emergency AC Power System are two identical 12 cylinder, opposed piston, turbo-charged diesel engines.

The generators for the Standby AC Power System are two identical synchronous alternators operating at 4160 Volts, 60 cycles. Each diesel generator has a continuous rating of

2850 KW, a 2000-hr rating of 3000 KW, and a 300-hr rating of 3250 KW. The generator is a grounded "wye"-configured source.

The auxiliary systems for the DAEC diesel generators are described in the following sections.

Fuel oil supply system. (Section 9.5.4)
Diesel generator cooling water system. (Section 9.5.5)
Air starting system. (Section 9.5.6)
Auto lube oil makeup system. (Section 9.5.7)
Combustion air intake and exhaust system. (Section 9.5.8)
Room ventilation system. (Section 9.5.8)

The standby diesel generators produce AC power at a voltage and frequency compatible with the normal bus requirements for essential equipment within the plant. Each diesel generator has sufficient capacity to start and carry the loads required to shut down the plant and maintain it in a safe shutdown condition.
Each of the diesel generators supplies standby power to a separate 4160 V bus, as shown in Figure 8.3-1.

The loads supplied by the standby diesel generator system are grouped into two main categories, as follows:

1. Loads required immediately.

2. Loads required for orderly shutdown without offsite power and may be time sequenced.

The location of all equipment within the diesel generator rooms, including air compressors, air receivers, day tanks, lube oil makeup tanks, control panels, and diesel generators, is shown in Figure 1.2-4. This figure also shows the position of the diesel generator rooms in the plant.

<u>TSC/PPC Standby Generator</u>

A 350 KW diesel generator provides reliable standby AC power for the plant process computer (PPC) and the technical support center (TSC). This diesel generator unit, which is not safety related, starts automatically on loss of power to either the LLRPSF transformer, 1XR1, or the site support substation transformer, T4, (see Figure 8.2-1). Automatic transfer switches then supply power from the diesel generator to the TSC and PPC, the PBX telephone power distribution system and the CARDOX fire suppression power supply.

The TSC/PPC standby diesel generator unit consists of a skid-mounted six cylinder diesel engine and a 350 KW, 480 VAC generator in a weatherproof enclosure. The unit and its dedicated 560 gallon fuel tank are located in the yard, north of the turbine building.

8.3.1.3 Analysis

On a reactor low-low-low water level, high drywell pressure signal, loss of offsite power, or a degraded voltage, the following events take place automatically.

The standby diesel generators are automatically started.

If there has been a loss of normal offsite auxiliary power sources, the normal power source breakers on the emergency service switchgear automatically trip open. All 4160 V feeder breakers on the emergency service buses are tripped open, except for the feeds to the emergency service 480 V load centers.

When the voltage on an emergency service bus is established from the diesel generator, some essential loads are started immediately and others are automatically started in a predetermined sequence. Manual operation from the plant main control room is available for other auxiliaries on the essential buses. Automatic functions are monitored in the main control room, permitting the operator to observe that proper conditions have been established.

Table 8.3-1 describes the loading sequence of loads onto the onsite power (diesel) supply, along with the corresponding voltage and frequency responses, during a post-LOCA period to prevent core damage and enable containment heat removal to begin. (Note: These are the original design values. Sensitivity studies have been performed (Ref. 8) that demonstrate that margin is available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. Actual relaxation of these performance requirements will be evaluated on a case-by-case basis.) The table indicates the total capacity required for the operation of equipment necessary for core and containment cooling during the post-LOCA period will be below the rated load capability of the diesel generators.

The sequence described in Table 8.3-1 is adjusted to 5-sec (nominal) intervals to permit each sequence group of motors to obtain operating speed before the application of the next sequence group. The total load in each sequence group is selected to prevent a voltage or frequency dip that would cause relays or contactors to drop out or motors to pull out or stall.

The diesel generator is designed such that an instantaneous loss of load up to the continuous rating of 2850 KW will not result in an overspeed trip of the diesel.

The excitation system of the diesel driven generators uses an ungrounded, open-delta-excitation, primary-side potential transformer configuration. There is no circuit connecting the generator ground and the exciter primary transformer. By design, this system will only pass low frequencies from phase to phase, and these frequencies will cancel each other out. Therefore, low frequency harmonics present in the system will cancel without producing undesirable high-circulating currents that could damage the exciter primary transformer.

The separation of the diesel generators to meet the single failure criterion is illustrated in Figure 1.2-4. Isolation is accomplished by locating the diesel generators in separate rooms and by ensuring that all control and support equipment for each diesel generator is separate and redundant. The electrical isolation of the diesel generators is shown in Figure 8.3-1.

Components of the diesel generators and support systems are located so as to minimize the possibility of damage due to explosions or missiles. Redundant components are protected from each other and from common failure due to any single explosion or missile through separation and protective structures.

Protection against seismic events is provided by designing all critical components of the diesel generators and support systems to withstand a design basis earthquake. The plant seismic design is discussed in Chapter 3.

The diesel generators and their auxiliary equipment are designed for approximately 7 days of unassisted operation. To ensure unassisted diesel generator operation, the following design features are provided:

Automatic recharging of the air starting compressed air tanks to permit starting and stopping the diesel generators during the period of required extended operation.

Adequate fuel storage for the continuous operation of one diesel generator for approximately 7 days, and automatic fuel transfer to that diesel generator.

Automatic lube oil makeup to the diesel crankcase for at least 7 days of continuous operation.

In the event that the diesel generator rooms are inaccessible, the diesel generators can be operated from the main control room.

Conditions or actions that render the diesel generator incapable of responding to an automatic emergency start signal, or prevent the diesel generator from performing its intended function are:

a. Stopping the diesel engine manually
b. Tripping the diesel generator circuit breakers
c. Interlocks preventing the automatic start of the diesel engine
d. Interlocks preventing the automatic closure of the diesel generator circuit breaker
e. Lube-oil not available, makeup tank empty.
f. Starting air pressure low.
g. 125 VDC control power failure.
h. Diesel day tank empty.

All conditions that render the diesel generator incapable of responding to an automatic emergency start are alarmed in the control room.

In the case of plant shutdown from outside the control room due to fire, key-locked manual transfer switches in 1C388 and 1C390 panels isolate diesel generator 1G21 from the control room. Control switches in 1C388 panel allow adjustment of 1G21 voltage and speed for synchronizing purposes and control of 1G21 4 KV switchgear (1A411). (See Section 7.4.2.)

8.3.1.4 Inspection and Testing

Readiness of the diesel generators is demonstrated by periodic testing, which simulates actual emergency conditions insofar as practical. The testing program is designed to confirm the diesel generator's ability to start as well as to run under load for a period of time long enough to reach equilibrium conditions to ensure that cooling and lubrication are adequate for extended periods of operation. Full functional tests of the automatic circuitry are conducted on a periodic basis to demonstrate proper operation.

The preoperational test program for the emergency diesel generators is discussed in the response to Safety Guide 9 in Section 1.8.

A test program was conducted increasing the load beyond the initial load increment and reducing the load sequence time intervals shown in Table 8.3-1. The object of these tests was to determine that adequate margin is included in the design.

The initial test was run with the loads and intervals indicated in Table 8.3-1. The voltage, frequency, and load time increments were recorded and used as a base for a following series of tests. In the series of tests that followed, the load was increased beyond the initial load increment and the load sequence test was repeated. The results of this test were compared to the base with respect to the load response interval times. From the resulting data, shorter load interval times were determined and the test was repeated. The load interval times were reduced and the test was continued until it was determined that the voltage and frequency perturbations did, in fact, degrade the ability of the system to pick up the designated loads in accordance with Table 8.3-1. The results of this series of tests were analyzed to determine the margin inherent in the design.

The frequency does not return to within 2% of nominal within 40% of the load sequence time interval as required by Safety Guide 9 acceptable limits. However, it is concluded from the above that the recovery time shown in Table 8.3-1 has no detrimental effect on system reliability or performance. (See Section 1.8, Safety Guide 9.)

Surveillance requirements are presented in the Technical Specifications for the diesel generators and their support equipment. In addition to the Technical Specifications' surveillance requirements, the diesel generators and their auxiliary equipment are subject to inspection and preventive maintenance in accordance with procedures based on the manufacturer's recommendations and industry experience. This ensures the availability of the diesel generators for periods of reliable, extended operation. During the monthly start test the emergency diesel generator starting air compressors shall be checked for operation and their ability to recharge air receivers.

8.3.2 DC POWER SYSTEMS

8.3.2.1 Description

8.3.2.1.1 Safety Objective

The safety objective of the DC power supply and distribution system is to provide a source of reliable, continuous power for the control and instrumentation of safeguard systems and for other loads required for normal operation and orderly shutdown.

8.3.2.1.2 Safety Design Bases

The plant essential DC power supply system consists of two 125 V batteries, one 250 V battery, and two plus and minus 24 V batteries, each system with its own charger. The plant battery systems (125 V and 250 V) are sized to supply, without recharging, the control and essential instrumentation power for a minimum of 4 hours and the emergency motor loads for their required length of time.

Each battery charger is sized to restore its battery to full charge after a 4-hr emergency discharge while carrying normal steady state dc loads. Each charger receives AC power from a separate AC bus. One spare battery charger is supplied for either of the two 125 V batteries, and one spare charger is provided for the 250 V battery.

The plant battery systems are arranged so that no single circuit component failure will prevent the combined systems from providing power to vital functions. The Division I and Division II batteries, chargers, and distribution panels are in separate Seismic Category I rooms.

8.3.2.1.3 Description of DC Power Systems

8.3.2.1.3.1 250 V System

One 250 V battery with two redundant full-capacity battery chargers is provided for heavy motor loads. Two 250 V motor control centers are provided, one of which is used for the high pressure coolant injection (HPCI) system and the other for containment isolation valves. The 250 V battery and dc distribution system are treated as a Division II system with divisional separation requirements applied.

Annunciators and computer logging are provided in the control room to alert the operator whenever the 250 V battery system has abnormal conditions.

8.3.2.1.3.2 125 V System

Two separate 125 V plant batteries are furnished, each with its own static-type battery charger, circuit breakers, and bus. One spare battery charger is provided that can be connected to either of the two batteries for servicing and as a backup to the normal power supply charger.

Four separate 125 VDC power panel boards are provided, two powered from one 125 V bus and two from the other. To maintain separation in the divisional essential systems, the dc control power that is provided to each redundant AC bus or group of essential equipment comes from different 125 V batteries. One battery is used to furnish power to the reactor core isolation cooling motor control center.

Annunciators and computer logging are provided in the control room to alert the operator whenever a 125 V battery system has abnormal conditions.

8.3.2.1.3.3 24 V System

Two independent plus and minus 24 V system buses are provided, each supplied by a center-tapped 48 V battery and two 24 V battery chargers that are fed from essential AC buses.

The systems are redundant, with each having its own 24-cell battery, two battery chargers, and a distribution panel. Separation is provided for all equipment and feeders as in all other safeguards systems.

Each plus and minus 24 VDC bus supplies Source and Intermediate range core activity monitors and liquid process radiation monitors.

8.3.2.2 Analysis

8.3.2.2.1 General

All of the normal loads connected to the plant battery system can be supplied by the battery chargers. The chargers can be powered from multiple sources of plant auxiliary power including the plant standby diesel generator system. The aggregate system is so arranged and powered that the probability of system failure resulting in a loss of DC power is very low. The system vital components are either self-alarming on failure, or provisions are made for periodic inservice testing to detect faults. Only the motor loads require the capacity of the storage battery for their operation.

The effect of a single DC power supply failure on emergency core cooling system performance has been reviewed by the NRC as documented in References 3, 6 and 7. The NRC has concluded that emergency core cooling system performance with a DC power supply failure is acceptable. The DAEC emergency core cooling system is discussed in Section 6.3.

Each 125 V and 250 V battery is located in a separately ventilated room of the control building. The battery racks meet the requirements for earthquake design. The 125 V and 250 VDC systems operate ungrounded with a ground detector alarm in the main control room set to annunciate a ground fault. Thus, multiple grounding, which is the only reasonable mode of failure and which usually affects only one circuit, is extremely unlikely. The normal mode of battery failure is the deterioration of a single cell. Such a failure is signaled well in advance by the routine tests performed on the battery.

The consideration of the consequences of ventilation system failure is discussed in the Technical Requirements Manual.

8.3.2.2.2 Loss of 250 V Battery

The 250 V battery supplies power for the HPCI turbine oil pump and other auxiliaries. A loss of the 250 V battery would thus prevent operation of the HPCI system. The HPCI system is redundant in its core cooling function with the automatic depressurization system that does not require 250 VDC for operation. All of the 250 VDC motor-operated isolation valves have redundant counterparts that do not rely on DC power. A loss of the 250 V system would be annunciated and would permit troubleshooting of the system. The uninterruptible AC inverter is also powered from the 250 V battery if the 250 VDC battery charger fails or if a loss of the 480

VAC system supplying the charger occurs. Alternate sources for the uninterruptible AC power system are discussed in Section 8.3.1.1.5.

8.3.2.2.3 Loss of 125 V Battery

The 125 V batteries are well protected from an electrical as well as a physical standpoint; however, it is assumed that one of the batteries or its bus system could malfunction. Equipment operated by DC power that is vital to plant safety is arranged so that the failure of one of the batteries would not prevent accomplishing the desired action. The safeguard systems using dc power are redundant in themselves and are supplied from separate 125 V buses. All system components are annunciated or are arranged to facilitate periodic testing while in service. Because of this redundancy, it is concluded that a loss of a battery or its bus would not be of serious consequence although it might cause an operating inconvenience.

8.3.2.2.4 Loss of 24 V Battery

The 24 VDC system provides power for source range monitoring, intermediate range monitoring, and liquid and gaseous process radiation monitoring. The two neutron monitoring functions are required for safety; however, the design is fail-safe in that loss of 24 VDC power would cause the associated trip to function.

8.3.2.3 Inspection and Testing

The plant batteries and other equipment associated with the dc system are easily accessible for inspection and testing. Service and testing are accomplished on a routine basis. The frequency and scope of maintenance and inspections are in accordance with normal plant practices, manufacturer's recommendations and operating history. Typical inspections include visual inspections for leaks and corrosion and the testing of all batteries for voltage, specific gravity, and level of electrolyte.

8.3.3 FIRE PROTECTION FOR CABLE SYSTEMS

Fire protection considerations include insulation flame resistance and the ability to maintain circuit integrity, including design load current capability, at elevated ambient temperatures resulting from a design basis accident. All cables prior to December 1, 1977, were required to pass the IPCEA flame-resistance tests in accordance with IPCEA Standards S-19-81, Section 6.19.6, and S-61-402, Section 6.5. The cables were also subjected to the following flame-resistance tests:

1. Horizontal and vertical tray configuration exposure to sustained flame with Fisher burner.

2. Vertical tray cable fire propagation test.

3. Horizontal bonfire test (600 V power and control cables only).

All cables procured after December 1, 1977, shall pass flame resistance tests in accordance with ICEA Standard S-19-81, Section 6.19.6. Power, control, and single pair thermocouple extension cables procured after December 1, 1977, shall pass flame tests in accordance with IEEE Standard 383-1974, Sections 2.5.1 through 2.5.5.

All cables procured after December 1, 1977, are not required to pass the three flame resistance tests listed above or the ICEA Standard S-61-402, Section 6.5, flame-resisting test, since these tests are less stringent than the newer flame tests.

All openings in floors and ceilings for the vertical ventilated tray installation are provided with fire stops. Similarly, all openings for cable runs into the control room, control equipment, switchgear, load centers, motor control centers, etc., are sealed with fire-resistant material.

Where redundant safety-related or associated trains of cables and/or equipment necessary to achieve and/or maintain cold shutdown conditions are located within the same fire zone, one of the redundant trains of cables and/or equipment is surrounded by a 3-hr rated fire barrier material or by a 1-hr rated fire barrier material plus area fire detection and suppression systems to meet the requirements of Appendix R to 10 CFR 50. The cable and/or equipment protected with fire barrier material will remain free of fire damage following any single design basis fire, including an exposure fire. As an alternative, 20-feet of horizontal separation between redundant trains of safe-shutdown cables and/or equipment with no intervening combustibles, detection and automatic fire suppression also meets the Appendix R separation criteria.

As part of initial construction, all cables in trays in the control room back panel area, exterior to the control panels, (upper cable spreading room) have been coated with Flamemastic 77, on top and bottom, to a wet thickness of 1/8 in. Flamemastic 77 is a fire-retardant compound utilized in the control room back panel area to retard the propagation of cable fires.

Because of the installation of the Alternate Shutdown Capability System (ASCS) and improvements in the fire retardant properties of cables, coating of cables in this area is not required. The DAEC ASCS is described in Section 7.4.2

REFERENCES FOR SECTION 8.3

1. Letter from L. D. Root, Iowa Electric, to J. G. Keppler, NRC, Subject: Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation, dated February 28, 1980.

2. Letter from D. L. Mineck, Iowa Electric, to L. Clardy, NRC, Subject: Evaluation of Class 1E Switchgear "Close" Circuits, dated June 21, 1983.

3. Letter from D. B. Vassallo, NRC, to L. Liu, Iowa Electric, Subject: Effect of a DC Power Supply Failure on ECCS Performance, dated October 24, 1983.

4. Letter from W. D. Shafer, NRC, to L. Liu, Iowa Electric, Subject: NRC Inspection Report 50-331/86020, dated February 6, 1987.

5. Letter from R. W. McGaughy, Iowa Electric, to A. B. Davis, NRC, Subject: Response to Request for Additional Information Regarding Our Response to NRC Inspection Report 50-331/86020, ERF Appraisal, dated June 10, 1987 (NG-87-1630).

6. Letter from J. R. Hall, NRC, to L. Liu, Iowa Electric, Subject: Transmittal of SER for LPCI Swing Bus Design Modification, dated January 19, 1989.

7. Letter from D. L. Mineck, Iowa Electric, to T. E. Murley, NRC, Subject: Consideration of Postulated Electrical Failure in 10CFR50.46 ECCS Analysis, dated June 26, 1989.

8. General Electric Company, Duane Arnold Energy Center SAFER/GESTR-LOCA Loss of Coolant Accident Analysis, NEDO-31310, 1986 and Supplement 1, 1993.

Chapter 9: AUXILIARY SYSTEMS

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9.1.2.3 Safety Evaluation

9.1.2.3.1 Criticality Considerations

9.1.2.3.1.1 Design Criteria

The design of the revised fuel storage rack complies with the criteria established for the spent fuel storage racks as described in the Section 9.1.2.1.3. For any operating or accident condition that is a design basis for the DAEC, the subcritical multiplication factor (K_{eff}) is maintained below 0.95. This includes the worst-case postulation of a dropped fuel assembly. This K_{eff} value is satisfied if the maximum exposure dependent K_∞ and enrichment of each individual bundle are within limits as discussed later.

9.1.2.3.1.2 Analysis Methods

PaR Racks

The PaR racks were analyzed in 1997 as documented in Reference 8. The principal methods of analysis were the NITAWL-KENO5a code package, a three dimensional Monte Carlo code package using the 238-group SCALE cross-section library, and the CASMO3 code, a two-dimensional multi-group transport code for assemblies. NITAWL-KENO5a has been extensively benchmarked, resulting in a bias of 0.0042 ± 0.0010 (95%/95%). Independent check calculations were made with the MCNP code developed by Los Alamos National Laboratory.

In the geometric model used in the calculations, each fuel rod and its cladding were described explicitly. Reflecting boundary conditions (zero neutron current) were used in the radial direction which has the effect of creating an infinite radial array of storage cells. The KENO5a calculational model represented the part-length fuel rods in a 3-dimensional calculation and was used to develop a correction to the two-dimensional CASMO3 depletion calculations, normalizing the results to the three-dimensional model with part-length rods, where appropriate.

Since Monte Carlo calculations (KENO5a) inherently include a statistical uncertainty due to the random nature of neutron tracking, a minimum of 1×10^6 neutron histories were accumulated in each calculation. Uniform average enrichments were used in the analyses, primarily because this assumption provides conservative results and actual distributions in enrichments have not yet been developed for the higher enrichment fuel. Similarly, in most cases, the Gd_2O_3 normally used in BWR fuel assemblies was not included in the calculations, again because the distribution and loadings have not yet been developed. This approach is the equivalent of neglecting any residual gadolinium at the peak reactivity over burnup.

When defining fuel acceptable for storage in terms of the K_∞ in the cold standard core geometry, the distribution in enrichments and the Gd_2O_3 loading are of secondary importance, since the core

K_∞ and the rack K_∞ are both affected in the same way. These parameters are, however, very important in determining the achievable peak reactivity over burnup. The average enrichment and the void content during core operation both affect the neutron spectrum and are more significant since they directly affect the production of plutonium during core operations.

Additionally, the MCNP code was used to independently verify specific KENO5a calculations. The resulting bias corrected values are listed below:

Case	MCNP	KENO5a
GE-10 @ 4.6% E (fully rodded)	0.9448 ± 0.0014	0.9442 ± 0.0012
GE-10 @ 4.4% E	0.9368 ± 0.0014	0.9353 ± 0.0012
GE-12 @ 4.6% E	0.9452 ± 0.0014	0.9457 ± 0.0012

These calculations are in good agreement (within the normal statistical variation) and confirm the reference KENO5a calculations.

Holtec Racks

Criticality analyses for the Holtec maximum density racks were performed with the CASMO-3 code, a two-dimensional multi-group transport theory code. Independent verification calculations were made with the KENO-5a computer package, using the 27-group SCALE (Standardized Computer Analysis for Licensing Evaluation, a standard cross-section set developed by the Oak Ridge National laboratory for the USNRC).

Benchmark calculations indicate a bias of 0.0000 +/- 0.0024 for CASMO-3 and 0.0101 +/- 0.0018 (95% probability at the 95% confidence level) for NITAWL-KENO5a. In the geometric model used in the calculations, each fuel rod and its cladding were explicitly described and reflecting boundary conditions (zero neutron current) were used in the axial direction and at the centerline of the Boral and steel plate between storage cells. These boundary conditions have the effect of creating an infinite array of storage cells in all directions.

The CASMO-3 computer code was used as the primary method of analysis as well as a means of evaluating small reactivity increments associated with manufacturing tolerances. Burnup calculations were also performed with CASMO-3, using the restart option to describe spent fuel in the storage cell. KENO-5a was used to assess the reactivity consequences of eccentric fuel positioning and abnormal locations of fuel assemblies.

9.1.2.3.1.3 Bases and Assumptions

The following conservative assumptions were used for both normal and abnormal configuration analyses:

a) Both PaR and Holtec Racks:

Conservative assumptions used for both PaR and Holtec racks are as follows:

- The racks are assumed to contain the most reactive fuel for the case being analyzed, without any control rods or burnable poison, except gadolinium, as appropriate.
- The moderator is assumed to be pure, unborated water at a temperature corresponding to the highest reactivity (4°C) over the expected range of water temperatures.
- Neutron absorption in minor structural members is neglected, i.e., spacer grids are assumed to be replaced by water.

b) PaR Racks:

The nominal spent fuel storage cell used for the criticality analyses of the PaR racks is as follows:

- The rack is composed of 0.125 inch thick aluminum boxes of 6.156 inch I.D.
- A Boral absorber panel is located between boxes in a 0.2185 inch cavity.
- The fuel assemblies are assumed to be centrally located in each storage cell on a lattice spacing of 6.625 ± 0.050 inches.
- The Boral absorbers have a core thickness of 0.080 inches with a minimum B-10 loading of 0.0232 g/cm^2, (nominally 0.025 g/cm^2 B-10), and are clad on both sides with 0.0175-inch thick aluminum.

Furthermore, the following conservative assumptions were made:

- The fuel assemblies were conservatively evaluated for uniform enrichment, i.e., the distribution in enrichments normally used in BWR fuel was calculated as the average.
- Criticality safety analyses are based upon the assumption of an infinite array of storage cells in the radial direction, i.e., no credit is taken for radial neutron leakage.
- In the CASMO3 model, the flow channel was homogenized with the immediately surrounding water.

c) Holtec Racks:

The following conservative assumptions were made for the Holtec racks to assure that the true reactivity will always be less than the calculated reactivity:

- Criticality safety analyses are based upon the infinite multiplication factor (K_∞), i.e., lattice of storage racks is assumed infinite in all directions. No credit is taken for axial or radial neutron leakage, except in the assessment of certain abnormal/accident conditions where neutron leakage is inherent.

- The rack is composed of 0.060 inch thick stainless steel boxes on a 6.06 inch lattice spacing with a 5.90 inch opening.
- The 0.070 inch thick boral absorber has a nominal loading of 0.0162 g B-10/sq cm.

d) Fuel Assemblies:

Three different fuel assembly configurations were assumed in the analysis, as follows:

- GE-10 8×8 fuel assemblies with a single large water rod replacing 4 fuel rods,
- GE-13, 9×9 fuel assemblies with 2 water holes replacing 7 fuel rods, and
- GE-12, 10×10 fuel assemblies with 2 large water rods replacing 8 fuel rods.

Each of the fuel assembly configurations has a fuel stack density of 10.544 g/cc, a maximum enrichment of 4.95 wt% ^{235}U, 7 gadolinia rods, and a zircalloy channel with an inner diameter of 5.278 inches. The GE-12 and GE-13 fuel assemblies contain part-length rods, creating an array of higher water-to-fuel ratio near the top. Specifications for the fuel assemblies are summarized in the following table.

FUEL DESIGN SPECIFICATIONS (from Reference 8)

Parameter	GE-10 8×8	GE-13 9×9	GE-12 10×10
Pellet O.D. (in.)	0.411	0.376	0.345
Clad I.D. (in.)	0.419	0.384	0.352
Rod O.D. (in.)	0.483	0.44	0.404
Fuel Rod Pitch (in.)	0.64	0.566	0.510
Gadolinia wt%	4.0/5.0	4.00	4.00
Water Rod O.D. (in.)	1.340	0.98	0.98
Water Rod I.D. (in.)	1.260	0.92	0.92
Channel Thickness (in.)	0.100	0.074 Avg.	0.074 Avg.

Of the various fuel assembly types investigated, the GE-12, 10×10 rod assembly was found to be the most reactive. All of the GE fuel assemblies have natural UO_2 blankets at each end. The calculations reported here do not include blankets, and are based on the lattice average (planar) enrichments. The blankets, therefore, do not contribute to the calculated reactivities. Blankets of natural UO_2 would result in lower and more conservative reactivities (k_{eff}) for the entire assembly. Fuel enrichments, as used in this report, refer to the enriched lattices in the assembly without consideration of any axial blankets that might be present.

Calculations were also made to determine the effect of removing the zircalloy flow channel. Results showed a decrease in reactivity with removal of the flow channel (-0.0027 Δk for the PaR racks and -0.0098 Δk for the Holtec racks). Therefore, the reactivity with the flow channel installed on the assembly yields the higher and controlling reactivity.

9.1.2.3.1.4 Results

PaR Racks

The criticality analyses subject of References 5 and 8 confirm that the PaR storage racks can safely accommodate, within the regulatory guidelines, all fuel assemblies which were at the DAEC as of August, 1997. In addition, the analyses documented that GE fuel of the 7×7 or 8×8 design with a K_∞ of 1.31 and a maximum average lattice enrichment of 4.6 weight percent U-235 is acceptable for storage in the PaR racks. Also, GE 9×9 or 10×10 fuel with K_∞ of 1.39 and a maximum average lattice enrichment of 4.95 weight percent U-235 can be stored in the PaR racks.

Holtec Racks

The analysis of Reference 5 proves that all fuel assemblies at the DAEC by August, 1997 may be stored in the Holtec storage racks while acceptably meeting the regulatory guidelines. A similar analysis was performed for advanced fuel designs initially enriched to 4.95 w/o U-235. These calculations verified that the GE-12, 10×10 array and GE-13, 9×9 array fuel assemblies may be acceptably stored in the Holtec racks providing that the core K_∞ is 1.29 or less.

9.1.2.3.1.5 Temperature and Boiling Effects

Using the normal geometry, the temperatures of the pool water and the fuel were allowed to range from 68°F to 200°F. The conditions necessary to cause such a temperature excursion are discussed below in Section 9.1.2.3.2.3. The reactivity change was calculated at 95°F, 120°F, 160°F, and 200°F. The result was that reactivity decreases as temperature increases and K_{eff} remained less than 0.92.

The additional analyses at 32°F (PaR racks) and 4°C (Holtec racks) have also shown that K_{eff} remains below the acceptance limit of 0.95.

9.1.2.3.1.6 Accident and Abnormal Conditions

Although the storage rack is designed to prohibit the insertion of a fuel assembly anywhere except at a design location, the dropping of a fuel assembly could result in an unintended fuel assembly location adjacent to the rack. Two locations are credible, as follows:

1. On top of the storage rack.

2. Outside the rack assembly between the outermost rack and spent fuel pool wall.

The consequences of a dropped fuel assembly on top of the other fuel assemblies result in K_{eff} less than 0.95.

The evaluation of a fuel assembly dropped alongside the rack was performed by conservatively assuming that the dropped assembly lodges parallel to an off-centered assembly in the outermost cavity. The analysis indicates that K_{eff} is less than 0.95.

9.1.2.3.1.7 Conclusion

The analyses performed for both the PaR and Holtec spent fuel storage racks shows that the K_{eff} of the SFP remains substantially below the limit of 0.95. This is assured if individual fuel assemblies have the following limits for maximum k_∞ in the normal reactor core configuration at cold conditions and maximum lattice-averaged U-235 enrichment weight percents:

		k_∞	wt %
i)	7×7 and 8×8 pin arrays (Holtec and PaR racks)	≤ 1.31	≤ 4.6
ii)	9×9 and 10×10 pin arrays (Holtec racks)	≤ 1.29	≤ 4.95
iii)	9×9 and 10×10 pin arrays (PaR racks)	≤ 1.39	≤ 4.95

For both nominal fuel assembly spacing and postulated worst-case clustering of fuel assemblies, analyses indicate that a fully loaded fuel pool would remain substantially subcritical. This is based on a conservative analysis that takes no credit for poisons in the fuel, soluble poisons in the water, or in-core fuel depletion. The accidental drop of a fuel assembly resulting in a postulated worst-case location does not increase the K_{eff} above 0.95, which is the acceptance criterion for the criticality evaluation.

9.1.2.3.2 Cooling Considerations

9.1.2.3.2.1 Design Bases

The Spent Fuel Pool Cooling System design was reanalyzed before the rerack was performed in 1994. Four heat load analyses (Cases 1, 2, 3 and 4) were performed to demonstrate the adequacy of the DAEC Spent Fuel Pool Cooling System to cool the discharged fuel under four separate scenarios. The first two scenarios were analyzed to show that the current configuration of PaR and Holtec racks would meet the NUREG-0800, SRP 9.1.3 for Spent Fuel Pool Cooling and Cleanup.

In 1997, three more analyses (Cases A, B, and C) were performed to demonstrate the adequacy of the FPCCU system and/or RHR Supplemental Fuel Pool Cooling (SFPC) to support an early core discharge scenario.

Case 1 - Maximum Normal Heat Load

The maximum normal heat load scenario assumes there are three (3) normal batches of 128 spent fuel assemblies each, with 4.5 years of full power exposure. The first two discharges occurred at 18-month intervals and the last discharge occurred one year after the second discharge. The discharge of the fuel assemblies to the pool begins after 150 hours of decay in the reactor and proceeds at the rate of 144 assemblies for each 24-hour period. Only one (1) loop of Fuel Pool Cooling and Cleanup (FPCCU) is assumed to be in operation. This analysis was performed to demonstrate the DAEC's FPCCU meets the requirements of NUREG-0800. This is not representative of the DAEC's current configuration. Analysis shows that the maximum bulk pool temperature peaks at 140.98° F, 198 hours after reactor shutdown.

Case 2 - Abnormal Maximum Heat Load

The abnormal maximum heat load scenario assumes the pool contains three batches of discharged fuel, two normal (128 fuel assemblies) and one total core off load (368 fuel assemblies). The first normal batch was assumed to have decayed for 19 months, the second normal batch to have decayed for 36 days. The full core was then off-loaded into the Spent Fuel Pool at a rate of 144 fuel assemblies in a 24-hour period after 150 hours of decay in the reactor. Both loops of FPCCU were in operation. The analysis showed that the pool water temperature would be kept below boiling, and that the maximum bulk pool temperature peaks at 161.38° F, 220 hours after reactor shutdown.

The above two cases were performed to illustrate compliance of the FPCCU System to the provisions of NUREG-0800, SRP 9.1.3. The following two cases were analyzed to more closely represent the refueling practices at the DAEC.

Case 3 - Normal Heat Load

This scenario describes the bounding discharge practices at the DAEC involving a total off-load of the core 120 hours after shutdown. The Spent Fuel Pool is assumed to have 3152 spent fuel storage locations (actual number of storage locations is 2411) and that, when 128 spent fuel assemblies are discharged into the pool, insufficient space remains to accept another normal batch, while maintaining full core off-load capability. The transfer of the fuel to the pool begins after 120 hours of in-core decay and at a rate of 144 fuel assemblies per 24 hours. Both loops of

FPCCU are assumed to be in service. The peak fuel pool water temperature is sought to be no greater than 180° F, which is below the regulatory limit of 212° F. Analysis shows that the maximum bulk pool temperature peaks at 164.61° F, 190 hours after reactor shutdown. This is considered to be the most limiting case for analysis purposes. This is considered the most limiting case for the 120 hour incore decay scenarios in that the analyzed peak temperature is the highest value for Cases 1 through 4.

This case was used to calculate maximums for local water and fuel clad temperatures. Calculations showed that the maximum local water temperature would reach 216.3° F and the maximum local fuel clad temperature would reach 264.4° F. No nucleate boiling is indicated at any location in the Spent Fuel Pool. It was, therefore, concluded that the reracked SFP complies with all thermal hydraulic regulatory criteria.

Case 4 - Abnormal Heat Load

This scenario described the abnormal discharge practices at the DAEC involving a total off-load of the core. The Spent Fuel Pool is assumed to have 3152 spent fuel locations (actual is 2411) and that, when 128 spent fuel assemblies are discharged into the pool, insufficient space remains to accept another normal batch (128 spent fuel assemblies), while maintaining fuel core off-load capability. In this case the reactor has been operating for 36 days after a 45-day refueling outage. The transfer of the fuel to the pool begins after 120 hours of in-core decay at a rate of 144 fuel assemblies per 24 hours. Both loops of FPCCU are assumed to be in service. The peak fuel pool water temperature is sought to be less than 180° F, which is below the regulatory limit of 212° F. Analysis shows that the maximum bulk pool temperature peaks at 163.03° F, 189 hours after reactor shutdown.

Early Core Discharge Scenario

The FPCCU system, with assistance from the RHR system, was analyzed to support core alterations starting as soon as 60 hours after the reactor shutdown (i.e., reactor scram or all rods in). The initial conditions for the scenarios analyzed are similar to Cases 3 and 4 discussed previously for core alterations beginning 120 hours after shutdown. Three separate calculations were analyzed, including a planned full core offload with one FPCCU loop operating before RHR-SFPC is initiated (Case A), a planned full core offload with two loops of FPCCU operating before RHR-SFPC is initiated (Case B) and an unplanned full core offload with both loops of FPCCU in operation prior to initiating RHR-SFPC (Case C). The most limiting calculation was the unplanned core discharge scenario, Case C.

Case C assumes that the core has been operated for 45 days after a 36 day refueling outage involving a discharge of 128 fuel assemblies but has the same decay heat load as a core operated for 18 months. The core is then offloaded at a rate that results in the total core being discharged in 61.33 hours (a rate of 6 fuel assemblies per hour with the total core being offloaded no sooner than 121.33 hours after shutdown).

The analysis assumes that RHR Shutdown Cooling is in operation (one loop) prior to the start of the core alterations with 85°F cooling water to the RHR Heat Exchanger. Both loops of FPCCU are in service at rated flow with 95°F RBCCW cooling water to the FPCCU heat exchangers. The Spent Fuel Pool temperature is assumed to be approximately 113°F at the start of the fuel discharge to the pool.

The Spent fuel pool temperature begins to rise and, for analysis purposes, at 120 degrees, the FPCCU system is removed from service and RHR supplemental fuel pool cooling is initiated. RHR Supplemental fuel pool cooling takes a suction on the reactor through the SDC line. The RHR heat exchanger removes the decay heat and then the flow is split between the reactor cavity and the Spent Fuel pool. Fuel pool water flows through the fuel transfer canal into the reactor cavity and back through the SDC suction to complete the flow path. The fuel pool temperature is analyzed to peak at 159.87°F, 124 hours after shut down (reference Figures 9.1-49 and 9.1-52).

Plant procedures exist that allow the FPCCU system to be in operation with RHR supplemental fuel pool cooling in service while the fuel pool gates are removed (as is the case in the above scenario). The FPCCU system must be shut down if RHR is to be used to cool the Fuel Pool with the fuel pool gates installed. The above scenario describes a worse case situation and takes no credit for the existence of the FPCCU system.

A time to boil calculation for Case C was performed assuming a total loss of cooling to the Spent fuel pool. If all forced cooling is lost, calculations show that 0.96 hours after the total loss of forced cooling, the Spent fuel pool would start to boil. Given there is 23 feet of water above the fuel racks, makeup water to the pool would have to be provided within 4.5 hours of the onset of boiling at a rate of 52.78 gpm to makeup for the steam being generated. This loss of cooling was conservatively analyzed assuming the fuel pool gates were installed simultaneously with the loss of forced cooling. In other words, no credit is taken for the existence of the reactor cavity water volume or the ability to reflood or cool the fuel pool from the reactor cavity through the transfer canal.

Case C, above, gives the most limiting situation and deposits the most decay heat to the FPCCU system. This analysis bounds Cases A and B (reference Figures 9.1-47 through 9.1-52). For more information on Cases A and B, see reference 7.

Procedures exist that control the initial conditions necessary to discharge the core 60 hours after reactor shutdown. Normal system lineups are expected to be used that keep the actual initial conditions more conservative than the assumed initial conditions. The analysis provides the maximum operating parameters that would allow discharge of the core to the Spent Fuel Pool 60 hours after shutdown.

Fuel Shuffling

Case One was performed to show that the FPCCU System, with the new spent fuel storage capacity, would meet the requirements of NUREG-0800, Standard Review Plan. This scenario is the closest representation of a fuel shuffle of the analyses performed. On-site analysis of off-load rates, system configuration and time after shutdown, could be performed to determine operating limits for a fuel shuffle at the DAEC with a single loop of FPCCU in service. However, DAEC's current analysis requires both loops of FPCCU to be operating before the discharge of spent fuel to the SFP begins. Subsequently, the SFP temperature will be maintained within operating limits using approved operating procedures. An operating limit of 150° F will ensure the operation of the FPCCU and the SFP system is within the design limits. Time after shutdown, off-load rate and system operation can be used to predict peak pool temperatures; however, an operational limit of 150° F will ensure operation within the design of the SFP and FPCCU systems. Total core off-loads or fuel shuffling activities will be performed such that the 150° F limit is avoided. The bounding analysis for the DAEC is Case 3, which restricts fuel movement to the SFP to begin no earlier than 120 hours after shutdown and at a rate not to exceed 144 fuel assemblies in any 24 hour period. Should the pool temperatures approach 150° F, actions will be taken to increase cooling or fuel handling rates will be adjusted to reduce the rate of heat addition to the SFP. The analysis for Case C, which takes credit for RHR-SFPC, allows fuel movement to begin at 60 hours after shutdown, but results in a lower maximum bulk pool temperature than Case 3. Fuel shuffling would be will within the bounds of Case 3 for fuel discharge 120 hours after shutdown or Case C for early core discharge at 60 hours after shutdown provided the initial plant conditions are bounded by these cases.

9.1.2.3.2.2 Cooling System Capacity

The analyses discussed in Section 9.1.2.3.2.1 show that the spent fuel storage racks and the fuel pool are designed and analyzed to accommodate significant bulk pool temperatures. The limiting factor then becomes the design of the FPCCU System. System design specifications show that, for example, the piping for the FPCCU System is designed to accommodate 150° F water at 200 psi. Procedural restrictions prevent the coolant exiting the FPCCU heat exchangers from exceeding 130° F to protect the demineralizers. The system design is such that a bulk pool temperature limit of 150° F is imposed. For fuel discharges at the DAEC starting 60 hours after shutdown, RHR-SFPC will be utilized as the fuel pool temperatures approach 120°F, if decay heat curves warrant, to preclude SFP temperatures from exceeding the value of 150°F.

Cases Three and Four assume that the FPCCU System is operating with both loops in service. The Heat Exchangers are assumed to be fouled to their design maximum with RBCCW inlet temperatures at or below 95° F. The design of the existing FPCCU System and the Residual Heat Removal (RHR) System permit operations of the systems in parallel, should it become necessary, to maintain the bulk pool temperature below 150° F. If the FPCCU System is lost, the RHR System can be placed into operation to fulfill the cooling requirements.

9.1.2.3.2.3 Cooling System Failures

The design of the existing fuel pool cooling system and the RHR system permits the operation of the systems in parallel for conditions that require heat removal to maintain bulk pool temperatures at or below 150° F. This arrangement of piping and valves also permits the use of the RHR system as a backup system in the event of a fuel pool cooling system failure. The fuel pool cooling system itself has the capability of maintaining the pool temperature below 150°F for conditions outlined in Case One with only one of two pumps and heat exchangers in operation.

The racks and the pool structure are designed for an accident thermal excursion to 212°F. For the freestanding rack design, thermal load resulting from confined expansion of the racks is negligible. Therefore, the only effect of this thermal excursion on the rack design was its associated reduction of material yield strengths, which was considered. The thermal excursion to 212°F was considered in the design of the pool structure. No additional thermal analysis of the pool structure design was required for the new high density fuel rack design.

9.1.2.3.2.4 Conclusion for Cooling System Capability

The Spent Fuel Pool and the FPCCU System were analyzed to determine whether modifications were needed to support both the current and future installation of the Holtec racks. The analyses performed for the thermal hydraulic response to the increased load capacity, i.e.; more spent fuel, showed that no modifications to the facility were necessary to support the increase in capacity of the SFP.

The analyses performed also showed different scenarios for adding decay heat to the SFP. These scenarios made different assumptions and showed that under varying conditions, the cooling systems associated with the SFP were capable of maintaining the SFP temperature within the design limits. Time after shutdown and off-load rate were inputs into the analysis; however, regardless of these two inputs, the key parameter to FPCCU and SFP operation was the ability to maintain SFP temperatures below 150° F.

The analyses performed for the total core off-loads bound the heat load that could be anticipated during a partial off-load or core shuffle. The plant configuration and analyses parameters are adhered to assure compliance to the safety analyses.

9.1.2.3.3 Mechanical, Material, and Structural Considerations

9.1.2.3.3.1 Design Requirements

The spent fuel pool and spent fuel pool storage racks are Seismic Category I. The storage racks are designed to withstand the effects of a design-basis earthquake (DBE), postulated jammed fuel and fuel drop accidents without loss of structural integrity or functional adequacy, that is, the retention of fuel element spacing and overall geometry. The fuel pool structure is analyzed for the resulting storage rack interface loads.

9.1.2.3.3.2 Loading Combinations and Allowable Stresses

The loading combinations and factored limits for the PaR racks are included in Table 9.1-3. The Holtec and PaR Storage Racks were designed to meet applicable requirements of Subsection NF, Section III, of the ASME Code.

The allowable stresses for stainless steel are in accordance with the ASME Code, Section III, Appendix XVII. This is interpreted as being identical to the AISC Steel Construction Manual, Section 5.

The allowable stresses for aluminum members are based on the Aluminum Construction Manual, Section 1, "Specifications for Aluminum."

The following specifications from the manual were used:

Table No.	Description
3.3.3	Factors of Safety for Use with Aluminum Allowable Stress Specification
3.3.4 and 3.3.4b	Formulas for Buckling Constraints
3.3.6	General Formulas for Determining Allowable Stress
5.1.1a	Allowable Bearing Stresses for Building-Type Structures
5.1.1b	Allowable Stresses for Rivets, Bolts for Building-Type Structures

9.1.2.3.3.3 Seismic Analysis

Analysis Method

Following a seismic event with accelerations in excess of the Operating Basis Earthquake, the gaps between the spent fuel racks are to be inspected and, if necessary, restored to their original dimensions. (Reference NRC letter dated February 24, 1994.)

A combination time-history/static seismic analysis was performed. A horizontal time history was developed such that the corresponding response spectra enveloped the E-W and N-S Design Basis Event spectra for 6% damping for the PaR racks and 2% damping for the Holtec racks. Both are conservative with respect to Regulatory Guides 1.60 and 1.61.

It was determined in the original seismic analysis that the building will cause no amplification of motion in the vertical direction. A vertical time history was developed such that the corresponding spectra would conservatively envelope the ground response spectra. The horizontal and vertical time histories were then input simultaneously to the dynamic model at the floor spring location. The forces computed from the time-history analysis were applied to the static model. Symmetry of the PaR storage rack about the principal axes accounts for the equivalence of this method to simultaneous excitation in three orthogonal directions.

The combination time-history/static seismic analysis was done for the PaR racks via computer solution programs ANSYS and SAP IV, respectively. The ANSYS User Manual, Swanson Analysis Systems Inc., Elizabeth, Pennsylvania, documents this program.

SAP IV (public version) for static and dynamic analysis of linear structural systems was used to analyze the mathematical model. The development and documentation of SAP IV was sponsored by grants from the National Science Foundation and was authored by Klaus-Jurgan Bathe, Edward L. Wilson and Fred Peterson of the University of California, Berkeley, California. It is available as Report EERC 73-11 revised April, 1974, from the Earthquake Engineering Research Center at the University of California. SAP IV has been installed on a Control Data Corporation Cyber 74 computer in Minneapolis, Minnesota, where the model was analyzed.

The seismic analysis for the Holtec racks used several different models to provide, as accurate as possible, the seismic response of the fuel racks. Single rack 3-D models were used and compared to the Holtec computer code DYNARACK and the Whole Pool Multi-Rack 3-D analysis. The intent of this parallel approach was to foster added confidence and to uncover any peculiarities in the dynamic response which was germane to the structural safety of the Holtec Storage System. More detailed information is available in Reference Five, Section 6.0 - Structural / Seismic Considerations.

9.1.2.3.3.3.1 Seismic Analysis of PaR Fuel Racks

The following paragraphs describe the mathematical models employed and assumptions used in the seismic analysis of the PaR fuel racks.

9.1.2.3.3.3.1.1 ANSYS Seismic Model (PaR Fuel Racks)

The rack structure consists of four side panels bolted top and bottom to a very stiff box grid. The corners of the side panels are riveted together via formed angles. The structural system may, therefore, be visualized as a large square or rectangular tube enveloped by the side panels with no structural stiffness added for either the poison cans or fuel assemblies. Dynamic analyses of a detailed SAP IV model have determined the first two natural frequencies to be orthogonal and simple cantilever modes at 8 Hz. Successive horizontal frequencies are greater than 28 Hz. A vertical damping frequency of the bottom casting exists at 14 to 18 Hz.

The rack structure for the simplified dynamic model used in the ANSYS analysis is idealized as a planar frame consisting of a cantilever beam at the base (bottom casting elevation) with leg beams connecting the ends of this member to the floor (see Figure 9.1-10). Section properties 2-4 are calculated directly from the composite of the four side panels and bottom casting legs. Section 5 is located at the same elevation as Section 3 and is pinned to it at the ends. It represents the vertical damping of the bottom casting. Fundamental frequencies of this idealized system agree closely with the detail model.

To consider the nonlinear effects of module rocking and sliding and fuel rattling, the ANSYS model is expanded and shown in Figure 9.1-11. The center pole, Section 1, representing the mass and stiffness of all the fuel assemblies extends the height of the rack. It is pinned at the bottom of the rack and is allowed to impact at the top and top quarter point, nodes 1 and 2, and 3 and 4. A 3/8-in. gap on each side occurs at these points, which represents the fuel assembly to can clearance. For worst-case analysis, it is assumed that all fuel in the rack is channeled (thus providing the stiffest section). This transmits the highest impact and overturning loads to the rack. Based upon the stiffness of this member and based on past analysis, fuel-can impact below the top quarter is unlikely, so that the 3/8-in. gap at nodes 5 and 6 will not close. This model conservatively assumed that all fuel assemblies are in phase and move together at all times.

The vertical spring under each leg is known as an "interface element." The interface element represents two plane surfaces that may maintain or break physical contact and slide relative to each other. At each time step, the program compares the horizontal force in the interface element against the coefficient of friction to see if sliding will occur and also allows for uplift and rocking by vertically releasing the element if tensile forces exist in the leg.

A single vertical degree of freedom represents the pool floor under the racks. Its mass is the total pool mass under the area of each rack. The spring rate is calculated to give the same first mode diaphragm frequency as the entire spent fuel floor, water, and racks.

The following assumptions are made relative to the rack submergence in the spent fuel pool:

1. All water entrapped within the rack envelope is added to the horizontal mass but not to the vertical mass.

2. Since the depth of water above the racks is large (greater than 20 ft), surface waves or sloshing effects are ignored.

3. Because the linear dimension of the pool is much smaller than the pressure waves generated by typical earthquakes ($l/\lambda << 1$), water in the pool will move in phase with the ground, provided the walls are rigid. Therefore, external water effects between the rack and the walls are ignored, which conservatively assumes that damping forces generated in "pumping" this confined water from the wall-rack gap as a result of the relative motion of the racks are greater than any added external mass effects of this water.

Figure 9.1-12 represents a two-rack model. It includes all the effects of the single-rack model plus the maximum interaction or potential for banging with other racks in the pool. Gap springs are located at the top and bottom casting elevation and are initially closed.

The coefficients of friction values used in the analysis are based on the following test reports: Simulated Rack Minimum Coefficient of Friction by Programmed and Remote Systems Corp. (PaR) and Friction Coefficients of Water-Lubricated Stainless Steels for a Spent Fuel Rack Facility by Professor Ernest Rabinowicz of the Massachusetts Institute of Technology, performed for Boston Edison Company. In the latter report, results of the 100 tests performed show a mean value of 0.503 with a standard deviation of 0.125. The upper ($x+2\sigma$) and lower ($x-2\sigma$) limits are 0.753 and 0.253, respectively. The values used in this analysis are 0.2 as lower limit and 0.8 as upper limit. Values measured under similar conditions agree closely for both independent tests.

The following freestanding and rack conditions were analyzed:

1. 0.2 coefficient of friction, empty, single rack.

2. 0.8 coefficient of friction, two full racks.

Condition 1 was analyzed to determine maximum displacement of the racks relative to the pool floor. Condition 2 determined the maximum rack loads for the SAP IV static analysis. The coefficients of friction remained constant throughout the time history.

9.1.2.3.3.3.1.2 SAP IV Finite-Element Model

Figure 9.1-13 shows the SAP IV computer model. The PaR Spent Fuel Rack is idealized as a three-dimensional detailed finite-element model of nodal points, consisting of over 400 flexural beam column elements and over 800 plate elements representing the side plates and formed angles.

Only two of the module feet are fixed. Reactions for the other two feet and nodal forces needed to put the rack in equilibrium are developed for worst-load cases from the ANSYS time-history analysis. These horizontal and vertical static forces were applied to the SAP IV model in the same manner as on the ANSYS model. An equal load set was applied in an orthogonal plane. Stresses were computed using the SRSS method for all members and plates for each of these two load sets and compared against their factored allowables.

9.1.2.3.3.3.1.3 Results of Seismic Analyses for the PaR Spent Fuel Racks

Displacements and loads resulting from the response of the PaR racks to seismic events were calculated for simultaneous vertical and horizontal safe-shutdown earthquake motion using conservative time histories as described above. The coefficient of friction is calculated to be greater than 0.2 and less than 0.8 under all conditions, including variations in rack loading and floor smoothness. Decreasing coefficients of friction increase sliding displacements. A conservatively low coefficient of 0.2 was used in determining these displacements. Increasing coefficients of friction increases rack and floor loads, rocking displacements, and rack-to-rack interaction forces. A conservatively high coefficient of 0.8 was used in determining these forces and displacements. The results are as follows:

9.1.2.3.3.3.1.4 Sliding displacement

The maximum sliding displacement of the PaR racks relative to the pool floor was calculated as 1.05 in. This displacement would occur during a condition of minimum friction and would be accompanied by no significant rocking displacement, that is, only pure rigid body sliding occurred.

9.1.2.3.3.3.1.5 Rocking displacement

The maximum rocking displacement of the PaR racks relative to the pool floor was calculated to result in one side of a rack lifting approximately 1 in. off the floor. This displacement would occur during a condition of maximum friction. The feet on the other side of the rack would remain in contact with the floor and very little sliding displacement would occur. Rocking displacements of this magnitude would only be on the outside rows of racks. Rocking displacement of racks on inner rows would be limited by interactions with other racks.

9.1.2.3.3.3.1.6 Rack-to-rack impact loads

The maximum PaR rack-to-PaR rack impact load was calculated as 120,000 lb. This impact load would result from the impact of racks having undergone rocking displacement.

9.1.2.3.3.3.1.7 Foot impact loads

The maximum foot impact load for a PaR was calculated as 276,084 lb. This impact load would occur at each foot of an 11 by 11 rack having undergone rocking displacement. This load would exert a bearing stress of 4838 psi on the pool floor, along with a punching shear stress of 84.5 psi. Allowable DBE stresses are 8806 psi and 344 psi, respectively. The uniform floor loading resulting from foot impact loads would be 2535 psf. This compares to the allowable DBE uniform floor load of 3200 psf.

9.1.2.3.3.3.1.8 Rack member stresses

The stresses in the various members of the PaR rack side plates, castings, and legs were computed and compared to the factored allowable stresses given in Standard Review Plan 3.8.4 (see Table 9.1-3). The most limiting stresses are listed below in terms of the appropriate factored allowable stresses. The symbols used are taken from the Standard Review Plan and are identified on Table 9.1-3. Because the rack poison cans and alignment lugs are not structural members of the racks, stresses for these members have not been computed.

Equation Number	Loading Combination	Factored Allowable Stress Limit	Largest Calculated Interaction Stress: Side Plates	Casting	Legs
1	D + L	1.0	0.219	0.484	0.206
2	D + L + E	1.0	<1.0	<1.0	<1.0
3	D + L + To	1.5	0.226	0.509	0.217
4	D + L + To + E	1.5	<1.5	<1.5	<1.5
5	D + L + Ta + E	1.5	<1.5	<1.5	<1.5
6	D + L + DF				
	Condition 1	1.6	0.299	0.633	0.297
	Condition 2	1.6	0.726	0.513	0.701
	Condition 3	1.6	0.381	1.2	0.278
	Condition 4	1.6	0.024	0.052	0.024
7	D + L + Ta + E	2.0	0.708	1.618	1.16

Note: E = DBE; E = OBE

The analysis discussed above in the ANSYS seismic model is a worst-case analysis for PaR fuel rack loading, but is not the worst case with respect to possible fuel damage due to loss of cladding integrity.

The compressive strength of concrete and the yield strength of reinforcing steel were determined by laboratory analyses of actual samples drawn from each pour of concrete and each heat of reinforcing steel. The most limiting of the results obtained were used as the bases for performing the structural analysis.

As discussed above, a conservative value is assumed for the coefficient of friction in each computation of rack response. Actual rack responses will therefore be bounded by the calculated response regardless of variations in K_f across the floor.

The overall floor load was calculated using the double-rack model shown in Figure 9.1-12. The seismic portion of the floor load was first determined separately from the dead load, using the SRSS method. To accomplish this, the seismic load for each rack pair was determined as a fraction of the dead load (F_S/F_D) using the following relation:

$$F_S/F_D = (F_{max}/F_D) - 1$$

where

F_S = maximum force in floor as a result of seismic load only

F_D = force in floor as a result of dead load only

F_{max} = maximum load calculated

This seismic portion (F_S/F_D) was summed for the total number of pairs of racks in the pool by the SRSS method to obtain the average seismic load as a fraction of dead load $(F_S/F_D)_T$. The total dead plus seismic floor load was then determined by the following:

$$P = (N)(D)[1 + (F_S/F_D)_T]$$

where

N = total number of cavities
D = deadweight of rack plus fuel per cavity
P = total dead plus seismic floor load

9.1.2.3.3.3.1.9 Dropped Fuel Bundle Analysis

Analyses were done to define the equivalent static load for the following drop conditions:

1. 18-in. fuel drop on the corner of the top grid castings and fuel rollover.

2. 18-in. drop in the middle of the top castings.

3. A fuel drop full length through the cavity impacting on the bottom grid.

The following methods were used in defining the impact loads.

For condition 1, the impact energy losses of the inertia of the rack module and the collapsing of the bottom tripod on the fuel bundle fitting were quantified for the 18-in. vertical drop to determine the net impact energy. Using the SAP IV model, spring rates were determined at various impact locations on the module. A static impact load was then determined for each of these locations by equating the elastic structural strain energy balance with the net impact energy. These impact loads have been verified by full-size tests on an actual top grid casting.

For condition 3, an unimpeded fuel drop through an empty cavity, a static load was determined to shear out the bottom fuel support. After shear out, the fuel bundle impacts the pool liner plate. The resulting load is applied to the pool as an interface load.

Equivalent static loads for different dropped fuel bundle cases were then applied at proper locations to the SAP IV finite-element model of the module and combined with the deadweight vertical load (rack full of fuel). Stresses for each member and plate were then tabulated and compared against the factored allowables.

A structural analysis was made to establish the maximum load-carrying capacity of the existing spent fuel pool. This analysis was based on the actual material strength and latest ACI Code requirements (ACI 318-71). A compressive concrete strength of 7400 psi and a yield strength of reinforcing steel of 65,700 psi, as determined from laboratory test reports, were used. The results of the analysis indicated that the maximum live load (including the associated earthquake loading from fuel rack and fuel elements) should not exceed 2.56 x 10^6 lb.

9.1.2.3.3.3.1.10 Pool Interface Loads

Rack leg vertical gap forces are computed for each time step of the analysis. These loads are used to determine the bearing and punching shear stress in the reinforced-concrete floor. The allowable stresses are defined by Section 1.10, "Alternative Design Method," of American Concrete Institute Building Code Requirements for Reinforced Concrete (ACI 318-71). As described in the Commentary to the Code, this section carries forward the working stress design method of ACI 318-63. Under dynamic impact loads, a factor of 1.25 is applied to allowable compressive stress. Information supporting the use of this factor is from a publication entitled Structural Analysis and Design of Nuclear Plant Facilities, prepared by the Committee on Nuclear Structures and Materials of the Structural Division of the American Society of Civil Engineers.

The overall floor load was checked taking the force in the floor spring "K_f" in Figure 9.1-11 and calculating a total for all the racks by an SRSS technique. This load, 2.04×10^6 lb, was compared against floor slab capacity of 2.56×10^6 lb.

9.1.2.3.3.3.1.11 Analysis of Rack and Pool Interaction

The maximum dry weight of the rack is 136 lb/cavity. For an 11 by 11 rack, this amounts to 16,456 lb.

Figure 9.1-8 presents a detail of the leveling foot assembly. A flat ABS plastic sheet separates the steel from the aluminum and is mechanically confined between these parts. The steel and the plastic are fastened to the aluminum with stainless steel bolts. ABS plastic washers on the bolts and oversize holes through the aluminum prevent contact between the aluminum and the bolts.

Calculations show that the plastic will withstand all design loadings while remaining within its elastic limits. The plastic will also withstand temperatures far in excess of the maximum expected without significant changes to the mechanical properties. The plastic will not affect the pool water chemistry and will not be significantly affected by irradiation. In the book Radiation Effects on Organic Materials by R. O. Bolt and J. G. Carrol, 1963 edition, test data of a styrene-acrylonitrile copolymer similar to ABS demonstrated that this material retains up to 80% of its initial strength at a total radiation dose of 10^8 rads. It should also be noted that because of mechanical confinement of the plastic, the integrity of the assembly would be maintained even if the plastic suffered some deterioration or failure such as cracking.

Figure 9.1-14 shows a section view of the underside of the corner of the bottom casting that indicates the water path through the casting into the corner cavity.

9.1.2.3.3.3.2 Holtec Rack Modeling for Dynamic Simulations, 3D-Single Rack Analysis

Spent fuel storage racks are Seismic Class I equipment. They are required to remain functional during and after a Design Basis Event (DBE). The racks are free-standing; they are neither anchored to the pool floor nor attached to the sidewalls. Individual rack modules are not interconnected. Figure 9.1-35 shows a typical module. The baseplate extends beyond the cellular region envelope ensuring that inter-rack impacts, if any, occur first at the baseplate elevation; this area is structurally qualifiable to withstand any large in-plane impact loads.

A rack may be completely loaded with fuel assemblies (which corresponds to greatest total mass), or it may be completely empty. The coefficient of friction, μ, between pedestal supports and pool floor is indeterminate. Analyses are, therefore, performed for coefficient of friction values of 0.2 (lower limit) and for 0.8 (upper limit), and for random friction values clustered about a mean of 0.5. The bounding values of $\mu = 0.2$ and 0.8 have been found to bracket the upper limit of module response in rerack projects at other facilities.

Since free-standing racks are not anchored to the pool slab, not attached to the pool walls, and not interconnected, they can execute a wide variety of motions. Racks may slide on the pool floor, one or more rack support pedestals may momentarily tip and lose contact with the floor slab liner, or racks may exhibit a combination of sliding and tipping. The structural models developed permit simulation of these kinematic events with inherent built-in conservatisms. The rack models also include components for simulation of potential inter-rack and rack-to-wall impact phenomena. Lift-off of support pedestals and subsequent liner impacts are modeled using impact (gap) elements, and Coulomb friction between rack and pool liner is simulated by piece-wise linear (friction) elements. Rack elasticity, relative to the rack base, is included in the model with linear springs representing a beam-like action. These special attributes of rack dynamics require strong emphasis on modeling of linear and non-linear springs, dampers, and compression only gap elements. The term "non-linear spring" is a generic term to denote the mathematical element representing the case where restoring force is not linearly proportional to displacement. In the fuel rack simulations, the Coulomb friction interface between rack support pedestal and liner is typical of a non-linear spring.

Three dimensional dynamic analyses of single rack modules require a key modeling assumption. This relates to location and relative motion of neighboring racks. The gap between a peripheral rack and adjacent pool wall is known, with motion of the wall prescribed. However, another rack, adjacent to the rack being analyzed, is also free-standing and subject to motion during a seismic event. To conduct the seismic analysis of a given rack, its physical interface with neighboring modules must be specified. The standard procedure in analysis of a single rack module is that neighboring racks move 180° F out-of-phase in relation to the subject rack. Thus, the available gap before inter-rack impact occurs is 50% of the physical gap. This "opposed phase motion" assumption increases the likelihood of intra-rack impacts and is, thus, conservative. However, it also increases the relative contribution of fluid coupling, which depends on fluid gaps and relative movements of bodies, making overall conservatism a less certain assertion. Three dimensional Whole Pool Multi-Rack (WPMR) analyses performed indicate that single rack simulations predict smaller rack displacement during seismic responses. Nevertheless, 3-D analyses of single rack modules permit detailed evaluation of stress fields, and serve as a benchmark check for the much more involved WPMR analysis.

Particulars of modeling details and assumptions for 3-D Single Rack analysis and for WPMR analysis are given in the following subsections.

9.1.2.3.3.3.2.1 The 3-D 22 DOF Model for Single Rack Module (Assumptions)

1. The fuel rack structure is very rigid; motion is captured by modeling the rack as a twelve degree-of-freedom structure. Movement of the rack cross-section at any height is described by six degrees-of-freedom of the rack base and six degrees-of-freedom at the rack top. Rattling fuel assemblies within the rack are modeled by five lumped masses. Each lumped fuel mass has two horizontal displacement degrees-of-freedom. Vertical motion of the fuel assembly mass is assumed equal to rack vertical motion at the baseplate level. The centroid of each fuel assembly mass can be located off center, relative to the rack structure centroid at that level, to simulate a partially loaded rack.

2. Seismic motion of a fuel rack is characterized by random rattling of fuel assemblies in their individual storage locations. All fuel assemblies are assumed to move in-phase within a rack. This exaggerates computed dynamic loading on the rack structure and, therefore, yields conservative results.

3. Fluid coupling between rack and fuel assemblies, and between rack and wall, is simulated by appropriate inertial coupling in the system kinetic energy. Fluid coupling terms for rack-to-rack coupling are based on opposed phase motion of adjacent modules..

4. Fluid damping and form drag is conservatively neglected.

5. Sloshing is negligible at the top of the rack and is neglected in the analysis of the rack.

6. Potential impacts between rack and fuel assemblies are accounted for by appropriate "compression only" gap elements between masses involved. The possible incidence of rack-to-wall or rack-to-rack impact is simulated by gap elements at top and bottom of the rack in two horizontal directions. Bottom elements are located at the baseplate elevation.

7. Pedestals are modeled by gap elements in the vertical direction and as "rigid links" for transferring horizontal stress. Each pedestal support is linked to the pool liner by two friction springs. Local pedestal spring stiffness accounts for floor elasticity and for local rack elasticity just above the pedestal.

8. Rattling of fuel assemblies inside the storage locations causes the gap between fuel assemblies and cell wall to change from a maximum of twice the nominal gap to a theoretical zero gap. Fluid coupling coefficients are based on the nominal gap.

9.1.2.3.3.3.2.2 Whole Pool Multi-Rack (WPMR) Model

The single rack 3-D model, outlined in the preceding subsection, is used to evaluate structural integrity, physical stability, and to initially assess kinematic compliance (no rack-to-rack impact in the cellular region) of the rack modules. Prescribing the motion of the racks adjacent to the module being analyzed is an assumption in the single rack simulations. For closely spaced racks, demonstration of kinematic compliance is further confirmed by modeling all modules in one comprehensive simulation using a WPMR model. In WPMR analysis, all racks are modeled, and their correct fluid interaction is included in the model.

9.1.2.3.3.3.2.3 Whole Pool Fluid Coupling

The presence of fluid moving in the narrow gaps between racks and between racks and pool walls causes both near and far field fluid coupling effects. A single rack simulation can effectively include only hydrodynamic effects due to contiguous racks when a certain set of assumptions is used for the motion of contiguous racks. In a WPMR analysis, far field fluid coupling effects of all racks are accounted for using the correct model of pool fluid mechanics. The external hydrodynamic mass due to the presence of walls or adjacent racks is computed in a manner consistent with fundamental fluid mechanics principles using conservative nominal fluid gaps in the pool at the beginning of the seismic event. Verification of the computed hydrodynamic effect by comparison with experiments is also provided. The fluid flow model used to obtain the whole pool hydrodynamic effect reflects actual gaps and rack locations.

9.1.2.3.3.3.2.4 Coefficients of Friction

To eliminate the last significant element of uncertainty in rack dynamic analyses, the friction coefficient is ascribed to the support pedestal / pool bearing pad interface consistent with data at other facilities. Friction coefficients, developed by a random number generator with Gaussian normal distribution characteristics, are imposed on each pedestal of each rack in the pool. The assigned values are then held constant during the entire simulation in order to obtain reproducible results. Thus, the WPMR analysis can simulate the effect of different coefficients of friction at adjacent rack pedestals. The friction coefficients at the interface between rack support pedestals and pool liner is assumed distributed randomly with a mean of 0.5 and permitted to vary between the limits of 0.2 - 0.8.

9.1.2.3.3.3.2.5 Material Properties

Physical properties of the rack and support materials were obtained from the ASME Boiler & Pressure Vessel Code, Section III and appendices. Maximum pool bulk temperature is less than 200° F; this is used as the reference design temperature for evaluation of material properties.

9.1.2.3.3.3.2.6 Results of 3-D Non-linear Analyses of Single Racks

This section focuses on results from all 3-D single rack analyses. The following section presents results from the whole pool multi-rack analysis and discuss the similarities and differences between single and multi-rack analysis.

The racks chosen to be analyzed are Rack G (the rack with maximum aspect ratio), Rack J (the largest rack in the pool), and Rack R (the rack in the cask pit). Altogether, 18 runs are carried out for governing cases using Holtec proprietary computer program DYNARACK. Results are abstracted from output files and presented here for the governing cases. Analyses have been carried out for regular fuel (680 lb. dry weight) and for opposed-phase motion assumption. The chosen racks would be installed in Campaigns II and III.

9.1.2.3.3.3.2.7 Racks in the Fuel Pool

A summary of results of all analyses performed for racks in the pool and in the cask pit as well, using a single rack model, is presented in Reference 5. The tabular results for each run give maximax (maximum in time and in space) values of stress factors at important locations in the rack. Results are given for maximum rack displacements, maximum impact forces at pedestal-liner interface, and rack cell-to-fuel, rack-to-rack, and rack-to-wall impact forces. It is shown that no rack-to-rack or rack-to-wall impacts occur in the cellular region of the racks.

In the single rack analysis, kinematic criteria are checked by confirming that no inter-rack gap elements at the top of the rack close. By virtue of the symmetry assumption discussed in Reference Five, impact is assumed to occur if the local horizontal displacement exceeds 50% of the actual rack-to-rack gap.

Structural integrity at various rack sections is considered by computing the appropriate stress factors. Results corresponding to the SSE event yield the highest stress factors. Limiting stress factors for pedestals are at the upper section of the support and are to be compared with the bounding value of 1.0 (OBE) or 2.0 (DBE). Stress factors for the lower portion of the support are not limiting and are not reported. The analysis shows all stress factors are below the allowable limits.

9.1.2.3.3.3.2.8 Impact Analyses

1. Impact Loading Between Fuel Assembly and Cell Wall

   Local cell wall integrity is conservatively estimated from peak impact loads. Plastic analysis is used to obtain the limiting impact load. Reference 5 compares limiting impact loads with the highest value obtained from any of the single rack analysis. The limiting load is much greater than the load obtained from any of the simulations calculated.

2. Impacts Between Adjacent Racks

   No non-zero impact loads are found for the rack-to-rack gap elements (in the cellular region), or for the rack-to-wall elements; it is concluded that no impacts between racks or between racks and walls are likely to occur during a seismic event. This is confirmed by the WPMR results in Reference 5.

9.1.2.3.3.3.2.9 Weld Stresses

Weld locations subjected to significant seismic loading are at the bottom of the rack at the baseplate-to-cell connection, at the top of the pedestal support at the baseplate connection, and at the cell-to-cell connections. Results from dynamic analyses of single racks are surveyed and maximum loading used to qualify the welds.

9.1.2.3.3.3.2.10 Rack in the Cask Pit Area

The cask area of the fuel pool is a separate pit area with a 108" x 120" horizontal envelope. Analyses have been carried out for a 17 x 19 free standing rack (Rack R) installed in the cask pit area. To evaluate the rack in the cask pit, analysis is performed using fluid gaps between rack and cask pit wall that reflects the actual dimensions of the cask pit area and the rack envelope. Runs were carried out for coefficient of friction of 0.2 and 0.8 and for different rack fuel loading scenarios. From all analyses performed for a spent fuel rack in the cask pit area, the bounding structural and kinematic results are given in Table 6.7.2 of Reference 5.

9.1.2.3.3.3.2.11 Results from Whole Pool Multi-Rack (WPMR) Analyses

Figure 9.1-7B shows the DAEC spent fuel pool with 18 new Holtec spent fuel racks. In the WPMR Analysis, a reduced degree-of-freedom (8-DOF) model for each rack and its contained fuel is employed. The WPRM dynamic model for DAEC contains 144 degrees-of-freedom and requires a non-linear analysis. All racks are assumed to be fully loaded with 680-pound fuel assemblies. Thirty-percent of the fuel load is assumed to be rattling and impacting the rack top.

Table 6.8.1 of Reference 5 shows maximum corner absolute displacements at both the top and bottom of each rack in global x and y direction from the multi-rack runs. As noted previously, a random set of friction coefficients in the range of 0.2 - 0.8 with mean value being 0.5 is used. The seismic loadings are the DBE earthquake time-histories which are the corresponding OBE time-histories multiplied by a factor of 2.0. No non-zero values found for impact indicate that there is no impact between racks and between rack and pool wall during a DBE seismic event. The absolute displacement values are higher than those obtained from single rack analysis. Thus, it appears essential to perform WPMR analyses to verify that racks to not impact or hit the wall. A survey of all of the rack-to-rack and rack-to-wall impact elements confirms that there are no rack-to-rack or rack-to-wall impacts in the cellular region of any rack in the spent fuel pool. The inter-rack gap elements in the whole pool analysis have an initial gap equal to the actual gap.

The WPMR analysis confirms that no new concerns are identified; overall structural integrity conclusions are confirmed by both single and multi-rack analyses. Because the values of all the stress factors obtained for DBE are less than 1.0 and no rack-to-rack / wall impacts are found, it is not necessary to perform the WPMR Analysis for OBE seismic.

9.1.2.3.3.3.2.12 Bearing Pad Analysis

To protect the slab from high localized dynamic loadings, bearing pads are placed between the pedestal base and the slab. Fuel rack pedestals impact on those bearing pads during a seismic event and pedestal loading is transferred to the liner. Bearing pad dimensions are set to ensure that the average pressure on the slab surface due to a static load plus a dynamic impact load does not exceed the American Concrete Institute (ACI-349-85) limit on bearing pressures. Pedestal locations are set to avoid overloading of leak chase regions under the slab. Time-history results from dynamic simulations for each pedestal are used to generate appropriate static and dynamic pedestal loads which are then used to develop the bearing pad size.

The limiting bearing pad size with the maximum liner stress from bearing pad pressure was found to be a 12" x 12" pad. The maximum load was found to be 103500 lbs. The calculated stress to the liner was calculated to be 719 lbs. which is well below the 2380 lbs. allowed. (See Reference Five, Table 6.9.1).

9.1.2.3.3.3.2.13 Refueling Accidents

1. Dropped Fuel Assembly

   The consequences of dropping a fuel assembly as it is being moved over stored fuel is discussed below. It is assumed that the lowest part of the fuel assembly being carried is 18" above the top of the new spent fuel racks. The fuel assembly weighs 680 lbs. and associated handling equipment is assumed to weight 120 lbs.

a. Dropped Fuel Assembly Accident (Deep Drop Scenario)

An 800 lb. fuel assembly plus handling equipment is dropped from 18" above the top of the storage location and impacts the base of the module. Local failure of the baseplate is acceptable; however, the rack design should ensure that gross structural failure does not occur and the subcriticality of the adjacent fuel assemblies is not violated. Calculated results show that there will be no change in the spacing between cells. Local deformation of the baseplate in the neighborhood of the impact will occur, but the dropped assembly will be contained and not impact the liner. Calculations also show that even if there is local cell-to-baseplate weld overstress in individual cells, the maximum movement of the baseplate toward the liner after the impact is at most between .94" and 1.52". The load transmitted to the liner through the support by such an accident is well below the loads caused by seismic events.

b. Dropped Fuel Assembly Accident (Shallow Drop Scenario)

One fuel assembly plus the channel is dropped from 18" above the top of the rack and impacts the top of the rack. Permanent deformation of the rack is acceptable, but is required to be limited to the top region such that the rack cross-sectional geometry at the level of the top of the active fuel (and below) is not altered. Assuming a minimal area of impact, it is shown that damage, if it occurs, will be restricted to a depth of less than or equal to 1.09" below the top of the rack. this is above the active fuel region.

9.1.2.3.3.3.3 Conclusions of Seismic Analysis

The analyses performed show that the PaR and Holtec spent fuel storage racks are capable of withstanding the loads associated with all the design loading conditions without exceeding allowable stresses. The analysis also indicates that the racks can withstand overturning moments and horizontal forces without structural attachment to the pool.

Interface loads transmitted to the fuel pool are within the load-carrying capability of the pool structure, including dropped fuel element loading.

9.1.2.3.4 Summary of Safety Evaluation

The safety evaluation of the spent fuel storage modifications was performed to consider the consequences of modifying the storage racks to accommodate 3152 fuel elements for the purpose of allowing continued operation of the DAEC at its licensed power level without dependence on offsite facilities. The spent fuel pool storage capacity includes storing no more than 323 fuel assemblies in the cask pit if the following requirements are met: 1) The transfer of spent fuel that has decayed less than 5 years to the cask pit is prevented, 2) The cask pit floor drain is sealed, 3) The installation of the gate between the cask pit and the spent fuel pool is prevented, and 4) The transfer of heavy loads over the cask pit if it is utilized to store spent fuel is prevented (see Reference 4). (The actual installation consisted of 2411 storage spaces.)

The evaluation considered all plant features that would be affected by the modification. It was concluded that the changes necessary were limited to storage rack replacement. Supporting systems were determined to be adequate to satisfy the design requirements for the modified conditions. The evaluation confirmed the adequacy of the spent fuel pool cooling and cleanup system, HVAC systems, and structural interfaces, which were included in the mechanical, structural, and criticality considerations. Acceptance criteria for those features that were not modified were based on FSAR commitments. The storage rack itself was analyzed using updated methods and evaluated in accordance with current criteria contained in applicable regulatory guides and NRC positions stated in the Standard Review Plan. This included requirements established for seismic and structural analysis.

The criticality evaluation confirmed that the stored fuel would remain substantially subcritical ($K_{eff} < 0.95$) with a fully-loaded fuel pool conservatively assuming loading of nondepleted fuel. This condition is met for nominal configuration, worst-case clustering due to gaps and fabrication tolerances, and postulated fuel drop locations.

Mechanical evaluation confirmed the acceptability of supporting cooling systems, and structural evaluation verified that the rack could withstand the design bases loading combinations. Interface loads transmitted to the fuel pool are within the load-carrying capability of the structure. The structural evaluation included a seismic analysis equivalent to a three-dimensional excitation using methods that conform to Regulatory Guides 1.60 and 1.61.

9.1.2.4 <u>Inspection and Testing Requirements</u>

The spent fuel storage racks require no special inspection and testing for nuclear safety purposes.

9.1.2.5 Instrumentation

Fuel Pool Water Level Indication is provided in the Control Room and at a local instrument panel. Level is sensed by an ultrasonic sensing element mounted along the north side of the Fuel Pool in a stainless steel 2-inch diameter seven (7) foot long stilling well. The level signal also provides High and Low alarms to the Control Room and local instrument panels.

9.1.3 SPENT FUEL POOL COOLING AND CLEANUP SYSTEM

9.1.3.1 Design Bases

9.1.3.1.1 Power Generation Objective

The power generation objective of the fuel pool cooling and cleanup system is to remove the decay heat and radioactivity released from the spent fuel elements. The system maintains a specified fuel pool water temperature, purity, water clarity, and water level.

9.1.3.1.2 Safety Objective

The safety objective of the fuel pool cooling and cleanup system is to maintain fuel pool water temperature at a level that will prevent damage to the fuel elements.

9.1.3.1.3 Safety Design Basis

The fuel pool cooling and cleanup system is designed to remove the decay heat from the fuel assemblies and maintain fuel pool water temperature for spent fuel storage and refueling operations and to prevent damage to the fuel elements caused by overheating.

9.1.3.1.4 Power Generation Bases

1. The fuel pool cooling and cleanup system minimizes corrosion product buildup and controls water clarity, so that the fuel assemblies can be efficiently handled underwater.

2. The fuel pool cooling and cleanup system minimizes fission product concentration in the water that could be released from the pool to the reactor building environment.

3. The fuel pool cooling and cleanup system monitors fuel pool water level and maintains a water level above the fuel sufficient to provide shielding for normal building occupancy.

9.1.3.2 System Description

The fuel pool cooling and cleanup system is shown in Figure 9.1-15. The system cools the fuel storage pool by transferring the spent fuel decay heat (see Table 9.1-2) through a heat exchanger to the reactor building closed cooling water system. The plant has installed a system cross-tie to allow well water to augment the GSW cooling for the reactor building closed cooling water system. This cross-tie is only used during the GSW out-of-service windows during refuel outages. Water purity and clarity in the storage pool, reactor well, and dryer-separator storage pit are maintained by filtering and demineralizing the pool water through a filter-demineralizer, which is shown in Figure 9.1-16. The system consists of two circulating pumps, two heat exchangers, two filter-demineralizers, and two skimmer surge tanks, all connected in parallel and the required piping, valves, and instrumentation. The pumps circulate the pool water in a closed loop, taking suction from the skimmer surge tanks, circulating the water through the heat exchangers and filters, and discharging it into the fuel pool and through diffusers near the bottom of the reactor well when the well is flooded. The water flows from the pool surface through skimmer weirs and scuppers to the surge tanks. The fuel pool pumps, filter-demineralizers, skimmer surge tanks, and heat exchangers are located in the reactor building.

Fuel pool water is continuously recirculated except during the period when the reactor well and dryer-separator pit are being drained or the FPCCU System is shutdown for maintenance. The heat exchangers are operated to remove the decay heat load from spent fuel to maintain bulk pool temperature at or below 150° F. The operating temperature of the fuel pool is permitted to rise to 150°F maximum when the circulating flow is interrupted to drain the reactor well, or when the system is shutdown. The heat exchangers in the RHR system can be used in conjunction with the FPCCU system to supplement pool cooling when the reactor is shut down, reactor head removed, and fuel pool gates open, and in the event that the bulk pool temperature cannot be maintained at or below 150° F by the FPCCU System. Makeup water for the system is normally transferred from the Condensate Storage Tank to the skimmer surge tanks to make up evaporative and leakage losses. The circulation patterns within the reactor well are established by the placement of the discharge and skimmers so as to sweep particles dislodged during refueling operations away from the work area and out of the pools. The normal flow pattern may be altered by taking suction from the bottom of the dryer-separator storage pit to control particles dislodged from parts transferred to the dryer-separator storage pit. A portable, submersible-type, underwater vacuum cleaner can be used to remove crud and miscellaneous objects from the pool walls and floor.

Pool water clarity and purity is maintained by a combination of filtering and ion exchange. The filter-demineralizer maintains total heavy element content (Cu, Ni, Fe, Hg, etc.) at 0.1 ppm or less with a pH range of 6.0 to 7.5 for compatibility with aluminum fuel racks and other equipment. Particulate material is removed from the circulated water by the pressure precoat filter-demineralizer unit in which a finely divided disposable filter medium is supported on permanent filter elements. The filter medium is replaced when the pressure drop is excessive or the ion exchange resin is depleted. Backwashing and precoating operations are manually controlled from a local panel in the reactor building. The spent filter medium is flushed from the elements and transferred to the waste sludge tanks by backwashing with air and Condensate. The new filter medium is mixed in a precoat tank and transferred as a slurry by a precoat pump to the filter where the solids deposit on the filter elements. The holding pump maintains circulation through the filter in the interval between the precoating operation and the return to normal system operation.

The filter-demineralizer units are designed to operate with water flowing at normal 2 gpm/ft^2 of the filter area. Earth cellulose or powdered ion-exchange resin is used as a filter medium. The holding element for the filter material is a stainless steel mesh, mounted vertically in a tubesheet and replaceable as a unit. Venting is possible from below the tubesheet and from the upper head of the filter vessel. The upper head has a removable manhole for installation and replacement of the holding element. The filter vessel is constructed of Type 304 stainless steel, phenolic resin-coated carbon steel, or material of equivalent structural properties and corrosion resistance. A strainer is provided in the effluent stream of the filter-demineralizers to limit the migration of the filter material. The filter-holding element is capable of withstanding a differential pressure greater than the developed pump head for the system.

The ion-exchange resin typically is a mixture of finely ground, 300 mesh or less, cation and anion resins in proportions as determined by service. The cation resin is a strongly acidic, polystyrene with a divinyl-benzene cross-linkage. The resin is supplied in the fully regenerated hydrogen form. The anion resin is strongly basic, Type I, quaternary ammonium polystyrene with a divinyl- benzene cross-linkage. The resin is supplied in fully regenerated hydroxide form.

The maximum pressure drop across the filter and associated process valves and piping at the time for filter media replacement should not exceed the value shown in Table 9.1-2. A holding pump is connected to each filter-demineralizer. This pump starts automatically to maintain sufficient flow through the filter media to retain it on the filter elements during loss of system flow. The holding flow rate is 0.1 gpm/ft^2 of the filter area. The backwash system is used to completely remove resins and accumulated sludge from the filter-demineralizers with a minimum volume of water. Backwash slurry is drained to the radwaste system waste sludge tank, located in the radwaste building. The precoat system is designed to rapidly apply a uniform precoat of filter media to the holding elements of a filter-demineralizer. The precoat tank is carbon steel coated with phenolic or epoxy materials and sized to provide adequate volume for one precoating.

An agitator is furnished with the tank for mixing. One precoat pump and associated piping and valves are provided to precoat either filter-demineralizer and to recirculate the water to the precoat tank or suction side of the precoat pump at a rate of 1.5 gpm/ft^2 of filter area. The precoat system is also capable of cleaning or decontaminating either filter-demineralizer unit with a detergent or citric acid solution. The two filter-demineralizer units are located separately in shielded cells. Sufficient clearance is provided in the cell to permit the removal of the filter elements from the vessels. Each cell contains only the filter-demineralizer and piping. All inlet, outlet, recycle, vent, drain, and other valves are located on the outside of one shielding wall of the cell, together with necessary piping and headers, instrument elements, and controls.

Penetrations through shielding walls are located so as not to compromise radiation shielding requirements.

The system instrumentation is provided for both automatic and remote manual operations. Fuel Pool level indication is provided in the control room. A Fuel Pool High/Low Level annunciator alarm is also provided in the control room. Surge tank high, low, and low-low switches are provided. The high- and low-level switches alarm in the control room and at a local control panel in the reactor building. Skimmer Surge Tank level indication is provided in the Control Room and to the Plant Process Computer. Local indication is also provided. The low-low-level switch trips the circulating pumps when surge tank reserve capacity is reduced to the volume that can be pumped in one minute with one pump at rated capacity. A level indicator is provided to monitor reactor well water level during refueling. The indicator is mounted on the fuel pool pump rack, which controls flow to or from the reactor well during refueling. A Fuel Pool high-low water level alarm relay operates a local indicator light and sounds an alarm in the control room whenever the level is either too high or too low. The trip point is adjustable over the entire range of Fuel Pool level indication.

The pumps are controlled from a local panel in the reactor building. Pump low suction pressure automatically turns off the pumps. A pump low discharge pressure alarms in the control room and at the local panel. The controls for the remote-controlled valve that discharge the fuel pool water to the condenser hotwell or Condensate storage tank are located on the local control panel. The open or closed condition of each of these valve is indicated by a light on the local panel.

A high rate of leakage through the refueling bellows assembly, drywell to reactor seal, or the fuel pool gates is indicated by lights on the operating floor instrument racks and is alarmed in the control room.

The filter-demineralizers are controlled from a local panel in the reactor building. Differential-pressure and conductivity instrumentation are provided for each filter-demineralizer unit to indicate when backwash is required. Suitable alarms, differential-pressure indicators, and flow indicators are provided to monitor the condition of the filter-demineralizers.

9.1.3.3 Safety Evaluation

The seven cases for decay heat load, transferred to the Spent Fuel Pool (SFP) and the FPCCU System described in 9.1.2.3.2.1, show the possible decay heat removal needs for the DAEC Spent Fuel Pool required by the most recent SFP rerack (1994) and analyses of the early core discharge (1997). In all but Case One, the imposed limit of 150° F bulk pool temperature is exceeded according to the analysis. The RHR System may be operated alone or in parallel with the FPCCU System in the event bulk pool temperatures cannot be maintained at or below 150° F for any decay heat addition scenario. The SFP bulk pool temperature may approach the 150° F limit during cavity drain down or maintenance activities but every effort should be made to keep the temperature at or below the limit of 150° F to mitigate approaching the SFP and storage rack design limits.

A loss of cooling event was analyzed. The event assumes that both the cask pool and reactor cavity drain, resulting in the loss of SFP level and external cooling sources. Forced circulation is assumed to be lost when the SFP level gets to 16 feet above the pool liner (starting at the minimum SFP level of 36 feet). Case C (9.1.2.3.2.1) is the most limiting case analyzed for all of the DAEC discharge scenarios. For Case C, it is demonstrated that the maximum boil-off rate is 52.78 gpm. The analysis also shows that the SFP level can be maintained above the top of active fuel if the makeup water can be initiated within 4.5 hours of the SFP level reaching 16 feet.

A hose connection is provided on the Emergency Service Water (ESW) System on the Refuel Floor as shown in Figure 9.2-5. This ensures a Seismic Class 1 water supply to replace the fuel pool water as it evaporates (boils off).

The flow rate of the fuel pool cooling and cleanup system is designed to be larger than that required for two complete water changes per day of the fuel pool or one change per day of the fuel pool, reactor well, and dryer-separator pit. The maximum system flow rate is twice the flow rate needed to maintain the specified water quality.

There are no connections to the fuel storage pool that could allow the fuel pool to be drained below the pool gate between the reactor well and the fuel pool. The return cooling water supply piping terminates just below the surface of the spent fuel pool.

Flow control valves at the operating floor enable the operator to achieve optimum recirculation patterns to control and maintain the specified water quality and operational conditions.

A suction line and discharge line connect the fuel pool cooling and cleanup system and the RHR system as shown in Figure 9.1-15. The discharge line (from RHR) contains two normally closed manually operated valves, one adjacent to the RHR system and one adjacent to the fuel pool cooling system. The suction line (to RHR) contains one normally closed manually operated valve adjacent to the fuel pool cooling system. The RHR pumps are isolated from the fuel pool cooling system suction line by the shutdown cooling RHR pump suction valves. The interconnecting piping from the RHR system through the second interconnecting valve is designed to Seismic Category I criteria. Fuel pool cooling piping is supported to ensure that it will not fall and damage the interties with the RHR system in the event of a DBE.

Figure 9.1-15 shows the fuel pool cooling and cleanup system and its connections to the RHR system. Both connections to the RHR system are Seismic Category I from the RHR system up to and including the closed isolation valve. In addition, there is a removable spool piece in the 8-in. line GBB-23 downstream of the manual isolation valve in that line. The manual isolation valves in the 8-in. lines HBB-25 and GBB-23 are designated as locked closed valves. This protection ensures that the RHR system will not be degraded by a failure of the non-seismic fuel pool cooling and cleanup system.

The interconnections are used (i.e. the spool piece installed and the isolation valves are open) only at times when the RHR system is in operation in the shutdown cooling mode with the reactor shut down and depressurized or when the LPCI mode of the RHR system is not required to be operable. The RHR system can be used for fuel pool cooling in the unlikely event of a prolonged outage of both fuel pool cooling pumps. More likely, it will be used at times when heat loads in the pool are high. The fuel pool cooling system may be capable of handling such heat loads, but by supplementing that system with the RHR system, more comfortable temperatures can be maintained for the benefit of personnel working in the vicinity of the pool.

The design of the spent fuel pool includes a separate cask pool (Figure 9.1-6). In the unlikely event that the cask were dropped inside the cask pool, there would be damage to the reactor building, but no loss of fuel pool water would occur. In addition, interlocks on the reactor building crane prevent positioning the fuel cask or any other load over the spent fuel pool.

9.1.3.4 Inspection and Testing Requirements

No special tests are required. Routine visual inspection of the system components, instrumentation, and trouble alarms is adequate to verify system operability.

9.1.4 FUEL HANDLING SYSTEM

9.1.4.1 Fuel Servicing Equipment

Two fuel preparation machines are used to strip the channel from spent fuel assemblies and to install the used channels on new-fuel bundles (see Figure 9.1-17). These machines are designed to be removed from the pool for servicing.

A new-fuel inspection stand is used to restrain the fuel bundle in a vertical position for inspection. The inspection stand can hold two bundles. The general purpose grapple, a small, hand-actuated tool used generally with fuel, can be attached to the reactor building auxiliary hoist, jib crane, and the auxiliary hoists on the refueling platform. The general purpose grapple is used to remove new fuel from the vault, place it in the inspection stand, and transfer it to the fuel pool. It also can be used to shuffle fuel in the pool and to handle fuel during channeling.

A channel handling boom with a spring-loaded take-up reel is used to assist the operator in supporting the weight after the channel is removed from the fuel assembly. The boom is set between the two fuel preparation machines. With the channel handling tool attached to the reel, the channel can be conveniently moved between fuel preparation machines.

9.1.4.2 Refueling Equipment

The refueling platform is used as the principal means of transporting fuel assemblies back and forth between the reactor well and the storage pool (see Figure 9.1-18). The platform travels on tracks extending along each side of the reactor well and the fuel pool. The platform supports the refueling grapple and auxiliary hoists. The grapple is suspended from a trolley system that can traverse the width of the platform. Platform operations are controlled from an operator station on the trolley.

The drawings of major refueling and reactor servicing equipment are presented in Figures 9.1-17 through 9.1-25.

The fuel grapple is designed to provide positive indication of fuel bundle engagement and grapple hook closure (see Figure 9.1-19). Proximity switches (for hook closure) and a limit switch, 400 lb. hoist-loaded, for fuel bundle bail engagement, are wired in series to indicating lights. Both switches must be closed up to allow a fuel assembly to be lifted. The design includes a lock tab washer installed as recommended in General Electric SIL No. 125 to maintain proper grapple hook adjustment. The grapple hook is modified per SIL No. 119 recommendations.

Positive indication that a fuel bundle is properly engaged in the fuel grapple is necessary to prevent dropping fuel bundles.

The fuel grapple will ensure the operator that a fuel bundle is properly engaged and that the grapple hook is fully closed, thereby minimizing the potential for a dropped fuel bundle accident. Also, the new grapple hook release bail has been modified per General Electric SIL No. 119 to prevent accidentally engaging a fuel bundle to the grapple hook release bail.

The refueling platform as well as all fuel-handling equipment is designed to Seismic Category I requirements.

9.1.4.3 Refueling Procedures

9.1.4.3.1 Pre-shutdown Preparations for Refueling (Typical)

1. Fuel Moving Plan (FMP) approved by Operations Management.

2. As new fuel is received, it is inspected and placed in the new-fuel storage vault or the fuel pool storage racks.

3. Refueling reactor servicing equipment is checked out.

4. Confirmation is made that the demineralized and/or condensate water supply is sufficient for filling the reactor well and dryer-separator storage pit.

5. Communications between the control room and refueling area are tested to ensure that they are in proper working order.

9.1.4.3.2 Post-shutdown Preparations for Refueling (Typical)

NOTE: The information listed below is typical of the activities necessary to prepare the Reactor for refueling. Actual sequences are determined by outage schedules.

1. Depressurize and cool (not <74°F) the reactor.

2. Remove reactor well shield, using reactor building crane, and store in designated area.

3. Remove shield blocks from fuel storage pool canal.

4. Purge primary containment with air.

5. Remove drywell head.

6. Remove the following piping, as necessary:

    a. Nitrogen vent extension pipes.

    b. Reactor vent pipe.

    c. Reactor instrument pipe.

7. Remove reactor vessel head insulation and temperature detectors.

8. Detension reactor vessel head bolts.

9. Remove reactor vessel head and place on head holding pedestal.

10. Remove and store vessel studs (typically four).

11. Attach dryer-seoarator sling (strongback), remove and store steam dryer (can be performed with reactor cavity drained or flooded).

11a. Remove and store fuel pool gates while completing cavity floodup.

12. Install underwater lights where necessary.

13. Install Main Steam Line Plugs.

14. Detension shroud head bolts.

15. Attach dryer-separator sling (strongback) to steam separator and shroud and raise it slightly.

16. Flood reactor well and dryer-separator storage pit (if not already removed).

17. Lift steam separator and shroud to storage.

18. Remove and store fuel pool gates (if not already removed).

19. Set up spent fuel pool cooling system to service the dryer-separator storage pit and the reactor well, as needed.

20. Recheck all critical path procedures to ensure they include the following:

    a. Adequate communications between the control room and refueling personnel.

    b. Checkout of refueling platform and its facilities for standby condition.

    c. All necessary tooling and equipment for fuel handling should be in place and in readiness for refueling operations.

9.1.4.3.2.1 Post Refueling Operations in Preparation for Startup

1. Confirm reactor has been refueled and fuel assembly positions verified.

2. Complete invessel work and inspections.

3. Install Fuel Pool Gates if cavity is to be drained to transfer steam dryer.

4. Transfer Steam Separator to the reactor.

5. Latch Steam Separator in place.

6. Remove Main Steam Line Plugs.

7. Transfer steam dryer to reactor.

8. Install Fuel Pool gates is cavity is still flooded.

9. Drained down cavity(if not performed earlier).

10. Install and tension Reactor head.

11. Install insulation head and associated piping.

12. Install Drywell head.

13. Install equipment pool, fuel transfer slot, and reactor cavity sheild blocks.

9.1.4.3.3 Refueling Operations

When verification has been made that the reactor and all refueling equipment and appurtenances are in readiness and administrative requirements of Section 9.1.4.3.1 above have been completed, refueling operations are initiated. These operations involve the removal of spent fuel assemblies and either reshuffling these fuel assemblies back into the core or replacing them with new-fuel assemblies as described below.

9.1.4.3.3.1 Spent Fuel

Spent fuel assemblies are those assemblies in which the reactivity burnup has been too high to permit their replacement in the reactor core for further power operation. These assemblies are stored in the spent fuel storage racks in the fuel pool.

9.1.4.3.3.2 Shuffled Fuel

Shuffled fuel is that fuel that is moved out of the reactor core, placed in the spent fuel storage racks in the fuel pool, or reloaded into the core in another location. This relocation position is based on a determination of fuel burnup and core physics calculations.

9.1.4.3.3.3 New Fuel

New-fuel assemblies are removed from the storage vault racks and placed in the fuel pool storage racks in preparation for reactor core loading. These fuel assemblies are loaded into specific locations in the core based on core physics calculations.

9.1.4.3.3.4 Fuel Assembly Orientation

Fuel assembly orientation is very important when performing core alterations. Fuel assembly identification is verified by its location in the core or spent fuel pool. These locations are used in lieu of verifying actual fuel assembly serial numbers. Administrative controls exist to account for the location of special nuclear material. Fuel assembly identification and orientation are verified each time it is moved as part of a core alteration.

9.1.4.3.4 Failed Fuel Inspection Operations

In the event that there is positive indication that significant fuel leakage has occurred during plant operations, the following inspection procedures may be implemented.

9.1.4.3.4.1 Sipping

With regard to "sipping," fuel assemblies in the core are water sampled in order to determine whether or not the assemblies contain failed fuel rods. The water samples are analyzed for iodine-131 (I-131) and iodine-132 (I-132), and concentrations of these isotopes are compared with an analyzed reactor water sample. If the I-131 and I-132 levels are higher than the level of the reactor water sample, the fuel assembly is considered as a suspected failed fuel assembly.

9.1.4.3.4.2 Suspect Fuel

When the suspect failed fuel assembly is removed from the reactor core, it will be placed in a fuel storage rack in the spent fuel pool.

9.1.4.3.4.3 Inspection in Fuel Pool

After suspect failed fuel assemblies are stored in the fuel storage racks, these assemblies may be subjected to nondestructive examination.

The channel and upper tie plate may be removed. Suspect fuel rods may be individually examined by nondestructive techniques (such as eddy current techniques) to detect holes or cracks and by ultrasonic techniques to detect moisture inside the fuel rod. Occasionally, a detected failed rod will be visually inspected by the use of underwater visual aids such as a television, camera, boroscope, or a periscope.

9.1.4.3.4.4 Reconstitution of Failed Fuel Assemblies

After nondestructive examination and visual inspections are performed on suspect fuel assemblies and all of the failed fuel rods are identified, the data are analyzed and calculations may be made for the reconstitution of fuel assemblies. This is the replacement of defective fuel rods with sound rods so as to permit continued irradiation of the assembly. Factors to be considered for the exchange of rods between fuel assemblies are as follows:

1. Reactor core burnup calculations

2. Type of pellets.

3. U-235 enrichment.

4. Rod traverse burnup modes.

Reconstituted fuel assemblies may be reloaded into the core. The unsalvageable failed fuel assemblies will be stored in the spent fuel storage racks for cooling.

9.1.4.4 Procedures and Plant Systems for Movement of Heavy Loads

9.1.4.4.1 Overhead Handling Systems

The following overhead handling systems and equipment are those at the DAEC from which a load drop could result in damage to irradiated fuel, plant shutdown systems, or decay heat removal systems:

1. Reactor building crane.

2. Turbine building crane.

3. Recirculation pump motor hoist.

4. Drywell Shield Blocks and personnel air lock hoist.

5. Fuel pool demineralizer area hoist.

6. Steam valve area monorails.

7. Drywell maintenance hoists.

8. Spent fuel pool gamma-scan collimator port hoist.

9. Torus monorail.

The DAEC program for inspection, testing, and maintenance of overhead and gantry cranes satisfies the criteria of Guideline 6, NUREG-0612, Section 5.1.1(6), which states that the crane should be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI-B30.2-1976, Overhead and Gantry Cranes, except that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI-B30.2 for periodic inspection and test, or where frequency of crane use is less than the specified inspection and test frequency.

The reactor building crane meets the requirements of NUREG-0554[2] and NUREG-0612,[3] as specified in the DAEC's responses to Generic Letters 81-07, 83-42 and 85-11.

9.1.4.4.2 Special Lifting Devices

The design of the special lifting devices in use at the DAEC has been compared with ANSI-N14.6-1978 criteria related to component design and load handling reliability. They were all shown to comply with the ANSI criteria after modifications were made to the vessel head strongback to provide safety margins of 10 to 1. Maintenance and testing are performed on these lifting devices in accordance with ANSI-N14.6-1978, Section 5 requirements.

9.1.4.4.3 Load Handling Procedures

The DAEC complies with the guidance of NUREG-0612 for the control of heavy loads. Procedures are in effect that prohibit movement of heavy loads over the spent fuel pool.

Specific procedures are provided for the handling of loads by the reactor building crane above the reactor building refueling floor which include the following:

1. Identification of required equipment.

2. Inspections and acceptance criteria required before movement of a heavy load.

3. The steps and proper sequence to be followed in handling the load.

4. Safe load paths for the movement of heavy loads.

General load handling procedures are provided for the handling of loads by the reactor building crane, turbine building crane, and the other overhead handling systems in the vicinity of safe shutdown equipment. The procedures contain safe load path drawings that show the location of all safe shutdown equipment, safe shutdown piping, and safety-related conduit and cable trays.

The procedures require that a crane signalman/supervisor direct heavy load movement according to the safe load path drawings. Crane operator training, qualification, and conduct is supported by administrative controls consistent with Chapter 2-3 of ANSI-B30.2-1976, Overhead and Gantry Cranes.

9.1.4.4.4 Movement of Heavy Loads During Refueling

Table 9.1-4 contains a list of all objects that are required to be moved over the reactor core during refueling. Table 9.1-5 is a list of all objects that are required to be moved over the spent fuel pool. Currently, procedures prohibit movement of heavy loads over the spent fuel pool.

Spent fuel racks are not located in the area where the pool gates are moved and hung. The cranes are equipped with interlocks to prevent any other load from passing over the spent fuel pool.

The reactor building with its entire lifting system is designed to Seismic Category I criteria as described in Section 3.8. Consequently, a postulated drop of the reactor vessel head onto the opened reactor vessel or the dryer-separator assembly into an opened reactor vessel due to hardware failure or procedural error is considered incredible. The consequences of dropping the reactor vessel head while it is in a position over the vessel would be damaging to the reactor vessel closure studs, and in some cases, cause damage to the sealing surfaces on both the vessel and vessel head. In all cases, no direct or indirect contact with the fuel would be possible, as the top of the fuel bundles are 27 ft below the vessel flange and the size of the vessel head (with respect to the vessel flange area) with all the possible orientations in the drop would not permit it to impact the fuel.

The consequences of dropping the dryer assembly onto an opened reactor vessel would be damaging to the reactor closure studs if the dryer impacted against them. If the dryer were directly over the vessel, the falling assembly would pass by the closure studs and impact upon the guide rods which control the azimuth position of the dryer and finally upon the dryer support blocks on the vessel wall. Again, no direct or indirect contact with the fuel bundles would be possible.

9.1.4.4.5 Spent Fuel Cask Movement

Figures 9.1-26 and 9.1-27 show the physical relationship between the reactor, the fuel transfer canal, the steam dryer and separator storage pool, the spent fuel storage pool, and the cask pool. The reactor building crane will be used to move any spent fuel cask used to transport spent fuel or irradiated components from the cask pool to the reactor building equipment hatch for subsequent shipment to a disposal site. The reactor building crane has been upgraded to a single failure proof design in accordance with NUREG-0554. Additionally, limit switches are installed which prevent the crane from inadvertently being moved over the spent fuel pool or the reactor cavity. Safe load paths are also employed which identify the path of load travel which in the unlikely event of a load drop would have the least impact on safety related equipment. The physical design of the DAEC Refuel Floor does not require a spent fuel cask to be lifted over irradiated fuel. A separate cask pool has been provided which is used for cask loading operations. The cask is typically staged in the Reactor Head wash down area. It is then moved to the cask pool for loading and then moved back to the Reactor Head wash down area for decontamination and preparation for shipment. At no time is the cask lifted over irradiated fuel.

Secondary Containment shall be operable if the fuel cask is being moved in the reactor building. Fuel cask movement shall be suspended in the reactor building if Secondary Containment becomes inoperable.

Secondary Containment isolation valves/dampers shall beoperable if the fuel cask is being moved in the reactor building. Fuel cask movement shall be suspended if a secondary containment isolation valve/damper inoperable and the associated penetration is open.

The SBGT system shall be operable if the fuel cask is being moved in the reactor building. If one train of SBGT inoperable and is not restored within the completion time, reactor building fuel cask movement shall be suspended.

For certain cask designs, rigging which meets the single failure proof criteria of ANSI-N14.6 cannot be installed on the cask until the cask has been upended and removed from the transporter and lowered to the reactor building 757'-6" floor. During this evolution the cask rigging does meet a safety factor of 5 to 1; however, it will not meet the single failure proof requirements of ANSI-N14.6. For this evolution the cask shall only be lifted in the area of the floor directly supported by the corner room wall below. Lift height of the cask while in this configuration shall be limited to that required to clear the cask transporter to support loading and unloading of the cask. For all other cask movements, from the 757'-6" elevation up to the Refueling Floor and back, and to and from the cask pool, the consequences of a load drop have been determined to be unacceptable. A single failure proof load handling system shall therefore be employed. This shall consist of the Reactor Building Crane and rigging which conforms to the single failure proof criteria of ANSI-N14.6 by either providing redundant load paths or by providing a safety factor of 10 to 1 when comparing the actual load to the ultimate breaking strength of the rigging. By employing these criteria, the probability of a load drop is sufficiently small that it is not considered to be a credible event, and as such, DAEC's commitments to NUREG-0612 are satisfied.

9.1.5 TOOLS AND SERVICING EQUIPMENT

9.1.5.1 Introduction

Tools and servicing equipment required for boiling water reactor (BWR) general servicing provide for efficient, safe serviceability in a minimum of time. Table 9.1-6 is a listing of tools and servicing equipment supplied with the nuclear system. The paragraphs below describe some of the major tools and servicing equipment for the following:

1. Fuel servicing equipment.
2. Servicing aids.
3. Reactor vessel servicing equipment.
4. In-vessel servicing equipment.
5. Refueling equipment.
6. Storage equipment.
7. Under reactor vessel servicing equipment.

The fuel servicing equipment and refueling equipment are described in Section 9.1.4.

9.1.5.2 Servicing Aids

General area underwater lights are provided with a suitable reflector for downward illumination. Lights can be supported by suitable support brackets in the reactor vessel to allow the light to be positioned over the area being serviced independent of the platform. Local area underwater lights are small diameter lights for additional downward illumination. Drop lights are used for intense radial illumination where needed. These lights are small enough in diameter to fit into fuel channels or control blade guide tubes.

A portable underwater television camera and monitor are part of the plant optical aids. The transmitted image can be viewed on the refueling platform. This assists in the inspection of the vessel internals and general underwater surveillance in the reactor vessel and fuel storage pool. A general purpose, clear plastic viewing aid that will float is used to break the water surface for better visibility.

A portable, submersible-type underwater vacuum cleaner is provided to assist in removing crud and miscellaneous objects from the pool floor or the reactor vessel. The pump and the filter unit are completely submersible for extended periods. Fuel pool tool accessories are also provided to meet servicing requirements.

9.1.5.3 Reactor Vessel Servicing Equipment

Reactor vessel servicing equipment is provided for the safe handling of the vessel head and its components, including nuts, studs, bushings, and seals.

The head strongback is used for lifting the drywell head and the vessel head. The strongback is designed to keep the head level during lifting and transport (see Figure 9.1-25). It is cruciform in shape with four equally spaced lifting points. The strongback is designed such that no single component failure would cause the load to drop or to swing uncontrollably. It has also been modified to meet higher safety margin criteria than originally designed to comply with the guidelines of NUREG-0612. The strongback has been proof-tested to 150% rated capacity.

A vessel nut handling tool is provided. This tool handles one nut at a time and features a spring device to lift the nut and clear the threads.

The head holding pedestals are designed to properly support the reactor vessel head and permit reactor o-ring removal and replacement and seal surface cleaning and inspection (see Figure 9.1-22). The mating surface between vessel and pedestal is selected to minimize the possibility of damaging the vessel head.

9.1.5.4 In-Vessel Servicing Equipment

The instrument strongback is attached to the reactor building crane auxiliary hoist and is used to lift replacement in-core detectors. The instrument handling tool is attached to the in-core detector by the personnel on the refueling floor. The strongback initially supports the in-core detector into the vessel. Final incore insertion is accomplished with the instrument handling tool. The instrument handling tool is attached to the refueling platform auxiliary hoist and is used for removing and installing fixed incore detectors as well as handling neutron sources and the source range monitor/intermediate range monitor dry tubes.

In the unlikely event that incore guide tube flange O-rings need replacing, an incore guide tube seal and a test plug are provided. The guide tube seal seats on the beveled guide tube entry in the vessel. When the drain on the spring reel is opened, water drains from the incore housing and guide tube; hydrostatic pressure seats the guide tube seal and allows the flange to be removed. The incore guide tube seal contains a bail, similar to the control rod and fuel bail. A fuel bail cleaner is provided to brush the bails and improve bundle number legibility.

The one-half ton auxiliary hoist can be used with appropriate grapples to handle control rods, flux monitors, sources, and other internals of the reactor. Interlocks on both the grapple hoist and auxiliary hoists are provided for safety purposes; the refueling interlocks are described and evaluated in Section 7.6.2.

9.1.5.5 Storage Equipment

Specially designed fuel storage racks are provided. Additional storage equipment is listed in Table 9.1-6. For fuel storage racks' description and fuel arrangement, see Sections 9.1.1 and 9.1.2.

Defective fuel assemblies may be placed in damaged fuel containers, which in turn are normally stored in the defective fuel storage racks. Each can is adaptable for individual sipping. For channel removal, the can may be removed from the rack and placed in the fuel preparation machine where the can cover is removed. Before shipment, the sipping head is removed and the shipping lid is installed. Provisions for dry sipping are provided. This system allows for the detection of leaking fuel pins in the fuel pool during refueling.

Fuel sipping techniques and equipment have been improved over the years. Several nuclear services providers are available to perform the "sipping" of nuclear fuel. The use of their equipment and procedures will be reviewed prior to implementation.

9.1.5.6 Under Reactor Vessel Servicing Equipment

The necessary equipment to remove several control rod drives during a refueling outage is provided. An equipment handling platform with a rectangular open center is provided. This platform can rotate to provide space under the vessel so the control rod drive can be lowered and removed. A control rod drive facile is used during drive removal; it is a rubber boot that clamps on the drive flange and directs water from the drive to the sump. A thermal sleeve installation tool is used to rotate the thermal sleeve within the CRD housing. Sleeve rotation permits disengagement of the guide tube. A rope and pulley integral with the tool permits complete sleeve removal. Special tools and instruments to service and test individual control rod hydraulic units are also provided.

Miscellaneous wrenches, a tapering tool, and a flaring tool are provided to install and remove the neutron detectors. The spring reel pulls the fixed incore detector string into the incore guide tube and also seals the opening in the incore flange during incore servicing. A drain can be opened after incore insertion to drain any residual water. Correct seating of the incore string is indicated when drainage ceases.

Undervessel servicing equipment can be provided by several nuclear services vendors. Their equipment is of the same form and function as the equipment at the DAEC but it has been modified to perform the tasks more efficiently. The equipment and procedures used by these vendors is reviewed and approved by DAEC personnel prior to their use.

Additional nuclear system tools and servicing equipment not covered in these paragraphs are listed in Table 9.1-6.

9.1.5.7 Dryer-Separator Pool Seal

During a refueling outage, the dryer and separator assemblies are placed in the dryer-separator pool. The dryer-separator storage pool may be filled with water to reduce radiation exposure for people on the refueling floor. The dryer-separator pool seal prevents leakage of water between the dryer-separator storage pool and the reactor cavity when the storage pool is flooded and the reactor cavity is drained for servicing.

REFERENCES FOR SECTION 9.1

1. Letter from Thomas A. Ippolito, NRC, to Duane Arnold, Iowa Electric, Subject: Amendment No. 45 to Facility License No. DPR-49 for the Duane Arnold Energy Center, dated July 7, 1978.

2. U. S. Nuclear Regulatory Commission, Single-Failure Proof Cranes for Nuclear Power Plants, NUREG-0554, May 1979.

3. U. S. Nuclear Regulatory Commission, Control of Heavy Loads at Nuclear Power Plants, NUREG-0612, July 1980.

4. Letter from Robert M. Pulsifer, NRC, to Lee Liu, IES Utilities, Subject: Amendment No. 195 to Facility License No. DPR-49 for the Duane Arnold Energy Center, Dated February 2, 1994.

5. Holtec Report, HI-92889, Licensing Report for Spent Fuel Storage Capacity Expansion DAEC, transmitted to NRC along with RTS-252, NG-93-0566, dated March 26, 1993.

6. Letter from K. Young, IES Utilities, to W. Russell, NRC, dated November 15, 1994, NG-94-3874.

7. Holtec Report, HI-971746, Thermal Hydraulic Evaluation of the DAEC Spent Fuel Pool with RHR Intertie, transmitted to NRC along with RTS-296, NG-97-1578, dated October 3, 1997.

8. Holtec Report, HI-971708, Criticality Safety Evaluation of the Spent Fuel Storage Racks in the Duane Arnold Energy Center for Maximum Enrichment Capability, dated August, 1997.

9.2 WATER SUPPLY SYSTEMS

9.2.1 WELL WATER SYSTEM

9.2.1.1 Design Bases

9.2.1.1.1 Power Generation Objectives

The power generation objectives of the well water system are to provide cooling water for all the plant ventilation cooling units, supply potable water for the plant requirements, and supply the required water for demineralizer makeup. Discharge from the plant ventilation cooling units is reused for cooling water in the offgas recombiner, offgas glycol refrigeration unit, and the containment N_2 compressor.

9.2.1.1.2 Power Generation Design Basis

The design is based on using the well water to remove heat from the components during startup, normal operation, shutdown, and cooldown and to discharge the water into the circulating water system as part of the makeup for that system.

9.2.1.2 Description

9.2.1.2.1 General

The system consists of four independent wells. Two have a 750-gpm pump capacity, one has a 1200-gpm pump capacity, and one has a variable speed pump with a maximum output of 1650 gpm (see Figure 9.2-1). Well number 1 is approximately 1500 ft southwest of the reactor building. Well number 2 is approximately 2000 ft north of well number 1, well number 3 is approximately 720 ft south of well number 1, and well number 4 is approximately 1500 ft northeast of the reactor building. All four production well locations are shown in Figure 11.2-8. All are located away from the plant. The supply headers from each well join one main supply header before entering the plant.

One of these wells is supplied from glacial deposits at a depth of 140 ft and is sealed to prevent the collection of the less desirable ground water from the more shallow aquifers. The other three wells are supplied by the deeper Devonian/Silurian formations and are also sealed. A discussion of the ground water in the site vicinity is presented in Section 2.4.13.

Should radwaste enter the ground water at the plant, it would flow away from the wells toward the river.

A backflow preventer is provided to ensure that contaminated water cannot flow into the wells or into the potable water system. The backflow preventer is shown in Figure 9.2-1.

During startup, normal operation, shutdown, and cooldown, combinations of one, two, or three pumps will be in service. The flow from the wells in service will normally be 1200 to 1500 gpm.

During startup, normal operation, shutdown, and cooldown, the well water system with the selected pump(s) in operation will supply the following equipment:

Note: The GPM shown adjacent to the plant equipment are nominal values for reference only. These numbers vary with system demand, winter or summer and/or day or night operation.

1. Plant ventilation cooling water.

   a. Drywell cooling units (six either train and two additional), 268 gpm, or 448 GPM with all the coolers inservice.

   b. Main plant air cooling coils, 480 gpm.

      Control building chillers (two).*

   c. Air compressors (three)

      1) Control Building/SBGT air compressors (two)*

      2) Backup instrument air compressor

   d. Control-rod drive (CRD) room coolers (two), 40 gpm total.

   e. Radwaste building cooler, 44 gpm.

   f. Reactor building cooler, 25 gpm.

   g. Recombiner room cooler, 40 gpm.

   h. Condenser area coolers (two), 160 gpm.

* Control building chillers and air compressors 1K3 and 1K4 are supplied by water discharged from the main plant air cooler, 480 gpm at 66°F.

An electrically operated gate is provided at the mouth of each of the intake channels to control the amount of sand transported into the pump pits from the river channel. Each of these radial gates may be raised or lowered by means of a hoist as required to maintain an acceptable differential between river water level and sand control gate position. A sand jet line, supplied with flow by its corresponding screen wash pump or an external connection, is also provided for each sand control gate. This line is used to flush away any sand which might accumulate around a gate and hinder its movement.

A manually operated gate is provided between the two pump pits so that either screen may serve either or both pump pits. A 24-in. line is provided to deliver either cooling tower blowdown or the entire output of the RHR and emergency service water system to flood the bar screens for de-icing.

The four river water pumps deliver water through two lines to a stilling basin supplying the RHR and emergency service water systems wet-pit pump sumps to maintain these sumps at their safe operating level at all times. An overflow weir in the stilling basin makes the excess flow available as makeup to the circulating water system and general service water system. Water for one method of radwaste dilution is made available by branch connections from each of these 24-in. pipelines located immediately upstream of the flow control valves at the entrance of the lines to the stilling basin. A valve in each branch connection and a valve in the common radwaste dilution header automatically close on drywell high pressure or low reactor water level or low wet-pit sump level to ensure an adequate supply of water for the RHR and emergency service water systems. An alternative method of radwaste dilution is provided by the return flow from the RHR and emergency service water systems.

The RHR and emergency service water systems are discussed in Section 9.2.3.

Water supply requirements for the river water system are as follows: Accident requirements are 4080 gpm for the RHR service water system and 756 gpm for the emergency service water system for a total requirement of 4836 gpm. (This is based on required minimum flows. Actual flows may be as high as 6000 gpm based on actual ESW and RHRSW pump performance.) During normal operation, the river water supply requirements are dependent on evaporative dissipation from the cooling towers and cooling tower blowdown, which are variable. The maximum requirements are expected to be 7000 gpm for evaporative dissipation and 4000 gpm for blowdown for a total of 11,000 gpm.

9.2.2.3 Safety Evaluation

On a Loss-of-Offsite Power, the running river water pump will be automatically load shed as essential bus voltage drops to less than 20%. When the bus is re-energized, the pump selected for automatic start will start immediately if it was not previously running. If the pump selected for automatic start was previously running, 2 minutes must elapse between pump trip and pump restart in order to ensure that the pump column has drained. A 2 minute timer in the pump control logic provides this protection. Valves at the pump house will go to their fail-safe position and ensure that the entire output is available to the safeguard system. Alternative or standby pumping capacity is available by manually connecting the idle pumps to the essential buses.

9.2.2.4 Testing and Inspection Requirements

As part of the plant normal preventive maintenance activities, the river water system will be periodically inspected during service. Pumps and auxiliary equipment can be maintained, put into service, and tested without affecting the system operational objectives. The frequency and scope of periodic maintenance of the pumps and equipment will be in accordance with plant practices, manufacturer's recommendations and operating history.

The DAEC has conducted an evaluation effort in response to IE Bulletin 81-03 and determined that there are no Corbicula (Asiatic clam) and Mytilus (mussel) present in the vicinity of the DAEC that could cause flow blockage problems of the DAEC cooling water systems. In order to detect the possible intrusion of these organisms into the system in the future, the DAEC conducts a sampling program of the intake structure, cooling tower basin and discharge canal on a semiannual basis. See References 2 and 3 for details.

9.2.2.5 Instrumentation Requirements

Instrumentation is provided at the intake structure to measure river water level and temperature. Excessive level differential across the screen will be alarmed in the control room.

9.2.3 RHR SERVICE WATER AND EMERGENCY SERVICE WATER SYSTEMS - (FIGURES 9.2-5 AND 9.2-6)

9.2.3.1 Design Bases

9.2.3.1.1 Safety Objectives

The safety objectives of the RHR service water system are to provide a reliable supply of cooling water for heat removal from the RHR system under postaccident conditions and supply a source of water if postaccident flooding of the core or primary containment is required.

The safety objective of the emergency service water system is to provide a reliable supply of cooling water to essential safeguards equipment under a loss-of-offsite-power condition or LOCA.

9.2.3.1.2 Safety Design Bases

1. The emergency service water system uses Cedar River water to provide long-term cooling for the essential safeguards systems both during and following the design-basis accident. The RHR service water system uses river water to remove heat from the primary containment under post-accident conditions. Both systems have the capability to return the water either to the cooling towers or directly to the river (if necessary), via the circulating water system.

2. For each of the two systems, two completely independent cooling water loops are provided to ensure redundant service water supply for emergency mode operation.

3. A normally closed cross-connection is provided between the RHR service water system supply header and the RHR system. Flow in this cross-connection is accomplished by opening two remotely operated, key-locked valves in series with a check valve, which prevents backflow from the RHR system to the RHR service water system.

4. The two emergency service water pumps (1P-99A and B, Figure 9.2-6) start automatically, in combination with the emergency core cooling systems following a design-basis LOCA or loss of offsite ac power. The RHR service water pumps (1P-22A, B, C, and D, Figure 9.2-6) can be started after adequate core cooling has been ensured as described in Section 8.3.

9.2.3.1.3 Power Generation Objectives

The power generation objective of the RHR service water system is to provide cooling water to the RHR heat exchangers during conditions of normal shutdown and cooldown.

The power generation objective of the emergency service water system is to provide cooling water to all emergency equipment except the RHR heat exchangers.

9.2.3.1.4 Power Generation Design Bases

1. During normal cooldown and shutdown, the design is based on discharging the water from both systems through the 24-in. HBD-32 to the circulating water system to remove heat from the systems.

2. To ensure that radioactive fluids are not released into the Cedar River or the circulating water system, the pumps of the two systems have sufficient head to maintain design flow through the RHR heat exchangers and the emergency equipment coolers, with the cold-side pressure exceeding the component hot-side pressure.

9.2.3.2 Description

9.2.3.2.1 RHR Service Water System

The RHR service water system provides coolant only for the RHR heat exchangers. A cross-connection (12-in. line GBB-22 in Figure 9.2-5) to the RHR system provides capability for core or containment flooding. The system consists of two independent and redundant trains each containing one full-size RHR heat exchanger supplied by two half-size RHR service water pumps. Each half-size RHR service water pump is rated at 2400 gpm at 674 ft total developed head. Analysis has shown that this rated flow of RHR service water is more than adequate to allow the RHR system to meet its design-basis requirements of 2040 gpm in the shutdown cooling mode (References 4 and 5).

The duty for each heat exchanger during the DBA mode is 51.3 x 10^6 Btu/hr using 95°F river water. During this mode, two RHR service water pumps are in service to supply the 4080 gpm river water flow which exceeds the required flow.

During normal shutdown, the two RHR heat exchangers and the four RHR service water pumps must be in service to achieve reactor cooldown to 125°F within 20 hr, and the RHR service water supply temperature must be 85°F or less. For temperatures over 85°F, the cooldown time will be extended accordingly. The design maximum river water temperature is 95°F. During normal shutdown, one RHR heat exchanger and two RHR service water pumps are capable of bringing the reactor to cold shutdown (reactor coolant temperature less than 212°F) in 20 hr following reactor trip using 95°F river water.

River water temperature data taken over a 29-yr period revealed only 8 days when the river water daily mean temperature exceeded 90°F. Data covering the highest recorded river water temperature over a 31-day period indicated a maximum temperature variation of 10°F in a 24-hr period, a 10.5°F daily mean temperature variation during a 31-day period, and a maximum daily mean temperature of 93.3°F. This 31-day period contained 5 days when the daily mean temperature exceeded 90°F. This data was recorded downstream of the City of Cedar Rapids. The DAEC is located 18 miles upstream of the City of Cedar Rapids.

River water temperature is measured at the DAEC at the inlet to the river water supply pump located in the Intake Structure. This temperature is monitored in accordance with the Technical Specifications.

To ensure against radioactive releases into the Cedar River or the circulating water, when the RHR service water pumps are running, the pressure of the RHR service water on the tube-side discharge will be maintained at a minimum of 20 psi higher than the process fluid on the shell-side inlet of the heat exchanger. This is accomplished by a valve controlling the RHR service water discharge on the tube side of each heat exchanger. The heat exchanger contains a be started until loads are shed from the emergency power system. During this period, suppression pool water is being discharged into the reactor vessel through the shell side of the RHR heat exchanger, and the differential-pressure controllers (PDIC 1947 and 2046) are sensing a negative differential pressure and therefore signaling the 14-in. motor-operated valves to go to the fully closed position.

In the event of a heat exchanger tube leak, a radioactive release would be detected as the RHR service water discharge is monitored by a process radiation monitor which will alarm in the control room on high radiation. The operators would then take action to terminate the release.

The RHR and emergency service water systems obtain their water from the pump house, which is supplied with water from the river by the river water supply system.

These water supply systems are completely redundant and therefore meet the single-failure criterion. The delineation of Seismic Category I/Nonseismic piping interfaces is shown in Figures 9.2-2 and 9.2-5 as denoted by the symbol . The piping for the river water system runs from the river intake structure to the pump house, and that for the RHRSW and emergency service water systems runs from there to the reactor building. The intake structure and the reactor building are Seismic Category I structures and the Seismic Category I portion of the pump house is shown in Figure 9.2-7. The piping runs for this piping are shown in Figures 9.2-8 through 9.2-11.

Additionally, the service water flow in each of the two redundant discharge headers downstream of the heat exchangers is measured and transmitted for flow indication in the control room.

9.2.3.4 <u>Testing and Inspection Requirements</u>

As part of the plant normal preventive maintenance activities, the RHR service water and emergency service water systems will be periodically inspected during service. Pumps and equipment can be maintained, put into service, and tested without affecting the system operational objectives. The frequency and scope of periodic inspection and maintenance of equipment will be in accordance with normal plant practices, manufacturer's recommendation and operating history.

The tests and inspections of the river water, RHR service water and emergency service water systems as listed in the Technical Specifications will not affect the availability of the redundant trains of these systems, except for the short periods required for testing the motor- or air-operated valves in either the supply or discharge header of each system. The required tests will be scheduled on a one-train-at-a-time basis, ensuring that one train of either system will always be available.

In case of a loss of offsite power during testing, the fail-safe features ensure the availability of both redundant trains of all three systems.

9.2.3.5 Instrumentation Requirements

9.2.3.5.1 RHR Service Water System

The flow capacity and discharge temperature in the RHR service water system are indicated and recorded, respectively, in the control room.

The differential pressure required between the tube-side discharge and the shell-side inlet of the RHR heat exchangers is also indicated in the control room.

Pressure-differential switches, located adjacent to each of the two RHR heat exchangers, initiate an alarm in the control room if the differential pressure between the primary fluid (shell) side and the service water (tube) side of either of the two heat exchangers drops below 20 psi.

In addition, the service water flow in each of the two redundant discharge headers downstream of the heat exchangers is measured and transmitted for flow indication in the control room.

Local pressure gauges are located on the discharge headers of the RHR and emergency service water pumps.

9.2.3.5.2 Emergency Service Water System

There are four valves and one flow element in each loop of the ESW system provided to balance the flow to each of the nine cooling units in each loop. These facilitate balancing the system with the different cooling requirements for each unit, by getting a dP indication for the control building chiller and RHR and core spray pump room unit, which are major users of the emergency service water system.

A pressure switch, located on each of the two pump discharge headers, initiates an alarm in the control room if the header pressure, because of system leakage, drops below a preset minimum required pressure.

The emergency service water pumps are located in the pump house. Leakage from these pumps and related pipe headers will drain into the pump house sump. This sump will be emptied by two sump pumps into the pump house wet pits. A high sump level alarm is annunciated in the control room.

9.2.4.3 Safety Evaluation

The general service water system is not safety related.

9.2.4.4 Testing and Inspection Requirements

As part of the plant normal preventive maintenance activities, the system is periodically inspected during service. Pumps and equipment can be maintained, put into service, and tested without affecting the system operational objectives. The frequency and scope of periodic maintenance and inspection of equipment is in accordance with normal plant practices, manufacturer's recommendation and operating history.

9.2.5 REACTOR BUILDING COOLING WATER SYSTEM

9.2.5.1 Design Bases

9.2.5.1.1 Power Generation Objective

The power generation objective of the reactor building cooling water system is to provide for the cooling of equipment in the reactor building, which may contain or have the potential to contain radioactive fluids.

9.2.5.1.2 Power Generation Design Bases

1. The design is based on using general service water for heat removal from this closed-loop system (Section 9.2.4).

2. The reactor building cooling water system is designed to meet flow requirements for startup, normal operation, and shutdown.

3. A spare pump and heat exchanger are provided to ensure design capacity in case of failure of the equipment in service.

4. The possibility of radioactivity being released from the plant is minimized.

5. System corrosion and fouling of heat exchangers are minimized by the use of inhibited demineralized water.

9.2.5.2 Description

The reactor building cooling water system is a closed cooling water system using inhibited demineralized water as the heat transfer medium to cool reactor auxiliaries. The system is designed to prevent reactor water contamination and is monitored to detect radioactive leakage into the system. Heat rejection is to the general service water system (Section 9.2.4).

The reactor building cooling water system consists of a forced-circulation closed loop, which contains three heat exchangers and three pumps (see Figure 9.2-13). The system provides coolant for the following equipment:

1. Drywell equipment drain sump cooler.

2. Reactor water cleanup nonregenerative heat exchangers (two).

3. Reactor building sample cooler.

4. Turbine building sample cooler.

5. Radwaste building sample cooler (two).

6. Fuel pool heat exchangers (two).

7. CRD pump coolers (two).

8. Reactor cleanup recirculating pump seal coolers (two).

9. Reactor recirculation pump heat exchangers (two).

10. Reactor building equipment drain sump heat exchanger.

11. Postaccident sampling system sample cooler.

Normally, two pumps and two heat exchangers are in service. For reactor cooldown and loss of offsite power, only one heat exchanger and one pump are required. The three pumps are connected to the essential buses; two pumps are on one bus and one pump is on the other. The pumps are automatically disconnected from the essential buses by a signal initiated by a LOOP-LOCA, but may be manually reconnected when power is available.

Inhibited demineralized water is circulated through the closed loop at a pressure lower than the reactor coolant. Therefore, any leakage will be into the reactor building cooling water system from the listed items 2, 6, 7, 8, 9, and 10 above. The return header is monitored continuously to detect any radioactive leakage.

An expansion tank is provided to accommodate system volume expansion and contraction. Inhibitors are added at the chemical feed tank, and makeup water from the demineralized water storage tank is added to the expansion tank located at the system high point. Provision for manual filling is provided and a low-level condition is alarmed.

9.2.5.3 Safety Evaluation

The reactor building cooling water system is not safety related.

9.2.5.4 Testing and Inspection Requirements

The reactor building cooling water system is periodically inspected during service. The spare pump and heat exchanger can be maintained and put into service and tested without affecting the system operational objectives. The frequency and scope of periodic maintenance and inspection of the pumps, pump motors, and heat exchangers is carried out in accordance with normal plant practices, manufacturer's recommendations and operating history.

9.2.5.5 Instrumentation Requirements

Local temperature indicators are provided in the outlet connections of all equipment heat exchangers and in the cooling water supply header.

The closed cooling water pumps have suction and discharge local pressure gauges. The pressure of the cooling water is indicated in the control room.

9.2.6 CONDENSATE STORAGE AND TRANSFER SYSTEM

9.2.6.1 Design Bases

9.2.6.1.1 Power Generation Objective

The power generation objective of the condensate storage and transfer system is to store the condensate required for the operation and servicing of the nuclear power plant and to transfer this condensate for the various services.

9.2.6.1.2 Power Generation Design Bases

1. The condensate storage facilities are designed to supplement the storage capacity for demineralized water during the preoperational periods when the demands for demineralized water for chemical cleaning, flushing, and initial filling will exceed the regular demineralized water storage capacity.

2. The condensate storage tanks are designed to provide sufficient capacity for refueling, normal service, and emergency demand. These requirements are as follows:

a. (1) Volume required to fill the reactor vessel from normal level to the vessel flange.

(2) Volume required to fill the basin cavity.

(3) Volume required to fill the slot.

(4) Volume required to fill the transition from the basin cavity to the slot.

(5) Volume required to fill the dryer separator pool.

The total volume for filling the fuel pool is 287,000 gal.

b. Normal service requirements

Normally, the water required for refueling is in the condensate storage tanks and may be considered available for satisfying the requirements for regular plant operation. These requirements are for filters, filter-demineralizers, waste centrifuges, radwaste and nuclear system flushing, radwaste tanks, and pump seals.

However, during the refueling process, an additional allowance must be made. For each tank this comprises

(1) A volume equal to the volume of one waste sample tank (10,000 gal).

(2) A volume equal to the largest of any normal service demand (i.e., 3000 gal for condensate backwash).

(3) Freeboard of 30% of allowances (1) and (2).

Each condensate storage tank will have a normal service volume of 17,000 gal.

c. Emergency demand

The storage tanks have an approximate 75,000-gal total reserve for the RCIC system and the HPCI system.

Table 9.2-1
EMERGENCY SERVICE WATER FLOW REQUIREMENTS[a]

Equipment	River Water Temperature				Flow for 3 ft/sec tube velocity
	95°F	90°F	85°F	80°F	
Diesel-generator	402	310	310	310	625
RHR and Core Spray room cooler	115	114	56	38	75*
RCIC room cooler	12	10	10	10	30
HPCI room cooler	16	16	16	16	50
Control Building Chiller	199	132	100	82	250
RHR pump seal coolers (two)[b]	0	0	0	0	N/A
Core spray pump motor cooler	1	1	1	1	1.5
Heating and ventilation instrument air compressor	1	1	1	1	1
RHR service water pump motor coolers	4	4	4	4	3
Total flow	756	594	504	468	1041.5

* The required flow is greater than the 3 ft/sec flow for river temperatures over 85°F.

[a] Flow rates are given in gallons per minute for various river water temperatures.

[b] The cooling water flow is not required to support any RHR operating mode.

- Excess flow check valve closure and reset capability are provided in the Control Room, along with position indication.

- Emergency shutdown buttons are provided to immediately isolate the hydrogen system. The oxygen system will be shut down after a 12 minute time delay. Air addition , if in service, will continue to operate to ensure that all excess hydrogen has had time to reach the offgas system.

The effect of hydrogen injection is monitored by instruments which measure electrochemical corrosion potential and crack growth rate. Sensors located outside the drywell are exposed to reactor coolant from a recirculation loop sample line. To verify that they were exposed to conditions which are representative of those in the primary system, additional sensors were placed in the recirculation piping and in-core via LPRM assemblies. These additional sensors are no longer in use. See Section 7.6.1.6.3.

9.3.6 ZINC INJECTION (GEZIP) SYSTEM

9.3.6.1 Description

GE Nuclear Energy has developed a system to inject zinc into the BWR primary system called GEZIP (General Electric Zinc Injection Passivation). The GEZIP process maintains trace quantities of ionic zinc in the reactor water for the purpose of reducing radiation buildup by maintaining/reducing CO-60 buildup on primary system surfaces.

The GEZIP system, SUS 63.01, consists of a zinc addition skid that is designed to inject trace amounts of Depleted Zinc Oxide (DZO) into the feedwater during normal plant operation. The system consists of a simple recirculation loop off of the feedwater system. The zinc solution is obtained by passing a stream of feedwater from the feedwater pumps' discharge header tap located on the 757ȁ elevation of the turbine building by the feedwater regulating valves. This feedwater then goes through a dissolution vessel containing pelletized DZO located on the 736ȁ elevation in the turbine building basement next to the turbine lube oil conditioner. The feedwater dissolves the pellets as it passes through the zinc vessel carrying the dissolved DZO into the feedwater pumps' suction header located on the condenser bay mezzanine. Manual valves are used to control feedwater flow to the reactor. Instrumentation associated with the skid includes a calibrated flow meter, a differential pressure indicator, and a temperature indicator.

9.3.7 NOBLE METAL CHEMICAL ADDITION

9.3.7.1 Description

Noble Metal Chemical Addition (NMCA) is a process used to inject noble metals into the reactor coolant to enhance the effectiveness and efficiency of Hydrogen Water Chemistry (HWC) in mitigating Intergranular Stress Corrosion Cracking (IGSCC) in Boiling Water Reactor (BWR) vessel internals. In addition, use of NMCA allows lowering injection rates of HWC which in turn reduces radiation exposure to plant personnel.

NMCA treatments have been applied into the DAEC's reactor coolant in an effort to mitigate IGSCC in the reactor vessel internals. 10CFR50.59 Safety Evaluations are performed to address implementation of the NMCA process to ensure that it does not create an unreviewed safety question within the context of 10CFR50.59. The reactor water limits in the Technical Requirements Manual have also been changed to allow application of the NMCA (References 4 through 9).

Noble metal monitoring equipment was installed during the 1996 refuel outage under Engineering Change Package 1573 to monitor the effectiveness and efficiency of the NMCA treatment (Reference 7).

REFERENCES FOR SECTION 9.3

1. General Electric Company, Anticipated Transient Without Scram (ATWS) Response to NRC Rule 10CFR50.62, GE/NEDE-31096-P, December 1985.

2. General Electric Company, Assessment of ATWS Compliance Alternatives, GE/NEDC-30921, March 1985.

3. General Electric Company, Duane Arnold ATWS Assessment, GE/NEDC-30859-1, March 1985.

4. IES Utilities Inc., RTS-290, Reactor Water Conductivity Limit Change for Noble Metal Chemical Addition, NG-96-1297, July 5, 1996.

5. IES Utilities Inc., Noble Metal Chemical Addition 10CFR50.59 Safety Evaluation, SE 96-07, August 1996.

6. IES Utilities Inc., 10CFR50.59 Safety Evaluation for Noble Metal Pretreated Fuel Pins, SE 96-09, August 1996.

7. IES Utilities Inc., Noble Metal Chemical Addition Monitoring Equipment, Engineering Change Package 1573, October 3, 1996.

8. IES Utilities Inc., TRMCR-004, October 20, 1999.

9. IES Utilities Inc., 10CFR50.59 Safety Evaluation for 2nd Noble Metal Chemical Addition, SE 99-046, August 1999.

the condenser and heater bays by way of a duct to the main plant exhaust plenum. Turbine exhaust is mixed with air from other plant areas and then discharged to the environs via the main plant ventilation stack by three exhaust fans, each of which is rated at 50% of the design rated flow. The turbine building areas of the highest potential contamination (the air ejector room, the condensate backwash room, etc.) are exhausted via a special exhaust system which directs its' flow to the offgas stack during normal operation. The system consists of two redundant 100% capacity fans. Should a Group 3 isolation occur, the standby gas treatment system makes use of common ductwork to the offgas stack and exhaust flow from this system may be interrupted.

In the event of a Group 3 isolation concurrent with a main plant ventilation stack high radiation level alarm, the normal air flow patterns in the turbine building will be altered. The main plant ventilation stack exhaust fans are isolated to prevent bypass of the SGTS filter units by air from the reactor building via the main plant ventilation stack. The turbine building roof exhaust system will continue to operate to provide a monitored release point for the turbine building ventilation system. The turbine building supply fans will be isolated to keep the turbine building at a negative pressure with respect to the environs.

Fresh air makeup to this building is filtered by units rated at a minimum of 80% to 85% average efficiency by the ASHRAE test. Heating coils in the main supply air plenum temper the air during cold weather. Air is supplied to different areas of the building by supply duct systems and differential- pressure flow.

9.4.3.3 <u>Inspection and Test Requirements</u>

The air distribution system for the turbine building was tested in accordance with Associated Air Balance Council procedures and balanced to provide design air quantities at each outlet to a tolerance of +10% -0%. The hydronic system was also tested and balanced.

9.4.4 CONTROL ROOM VENTILATION SYSTEM

9.4.4.1 Design Bases

Refer to Sections 9.4.1.1 and 9.4.6.1.

9.4.4.2 System Description

The control room air-conditioning system has two normal modes of operation controlled from Panel 1C-26. The system can operate in a recirculation mode which will provide 1.2 air changes per hour. The system also has a fresh air (purge) mode which will provide six air changes per hour. The source of intake air is remote from potential contamination. See Figures 9.4-7 and 9.4-8.

Fresh air makeup is filtered during normal operation by filters rated at a minimum of 80% to 85% average efficiency by the ASHRAE test. Should fission products leaving the main stack reach ground level during a brief atmospheric fumigation, air radiation monitors will isolate the normal ventilation path and initiate high-efficiency filtration of incoming outside air.

Two 1000 cfm single-pass high-efficiency filter trains are provided in parallel with the normal outside air inlet duct. The filter trains each consist of inlet and outlet isolation dampers, a heating coil, high-efficiency particulate absorber (HEPA), charcoal filter (2-in. bed, tray-type), and final HEPA filter.

Control room air is recirculated through dust filters and heated or cooled as necessary to maintain comfortable working conditions. Power for the filtration-recirculation system may be supplied from the emergency bus. The filtration-recirculation system is Seismic Category I and is located in a Seismic Category I structure.

Two types of ductwork systems distribute air from the filter trains. One supply system is connected to the cable spreading room below the control room floor and supplies cooling air directly to the space. The other supply system is for general space cooling and consists of ductwork supplying ceiling diffusers and air flows upward through the central panels, out to the

9.4.6.1.2 Safety Design Bases

1. The system is designed to protect the safeguards equipment against overheating.

2. The system is provided with redundant components for reliable operation.

3. Power supply to appropriate cooling and ventilating equipment is provided from the standby power supply system during loss of offsite power supplies.

4. All equipment is designed to withstand the DBE motions without impairing system function.

9.4.6.2 System Description

Engineered safeguards heating and ventilation systems are provided for the following areas:

1. Control, emergency switchgear, and battery rooms.
2. Standby diesel-generator rooms.
3. Pump structure emergency cooling water pump rooms.
4. Reactor building RHR, RCIC, HPCI, and core spray rooms.

9.4.6.2.1 Control, Emergency Switchgear, and Battery Rooms

The system consists of an air supply, a return system, and an exhaust system. Supply air to the switchgear rooms is recirculated while that to the battery room is exhausted to the atmosphere. Supply air is filtered and tempered with heating coils as required. The equipment is installed in a Seismic Category I structure. The ventilation system continues to operate during accident conditions, including loss of offsite power supply. System controls are located on a local panel, and in the control room back panel area. Redundant fans are provided for reliable system operation. See Figure 9.4-7.

In the event of loss of ventilation in the emergency switchgear rooms during shutdown of the control building ventilation system due to fire, an alternative ventilation path is established to cool the Division II switchgear room. This ventilation path is established by opening security doors and manually energizing two permanently mounted fans. These fans are provided with power from the emergency bus and provide air flow from the control building through the Division I and II switchgear rooms into the turbine building.

9.4.6.2.2 Standby Diesel-Generator Rooms

Each standby diesel-generator room is provided with a ventilation air supply fan and a suitable means of exhaust. Heating is provided for equipment freeze protection. The ventilation system is supplied with standby power during loss of offsite power supplies. See Figure 9.4-5.

9.4.6.2.3 Emergency Cooling Water Pump Rooms

The pump rooms housing the RHR service water pumps and emergency service water pumps are provided with ventilation supply and exhaust systems. Heating is provided for equipment and piping freeze protection. The ventilation system is supplied with standby power during loss of offsite power.

Supply fans introduce filtered air through roughing and medium-efficiency filters into the pump house to remove excess heat generated by equipment. The air is mostly recirculated and is tempered by mixing return air with outdoor air to maintain design temperature.

Two physically separated Seismic Category I supply fans supply cooling air to the area where the RHR service water pumps and the emergency service water pumps are located. One supply fan is used to provide cooling air to each division of RHR service water and emergency service water pumps. These fans are connected to the emergency bus. When a fan operates, the exhaust louvers automatically open to permit exhaust.

The heating of the pump house for freeze protection is by electric unit heaters.

9.4.6.2.4 Reactor Building RHR, RCIC, HPCI, and Core Spray Pump Rooms

The pump rooms for the RHR, RCIC, HPCI, and core spray systems are provided with ventilation supply air. Fan coil units using Emergency Service Water are used to limit pump room temperatures during accident conditions. Heating is provided for equipment and piping freeze protection. The fan coil units are supplied with emergency power during loss-of-offsite-power events. See Figures 9.4-3 and 9.4-4.

A non-essential cooling system was added in the HPCI and RCIC rooms to maintain the normal operation temperatures below the 104°F limit. This system supplements the normal building ventilation when the emergency coolers are not in service. The chiller for this additional system is located south of the HPCI building. The chiller provides glycol to the non-essential cooling units and exhausts heat directly to the atmosphere. The fan coil units and associated piping and ductwork for this system, within the HPCI and RCIC rooms, were

All yard fire hydrants, automatic and manual water suppression systems, and interior fire hose lines are supplied by the fire loop. Sectionalizing valves of the post indicator type are provided on the fire loop to provide flexibility during an impairment of the loop. All hydrant leads have curb box valves for hydrant isolation. Hose stations and automatic systems are generally fed off separate feeds into the various buildings. All post indicator and OS&Y gate and butterfly valves in the fire water piping systems are administratively controlled with the use of locks and/or seals. Periodic inspections are used to verify that the valves are in the proper position.

Yard fire hydrants have been provided at approximately 250-ft intervals around the exterior of the plant. An isolation valve is provided on each lateral to permit hydrant isolation and maintenance without removing a portion of the fire loop from service. A hose trailer is provided at a central location and is equipped with hose, nozzles, adapters, and other fire-fighting tools. The hydrant hose threads are compatible with the local fire department but are not compatible with the Cedar Rapids fire department. Hose adapters are provided for the Cedar Rapids fire department.

Interior Hose Stations

Interior hose stations, each equipped with between 50 and a maximum of 100 ft of 1.5-in. woven jacket rubber-lined hose, have been provided throughout the plant except in the primary containment and torus areas. One inch booster reels with low-capacity nozzles are provided at the entrance to the essential switchgear rooms and in the Control Room back panel area.

Covers are provided for the interior hose stations throughout the plant to protect the hose from dust, oil, water, and for ease of identification.

Hose nozzles in the turbine building, reactor building, pump house, radwaste building, reactor building, railroad airlock, offgas recombiner room, machine shop, and the control building are equipped with a quick-acting ball straight-valve which allows the fire fighter to select the setting-fog, spray or straight stream-prior to discharging water.

Hose nozzles in the training center, data acquisition center, both warehouses, administration building, technical support and the LLRPSF are either ball valve or twist type that require the fire fighter to pass through a fog pattern setting before selecting a spray or straight stream pattern.

Spare coils of hose are provided at hose stations near the containment when it is deinerted.

Water Suppression Systems

Sprinkler, deluge and preaction systems have been provided to cover specific and area hazards. These areas of coverage include portions of the turbine building, machine shop area, radwaste building, LLRPSF, control building, warehouses, reactor building, training center, and the PSC. The actuation of each system sounds an alarm in the control room or at a security control station.

Water suppression systems are supplied by connections to the plant yard main. Manual hose stations have independent connections to the yard main. Fire suppression systems have been designed and installed in accordance with sound engineering principles using some of the following as guidance: National Fire Protection Association (NFPA) Standards, industry experience, manufacturer's recommendations and discussions with the NRC or insurance carriers, as appropriate. Since installation, periodic inspections and testing of the systems have been performed.

In the event that automatic initiation is lost for suppression systems identified in Table 9.5-1, compensatory measures will be implemented in accordance with DAEC Fire Plan Operability Requirements.

Curbing is provided in the diesel-generator rooms to contain possible oil spillage within the area covered by the sprinklers.

The turbine building basement (elevation 734 ft) contains turbine lube-oil storage facilities. Curbing is provided around all tanks to contain possible spillage within the area covered by the deluge and sprinkler systems and protect safety-related cables routed through the north area of the turbine building from exposed fires.

Effects of Suppression Systems on Safety Systems

Inadvertent operation of a fire suppression system will not adversely affect redundant safety-related equipment. A low-flow capacity hose station with hose nozzle shutoff is provided

9.5.1.2.3.3 Portable Fire Extinguishers

Portable dry chemical and carbon dioxide fire extinguishers have been distributed throughout the plant. The fire extinguishers meet the requirements of the NFPA. The primary areas that initially rely on portable carbon dioxide extinguishers are the control room and the switchgear rooms. The concentrations of carbon dioxide that would be in these rooms after the discharge of the portable extinguisher are not sufficient to cause asphyxiation.

A large-wheeled Halon unit is provided for the control room. This extinguisher provides extended throw and duration for potential fires.

Additional portable extinguishers are provided at the primary containment when it is deinerted.

9.5.1.2.4 Ventilation Systems and Breathing Equipment

Smoke and heat vents are provided in the turbine building roof. The primary coolant recirculation pump M-G sets are located in a room isolated from the remainder of the reactor building and the exhaust duct from this area provides gravity venting. Louvers in the exterior wall for the diesel-generator rooms provide smoke venting for these areas. Other areas of the plant do not have ventilation systems that are designed specifically for smoke and heat removal. The normal air handling systems in most areas can be used for smoke removal; however, their effectiveness may be limited.

Portable smoke ejectors are available for fire brigade use. Louvered vents are provided at the floor and ceiling level of the diesel-generator day tank room to provide gravity venting.

Seven self-contained air-breathing apparatuses (SCBA) are located in the control room and 10 additional units are located near the access control area. On-site recharge capability is provided for the SCBA cylinders.

Additional air bottles are available such that two spare bottles exist for each apparatus. Sixteen air bottles are readily available for the seven apparatuses located in the control room. The complement of air-breathing apparatuses, spare air bottles, and recharge capability is sufficient for a period of 6 hr for seven people at a usage rate of three air bottles per hour per person.

9.5.1.2.5 Floor Drains

Floor drains have been provided in areas protected by automatic water suppression systems. Drains are also provided in all areas where manual hoses are likely to be used with the exception of the control building. The control equipment in cabinets in the control room is elevated 3 to 4 in. above the floor. In these areas, fire water will be drained out through the door openings. Drains from the turbine building are directed to an oil separator. The drains from the diesel-generator rooms and the auxiliary boiler room are provided with backflow valves before their connection to the rest of the drainage piping from other spaces. In areas where expected water buildup could cause system damage, the equipment is provided with pedestals that elevate the equipment above the expected buildup.

9.5.1.2.6 Lighting Systems Required for Fire Protection

The normal lighting system receives its power from the station auxiliary transformers. Upon the loss of these power sources, standby sources are made available from the station batteries, dedicated batteries or the diesel-generators to provide an uninterrupted supply of power. These features ensure that lighting is continuous for emergency conditions. See Section 9.5.3 for additional lighting description.

There is fixed emergency lighting consisting of individual units with 8-hour self-contained battery power supplies for Appendix R Safe shutdown manual actions. Fixed emergency lighting with self-contained batteries is also provided for plant exit lighting. See section 9.5.3 for additional details.

High-intensity, battery-operated portable lighting units are provided for emergency and fire brigade use.

9.5.1.2.7 Communications Systems

The primary line of communications would be through the use of the plant paging system, which is strategically located throughout the plant site. As a backup, the intra-plant telephone system would be used. This system allows direct dialing between all plant telephones. Additionally, various radio-based equipment can be used for mobile communications to some areas of the plant and site. The communications systems are further described in Section 9.5.2.

9.5.1.2.8 Electrical Cables

The electrical cables used in the plant consist mainly of ethylene-propylene insulation with a neoprene jacket. The flame test standard for cables, IEEE Standard 383, was not in effect at the time cables were purchased and installed at the facility. The fire protection system gives due consideration to the combustibility of cables. Section 8.3.3 provides more information on cables installed at the DAEC.

(Reference 1) and meets or exceeds the requirements of NFPA-27, except that the fire brigade training sessions are held at least four times per year instead of monthly as suggested in NFPA-27.

9.5.1.3 Alternate Safe Shutdown Capability

The DAEC has an alternative shutdown capability permitting safe shutdown of the plant in the event that the main control room becomes unusable because of a design-basis fire in the control room fire area. This system is the Alternate Shutdown Capability System (ASCS) which is described in Section 7.4.2. The basis for NRC-approval of the ASCS at the DAEC is discussed in Section 13.7.

9.5.1.4 Evaluation of Hydrogen Hazard

Three possible sources of hydrogen exist at the DAEC; the plant batteries, the hydrogen used to cool the main generator, and the hydrogen injected into the feedwater to control water chemistry. In addition to hydrogen, a liquid oxygen source is also used for water chemistry.

The prevention of hydrogen fires and explosions due to hydrogen accumulation is accomplished by maintaining adequate ventilation in these areas at all times. In addition, the generator hydrogen system maintains hydrogen pressure at about 45 psi and alarms when purity concentration in the generator falls below about 90%. Additional above-building venting at other possible points of gas accumulation and a vented shield pipe on the hydrogen line to the building preclude hydrogen fires.

The risk of fires or explosions due to releases of hydrogen or oxygen from the water chemistry injection piping is prevented by excess flow check valves in the supply lines at the entrance to the turbine building, supply system isolation on high H_2 flow, area hydrogen monitors that automatically isolate supply at concentrations below combustible limits and automatic hydrogen supply isolation upon actuation of turbine building feed pump or lube oil area deluge systems.

Hydrogen is supplied from a remote storage facility that is located more than twice the recommended distance from the nearest safety related structure (Reference 3). Oxygen is supplied from a liquid oxygen storage tank located outside the east wall of the turbine building. The tank is located in accordance with the recommended separation distances of NFPA 50 and is separated from the main and auxiliary transformers by concrete fire walls.

A vane-type air-flow switch has been installed in each of the exhaust outlets for the battery rooms. A common alarm will be annunciated in the control room to indicate a no-flow condition in one of the rooms. Physical inspection will determine the individual exhaust outlet not functioning, prompting early correction of the condition.

Smoke detectors located in the battery rooms alarm in the control room, and a fire hose station and a portable dry-chemical fire extinguisher are located outside the rooms.

9.5.1.5 Safety Evaluation

The DAEC fire protection systems and features are designed to detect, confine and control or extinguish fires at DAEC. The fire protection system includes one diesel-driven and one motor-driven fire pump. Fire pumps are started automatically or manually. Each pump has adequate operating characteristics to supply water at required pressure to the highest point in the plant. Valving is so arranged that a single break in the discharge piping will not remove both pumps from service. The well water and general service water systems provides a measure of backup to the fire water system.

Sprinkler, deluge and preaction systems have been provided to cover specific and area fire hazards. The actuation of each system sounds an alarm in the control room or at a security control station. Inadvertent operation of a fire suppression system will not adversely affect redundant safety-related equipment. Failure of the suppression and fire system piping has been evaluated to determine the effects on safety-related equipment.

Plant buildings are metal and concrete construction with fire walls and/or shield walls to isolate critical areas or equipment. Fire areas utilize separation or barriers to prevent the spread of fire and to permit the isolation of the fire area. Oil storage areas are isolated with fire walls and/or shield walls. Curbs or walls contain any oil leakage in the oil tank areas, diesel-generator rooms, reactor recirculation pumps motor-generator (M-G) room and the reactor feed pump area. Floor drains have been provided in areas protected by automatic water suppression systems. Drains are also provided in all areas where manual hoses are likely to be used with the exception of the control building.

Smoke and heat ventilation systems are provided in the turbine building roof, M-G set room, diesel-generator rooms and the diesel-generator day tank room. Other areas of the plant do not have ventilation systems that are designed specifically for smoke and heat removal. The normal air handling systems in most areas can be used for smoke removal. Portable smoke ejectors are available for fire brigade use. Self-contained air-breathing apparatuses (SCBA) are located in the control room and near the access control area. On-site recharge capability is provided for the SCBA cylinders.

Most combustible materials are stored in special areas in the yard and are located remotely from the plant. Combustible materials stored in the plant are controlled via the FHA methodology for permanent combustibles or the plant transient combustible control program. The types of chemical fire extinguishers located in a particular area are appropriate for the types of fires that might occur.

Several fire detection and signaling systems are provided that transmit alarm and supervisory signals to the control room or at a security alarm station. Supervisory signals are provided to indicate the locations of the affected areas or units. Fire and smoke detection systems generally do have backup power supplies. Fire detection systems for the charcoal filters and safety related areas are equipped with backup power supplies.

The DAEC has an alternative shutdown capability permitting safe shutdown of the plant in the event that the main control room becomes unusable because of a design-basis fire in the control room fire area.

9.5.1.6 Inspection and Testing Requirements

Surveillance requirements for the fire protection system and features required to protect plant systems required for safe plant shutdown are contained in Table 9.5-1 and in the Fire Plan.

Fire protection systems and features are inspected and tested in accordance with the regular plant maintenance programs.

Fire protection systems and features are inspected and tested upon installation and are subsequently tested using fire protection industry and DAEC property insurance provider guidelines.

9.5.1.7 Operability Requirements

The operability requirements associated with Fire Protection Systems and features are provided in Table 9.5-1 and in the Fire Plan.

9.5.2 COMMUNICATIONS SYSTEMS

9.5.2.1 Design Bases

9.5.2.1.1 Power Generation Objective

The power generation objective of the communications systems is to provide convenient, effective operational communications between various plant buildings and locations and between the plant and remote locations.

9.5.2.1.2 Power Generation Design Bases

Communications systems are provided in the plant to ensure reliable communications for startup, operation, shutdown, and maintenance under all normal and emergency conditions.

1. A public address (PA) system is equipped with a page and with a single party channel. The page channel is used to issue plant-wide instructions, for intercommunications between two or more stations, or to call personnel who may continue their conversation on the party channel or other communications system. For high reliability under emergency conditions, the PA system is divided into multiple zones so that power and/or multi circuit failure in any zone will not affect system operability in the other zones. Alarm signals can be transmitted over the PA system to warn personnel of emergency conditions. To supplement the PA, warning lights are also provided in high-noise areas.

2. A telephone system, installed by the local telephone utility provides direct dialing between all plant telephones as well as to outside local and long distance areas. The plant telephone system includes a wireless telephone subsystem that provides cellular coverage to selected plant areas.

3. Sound-powered telephone jacks located throughout the plant provide communications for maintenance purposes.

4. A VHF radio facility provides radio contact with local emergency agencies.

5. A UHF plant radio system provides communications for plant operations with portable transceivers.

6. A VHF radio repeater system provides radio communications for Security mobile systems and personnel.

7. A microwave communication facility is used when local telephone service is disabled in the vicinity of Palo and the DAEC. The system employs a Cedar Rapids microwave tower and permits uninterrupted direct communications to the plant.

8. A radio/telephone system has been installed on the refueling floor so that the refueling bridge operators can communicate "hands-free" with the control room.

The communications systems are designed to be operable during loss of offsite power. The telephone system receives normal AC power from two sources, and has redundant backup sources from the TSC Standby Generator and the 48 VDC system battery. The sound-powered telephones require no power supply. The PA system receives power from the uninterruptible and/or essential ac bus.

9.5.2.2 Description

The PA system is of industrial quality using local transistorized amplifiers. All system speakers carry the conversation during the page mode of operation. Switching to the party mode makes the page channel available to others since simultaneous conversations can take place on both the page and party channels without interference. Speakers are oriented and volume levels adjusted to cover all areas inside the plant and selected outdoor areas. Outdoor stations use weatherproof speakers and amplifier enclosures and may be turned on or off from the control room.

Switches available in several locations in the plant allow the initiation of a plant evacuation or fire alarm. Actuating the switch energizes a special oscillator whose output is fed into the PA system.

The telephone system used at the DAEC is owned by IES Utilities, Inc. and was installed and is maintained by the local telephone utility. The sound powered phone system provides communications between approximately 36 locations in the plant.

The DAEC is connected into the nationwide emergency notification system (ENS) which is a dedicated telephone system connecting Nuclear facilities to the NRC Operations Center. The ENS is designed to facilitate notification of the NRC of certain events and conditions at nuclear power plants. The DAEC has ENS stations at the following locations:

- Control room.
- Shift Supervisor's office (immediately adjacent to the control room).

- Technical support center.

- Emergency operations facility.

The VHF and UHF systems are installed and operate on assigned frequencies in accordance with FCC licensing requirements. These systems are maintained by local radio maintenance companies.

9.5.2.3 Safety Evaluation

Communications systems are provided in the plant to ensure reliable communications for startup, operation, shutdown, and maintenance under all normal and emergency conditions. The communication system at the DAEC consists of many diverse and redundant systems. These systems are designed to be operable during a loss of offsite power.

9.5.2.4 Inspection and Testing

The design of the communications systems permits routine surveillance and testing at any time.

Audibility problems encountered with the evacuation of personnel from high-noise areas have been evaluated as follows:

1. An evaluation of the evacuation alarm system in accessible high and low noise level areas was performed. The evaluation included a special test involving the stationing of personnel in the areas during the sounding of the evacuation alarm and an interview with operating personnel to determine if they had encountered any audibility problems with the plant paging system (the evacuation alarm is relayed over the plant paging system). The evaluation identified five plant areas where the evacuation alarm was not audible and two high noise level areas having reduced audibility.

2. Additional plant paging system speakers were installed in the five plant areas where the evacuation alarm was not audible. For plant areas where the audibility of the evacuation alarm was reduced, current preparedness plan implementing procedures provide adequate mechanisms for identifying any personnel who may not have heard the evacuation alarm. The procedures require that an audit be performed to verify accountability of all personnel. Any personnel not hearing the evacuation alarm would be identified at that time and appropriate actions to locate the personnel would be initiated. It should be noted that security hardware installed as part of the Security Plan will expedite personnel accountability procedures in the event of an evacuation.

TABLE 9.5-1
FIRE PROTECTION SYSTEM EQUIPMENT OPERABILITY, COMPENSATORY ACTION AND INSPECTION/TESTING REQUIREMENTS

OPERABILITY REQUIREMENT

1 FIRE PROTECTION SYSTEMS

Applicability:
Applies to the operational status of the Fire Protection Systems and Features required by Appendix R Safe Shutdown Analysis.
Objective:
To assure the ability of the Fire protection Systems to protect plant systems required for safe plant shutdown.
Requirement:

A. Fire Detection Instrumentation
1. The fire detection instrumentation for each area shown below shall be operable whenever safe shutdown equipment in that fire detection zone is required to be operable.

Instrument Location	Minimum Operable
1. Control Auxiliary Panel Room El. 786'	
a. XL3 device numbers 11-01 through 11-20	18* (Smoke)
2. Control Room Panel Detection El. 786'	
a. Zone 25	21 (Smoke)
b. Zone 26	21 (Smoke)
c. Zone 27	17 (Smoke)
d. Zone 28	19 (Smoke)
3. Control Room Computer Room El. 786'	
a. Zone 29	2 (Smoke)
4. Control Building HVAC Room El. 812'	
a. XL3 device numbers 31-01 through 31-10	10 (Smoke)
5. Cable Spreading Room El. 772'-6"	
a. Zone 5	9* (Smoke)
b. Zone 6	9* (Smoke)
c. Zone 7	9* (Smoke)
d. Zone 8	9* (Smoke)
6. Reactor Building Southeast Corner Room	
a. Zone 43	4 (Smoke)
7. Pump house El. 747'	
a. Zone 45	2 (Smoke)

* No two adjacent detectors may be inoperable at the same time. Otherwise that zone is inoperable

2. If the number of instruments operable for any zone is less than the minimum required:
a. Verify the integrity of all required fire rated assemblies in the affected zone per Requirement 1.F or within 1 hour establish a continuous fire watch on at least one side of affected barrier

SURVEILLANCE REQUIREMENT

2 FIRE PROTECTION SYSTEMS

Applicability:
Applies to the surveillance requirements of the Fire Protection Systems.

Objective:
To verify the ability of the Fire protection Systems to protect plant systems required for safe plant shutdown.
Requirement:

A. Fire Detection Instrumentation
1. Fire Detection Instrumentation testing.

a. Each smoke detection instrument listed in Requirement 1.A.1 shall be demonstrated operable by performance of annual smoke testing and sensitivity tests on alternate years.

b. The circuitry associated with the detector alarms shall be demonstrated operable at least once every two months

TABLE 9.5-1
FIRE PROTECTION SYSTEM EQUIPMENT OPERABILITY, COMPENSATORY ACTION AND INSPECTION/TESTING REQUIREMENTS

OPERABILITY REQUIREMENT	SURVEILLANCE REQUIREMENT
b. Within 1 hour, establish a fire watch to inspect the zone with the inoperable instrument(s) at least once per hour, and c. Restore inoperable instrument(s) to operable status within 14 days. 3. If Requirement 1.A.2.c cannot be met, outline in a Monthly Operating Report within 45 days, the cause of the malfunction and the plans for restoring the instrument(s) to operable status.	
B. Fire Protection Water System 1. The Fire Suppression Water shall be OPERABLE with: a. The river water supply system OPERABLE. b. Two (2) fire pumps OPERABLE and aligned to the fire yard header. c. Automatic initiation logic for each fire pump. 2. When only one pump is OPERABLE restore the second pump to operable status within 14 days or outline in a Monthly Operating Report within 45 days, the plans and procedures to be used to provide for the loss of redundancy in this system. 3. If the Fire Suppression Water Distribution System is not OPERABLE: a. Refer to Requirements 1.C.1 through 1.C.2 and 1.E.1 through 1.E.2. b. Establish a backup fire suppression water system within 24 hours (GSW or Well Water).	B. Fire Suppression Water System 1. The Fire Suppression Water System shall be demonstrated OPERABLE: a. By verifying that the river water Supply system is OPERABLE per Technical Specifications. b. Once per month by starting the diesel-driven fire pump and operating it for at least 30 minutes. c. Once per month by starting the motor-driven fire pump and operating it for at least 15 minutes on recirculation flow. d. Once per six months by a flush of the yard header. e. Annually by verifying that each pump develops at least 3115 gpm with a discharge pressure of at least 96 psig. f. Once per three years by verifying the hydraulic performance of the system by starting the motor- driven fire pump and directing flow around the yard header. Under this condition, the flow and pressure requirements described in Requirement 2.B.1.e shall be met. g. Once per 92 days by verifying that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM-D270-65, is within the acceptable limits specified in Table 1 of ASTM-D975-74 with respect to viscosity, water content and sediment. h. Annually, by verifying the diesel starts from ambient conditions on the auto-start signal and operates for 30 minutes while loading with the fire pump. i. Once per 31 days by verifying that the diesel day tank contains fuel for two hours of operation. j. Once per month by verifying that each valve in the flow path is in its correct position.

TABLE 9.5-1
FIRE PROTECTION SYSTEM EQUIPMENT OPERABILITY, COMPENSATORY ACTION AND INSPECTION/TESTING REQUIREMENTS

OPERABILITY REQUIREMENT	SURVEILLANCE REQUIREMENT
c. If neither fire pump is OPERABLE within 24 hours, outline in a Monthly Operating Report within 45 days, the cause of the inoperability and the plans for restoring the system to OPERABLE status.	
d. If Requirement 1.B.3.a cannot be met, place the reactor in HOT STANDBY within the next six (6) hours and in COLD SHUTDOWN within the following 30 hours.	
4. When maintenance on the circulating water/fire pump pit is being performed, the following conditions shall be met:	
a. The River Water Supply System will be maintained such that the fire water supply can be restored within one hour; and	
b. Verify the integrity of all Fire Rated Assemblies in the affected zones where required suppression systems would be unable to alarm in Control Room or within 1 hour establish a continuous fire watch on at least one side of affected barrier per Requirement 1.F.	
c. Refer to Requirements 1.C.1 through 1.C.3 and 1.E.1 through 1.E.2.	
d. An hourly fire watch patrol will be established in areas listed in C.1.a, b and c and maintained until a backup fire suppression water system is established.	
C. Deluge and Sprinkler Systems	C. Deluge and Sprinkler Systems
1. The deluge and sprinkler systems located in the following areas shall be OPERABLE whenever safe shutdown equipment in the deluge/ sprinkler protected area is required to be OPERABLE.	1. The deluge and sprinkler systems shall be demonstrated to be OPERABLE: a. Annually: 1) For automatic systems, by performing a system functional test which includes simulated automatic actuation of the system and verifying that the automatic valves in the flow path actuate to their correct positions.
a. RB Hatch (Deluge 18)	
b. CB HVAC Room (Sprinkler 12)	
c. PH, 747 (Sprinkler 21)	
2. If any of the above listed deluge and sprinkler systems is found to be inoperable,	2) By visual inspection of sprinkler headers to verify their integrity.
a. Verify the operability of all required fire rated assemblies in the affected zones where suppression systems would be unable to alarm in Control Room per Requirement 1.F or within 1 hour establish a continuous fire watch on at least one side of affected barrier.	
b. Within one hour, establish a fire watch to ensure that each area where protection is lost is checked hourly, and	
c. Restore the system to OPERABLE status within fourteen days.	
3. If Requirement 1.C.2.c cannot be met, outline in a Monthly Operating Report within 45 days, the cause of inoperability and plans for restoring the system to OPERABLE status.	3) By inspection of each nozzle for obstruction or damage.

TABLE 9.5-1
FIRE PROTECTION SYSTEM EQUIPMENT OPERABILITY, COMPENSATORY ACTION AND INSPECTION/TESTING REQUIREMENTS

OPERABILITY REQUIREMENT	SURVEILLANCE REQUIREMENT
	4) For Deluge 18, by performing a functional test of the system detection. 5) For fixed systems, cycle normally closed supply isolation valves to the open position. b. Once per three years by an air flow test of the deluge systems.
D. CO2 System 1. The CO2 System for the cable spreading room shall be OPERABLE with a minimum level of 80% and a minimum pressure of 275 psi in the storage tank.	D. CO2 System 1. The CO2 System shall be demonstrated OPERABLE: a. Once per seven days by verifying CO2 storage tank level and pressure. b. Annually by verifying that the system valves actuate automatically and manually to a simulated actuation signal. A brief air flow test shall be made to verify flow from each nozzle. c. Semi-annually by verifying that the CO_2 thermal detectors are operable.
2. If Requirement D.1 cannot be met, a. Verify immediately that hose stations #35 and #36 outside the cable spreading room are OPERABLE per Requirement 2.E.1.a b. Verify the integrity of all required fire rated assemblies in the cable spreading room per Requirement 1.F or within 1 hour establish a fire watch to ensure that the cable spreading room is checked continuously. c. Within one hour, establish a fire watch to ensure that the cable spreading room is checked hourly, and d. Restore the system to OPERABLE status within 14 days. 3. If Requirement 1.D.2.c cannot be met, outline in a Monthly Operating Report within 45 days, the cause of inoperability and the plans for restoring the system to OPERABLE status. 4. For personnel safety considerations, the system shall be isolated when personnel occupy the cable spreading room, with the exception of plant security personnel performing security door checks.	
E. Fire Hose Stations 1. The fire hose stations in the following locations shall be OPERABLE whenever safe shutdown equipment in the areas protected by the fire hose stations is required to be operable.	E. Fire Hose Stations 1. Each fire station shall be verified to be OPERABLE:
a. Hose Station #37 - Admin Building corridor to Control Room.	a. Once every three months by visual inspection of the station to assure all equipment is available and the pressure in the standpipe is within limits, and that all valves in the flowpath to the hose station are open.

TABLE 9.5-1
FIRE PROTECTION SYSTEM EQUIPMENT OPERABILITY, COMPENSATORY ACTION AND INSPECTION/TESTING REQUIREMENTS

OPERABILITY REQUIREMENT	SURVEILLANCE REQUIREMENT
b. Hose Station #38 - Control Room.	b. Annually, by removing the hose for inspection and repacking and replacing all gaskets in the couplings that are degraded. c. Once per three years partially open hose station valves to verify operability and no blockage. d. Once per three years conduct a hose hydrostatic test at a pressure 50 psig greater than the maximum at that hose station.
2. With the hose station inoperable, restore the hose station to operable status within 1 hour or, establish an hourly fire watch until an additional hose can be routed from an operable hose station to the unprotected area.	
F. Fire Rated Assemblies	F. Fire Rated Assemblies
1. All fire barrier penetration seals protecting systems required for safe plant shutdown shall be intact. Fire barrier guidance may be found in Administrative Control Procedure (ACP) 1412.4, Impairments to Fire Protection Systems.	1. Fire barrier penetration seals shall be verified to be functional by: a. A visual inspection of approximately 35% of the fire barrier penetration seals once every 18 months, with 100% of the fire barrier penetration seals visually inspected within a period of five years. b. A visual inspection of a fire barrier penetration seal following maintenance to verify that it has been returned to its original condition.
2. All fire doors protecting systems required for safe plant shutdown shall be functional. Required fire doors are identified in Surveillance Test Procedure (STP) NS13F002 and ACP 1412.4.	2. Fire doors shall be verified to be functional: a. Semi-annually to verify operation of auto-closing devices and latch mechanisms, except in the case of locked fire doors permitting access to cable and pipe chases and to the steam tunnel, which are inspected once every 18 months. b. At least once every 18 months via visual inspection to verify integrity and assure no blockage exists. c. Prior to restoring a fire door to functional status following repairs or maintenance to verify it has been returned to its original condition.
3. All fire dampers protecting systems required for safe plant shutdown shall be functional. Required fire dampers are identified in STP NS13F003.	3. Fire dampers shall be verified to be functional by: a. A visual and functional inspection of approximately 35% of the fire dampers at least once every 18 months, with 100% of the fire dampers inspected within a period of five years.

TABLE 9.5-1
FIRE PROTECTION SYSTEM EQUIPMENT OPERABILITY, COMPENSATORY ACTION AND INSPECTION/TESTING REQUIREMENTS

OPERABILITY REQUIREMENT	SURVEILLANCE REQUIREMENT
4. Fire protection raceway wrap and structural steel fireproofing protecting systems required for safe plant shutdown shall be intact. Required raceway wrap is identified in STP NS13F005. Required structural steel fireproofing is identified in STP NS13F006.	4. Fire protection raceway wrap and structural steel fireproofing shall be verified to be functional by: a. A visual inspection of approximately 35% of the structural steel fireproofing at least once every 18 months with 100% of the structural steel fireproofing visually inspected within a period of five years. b. A visual inspection of 100% of the DARMATT fire protection raceway wrap within a period of five years. c. Returning the fire protection raceway wrap and structural steel fireproofing to its original condition following repairs or maintenance.
5. If Requirement 1.F.1, 1.F.2 or 1.F.3 cannot be met: a. A continuous fire watch shall be established within 1 hour on at least one side of the affected barrier, or b. Verify the OPERABILITY of fire detectors or fire suppression systems capable of alarming to the Control Room on at least one side of the non-functional fire barrier and establish an hourly fire watch patrol.	
6. If Requirement 1.F.4 cannot be met: a. A continuous fire watch shall be established within 1 hour in the affected fire zone, or b. Verify the OPERABILITY of fire detectors or fire suppression systems capable of alarming to the Control Room in the affected fire zone and establish an hourly fire watch patrol.	

10.4.5.1.1 Power Generation Objective

The power generation objective of the circulating water system is to provide a continuous supply of cooling water to remove the heat rejected to the main condenser.

10.4.5.1.2 Power Generation Design Bases

1. The circulating water system is designed to circulate the flow required to remove the design heat load from the main condenser.

2. The circulating water system is designed to operate on a closed cycle using induced-draft cooling towers.

3. The cooling towers are designed to remove the heat load of the circulated flow under all predicted weather conditions.

10.4.5.2 Description

The circulating water system is a closed-loop system with two motor-driven pumps circulating cooling water through the main condenser and two induced-draft cooling towers. See Figure 10.4-2.

Each of the vertical, mixed-flow, wet-pit pumps is rated at 141,500 gpm at 80 ft total head. They are installed in a pump house approximately 250 ft east of the turbine building. The sump in which they are installed is gravity-fed from the cooling tower basins by two 78-in. lines. The discharge of each pump is through a 78-in. line to the main condenser, which at design rating rejects 3.66×10^9 Btu/hr to the cooling water.

The heated water is discharged to the cooling towers, each of which normally receives one-half of the total flow. Each tower is a cross-flow type, divided into 12 cells, with motor-driven fans in each cell to induce the required draft. Each single-speed, reversing fan is driven by a 200-hp motor and is rated at 1,471,800 scfm. Each tower is designed for an inflow of 146,000 gpm at 112°F and an outflow temperature of 87°F with ambient wet-bulb temperature at 76.5°F. Flow and cooling capacities of the towers exceed that of the circulating water pumps and main condenser to the extent necessary to handle the discharge from the service water system. This system discharges to the heated side of the circulating water system and passes through the cooling towers.

Water required to make up for evaporation and blowdown from the cooling towers is obtained from the Cedar River. A pumping plant at the river with two river water supply pumps normally operating for plant makeup to the circulating water system delivers a total of 12,000 gpm. The water is piped to the stilling basin which is designed to overflow to the wet-pit sump of the circulating water pumps. The rate of delivery of this makeup water is controlled by modulating valves acting in response to water level at the cooling tower basins. At full plant power, approximately 6,000 gpm will be required for cooling tower evaporation. Blowdown is limited by the Iowa Department of Natural Resources permit.

Cooling water quality is controlled by chemical additives, including sodium hypochlorite, acid, a stabilizer, a biocide, and a dispersant.

The circulating water system pH is maintained between 7.6 and 8.5. Approximately 1200 lb of H_2SO_4 is used for every 1,000,000 gal of makeup on a continuous feed basis to maintain pH.

10.4.5.3 Safety Evaluation

The circulating water system contains about 2.4 x 10^6 gallon of water stored in the cooling tower basins, pump house, condenser, and associated piping. Depending on the size of an expansion bellows break, the circulating water pump could discharge the entire volume into the turbine building lower level or into the pump house within 10 min. The water would reach a depth of 8 feet in the turbine building. However, failure of safety-related equipment located within the floodable space due to damage from flooding does not prevent achievement of safe plant shutdown following a circulating water system rupture.

The rupture of a circulating water line in the pump house could result in an accumulation of water above the operating level, the depth of which would be determined by the rate of escape through the openings in the pump-house walls. The maximum flooding of the Nonseismic pump house would be limited to the level of the ventilation air intake louvers, at which point water would be relieved through this opening. A Seismic Category I wall separates the floodable volume from the Seismic Category I emergency pump room area housing the emergency service water and residual heat removal service water pumps. The only penetration in this wall within the level subject to flooding is a water-tight door that seals the Seismic Category I area of the pump house from the circulating water pump area. A limit switch on the door provides an alarm at security when the door is not closed and dogged.

Safety analysis of degraded circulating water system operation is provided in the analysis of the turbine trip from high power without bypass as an initiator, provided in Chapter 15.

If an expansion bellows failure in the circulating water line should occur either at the condenser or in the pump house, the leak would cause the water level in the cooling tower basin to drop due to insufficient makeup. An 18 inch drop below normal operating level will alarm in the control room alerting the operator of a failure in the river water supply system or a leak in the circulating water system.

drop across the vessel. Specific system problems are annunciated on the local control panel and result in a single alarm in the main control room.

The system is designed for automatic operation following mode initiation. This means the operator is required to initiate each phase of operation but, having once done so, the system will operate automatically through that mode (i.e., backwash, precoat, filter, and hold). In addition to the automatic operation, each valve and motor has a selector switch on the control panel for manual operation. Normally, all of these should be in the "auto" position except for certain auxiliary equipment that is only operated manually.

Four units are typically used during normal operation with the additional unit on standby or in operation. The flow through those on the line is typically balanced, and a minimum system differential is maintained. Each unit has an individual flow controller, an orifice with a flow transmitter, and a discharge throttling valve, which controls flow.

The termination of each filter run is normally because of pressure drop but may also be caused by deterioration of effluent conductivity. At this time, the unit to be backwashed is taken out of service and placed into a holding condition by means of its "HOLD" push button on the control panel.

The manufacturer's experience indicates that a filter area of 915 ft^2 per vessel is conservative for the design flow rate of 3625 gpm through each vessel. The system was thoroughly tested and all design bases were verified during preoperational testing.

An operator controlled bypass has been incorporated into the condensate demineralizer system. The bypass is used to maintain system flow as necessary in order to provide a backwashing capability when more than one filter demineralizer is out of service. The bypassing of condensate flow is permitted only if water quality standards are met in the system effluent. Normally, 100% of the feedwater will be processed through the filter demineralizers.

The filter-demineralizer is located on the system such that all of the condensate flow may be demineralized, including the condensate reject and feed pump seal water.

Individual filter-demineralizer vessels can be isolated. Thus, maintenance can be performed when required on individual filters while leaving the condensate demineralizer system and the plant in operation.

Each filter-demineralizer vessel has an inlet baffle consisting of multiple plates with offset orifices. The purpose of the baffle is to prevent turbulent flow during the precoat cycle, and thereby prevent scouring and resin loss from the lower portions of the vessel septa.

The demineralizers are located in separate shielded compartments to permit personnel access to an inoperative unit for maintenance during plant operation. The units are arranged to permit easy replacement of filter septa or other vessel components.

10.4.7 CONDENSATE AND REACTOR FEEDWATER SYSTEMS

10.4.7.1 Design Bases

10.4.7.1.1 Power Generation Objective

The power generation objective of the condensate and reactor feedwater systems is to provide a dependable supply of feedwater to the reactor, to provide feedwater heating, and to minimize water-quality problems.

The power generation objective of the feedwater lines is to provide the piping path for delivery of water back to the reactor vessel.

10.4.7.1.2 Power Generation Design Bases

1. The feedwater equipment and piping is designed to provide at least 115% of design flow to the reactor at 1100 psi pressure at the reactor vessel feedwater connections.

2. The feedwater heaters are designed to provide 420°F feedwater to the reactor with six stages of closed feedwater heating.

3. A cleanup recirculation line is provided from the last feedwater heater to the condenser hotwell in order to minimize corrosion product input to the reactor.

4. The feedwater lines are designed with suitable accesses to allow inservice testing and inspections.

5. The feedwater lines are designed to conduct water to the reactor vessel over the full range of reactor power operation.

10.4.7.1.3 Safety Design Basis

The feedwater lines are designed to accommodate operational stresses, such as internal pressures, without a failure which could lead to a release of radioactivity in excess of guideline values in published regulations.

11.2.1.5 Codes and Standards

The liquid radwaste system equipment is designed to codes and standards given in Tables 3.2-2 and 3.2-4 for "Components Ordered Before January 1, 1970." In addition, the waste collector filter and waste demineralizer vessels are designed per ASME Code, Section III.C. Further information on codes and standards commitments are discussed in UFSAR Section 1.8.31.

11.2.2 SYSTEM DESCRIPTION

The liquid radwaste system collects, monitors, processes, stores, and disposes of radioactive liquid wastes. The liquid radwaste system equipment and flow paths are shown in Figure 11.2-1. The following are included in the system:

1. Piping and equipment drains carrying potentially radioactive wastes.

2. Floor drain systems in controlled access areas that may contain potentially radioactive wastes.

3. Tanks and sumps used to collect potentially radioactive wastes.

4. Tanks, sumps, piping, pumps, process equipment, instrumentation, and auxiliaries necessary to collect, process, store, and dispose of potentially radioactive wastes.

Expected annual liquid volume total for floor drain, detergent, and chemical wastes is 2,873,000 gal.

Figures 11.2-2, 11.2-3, 11.2-4 and 11.2-5 are piping and instrumentation diagrams for the liquid radwaste system.

Current operating procedures provide for both chemical and detergent wastes to be processed through the floor drain system or solidified and disposed of as solid waste.

The normal method of processing chemical waste is through the radwaste floor drain system. If for any reason the waste cannot be handled by the floor drain system, chemical waste is processed through the chemical waste filter, pumped to the chemical waste sample tank, and sent to the discharge canal by the route described below.

Equipment is selected, arranged, and shielded to permit operation, inspection and maintenance with acceptable personnel exposures. For example, sumps, pumps, valves and instruments that may contain radioactivity are located in controlled access areas. Tanks and processing equipment that may contain significant quantities of radioactive material are shielded. The operation of the radwaste system is essentially manual start/automatic stop.

Protection against accidental discharge is provided by instrumentation for the detection and alarm of abnormal conditions and procedural controls. The radwaste facility arrangement and the methods of waste processing provide a substantial degree of immobility of the wastes within the plant. These provisions ensure that, in the event of a failure of the liquid waste system equipment or errors in the operation of the system, the potential for inadvertent release of liquids is small. The immobility of wastes is further accomplished by collecting solids on filters and demineralizer resins.

The liquid radwaste system is divided into several subsystems so that the liquid wastes from various sources can be kept segregated and processed separately. Cross-connections between the subsystems provide additional flexibility for the processing of the wastes by alternative methods. The liquid radwastes are classified, collected, and treated as high purity, low purity, chemical, detergent, sludge, or spent resins. The terms "high purity" and "low purity" refer to the conductivity and not the radioactivity.

The liquid radwaste system design provides for the filtration and demineralization of both waste collector (high purity) and floor drain (low purity) effluents. Radioactive liquids are recycled within the plant to the extent practicable. The liquid radwaste systems are used to ensure that levels of radioactive materials in liquid effluents are as low as reasonably achievable as discussed in Section 11.2.2.7.

DAEC operating experience has revealed that from time to time it is necessary to employ temporary filtration or processing equipment to supplement the processing capability of the permanent Liquid Radwaste System. Such systems may include the use of equipment designed to address intrusions of liquid waste streams high in the levels of organics, conductivity, turbidity or other waterborne chemical agent. In circumstances where temporary equipment is utilized, such equipment is either designed in a manner to be consistent with the pressure rating of the Liquid Radwaste System or pressure regulating devices will be used to ensure that the pressure does not exceed the design pressure of the temporary equipment. The effluents from the temporary equipment are returned to the Radwaste System for final processing prior to transfer to the Condensate Storage System or environmental release.

The release of all liquid radwaste to the environment is via the HBD-79 2-in. discharge line beginning in Figure 11.2-4, teeing into the HBD-67 24-in. radwaste dilution flow line shown in Figure 11.2-6, and continuing in Figure 11.2-7. The radwaste dilution line terminates at the dilution structure. The dilution line, dilution structure, and discharge from the dilution structure to the river via the discharge canal are shown in detail in Figures 11.2-8, 11.2-9 and 11.2-10.

The auxiliary turbine building floor drain sump is connected to the radwaste drain system, which can be discharged to the river. Discharge lines coming into the auxiliary turbine building floor drain sump are the general floor area drain from the south end of the turbine building. Discharge lines coming into the chemical waste sump are from the makeup demineralizer floor drain (low-curb area), backwash line from the makeup demineralizer, floor drain from the neutralizing tank (high-curb area), flush line from acid and caustic tanks (by way of neutralizing tank), and the acid and caustic tank sump (by way of neutralizing tank/high-curb area). In addition, the auxiliary turbine building floor drain and chemical waste sumps are connected by a cross-connection with a shear valve near the bottoms of the sumps.

To preclude an accidental release, the system is designed as follows:

1. The cross-connection between the chemical waste sump and the auxiliary turbine building floor drain sump is eliminated by filling the cross-connection with grout.

2. The auxiliary turbine building floor drain sump is isolated from the normal waste drain system by rerouting the piping so that the sump pumps into the turbine building radwaste sump system.

3 The chemical sump pumps are connected to the normal waste drains by the addition of necessary piping and valves.

4. The drain line from the neutralizing tank to the auxiliary turbine building floor drain sump has been capped. It now drains only to the chemical waste sump.

5. A lock is installed on the discharge transfer valves used to transfer waste from the chemical waste sump to the normal drain system and the breakers on the pumps are turned off. The key for this lock is under the control of the Operations Shift Supervisor who will call the Radiation Protection Department for sampling for solids and pH before release to the normal drain system. This is also covered by a written procedure.

6. A two foot high retaining wall surrounds the auxiliary turbine building floor drain sump to prevent overflow from either sump from entering the other sump.

7. A lock has been installed on the Turbine Building waste sump pumps discharge valves to prevent pumping into the normal waste system. These will remain permanently locked closed and the sump will be emptied by the use of barrels or

transferred to Radwaste system floor drains. This is covered by a written procedure. The Turbine Building oil sump pump discharge has been capped and a hose fitting installed to allow contents of this sump to be transferred into barrels or to Radwaste system floor drains.

It is not a normal operating practice to release any effluent containing radioactivity to the river by way of the auxiliary turbine building floor drain sump. Chemical waste can be discharged to the river, but only after it has been properly sampled by the Radiation Protection Department and permission given by the Operations Shift Supervisor to close the sump pump breakers and unlock the discharge transfer line sumps from the chemical waste sump to the normal drain system. Discharges from the oily waste sumps are accomplished as described in Item 7 above.

The design of the liquid radwaste system incorporates floor drain demineralization, the filtration of chemical wastes, and the ability to recycle liquids to the maximum extent practicable.

The design of the DAEC liquid radwaste system fully satisfies the requirement that releases of radioactivity be reduced to the lowest practicable level.

All process piping designated to carry radioactive materials is routed in shielded pathways to meet the criteria for radiation zones as specified in Section 12.3.1.1.

11.2.2.1 <u>High-Purity Wastes</u>

High-purity (low conductivity) liquid wastes are collected in the waste collector tank from the following sources:

1. Drywell equipment drain sump.
2. Reactor building equipment drain sump.
3. Radwaste building equipment drain sump.
4. Turbine building equipment drain sump.
5. Reactor water cleanup system.
6. Residual heat removal (RHR) system.
7. Decantate from cleanup phase separators.

2. Condensate Phase Separator
Construction materials: carbon steel phenolic-lined tank; stainless steel internal piping and eductor.
Design pressure: atmospheric.
Design temperature: 250°F.
Capacity 12,500 Gal [2]

3. Cleanup Phase Separator

Construction material: stainless steel tank, internal piping and eductor.
Design pressure: atmospheric.
Design temperature: 250°F.
Capacity 4,500 Gal [2]

4. Chemical Waste Filter

Construction material: stainless steel used for shell, tube shell, and nozzles.
Design pressure: 190 psig.
Design temperature: 175°F.

5. Reagent Addition Pump

Construction material: stainless steel used for all wetted parts.
Design pressure: 15 psig.
Design temperature: 100°F.

6. Detergent Drain Filter

Construction materials: carbon steel vessel and nozzle flanges and stainless steel internals.
Design pressure: 75 psig.
Design temperature: 150°F.

7. Waste Collector Filter and Floor Drain Filter
Construction materials: carbon steel Plasite-lined vessel and stainless steel filter elements.
Design pressure: 150 psig.
Design temperature: 150°F filter element.
Design temperature: 200°F vessel.
Capacity 120 ft^3

8. Waste Precoat Tank and Filter Aid Tank

Construction material: carbon steel Plasite-lined tank.
Design pressure: atmospheric.
Design temperature: 150°F.

9. Radwaste Filter and Floor Drain Filter Holding Pump Coolers

Construction material: carbon steel.
Design pressure: 150 psig.
Design temperature: 200°F.

10. Radwaste Filter and Floor Drain Filter Holding Pumps

Construction material: carbon steel.
Design pressure: 150 psig.
Hydrotest pressure: 300 psig.
Design temperature: 200°F.

11. Waste Precoat Pump

Construction material: carbon steel.
Design pressure: 150 psig.
Hydrotest pressure: 300 psig.
Design temperature: 150°F.

12. Waste Filter Aid Pump and Floor Drain Filter Aid Pump

Construction material: cast steel.
Design pressure: 150 psig.
Design temperature: 200°F.

13. Filter Aid Agitator

Construction material: stainless steel.
Design pressure: atmospheric.
Design temperature: 150°F.

11.3.2 SYSTEM DESCRIPTION

11.3.2.1 Process Description

The offgas treatment system shown in Figure 11.3-1 uses a high-temperature catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen from the air ejector system. After chilling to strip the condensibles and reduce the volume, the remaining noncondensibles (principally kryptons, xenons, and air) are delayed in a 30-min holdup system cooled to a dewpoint of 45°F with a chilled glycol cooler, passed through a de-entrainer, heated to 74°F (relative humidity of 35%), and passed through a HEPA filter before reaching the adsorption bed. The charcoal adsorption bed, operating in a constant temperature vault, selectively adsorbs and delays the xenons and kryptons from the bulk carrier gas (principally air). This delay on the charcoal permits the xenon and krypton to decay in place. This system results in a reduction of the offgas activity released by a factor of approximately 61 relative to a 30-min holdup system and based on a diffusion mixture.

The design of the offgas system incorporates an automatic loop seal isolation system that monitors system pressure at the 37-sec holdup volume ahead of the recombiner and in the 30-min holdup volume downstream of the recombiner. These isolation setpoints are set at 4.0 psig and 4.5 psig, respectively, with associated control room indication.

In the event of a loop seal liquid loss, leaking gas mixtures would be alarmed in the control room through the reactor building ventilation stack gaseous monitors, reactor building ventilation radiation monitors, ventilation shaft radiation monitors, offgas post-treatment radiation monitors, and offgas stack radiation monitors.

On the isolation of the offgas loop seals, the normal operating procedure is to keep loop seals isolated until they naturally fill through condensation buildup.

In the event of an inadvertent offgas system explosion, the site preparedness plan and implementing procedures provide adequate guidance for proper response.

During the review of off-normal offgas system operation, one condition was identified that could lead to the accumulation of an explosive mixture. During normal operation, offgas is diluted in jet compressor 1S-111. In the event of the loss of dilution steam, flow valve MO-4151 is automatically shut, isolating the jet compressor. This causes a pressure transient in the system that actuates several pressure switches, which in turn automatically close the isolation valves on the system loop seals.

Two loop seals are located upstream of MO-4151. In the event that insufficient water is available in one of the loop seals upstream of MO-4151, the loop seal may blow before sufficient pressure to actuate the system pressure switches develops. Under these conditions, undiluted offgas would be discharged to the turbine building equipment drain sump or the offgas retention building equipment drain sump. Considering normal ventilation flow, the average hydrogen concentration in each area would be 16.7% and 13.0% by volume, respectively.

No other conditions have been identified that could result in the accumulation of sufficient hydrogen to form an explosive mixture. The review considered loss of ventilation flow, loss of dilution steam, lost loop seals, blown rupture disks, and leakage of offgas into isolated portions of the system. Bypassing the recombiners was not considered as this is not applicable to the DAEC design.

To ensure that the conditions identified above do not occur, the system has been designed in the following manner:

1. Water fill lines are installed to all loop seals that do not presently have fill capability.

2. System logics are designed to automatically isolate the two loop seals upstream of MO-4151 on the closure of MO-4151.

The adsorption of noble gases on charcoal depends on gas flow rate, holdup time, mass of charcoal, and a gas-unique coefficient known as the dynamic adsorption coefficient. The parametric interrelationships and governing equations are well proven from 3 yr of operation of a similar unit at KRB in Germany.

The basis for these coefficients and supporting experimental data are discussed in a proprietary document submitted with Amendment 1, May 1972, in response to an AEC question.

11.3.2.2 Equipment Description

The design of the DAEC gaseous radwaste system incorporates a catalytic recombiner and a 12-bed charcoal adsorber system. The design fully satisfies the requirements that releases of radioactivity be reduced to the lowest practicable level.

12. Carbon Bed Adsorbers (12 Beds)

Construction: Carbon steel. Four ft outside diameter x 21 ft vessels, each with a 19-ft packed section containing ~3 tons of 8-14 mesh carbon (~200 ft^3 of charcoal) Columbia G or equivalent.
Design pressure: 350 psig.
Design temperature: 130°F.

Flow channeling and bed settling are minimized in the charcoal adsorber vessels by the following design considerations:

a. Charcoal adsorber beds are installed for vertical flow of the process gas stream.

b. The first three charcoal beds in each parallel pathway have piping arrangements that cause up-flow from vessel bottom to vessel top of the process gas.

c. As shown in Figures 11.3-4 and 5, toroidal-shaped flow-distribution rings are positioned at the bottom and top ends of each charcoal vessel to enhance the process gas flow pattern. For the first three charcoal vessels in the process stream, the gas enters the distribution ring nozzle at the bottom of the vessel and flows through a distribution torus and out through 251 one-in. holes and 3 layers of screen on the bottom of the torus; the gas then flows upward around both outside walls of the distribution torus and through the charcoal to the upper torus region. In the upper vessel region, the charcoal-filtered gas enters the distribution torus through 3 layers of screen and 251 holes on the top of this torus and proceeds out of the distribution ring nozzle to the next charcoal vessel in the process flow path.

   Process gas enters the top distribution ring and exits out the lower ring nozzle for charcoal vessels other than the first three in each parallel path.

13. Offgas Jet Compressor

Construction: Carbon steel body.
Design pressure: 2150 psig.
Design temperature: 400°F.
Flow rate: 4624 lb/hr.

The ventilation system for each DAEC building that can be expected to contain radioactive materials is described in Section 9.4.

The main condenser gas removal system is described in Section 10.4.2. The main steam line isolation valve leakage treatment path is described in Section 6.7.

11.3.2.3 Instrumentation and Control

The radiation levels at the air ejector offgas discharge line and after the offgas treatment system are continuously monitored by pairs of detectors. This system is also monitored by flow and temperature instrumentation and hydrogen analyzers to ensure proper operation and control and to ensure that hydrogen concentration is maintained below the flammable limit. Process radiation instrumentation is described in Section 11.5. Table 11.3-4 lists process instrument alarms.

11.3.2.4 Safety Evaluation

The decay time provided by the 30-min holdup pipe and the long-delay charcoal adsorbers is established to provide for radioactive decay of the activation gases and fission gases in the main condenser offgas. The adsorbers provide a 15-day xenon and a 19-hr krypton holdup. The daughter products that are solids are removed by filtration following the 30-min holdup and/or are retained on the charcoal. Final filtration of the charcoal adsorber effluent precludes the escape of charcoal fines that contain radioactive materials. Thus, there is virtually no particulate activity release.

Iodine input into the offgas system is small because of its retention in the reactor water and condensate. The charcoal effectively removes the iodine entering the system by adsorption and prevents its release.

Radiation monitors at the recombiner outlet continuously monitor radioactivity releases from the reactor and, therefore, continuously monitor the degrees of fuel leakage and input to the charcoal adsorbers. Radiation monitors are used to provide an alarm on high radiation in the offgas. Two radiation monitors are provided at the outlet of the charcoal adsorbers to continuously monitor the release rate from the adsorber beds. The radiation monitors are further described in Section 11.5.

Dry Active Waste (DAW) process on-site is packaged for shipment to an off-site processor and/or packaged for shipment to a licensed disposal facility. Packaging and shipping is performed in accordance with applicable NRC and DOT regulations. Waste form is determined by the applicable disposal criteria of the licensed disposal facility.

Wet Wastes are processed in order to achieve a stable form in accordance with 10CFR61, and applicable site disposal criteria for the licensed disposal facility.

11.4.2.2 Wet Wastes

Wet wastes consist of spent demineralizer resins and filters and filter-demineralizer sludge wastes.

Sludge wastes are removed from filters and demineralizers as these components are backwashed. Sludge wastes from the reactor water cleanup system and condensate treatment system are collected in phase separators. Sludge wastes from the fuel pool cooling and cleanup system are collected in the waste sludge tank. Sludge from the radwaste system waste demineralizer and floor drain demineralizer is collected in the spent-resin tank or the waste sludge tank. Sludge from the waste collector filter and floor drain filter is collected in the waste sludge tank and floor drain sludge tank, respectively.

The sludge wastes consist of spent ion-exchange resins, corrosion products, fission products, and other insoluble material removed from the various systems. The reactor water cleanup system sludges are kept separate from the condensate and fuel pool system sludges because of the variation in radioactive material content. This reduces shielding requirements for the storage and shipping of the lower activity solid wastes.

The excess backwash water from the sludge wastes collected in the phase separators is decanted and transferred to the collection tanks. The concentrated sludge that remains after each batch is decanted is held until the resin volume reaches a predetermined level. The sludge is processed to remove the excess water, the solids are prepared for disposal, and the extracted water is routed back to the collection tanks.

Solidification of waste sludge is methods of waste stabalization. Solidification of the sludge is achieved by first removing a portion of the water from the sludge. Cement is added to the waste. The waste will then become a solid mass. The waste is then prepared for loading and offsite shipment. Dewatering of sludges is method of waste stabalization.

The dewatering equipment is located in the LLRPSF. The waste is transferred from the waste holding tank to a HIC or liner located in the dewatering pit in the storage portion of the LLRPSF. The dewatering system uses DAEC service air which exhausts into the LLRPSF ventilation system. Water removed from the HIC or liner is returned to the radwaste system via the conveyor floor drain sump.

Dewatering is performed by pulling a suction on an underdrain manifold in the HIC. The dewatering process achieves a residual of less than 1% freestanding water in the waste, which meets the requirements of 10 CFR 61.56(a)(3) and (b)(2).

When dewatering is complete, the liner or HIC can be stored in the LLRPSF storage area or moved to the truck bay for loading and offsite shipment by a licensed carrier to a licensed disposal site in accordance with applicable regulations of the Department of Transportation and the NRC.

HICs are used for packaging of solid waste during temporary onsite storage, shipment, and permanent offsite storage because of ready availability, ease of handling, and conformance with present shipping practices and disposal site requirements.

Loading of HICs and drums for offsite shipment is done within the radwaste building or the LLRPSF.

11.4.2.3 Dry Wastes

Miscellaneous solid wastes result from operation and maintenance, and a means for handling and disposal are necessary to ensure proper control and prevent the spread of contamination. Typical of these wastes are air filters; miscellaneous paper, rags, etc., from contaminated areas; contaminated clothing, tools, and equipment parts, which cannot be economically decontaminated; solid laboratory wastes; used reactor equipment such as spent control rod blades, fuel channels, and incore ion chambers; and large pieces of equipment.

The disposition of a particular item of waste is determined by its radiation level, type, and the availability of disposal space. Because of high activation and contamination levels, used reactor components are stored in the spent-fuel pool for sufficient time to obtain optimum radioactive decay before removal to either in-plant or offsite storage and final disposal. Otherwise, the wastes need to be held on the site only until quantities large enough for economical shipment are accumulated.

11.5.1.5 Inspection and Testing

A built-in, adjustable current source is provided with each log radiation monitor for test purposes. Routine verification of the operability of each monitoring channel can be made by comparing the outputs of the channels during power operation.

11.5.2 AIR EJECTOR OFFGAS RADIATION MONITORING SYSTEM

11.5.2.1 Power Generation Objectives

The power generation objectives of the air ejector offgas radiation monitoring system are to indicate when limits for the release of radioactive material to the environs are approached and to effect appropriate control of the offgas so that the limits are not exceeded.

11.5.2.2 Power Generation Design Bases

1. The air ejector offgas pre-treatment radiation monitoring system provides an alarm to operations personnel when the radioactivity discharge rate exceeds 1 Curie/second after 30 minutes of delay and decay.

2. The air ejector offgas radiation monitoring system provides a record of the radioactivity released via the air ejector offgas line.

3. The air ejector offgas post-treatment radiation monitoring system initiates appropriate action in time to prevent exceeding the maximum instantaneous release rate limit of radioactive materials to the environs from the air ejector offgas.

11.5.2.3 System Description

The air ejector offgas radiation monitor system is shown in Figures 11.5-1 and 11.3-2, and specifications are given in Table 11.5-1. The offgas is monitored both before and after the recombiner/carbon-bed treatment. The monitoring system used before treatment is comprised of one instrument channel monitoring the gases passing through a vertical section of stainless steel pipe designed to minimize plateout. A sample is drawn from the offgas line through the sample chamber by the main condenser suction. The sample system is arranged to give at least a 2-min time delay before the sample is monitored to allow nitrogen-16 and oxygen-19 activity decay. This reduces the background radiation that the detector would otherwise measure. The channel consists of a gama-sensitive ion chamber, a log radiation monitor that includes a power supply and a meter, and a one-pen strip chart recorder. The monitor and the one-pen recorder are located in the main control room.

The monitor has two upscale trip circuits, one downscale trip circuit and an instrument inoperative trip. The upscale trips indicate high and high-high radiation, the downscale trip (low) indicates instrument trouble or a dose rate below the downscale setpoint and the instrument inoperative trip indicates instrument trouble. Any one trip will give an alarm in the main control room.

The monitoring system used after the recombiner/carbon-bed treatment is comprised of two independent channels monitoring gases passing through a sample chamber mounted on a sample rack along with pump, flow measuring and control equipment, check sources, purge equipment, scintillation detectors, and pre-amplifiers. Each channel is comprised of a detector, a pre-amplifier, a log count-rate monitor including power supply and meter, and one pen of a continuous two-pen strip chart recorder. The detectors monitoring the process after treatment are gamma-sensitive scintillation detectors. The monitors for these channels are seven-decade log count rate monitors located in the control room with three adjustable upscale trip circuits, one downscale trip circuit, and an instrument inoperative trip. An instrument failure gives a downscale trip or an inoperative trip. If either channel experiences the lower level upscale trip (high), the carbon bed bypass line will close, the treatment line isolation valve will open and an alarm will be received. The intermediate upscale trip (high-high) is used to alarm only. If an inoperative, downscale or upscale trip (high-high-high) occurs on one channel along with any of the same trips on the other channel, an alarm will occur. The offgas post-treatment radiation monitor system is shown schematically in Figure 11.5-2.

The electronic signals from the post-treatment radiation monitors (Figure 11.5-1) feed the "Treat, Auto, and Bypass" remote manual switch, which controls valves CV-4134A (treat) and CV-4134B (bypass) (Figure 11.3-2). The automatic provisions of shifting from bypass to treat are only applicable in the auto mode.

The following are examples of system operation using the above-described logic:

1. If the offgas system is operating with valve CV-4134B open and valve CV-4134A closed (bypass mode configuration), and the mode switch is in the auto position, on the receipt of a low-radiation alarm signal, no change in valve positions would occur. On the receipt of a high-radiation alarm signal, valve CV-4134B would close and valve CV-4134A would open, thereby directing the offgas process stream through the charcoal beds for treatment. If the high-radiation alarm is cleared and it is determined that the operator desires to return the system to bypass, the operator may do this by resetting the alarm.

2. If the offgas system is operating with valve CV-4134A open (charcoal bed process valve) and valve CV-4134B (bypass valve) closed, and the mode switch is in the treat mode, on the receipt of a low-radiation signal or a high-radiation signal, no change in valve positions would occur. The offgas system mode switch will normally be maintained in the treat position. The auto and bypass provisions are retained for system flexibility so that plant reliability is not compromised.

The operation of the offgas system with the offgas system mode switch in the bypass position is not normally permitted.

Small changes in the offgas gross fission product concentration can be detected by the continuous use of the linear (flux tilt) radiation monitor. The linear radiation monitor is not a process monitor such as the channels described above but is used as an expanded scale device for aiding in the measurement of small changes in the offgas radiation level. The detector is a gamma-sensitive ionization chamber that monitors the same sample as the air ejector offgas detectors monitoring the process before treatment. The system uses a linear readout with a range switch instead of a logarithmic readout. The output from the monitor is recorded on a one-pen recorder. (Improved fuel sipping technology and the poor sensitivity of the flux tilt monitoring process have made the use of this monitor obsolete. This equipment has been abandoned in place.)

The carbon vault is monitored for gamma activity with a single instrument channel. The channel includes a sensor and converter, an indicator and trip unit, and a locally mounted auxiliary unit. The power source is one of the power supplies associated with the refuel pool ventilation exhaust radiation monitors. The indicator and trip unit is located in the main control room. The channel provides for sensing and readout, both local and remote, of gamma radiation over a range of six logarithmic decades (1 to 10^6 mR/hr).

The indicator and trip unit has one adjustable upscale trip circuit for alarm and one downscale trip circuit for instrument trouble. The trip circuits provide convenient operational verification by means of test signals or through the use of portable gamma sources. All components are self-monitoring to the extent that power failure to any component operates the trip circuits.

The following applies to effluent and in-plant gaseous radwaste sampling locations subject to periodic sampling:

1. There are four general areas where periodic samplings are taken:

    a. Last stage of steam jet air ejectors before dilution steam to obtain data on "raw" offgas process steam.

    b. Just upstream of 30-min holdup pipe to acquire data on recombined offgas stream.

c. Just before entry to charcoal bed vault to obtain data before gas treatment through charcoal bed adsorbers.

d. Two sample points in vault downstream of first bed in each adsorber train to monitor performance of first bed.

2. Expected composition and respective concentrations are one-fourth of those contained in Tables 11.3-2 and 11.3-6.

3. Quantity measurements for atmospheric releases are discussed in Section 1.8.2.1.

4. Frequency of measurements for atmospheric releases are also discussed in Section 1.8.

11.5.2.4 Power Generation Evaluation

The air ejector offgas radiation monitors have been selected with characteristics sufficient to provide plant operations personnel with accurate indication of radioactivity in the air ejector offgas. The system thus provides the operator with enough information to easily control the activity release rate. Sufficient redundancy is provided to allow maintenance on one channel without losing the indications provided by the system.

11.5.2.5 Inspection and Testing

Each channel can be calibrated by the analysis of a grab sample.

11.5.3 OFFGAS STACK RADIATION MONITORING SYSTEM

The offgas stack radiation monitoring system described herein is in addition to the offgas stack radiation monitoring subsystem of the extended range airborne effluent radiation monitoring system described in Section 11.5.9.

11.5.3.1 Power Generation Objectives

The power generation objectives of the offgas stack radiation monitoring system are to indicate when limits on the release of radioactive material to the environs are reached or exceeded and to indicate the rate of radioactive material released during planned operation.

11.5.3.2 Power Generation Design Bases

1. The offgas stack radiation monitoring system provides a clear indication to operations personnel when limits on the release of radioactive material to the environs are reached or exceeded.

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Chapter 13

CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE OF IES UTILITIES INC.

IES Utilities Inc. (formerly Iowa Electric Light and Power Company) is responsible for all station operations from the start of preoperational testing and is responsible for using properly licensed personnel to operate the plant. Technical assistance and direction during the preoperational testing, initial core loading, startup, and precommercial testing was provided by Bechtel Corporation (Bechtel) and the General Electric Company (GE). Technical assistance is made available as required during plant operation.

The DAEC Plant Manager is responsible for the safe, reliable, and efficient operation of the facility. He has a staff of trained and properly licensed personnel to accomplish all of the various plant functions and disciplines. All phases of plant operation are performed in accordance with written and approved operation, maintenance, radiation protection, and emergency procedures. These procedures factor in all available experience encountered in the startup and operation of earlier boiling-water reactor (BWR) plants. Significant operations, tests, and pertinent information are recorded and a file of these records is maintained.

A training program to qualify the staff to satisfy the then existing Atomic Energy Commission (AEC) license requirements for the initial fuel loading, preliminary testing, and commercial operation was carried out. Training, retraining, and licensing has continued after startup to ensure an adequate number of licensed operators and properly trained replacement personnel for all disciplines.

A Safety Committee has been established to advise the President, IES Utilities Inc. on the status of nuclear safety and make recommendations regarding major procedure, facility, and license modifications, and to conduct periodic safety reviews on the site. An Operations Committee consisting of plant supervisory personnel makes recommendations to the DAEC Plant Manager, reviews plant operations in detail, and approves procedure changes involving nuclear safety. Records of the proceedings of both committees are maintained.

13.1.1 MANAGEMENT AND TECHNICAL SUPPORT ORGANIZATION

13.1.1.1 Design and Operating Responsibilities

13.1.1.1.1 Design and Operating Responsibilities - Project Phase

The Design and Operating responsibilities for the DAEC during the project phase were described in Section 1.1.2.1 of the original FSAR.

13.1.1.1.2 Technical Support for Operations

Management and technical responsibility for the operation of the DAEC resides in the Nuclear Generation Division. This Division is responsible for the integration of licensing, engineering and technical support, and operation of the DAEC. The Engineering Department within the Nuclear Generation Division is responsible for providing engineering and technical support for the DAEC.

DAEC depends on consultant assistance from specialized consulting companies. Work activities are authorized by the Vice President, Nuclear, or his designated alternate. Work may be authorized by purchase order or letter.

Offsite senior management resources are readily available by virtue of the proximity of the DAEC to the IES Utilities Inc. corporate offices.

13.1.1.2 Organizational Arrangement

13.1.1.2.1 Corporate Organization

IES Utilities Inc., which is a subsidiary of Alliant Energy Corporation, is organized into divisions, departments, groups, and committees, which are unique entities that have been assigned specific responsibilities. The corporate organizational arrangement is shown in Figure 13.1-1. The President, IES Utilities Inc. and the Executive Vice-President Corporate Services report to the President and Chief Executive Officer Alliant Energy Corporation. The Vice President, Nuclear and the Safety Committee report to the President, IES Utilities Inc. These individuals, committees, and their reporting organizations have responsibilities that are germane to the safe operation of the DAEC.

President and Chief Executive Officer Alliant Energy Corporation

The President and Chief Executive Officer Alliant Energy Corporation has general supervision of the Company's business affairs and performs such other duties as required by the Board of Directors.

President, IES Utilities Inc.

The President, IES Utilities Inc.:

1. Directs the Company's affairs, subject to policies and directives formulated by the Board of Directors.

2. Assigns to other corporate officers the authority to conduct the Company's operations. He is responsible for all of the operating, maintenance, and facility expansion activities in the Company.

3. Responsibilities include, but are not limited to: the management of engineering, design, construction and contractual execution of all expansion or revisions of physical plant facilities; the management of all electrical generation facilities, including fuel supply to support these functions; and the management of all gas department activities, including the wholesale purchases of same.

4. Is responsible for all marketing and commercial activities and for the inter-Company relations, including wholesale sales and purchases, other utility and REA relations, and Regional and/or business and professional organizational participation.

5. Endorses the Operational Quality Assurance Program Policy.

13.1.1.2.2 Nuclear Generation Division Organization

Vice President, Nuclear

The Vice President, Nuclear reports to the President, IES Utilities Inc.. The Nuclear Generation Division Organization is shown in Figure 13.1-1.

The primary responsibility of the Vice President, Nuclear is the safe operation of the DAEC. Other responsibilities include, but are not limited to, the following:

1. Managing the Nuclear Generation Division, which is responsible for:

   a. Operation and maintenance of the DAEC,

   b. Regulatory agency interfaces and relations,

   c. Licensing activities,

   d. Emergency planning activities,

   e. Nuclear fuel management activities,

   f. Nuclear facility engineering activities, including consultative or special engineering requirements and the special consultant support that may be necessary to ensure the most effective operation,

   g. Training of nuclear personnel,

   h. Outage planning, scheduling, and

   i. Overall effectiveness of the Quality Assurance Program.

Specific quality program responsibilities include:

- approval of the Quality Assurance Manual,
- conducting an evaluation of the effectiveness of the Quality Assurance Program every other year, alternating with the Safety Committee,
- supporting the Manager, Quality Assurance in the resolution of conflicts regarding quality matters with the Manager Regulatory Performance,
- and reserve the authority to conduct or order the auditing of any activity at any time to determine compliance to the Quality Assurance Manual.

2. Maintaining relationships and integration with the co-owners of the nuclear facilities.

Site General Manager

The Site General Manager reports to the Vice President, Nuclear. Responsibilities of the Site General Manager include, but are not limited to, overseeing the operation and maintenance of the DAEC, licensing activities, nuclear fuel management activities, training of nuclear personnel, and engineering activities.

13.1.1.2.2.1 Duane Arnold Energy Center

To achieve the objective of safe operation of the DAEC, the Nuclear Generation Division has been given specific assignments for operation, engineering, licensing, and emergency planning, and the procurement of nuclear fuel. These responsibilities are distributed among the organizations within the division. These include the Engineering Department, Regulatory Performance Department, Nuclear Training Department, Business Unit and the Duane Arnold Energy Center (see Figure 13.1-1).

Engineering Department

The Manager, Engineering is assigned the primary responsibility for the design changes and engineering relative to the safe operation of the DAEC. The Manager, Engineering reports to the Site General Manager and is responsible for the following:

1. Planning, designing and construction of all facility changes at the DAEC.

2. Supervising project engineering activities assigned to the Nuclear Generation Division. This includes the implementation of appropriate project financial and schedular control.

3. Assisting in negotiations involving Nuclear Generation Division projects in achieving compliance with legal and regulatory requirements.

4. Coordination of those activities associated with maintaining those engineering documents, drawings, specifications, manuals, and computer software and databases necessary to support the day-to-day activities within the Nuclear Generation Division.

5. Providing specialized engineering support to the organization in such areas as Systems, Procurement, Analysis, ASME, ISI, IST, Environmental Qualification (EQ), Maintenance, etc.

6. Preparing and maintaining lists that denote the specific safety-related structures, systems, and components.

7. Receipt, storage and issuance of spare parts and materials utilized in the operation and maintenance of the DAEC. This includes inventory control and issuance of part numbers for the Bill of Materials program.

8. Procuring of new, replacement, and spare components, parts, equipment and services relative to the operation of the DAEC, establishing procedures for the control of associated procurement activities, and evaluating suppliers for their commercial qualifications.

9. Maintaining the DAEC Fire Plan and for coordination of those activities necessary to ensure compliance with the Plan, applicable Fire codes and Federal Regulations. Such activities include control of combustibles materials on site, coordination and scheduling of fire drills, ensuring routine maintenance of the fire protection equipment is properly performed, ensuring that the DAEC fire brigade is properly trained and staffed and providing fire protection engineering support. The DAEC Fire Marshall reports to the Team Leader, Long Term Programs.

A description of organizational responsibilities is contained within the Nuclear Generation Division Procedures.

Regulatory Performance

The Manager, Regulatory Performance reports to the Site General Manager and has responsibility for the areas of Nuclear Licensing, Security, and Quality Assurance activities.

The Manager, Nuclear Licensing reports to the Manager, Regulatory Performance. Responsibilities for Nuclear Licensing include, but are not limited to the following:

1. Managing nuclear licensing activities regarding the DAEC to ensure compliance with regulatory requirements.

2. Maintaining the Updated Final Safety Analysis Report and preparing the periodic submittal of revisions in accordance with 10 CFR 50.71(e) requirements.

3. Preparation and submittal of any necessary changes to the DAEC Operating License and/or Technical Specifications in accordance with 10 CFR 50.90, §50.91 and §50.92.

4. Assigning the responsibility for the evaluation of Inspection and Enforcement Bulletins, Generic Letters and Regulatory Guides. Such evaluations will determine applicability to the DAEC and the necessity for establishing a DAEC position.

5. Investigating plant incidents to determine root cause and recommend corrective actions to plant management, assist in the determination of the reportability of such events pursuant to 10 CFR 50.72 and 50.73 requirements and prepare Licensee Event Reports (LERs) in accordance with 10 CFR 50.73 requirements.

6. Performing Post Scram reviews and making recommendations to the Operations Committee for plant re-start in accordance with NRC Generic Letter 83-28, Item 1.1 requirements.

7. Coordinating the dissemination and review of Industry Operating Experience on site.

The Security Superintendent is responsible for conducting the security program under the direction of the Manager, Regulatory Performance. The primary responsibility of the security organization is to regulate access to the plant and protect against radiological sabotage. In addition, they issue and collect radiation monitoring devices. They also are responsible for implementing the DAEC Fitness-for-Duty Program. See Section 13.6.

A description of organizational responsibilities is contained in the Nuclear Generation Division Procedures.

Duane Arnold Energy Center

The duties and responsibilities of the DAEC Plant Manager can be found in Section 13.1.2.2.1. The DAEC Plant Manager reports to the Site General Manager.

Training

The Training Department is headed by the Manager, Nuclear Training, who reports to the Site General Manager and includes the instructors, the DAEC Simulator and other training facilities needed for carrying out the DAEC training programs for licensed personnel, unlicensed personnel, and general employee training discussed in Section 13.2.2.

Emergency Planning

The Manager, Emergency Planning, reports to the Manager, Nuclear Training and is assigned the primary responsibility for Emergency Planning activities for the Nuclear Generation Division, both onsite and offsite. The Manager, Emergency Planning is authorized direct access to the Vice President, Nuclear in support of maintaining the effectiveness of onsite and offsite emergency plans and corporate management level support. The purpose of the DAEC onsite and offsite plans is to ensure that the public is adequately protected in the event of a radiological emergency at the DAEC. The Manager, Emergency Planning, is designated as the primary contact with the NRC, State of Iowa and the Federal Emergency Management Agency (FEMA) in matters affecting the emergency plans and implementing procedures.

Business Unit

The Manager, Business Unit reports to the Site General Manager. The Business Unit is responsible for the Nuclear Generation Division accounting, budgeting and contract administration. The Unit is also responsible for long-term planning, monitoring of the financial viability and decommissioning of the DAEC. The Manager, Business Unit coordinates communications with the DAEC co-owners, i.e. CIPCO and Cornbelt.

The Nuclear Fuels function within the Business Unit is responsible for the economics of each fuel reload, the procurement of nuclear fuel, long-term fuel management for the DAEC, providing for the long term disposition of spent fuel and for providing operational support to the DAEC.

13.1.1.2.2.2 Quality Assurance Department

The Manager, Quality Assurance, is assigned the primary responsibility for ensuring that quality requirements relative to the safe operation of the DAEC are identified and met. He reports to the Manager, Regulatory Performance. The Manager, Quality Assurance also has direct access to the Vice President, Nuclear as necessary regarding quality matters. (See Figure 13.1-1).

The current description of organizational responsibilities is contained within the Quality Assurance Department Procedures.

The Manager, Quality Assurance, is responsible for:

1. Preparing and maintaining the DAEC Operational Quality Assurance Program. (See Chapter 17.2)
2. Evaluating the effectiveness of the DAEC Operational Quality Assurance Program and issuing periodic reports to the appropriate levels of management.

13.1.1.2.2.3 Records and Microfilm Administrator

The Records and Microfilm Administrator ultimately reports to the President and Chief Executive Officer Alliant Energy Corporation and is responsible for storing, protecting, and retrieving records relating to the operation of the DAEC. The organizations responsible for initially controlling records are responsible for the formal turnover of records to the Records and Microfilm Administrator who provides microfilming and record reproduction services.

13.1.1.2.3 Safety Committee

The Safety Committee functions to provide independent reviews and audits of designated activities. The functions and composition of the Safety Committee are specified in Appendix A of Chapter 17.2 and the Safety Committee Charter. See Section 13.4.2.1.

13.1.1.3 Qualifications

The principal senior members of the IES Utilities Inc. staff responsible for providing technical support for operations of the DAEC include the President and Chief Executive Officer Alliant Energy Corporation; President, IES Utilities Inc.; the Vice President, Nuclear; Site General Manager; the Manager, Engineering; the Manager, Regulatory Performance; the Manager, Nuclear Licensing; the Manager, Emergency Planning; the Manager, Business Unit; the Manager, Nuclear Training and the Manager, Quality Assurance.

The Regional Administrator, Region III, U.S. Nuclear Regulatory Commission, will be kept informed of the individuals filling these positions. Information regarding their individual educational background and related experience will be made available at IES Utilities Inc. for NRC review upon request.

13.1.2 OPERATING ORGANIZATION

13.1.2.1 Plant Organization

The Site General Manager has direct line responsibility for the operation of the DAEC. The DAEC Plant Manager is responsible for the safe, reliable, and efficient management of the plant. The DAEC Plant Manager may designate personnel to act in his behalf during his absence from the plant, in accordance with ANSI/ANS-3.1-1978, Section 4.2.1. The basic organization of the DAEC consists of departments headed by the Operations Manager, Operations Support Manager, Maintenance Manager, and the Radiation Protection Manager. The Operations Committee also reports to the DAEC Plant Manager. The plant organization is shown in Figure 13.1-2. This basic group is backed up by technical personnel as required, and it is enlarged during periods of refueling, and major equipment maintenance.

IES Utilities Inc. has been responsible for all station operations from the start of preoperational tests. General Electric and Bechtel provided technical direction and assistance during the period of preoperational testing, core loading, startup, and pre-commercial operations.

Operations Department

The Operations Department is headed by the Operations Manager and the Operations Supervisors. Each is a Senior Reactor Operator as required by ANSI/ANS 3.1-1978.

Most of the personnel who make up this group are qualified by academic instruction and experience at operating reactor and simulator facilities. The Operations Manager, Operations Supervisors, Operations Shift Managers, Operations Shift Supervisors, the Nuclear Station Operating Engineers, and the Assistant Nuclear Station Operating Engineers hold appropriate NRC licenses. These persons monitor and operate the plant nuclear, mechanical, and electrical equipment and conduct radiation surveys as required. Fuel handling activities are directed by Fuel Handling Senior Reactor Operators under the direction of the Operations Department.

The personnel for these positions were initially assigned their duties by selection from those undergoing training. Their experience and performance during training were evaluated before they were assigned to a position. Most of the initial individuals were chosen from a group of Company personnel who successfully completed a

Company-conducted nuclear power orientation course. These individuals were supplemented by personnel who had previous nuclear experience in the Naval Nuclear Power Program.

Since the DAEC has become operational, positions on the staff that become vacant are filled, where possible, by employees who progress through the different positions. They, of course, have to meet all the requirements of the appropriate NRC licenses. Individuals are initially assigned to these positions after a careful evaluation of their qualifications, their progress in the training program, and the proficiency level reached in their last position.

The duties and responsibilities of personnel from the Operations Group on an operating shift are described in Section 13.1.2.3.

Operations Support Department

The Operations Support Department is headed by the Operations Support Manager, who reports to the Plant Manager and is responsible for the Shift Technical Advisors (STAs), the Reactor Engineering Group and the Procedures Department. The Operations Support Manager is also responsible for maintaining Emergency Operating Procedures (EOPs).

The Reactor Engineering Group, headed by the Reactor Engineering Group Leader, reports to the Operations Support Manager. The group has responsibility for nuclear fuel reload design, monitoring the performance of the reactor core to ensure safe and economical use of the nuclear fuel and for maintaining all the necessary records for the special nuclear material on site.

The Plant Procedures Supervisor leads the Procedures Department and reports to the Operations Support Manager. The Procedures Department is responsible for maintaining plant procedures and procedure programs including the DAEC Surveillance Program, Modifications Acceptance Testing, Special Testing (SpTP), and Biannual Review Program.

Maintenance Department

The Maintenance Department is headed by the Maintenance Manager and is divided into six groups: the Mechanical Group, headed by the Mechanical Maintenance Supervisor; the Electrical Group, headed by the Electrical Maintenance Supervisor; the Instrumentation and Controls Group, headed by the Instrumentation and Controls Maintenance Supervisor; the Maintenance Process Support Group, headed by the Maintenance Process Support Supervisor; the Fix It Now (FIN) Team, headed by the FIN Team Leader; and the Work Management Group, headed by the Work Management Maintenance Supervisor.

The Mechanical Maintenance Group is composed of the Supervisor, nuclear mechanics, nuclear mechanic machinists, nuclear mechanic welders, and apprentices as required. Their duties consist of day-to-day repairs and adjustments, equipment condition inspections, equipment overhauls, and equipment modifications.

The Electrical Maintenance Group is composed of the Supervisor, nuclear station and substation electricians, and apprentices as required. Their duties consist of the maintenance, and modification of plant electrical equipment and equipment condition inspections.

The Instrumentation and Controls Group is composed of the Supervisor, nuclear station control system technicians and apprentices as required. Their duties consist of the maintenance, modification and calibration of instruments and controls.

The Maintenance Process Support Group is composed of the Supervisor, the Metrology Group, the Administrative Control Group, and the Quality Control Group and the Civil/Facilities Support Group. Their function is to provide the administrative support duties for the Maintenance organization, including inspection and testing necessary to support operation, testing, maintenance and modification of the DAEC.

The FIN Team is composed of the Team Leader and technicians from various craft groups. The duties of the FIN Team include minor equipment repairs.

The Work Management Group includes the Supervisor, the Scheduling Group and the Work Control Center. The duties include managing activities required to prepare for and conduct outage and on-line work. These responsibilities include, but are not limited to, budget and cost monitoring, planning and scheduling, resource procurement, scope control, and work execution, management and coordination.

The maintenance staff is augmented with qualified personnel from outside sources during refueling and major maintenance periods. The maintenance staff closely coordinates its work with the Operations Department and assisted during the initial core loading and subsequent refueling operations.

Radiation Protection Department

The Radiation Protection Department is headed by the Radiation Protection Manager. This Department includes the Health Physics, Chemistry, Radiological Engineering and Radioactive Waste Groups.

The Radiation Protection Department is responsible for plant radiation safety and performs contamination and radiation surveys and radiological decontamination activities necessary to ensure plant safety. The Radiation Protection Department is on call at all times.

The department is also responsible for those plant activities associated with maintaining the plant water chemistry as well as collection, packaging and transport of all radioactive waste materials.

The department is responsible for satisfying the Technical Specifications and manpower requirements for shift coverage in radwaste, chemistry, and health physics.

Health Physics Technicians are assigned shift work as required to meet plant operating needs. All members of the plant operating shift crews receive sufficient health physics training to be able to perform self-monitoring activities.

13.1.2.2 Plant Personnel Responsibilities and Authorities

The job description, requirements, and responsibilities of key plant personnel are included in this section. The responsibilities described are not meant to apply to only one specific position. Supervisors who meet the necessary qualifications may assume the responsibilities of positions other than their own on a temporary basis.

13.1.2.2.1 DAEC Plant Manager

The DAEC Plant Manager is assigned the primary responsibility for the safe operation of the DAEC. The DAEC Plant Manager has supervisory control over those onsite activities necessary for safe operation and maintenance of the DAEC. The organizational arrangement is presented in Figure 13.1-2. The current organizational arrangement and description of organizational responsibilities are contained within the administrative procedures and the Technical Specifications. The license requirements for each position are specified in Table 13.1-2.

- The various organizations reporting to the DAEC Plant Manager are responsible for those activities associated with operations, maintenance, repair, refueling, performance evaluation, testing, radiation protection/ALARA, and the environmental survey program.

- The Operations Committee functions to advise the DAEC Plant Manager on all matters related to nuclear safety. The composition, function, and responsibilities of the Operations Committee are specified in the Appendix A of Chapter 17.2 and are delineated in appropriate DAEC administrative procedures.

The DAEC Plant Manager reports to the Site General Manager. Specific responsibilities include, but are not limited to, the following:

1. Managing the day-to-day activities of the DAEC. These activities include power plant operations, maintenance, radiation protection, security, and technical support.

2. Coordinating interfacing activities with the NRC inspecting personnel and Quality Assurance personnel.

3. Planning and coordinating all onsite activities.

13.1.2.2.2 Operations Manager

The Operations Manager is responsible for the operation, safety, and security of all plant equipment and the safety and action of all personnel involved in plant operations. The Operations Manager is responsible for maintaining station operating records in accordance with the facility license.

13.1.2.2.3 Operations Shift Managers

The Operations Shift Managers are in charge of their respective shifts and supervise personnel and equipment operation for the safe, efficient, and reliable operation of the plant. See Section 13.1.2.3.

13.1.2.2.4 Maintenance Manager

The Maintenance Manager is responsible for day-to-day maintenance, alteration, overhaul, and repair of electrical, mechanical, and auxiliary equipment associated with the plant. The Mechanical Maintenance Supervisor, Electrical Maintenance Supervisor, Instrumentation and Controls Maintenance Supervisor, Maintenance Process Support Supervisor, Work Management Maintenance Supervisor and FIN Team Leader report to the Maintenance Manager.

13.1.2.2.5 Mechanical Maintenance Supervisor

The Mechanical Maintenance Supervisor is responsible for supervising the day-to-day maintenance, alteration, overhaul, and repair of mechanical equipment associated with the facility. The Mechanical Maintenance Supervisor participates in personnel training and in the review of operating and maintenance manuals for his area of responsibility.

13.1.2.2.6 Electrical Maintenance Supervisor

The Electrical Maintenance Supervisor is responsible for supervising the day-to-day maintenance, alteration, overhaul, and repair of electrical equipment associated with the facility. The Electrical Maintenance Supervisor participates in personnel training and in the review of operating and maintenance manuals for his area of responsibility.

13.1.2.2.7 Instrumentation & Controls (I&C) Maintenance Supervisor

The I&C Maintenance Supervisor is responsible for supervising the day-to-day maintenance, alteration, overhaul, calibration, repair and surveillance of instrumentation and control equipment associated with the facility. The I&C Maintenance Supervisor participates in personnel training and in the review of operating and maintenance manuals for his area of responsibility.

13.1.2.2.8 Maintenance Process Support Supervisor

The Maintenance Process Support Supervisor is responsible for supervising the day-to-day administrative duties of the Maintenance Department. This includes the Quality Control, Metrology functions and Civil/Facilities Support for the organization.

13.1.2.2.9 Fix It Now (FIN) Team Leader

The FIN Team Leader is responsible for the screening of work request cards in the conduct of maintenance activities and directing the conduct of the short duration tasks performed under the fix-it-now repair process.

13.1.2.2.10 Work Management Maintenance Supervisor

The Work Management Maintenance Supervisor is responsible for supervising the work of the Work Control Center, Scheduling, and Outage Management.

13.1.2.2.11 Radiation Protection Manager

The Radiation Protection Manager (RPM) is responsible for plant radiation safety and plant chemistry. The RPM supervises plant chemical and radiological activities and is in charge of the laboratory, plant chemical equipment, and radiological analysis. In addition, the RPM maintains a documented record of radiation levels within plant areas as specified by the Plant Manager, and maintains a documented exposure history on all plant personnel and visitors who are subject to exposure. The RPM provides technical advice to plant personnel. The RPM is responsible for establishing, and has the authority to enforce, the radiation safety control policies by which the plant operates and with which all plant personnel and visitors must comply.

13.1.2.2.12 Chemistry Supervisor

The plant Chemistry Supervisor is responsible for performing the chemical and radio-chemical analyses for the power plant. The Chemistry Supervisor is responsible for maintaining the Plant Water Chemistry and the radiological environmental monitoring program, including regulations on liquid (non-radiological) discharges, water use regulations, and air emission regulations.

13.1.2.2.13 Radwaste Supervisor

The Radwaste Supervisor is responsible for the collection, treatment and processing of all radioactive liquid and solid waste generated at the DAEC. The Radwaste Operators report to the Radwaste Supervisor.

13.1.2.2.14 Radwaste and Material Handling Supervisor

The Radwaste and Material Handling Supervisor is responsible for coordinating all radiological decontamination activities performed on site and for the lease, purchase, storage and issue of all radiological protective clothing. The Radwaste and Material Handling Supervisor is responsible for processing and storage of Dry Active Waste (DAW) and shipping of all radioactive materials/waste.

13.1.2.2.15 Health Physics Supervisor

The Health Physics Supervisor is responsible for performing the radiation and contamination surveys of the plant, posting of radiological conditions, issuance of Radiation Work Permits and establishing the necessary radiological controls for work performed in radioactive areas of the plant. The Health Physics Supervisor is also responsible for evaluating radiological conditions in the plant, making recommendations on work practices and design changes to ensure doses are ALARA, issuance and analysis of personnel dosimetry, maintenance of records of personnel exposure and the off-site environmental monitoring program. The Health Physics technicians report to the Health Physics Supervisor.

13.1.2.2.16 Radiological Engineering Supervisor

The Radiological Engineering Supervisor provides oversight of professional support to the radiation protection programs including responsibilities for the measurement and documentation of personnel radiation exposure.

13.1.2.2.17 RCRA/HAZMAT Program Owners

The RCRA/HAZMAT Program Owners are responsible for developing and maintaining programs for onsite compliance with environmental regulations. This includes compliance with RCRA hazardous waste regulations and spill regulations.

13.1.2.3 Operating Shift Crews

The normal operating shift crews consists of an Operations Shift Manager (SRO) in charge, an Operations Shift Supervisor (SRO), a Nuclear Station Operating Engineer (RO), two Assistant Nuclear Station Operating Engineer (RO), two Nuclear Station Plant Equipment Operators, and a Shift Technical Advisor.

The duties and responsibilities of the personnel on an operating shift are as follows:

1. Operations Shift Manager - SRO

   The Operations Shift Manager is in charge of the shift. He supervises personnel to ensure safe, efficient, and proper operation of the DAEC. He is responsible for radiation safety and chemistry, as well as tests and results on his shift. He participates in personnel training and in the review of operating manuals and instructions in the startup, operation, and shutdown of the facility. He participates in and contributes to the planning and scheduling of maintenance and refueling activities.

2. Operations Shift Supervisor - SRO

   The Operations Shift Supervisor has the same duties and responsibilities as the Shift Manager except that of being in charge of the shift. He is included in the shift in order to permit the Shift Manager to move about the plant as needed during normal and emergency situations while at the same time fulfilling the NRC requirement that a Senior Licensed Operator be present at all times in the control room when the unit is being operated. The Operations Shift Supervisor is required for all reactor modes except cold shutdown and refuel mode.

3. Nuclear Station Operating Engineer - RO

   The Operating Engineer, on instructions from the Operations Shift Supervisor, directs generator loading and electrical switching. He monitors, controls, and directs the operation of the reactor, turbine-generator, auxiliaries, and electrical equipment. He interprets, audits, and reviews instrumentation and chart indications as to the performance, efficiency, radiation, and chemistry of the plant. He assists in the training of personnel in the skills and knowledge required for the safe and efficient operation of the facility. He performs work in reactor-fuel-handling operations involving the preparation, transfer, loading, and unloading of fuel. He may be assigned to the maintenance crew while the reactor plant is not in operation.

4. Assistant Nuclear Station Operating Engineer - RO

The First Assistant Operating Engineer works under the intermittent supervision of the Operations Shift Manager, Operations Shift Supervisor, or Operating Engineer. The duties of the First Assistant Operating Engineer are essentially the same as those of the Operating Engineer; thus, the Operating Engineer and First Assistant Operating Engineer are equally qualified to operate either the reactor control board or turbine-generator control board. The First Assistant Operating Engineer may be assigned to the maintenance crew while the reactor plant is not in operation.

5. Nuclear Station Plant Equipment Operators

The Nuclear Station Plant Equipment Operators (NSPEO), under the direction of licensed operators in the plant control room, inspects, services, starts, and stops the turbine-generator, mechanical, electrical, related nuclear equipment, and auxiliaries in the reactor building, turbine building, pump house, intake structure, and cooling towers. The NSPEO observes charts, gauges, instruments and controls, records readings as required and assists in the preparation of station log sheets and reports. The NSPEO is able to conduct radiation surveys and possesses a working knowledge of water treatment equipment. The NSPEO may be assigned to the maintenance crew while the reactor plant is not in operation.

6. Shift Technical Advisor

The Shift Technical Advisor (STA) provides engineering support on-shift in accordance with NUREG-0737, Item I.A.1 requirements.

The requirements and responsibilities of the STA include the following:

a. The Shift Technical Advisor will be stationed onsite and will be present in the control room within 10 minutes of being summoned during plant power operation, in other than cold shutdown or refuel mode.

b. The Shift Technical Advisor serves as an advisor to the Operations Shift Manager during off-normal reactor plant conditions.

c. The Shift Technical Advisor will provide operating experience assessment functions as related to DAEC design, procedures, and practice, and in support of their transient/accident assessment functions.

d. In the performance of these duties, the Shift Technical Advisor will be free of duties associated with the commercial operation of the plant and will report directly to the Operations Shift Manager.

13.1.3 QUALIFICATION OF NUCLEAR PLANT PERSONNEL

13.1.3.1 Qualifications Requirements

The qualifications of individual members of the plant staff meet or exceed the minimum qualification requirements referenced in ANSI/ANS 3.1-1978 for comparable positions.

Either the Plant Manager, Nuclear or one of his designated principal alternates shall have the experience and training normally required for a Senior Reactor Operator's license examination (ANSI/ANS 3.1-1978).

The Radiation Protection Manager meets or exceeds the qualification requirements of Regulatory Guide 1.8, September 1975.

Table 13.1-1 provides the cross-reference for the various positions within the DAEC organization to those comparable position descriptions and training and experience requirements within ANSI/ANS 3.1-1978, where applicable.

13.1.3.2 Qualifications of Plant Personnel

Personnel qualifications are set forth in the Technical Specifications. It is the intent of IES Utilities Inc. to adhere to these qualifications when obtaining replacements for vacant positions, whether they be current DAEC employees advancing to positions of greater responsibility or newly hired personnel.

The personnel qualifications of key plant managerial and supervisory personnel at the time of DAEC initial fuel loading were included in the original FSAR.

Information regarding qualifications of personnel currently occupying positions in the operating organization of the DAEC is on file and available at the site for NRC inspection.

Table 13.1-1

DAEC Plant Staff Position	Standard of Qualification (Note 1)				Description of Duties UFSAR Section (Note 3)
	ANSI/ANS 3.1-1978 Section (Note 2)	Tech Spec Section	NUREG 0737	Reg Guide	
Plant Manager	4.2.1				13.1.2.2.1
Operations Manager	4.2.2	5.2.2.f			13.1.2.1, 13.1.2.2.2
Operations Shift Manager	4.3.1				13.1.2.1, 13.1.2.2.3, 13.1.2.3
Operations Shift Supervisor	4.3.1				13.1.2.1, 13.1.2.3
Operating Engineers	4.5.1				13.1.2.3
Shift Technical Advisors	4.5.1	5.2.2.g	Item 1.A.1		13.1.2.3
Maintenance Manager	4.2.3				13.1.2.1, 13.1.2.2.4
Mechanical Maintenance Supervisor	4.3.2				13.1.2.1, 13.1.2.2.5
Electrical Maintenance Supervisor	4.3.2				13.1.2.1, 13.1.2.2.6
I & C Maintenance Supervisor	4.4.2				13.1.2.1, 13.1.2.2.7
Maintenance Process Support Supervisor	4.3.2				13.1.2.1, 13.1.2.2.8
FIN Team Leader	4.3.2				13.1.2.1, 13.1.2.2.9
Work Management Maintenance Supervisor	4.3.2				13.1.2.2.10
Reactor Engineers	4.4.1				13.1.2.1
Radiation Protection Manager	4.4.4	5.3.1		1.8-1975	13.1.2.1, 13.1.2.2.11
Chemistry Supervisor	4.4.3				13.1.2.2.12
Radwaste Supervisor	4.3.2				13.1.2.2.13
Health Physics Supervisor	4.3.2				13.1.2.2.15
Radwaste and Material Handling Supervisor	4.3.2				13.1.2.2.14
Radiological Engineering Supervisor	4.3.2				13.1.2.2.16
Supervisor, Procedures Department	4.3.2				13.1.1.2.2.1
Security Superintendent	4.3.2				13.1.1.2.2.1
Manager, Quality Assurance	4.2.4				13.1.1.2.2.2
Manager, Regulatory Performance	4.2.4				13.1.1.2.2.1
Manager, Nuclear Licensing	4.3.2				13.1.1.2.2.1
Manager, Engineering	4.2.4				13.1.1.2.2.1, 13.1.2.1
Project Engineering Supervisor	4.3.2				
System Engineering Supervisor	4.3.2				
Program Engineering Supervisor	4.3.2				
Materials Management Supervisor	4.3.2				
Manager, Nuclear Training	4.2.4				13.1.1.2.2.1
Training Supervisor-Technical Programs	4.3.2				
Training Supervisor-Operations	4.3.2				
Training Supervisor-Administrative	4.3.2				

Note: 1 - In some cases, plant design features or unusual operating conditions may indicate that additional or more specialized expertise beyond qualifications presented in this Standard is needed. This determination will be made on a case-by-case basis.

Note: 2 - See DAEC Technical Specifications Section 5.3.1 for commitment to ANSI/ANS 3.1-1978.

Note: 3 - If no UFSAR Section is listed, staff position is not discussed in Chapter 13.1.

Table 13.1-2

MINIMUM SHIFT CREW PERSONNEL AND LICENSE REQUIREMENTS

DAEC Job Title	Reactor Mode: Other Than Cold Shutdown	Reactor Mode: Cold Shutdown
Operations Shift Manager	1 - SRO[1]	1 - SRO[1]
Operations Shift Supervisor	1 - SRO[1,2]	
Nuclear Station Operating Engineer	1 - RO[3]	1 - RO
Assistant Nuclear Station Operating Engineer	1 - RO[3]	
Nuclear Station Plant Equipment Operator	2	1
Shift Technical Advisor Position	1[2]	None Required
Minimum Total Personnel	7	3

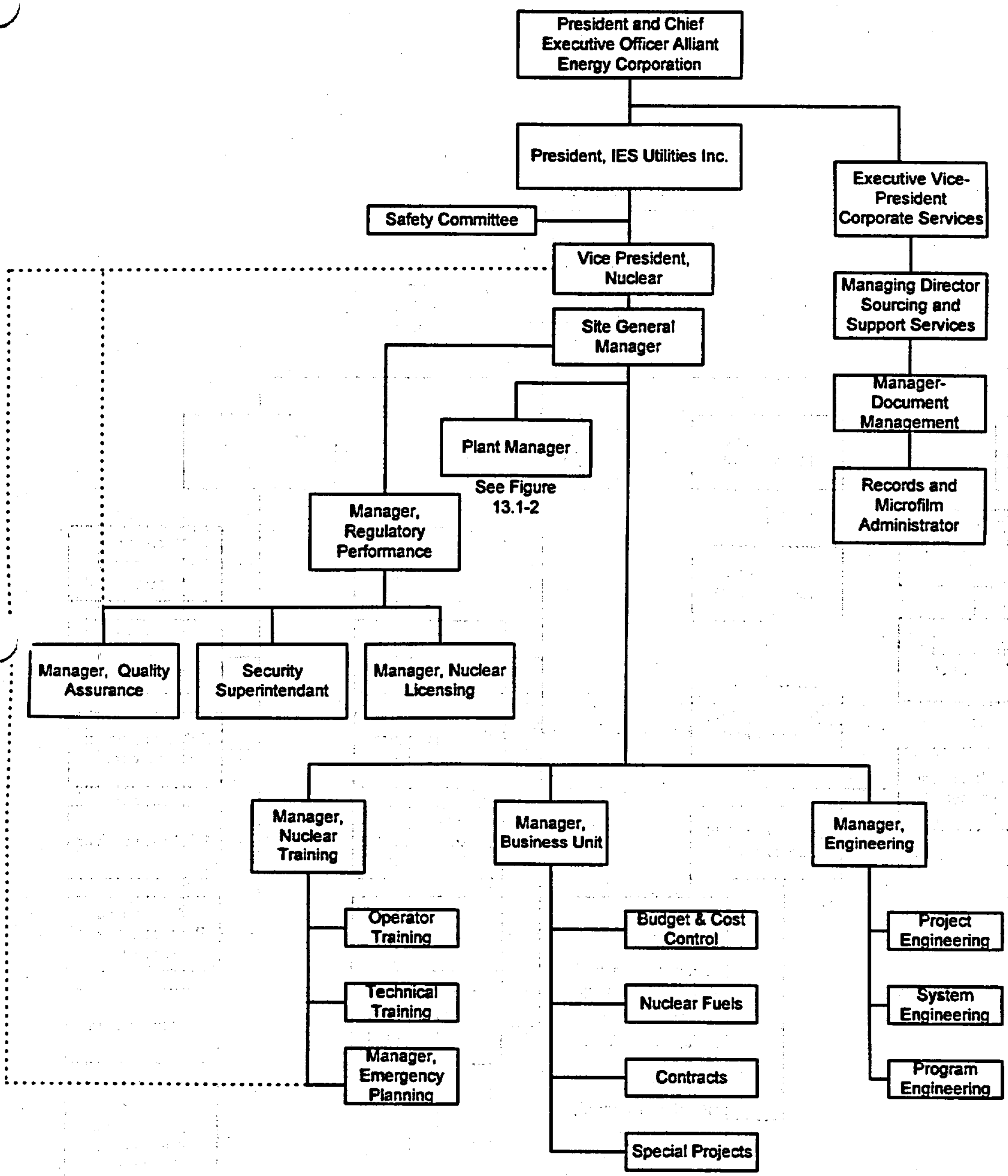
SRO - Senior Reactor Operator
RO - Reactor Operator

Substitutions - without changing minimum total personnel requirements:

a. Individuals with senior reactor operator license may substitute for reactor operator or nonlicensed position.
b. Individuals with reactor operator license may, if otherwise qualified, substitute for nonlicensed position.

NOTES

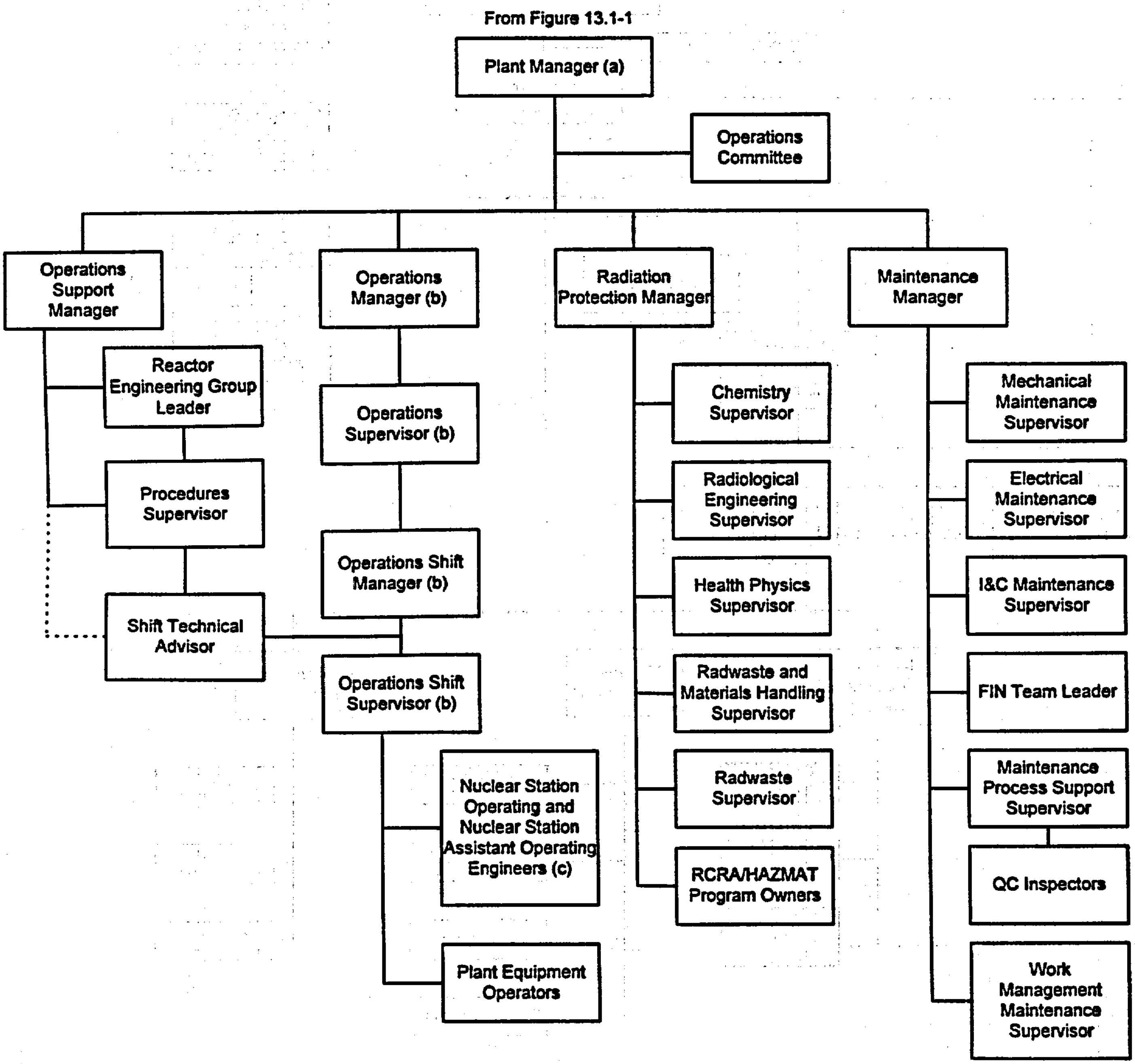
1. Does not include the SRO or SRO Limited to Fuel Handling, Supervising Core Alterations
2. Not required while in the Refuel Mode
3. Only one RO is required during the Refuel Mode with an additional RO required to be assigned the responsibilities of movement of fuel during Core Alterations



DUANE ARNOLD ENERGY CENTER
IES UTILITIES
UPDATED FINAL SAFETY ANALYSIS REPORT

IES UTILITIES INC. CORPORATE ORGANIZATION

FIGURE 13.1-1



a - Plant Manager or one of his designated principle alternates meet ANSI 3.1-1978 License Requirements
b - Senior Reactor Operator
c - Reactor Operator

DUANE ARNOLD ENERGY CENTER
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IES UTILITIES INC. CORPORATE ORGANIZATION

FIGURE 13.1-2

13.3 EMERGENCY PLANNING

The Duane Arnold Energy Center Emergency Plan has been submitted to the NRC as a separate document.

Provisions have been made for periodic review and updating of the Emergency Plan. Provisions have also been made for informing all concerned persons of significant revisions to the Emergency Plan and procedures. Revisions to the Emergency Plan and procedures are also submitted to the NRC.

An onsite Technical Support Center (TSC), an onsite Operational Support Center (OSC), and an offsite Emergency Operations Facility (EOF) have been established.

The onsite TSC is located in a facility adjacent to the administration building north of the turbine building.

The onsite OSC is located in the administration building and is composed of the security control point, the health physics access control area, and adjacent emergency lockers. The OSC supervisory staff area is located by the TSC.

The offsite EOF is located on the fourteenth floor of the Alliant Energy Tower in Cedar Rapids.

The DAEC TSC, OSC, and EOF are fully functional and meet the requirements of Section 8 of Supplement 1 to NUREG-0737.

13.4 REVIEW AND AUDITS

13.4.1 ONSITE REVIEW

13.4.1.1 Administrative Control

Administrative control of plant operations is exercised through the Site General Manager.

13.4.1.2 Routine Reviews

The routine review of plant operations is at the plant level under the direction of the DAEC Plant Manager or designee, with the active participation of the plant supervisory staff. The DAEC Plant Manager and his support personnel review operating logs, recorded data, performance data, and radiation exposure and environmental monitoring records and make corrections in operations as needed. Proposed revisions in operating procedures are referred to and reviewed by the Operations Committee.

The DAEC Plant Manager, is responsible for operating the station in strict compliance with the facility license and the Technical Specifications. He is also responsible for operating the station in accordance with applicable rules and practices.

13.4.1.3 Operations Committee

The Operations Committee is organized on the plant level and is composed of selected Managers, Supervisors, and personnel from the following areas: Operations, Maintenance, Reactor Engineering, Radiation Protection, Quality Assurance, Licensing, Engineering, and Procedures.

One member is designated as the Chairman. One or more of the members are designated as Vice Chairmen. The Chairman, Vice Chairmen, Members, and Alternates are appointed in writing by the DAEC Plant Manager to serve on a permanent basis; however, no more than three alternates can participate as voting members in Operations Committee activities at any one time.

The Operations Committee functions to advise the DAEC Plant Manager on all matters related to nuclear safety.

The Committee meets at least once per calender month and as convened by the Committee Chairman or Vice Chairman. A quorum of the Operations Committee consists of the Chairman or Vice Chairman and five members including alternates.

The responsibilities and authority of the Operations Committee are specified in UFSAR 17.2 and in the Operations Committee Charter.

During the startup period when power levels were being increased, the Committee reviewed the results and analyzed the tests performed at previously achieved power levels for conformance with design parameters and approved tests at the next higher power level. General Electric was represented on the Committee before commercial operations.

Minutes of the Operations Committee proceedings are recorded and provided to the Vice President, Nuclear, and to the Chairman of the Safety Committee.

13.4.2 INDEPENDENT REVIEW

13.4.2.1 Safety Committee

The Safety Committee functions to provide independent review and audit of designated activities in the areas of nuclear power plant operations, nuclear engineering, chemistry and radiochemistry, metallurgy, instrumentation and control, radiological safety, mechanical and electrical engineering, quality assurance practices, non-destructive testing and administration. The functions, composition, and authority of the Safety Committee are specified in the Safety Committee Charter. The Safety Committee commenced operation at the time of cold functional tests; approximately 2 weeks before fuel loading.

Charter. The Safety Committee has responsibility and authority for review and audit of DAEC plant operations to verify that operation of the plant is consistent with Company policy and rules, approved operation procedures, and license provisions. The Safety Committee charter reflects the guidelines of ANSI N18.7-1976.

Membership. Membership on the Safety Committee is by appointment in writing by the President and includes individuals designated as Chairman and at least one Vice-Chairman. A current list of permanent members and alternates is maintained in Committee records.

Authority. The Safety Committee reports to and advises the President in areas of responsibility specified in UFSAR 17.2.

Responsibility. In addition to any other matter referred to it by the DAEC Operations Committee or the DAEC Plant Manager, or any studies or investigation it may initiate, the Safety Committee shall perform reviews in accordance with the guidance of ANSI N18.7-1976. In addition, formal audits are conducted under the cognizance of the Safety Committee of operation of the nuclear power plant on a periodic basis. Audits of selected aspects of plant operation shall be performed with a frequency commensurate with their safety significance. (See Section 13.4.3.)

Meetings. The Safety Committee shall meet periodically and on call by the Chairman or Vice-Chairman of the Safety Committee. A quorum of membership must be present to conduct Committee business and must consist of the Chairman or Vice-Chairman and a number of permanent members including alternates appointed in writing by the President of IES Utilities to serve on a permanent basis. No more than a minority of the quorum may have concurrent onsite line responsibilities for operations of the DAEC.

Records. Records of Safety Committee activities are prepared, approved, and distributed as follows: minutes of each Safety Committee meeting shall be prepared, approved, and forwarded to the President of IES Utilities Inc.

13.4.2.2 Fire Protection Inspection

An independent fire protection and loss prevention inspection and audit is performed annually utilizing either qualified offsite licensee personnel or an outside fire protection firm. An inspection and audit by an outside qualified fire consultant is performed at intervals no greater than 3 years.

13.4.3 AUDIT PROGRAM

The Quality Assurance Department and the DAEC Safety Committee are assigned responsibilities for audits of facility activities. The audit program is described in the Operational Quality Assurance Program (see Section 17.2).

The responsibilities for the Safety Committee audit program are assigned to the Quality Assurance Department. However, the responsibility for performing various audits may be assigned to other organizations as deemed appropriate by the Safety Committee. The Safety Committee reviews audit plans prior to the conduct of the audit. The Safety Committee reviews audit schedules and directs the audits.

13.5 PLANT PROCEDURES

13.5.1 ADMINISTRATIVE PROCEDURES

The DAEC administrative procedures are contained in the 1400 Manual, Administrative Control Document.

13.5.2 OPERATING AND MAINTENANCE PROCEDURES

13.5.2.1 Control Room Operating Procedures

13.5.2.1.1 Original Operating Procedures

The original operating and maintenance procedures are discussed in Section 13.6 of the original FSAR.

13.5.2.1.2 Current Operating Procedures

Integrated Plant Operating Instructions (IPOIs) exist to provide integrated procedures for major plant evolutions such as startup, power operation, reactor scram, cold weather operations, and special operations as required.

Operating instructions for individual plant systems are contained in the DAEC Operations Manual.

The Technical Specifications list the areas which are to be covered by detailed written plant operating and maintenance procedures. These procedures, and changes thereto, are reviewed by the Operations Committee (or subcommittee) and approved by the Plant Manager prior to implementation except as follows: temporary minor changes to these procedures which do not change the intent of the original procedure may be made with the concurrence of two members of the plant management staff, at least one of whom must hold a Senior Operator license. Such changes are documented and promptly reviewed by the Operations Committee and by the Plant Manager (see Technical Specifications).

The DAEC has implemented procedures for limiting access to the control room to authorized individuals in accordance with the NUREG-0578, Section 2.2.2.a, NRC position, and shift turnover procedures in accordance with the NUREG-0578, Section 2.2.1.c, NRC position.

The NRC in Supplement 1 to NUREG-0737 (Generic Letter 82-33) required licensees to develop a set of human factored, symptom-based, emergency operating procedures (EOPS) to improve human reliability and the ability to mitigate the consequences of a broad range of initiating events and subsequent multiple failures or operator errors to respond to potential accident situations. The BWR Owner's Group (BWROG) developed a set of Emergency Procedure Guidelines (EPGs) which could be utilized by individual licensees in their development of plant-specific EOPs. The EPGs have been updated to include Severe Accident Guidelines (SAGs) beyond that previously covered in EOPs. This updated guidance was issued by the BWROG as EPG/SAG Revision 1. This guidance maintained the same symptom-based approach as the previous revisions to the EPGs. DAEC implemented EPG/SAG Revision 1 such that any steps or actions in the SAG flowcharts are beyond the plant's design and licensing basis. The current EOP flowcharts have also been updated from the guidance in EPG/SAG Revision 1.

13.5.2.2 Other Procedures

13.5.2.2.1 Maintenance and Testing Procedures

Maintenance and testing procedures, checklists, and other necessary records to satisfy routine inspections, preventive maintenance program, and license requirements, are developed by qualified plant staff members.

The Technical Specifications specify that detailed written procedures, including applicable check-off lists and instructions, are to be prepared for surveillance and testing requirements and preventive and corrective maintenance operations which could have an effect on the nuclear safety of the facility.

The maintenance procedures can be found in the Maintenance Procedures Manual and the surveillance and testing procedures are listed in a controlled database. The procedures can be divided into the following categories:

1. Routine Testing of Engineered Safeguards and Equipment as Required by the Facility License and the Technical Specifications is directed by the Supervisor, Procedures Department and is completed at the specified frequency. Written procedures and checklists are provided for these operations.

2. Routine Testing of Standby and Redundant Equipment

   Routine testing of standby and redundant equipment is directed by the Work Management Maintenance Supervisor. The frequency of testing follows normal steam plant practice.

3. Routine Inspection and Preventive Maintenance

   Routine inspection and preventive maintenance of equipment is directed by the Mechanical Maintenance Supervisor, Electrical Maintenance Supervisor and Instrumentation and Controls Maintenance Supervisor. The frequency and scope of inspections are in accordance with normal steam plant practices. Plant operating history and manufacturer's recommendations are also used in determining specific inspection and maintenance schedules. Routine inspection, calibration, and preventive maintenance of instruments are directed by the Instrumentation and Controls Maintenance Supervisor. The frequency and scope of this work are established according to normal plant practice, operating history, and manufacturer's recommendations.

4. Special Testing

Special testing encompasses all testing not covered by items 1, 2, and 3 above. Some items in this category are:

a. Operational testing of equipment after overhaul.

b. Testing of equipment for proposed changes to operational procedures.

c. Testing of equipment for proposed design changes to equipment.

Special testing will be under the direction of the Supervisor, Procedures Department and the Operations Manager. When necessary, appropriate procedures will be written by qualified members of the plant staff with review and approval by the Operations Committee and the Safety Committee if necessary.

13.5.2.2.2 EMERGENCY PLANNING PROCEDURES

Organized emergency procedures outlining the actions and responsibilities of plant personnel and offsite support groups have been developed and are contained in the DAEC Emergency Plan and the Emergency Plan Implementing Procedures (EPIPs). These procedures implement the Emergency Plan discussed in Section 13.3.

The purposes of these emergency procedures are to classify emergencies according to severity, assign responsibilities, and outline the actions to be taken to confine and reduce the hazard in order to protect both the general public and plant personnel.

In the implementation of the Emergency Plan, detailed procedures have been prepared to specify the manipulation of controls and equipment to place the facility in a safe condition and to prescribe other appropriate protective measures to be taken by the employees. These implementing procedures are available at the site for review by the NRC. This section describes the principal features of the implementing procedures as follows:

1. Individual assignments of authorities and responsibilities for the performance of specific tasks are included in each procedure.

2. Protective action levels requiring implementation of the protective measure outlined in the Emergency Plan are specified in the procedures for the emergency identified. Action required for such protective measures are stated.

3. Specific actions to be performed by coordinated support groups are identified in the procedures dealing with their activities.

4. Procedures for medical treatment and handling of contaminated individuals are specified.

5. Special equipment requirements are identified for items such as medical treatment equipment, emergency removal equipment, specific radiation-detection equipment, personnel dosimetry, and rescue operations. The equipment is made available and operating instructions have been prepared and stored with the equipment and provisions made for periodic inspection and maintenance.

6. Communications networks for the emergency organization have been identified, including those communications required for effective coordination of all support groups.

7. Alarm signals incorporated into the facility are clear and distinct. Signals for initiating protective measures are distinct to avoid confusion.

8. Procedures required to restore the emergency situation to normal have been prepared.

9. The implementing procedures are periodically tested, within reasonable limits, to ensure that they can be completed as anticipated.

10. The implementing procedures are periodically reviewed and updated. Individuals and groups assigned responsibilities in an emergency will be informed of changes in procedural requirements.

Selected drills of emergency procedures are to be conducted in accordance with the provisions of the Emergency Plan.

Controlled copies of the DAEC Emergency Plan Implementing Procedures (EPIP) are provided to the NRC Region III office.

13.5.2.2.3 Refueling Operations

Detailed refueling procedures are used to ensure a safe and orderly refueling. The procedures specify or make reference to other system operation documents that specify periodic shutdown margin checks, detailed channeling and fuel-handling techniques, and other precautionary steps to ensure that the facility license and Technical Specifications are not violated.

When fuel is being inserted, removed, or rearranged in the core or when control rods are being installed, removed, or manipulated, licensed operators will be in the control room. Senior Reactor Operators (SROs) or SROs limited to fuel handling will be present on the Refuel Floor during core alterations. Technical personnel may provide guidance where necessary. Core verification will be performed after the refueling operations are completed.

Fuel and control rod identifications are tracked using Spent Fuel Pool and core locations. The serial numbers on both the fuel and control rods are matched to these locations and records are kept for these items as lifetime records.

Core alterations are performed using fuel handling procedures and fuel moving plans that are developed from analysis of the previous cycle's fuel exposure and taking into account shutdown margin.

Other refueling operations include the replacement of control rods and incore monitors, channeling operations, fuel sipping when necessary, and the inspection of selected portions of the reactor vessel and primary system.

13.5.2.2.4 Radioactive Materials Safety Procedures

Procedures for the handling and monitoring of radioactive materials are contained in plant procedures and manuals. The provisions of these procedures are designed to conform to the standards of the Code of Federal Regulations, particularly those applicable in Title 10 and Title 49. These procedures are approved by the Operations Committee.

13.5.2.2.5 Radiological Procedures

Procedures for personnel radiation protection are prepared consistent with the requirements of 10 CFR 20 and are to be approved, maintained, and adhered to for all operations involving personnel radiation exposure.

REFERENCES FOR SECTION 13.5

1. NRC Safety Evaluation Report - BWROG EPG, Revision 4, September 1988.

2. Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability (Generic Letter 82-33), December 17, 1982.

3. NUREG-0899, Guidelines for the Preparation of Emergency Operating Procedures Resolution of Comments on NUREG-0799, August 1982.

4. NRC Safety Evaluation of the DAEC Procedures Generation Package, dated May 9, 1990.

Chapter 15

ACCIDENT ANALYSES

15.0 PLANT SAFETY ANALYSIS

15.0.1 ANALYTICAL OBJECTIVE

The objective of the plant safety analysis is to evaluate the ability of the plant to operate without undue hazard to the health and safety of the public.

Earlier chapters of this FSAR describe and evaluate the reliability of major systems and components of the plant from a safety standpoint. This chapter assumes that certain severe incidents occur notwithstanding precautions taken to prevent their happening. This chapter then examines the potential consequences of each occurrence to determine the effect on the plant, to determine whether the plant design evaluated in earlier sections is adequate to minimize the consequences of these occurrences, and finally, to ensure that the health and safety of the public are protected from the consequences of even the most severe of the hypothetical accidents analyzed.

15.0.2 ANALYTICAL CATEGORIES

Transient and accident events contained in this section are discussed in individual categories as required by Reference 1. Each event evaluated is assigned to one of the following applicable categories:

1. Decrease in Core Coolant Temperature: A reduction in reactor vessel water (moderator) temperature results in an increase in core reactivity. This could lead to fuel-cladding damage.

2. Increase in Reactor Pressure: Increases in nuclear system pressure threaten to rupture the reactor coolant pressure boundary (RCPB). Increasing pressure also collapses the voids in the core moderator, thereby increasing core reactivity and power level, which threatens fuel cladding because of overheating.

3. Decrease in Reactor Core Coolant Flow Rate: A reduction in the core coolant flow rate threatens to overheat the cladding as the coolant becomes unable to adequately remove the heat generated by the fuel.

4. Reactivity and Power Distribution Anomalies: Transient events included in this category are those which cause rapid increases in power resulting from increased core flow disturbance events. Increased core flow reduces the void content of the moderator, thereby increasing core reactivity and power level.

5. Increase in Reactor Coolant Inventory: Increasing coolant inventory could result in excessive moisture carryover to the main turbine.

6. Decrease in Reactor Coolant Inventory: Reductions in coolant inventory could threaten the fuel as the coolant becomes less able to remove the heat generated in the core.

7. Radioactive Release from a Subsystem or Component: Loss of integrity of a radioactive containment component is postulated.

8. Anticipated Transients Without Scram: To determine the capability of plant design to accommodate an event of extremely low probability, a multisystem maloperation situation is postulated.

9. Analytical Methods: These are identified to delineate methods used in the various analyses.

10. Dose Sensitivity Evaluation Using Assumptions of the U.S. Atomic Energy Commission (AEC)/Division of Reactor Licensing (DRL): This compares the AEC assumptions with the base case.

The general method of identifying and evaluating abnormal operational transients is shown in Figure 15.0-1.

Parameter variations (for events 1 through 6 above), if uncontrolled, could result in excessive damage to the reactor fuel or damage to the nuclear system process barrier or both. An increase in nuclear system pressure threatens to rupture the nuclear system process barrier from internal pressure. A pressure increase also collapses the voids in the moderator, causing an insertion of positive reactivity that threatens to damage the fuel from overheating. A decrease in reactor vessel water (moderator) temperature results in an insertion of positive reactivity as density increases. This could lead to fuel overheating. Positive reactivity insertions are possible from causes other than nuclear system pressure or moderator temperature changes. Such reactivity insertions threaten fuel damage by overheating. Both a decrease in reactor vessel coolant inventory and a reduction in the flow of coolant through the core threaten to overheat the fuel as the coolant becomes unable to adequately remove the heat generated in the core. An increase in coolant flow through the core reduces the void content of the moderator, resulting in an increased fission rate.

These six parameter variations include all of the effects within the nuclear system caused by abnormal operational transients that threaten the integrities of the reactor fuel or nuclear system process barrier. The variation of any one parameter may cause a change in another listed parameter; however, for analytical purposes, threats to barrier integrity are evaluated by groups according to the parameter variation originating the threat. For example, positive reactivity insertions resulting from sudden pressure increases are evaluated in the group of threats stemming from nuclear system pressure increases.

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15.3 EVENTS RESULTING IN A CORE COOLANT FLOW DECREASE

Events that result directly in a core coolant flow decrease are those that affect the reactor recirculation system. The following events result in the most significant transients in this category:

1. Recirculation flow control failure - decreasing flow.

2. Trip of one recirculation pump.

3. Trip of two recirculation pumps.

4. Recirculation pump seizure.

15.3.1 RECIRCULATION FLOW CONTROL FAILURE - DECREASING FLOW

Several varieties of recirculation flow control malfunctions can cause a decrease in core coolant flow. A master controller could malfunction in such a way that a zero speed signal is generated for both recirculation pumps. The recirculation flow control system is provided with a speed demand limiter that is set so that this situation cannot be more severe than the simultaneous tripping of both recirculation pumps. A simultaneous trip of both recirculation pumps is evaluated in Section 15.3.3. The master controller has been removed, thus, this is no longer a credible event.

The remaining recirculation flow controller malfunction is one in which the speed controller for one recirculation pump motor-generator (M-G) set fails in such a way that the speed controller output signal changes in the direction of zero speed. This transient is similar to the trip of one recirculation pump (evaluated in Section 15.3.2). However, the pump speed reduction is slower than that resulting from the opening of a field breaker so that the decrease in fuel thermal margins is less severe. This transient is a nonlimiting event (see Reference 2 of Section 15.0); accordingly, only the foregoing narrative description of the event is provided here.

15.3.2 TRIP OF ONE RECIRCULATION PUMP

This transient is the result of either opening the breaker for one M-G set drive motor or opening the field excitation breaker for one recirculation pump M-G set. Opening the field excitation breaker results in the more severe transient because the inertia of the M-G set cannot contribute to the coastdown of the recirculation pump with the generator field circuit open.

Normal trips of one recirculation pump are accomplished through the drive motor breaker. However, as the worst coastdown transient occurs when the generator field breaker is open, this latter transient was the most limiting of the two. This transient is a nonlimiting event (see Reference 2 of Section 15.0); accordingly, only the foregoing narrative description of the event is provided here.

15.3.3 TRIP OF TWO RECIRCULATION PUMPS

This transient primarily evaluated the fuel thermal margin maintained by the rotating inertia of the recirculation system drive equipment. The inertia from the recirculation flow control system M-G sets is included because no single event can simultaneously open the generator field circuits of both M-G sets. This transient results if the power supply to both M-G sets is lost. This transient is a nonlimiting event (see Reference 2 of Section 15.0); accordingly, only the foregoing narrative description of the event is provided here.

15.3.4 RECIRCULATION PUMP SEIZURE

This accident is assumed to occur as a consequence of an unspecified, instantaneous stoppage of one recirculation pump shaft while the reactor is operating at full power.

The pump seizure event is a very mild accident in relation to other accidents such as the loss-of-coolant accident (LOCA). This is easily verified by a comparison of the two events. In both accidents, the recirculation driving loop flow is lost extremely rapidly. In the case of the seizure, the stoppage of the pump occurs; for the LOCA, the severance of the line has a similar but more rapid and severe influence. Following a pump seizure event, flow continues, water level is maintained, and the core remains submerged; this provides a continuous core cooling mechanism. However, for the LOCA, complete flow stoppage occurs and the water level decreases from the loss of coolant resulting in the uncovering of the reactor core and subsequent overheating of the fuel rod cladding. In addition, for the pump seizure accident, reactor pressure does not significantly decrease, whereas complete depressurization occurs for the LOCA. Clearly, the increased temperature of the cladding and reduced reactor pressure for the LOCA both combine to yield a much more severe stress and potential for cladding perforation for the LOCA than for the pump seizure. Therefore, it can be concluded that the potential effects of the hypothetical pump seizure accident are very conservatively bounded by the effects of a LOCA and specific analyses of the pump seizure accident are not required.

The pump seizure event during single loop operation (SLO) has also been analyzed for the DAEC (Reference 44 of Section 15.0) and is a relatively mild event compared to the LOCA. The core would remain covered and it is expected that the transient would terminate with a condition of natural circulation and continued reactor operation. There would also be a small decrease in system pressure.

The SLO pump seizure event is evaluated to determine the impact on MCPR, specifically to ensure that this event does not violate the Safety Limit MCPR for the Cycle. The resulting Operating Limit MCPR-SLO Pump Seizure is compared to the Operating Limit MCPR, adjusted for SLO, from the other transient events to determine the bounding SLO Operating Limit in the Core Operating Limits Report.

position mode from the 75% control rod density point to the preset power level, there is no basis for the continuous control rod withdrawal error in the startup and low-power range. The low-power range is defined as zero power to the RWM low-power setpoint (i.e., 10% of rated core power).

15.4.3 CONTROL ROD REMOVAL ERROR DURING REFUELING

The nuclear characteristics of the core ensure that the reactor is subcritical even in its most reactive condition with the most reactive control rod fully withdrawn during refueling.

When the mode switch is in REFUEL, only one control rod can be withdrawn. The selection of a second rod initiates a rod block, thereby preventing the withdrawal of more than one rod at a time. Therefore, the refueling interlocks prevent any condition that could lead to inadvertent criticality due to a control rod withdrawal error during refueling.

In addition, the design of the control rod, incorporating the velocity limiter, does not physically permit the upward removal of the control rod without the simultaneous or prior removal of the four adjacent fuel bundles, thus eliminating any hazardous condition.

15.4.4 FUEL ASSEMBLY INSERTION ERROR DURING REFUELING

The core is designed such that it can be made subcritical under the most reactive conditions with the strongest control rod fully withdrawn. Therefore, any single fuel bundle can be positioned in any available location without violating the shutdown criteria, providing all the control rods are fully inserted. The refueling interlocks require that all control rods must be fully inserted before a fuel bundle may be inserted into the core. Because of the above-mentioned constraints, there is no analysis required for this event.

15.4.5 STARTUP OF AN IDLE RECIRCULATION PUMP

This transient is caused by starting an idle recirculation loop without warming the drive loop water. The assumed initial conditions are as follows:

1. One recirculation loop is idle and filled with cold water (100°F). (Normal procedure requires warming this loop.) Per General Electric Service Information Letter 517, Supplement 1, dated August 26, 1998, a value of 50°F ΔT between the idle loop and the active loop had been used for the idle loop startup event analysis. The traditional assumption of the 100°F idle loop temperature was concluded to be unnecessarily conservative. This change in assumptions was presented to the NRC in the initial ARTS application for a BWR/4 plant (Hatch) and approved for DAEC via Amendment 120.

2. The active recirculation pump is operating at a speed that produces about 98% of normal rated jet pump diffuser flow in the active jet pumps.

3. The core is receiving 40% of its normal rated flow; the remainder of the coolant flows in the reverse direction up through the inactive jet pumps.

4. Reactor power is 55% of reactor warranted power. This is the highest initial power for which a high neutron flux scram does not result from the transient. (Normal procedure requires the startup of an idle loop at a much lower power and the warming of the drive loop water.)

5. The idle recirculation pump suction valve is open; the pump discharge valve is closed.

6. The idle pump fluid coupler is at a setting that approximates 50% of generator speed demand.

The loop startup transient sequence is as follows:

1. The recirculation pump M-G set breaker is closed at t = 0.

2. The motor reaches near synchronous speed quickly, while the generator approaches full speed in approximately 5 sec.

3. Next, the generator field breaker is closed, loading the generator and applying starting torque to the pump motor. Generator speed decreases as the generator tries to start the stopped rotor of the pump. Pump breakaway is modeled to occur at 8 seconds. Speed demand is sequentially programmed back to minimum speed.

4. The pump discharge valve is started open as soon as its interlock with the drive motor breaker is cleared. (Normal procedure would delay valve opening to separate the two portions of the flow transient and make sure the idle loop water is properly mixed with the hot water in the reactor vessel.) A nonlinear 30-sec valve-opening characteristic is used.

Shortly after the pump begins to move, a surge in flow from the started-up jet pump diffusers gives the core inlet flow a sharp rise. A short-duration neutron flux peak is produced; however, surface heat flux follows the slower response of the fuel, as the reactor settles out at its new steady-state condition. No damage occurs to the fuel barrier. No significant changes in nuclear system pressure result from the transient. For single loop operation, the rated condition steady-state MCPR has been increased by 0.02 over the two loop operation MCPR to account for increased uncertainties. During periods of single loop operation, the idle recirculation loop is isolated by electrically disarming the recirculation pump to prevent inadvertent pump startup (see the Technical Specifications). This transient is a nonlimiting event (see References 2 and 5 of Section 15.0); accordingly, only the foregoing description of the event is provided here.

15.4.6 RECIRCULATION FLOW CONTROLLER FAILURE - INCREASING FLOW

Several possibilities exist for an unplanned increase in core coolant flow resulting from a recirculation flow control system malfunction. However, the most severe case of increasing coolant flow results when the M-G set fluid coupler for one recirculation pump attempts to achieve full speed at maximum rate. The maximum rate for this failure is 25% of full speed per second. This transient is a non-limiting event (see Reference 2 of Section 15.0); accordingly, only the foregoing narrative description of the event is provided here.

15.4.7 CONTROL ROD DROP ACCIDENT

There are many ways of inserting reactivity into a BWR; however, most of them result in a relatively slow rate of reactivity insertion and therefore pose no threat to the system. It is possible, however, that a rapid removal of a high worth control rod could result in a potentially significant excursion. Therefore, the accident that has been chosen to encompass the consequences of a reactivity excursion is the control rod drop accident.

The analysis of this accident is performed at various reactor operating states; the key reactivity feedback mechanism affecting the shutdown of the initial prompt power burst is the Doppler coefficient. Final shutdown is achieved by scramming all but the dropped rod. The methods used to evaluate the rod drop accident have been updated on a continuing basis to reflect various refinements and improvements in analytical capability (References 2 and 44 of Section 15.0).

15.4.7.1 Starting Conditions and Assumptions

Before the control rod drop accident is possible, the sequence of events described below must occur:

1. A complete rupture, breakage, or disconnection of a fully inserted control rod drive from its cruciform control blade at or near the coupling occurs.

2. The blade sticks in the fully inserted position as the rod drive is withdrawn.

3. The blade falls from the fully inserted to the fully withdrawn position.

This unlikely set of circumstances makes possible the rapid removal of a control rod. The dropping of the rod results in a high local reactivity in a small region of the core and for large, loosely coupled cores, significant shifts in the spatial power generation during the course of the excursion. Therefore, the method of analysis must be capable of accounting for any possible effects of the power distribution shifts.

To limit the worth of the rod that could be dropped, a systematic sequence of rod withdrawal is used to control the sequence of rod withdrawal. These defined sequences of rod withdrawal are enforced by the Rod Worth Minimizer system. This system prevents the movement of an out-of-sequence rod before the 50% rod density configuration is achieved and prevents high incremental control rod worths beyond the 50% rod density configuration by requiring a notch mode of rod withdrawal. The 50% rod density configuration occurs during each reactor startup and corresponds to a "checkerboard" rod pattern in which 50% of the rods are fully inserted in the core and 50% are fully withdrawn. The rod drop accident design limit restricts peak enthalpies in excess of 280 cal/g for any possible plant operation or core exposure.

NOTE

Amendment 180 to Facility Operating License for the DAEC removed the operability requirements for the rod sequence control system. The following description has been revised accordingly.

15.4.7.2 Accident Description

The sequence of events and approximate time of occurrence for this accident are described below:

	Event	Approximate Elapsed Time
1.	Reactor is at a control rod pattern corresponding to maximum incremental worth.	--
2.	Rod worth minimizer is not functioning. Maximum worth control blade that can be developed at any time in core life under any operating conditions with the banked position withdrawal sequence being enforced becomes decoupled from the control rod drive.	--
3.	Operator selects and withdraws the control rod drive of the decoupled maximum worth rod along with the other rods assigned to its banked position withdrawal sequence group to the fully withdrawn position.	--
4.	Decoupled control blade sticks in the fully inserted position.	--
5.	Blade becomes unstuck and drops at the nominal measured velocity determined from experimental data (3.11 fps).	0

	Event	Approximate Elapsed Time
6.	Reactor goes prompt critical and initial power burst is terminated by the Doppler reactivity feedback.	≤ 1 sec
7.	Average power range monitor 120% power signal scrams reactor (conservative; the upscale scram trip setpoint is set at 15% of rated power during system startup plus the intermediate range monitor is functional).	- -
8.	Scram terminates accident.	≤ 5 sec

15.4.7.3 Analytical Methods

Techniques and models used to analyze the rod drop accident are documented in Reference 2 of Section 15.0.

15.4.7.4 Model Parameters Assumptions

Although there are many input parameters to the rod drop accident analysis, the resultant peak fuel enthalpy is most sensitive to the following input parameters:

1. Steady-state accident reactivity shape function.

2. Total control rod reactivity worth.

3. Maximum interassembly local power peaking factor, P_F (see Reference 2 in Section 15.0 for a definition of P_F).

4. Delayed neutron fraction.

5. Scram reactivity shape function.

6. Doppler reactivity feedback.

7. Moderator temperature.

For a fixed control rod drop velocity and scram insertion rate, these parameters can be varied and combined to yield a peak fuel enthalpy of 280 cal/g.

Rod drop velocity is that justified by the statistical evaluation in Reference 2 of Section 15.0 (that is, the maximum velocity of 3.11 fps was used). Therefore, scram times tabulated below were used in developing the scram reactivity curves for the 280 cal/g design limit boundary.

Percentage of Rod Insertion	Time from Deenergization of Scram Solenoid Valve (sec)
5	0.475
20	1.10
50	2.0
90	5.0

To meet the rod drop accident design limit of 280 cal/g, the above parameters are combined to meet three basic conditions. These are: (1) the accident reactivity characteristics, (2) the Doppler reactivity feedback, and (3) the scram reactivity characteristics. If any one of these conditions were not satisfied, then a more detailed analysis would be necessary to establish compliance with the 280 cal/g design limit.

The Technical Specification scram times will ensure the above scram times are met.

15.4.7.5 Results and Consequences

From the analysis presented in Reference 2 of Section 15.0, it was conservatively determined that 850 fuel rods of the 8 x 8 configuration would reach a fuel enthalpy of 170 cal/g, which is the enthalpy limit for eventual cladding perforation.* The original safety analysis report predicted the failure of approximately 330 fuel rods for the 7 x 7 fuel. If the conservative assumption is made that the fractional plenum activity for the 8 x 8 fuel is the same as for the 7 x 7 fuel, the resultant increase in activity released from the 8 x 8 fuel and the subsequent radiological exposures relative to the 7 x 7 analysis for the failure of 330 rods is (850/330) x (49/63) = 2 times the 7 x 7 analysis. Even if the radiological exposures are increased by a factor of 2, the effects are still orders of magnitude below those identified in 10 CFR 100.

For advanced fuel designs with larger fuel arrays (e.g., 10 x10), generic evaluations have been performed as part of the demonstration of their compliance with Amendment 22 of Reference 2 to Section 15.0. For the GE12 fuel design (Ref. 45 to Section 15.0), the original generic analyses were shown to remain bounding.

Confirmation that the generic evaluations remain bounding is supplied in the specific plant supplemental reload submittal (Reference 3 of Section 15.0). If the plant is not covered by the bounding analysis (i.e., one or more of the bounding parameters is exceeded), a plant-specific analysis will be performed to determine if the 280 cal/g design limit is exceeded.

* The 850 fuel rods include a 10% allowance for uncertainties in the calculation.

15.4.7.10 Radiological Effects (with MSIVs remaining open, elevated release)

Dose calculations were performed for an assumed release of 100% of the kryptons and for an assumed release of 100% of the xenons. Results of each of these calculations were plotted against an assumed delay time before release and shown in Figures 15.4-2 and 15.4-3. In this scenario it was assumed that all of the remaining activity of each gas was released at approximately the same time. The doses shown in Figures 15.4-2 and 15.4-3 are integrated doses over the 2 hours subsequent to release from the augmented offgas system. The 2-hour DAEC Exclusion Area boundary Chi/Q value applicable to the augmented offgas system release point used has a value of 1.03 E-05 seconds per cubic meter. The lowermost curves shown in Figures 15.4-2 and 15.4-3 correspond to this value.

As a result of not closing the MSIVs, some of the activity available for release is considered to be diverted from the uncontrolled leakage path (i.e., condenser leakage) to the controlled leakage path through the augmented offgas system. This path is monitored by the air ejector offgas pre-treatment and post-treatment radiation monitors.

With the augmented offgas treatment system, substantial decay times are assured for noble gases, and any iodine releases are negligible because of retention in the charcoal beds. The delay time in the charcoal beds is proportional to the mass of charcoal and to the dynamic adsorption coefficient for the gas (which is a function of operational temperature and humidity conditions in the charcoal) and inversely proportional to the condenser air inleakage flow rate. Using the decay times of 19 hours for kryptons and 15 days for xenons (UFSAR Section 11.3.2.4) and Figures 15.4-2 and 15.4-3 for the site specific Chi/Q value of 1.03 E-05 seconds per cubic meter, the doses corresponding to 100% release are approximately 0.01 Rem kryptons and 0.01 Rem xenons. Summing these doses results in an approximate total of 0.02 Rem which is well within the 6.25 Rem dose limit, as specified in Reference 33, for the whole body established by 10 CFR Part 100 guidelines.

Using the above assumptions, the following amounts of radioactive materials are released from the nuclear system process barrier:

Noble gases	5.7 Ci
Iodine-131	1.4 Ci
Iodine-132	13.3 Ci
Iodine-133	9.5 Ci
Iodine-134	25.0 Ci
Iodine-135	13.7 Ci

The above releases take into account the total amount of liquid released as well as the liquid converted to steam during the accident.

15.6.5.2.3 Steam Cloud Movement

The following initial conditions and assumptions are used in calculating the movement of the steam cloud:

1. Additional flashing to steam of the liquid exiting from the main steam line break will occur as a result of its superheated condition in the atmosphere.

2. The pressure buildup inside the turbine building will cause the blowout panels to function and result in the release of the steam cloud in a matter of seconds.

3. Steam cloud rise as predicted by the following equation (see Reference 12 of Section 15.0) could vary between 100 and 600 m, depending on assumptions regarding wind speeds:

$$h = \frac{11\,Q^{1/3}}{U}$$

where

h = height of cloud rise, ft
U = wind speed, fps
Q = heat output of cloud, cal/sec

While the effect of cloud rise is a physical reality, this effect is neglected for this accident, and it is assumed that the steam cloud does not attain an elevation greater than the height of the turbine building.

15.6.5.3 Radiological Effects

The radiological exposures are shown in Table 15.6-1. The maximum cloud gamma and thyroid inhalation doses are 5.8×10^{-4} rem and 2.7×10^{-1} rem, respectively. These values are well below the guideline doses set forth in 10 CFR 100. These values would be increased by 2% to account for the DBA power level increase of 2% to 1691 MWt.

Because all of the activity is released to the environment in the form of a puff, the indicated doses are maximum values regardless of the dose period being evaluated.

It is concluded that no danger to the health and safety of the public will result from this postulated accident.

15.6.6 LOSS-OF-COOLANT ACCIDENT

Accidents that could result in the release of radioactive material directly into the primary containment are the results of postulated nuclear system pipe breaks inside the drywell. All possibilities for pipe break sizes and locations have been investigated, including the severance of small pipe lines, the main steam lines upstream and downstream of the flow restrictors, and the recirculation loop pipelines. The most severe nuclear system effects and the greatest release of radioactive material to the primary containment result from a complete circumferential break of one of the recirculation loop pipelines. This accident is established as the design-basis LOCA.

15.6.6.1 Initial Conditions and Assumptions

The analysis of this accident is performed using the following assumptions:

1. The reactor is operating at design power at the time the recirculation pipe breaks. This maximizes the core heat generation rate and results in the highest fuel temperatures following the loss of coolant.

2. A complete loss of normal ac power occurs simultaneously with the pipe break. This additional condition results in the longest delay time for the emergency core cooling systems to become operational.

3. The recirculation loop pipeline is considered to be instantly severed. This results in the most rapid coolant loss and depressurization with coolant discharged from both ends of the break.

Flow-dependent correction factors are applied to the maximum average planar linear heat generation rate (MAPLHGR) at rated conditions to ensure that the consequences of a LOCA initiated from less than rated core flow conditions for either two loop or single loop operations will not exceed those of the design-basis LOCA (see the Technical Specifications).

15.6.6.2 Nuclear System Depressurization and Core Heatup

Section 6.3 and References 4 and 45 to Section 15.0 describe and evaluate the initial phases of this accident. Included in that description are the rapid depressurization of the nuclear system, the operating sequences of the emergency core cooling systems, the heatup of the fuel, and the perforation of fuel rods.

15.6.6.3 Primary Containment Response

See Section 6.2.1.3.3.

15.6.6.4 Fission Product Release, Design-Basis LOCA

The following assumptions and initial conditions were used in calculating the amount of the fission products released from the core:

1. The reactor has been operating at design power for 1000 days before the accident. This assumption results in equilibrium concentrations of fission products in the fuel. Longer operating histories would not increase the concentrations of the longer-lived fission products significantly.

2. The equilibrium fission product activity contained in the core is

Noble gases	4.1×10^8 Ci
Halogens	4.6×10^8 Ci

   The above fission product inventory reflects an assumed 1000 days at design power followed by a decay period of 1 min. The 1-min assumption results in the decay of the very short-lived fission products that contribute significantly to the fission products in the fuel but are insignificant as far as plenum activity and offsite doses are concerned.

3. Twenty-five percent of the fuel rods in the core are conservatively assumed to be perforated even though the analysis in Reference 4 of Section 15.0 indicates no perforations.

4. An average of 1.8% of the noble gas activity and 0.32% of the halogen activity contained in a fuel rod is in the plenums and available for release from those rods experiencing perforation. These assumptions are consistent with measurements made on defective fuel experiments for high power density operation.

5. Because of the negligible particulate activity available for release from nonmolten fuel, none of the volatile or nonvolatile radioactive solids are released from the fuel during the accident.

6. All of the noble gases and halogens released from the perforated fuel rods are assumed to be transported to the drywell.

7. Fission product decay during the depressurization of the reactor vessel is neglected.

8. Fission product release to the primary containment is as follows:

Noble gases	9.3×10^5 Ci
Halogens	3.2×10^5 Ci

15.6.6.5 Primary Containment Airborne Fission Product Inventory

Using the preceding fission product release and the following assumptions, the primary containment airborne fission product inventory is determined as follows:

1. The noble gas activity is removed only by radioactive decay and leakage to the secondary containment.

2. The leak rate to the secondary containment is 0.5% per day.

3. The halogen activity released to the primary containment will experience such removal effects as washout, fallout, plate out, and removal by the pressure suppression pool. The effects of washout and plate out have been shown by various investigators to vary between 10 and 1000. A value of 2 has been conservatively chosen for those removal effects for this plant.

4. An iodine partition factor of 100 is conservatively assumed to be applicable. Numerous experiments have been conducted to investigate the iodine partition factor between water and air. The results of these experiments show that a partition factor of 10^3 to 10^8 is appropriate for conditions existing in the primary containment following a LOCA.

Determined from these assumptions, the fission product activity airborne in the primary containment is presented in Table 15.6-2.

15.6.6.6 Secondary Containment Airborne Fission Product Inventory

The fission product activity in the secondary containment at any time is a function of the leakage rate from the primary containment and the volumetric discharge rate from the secondary containment. During normal power operation, the secondary containment ventilation rate is 100 air changes per day. However, the normal ventilation system is turned off, and the standby gas treatment is initiated, during the design-basis LOCA, as a result of high drywell pressure. The secondary containment ventilation during the LOCA is one air change per day. Any fission product removal effects in the secondary containment, such as plate out and fallout, are temperature and pressure increase during the isolation, but remain within the design limits when Abnormal Operating Procedures are implemented. (ref. UFSAR Section 15.6.7.4.9)

Also, Suppression pool heat capacity is adequate to accept the steam discharged from the reactor vessel from the SRV actuations and HPCI/RCIC operation. (ref. UFSAR Section 15.6.7.4.9)

15.6.7.3.8 Fuel Pool Cooling

The spent fuel storage pool is cooled by the fuel pool cooling (FPC) and auxiliary systems. The systems are AC dependent and are not available during the event. There is sufficient heat capacity within the spent fuel pool to maintain the pool temperature within acceptable limits throughout the event. Fuel pool cooling is re-established when auxiliary AC power is available following the event. (ref. UFSAR Section 15.6.7.4.7)

15.6.7.3.9 Equipment Room Cooling

The HPCI, RCIC, Control Room and DC equipment rooms are cooled by AC dependent systems and are not available during the event. Room temperatures remain within acceptable limits throughout the event when Abnormal Operating Procedures are implemented. Room cooling is re-established when auxiliary AC power is available following the event. (ref. UFSAR Sections 15.6.7.4.8)

15.6.7.4 Station Blackout Basis

Effective July 21, 1988, the Nuclear Regulatory Commission (NRC) amended its regulations by adding a new section 50.63 to the Code of Federal Regulations, Part 10 which requires each light-water-cooled nuclear power plant to be able to withstand and recover from a Loss of All AC Power (Station Blackout) of a specified duration. Licensees are expected to have available for NRC review the baseline assumptions, analyses, and related information used in their coping evaluation. 10CFR 50.63 requires that the plant be capable of maintaining core cooling and appropriate containment integrity during a Station Blackout and identifies the factors that must be considered. The NRC issued Regulatory Guide 1.155, "Station Blackout," which describes a method acceptable to the NRC staff for meeting the requirements of 10CFR 50.63. RG 1.155 states that NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," also provides guidance that is essentially identical to RG 1.155 and is acceptable for meeting 10CFR 50.63 requirements.

The Duane Arnold Energy Center (DAEC) has been assessed for compliance to 10CFR 50.63 using guidance from RG 1.155 and NUMARC 87-00. Assessments have been prepared which address the programs, procedures, systems, modifications and analysis necessary for 10CFR 50.63 compliance. The results of the assessments where included in a submittal to the NRC (ref. UFSAR Section 15.0.11.37). The NRC approved the submittal in a Supplemental Safety Evaluation (ref. UFSAR Section 15.0.11.38). A summary of the assessments are contained below.

1. The duration of the coping period is four hours. This determination is based on the methodology in Section 3 of NUMARC 87-00 with the following criteria:

    a. The AC Power Design Characteristic Group is P2 which considers the expected frequency of grid-related LOOPs (less than 1 per 20 years), estimated frequency of LOOPs due to severe (SW Group 3) and extremely severe weather (ESW Group 2), and the offsite power system design (I1/2).

    b. The Emergency AC Power Configuration is Group C which considers the number of emergency AC sources available (2 EDGs) but not credited as an alternate AC power source vs. the number required (1 EDG) to operate safe shutdown equipment following a loss of offsite power.

    c. The Emergency Diesel Generator (EDG) Target Reliability is 0.975.

2. Analyses have been performed to evaluate the SBO's effect on plant parameters. The analyses identify the equipment, systems and actions required for safe shutdown. (ref. UFSAR Sections 15.6.7.2, 15.6.7.3)

3. The appropriate AOPs, EOPs, ARPs and OIs have been prepared or amended to include guidance on coping with and recovering from a Station Blackout. This includes a specific procedure for Station Blackout and support procedures regarding emergency depressurization, loss/restoration of one or both essential busses, loss/restoration of offsite power or emergency AC power, and severe weather conditions (tornadoes).

4. The Condensate Storage Tank's reserve capacity for HPCI/RCIC usage (75,000 gal.) is adequate to provide the makeup required during the coping period. The amount of makeup required includes conservative allowances for inventory loss due to normal system leakage, recirculation pump seal leakage and HPCI/RCIC/SRV discharge to the suppression pool. (ref. UFSAR Section 9.2.6)

5. The 24, 48, 125 and 250 Vdc Class 1E battery capacity is adequate to power loads during the coping period and support restoration of on-site or off-site AC power. This includes margin to account for design and loading uncertainties, changes in battery electrolyte temperature, and aging. Also, the loss of ventilation does not result in a potentially explosive hydrogen build-up. (ref. UFSAR Section 8.3.2 and 15.0 Reference 43)

6. The compressed air/nitrogen accumulator capacity is adequate to supply safe shutdown equipment during the coping period. This includes the CRD HCUs for scram, the ADS/LLS SRVs for pressure relief, HPCI/RCIC for core cooling (applicable in CST-CST test mode only) and, MSIVs for primary containment isolation. AOPs and ARPs direct that the auxiliary diesel driven air compressors be used to recharge the EDG air start accumulators to support restoration of on-site AC power. (ref. UFSAR Section 9.3.1)

If the dropped fuel assembly strikes only one or two fuel assemblies on the first impact, the energy absorption by the core support structure results in about the same energy dissipation on the first impact as in the case where four fuel assemblies are struck. The energy relations on the second and third impacts remain about the same as in the original case. Thus, the calculated energy dissipation is as follows:

Impact	Percentage
First	80
Second	19
Third	1 (no cladding failures)

The first impact dissipates 0.80 x 17,000 or 13,600 ft-lb of energy. It is assumed that 50% of this energy is absorbed by the dropped fuel assembly and that the remaining 50% is absorbed by the struck fuel assemblies in the core. Because the fuel rods of the dropped fuel assembly are susceptible to the bending mode of failure, and because 1 ft-lb of energy is sufficient to cause cladding failure due to bending, all rods of the dropped fuel assembly are assumed to fail. Because the eight tie rods of each struck fuel assembly are more susceptible to bending failure than the other rods, it is assumed that they fail on the first impact. Thus, 32 (4 x 8) tie rods (total in four assemblies) are assumed to fail.

Because the remaining fuel rods of the struck assemblies are held rigidly in place in the core, they are susceptible only to the compression mode of failure. To cause cladding failure of one fuel rod because of compression, 250 ft-lb of energy is required. To cause the failure of all the remaining rods of the four struck assemblies, 250 x 56 x 4 or 56,000 ft-lb of energy would have to be absorbed in cladding alone. Thus, it is clear that not all the remaining fuel rods of the struck assemblies can fail on the first impact. The number of fuel rod failures due to compression is computed as follows:

$$\frac{0.5 \times 13{,}600 \times 11/(11+17)}{250} = 11$$

where

0.5 x 13,600 = energy absorbed by fuel assembly

11/(11 + 17) = fraction of assembly consisting of clad (assumption made that no energy absorbed by fuel)

250 = energy required to cause clad failure

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

Dropped assembly	62	rods (8 x 8R, P8 x 8R) or 63 rods (8 x 8) (bending)
Struck assemblies	32	tie rods (bending)
Struck assemblies	11	rods (compression)
Total	105	or 106 failed rods

Because of the less severe nature of the second impact and the distorted shape of the dropped fuel assembly, it is assumed that in only 2 of the 24 struck assemblies are the tie rods subjected to bending failure. Thus, 16 (2 x 8) tie rods are assumed to fail. The number of fuel rod failures due to compression on the second impact is computed as follows:

$$\frac{0.5 \times (0.19 \times 17{,}000) \times 11/11 \times 17)}{250} = 3$$

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

Struck assemblies	16	tie rods (bending)
Struck assemblies	3	rods (compression)
Total	19	failed rods

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

First impact	105	or 106 rods
Second impact	19	rods
Third impact	0	rods
Total	124	or 125 failed rods

For advanced fuel designs with larger arrays (e.g., 10 x 10), generic evaluations have been performed as part of the demonstration of their compliance with Amendment 22 of Reference 2 to Section 15.0. For the GE12 fuel design (Ref. 45 to Section 15.0), this existing evaluation was shown to remain bounding.

15.7.1.3 Fission Product Release from Fuel

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

1. The reactor fuel has an average irradiation time of 1000 days at design power up to 24 hr before the accident. This assumption results in an equilibrium fission product concentration at the time the reactor is shut down. Longer operating histories do not increase the concentration of the fission products of concern. The 24-hr decay time allows time to shut down the reactor, depressurize the nuclear system, remove the reactor vessel head, and remove

the reactor vessel upper internals. It is not expected that these operations could be accomplished in less than 24 hr.

2. An average of 1.8% of the noble gas activity and 0.32% of the halogen activity is in the fuel rod plenums and available for release. This assumption is based on fission product release data from defective fuel experiments (see Reference 11 of Section 15.0).

3. Because of the negligible particulate activity available for release in the fuel plenums, none of the solid fission products are assumed to be released from the fuel.

4. From the analysis of mechanical damage to the fuel, 125 fuel rods are assumed to fail.

5. The fission product activities in the core at the time of the accident are as follows:

Noble gases	1.2×10^8 Ci
Halogens	1.5×10^8 Ci

Using the above assumptions, the following amount of fission product activity is released from the fuel to the water in the reactor vessel as a result of the dropped fuel assembly:

Noble gases	1.7×10^4 Ci
Iodine-131	2.9×10^3 Ci
Iodine-132	4.0×10^2 Ci
Iodine-133	7.8×10^2 Ci
Iodine-134	1.4×10^{-5} Ci
Iodine-135	0.97×10^2 Ci

15.7.1.4 Fission Product Release to Secondary Containment

The following assumptions and initial conditions are used in calculating the fission products released to the secondary containment:

1. The fission product activity released to the secondary containment will be in proportion to the removal efficiency of the water in the refueling pool. Because water has a negligible effect on the removal of the noble gases, the gases are assumed to be instantaneously released from the pool to the secondary containment.

2. As noted in Section 15.6.6.5, the removal efficiency of the water for halogens can be defined in terms of the partition factor, for which values between 10^3 and 10^8 have been experimentally determined to be applicable for the conditions under investigation (see Reference 11 of Section 15.0). A partition factor of 10^2 for the halogens has been conservatively assumed for this accident. Thus, the computed inhalation exposures will be overestimated by a factor of from 10 to 10^6.

3. It is also conservatively assumed that instantaneous equilibrium is attained between the refueling pool and the secondary containment. By assuming such a condition, the resultant radiological exposures will be maximized, although a true equilibrium condition will never be achieved.

4. The effects of plateout and fallout are neglected. Fission product plateout and/or fallout will occur in the secondary containment; however, for the assumption that a true equilibrium is maintained, the effects of plateout or fallout would be compensated for by the release of activity from the refueling pool.

5. The refueling cavity liquid volume is 35,876 ft^3 and the effective air volume in the secondary containment above the refueling floor is 580,000 ft^3.

6. The standby gas treatment system removes one secondary containment air volume per day.

Using these assumptions, the activity airborne in the secondary containment is shown in Table 15.7-1 for a 7 x 7 core. For an 8 x 8 core, the activity released is 88% of the activity released for a 7 x 7 core. For the GE12 fuel design, which is a 10 x 10 array, the activity released is bounded by the 8 x 8 core (Ref. 45 to Section 15.0).

15.7.1.5 Fission Product Release to Environs

The following assumptions and initial conditions are used in calculating the fission products released to the environs:

1. High radiation levels in the reactor building refueling ventilation exhaust will isolate the normal ventilation system and actuate the standby gas treatment system.

2. Because the refueling accident does not result in the release of any liquid or vapor to the secondary containment, the normal building environmental condition existing before the accident will also exist after the accident, except for the addition of the released fission products. Relative humidity in the secondary containment will therefore be considerably below any levels that can be detrimental to the filter media in the standby gas treatment system.

However, the air flowing through the filter system is heated to reduce the relative humidity to approximately 70%.

3. The filter efficiency is 99% for iodines and 0% for noble gases.

Using these conditions, the fission product activity release rate to the environs is shown in Table 15.7-2 for a 7 x 7 core. For an 8 x 8 core, the activity released is 88% of the activity released for a 7 x 7 core. For the GE12 fuel design, which is a 10 x 10 array, the activity released is bounded by the 8 x 8 core (Ref. 45 to Section 15.0).

15.7.1.6 Radiological Effects

Radiological exposures to the general population have been evaluated for six meteorological diffusion conditions ranging from very stable to unstable occurring with 1- and 5-m/sec winds. Two exposure periods were evaluated, a 2-hr exposure period and a 24-hr exposure period, commonly referred to as the total dose. It should be emphasized that the radiological exposures presented in Tables 15.7-3 and 15.7-4 are based on the assumption that the stated meteorological conditions exist for the duration under consideration and that the wind blows in one direction during the entire release period.

Tables 15.7-3 and 15.7-4 show the radiological exposure beyond the site boundary, which was assumed to be 457 m from the release point. The values shown in these tables should be multiplied by 0.88 for 8 x 8 cores. The values for the 8 x 8 fuel design bound those for the GE12 fuel design. Thus, the maximum 2-hr radiological exposures at the site boundary are 1.1×10^{-2} rem whole body and 6×10^{-3} rem thyroid, and the maximum 24-hr offsite doses are 3.6×10^{-2} rem cloud gamma and 3.8×10^{-2} rem thyroid inhalation. Doses should be multiplied by 102% to account for 2% increase in assumed power level to 1691 MWt.

15.7.2 EVALUATION OF ENGINEERED SAFETY FEATURE SYSTEMS USING TID-14844 SOURCE TERMS

In addition to the analysis presented in the preceding sections, an evaluation was made of the adequacy of the containment and engineered safety features using the assumptions of TID-14844 with regard to the fission product source term.

15.7.2.1 Source Term Assumptions

For the purposes of calculating the dose, heat loading, and airborne or waterborne activities, the following assumptions were made:

1. The halogen and noble gas initial sources were taken from data on fission product loading for BWR fuel. This data contains a more extensive list of isotopes, and results in a larger (conservative) radiological source term than would be obtained using only the isotopes listed in Table IV, "External Gamma Dose Rates," of TID-14844 (see Reference 13 of Section 15.0).

2. The core particulate activity was taken from the ANS standard afterheat curve (see Reference 14 of Section 15.0). The activity at any time was obtained by dividing the afterheat curve at that particular time by an average energy of 0.7 MeV.

3. The charcoal adsorber iodine loading includes iodine-129 and iodine-127. The amount of each of these isotopes in the core was determined from Blomeke and Todd (see Reference 15 of Section 15.0).

4. The activity in the suppression pool was assumed to be 50% of the core halogen inventory and 1% of the core particulate activity, which are instantaneously released to the suppression pool.

5. The airborne activity in the primary containment was assumed to consist of 100% of the core noble gas activity, 25% of the core halogen activity, and 1% of the core particulate activity, which are instantaneously released to the primary containment.

6. The airborne activity noted in item 5 is released at a constant leak rate of 2.0% per day to the secondary containment, uniformly mixed in the secondary containment, and released to the standby gas treatment system at the rate of 1.0 air changes per day.

7. For the determination of the activity and heat loading on the charcoal adsorbers and the high-efficiency particulate air (HEPA) filters in the standby gas treatment system, the primary containment activity noted in item 5 above was assumed to be released at a constant leak rate of 2.0% per day directly to the standby gas treatment system where the filter and adsorber efficiency was assumed to be 100%.

A historical table of the activities in the various systems at various times after the TID-14844 release accident are shown in Table 15.7-5. The values in Table 15.7-5 are based on a primary containment leak rate of 2.0% per day. Reference 9 of Section 3.11 contains references to current analyses and source terms. These source terms contain a larger set of fission products and result in conservative dose rates compared to TID-14844.

15.7.2.2 Standby Gas Treatment System

The standby gas treatment system contains two complete filtration trains, each containing a moisture separator, a heater to control relative humidity, a prefilter, a HEPA filter, charcoal adsorbers, and a downstream HEPA filter.

The HEPA filters are steel cased and open faced. These filters are rated at 250°F for continuous service. This design incorporates two such filter banks in each filtration

Table 15.7-1

REFUELING ACCIDENT
SECONDARY CONTAINMENT AIRBORNE FISSION PRODUCT INVENTORY

Time After Accident	Noble Gases (Ci)	Iodines (Ci)
1 min	1.89×10^{4}	5.71×10^{2}
30 min	1.74×10^{4}	5.55×10^{2}
1 hr	1.59×10^{4}	5.41×10^{2}
2 hr	1.34×10^{4}	5.15×10^{2}
8 hr	4.79×10^{3}	5.13×10^{2}
12 hr	2.44×10^{3}	3.67×10^{2}
1 day	3.37×10^{2}	2.66×10^{2}
2 day	6.97×10^{0}	1.47×10^{2}
4 day	3.22×10^{-3}	4.90×10^{1}
30 day	1.12×10^{-34}	5.38×10^{-5}

Note: Fission product inventory should be reduced by multiplying by 0.88 to reflect differences between 7x7 and 8x8 fuel design (Reference 2 of Section 15.0). The 10x10 fuel design of GE12 has been shown to remain bounded by the 8x8 fuel design (Reference 45 to Section 15.0). Fission product inventory should be multiplied by 102% to account for 2% increase in assumed power level to 1691 MWt.

Table 15.7-2

REFUELING ACCIDENT
FISSION PRODUCT RELEASE RATE TO THE ENVIRONS

Time After Accident	Noble Gases (Ci/sec)	Iodines (Ci/sec)
1 min	8.14×10^{-1}	2.45×10^{-4}
30 min	7.47×10^{-1}	2.39×10^{-4}
1 hr	6.85×10^{-1}	2.33×10^{-4}
2 hr	5.76×10^{-1}	2.21×10^{-4}
8 hr	2.06×10^{-1}	1.78×10^{-4}
12 hr	1.05×10^{-1}	1.58×10^{-4}
1 day	1.45×10^{-2}	1.14×10^{-4}
2 days	3.00×10^{-4}	6.34×10^{-5}
4 days	1.38×10^{-7}	2.10×10^{-5}
30 days	3.46×10^{-39}	2.31×10^{-11}

Note: Fission product inventory should be reduced by multiplying by 0.88 to reflect differences between 7x7 and 8x8 fuel design (Reference 2 of Section 15.0). The 10x10 fuel design of GE12 has been shown to remain bounded by the 8x8 fuel design (Reference 45 to Section 15.0). Release rate should be multiplied by 102% to account for 2% increase in assumed power level to 1691 MWt.

Table 15.7-3

REFUELING ACCIDENT
RADIOLOGICAL EFFECTS FOR CONTINUOUS RELEASE AT 100 METERS, 2-HOUR DOSE[a]

Distance (m)	Meteorological Conditions[b] VS-1	MS-1	N-1	N-5	U-1	U-5
			Passing-Cloud Whole-Body Dose (rem)			
457[c]	8.4×10^{-3}	8.4×10^{-3}	8.5×10^{-3}	1.4×10^{-3}	1.3×10^{-2}	1.9×10^{-3}
805	7.3×10^{-3}	7.3×10^{-3}	8.3×10^{-3}	1.2×10^{-3}	1.0×10^{-2}	1.5×10^{-3}
1,609	5.2×10^{-3}	5.2×10^{-3}	6.5×10^{-3}	8.9×10^{-4}	5.5×10^{-3}	8.4×10^{-4}
8,045	1.5×10^{-3}	1.6×10^{-3}	9.8×10^{-4}	2.4×10^{-4}	4.4×10^{-3}	1.0×10^{-4}
16,090	7.3×10^{-4}	7.9×10^{-4}	2.8×10^{-4}	9.4×10^{-5}	1.1×10^{-3}	3.6×10^{-5}
			Thyroid Dose (rem)			
457[c]	0	2.5×10^{-10}	5.3×10^{-6}	5.3×10^{-9}	6.9×10^{-3}	9.0×10^{-4}
805	0	7.1×10^{-8}	9.2×10^{-4}	3.0×10^{-5}	7.7×10^{-3}	1.5×10^{-3}
1,609	4.6×10^{-31}	9.9×10^{-6}	3.5×10^{-3}	5.0×10^{-4}	3.5×10^{-3}	8.0×10^{-4}
8,045	8.2×10^{-12}	6.5×10^{-4}	6.9×10^{-4}	1.9×10^{-4}	2.8×10^{-4}	7.4×10^{-5}
16,090	7.3×10^{-8}	7.2×10^{-4}	2.5×10^{-4}	7.2×10^{-5}	9.9×10^{-5}	2.6×10^{-5}

Note: Doses should be multiplied by 0.88 to reflect differences between 7x7 and 8x8 fuel design (Reference 2 of Section 15.0). The 10x10 fuel design of GE12 has been shown to remain bounded by the 8x8 fuel design (Reference 45 to Section 15.0).

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[a] Doses should be multiplied by 102% to account for 2% increase in assumed power level to 1691 MWt.

[b] Abbreviations used to describe meteorological conditions

	Meteorology	Wind Speed (m/s)
VS-1	Very stable	1
MS-1	Moderately stable	1
N-1	Neutral	1
N-5	Neutral	5
U-1	Unstable	1
U-5	Unstable	5

[c] Site boundary.

Table 15.7-4

REFUELING ACCIDENT
RADIOLOGICAL EFFECTS FOR CONTINUOUS RELEASE AT 100 METERS,
24-HOUR DOSE[a]

Distance (m)	Meteorological Conditions[b] VS-1	MS-1	N-1	N-5	U-1	U-5
			Passing-Cloud Whole-Body Dose (rem)			
457[c]	2.7×10^{-2}	2.7×10^{-2}	2.7×10^{-2}	4.6×10^{-3}	4.1×10^{-2}	5.9×10^{-3}
805	2.3×10^{-2}	2.3×10^{-2}	2.6×10^{-2}	4.0×10^{-3}	3.3×10^{-2}	4.8×10^{-3}
1,609	1.6×10^{-2}	1.6×10^{-2}	2.1×10^{-2}	2.8×10^{-3}	1.7×10^{-2}	2.7×10^{-3}
8,045	4.7×10^{-3}	5.2×10^{-3}	3.1×10^{-3}	7.6×10^{-4}	1.4×10^{-2}	3.3×10^{-4}
16,090	2.3×10^{-3}	2.5×10^{-3}	8.9×10^{-4}	3.0×10^{-4}	3.6×10^{-3}	1.2×10^{-4}
			Thyroid Dose (rem)			
457[c]	0	1.4×10^{-9}	3.0×10^{-5}	3.0×10^{-8}	3.9×10^{-2}	5.0×10^{-3}
805	0	4.0×10^{-7}	5.1×10^{-3}	1.7×10^{-4}	4.3×10^{-2}	8.1×10^{-3}
1,609	2.5×10^{-30}	5.4×10^{-5}	1.9×10^{-2}	2.7×10^{-3}	1.9×10^{-2}	4.3×10^{-3}
8,045	4.0×10^{-11}	3.2×10^{-3}	3.3×10^{-3}	8.8×10^{-4}	1.4×10^{-3}	3.5×10^{-4}
16,090	3.3×10^{-7}	3.3×10^{-3}	1.2×10^{-3}	3.2×10^{-4}	4.5×10^{-4}	1.2×10^{-4}

Note: Doses should be multiplied by 0.88 to reflect differences between 7x7 and 8x8 fuel design (Reference 2 of Section 15.0). The 10x10 fuel design of GE12 has been shown to remain bounded by the 8x8 fuel design (Reference 45 to Section 15.0).

[a] Doses should be multiplied by 102% to account for 2% increase in assumed power level to 1691 MWt.

[b] Abbreviations used to describe meteorological conditions

	Meteorology	Wind Speed (m/s)
VS-1	Very stable	1
MS-1	Moderately stable	1
N-1	Neutral	1
N-5	Neutral	5
U-1	Unstable	1
U-5	Unstable	5

[c] Site boundary.

15.10 DOSE SENSITIVITY EVALUATION USING ASSUMPTIONS OF THE NRC (SAFETY GUIDES 3 AND 5)

The following accidents were evaluated to determine their radiological consequences using the conservative NRC assumptions of Safety Guides 3 and 5:

1. Loss-of-coolant accident.

2. Refueling accident.

3. Steam-line break accident

4. Control rod drop accident.

The analyses were originally performed at design power of 1658 MWt and for an exclusion area distance of 457 m and a low-population zone distance of 9554 m. The loss-of-coolant accident and control rod drop accident were reevaluated for the power uprate program in 1984 because they would produce the most severe radiological effects. For these analyses, 102% of rated power (1691 MWt) and an assumed exclusion area distance of 490 m and the emergency planning zone distance of 3218 m were used. As stated earlier, the GE12 fuel design has been evaluated and determined to remain bounded by the 8 x 8 fuel design (Reference 45 to Section 15.0). The assumptions for the four accidents are given in Sections 15.10.1 through 15.10.4.

15.10.1 LOSS-OF-COOLANT ACCIDENT (100-m Release Height)

1. The reactor has operated for 1000 days at 1691 MWt.

2. One hundred percent of the equilibrium radioactive noble gas inventory developed from the above operating condition and 25% of the iodine inventory instantaneously become available for leakage from the primary containment as an aerosol. Eighty-seven percent of this iodine is in the form of elemental iodine, 5% is in the form of particulate iodine, and 8% is in the form of organic iodides.

3. The primary containment volumetric leak rate is 2.0% per day for 30 days. This is the design-basis accident leakage rate incorporated in the Technical Specification.

4. The escaping aerosol immediately flows through the standby gas treatment system and the stack without mixing in the secondary containment building.

5. Ninety-nine percent of the iodine entering the standby gas treatment system is retained by charcoal filters.

6. No credit is taken for the retention of iodine in the suppression pool.

7. Meteorology used to evaluate atmospheric dispersion factors is consistent with the assumptions of Regulatory Guide 1.3, Revision 2.

8 There is a ground reflection factor of 2 for the plume with no credit for ground deposition or rain washout of the plume.

9. The breathing rate is 347 cm^3/sec for the first 8 hr, 175 cm^3/sec for the next 16 hr, and 232 cm^3/sec thereafter.

15.10.2 REFUELING ACCIDENT (100-m Release Height)

1. The reactor has operated for 1000 days at 1658 MWt.

2. Assumptions 8 and 9 of the LOCA apply (Section 15.10.1).

3. One hundred and eleven rods for 7 x 7 fuel, 125 rods for 8 x 8 fuel, and 124 rods for 8 x 8R and P8 x 8R fuel are assumed to be damaged.

4. Each damaged fuel rod contains 50% more activity than the average fuel rod in the core.

5. Thirty percent of the Kr-85 activity, 10% of the other noble gases, and 10% of the iodine contained within the damaged rods are released to the refueling pool.

6. Ninety-nine percent of the iodine released from the rods and 0% of the noble gas activity are retained by the refueling pool water.

7. All of the noble gas and iodine activity released to the secondary containment is released via the standby gas treatment system to the environment with 2 hr.

8. Meteorology - For the exclusion area calculations, the meteorological condition is fumigation Pasquill F for the first 0.5 hr. For the following 1.5 hr, the condition is extremely unstable, Pasquill A, 1-m/sec wind speed. For the LPZ calculations, the meteorological condition is moderately stable, Pasquill F, 1-m/sec wind speed. The concentrations are at the plume centerline for both the LPZ and exclusion area calculations.

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QUALITY ASSURANCE DURING THE OPERATIONS PHASE

17.2.0 INTRODUCTION

17.2.0.1 Scope

To maintain the high quality of plant systems and equipment during operation, maintenance, repair, modification, and refueling of the Duane Arnold Energy Center (DAEC), a comprehensive quality assurance program has been implemented. The objective of this program is to maintain managerial and administrative control over the operations of and activities relative to safety-related structures, systems, equipment, and components during the operating life of the DAEC. This program is designed to meet the intent of Appendix B to 10 CFR Part 50.

17.2.0.2 Corporate Policy

IES Utilities Inc. (the Company), considers the operation of the DAEC to be an extension of the basic policies established and documented for design, construction, and startup.

The policies and procedures identified within this report regarding "operating phase" will form the basis for plant-life operation of the DAEC.

Where contractors and suppliers are used during the life of the operating DAEC, their function will be controlled by the Operational Quality Assurance Program.

It is the objective of the Company that the DAEC shall be operated effectively, efficiently, and in such a manner as not to jeopardize the health or safety of the public.

17.2.1 ORGANIZATION

17.2.1.1 Scope

The Company has established an operating organization that is structured to support DAEC operating requirements as well as meet corporate needs in other areas. This overall organization is described in UFSAR Chapter 13, Conduct of Operations, Section 13.1, Organizational Structure for IES Utilities Inc. The organization chart, which identifies both the "on-site" and "off-site" organizational elements that function under the cognizance of the quality assurance program, appears as Figure 13.1-1, IES Utilities Inc. Corporate Organization. Chapter 13 describes the quality assurance responsibilities of each of the organizational elements noted on the organization chart.

Additional detail concerning the Quality Assurance Department is presented in Chapter 17.2, Section 17.2.1.2.
The responsibility and authority for the establishment and execution of the Operational Quality Assurance Program for the operation of the DAEC will be retained by the Company.

17.2.1.2 Manager, Regulatory Performance

The Manager, Regulatory Performance reports to the Site General Manager and is responsible for quality assurance, security and nuclear licensing functions. Reporting to the Manager, Regulatory Performance are the Manager, Quality Assurance, Security Superintendent and Manager, Licensing.

17.2.1.3 Manager, Quality Assurance

The Manager, Quality Assurance reports to the Manager, Regulatory Performance and is assigned primary responsibility for ensuring that quality requirements relative to the safe operation of the DAEC are identified and met. The Manager, Quality Assurance also has the authority and organizational freedom to directly access the Vice President, Nuclear regarding quality matters. The Manager, Quality Assurance is responsible for elevating conflicts regarding quality matters with the Manager, Regulatory Performance to the Vice President, Nuclear for resolution.

Fulfilling the responsibilities of the Quality Assurance Department requires significant communication with the Nuclear Licensing Department, the Emergency Planning Department, the Nuclear Business Unit, the Engineering Department, the Training Department and corporate personnel.

The Manager, Quality Assurance is responsible for preparing, approving and maintaining the Operational Quality Assurance Program and the Quality Assurance Department implementing procedures.

The Manager, Quality Assurance is also responsible for evaluating the effectiveness of the Operational Quality Assurance Program and issuing periodic reports to the appropriate levels of management. Effectiveness of the Operational Quality Assurance Program at the DAEC is determined through internal audits and surveillances and through analysis and trending of reported conditions adverse to quality. The Manager, Quality Assurance also provides support for the procurement of materials and equipment through audits, surveillances, and evaluations of suppliers and contractors for quality capabilities and performance and maintains the list of approved suppliers for nuclear procurements.

Training responsibilities include the training of Quality Assurance Department personnel and Nuclear Generation Division personnel relative to the Operational Quality Assurance Program.

The Manager, Quality Assurance provides direct support to the nuclear Safety Committee and assures that Quality Assurance Department personnel are designated to support the Operations Committee.

17.2.1.3.1 Stop Work Authority

The Manager, Quality Assurance has the authority to issue a stop work instruction to the organization that has direct responsibility for the work. Only the Vice President, Nuclear has the authority to override the stop work instruction.

17.2.2 OPERATIONAL QUALITY ASSURANCE PROGRAM

17.2.2.1 Scope

The Company has established an Operational Quality Assurance Program that applies to those structures, systems, and components, that are safety-related and those activities that affect those structures, systems, and components that are safety-related. Safety-related structures, systems, and components are those that ensure the integrity of the reactor coolant pressure boundary, shut down the reactor, and maintain the reactor in a safe shut down condition, or prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public.

17.2.2.2 Basis

10 CFR Part 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, and certain regulatory guides, form the basis for the Operational Quality Assurance Program. Appendix A to UFSAR Chapter 17.2 identifies the particular regulatory guides to which DAEC is committed and which are included in the basis for the Operational Quality Assurance Program.

17.2.2.3 Identification of Safety-Related Structures, Systems, Components and Items

The pertinent requirements of the Operational Quality Assurance Program apply to all activities affecting the safety-related functions of those structures, systems, and components that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public. A current list of safety-related structures, systems and components is contained in Section 3.2 of the DAEC Updated Final Safety Analysis Report. This list includes structures, systems, and components identified during the design and construction phase and may be modified as required during operations consistent with their importance to safety.

The list of safety-related structures, systems and components from Section 3.2 of the DAEC Updated Final Safety Analysis Report is further defined in data bases through the assignment of plant specific unique identifiers. These data bases include items in addition to safety-related structures, systems and components and are maintained by the Manager, Engineering.

17.2.2.4 Operational Quality Assurance Program Implementation

The implementation of the Operational Quality Assurance Program by the Company is directed toward the assurance that operating phase activities and maintenance activities are conducted under controlled conditions and in compliance with applicable regulatory requirements, including 10 CFR Part 50, Appendix B. Management personnel responsible for the conduct of safety related activities are responsible for providing approved procedures before initiating the activity.

The Company Operational Quality Assurance Program is implemented via four levels of documents:

1. Quality Assurance Manual,

2. Nuclear Generation Division Manual,

3. Departmental Procedures, and

4. Departmental Instructions.

17.2.2.4.1 Quality Assurance Manual

The Quality Assurance Manual is the highest level internal quality program document that implements UFSAR/DAEC-1 Chapter 17.2, Quality Assurance During the Operations Phase. It is directed to those the Company organizations responsible for safety-related activities. The Quality Assurance Manual presents upper management philosophy and concepts to the middle management level, defines organizational responsibilities, and identifies organizational interfaces.

17.2.2.4.2 Nuclear Generation Division Manual

The Nuclear Generation Division Manual contains administrative procedures that are common to the Nuclear Generation Division. These divisional administrative procedures eliminate the need for separate departmental procedures addressing the same subject.

17.2.2.4.3 Departmental Procedures

The Departmental Procedures are organizationally unique documents that describe the activities of each department within the Company that has responsibilities for the operation, maintenance, or modification of the DAEC. The Departmental Procedures specify how to accomplish a specific activity.

17.2.2.4.4 Departmental Instructions

The Departmental Instructions are unique to the department and activity for which they have been prepared. Departmental Instructions provide the specific, detailed information necessary to perform an activity. Departmental Instructions are issued at the discretion of the responsible manager and are not required for all activities.

17.2.2.5 Control of DAEC Suppliers

The Company may employ the services of architect-engineers, NSSS suppliers, fuel fabricators, constructors, and consultants to augment the Company capabilities. These organizations are required to work under a quality assurance program to provide the control of quality activities consistent with the scope of their assigned work. The quality assurance programs of such organizations are subject to review, evaluation, and acceptance by the Company Quality Assurance Department before the initiation of activities affected by the program.

17.2.2.6 Indoctrination and Training

The indoctrination, training, and retraining of personnel who participate in safety-related activities are provided in five broad areas: operator training, quality assurance indoctrination, technical training, radiation safety indoctrination and training, and emergency preparedness training.

The Operator training provided to senior reactor operators and reactor operators is under the cognizance of the Plant Manager and the Manager, Nuclear Training.

The quality assurance indoctrination provided to DAEC personnel is under the cognizance of the Manager, Quality Assurance and the Manager, Nuclear Training.

The technical training provided to DAEC personnel is under the cognizance of the Manager, Engineering, the Plant Manager and the Manager, Nuclear Training. The training may be provided in a number of ways, from self-study courses to formalized courses at the DAEC and educational institutions.

Indoctrination and training provided to DAEC personnel and contract personnel relative to performing work in areas that are potentially hazardous because of radioactivity are under the cognizance of the Radiation Protection Manager and the Manager, Nuclear Training.

The indoctrination and training provided to DAEC personnel and contract personnel relative to emergency preparedness is under the cognizance of the Manager, Emergency Planning.

17.2.2.7 Management Review and Audit

The status of the Company Operational Quality Assurance Program is periodically made known to management. A periodic report is prepared by the Manager, Quality Assurance and submitted to the Vice President, Nuclear.

An annual audit of the Operational Quality Assurance Program is conducted to evaluate the effectiveness of the overall program. Direction for these audits alternates between the Vice President, Nuclear and the Safety Committee. The Safety Committee audit is in accordance with the requirement for a biennial audit of the quality assurance program as delineated in Section 17.2.18.2.2 of this UFSAR Chapter. These alternating audits complement each other and provide an annual evaluation.

17.2.3 DESIGN CONTROL

17.2.3.1 Scope

The design, modification, addition, and replacement of safety-related structures, systems, and components at the DAEC is controlled to ensure that appropriate measures are implemented and to ensure that "as-built" quality is not degraded. The plant design is defined by the Company, the NSSS supplier, architect/engineer, and selected suppliers. Design drawings and specifications illustrate the general arrangement and details of safety-related structures, systems, and components and define the requirements for ensuring their continuing capability to perform their intended operational or safety design function.

Design activities include the correct translation of regulatory requirements and design bases into specifications, drawings, written procedures, and instructions that define the design. Design analyses regarding reactor physics, stress, seismic, thermal, hydraulic, radiation, and accident analyses used to produce design output documents are performed when appropriate. Design verification is performed.

Procedures establish requirements, assign responsibilities, and provide control of design activities to ensure performance in a planned, controlled, and orderly manner.

17.2.3.2 Design Responsibility

The design and engineering effort is the responsibility of the Manager, Engineering within the Nuclear Generation Division. Assistance may be provided by other engineering organizations; individuals providing that assistance are required to perform their activities in compliance with the Company Operational Quality Assurance Program. The design of nuclear fuel reloads is the responsibility of Reactor Engineering.

17.2.3.3 Design Criteria

Design requirements and changes thereto are identified, documented, reviewed, and approved to ensure the incorporation of appropriate quality standards in design documents. Design requirements and quality standards are described to an appropriate level of detail in design criteria. Any exception to quality standards will be listed. Criteria for modifications to structures, systems, and components will consider, as a minimum, the design bases described in the UFSAR. All design criteria will be satisfied in the design.

17.2.3.4 Design Process Controls

The organization performing design will have the responsibility for design control unless specified otherwise. The control of design will be specified in procedures. These procedures will include instructions for defining typical design requirements; communicating needed design information across internal and external interfaces; preparing, reviewing, approving, releasing, distributing, revising, and maintaining design documents; performing design reviews; and controlling field changes.

Design control involves measures that include a definition of design requirements; a design process that includes design analysis and the delineation of requirements through the issuing of drawings, specifications, and other design documents (design outputs); and design verification.

The design process establishes controls for releasing technically adequate and accurate design documents in a controlled manner with a timely distribution to responsible individuals and groups. Documents and revisions are controlled through the use of written procedures that apply to the issuer, distributor, and user to prevent inadvertent use of superseded documents. Document control procedures govern the collection, storage, and maintenance of design documents, results of design document reviews, and changes thereto. Design documents subject to procedural control include, but are not limited to, specifications, calculations, computer programs, the UFSAR when used as a design document, and drawings, including flow diagrams, piping and instrument diagrams, control logic diagrams, electrical single-line diagrams, structural systems for major facilities, site arrangements, and equipment locations.

17.2.3.5 Design Interface Control

Design interfaces with external and internal organizations participating in the design are controlled. The design interface measures ensure that the required design information is available in a timely fashion to the organization(s) responsible for the design.

17.2.3.6 Design Verification

The applicability of previously proven designs, with respect to meeting pertinent design inputs, including environmental conditions, will be verified for each application. Where the design of a particular structure, system, or component for a specific application has been subjected to a previous verification process, the verification process need not be duplicated for subsequent identical applications. However, the original design and verification will be documented and referenced for the subsequent application.

When changes to previously verified designs have been made, design verification will be required for the changes, including an evaluation of the effects of those changes on the overall design.

Design verification will be performed by competent individuals who:

1. have not participated in the original design but may be from the same organizational entity,

2. do not have immediate supervisory responsibility for the individual performing the design,

3. have not specified a singular design approach,

4. have not ruled out certain design considerations, and

5. have not established the inputs for the particular design aspect being verified.

Under exceptional circumstances, the design verification may be performed by the originator's supervisor provided:

1. the supervisor is the only technically qualified individual in the organization competent to perform the verification,

2. the need is individually documented and approved in advance by the supervisor's management, and

3. QA audits cover the frequency of occurrence and effectiveness of the supervisor as design verifier to guard against abuse.

Cursory supervisory reviews do not satisfy the intent of providing a design verification.
If errors or deficiencies in the design process are detected during the design verification cycle or during audits, resolution of errors and deficiencies will be the responsibility of the design engineer, who must provide documented evidence of resolution to the appropriate levels of management.

Acceptable verification methods include, but are not limited to, any one or a combination of the following:

1. Design reviews,
2. Alternative or simplified calculational methods, and
3. Performance of suitable qualification testing.

The method selected will consider the item's complexity, previous operational experience, and importance to safety.

The results of the design verification efforts will be clearly documented, with the identification of the verifier clearly indicated and filed. The documentation of results will be auditable against the verification methods identified by the responsible design organization.

17.2.3.6.1 Design Reviews

Design reviews will be sufficient to verify the appropriateness of the design input, including assumptions, design bases and applicable regulations, codes and standards, and that the design is adequate for the intended application of the design.

Design reviews can range from multi-organization reviews to single-person reviews. The depth of review can range from a detailed check of the complete design to a limited check of the design approach, calculations, and results obtained.

17.2.3.6.2 Calculations

Alternative, simplified calculations can be made, or a check of the original calculations may be performed, to verify the correctness of the original calculation. Where computer programs are used, the program verification will be documented and the inputs shall be considered in the design review.

17.2.3.6.3 Qualification Testing

Design verification for some designs or specific design features may be achieved by suitable qualification testing of a prototype or initial production unit.

In those cases where the adequacy of a design is to be verified by a qualification test, the testing will be identified and documented. Testing will demonstrate the adequacy of performance under conditions that simulate the most adverse design conditions.

17.2.3.7 Changes To Design Documents

Changes to design documents receive a review and approval process as equivalent to original design documents. Design documents issued by the original architect-engineer, NSSS supplier, and other organizations may be changed and revised by the responsible design organizations within the Company or contracted by the Company.

17.2.3.8 Independent Review Committees

Independent of the responsibilities of the design organization, the requirements of the Operations Committee and the Safety Committee, as specified in UFSAR 17.2 Appendix A, Section 6.4, will be satisfied.

17.2.4 PROCUREMENT DOCUMENT CONTROL

17.2.4.1 Scope

Procurement document control applies to documents employed to procure safety related materials, parts, components, and services required to modify, maintain, repair, test, inspect, or operate the DAEC. The Company controls procurement documents by written procedures that establish requirements and assign responsibility for measures to ensure that applicable regulatory requirements, design bases, and other requirements necessary to ensure quality are included in or invoked by reference in documents employed for the procurement of safety related materials, parts, components, and services.

17.2.4.2 Procurement Responsibility

The responsibility for the initiation of a purchase requisition is that of the organization that ultimately has the responsibility for the procurement.

17.2.4.3 Quality Classification

Each item or service to be procured is evaluated by the Engineering Department to determine whether or not it performs a safety-related function or involves activities that affect the function of safety-related materials, parts, or components and to appraise the importance of this function to plant or public safety. For those cases where it is unclear if an individual piece (that is, part of a safety-related structure, system, component, or service) is governed by the Operational Quality Assurance Program, an engineering evaluation will be conducted. The evaluation will classify the safety relationship of the service or questionable component parts or items of safety-related structures, systems, or components.

17.2.4.4 Quality Requirements in Procurement Documents

Procurement document control measures will ensure that appropriate regulatory requirements, design bases, and other requirements are included in the procurement process. Originating and reviewing organizations shall require that the following be included or invoked by reference in procurement documents, as appropriate:

1. Requirements that the supplier provide a description of his quality assurance program that implements the applicable criteria of 10 CFR Part 50, Appendix B, and that is appropriate for the particular type of item or service to be supplied. Certain items or services will require extensive controls throughout all stages of manufacture or performance, while others may require only a limited control effort in selected phases.

2. Basic administrative and technical requirements, including drawings, specifications, regulations, special instructions, applicable codes and industrial standards, and procedural requirements identified by titles and revision levels; special process instructions; test and examination requirements with corresponding acceptance criteria; and special requirements for activities such as designing, identifying, fabricating, cleaning, erecting, packaging, handling, shipping, and storing.

3. Requirements for supplier surveillance, audit, and inspection, including provisions for Company access to facilities and records and for the identification of witness and hold points.

4. Requirements for extending applicable requirements to lower-tier suppliers and subcontractors. These requirements will include right-of access by the Company to sub-supplier facilities and records.

5. Requirements for the supplier to report certain nonconformances to procurement document requirements and conditions of their disposition.

6. Documentation requirements, including records to be prepared, maintained, submitted, or made available for review, such as drawings, specifications, procedures, procurement documents, inspection and test records, personnel and procedural qualifications, chemical and physical test results, and instructions for the retention and disposition of records.

7. Requirements for supplier-furnished records.

8. Applicability of the provisions of 10 CFR Part 21 for safety-related items, to the extent that a loss of their function may cause potential substantial safety hazards. Certain items, as off-the-shelf items, will be exempt from this requirement.

9. Requirements for packaging and transportation as necessary to prevent degradation during transit.

17.2.4.5 Acquisition from Other Licensed Nuclear Power Plants

Items may be procured from another NRC-licensed nuclear power plant provided that the procured item meets the requirements of the DAEC procurement specification. If the item was originally procured by the other utility as a "basic component" as defined in 10 CFR Part 21, then the reporting requirements of the regulation are accepted by the Company. The Company shall notify the original supplier in writing of this item(s) change in ownership to give the original supplier the opportunity to change the 10 CFR Part 21 notification records.

17.2.5 INSTRUCTIONS, PROCEDURES, AND DRAWINGS

17.2.5.1 Scope

Instructions, procedures, and drawings will be generated to provide direction and guidance to ensure that safety-related activities are performed correctly. The need for, content of, and depth of detail of the instructions, procedures, and drawings will be consistent with the importance and complexity of that activity.

17.2.5.2 Content

The content of the instructions, procedures, and drawings will be appropriate to the activities being performed.

Instructions and procedures will include, as appropriate, scope or purpose, responsibilities of individuals performing the work, the information needed, and required output and acceptance criteria.

Drawings will be prepared using industrially accepted standards.

17.2.5.3 Compliance

Following approval and issuance of instructions, procedures and drawings, respective activities will be performed in accordance with the documents. If an activity cannot be accomplished due to an inadequacy of the document, the document will be formally revised to reflect the manner in which the activity is to be performed.

17.2.6 DOCUMENT CONTROL

17.2.6.1 Scope

The organization responsible for the documents will establish measures to ensure that the documents, including changes, are reviewed for adequacy and are approved for release by authorized personnel. The responsible organization also establishes measures to ensure the documents are distributed to and used at the location where the prescribed activity is performed and are controlled.

17.2.6.2 Preparation

Administrative techniques will be established that define the documents to be issued and controlled, identify the current revision or issue of the document, and identify the individuals who are to receive the document.

17.2.6.3 Review and Approval

Documents that are specified as being controlled documents are reviewed to ensure that regulatory, technical, and quality assurance requirements have been appropriately addressed;

that review comments have been considered and resolved; and that the document is approved before issuance and use.

The review and approvals required for instructions, procedures and drawings will be established by the organization responsible for those documents. Reviews will be performed by knowledgeable personnel other than the originator. Review and approval will occur prior to issuance or implementation of the changed document.

17.2.6.4 Distribution and Use

Documents will be issued before the commencement of the activity to be controlled by that document. The mechanism for distribution will provide assurance that the controlled document arrives at the point of use; the user will provide assurance that the document to be used is the proper document and revision.

When formal distribution lists are used to prescribe an established distribution, they will be maintained current to reflect changes in assigned responsibilities.

Document transmittals will be reviewed for accuracy and dated and made suitable for transmittal. The recipient is informed of what is being transmitted and of the status of the documents being transmitted.

An acknowledgment of the receipt of controlled documents by recipients may be required if the organization responsible for the document deems such controls necessary.

The organization responsible for the use of the document will establish administrative controls to provide for positive identification and prevent the loss of such documents. The administrative controls will have provisions to remove obsolete documents, thereby precluding the possibility that the wrong documents or revisions will be used.

17.2.6.5 Changes to Documents

Changes to documents previously released will be reviewed, approved, dated, and distributed in the same manner as the original document.

Personnel who review changed documents will have access to pertinent background information upon which to base their approval. Reviewers shall have adequate understanding of the requirements and the intent of the original documents, including source documentation. Revisions will be reviewed and approved by the same organizations that performed the original review and approval unless another qualified organization is designated.

Revised instructions and procedures will reflect the new revision and date and clearly identify the scope or portion of the instruction and procedure being changed.

Documents that have been approved by the original designers of the DAEC will be revised by the DAEC Engineering Department.

17.2.7 CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES

17.2.7.1 Scope

Purchased material, equipment, and services are controlled to ensure that the specified technical and quality requirements are obtained. The responsibility for the control of purchased material, equipment, and services is that of the Quality Assurance Department in close cooperation with the Engineering Department and the DAEC. The technique used for the control of purchased material, equipment and services includes, as appropriate, source evaluation and selection, objective evidence of quality furnished, inspection at the source, supplier's history of providing a satisfactory product, and examination of the product on delivery.

17.2.7.2 Source Evaluation and Selection

Potential suppliers are evaluated. These evaluations are performed by qualified personnel to determine the capability of the supplier to provide the items or services.

Suppliers are evaluated on the basis of one or more of the following:

1. Capability to comply with the requirements of 10 CFR 50, Appendix B, applicable to the type of material, equipment, or service being procured,

2. Past records and performance for similar procurements to ascertain the capability of supplying a manufactured product or services under an acceptable quality assurance system,

3. Audits or surveys of supplier's facilities and quality assurance program to determine the capability to supply a product that satisfies the design, manufacturing, and quality requirements,

4. The certification of the supplier by the ASME, and

5. The results of audits performed by other utilities and consultants.

The supplier's bid proposal is reviewed and evaluated to ensure that the bid is responsive to the procurement documents.

Depending on the importance of the item or service and its importance to safety, a post-award meeting may be held to discuss the requirements of the procurement document.

17.2.7.3 Inspection or Surveillance at the Source

Subsequent to the award of a purchase order, a surveillance/inspection plan may be prepared. The extent of the plan will consider the complexity and importance of the item or service, supplier's past performance, and those aspects of the manufacturing process that may not be verified at receipt inspection.

The plan will establish, as appropriate, the frequency of surveillance/inspection; processes to be witnessed, inspected, or verified; the method of surveillance/inspection; and documentation requirements.

Activities specified in the plan will be conducted at the supplier's facilities by qualified personnel using approved procedures that provide for the following as applicable:

1. Reviewing material acceptability,
2. Witnessing in-process inspections, tests, and nondestructive examination,
3. Reviewing the qualification of procedures, equipment, and personnel,
4. Verifying that fabrication or construction procedures and processes have been approved and are properly applied,
5. Verifying quality assurance/quality control systems, to the extent necessary,
6. Reviewing document packages for compliance to procurement document requirements, including qualifications, process records, and inspection and test records,
7. Reviewing Certificates of Compliance for adequacy, and
8. Verifying that nonconformances have been properly controlled.

Hold points specified in the procurement document will be complied with and the Company will be notified in a timely manner when hold points are reached.

A method will be established to provide information relative to the characteristics that have been inspected at the source and the characteristics that are to be inspected on receipt.

17.2.7.4 Receipt Inspection

Items purchased by the Company are controlled at the final destination by the performance of a receipt inspection. The extent of the receipt inspection depends on the importance to safety, the complexity, the quantity of the product or service, and the extent of source inspection, source surveillance or audit that was performed.

Receipt inspection is performed by trained and qualified personnel in accordance with approved procedures and acceptance criteria before the installation or use of the item(s) to preclude the placement or use of nonconforming item(s).

Documentary evidence will demonstrate that materials and equipment conform to the procurement requirements.

If receipt inspection indicates that the item is unacceptable, the item is treated as nonconforming.

17.2.7.5 Post-installation Testing

Acceptance by post-installation test may be used following one of the preceding verification methods. Post-installation testing is used as the prime means of acceptance verification when it is difficult to verify item quality characteristics, the item requires an integrated system check out or test, or the item cannot demonstrate its ability to perform when not in use. Post-installation test requirements and acceptance documentation are established by the Company.

17.2.8 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS, AND COMPONENTS

17.2.8.1 Scope

Materials, parts, and components will be identified and controlled to ensure that the correct materials, parts, and components are used during fabrication, manufacture, modification, repair, and replacement.

It is the responsibility of the organization responsible for the engineering design and procurement to include the requirements for proper identification and control in the procurement documents.

It is the responsibility of the supplier for maintaining the traceability of materials, parts, and components throughout fabrication and shipment.

It is the responsibility of the DAEC for maintaining the traceability of materials, parts, and components throughout repair, replacement, modification, and installation.

17.2.8.2 Identification

Identification will be applied in locations and by methods that will not affect the fit, function, or quality of the item.
The identification of the item will be maintained by a unique method such as heat number, part number, serial number, batch number, or other appropriate means in a form that is durable and legible.

The identification may be on the item or on records traceable to the item. Where feasible, direct placement of the identification on the item will be by stamping, marking, tags, labels, or other similar methods.

Where direct placement of identification on the item is not feasible, proper controls will be established that ensure direct positive identification of the item. Where physical identification is either impractical or insufficient, physical separation, procedural control, or other approved means will be employed.

Receipt inspection will verify that identification for received items is complete and accompanied by appropriate documentation.

When an item is subdivided, the identification will be immediately transferred to the sub-parts so that all sub-parts contain the appropriate identification label.

Any identification that will be obliterated or hidden by surface coatings or surface treatments will be reestablished or will be traceable by administrative means.

Standard catalog items or off-the-shelf items may be identified by catalog number or other appropriate designation.

17.2.8.3 Verification and Control

The items will be controlled and the identity of the item verified.

Inventory and storage controls will be established at the DAEC to ensure proper traceability of items.

The correctness of the item will be verified on withdrawal from storage and before the initiation of the repair, replacement, and modification.

17.2.9 CONTROL OF SPECIAL PROCESSES

17.2.9.1 Scope

Special processes are those controlled fabrications, tests, and final preparation processes that require the qualification of procedure, technique, and personnel and that are performed in accordance with applicable codes and standards. Certain special processes require interim in-process controls in addition to final inspection to ensure quality.

The control of special processes is the joint responsibility of the Engineering Department, the DAEC, and the Quality Assurance Department.

The Engineering Department is responsible for providing technical expertise relative to materials, metallurgy, welding, brazing, special processes and nondestructive examination

(NDE). Nondestructive examinations will be performed under the direction of the Engineering Department by personnel independent of the activity and qualified in accordance with SNT-TC-1A.

17.2.9.2 General Requirements

Measures will be established to ensure that special processes are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.

Written procedures will be reviewed or prepared before use to ensure that special processes are controlled and accomplished.

These procedures will describe the operations to be performed, the sequence of operations, the characteristics involved, the limits of these characteristics, measuring and test equipment to be used, acceptance criteria, and documentation requirements.

Special processes will be accomplished in accordance with written procedures and process sheets, or their equivalent.

Personnel will be trained and qualified in accordance with applicable codes and standards.

Equipment used to perform special processes or measure or test the product will be qualified, before use, in accordance with applicable codes, standards, specifications, or procedures.

The extent and period of training, qualification, and testing of personnel and equipment will be in accordance with applicable codes, standards, specifications, or procedures.

17.2.9.3 Personnel Qualification

The personnel who perform nondestructive examinations will be certified to the precise technique to be used and for the proper level of expertise.

A Level III Examiner will be responsible for qualifying and certifying, in accordance with Company written practice, the Company personnel who perform nondestructive examinations.

17.2.9.4 Verification and Control

The procedures, process sheets, personnel, and equipment will be verified as appropriate, before the initiation of work at the DAEC.

The Quality Assurance Department will determine that suppliers performing special processes at the DAEC have sufficient controls before the initiation of the work.

The Engineering Department will determine that personnel performing special processes have current qualifications.

17.2.9.5 Special Protective Coatings (Paint)

The application of a special protective coating shall be controlled as a special process when the failure (i.e. peeling or spalling) of the coating to adhere to the substrate can cause the malfunction of a safety-related structure, system or component. Special process coatings shall be applied by qualified personnel using qualified materials and equipment, and approved procedures. Documentation shall include identification of the following:

1. person applying the coating (and qualification),
2. material used,
3. procedure used (and qualifying procedure if different),
4. tests performed and results,
5. date of application of coating, and
6. traceability of coating location.

17.2.10 INSPECTION

17.2.10.1 Scope

A program for the inspection of safety-related activities at the DAEC will be established and executed to verify conformance with applicable documented instructions, procedures, drawings, and specifications.

The responsibility for the receipt, in-process and final inspection of materials, parts, and components affecting quality is that of the Maintenance Department. The responsibility for the performance of nondestructive examinations is that of the Engineering Department.

17.2.10.2 General Requirements

A program for the inspection of activities affecting quality will be established and executed by or for the organization performing the activity to verify conformance with the documented instructions, procedures, and drawings for accomplishing the activity.

Inspection will be performed by individuals other than those who performed the activity being inspected. Inspections will be performed by personnel using appropriate equipment in accordance with applicable codes, standards, and procedures.

Procedures, instructions, or checklists will be established and used that identify the characteristics to be inspected, inspection methods, special devices, acceptance and rejection criteria, methods for recording inspection results, and groups responsible for the inspection. Special preparation, cleaning, and the use of measuring devices will be included.

Inspections will be planned to identify where in the sequence of work each inspection activity will be performed, to what extent, procedures to be used, and mandatory hold or witness points.

Repairs, modifications, or replacements will be inspected in accordance with the original inspection requirements or acceptable alternatives.

Sampling methods and process monitoring will be used when inspection is impossible or disadvantageous.

17.2.10.3 Process Monitoring

Process monitoring of work activities, equipment, and personnel will be used as a control if inspection of processed items is impossible or disadvantageous. Both inspection and process monitoring will be provided when control is inadequate without both. As an alternative, a suitable level of confidence in structures, systems, or components on which maintenance or modifications have been performed will be attained by inspection. As appropriate, an augmented inspection program will be implemented until such time as a suitable level of performance has been demonstrated.

The monitoring of processes will be performed to verify that activities affecting quality are being performed in accordance with documented instructions, procedures, drawings, and specifications.

17.2.10.4 In-Service Inspection

Required in-service inspection, including nondestructive examination, pressure tests, and in-service tests of pumps and valves, will be planned and executed. The results of these examinations and tests shall be documented, including corrective actions required and the actions taken.

The basis for the in-service inspection program is the ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition with no Addenda. The specific issue and addendum of requirements beyond the base commitment is as specified in 10 CFR Part 50, Section 50.55a(g), except where specific exemptions have been granted by the NRC.

The Engineering Department has the overall responsibility for developing the inspection program, for ensuring compliance with the ASME Code Section XI rules, and for evaluating the inspection results. The inspection plans shall be updated as required to accommodate the as-built condition of the DAEC.

17.2.10.4.1 Ten Year Inspection Program

The Ten-Year Inspection Program includes inspections and tests of those pressure boundary welds and materials as defined in ASME Boiler and Pressure Vessel Code, Section XI. Also included are the pressure boundary welds and materials that are defined as "Augmented" in-service inspections. The Ten-Year Inspection Program identifies the welds and items to be examined, the frequency of such examinations, the methods, and confirms the continuing acceptability of the selected welds and items.

The Engineering Department has the responsibility for conducting the planned nondestructive examinations (NDE) and providing the services of the NDE Level III Examiner as required by Code.

17.2.10.4.2 In-service Testing Program

The DAEC has the responsibility for conducting the ASME Boiler and Pressure Vessel Code, Section XI, pump and valve tests, system pressure tests, and snubber tests. These performance tests to verify operational readiness are part of the plant performance program.

17.2.10.5 Personnel Qualification

Personnel performing inspections and examinations, or accepting the results of inspections and examinations, will be trained and qualified in accordance with governing codes, standards, and regulations. The personnel will be competent and cognizant of the technical requirements of the work activity. Qualification records will be maintained by the organization responsible for the individual(s) performing the inspections.

17.2.10.6 Documentation and Records

Inspection and examination activities will be reported on a form that indicates the date of the activity, identification of inspector or examiner, and rejection or acceptance of the item(s).

17.2.11 TEST CONTROL

17.2.11.1 Scope

Testing will be performed at the DAEC to demonstrate that safety-related structures, systems, and components perform satisfactorily in service. The testing program will include the following, as appropriate:

1. Qualification tests for design verification,
2. Proof tests before installation,
3. Pre-Operational tests, and
4. Operational tests.

17.2.11.2 General Requirements

The tests will be performed in accordance with approved written test procedures that incorporate the requirements and acceptance limits. The test procedure will identify the item to be tested and the purpose of the test.

Test procedures will include provisions for ensuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions. The test procedure will incorporate directly, or by reference, the following requirements:

1. Performance of tests by trained personnel who are qualified in accordance with applicable codes and standards,
2. Verification of test prerequisites,
3. Identification and description of acceptance or rejection criteria, and
4. Instructions for performing the test.

17.2.11.3 Surveillance Testing

Provisions will be established for the performance of surveillance testing to ensure that the necessary quality of systems and components is maintained, that facility operations are within the safety limits, and that limiting conditions of operation can be met. The testing frequency will be at least as frequent as prescribed in the Technical Specifications. The provisions for surveillance testing will include the preparation of schedules that reflect the status of planned surveillance tests. Qualified plant staff will perform surveillance tests.

17.2.11.4 Personnel Qualification

Personnel performing testing will be trained and qualified. The personnel will be competent and cognizant of the technical requirements of the work activity.

17.2.11.5 Documentation and Records

Test procedures and results will be documented and approved by qualified personnel.

Test results shall be documented and indicate that the prerequisites and other test requirements have been met.

17.2.12 CONTROL OF MEASURING AND TEST EQUIPMENT

17.2.12.1 Scope

The responsibility for the control of measuring and test equipment and permanently installed plant instrumentation, is that of the DAEC. The control measures will include the identification and calibration of the equipment to the activity. The requirements contained within this section do not apply to devices for which normal industry practice provides adequate control, that is, tape measures, rulers, and measuring glasses.

17.2.12.2 General Requirements

Measures will be established for the control, calibration, and adjustment of measuring and testing devices.

Calibration intervals will be based on required accuracy, the use of equipment, stability characteristics, or other factors affecting the measurement.

The following requirements will be specified in written procedures that are used to control measuring and test equipment:

1. Identification of equipment and traceability to calibration data,
2. Calibration methods, frequency, maintenance, and control,
3. Labeling and marking of portable equipment to indicate due date for next calibration. Due dates for permanently installed plant equipment are controlled by means of a central record system,
4. Provisions for determining the validity of previous measurements when equipment is determined to be out of calibration, and
5. Traceability of reference and transfer standards to nationally recognized standards. When national standards do not exist, the basis for calibration shall be documented.

Calibration may be performed at the DAEC or by qualified laboratories using competent personnel.

Equipment that is consistently found to be out of calibration shall be repaired or replaced.

When the accuracy of the measuring or test device can be adversely affected by environmental conditions, special controls will be prescribed to minimize such effects.

17.2.12.3 Traceability

The measuring and test equipment will be traceable to the item on which the equipment has been used.

When calibration, testing, or other measuring devices are found to be out of calibration, an evaluation shall be made and documented concerning the validity of previous tests and the acceptability of devices previously tested from the time of the previous calibration.

17.2.13 HANDLING, STORAGE, AND SHIPPING

17.2.13.1 Scope

The handling, storage, shipping, cleaning, and preservation of material and equipment will be controlled to prevent damage, deterioration, and loss.

It is the responsibility of the organization initiating procurement to specify any special instructions and requirements for packaging and handling, shipping, and extended storage.

It is the responsibility of the DAEC to provide for the proper handling and storage of material and equipment upon receipt and throughout repair, replacement, and modification.

17.2.13.2 General Requirements

Measures will be established to control the handling, storage, shipping, cleaning, and preservation of material and equipment in accordance with work and inspection instructions to prevent damage or deterioration.

When necessary for particular products, special protective environments such as inert gas atmosphere, temperature levels, and specific moisture-content levels will be specified and provided.

Consistent with the need for preservation, material and equipment will be suitably cleaned to prevent contamination and degradation. The cleaning method selected will in itself not damage or contaminate the material or equipment.

17.2.13.3 Shipping

When required to prevent contamination or to prevent damage during shipment, special packaging methods will be specified and implemented.

Special-handling requirements, if required, will be specified in the shipping instructions. The package should be appropriately marked to indicate that special handling or storage requirements are necessary.

Markings of packages will conform to applicable Federal and state regulations.

17.2.13.4 Radioactive Materials

Measures will also be established to control the shipping of licensed radioactive materials in accordance with 10 CFR Part 71. These measures will apply to the use of shipping containers only, and not to the design and fabrication of shipping containers for which an NRC certification is required under Part 71.

17.2.13.5 Handling

The requirements for special handling will be considered when the item is moved from the receipt point to the storage area and from the storage area to the point of use. Special-handling equipment will be periodically tested and inspected.

17.2.13.6 Storage

Materials and equipment will be stored to minimize the possibility of damage or lowering of quality from the time an item is stored on receipt until the time the item is removed from storage.

The manufacturers' recommendations are considered; however, the relaxation of manufacturers' storage requirements may be implemented if the storage recommendations are not reasonably necessary to preclude equipment degradation. Material and equipment will be stored at locations that have a designated storage level. The various storage levels will be defined and will have prescribed environmental conditions. The storage conditions will be in accordance with design and procurement requirements to preclude damage, loss or deterioration due to harsh environmental conditions. Items having limited shelf life will be identified and controlled to preclude the use of items whose shelf life has expired.

17.2.14 INSPECTION, TEST, AND OPERATING STATUS

17.2.14.1 Scope

Measures will be established to ensure that necessary inspections of items have not been inadvertently bypassed or that systems or components are not inadvertently operated.

17.2.14.2 General Requirements

Measures will be established to indicate, by the use of marking such as stamps, tags, labels, routing cards, log books, or other suitable means, the status of inspection, test and operating status of individual structures, systems, or components.

Procedures will provide for controls to preclude the inadvertent use of nonconforming, inoperative, or malfunctioning structures, systems, or components.

The procedures will include the following:

1. Identification of authority for application and removal of status indicators,

2. The use of specific status indicators, and

3. Provisions for maintaining the status of the structures, systems, or components until removed by an appropriate authority.

17.2.14.3 Inspection and Test Status

Measures will be established to provide for the identification of items that have satisfactorily passed required inspections and tests.

Only items that have passed inspection or testing will be used in the manufacture or installation of an item.

Documented procedure requirements will include the following:

1. Maintenance of the status of the item throughout fabrication and installation,

2. Use of status indicators such as stamps, tags, markings, or labels either on the items or on documents traceable to the items, and

3. Provisions for controlling the bypassing of required inspections, tests, and other critical operations.

Items at the DAEC will be identified by status indicators to indicate whether they are awaiting inspection, acceptable for use, unacceptable, or in a hold status pending further evaluation.

17.2.14.4. Operating Status

Procedures relating to the operational status of safety-related structures, systems, and components, including temporary modifications, will include the following:

1. Authorization for requesting that equipment be removed from service,

2. Checks that must be made before approving the request,

3. Approval of the action to remove the equipment from service,

4. The actions necessary to isolate the equipment and responsibility for performing these actions, and

5. The actions necessary to return the equipment to its operating status and responsibility for these actions.

Equipment and systems in a controlled status will be identified. Plant procedures will establish controls to identify the status of inspection and test activities associated with maintenance, instrumentation, and control system calibration and testing. The status of nonconforming, inoperative, or malfunctioning structures, systems, and components will be documented and identified to prevent inadvertent use.

The Technical Specifications establish the status required for safe plant operation, including provisions for periodic and non-periodic tests and inspections, of various structures, systems, and components. Periodic tests may be operational tests or tests following maintenance, and non-periodic tests may be made following repairs or modifications.

17.2.14.5 Sequence Change Control

Procedures will include the control of the sequence of required tests, inspections, and other operations when important to safety. To change these controls, the individual procedure must be changed, which requires the same review and approval cycle as that which authorized the original procedure.

17.2.14.6 Startup Report

A summary report of plant startup and power escalation testing shall be submitted to the NRC Regional Office following (1) receipt of an operating license, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant. The report shall address each of the tests identified in the UFSAR and shall in general include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specified details required in license conditions based on other commitments shall be included in this report.

Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operations, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of startup test program and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

17.2.15 NONCONFORMING MATERIALS, PARTS, OR COMPONENTS

17.2.15.1 Scope

The nonconformance reporting system is established to control materials, parts or components which do not conform to requirements in order to prevent their inadvertent use or installation. Nonconforming materials, parts or components shall be identified, documented and segregated, and notification shall be provided to affected organizations. The responsibility for the disposition of the nonconforming materials, parts, or components is that of the Engineering Department, DAEC, and the Quality Assurance Department.

17.2.15.2 Identification and Segregation

The identification and segregation will be sufficient to prevent inadvertent use or installation of the nonconforming item. Material, parts, or components for which nonconformances have been identified will be immediately segregated, when practical, in areas that are reserved for nonconforming items. When segregation is impractical, administrative measures will be used, such as tagging, roping off the area, etc.

17.2.15.3 Reporting and Disposition

The reporting mechanism will provide the means to disposition the nonconforming material, part, or component.

The nonconformance report will identify the item, describe the nonconformance, and contain sufficient information to evaluate the nonconformance. The nonconformance report will be transmitted to the proper organization(s) for evaluation and disposition.

17.2.15.4 Disposition

The disposition will be limited to one of the following: use-as-is, rework to original requirements, repair to an acceptable condition, or reject.

For disposition of use-as-is and repair, a technical justification will provide assurance that the item will function as originally intended.

Items that are to be repaired or reworked will be required to be reinspected or retested to determine that the original or new acceptance criteria have been satisfied.

17.2.16 CORRECTIVE ACTION

17.2.16.1 Scope

Corrective action control measures will be established to ensure that conditions adverse to quality are promptly identified, reported, and corrected.

17.2.16.2 Conditions Adverse to Quality

Conditions adverse to quality such as failures, malfunctions, deficiencies, deviations, defective material and equipment, nonconformances, and abnormal occurrences will be promptly identified and corrected.

The Nuclear Licensing Department is the responsible for administration of the Corrective Action Program. Administrative responsibilities include receipt, tracking, assignment of actions to appropriate personnel for correction, and classification of the reported conditions as a condition adverse to quality or a significant condition adverse to quality.

The Quality Assurance Department will perform an analysis of reported conditions adverse to quality to identify negative trends in quality performance and to determine if there are any broad programmatic areas where trending reveals a significant condition adverse to quality. This analysis will be performed at least annually and will be reported to appropriate levels of management. This analysis will be documented and retained as a quality assurance record.

17.2.16.3 Significant Conditions Adverse to Quality

Significant conditions adverse to quality that impede the implementation or reduce the effectiveness of the program will be controlled. These conditions will be reported to appropriate management and evaluated. The cause of a significant condition adverse to quality shall be determined, and corrective action will be taken to preclude repetition. Significant adverse conditions may include, but are not limited to, a recurring condition for which past corrective action has been ineffective, significant trends adverse to quality, or significant Operational Quality Assurance Program deficiencies.

17.2.16.4 Reporting of 10 CFR 21 Defects and Non-compliances

A 10 CFR 21 defect and noncompliance is defined as one which could reasonably indicate a potential substantial safety hazard.

A procedure has been established, and appropriate posting provided in accordance with the provisions of 10 CFR Part 21, so that Company employees will be aware of the methods by which 10 CFR Part 21 defects and non-compliances are reported to the NRC.

The Vice President, Nuclear, is designated as the Company officer responsible for reporting defects and non-compliances, as appropriate, to the NRC.

17.2.16.5 Reportable Events

Each reportable event shall be reviewed by the Operations Committee and a report shall be submitted to the Safety Committee and the Vice President, Nuclear.

17.2.17 QUALITY ASSURANCE RECORDS

17.2.17.1 Scope

Quality assurance records will be prepared, identified, collected, and protected so that adequate evidence of activities affecting quality is available.

17.2.17.2 Preparation and Identification of Quality Assurance Records

The organization responsible for the activity will also be responsible for the preparation and identification of the quality assurance records that attest to the quality of that activity.

As a general criterion, those documents that reflect the as-built condition of an item, component, system, or plant, and those documents that attest to the quality of an activity, item, structure, or system will be treated as quality assurance records. Also, the qualification records of inspection, examination and testing personnel, and quality assurance audit personnel, are classified as quality assurance records.

Quality assurance records will be legible, accurate, and complete.

17.2.17.3 Collection and Protection of Quality Assurance Records

The quality assurance records will be collected, indexed, classified, and protected.

The organization that generates the quality assurance record will be responsible for collecting the records. The collected quality assurance records will be classified as either lifetime or non-permanent quality assurance records. The lack of a classification will mean that the quality assurance record is a lifetime record.
The quality assurance records that have been identified and collected will be suitably protected against fire, theft, and damage. The manner in which the records are protected will be consistent with the retention period.

17.2.17.3.1 Retention of Records

The following records shall be retained for at least 5 years:

1. Records and logs of facility operation covering time interval at each power level,

2. Records and logs of principal maintenance activities, inspections, and repair and replacement of principal items of equipment related to nuclear safety,

3. All Licensee Event Reports,

4. Records of surveillance activities, inspections and calibrations required by Technical Specification,

5. Records of reactor tests and experiments,

6. Records of changes made to Operating Procedures,

7. Records of radioactive shipments,

8. Records of sealed source leak test and results,

9. Records of annual physical inventory verifying accountability of sources on record, and

10. Records of radioactive effluent monitor setpoints and setpoint determinations.

The following records shall be retained for the duration of the Facility Operating License

1. Record and drawing changes reflecting facility design modifications made to systems and equipment described in the Final Safety Analysis Report,

2. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories,

3. Records of facility radiation and contamination surveys,

4. Records of radiation exposure for all individuals for whom monitoring was required,

5. Records of gaseous and liquid radioactive material released to the environment,

6. Records of transient or operational cycles for those facility components designed for a limited number of transients or cycles,

7. Records of training and qualification for current members of the plant staff,

8. Records of in-service inspections performed pursuant to the Technical Specifications,

9. Records of Quality Assurance activities required by the QA Manual with the exception of the records to be retained for 5 years as noted above,

10. Records of reviews performed for changes made to procedures or equipment or reviews for tests and experiments pursuant to 10CFR 50.59,

11. Records of meetings of the Operations Committee and the Safety Committee,

12. Records of the service lives of all safety-related hydraulic and mechanical snubbers including the date at which the service life commences and associated installation and maintenance records,

13. Records of results of analyses required by the radiological environmental monitoring program,

14. Records of reviews performed for changes made to the Offsite Dose Assessment Manual and the Process Control Program.

17.2.17.4 Record Storage on Optical Disks

Records may be stored on an optical disk storage system which utilizes a write once read many (WORM) system. The image of each record shall be placed onto two optical disks, with verification of the image on each record. Should any of the images be illegible, the hard copy record is maintained as the record. One optical disk shall be used for on-line access and the second optical disk shall be stored in a records storage facility meeting the requirements for single copy storage or in a separate remote location meeting the requirements of the Company commitment to ANSI N45.2.9-1974.

To ensure permanent retention of records, the records stored on an optical disk are acceptably copied onto a new optical disk before the manufacturer's certified useful life of the original disk is exceeded. Records copied shall be verified.

Periodic random inspections of images stored on optical disks are performed to verify that there has been no degradation of image quality.

Should it become necessary to replace the optical imaging system with a new system which is not compatible, the records stored on the old system shall be converted onto the new system prior to the old system being taken out of service. This conversion process shall include a verification of the records converted.

17.2.17.5 Transfer or Destruction of Records

The organization responsible for the quality assurance record will be responsible for the transfer of that quality assurance record for the purposes of microfilming and/or lifetime storage.

The transfer of quality assurance records from one organization to another organization will be accomplished by a formal mechanism that provides for the acceptance of the quality assurance record.

The destruction of quality assurance records will be accomplished only with the approval of the concerned organizations.

17.2.18 AUDITS

17.2.18.1 Scope

A comprehensive audit program will be established and implemented.

The audit program will be sufficient to verify compliance with the Operational Quality Assurance Program and to determine the effectiveness of the Operational Quality Assurance Program.

The responsibility for the audit system will be that of the Quality Assurance Department, the Safety Committee, and the Vice President, Nuclear.

17.2.18.2 Audit System

The audit system will be applied to those organizations, both external and internal to the Company, that are involved in safety-related activities.

17.2.18.2.1 External Organizations

The audit program for suppliers is the responsibility of the Quality Assurance Department. Audits will be scheduled at a frequency commensurate with the status and importance of the activity.

In general, the audit schedule will be responsive to the performance of audits before the initiation of an activity to ensure that the proper controls are in place, during the early stages of the activity to determine that the proper controls are being implemented, and near the end of the activity to determine that all specified requirements have been met.

In general, the audit schedule will also include the performance of audits during the activity, assuming that the activity occurs over a sufficient length of time, to determine that the proper controls are being applied and no problems are occurring.

17.2.18.2.2 Internal Organizations

The audit program for the internal Company organizations is the responsibility of the following:

1. The Quality Assurance Department, to determine the compliance of the other organizations to the Operational Quality Assurance Program and to evaluate performance,

2. The Safety Committee, to determine the compliance of the DAEC to the Technical Specification requirements and license provisions and to evaluate performance, and

3. The Vice President, Nuclear, to determine the overall effectiveness of the Operational Quality Assurance Program.

A prominent factor in developing and revising audit schedules will be performance in the subject area. The audit schedule will be revised so that weak or declining areas get increased audit coverage and strong areas receive less coverage.

An audit of safety related functions will be performed at least once per 24 months, except where a specific frequency is listed. Other audits will be performed as required by regulations. Audits of facility activities performed under the cognizance of the Safety Committee include:

1. The conformance of facility operation to provisions contained within the Technical Specifications and applicable license conditions,

2. The performance, training and qualifications of the facility staff,

3. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems, or method of operation that affect nuclear safety,

4. The performance of activities required by the Quality Assurance Program to meet the criteria of Appendix "B", 10 CFR Part 50,

5. The DAEC fire protection program and implementing procedures. An independent fire protection and loss prevention inspection and audit will be performed annually utilizing either qualified offsite licensee personnel or an outside fire protection firm. An inspection and audit by an outside qualified fire consultant will be performed at intervals no greater than three years,

6. Any other area of facility operation considered appropriate by the Safety Committee or the President,

7. The radiological environmental monitoring program and the results thereof,

8. The Offsite Dose Assessment Manual and implementing procedures,

9. The Process Control Program and implementing procedures,

10. The performance of activities required by the QC Program for effluent and the vendor's QA Program for radiological environmental monitoring, and

11. Design change package safety evaluations.

Audit reports for audits performed under the cognizance of the Safety Committee will be forwarded to the President and to the management position responsible for the areas audited within 30 days after completion of the audit.

17.2.18.3 Personnel Training and Qualification

The personnel who participate in audits will have sufficient experience and/or training to fulfill their role in the audit.

Personnel who perform as Lead Auditors will be trained, qualified, and certified.

A Lead Auditor will review the experience of each potential team member, determine their acceptability to perform the audit, determine if any additional training is required, and ensure that the additional training is performed if required.

17.2.18.4 Performance of Audit

The selected audit team shall collectively have experience or training commensurate with the total scope of the audit.

Audit checklists will be developed for the total scope of the audit.

The audit shall be initiated by a pre-audit conference to introduce the audit team and to confirm the scope and plan of the audit. A pre-audit planning meeting as defined in Appendix A may be substituted for the pre-audit conference.

Audits shall be concluded by the Audit Team with a post-audit conference at which the Audit Team will discuss the audit findings and clarify any misunderstandings.

17.2.18.5 Report and Closeout of Audit Findings

The audit will be documented by an audit report signed by a Lead Auditor.

The audit report shall be sent to the responsible management of the audited organization. The audit findings will be tracked to ensure that corrective action has occurred.

The Quality Assurance Department will evaluate the responses to the audit findings. The evaluation will include the necessity for re-audits, submittal of documentation, or any other means of verifying the corrective action. Statements by the audited organization that define the corrective action may be accepted.

The corrective actions will be tracked to ensure that proper and timely corrective actions have occurred prior to closure of the audit findings.

Inadequate or unresponsive corrective action will be brought to the attention of appropriate levels of management.

INTRODUCTION

This Appendix describes the manner by which the IES Utilities Inc. Operational Quality Assurance Program for the Duane Arnold Energy Center (DAEC), as set forth in the Quality Assurance Program Description (QAPD), UFSAR Chapter 17.2, conforms to NRC Regulatory Guides listed in the June 6, 1990, letter from Region III (Miller) to Iowa Electric (Liu) and certain other commitments previously contained in Table 2-1 of the Quality Assurance Manual. Comments and clarifications to these specific commitments are identified in this Appendix.

IES Utilities Inc.(the Company) position on each ANSI standard which is endorsed by a Regulatory Guide to which the Company is committed is stated in either the UFSAR or the QAPD. Other ANSI standards are not requirements for the Company even if they are listed as references in a standard endorsed by a Regulatory Guide to which the Company is committed. (Such standards may, of course, be used as guidance.) However, a section of a standard which is specifically referred to in a standard endorsed by a Regulatory Guide to which the Company is committed is a requirement for the Company unless an exception is stated.

The Company is not committed to ANSI N45.2 for the operational phase. Regulatory Guide 1.33, Revision 2, Section B, "Discussion" states ANSI N18.7-1972, along with ANSI N45.2-1971, "Quality Assurance Program Requirements for Nuclear Power Plants", was endorsed by Regulatory Guide 1.33. The dual endorsement was necessary in order for the guidance contained in the regulatory guide to be consistent with the requirements of Appendix B to 10 CFR Part 50; however, this dual endorsement caused some confusion among users. To clarify this situation, ANSI N18.7-1972 was revised so that a single standard would define the general quality assurance program "requirements" for the operation phase. This revised standard was approved by the American National Standards Committee N18, Nuclear Design Criteria. It was subsequently approved and designated N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants", by the American National Standards Institute on February 19, 1976. Therefore, for the operations phase, where a standard endorsed by a Regulatory Guide refers to the use of ANSI N45.2 in conjunction with that Standard, the Company inserts the ANSI Standard N18.7-1976.

1.0 REGULATORY GUIDE 1.8, "Personnel Selection and Training"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

1.1 IES Utilities Inc's. commitment is to Regulatory Guide 1.8, Revision 1-R, September 1975 (reissued May 1977), which endorses ANSI N18.1-1971. However, the Company commitment is to ANSI/ANS 3.1-1978, which is a revision of N18.1-1971.

1.2 With respect to selection and training of security personnel, the Company does not commit to the standard [ANSI N18.17-1973 (ANS 3.3)] referred to in ANSI/ANS 3.1-1978, Sections 1 (Scope) and 6 (References). The Company training and qualification plan for security personnel complies with 10 CFR Part 73, Appendix B.

2.0 REGULATORY GUIDE 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste- Containing Components of Nuclear Power Plants"

COMMENTS AND CLARIFICATIONS:

The Company commitment to Safety Guide 26 (3/23/72), Quality Group Classifications and Standards, is stated in UFSAR Chapter 1.8, Conformance to NRC Regulatory Guides.

3.0 REGULATORY GUIDE 1.28, "Quality Assurance Program Requirements (Design and Construction)"

COMMENTS AND CLARIFICATIONS:

This Regulatory Guide (Safety Guide 28, dated June 7, 1972) endorses ANSI N45.2 and is not applicable to the operating phase. DAEC's operational QA program is based on Regulatory Guide 1.33, Rev. 2, as stated in UFSAR Section 1.8.

4.0 REGULATORY GUIDE 1.29, "Seismic Design Classification"

COMMENTS AND CLARIFICATIONS:

The Company commitment to Safety Guide 29 (6/7/72), Seismic Design Classification, is stated in UFSAR Section 1.8, Conformance to NRC Regulatory Guides.

5.0 REGULATORY GUIDE 1.30, "Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

5.1 The Company commitment is to Safety Guide 30, dated August 11, 1972 and therefore by reference to ANSI N45.2.4-1972 which it endorses.

5.2 For maintenance and modification activities, the Company shall comply with the Regulatory Position established by this Regulatory Guide in that the quality assurance program requirements included therein (subject to the clarifications below) shall apply. Technical requirements associated with maintenance and modification activities shall be equal to or better than the original requirements (e.g., Code requirements, design and construction specification requirements, and inspection requirements).

5.3 Regulatory Position C.1 states that ANSI N45.2.4-1972 should be used in conjunction with ANSI N45.2-1971. In lieu of this, the Company uses ANSI N45.2.4-1972 in conjunction with ANSI N18.7-1976.

5.4 Section 2.2(5)(d) of ANSI N45.2.4-1972 requires evidence of compliance by manufacturer with purchase requirements, including quality assurance requirements, before the requirements of ANSI N45.2.4-1972 are implemented. In lieu of this, the Company may proceed with installation, inspection, and testing activities for equipment lacking its quality documentation provided that this equipment has been identified and controlled in accordance with the Company's nonconformance reporting system.

5.5 With respect to Section 2.5.2 of ANSI N45.2.4-1972, calibration and control covers two classes of instrumentation used by the Company: (1) portable equipment and (2) permanently-installed equipment. With respect to permanently-installed instrumentation, in lieu of marking the equipment to indicate the date of the next required calibration, a computer-based preventative maintenance program is used. Once a permanently-installed instrument is identified as needing control, a calibration frequency is assigned, and the information is entered into the data base. The calibration task is then automatically tracked and tasked by the data base. A "DO NOT USE Until Tested and Calibrated" or equivalent sticker is applied to instruments not calibrated before their due date and to instruments unacceptable for use. The provisions of ANSI N45.2.4-1972, Section 2.5.2, are applied to portable equipment.

5.6 Section 3 of ANSI N45.2.4-1972 regarding "Preconstruction Verification" states it is necessary to verify that the quality of an item has not suffered during the interim period and it is not intended to duplicate inspections but rather verify that items are in a satisfactory condition for installation. Verifications and checks are then required. In lieu of these verifications and checks, the Company considers the provisions of QAPD Sections 17.2.8 (Identification and Control of Materials, Parts, and Components) and 17.2.13 (Handling, Storage and Shipping) to be equivalent.

5.7 The last paragraph of Section 6.2.1 of ANSI N45.2.4-1972 requires that items requiring calibration be tagged or labeled on completion, indicating date of calibration and identity of person who performed the calibration. In lieu of this, for permanently-installed instrumentation, the calibration status is reflected in a computerized preventive maintenance program as described in Section 5.5 above.

6.0 REGULATORY GUIDE 1.33, "Quality Assurance Program Requirements (Operation)"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

6.1 The commitment is to Regulatory Guide 1.33, Rev. 2, February 1978, and to ANSI N18.7-1976/ANS-3.2 which it endorses.

6.2 Regulatory Guide 1.33 Regulatory Position, Section C.2, also lists fifteen Regulatory Guides and ANSI standards that are referenced in ANSI N18.7-1976/ANS-3.2. The Company position with respect to each of these standards is stated elsewhere in this Appendix A.

6.3 Regulatory Guide 1.33 Regulatory Position, Section C.4, refers to Section 4.5, "Audit Program", of ANSI N18.7-1976/ANS-3.2 and lists specified audit frequencies for three (3) audits. The frequencies for audits are now specified in UFSAR Section 17.2.18.2.2.

6.4 Section 4.3, "Independent Review Program" of ANSI N18.7-1976/ANS-3.2 describes the requirements of bodies fulfilling the independent review function. DAEC utilizes a standing committee (i.e. Safety Committee) further described in Section 4.3.2. Section 4.4, "Review Activities of the Onsite Operating Organization" of ANSI N18.7-1976/ANS-3.2 describes the required activities of the DAEC Operations Committee. The Operations Committee and the Safety Committee implement such requirements as follows:

6.4.1 The Operations Committee shall function to advise the Plant Manager on all matters related to nuclear safety. The committee shall be composed of Managers, Supervisors and personnel selected from the following areas: Operations, Procedures, Maintenance, Reactor Engineering, Radiation Protection, Quality Assurance, Engineering and Licensing. One member is designated as the Chairman. One or more of the members shall be designated as Vice Chairman. The Chairman, Vice Chairman, Members, and Alternates shall be appointed in writing by the Plant Manager to serve on a permanent basis; however, no more than three alternates shall participate as voting members in Operations Committee activities at any one time. The committee shall meet at least once per calendar month and as convened by the Operations Committee Chairman or Vice Chairman. A quorum of the Operations Committee shall consist of the Chairman or Vice Chairman and five members including alternates.

The Operations Committee shall be responsible for:

a) review of (1) written procedures, and changes thereto, involving nuclear safety, including applicable check off lists and instructions, covering areas listed below. These procedures shall be approved by the Plant Manager or designee prior to implementation, except as provided in Section 6.7.

   1. Normal startup, operation, and shutdown of systems and components of the facility.

   2. Refueling operation.

   3. Actions to be taken to correct specific and foreseen potential malfunctions of systems or components, including responses to alarms, suspected primary system leaks, and abnormal reactivity changes.

   4. The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33.

   5. Preventive and corrective maintenance operations which could have an effect on nuclear safety of the facility.

   6. Surveillance and testing requirements of equipment that could have an effect on the nuclear safety of the facility.

   7. Operation of radioactive waste systems

   8. Fire Protection Program implementation

   9. A preventive maintenance and periodic visual examination program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient to as low as practical levels. This

program shall also include provisions for performance of periodic systems leak tests of each system once per Operating Cycle.

10. Program to ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions, including training of personnel, procedures for monitoring and provisions for maintenance of sampling and analysis equipment.

11. Administrative procedures for shift overtime for Operations personnel to be consistent with Commission's June 15, 1982 policy statement.

12. Offsite Dose Assessment Manual.

13. Process Control Program.

14. Quality assurance for effluent and environmental monitoring

(2) any other proposed procedures or changes thereto as determined by the Plant Manager to affect nuclear safety.

b) Review of all proposed tests and experiments that affect nuclear safety.

c) Review of all proposed changes to the Technical Specifications.

d) Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety.

e) Investigation of all violations of the Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Vice President, Nuclear and the Chairman of the Safety Committee.

f) Review of all Reportable Events.

g) Review of facility operational to detect potential safety hazards.

h) Performance of special reviews, investigations or analyses and reports thereon as requested by the Chairman of the Safety Committee.

i) Review of DAEC Security Plan.

j) Review of Emergency Plan.

k) Review of every unplanned release of radioactivity to the environs for which report to the NRC is required.

l) Review of changes to the Offsite Dose Assessment Manual and changes to the Process Control Program.
m) Review of the Fire Protection Program and implementing procedures.

The Operations Committee has the authority to:

- recommend to the Plant Manager written approval or disapproval items (a) through (d) above,
- render determinations in writing with regard to whether or not each item (a) through (e) above constitutes an unreviewed safety question,
- provide written notification within 24 hours to the Vice President, Nuclear and the Safety Committee of disagreement between the Operations Committee and the Plant Manager; however, the Plant Manager shall have responsibility for resolution for such disagreements.

The Operations Committee shall maintain written minutes of each meeting and copies shall be provided to the Vice President, Nuclear and the Chairman of the Safety Committee.

6.4.2 The Safety Committee shall function to provide independent review and audit of designated activities in the areas of :

a) Nuclear power plant operations

b) Nuclear engineering

c) Chemistry and radiochemistry

d) Metallurgy

e) Instrumentation and control

f) Radiological safety

g) Mechanical and electrical engineering

h) Quality Assurance practices

i) Non-destructive testing

j) Administration

The Safety Committee shall be composed of persons who have been appointed in writing by the President, IES Utilities Inc. to serve on a permanent basis and who collectively have or have access to applicable technical and experimental expertise in the a. through j. areas above. All alternate members shall be appointed in writing by the President, IES Utilities Inc. to serve on a permanent basis. Consultants shall be utilized as determined by the Safety Committee Chairman to provide expert advice to the Safety Committee. The Safety Committee shall meet at least once per calendar quarter during the initial year of facility operation following fuel load and at least once per six months thereafter. A quorum of the Safety Committee shall consist of the Chairman or Vice Chairman and at least four members with a maximum of two alternates as voting members. No more than a minority of the voting members shall have line responsibility for operation of the facility.

The Safety Committee shall be responsible for the review of :

a) The safety evaluation for (1) changes to procedures, and (2) tests or experiments completed under the provisions of Section 50.59, 10CFR, to verify that such actions did not constitute an unreviewed safety question.

b) Proposed changes to procedures, equipment or systems which involve an unreviewed safety question as defined in Section 50.59, 10CFR.

c) Proposed tests or experiments which involved an unreviewed safety question as defined in Section 50.59, 10CFR

d) Proposed changes in Technical Specifications or licenses.

e) Violations of applicable statutes, codes, regulations, orders, technical specifications, license requirements, or of internal procedures or instructions having nuclear safety significance.

f) Significant operating abnormalities or deviations from normal and expected performance of plant equipment that affect nuclear safety.

g) All reportable events.

h) All recognized indications of an unanticipated deficiency in some aspect of design or operation of safety-related structures, systems, or components.

i) Reports and meeting minutes of the Operations Committee.

The Safety Committee shall report to and advise the President on those areas of responsibility specified for items (a) through (i) above. Records of Safety Committee activities shall be prepared, approved, and distributed as noted below:

a) Minutes of each Safety Committee meeting shall be prepared, approved, and forwarded to the President within 14 days following each meeting.

b) Reports of reviews for items (a) through (i) above shall be prepared, approved and forwarded to the President within 14 days following completion of the review.

6.5 With respect to Section 4.3.4 (1), Subjects Requiring Independent Review, of ANSI N18.7-1976/ANS-3.2, the DAEC Safety Committee is not required to review safety evaluations of changes in the facility which are completed under 10 CFR Part 50.59.

6.6 Section 5.1 (Program Description) of ANSI N18.7-1976/ANS-3.2 requires a "summary document" for the Quality Assurance Program. The QAPD and Appendix A thereto fulfill this requirement for the Company.

6.7 Section 5.2.2 (Procedure Adherence) of ANSI N18.7-1976/ANS-3.2 states that temporary procedure changes which do not change the intent of the procedure are required to be approved by two members of the plant staff, of which one shall hold a senior operators license. In lieu of one of these members being the on-shift senior operator, a non-shift senior licensed operator may approve of these temporary changes.

These temporary minor changes shall be documented and promptly reviewed by the Operations Committee and by the Plant Manager or designee. Subsequent incorporation, if necessary, as a permanent change, shall be in accord with approved procedure review and approval procedures.

6.8 Not Used

6.9 Section 5.2.7 (Maintenance and Modifications) of ANSI N18.7-1976/ANS-3.2 lists six standards that are to be applied to activities occurring during the operational phase that are comparable to related activities during design and construction. Five of these standards are addressed elsewhere in this Appendix A.

The Company does not follow one of those listed, ANSI N101.4-1972, Quality Assurance for Protective Coatings Applied to Nuclear Facilities. See UFSAR Section 17.2.9.5 for the Company's controls relative to "Special Protective Coatings".

6.10 With respect to Section 5.2.9 (Plant Security and Visitor Control) of ANSI N18.7-1976/ANS-3.2, the DAEC Security Plan meets the stated requirements.

However, the Standard references ANSI N18.17 for guidance. The Company is not committed to ANSI N18.17. The DAEC Security Plan complies with 10 CFR Part 73.

6.11 Section 5.2.15 (Review, Approval and Control of Procedures) of ANSI N18.7-1976/ANS-3.2, fourth paragraph requires:

"Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary or desirable."

This requirement is replaced by the following:

"Plant procedures shall be reviewed, in accordance with the following, to determine if changes are necessary or desirable:

1) Non-routine procedures, such as emergency operating procedures, off-normal procedures, those that implement the emergency plan, and others where usage may be dictated by an event, shall be reviewed at least every two years by an individual knowledgeable in the area affected by the procedure.

2) The procedures which have a frequency of use which exceeds two years, shall be reviewed prior to use, or every two years by an individual knowledgeable in the area affected by the procedure.

3) Routine plant procedures which are not addressed by (1) and (2) above shall be maintained through use of the procedure revision process. The need for changes to these procedures are identified through other processes, such as: plant modifications; nonconformance reporting system; test control; performance of operations and maintenance activities; updates to the Updated Final Safety Analysis Report (UFSAR); vendor manual control; reviews of industry operating experience; Operating/License Amendments; design specification changes; control of procedure changes; Quality Assurance audits; training; and other routine activities under the Quality Assurance Program. In addition, on a frequency not to exceed 2 years, an independent audit or assessment of a representative sample of routine plant procedures shall be performed to evaluate the effectiveness of the procedure review and revision program.

6.12 Section 5.2.16 (Measuring and Test Equipment) of ANSI N18.7-1976/ANS-3.2 requires that equipment be suitably marked to indicate calibration status. Section 5.2.16 refers to ANSI N45.2.4-1972, which requires (Section 2.5.2, Calibration and Control) that equipment be suitably marked to indicate date of next required calibration and (Section 6.2.1, Equipment Tests) that items requiring calibration be tagged or labeled on completion, indicating date of calibration and identity of the person who performed the calibration. See the discussion provided in Section 5.5 of this document for the Company's commitment.

6.13 Instead of the format specified in Section 5.3.9.1, (Emergency Procedure Format and Content) of ANSI N18.7-1976/ANS- 3.2, of the Company's DAEC Emergency Operating Procedures (EOPs) are in a flowchart format. The format and contents of the DAEC Emergency Operating Procedures are based upon the BWR Owner's Group (BWROG) Emergency Procedure Guidelines (EPGs) Revision 4 and the associated generic NRC SER and were updated in accordance with the Emergency Procedure Guidelines/Severe Accident Guidelines (EPGs/SAGs) Revision 1.

7.0 <u>REGULATORY GUIDE 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants"</u>

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

7.1 The commitment is to Regulatory Guide 1.37, Revision 0, 3/16/73, and to ANSI N45.2.1-1973 which it endorses.

7.2 The Company shall comply with the Regulatory Position established in this Regulatory Guide for maintenance and modification activities in that the quality assurance program requirements included therein shall apply. Technical requirements associated with maintenance and modification activities shall be equal to or better than the original requirements (<u>e.g.,</u> Code requirements, design and construction specification requirements, and inspection requirements).

8.0 <u>REGULATORY GUIDE 1.38, "Quality Assurance Requirements for packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants"</u>

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

8.1 The Company commitment is to Regulatory Guide 1.38, Revision 2, May 1977, which endorses ANSI N45.2.2-1972. However, the Company commitment is to the later version of this Standard, ANSI/ASME N45.2.2-1978.

8.2 The applicability of the requirements of Section 3 and 4 and the Appendix of ANSI N45.2.2, and the paragraphs of the Regulatory Guide relating to these Sections (C.1.c, C.1.e, and C.2), is limited to the procurement of major plant equipment replacements; they are not applied to procurement of operating plant spares and modifications.

8.3 The shipping damage inspections required by Section 5.2.1 of ANSI N45.2.2 will be performed by Storekeepers prior to unloading in lieu of ANSI N45.2.6 certified inspectors. A shipping damage inspection is performed by ANSI N45.2.6 certified inspectors at a later point in the receiving process for applicable items.

9.0 REGULATORY GUIDE 1.39, "Housekeeping Requirements for Water-Cooled Nuclear Power Plants"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarification:

9.1 The Company commitment is to Regulatory Guide 1.39, Revision 2, September 1977, and to ANSI N45.2.3-1973 which it endorses.

10.0 REGULATORY GUIDE 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants"

COMMENTS AND CLARIFICATIONS:

The Company is not committed to Regulatory Guide 1.54, June 1973. The Company's controls relative to protective coatings are contained in UFSAR Section 17.2.9.5.

11.0 REGULATORY GUIDE 1.58, "Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

11.1 The Company commitment is to Regulatory Guide 1.58, Revision 1, September 1980, and to ANSI N45.2.6-1978 which it endorses.

11.2 ANSI N45.2.6-1978 Section 1.2, "Applicability", first paragraph, states that this standard applies to personnel who perform inspections, examinations, and tests during fabrication prior to and during receipt of items at the construction site, during construction, during preoperational and startup testing, and during operational phases of nuclear power plants.

The qualification of inspection personnel shall be documented on the basis of either this standard (i.e., ANSI N45.2.6-1978) or on the basis of task qualification in accordance with Regulatory Guide 1.8, Revision 1-R, May 1977 and ANSI/ANS 3.1 -

1978. The basis for deciding which method is used for qualification is described below:

- Personnel performing inspections as of October 1, 1995, are certified to this standard (ANSI N45.2.6-1978) for the performance of inspections.

- Personnel contracted to perform inspections at the DAEC will continue to be qualified for the performance of inspections in accordance with this standard (ANSI N45.2.6-1978).

- Effective with the approval of Revision 16 to the DAEC QADP Quality Assurance Program Description, craft personnel may become qualified to perform inspection by the successful completion of the training for that task. For example, the performance of dimensional measurements by a craftsperson in the performance of a repair activity is an equivalent task performed by an inspector qualified per ANSI N45.2.6 - 1978 for performing dimensional measurements. In addition to this task qualification, craft personnel qualified in accordance with this method shall also receive an annual eye examination for vision and color acuity.

- Personnel performing testing activities shall have appropriate experience and training to assure competence in accordance with Regulatory Guide 1.8 (ANSI/ANS 3.1-1978).

11.3 ANSI N45.2.6 Section 1.2, "Applicability", third paragraph, requires that this standard be used in conjunction with ANSI N45.2. The Company is not committed to ANSI N45.2.

11.4 ANSI N45.2.6 Section 1.2, "Applicability", fourth paragraph, requires that this standard be applied to organizations other than the Company The specific applicability of this standard to other organizations is specified on a case-by-case basis in the procurement documents issued to those suppliers of materials and services.

11.5 Regulatory Guide 1.58 Revision 1, in Section B, "Discussion", endorses ASNT Recommended Practice No. SNT-TC-1A-1975 for the qualification of nondestructive testing personnel. In accordance with the Company ASME Section XI program the 1989 Edition shall govern. Section IWA-2300 of this Code requires nondestructive personnel to be qualified to SNT-TC-1A-1984.

12.0 REGULATORY GUIDE 1.64, "Quality Assurance Requirements for the Design of Nuclear Power Plants"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide. The Company commitment is to Regulatory Guide 1.64, Revision 2, June 1976, and to ANSI N45.2-11-1974 which it endorses.

13.0 REGULATORY GUIDE 1.74, "Quality Assurance Terms and Definitions"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

13.1 The Company commitment is to Regulatory Guide 1.74, February 1974, and to ANSI N45.2.10-1973, which it endorses.

13.2 The Company has adopted the definition of "Audit" which appears in ANSI/ASME N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants, in lieu of the definition in ANSI N45.2.10-1973.

14.0 REGULATORY GUIDE 1.88, "Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

14.1 The Company commitment is to Regulatory Guide 1.88, Revision 2, October 1976, and to ANSI N45.2.9-1974 which it endorses.

14.2 Section 3.2.2 of ANSI N45.2.9-1974 specifies establishment of an "index". As we understand this term, it can include a collection of documents or indices (some of which may be computer-based) which, when taken together, supply the information attributed to an "index" in the Standard. Record retention requirements for records are specified. The specific retention times for records are indicated when the records are transmitted for permanent storage. The Company utilizes computer-aided retrieval systems to index and locate records.

14.3 Section 5 of ANSI N45.2.9-1974, "Storage, Preservation and Safekeeping", provides no distinction between temporary and permanent facilities. To address temporary storage, the following position is established: Active records (those completed but not yet duplicated or placed on microfilm) may be temporarily stored in one-hour fire rated file cabinets until such time as they are duplicated or microfilmed. Open-ended documents--those revised or updated on a more-or-less continuing basis over an extended period of time (e.g. personnel qualification and training documents) and those which are cumulative in nature (e.g. nonconforming item logs and control room log books)--are not considered as QA records since they are not "complete". These types of documents shall become QA records when they are issued as a specific revision, when they are filled-up or discontinued, or on a periodic basis when the completed portion of the on-going document shall be transferred to permanent storage as a "record".

14.4 The requirements of Section 4.3 (Receipt Control) of ANSI N45.2.9-1974 are implemented only for the permanent record files and not for temporary record files.

14.5 The requirements of Section 5.3 (Storage) of ANSI N45.2.9-1974 are implemented only for the permanent record files and not for temporary record files.

15.0 <u>REGULATORY GUIDE 1.94, "Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants"</u>

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

15.1 The Company commitment is to Regulatory Guide 1.94, Revision 1, April 1976, and to ANSI N45.2.5-1974 which it endorses.

15.2 For modification activities the Company shall comply with the Regulatory Position established by this Regulatory Guide in that the quality assurance program requirements included therein shall apply. Technical requirements associated with modification activities shall be equal to or better than the original requirements (e.g., Code requirements, design and construction specification requirements, and inspection requirements).

16.0 REGULATORY GUIDE 1.116, "Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

16.1 The Company commitment is to Regulatory Guide 1.116, Revision O-R, June 1976, with first page revision May 1977, and to ANSI N45.2.8-1975 which it endorses.

16.2 The Company's commitment to this Regulatory Guide is applicable to maintenance and modification activities in that the quality assurance program requirements included therein shall apply. Technical requirements associated with maintenance and modification activities shall be equal to or better than the original requirements (e.g., Code requirements, design and construction specification requirements, and inspection requirements).

17.0 REGULATORY GUIDE 1.123, "Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

17.1 The Company commitment is to Regulatory Guide 1.123, Revision 1, July 1977, and to ANSI N45.2.13-1976 which it endorses.

18.0 REGULATORY GUIDE 1.144, "Auditing of Quality Assurance Programs for Nuclear Power Plants"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

18.1 The Company commitment is to Regulatory Guide 1.144, Revision 1, September 1980, and to ANSI N45.2.12-1977 which it endorses.

18.2 Section 1.1, "Scope", and Section 1.2, "Applicability", of ANSI N45.2.12-1977 reference ANSI N45.2. The Company is committed to ANSI N18.7-1976 for the operational phase, consistent with its commitment to Regulatory Guide 1.33.

18.3 Regulatory Position C.3.b(1) states that external audits, after the award of a contract, are not necessary for procurement actions where acceptance of the product is in accordance with Section 10.3.2, "Acceptance by Receiving Inspection", of ANSI N45.2.13-1976. The suppliers of products that meet this requirement are included on the Company external audit schedule and are audited on a triennial basis.

18.4 ANSI N45.2.12, Section 4.3.1 "Pre-Audit Conference"

For internal audits, a "pre-audit planning meeting" may be substituted for the "pre-audit conference." The pre-audit planning meeting should accomplish the following:

1) The Lead Auditor to present the proposed audit plan and an opportunity for the audited organizations to provide input to the proposed audit plan.
2) Introduce the Lead Auditor and identify proposed audit team members. Those audit team members available will be introduced. Note: Non-utility team members are usually not available at these meetings.
3) Counterparts are invited to these audit planning meetings as part of the planning process.
4) The audit schedule is presented, including a tentative exit date. The final exit date is announced separately during the audit period.
5) The channels of communication are opened at the audit planning meeting through participation in the audit planning process.
6) Following the audit planning meeting, the Lead Auditor will finalize the audit plan.

18.5 In lieu of an annual supplier evaluation specified by Regulatory Position C.3.b(2), a documented ongoing evaluation of the supplier should be performed. Where applicable, this evaluation should take into account (1) review of supplier-furnished documents such as certificates of conformance, non-conformance notices, and corrective actions, (2) results of previous source verifications, audits, and receiving inspections, (3) operating experience of identical or similar products furnished by the same supplier, and (4) results of audits from other sources, e.g., customer, ASME, or NRC audits. The results of the evaluations should be reviewed and appropriate corrective action should be taken. Adverse findings resulting from these evaluations should be periodically reviewed in order to determine if, as a whole, they result in a significant condition adverse to quality and to provide input to support supplier audit activities conducted by IES Utilities or a third party auditing entity.

19.0 REGULATORY GUIDE 1.146, "Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants"

COMMENTS AND CLARIFICATIONS:

The Company complies with the Regulatory Position of this Regulatory Guide with the following clarifications:

19.1 The Company commitment is to Regulatory Guide 1.146, August 1980, and to ANSI N45.2.23-1978 which it endorses.

19.2 ANSI N45.2.23 Section 1.2 references ANSI N45.2. For the Company, the entities subject to audit are defined in 10 CFR 50 Appendix B and ANSI N18.7-1976. This is consistent with the Company's commitment to Regulatory Guide 1.33 which endorses ANSI N18.7-1976, in lieu of ANSI N45.2.

19.3 In lieu of ANSI N45.2.23 Section 2.3.4, prospective lead auditors shall demonstrate their ability to effectively implement the audit process and effectively lead an audit team. This demonstration process shall be described in written procedures or instructions. The demonstration shall be evaluated and the results documented. Regardless of the methods used for the demonstration, the prospective lead auditor shall have participated in at least one nuclear quality assurance audit within the year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met the other provisions of Section 2.3 of ANSI N45.2.23 - 1978, the individual may be certified as being qualified to lead audits.

20.0 REGULATORY GUIDE 1.155, "Station Blackout"

COMMENTS AND CLARIFICATIONS:

The Company complies with Appendix A, "Quality Assurance Guideline for Non-Safety Systems and Equipment," to Regulatory Guide 1.155, Revision 1, August 1988.

21.0 REGULATORY GUIDE 4.15, "Quality Assurance for Radiological Monitoring Programs (Normal Operations) - Effluent Streams and the Environment"

COMMENTS AND CLARIFICATIONS

The Company complies with the Regulatory Position in Regulatory Guide 4.15, Revision 1, February 1979.

22.0 ASME B&PV Code, Section XI, 1989 Edition with no Addenda

COMMENTS AND CLARIFICATIONS:

The Company commitments relative to the Ten-Year Inspection Program and the Pump and Valve Test Program are established separately in formal correspondence with the Nuclear Regulatory Commission and incorporated into appropriate the Company documents.