Chapter 6: ENGINEERED SAFETY FEATURES

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6.1 ENGINEERED SAFETY FEATURE MATERIALS

6.1.1 METALLIC MATERIALS

See Section 6.2.1.1.1.3 for mechanical property requirements for all materials used in the fabrication of pressure-containing components of the containment system. Applicable codes and regulations used in the design and fabrication of the pressure suppression containment system are discussed in Section 6.2.1.1.1.4.

See Table 6.2-3 for a listing of primary containment materials. The primary containment is chiefly fabricated of SA-516, Grade 70 plates. The vent pipes connecting the drywell and torus are fabricated of SA-516, Grade 70 steel. The vent system is coated inside and out with paint to protect the metal against rusting.

Material and examination requirements for piping and valves are described in Section 17.1.8.

The environmental design requirements for mechanical and electrical equipment are discussed in Section 3.11.

6.1.2 ORGANIC MATERIALS

2011-021 Coating qualified for use inside primary containment (i.e., safety related, Service Level I) are qualified and controlled under the DAEC Protective Coatings Program (DAECPCP). In the case of Service Level I coatings system laboratory testing, irradiation and simulated Design Basis Accident (DBA) testing are included in the qualification process.

The suppression pool contains demineralized water with no inhibitors or additives.

6.2 CONTAINMENT SYSTEMS

6.2.1 PRIMARY CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Containment Structure

6.2.1.1.1 Design Basis

The primary containment system consists of a drywell, a pressure suppression chamber that stores a large volume of water, a connecting vent system between the drywell and the water pool, isolation valves, containment cooling systems, and other service equipment. The pressure suppression containment system is shown in Figure 6.2-1, and its principal parameters are listed in Table 6.2-1.

The performance criteria and design information regarding the isolation valves, containment cooling systems, and other service equipment are included elsewhere in this FSAR.

The reactor building encloses the reactor and the primary containment. This structure provides secondary containment when the primary containment is in service and serves as the containment during periods when the primary containment is open. A detailed description of the secondary containment is included in Section 6.2.3.

6.2.1.1.1.1 Safety Objective

The safety objective of the primary containment system is to provide the capability, in conjunction with other safeguard features, 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 50.67.

6.2.1.1.1.2 Safety Design Bases

The safety design bases are discussed below:

1. The primary containment system has the capability of withstanding the pressures and temperatures that could result from any of the postulated design-basis accidents for which it is assumed to be functional.

2. The primary containment system has the capability of withstanding the effects of postulated metal-water reactions subsequent to any postulated design-basis accident for which it is assumed to be functional.

3. The primary containment system has the capability to maintain its integrity during any postulated accident for which it is assumed to be functional or during any of the postulated environmental events.

4. The primary containment system has the capability of filling the primary containment vessel with water to a level above the reactor core.

5. The primary containment system has the capability to reliably isolate all pipes necessary to establish the primary containment barrier.

6. The primary containment system has the capability to store sufficient water to supply the emergency core cooling system requirements.

7. The primary containment has the capability of being maintained during normal operation within the range of initial conditions assumed in Chapter 15.

8. The primary containment has the capability of being periodically leak tested to confirm that the integrity of the containment is maintained.

Section 6.2.1.1.2 gives the detailed description of the primary containment vessel. It discusses the internal and external pressures, temperatures, and other parameters to which the containment is designed. Section 6.2.1.1.1.5 lists the loads and load combinations used for the structural design of the containment vessels. Also listed in these sections are calculated stresses of major components.

The drywell shell, pressure suppression chamber, and the penetrations together form the containment and suppression system.

Table 6.2-2 lists the penetrations, with their functions and sizes, for the containment vessel.

6.2.1.1.1.3 Mechanical Property Requirements

The mechanical property requirements for all materials used in the fabrication of pressure-containing components of the containment system are based on the more restrictive of either the mechanical property requirements of the containment vessel, or in the case of the penetration flued-head fitting, the mechanical property requirements of the piping to which they are attached. The following criteria were applied:

	Component	Criteria
1.	Containment vessel and penetration nozzles	N-1210 and N-1211 of the 1968 Edition of ASME Boiler and Pressure Vessel (B&PV) Code, Section III
2017-002 2.	Flued-head fittings attached to Nuclear Class 1 piping systems Component	Tables I-1.1 and I-1.3 of the 1971 Edition of ASME Code, Section III Criteria
2017-002 3.	Flued-head fittings attached to Nuclear Class 2 piping systems	Table I-7.1 of the 1971 Edition of ASME Code, Section III
4.	Nuclear Class 1 extension of containment piping	N-330 of the 1968 Edition of ASME Code, Section III
5.	Nuclear Class 2 extension of containment piping	N-1210 and N-1211 of the 1968 Edition of ASME Code, Section III

The required impact tests were performed at a maximum test temperature of 0°F for all components except the flued-head fittings for the feedwater piping penetrations, for which the impact tests are performed at a maximum test temperature of -20°F. The 0°F test temperature is based on a lowest service metal temperature of 30°F, which was expected to occur at the time of the ASME Code overload pneumatic test. The -20°F is based on a lowest service metal temperature in the feedwater piping of 40°F, which could occur during the high-pressure coolant injection (HPCI) injection mode.

The lowest metal temperature that the containment steel may be expected to experience after the plant is placed in operation is 50°F during the periodic leakage rate testing.

6.2.1.1.1.4 Applicable Codes and Regulations

The following issues of the publications listed below form a part of the applicable codes and regulations, along with the applicable codes of the State of Iowa, used in the design of the pressure suppression containment system.

American Society of Mechanical Engineers (ASME)

B&PV Code, Sections III, VIII, and IX, and all addenda to Summer 1968, and the particular requirements for Class B vessels as defined in paragraph N-132, Section III and Section II, 1968 edition with all applicable addenda, for the following material specifications:

Designation	Title
SA-193	Alloy Steel Bolting Materials for High Temperature Service (Grade B7)
SA-194	Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service (Grade 4 or 7)
SA-240	Corrosion-Resisting Chromium and Chromium-Nickel Steel Plate, and Strip for Fusion Welded Unfired Pressure Vessels
SA-312	Seamless and Welded Austenitic Stainless Steel Pipe
SA-320	Alloy-Steel Bolting Materials for Low-Temperature Service (Grade L7 or L43)
SA-333	Seamless and Welded Steel Pipe for Low-Temperature Service (Grade 1 or 6)
SA-350	Forged or Rolled Carbon and Alloy Steel Flanges, Forged Fittings, and Valves and Parts for Low-Temperature Service (Grade LFI)
SA-516	Carbon Steel Plates for Pressure Vessels for Moderate and Lower Temperature Service (Grade 70)

American Society for Testing and Materials Standards (ASTM)

Designation	Title
A-36	Structural Steel
A-53	Welded and Seamless Steel Pipe (Grade B)
A-106	Seamless Carbon-Steel Pipe for High-Temperature Service
A-155	Welded Pipe (Grade KCF-55)
A-193	Bolts (Grade B7)
A-194	Nuts
A-514	High Yield Strength, Quenched and Tempered Alloy Steel Plate, Suitable for Welding (Type F)

American National Standards Institute (ANSI)

Designation	Title
B31.1.0	Power Piping

American Institute of Steel Construction (AISC)

"Specification for the Design, Fabrication, and Erection of Structural Steel for Building" adopted April 1963.

Applicable Codes of the State of Iowa

6.2.1.1.1.5 Design Loadings

Table 6.2-3 shows the allowable stresses for various materials used in the construction of the primary containment. The loadings considered in the design of the drywell, suppression chamber, and interconnecting elements are shown in Tables 6.2-4 and 6.2-5.

The primary containment system is designed to withstand pressure and temperature loads associated with a loss-of-coolant accident (LOCA) simultaneous with earthquake loads. The design parameters for the primary containment system are given in Tables 6.2-4, 6.2-5, and 6.2-6. The design internal pressure and temperature are based on results of the primary containment response analysis to a LOCA. Section 15.2 discusses the analytical techniques, assumptions, and results of the containment response analysis. The design external pressure is determined from the maximum differential pressure that can occur before the operation of the automatic pressure relief system.

In addition to the aforementioned pressure and temperature loads, the primary containment system is designed to withstand jet forces resulting from postulated accidents. The magnitude and location of the jet forces are given in Section 3.8 and Tables 6.2-4 and 6.2-5; the jet forces are discussed in Section 6.2.1.1.3.5.

Tables 6.2-7 and 6.2-8 show the Chicago Bridge & Iron Company (CB&I) case numbers used in the design of the drywell and the suppression chamber. The right-hand columns contain and relate "load symbols" used in Tables 6.2-9 through 6.2-14 to the loads shown in Tables 6.2-7 and 6.2-8.

The combination of design loads used in the design of the containment system and associated allowable stress levels are given in Section 3.8 and in this section. In addition, Tables 6.2-9 and 6.2-12 identify the design loads and resulting stress intensity values for various regions of the containment vessel. It should be noted that the Summer 1968 edition of ASME Code, Section III, did not specify design load conditions as normal, upset, and emergency for

containment vessels. For that reason, the loading cases are classified as test, normal operating, refueling, accident, or flooded condition. Tables 6.2-7 and 6.2-8 identify the load combinations for each loading condition that was considered in the design of the containment vessel.

The penetration assemblies are designed in accordance with ANSI B31.7, 1969, with allowable stress in accordance with Code Case 70. The following load combinations were considered in the design of the penetration assemblies:

Normal and upset:	Deadweight plus seismic (operating-basis earthquake (OBE)) plus operating thermal and pressure loads.
Emergency:	Deadweight plus seismic (design-basis earthquake (DBE)) plus operating thermal and pressure loads.

Section 6.2.1.1.2.3 includes the design capabilities of the penetration assemblies to be tested and a discussion of the test.

Section 3.8 further discusses the design loads applied to the primary containment system.

Description of Loads

Pressures and Temperatures Under Normal Operating Conditions. During reactor operation, the vessels will be subjected to temperatures up to 150°F at atmospheric pressure. The suppression chamber will also be subjected to the loads associated with the 58,900 ft^3 of water distributed uniformly within the vessel.

Pressures and Temperatures Under Accident Conditions. The drywell, the suppression chamber, and the vent system are designed for a maximum internal pressure of 62 psig coincident with a temperature of 281°F, and the suppression chamber will be subjected to the increased loads associated with the storage of 61,500 ft^3 of water.

Jet Forces. The drywell closure head is designed to withstand the jet forces listed in Table 6.2-4. These listed forces do not occur simultaneously. However, the jet force was assumed to occur concurrently with the design internal pressure of 56 psig and a temperature of 150°F. The jet forces consist of steam and/or water at 300°F. The drywell is largely enclosed within the structural and shielding concrete. There is a nominal 2-in. gap between the vessel and the concrete except at the closure head and top flanges. Where the drywell shell is backed up by concrete, local yielding may take place because of jet force impingement; however, rupture will not occur.

The design criterion for areas of the drywell shell not backed up by a 2-in. air gap and concrete is that for any combination of loads including jet impingement; the stresses in the drywell shell should not exceed 0.9 of the yield strength of the material.

In areas with the 2-in. air gap, the shell is allowed to deform locally under jet impingement until it is stopped by the concrete shielding. The ability of the drywell to withstand this local deformation without failure was demonstrated by CB&I in their performance test entitled "Loads on Spherical Shells" by Phillip Thullen, August 1964. In this test, a plate section was placed in a hydraulic press and deformed with a hemispherical die. The test showed that the plate could withstand local deformations in excess of 3 in. without loss of integrity.

The primary containment allowable external pressure of -2 psig represents a sound engineering compromise between the conflicting requirements of vacuum relief and vessel external pressure design. It provides sufficient margin below the maximum allowable vessel external pressure to ensure that this negative pressure is never exceeded. This -2 psig also provides a sufficient pressure differential across the vacuum relief devices to facilitate an economic valve size. The combination of -2 psig at 281°F represents the most conservative situation of peak negative pressure at the vessel design temperature. The actual vessel temperature at the negative design pressure would be less than 281°F with correspondingly higher allowable stress levels.

Load Combinations Used in the Design of the Primary Containment Vessel.

The load symbols considered in the design summary of the containment include the following:

D = Dead load of the structure and related equipment plus any other permanent loads contributing stress, such as soil or hydrostatic loads, live loads expected to be present when the station is operating, and the loads due to thermal expansion under normal operating conditions. This load takes into account any deviations from normal operating conditions that are reasonably expected to occur during the design lifetime of the plant.

R = Loads resulting from jet forces and pressure and temperature transients associated with the rupture of a single pipe within the primary containment. This load is considered as indicated in the tables.

E = Loads due to the operating-basis earthquake (0.12g horizontal ground acceleration, 0.053g applied simultaneously for vertical seismic acceleration).

E'= Loads due to design-basis earthquake (0.24g horizontal ground acceleration, 0.108g vertical acceleration).

Flood = Loads due to flooding the drywell up to elevation 854.5 ft.

W = Design wind loading conditions.

The following are the load combinations and corresponding allowable stress limits as shown in Tables 6.2-9 through 6.2-14.

1. D + E

   Stresses remain within normal code-allowable stresses (AISC for structural steel, ACI for reinforced concrete, ASME Code, Section III (Class B), for the primary containment). The customary increase in design stress for earthquake loadings is not permitted.

2. D + W

   Maximum allowable stresses may be increased one-third above normal code-allowable stresses.

3. D + R + E

   Stresses remain within normal code-allowable stresses (AISC for structural steel, ACI for reinforced concrete, ASME Code, Section III (Class B), for the primary containment). The customary increase in design stress for earthquake loadings is not permitted. In the case of jet impingement loading on the primary containment where it is backed up by concrete, local yielding may occur. For jet impingement loading on the primary containment (including containment penetration assemblies) where the primary containment is not backed up by concrete, the primary stresses must not exceed 90% of the yield strength of the material at 300°F.

4. D + E + Flood

   Local membrane stresses in the primary containment may not exceed the yield point.

5. D + R + E'

   Membrane stresses in the primary containment may not exceed the yield point. Local yielding may occur where backed up by concrete.

6.2.1.1.2 Design Features of the Primary Containment

6.2.1.1.2.1 <u>Introduction</u>

The design of the primary containment uses a pressure suppression concept.

In the event of a process system piping failure within the drywell, reactor water and steam will be released into the drywell gas space. The resulting increased drywell pressure forces a mixture of noncondensible gases, steam, and water through the vent system into the pressure suppression pool. The steam condenses rapidly in the suppression pool resulting in a pressure reduction in the containment. Noncondensible gases transferred during reactor blowdown to the suppression chamber pressurize the chamber and subsequently are vented to the drywell through the vacuum relief system as the pressure in the drywell drops below that in the suppression chamber. Cooling systems are provided to remove heat from the drywell and from the water in the suppression chamber. Isolation valves are provided to maximize the retention of radioactive materials within the primary containment should they be released from the reactor to the containment during the course of an accident. Other service equipment is provided to maintain the containment within its design parameters during normal operation.

The primary containment principal design parameters and characteristics are given in Table 6.2-1.

The primary containment system design loading considerations are given in Section 6.2.1.1.1.5. Chapter 15 demonstrates the effectiveness of the primary containment system as a radiological barrier. In addition, primary containment pressure and temperature transients from postulated design-basis accidents are also presented in Chapter 15.

6.2.1.1.2.2 Drywell

The drywell is a steel pressure vessel with a spherical lower portion 63 ft in diameter and a cylindrical upper portion 32 ft in diameter. The overall height is approximately 108 ft 9 in. The design, fabrication, inspection, and testing of the drywell vessel complies with requirements of the ASME Code, Section III, Subsection B, "Requirements for Class B Vessels," Summer 1968 Addenda, ASME Code Cases 1177, 1330, 1413 and 1431, which pertain to containment vessels for nuclear power stations. The primary containment is primarily fabricated of SA-516, Grade 70 plates.

The drywell is designed for an internal pressure of 56 psig coincident with a temperature of 281°F with applicable dead, live, and seismic loads imposed on the shell. Thus, in accordance with the ASME Code, Section III, the maximum internal drywell pressure is 62 psig. Design external pressure is 2 psig at 281°F. Thermal stresses in the steel shell resulting from temperature gradients were taken into account in the design. Containment stresses are within allowable stresses permitted by the ASME Code. Detailed investigation is performed in areas where local buckling can occur from the effects of concentrated loads, thermal loads, and nonaxisymmetric distribution loads. Where stress intensities in these areas are not covered by the ASME Code, allowable stresses are determined using recognized buckling formulas such as those used by the AISC and recognized, reputable authors (Roark, Timoshenko, and Grintner).

Special precautions not required by codes were taken in the fabrication of the steel drywell shell. Charpy V-notch specimens were used for impact testing of plate and forging

material to give assurance of correct material properties. Plates, forgings, and pipe associated with the drywell have an initial nil ductility transition (NDT) temperature of 0°F when tested in accordance with the appropriate code for the materials. It is not intended that the drywell will be pressurized or subjected to substantial stress at temperatures below 30°F.

The drywell is enclosed in a reinforced-concrete structure for shielding purposes. In areas where it backs up the drywell shell, this reinforced concrete provides additional resistance to deformation and buckling of the shell. Above the transition zone, and below the flange, the drywell is separated from the reinforced concrete by a gap of approximately 2 in. Shielding over the top of the drywell is provided by removable, segmented, reinforced-concrete shield plugs.

In addition to the drywell head, one combination double-door air lock/equipment lock, one bolted equipment hatch, and one bolted personnel access hatch are provided for access into the drywell.

6.2.1.1.2.3 Pressure Suppression Chamber and Vent System

The pressure suppression pool, which is contained in the pressure suppression chamber, initially serves as the heat sink for any postulated transient or accident condition in which the normal heat sink (main condenser or shutdown cooling mode of the residual heat removal (RHR) system is unavailable.) Energy is transferred to the pressure suppression pool by either the discharge piping from the reactor pressure relief valves or the drywell vent system. The relief valve discharge piping is used as the energy transfer path for any condition that requires the operation of the relief valves. The nuclear system pressure relief system is further discussed in Section 5.2.2. The drywell vent system is the energy transfer path for all energy releases to the drywell.

Of all the postulated transient and accident conditions, the instantaneous circumferential rupture of the reactor coolant recirculation piping represents the most rapid energy addition to the containment. For this accident, the vent system conducts flow from the drywell to the suppression chamber without excessive resistance and distributes this flow into the pool. The pressure suppression pool condenses the steam portion of this flow and releases the noncondensible gases and any gaseous fission products to the pressure suppression chamber gas space.

Pressure Suppression Chamber

The pressure suppression chamber is a steel pressure vessel in the shape of a torus located below and encircling the drywell, with a major diameter of 98 ft 8 in. and a cross-sectional diameter of 25 ft 8 in. The pressure suppression chamber contains the suppression pool and the gas space above the pool. The suppression chamber will transmit seismic loading to the reinforced-concrete foundation slab of the reactor building. Space is provided outside the chamber for inspection.

The toroidal suppression chamber is designed to the same material and code requirements as the steel drywell vessel. The material has an NDT temperature of 0°F.

Vent System

Large vent pipes connect the drywell and the pressure suppression chamber. A total of eight circular vent pipes are provided, each having a diameter of 4 ft 9 in. The vent pipes are designed for the same pressure and temperature conditions as the drywell and suppression chamber. Jet deflectors are provided in the drywell at the entrance of each vent pipe to prevent possible damage to the vent pipes from jet forces that might accompany a pipe break in the drywell. The vent pipes are fabricated of SA-516, Grade 70 steel and comply with requirements of ASME Code, Section III, Subsection B. The vent pipes are provided with two-ply expansion bellows to accommodate differential motion between the drywell and suppression chamber. The vent pipe bellows are designed and fabricated to the same criteria as the containment vessels (ASME Code, Section III, Class B, Summer 1968) with complete radiograph, dye penetrant, or magnetic particle inspection as required by the Code.

The drywell vents are connected to a 3 ft 6 in. diameter vent header in the form of a torus, which is contained within the airspace of the suppression chamber. Projecting downward from the header are 48 downcomer pipes, 24 in. in diameter and terminating not less than 3 ft below the water surface of the pool. The vent header has the same temperature and pressure design requirements as the vent pipes.

The boundary separation structure between the drywell and suppression chamber, including the vacuum breakers vent pipes, vent header, and downcomers, was fabricated, erected, and inspected by nondestructive testing methods in accordance with and to the acceptance standards of the ASME Code, Section III, Subsection B. This superior construction and inspection quality control ensure the integrity of this boundary. The design pressure and temperature for this boundary were established at 56 psig and 281°F, respectively, which are substantially greater than that which would occur during a design-basis accident. Actual accident differential pressure and temperature across this boundary will be less than approximately 32 psid and approximately 200°F.

All penetrations of this boundary, except the vacuum breaker flanges, are welded. All accessible vent system welds are radiographed 100%. Inaccessible welds are either magnetic particle or liquid penetrant inspected. The vent system is coated inside and out with paint to protect the metal against rusting. The vent system, even though designed for the pressure given above, is not normally under a pressure differential. Hence, the vent system has been designed for the same integrity as the primary containment pressure boundary proper.

The vacuum breakers on this vent system seal and increase in leaktightness with increased pressure on the drywell side. Each vacuum breaker is equipped with an air test operator and valve position indicating lights displayed in the control room (see Section 6.2.1.1.2.5). The air test operator allows remote testing of the valve from the control room

during plant operation. The hand switch in the control room is a test button that is spring loaded and will return the valve to the closed position. The vacuum breaker valves are provided with a counter-balanced pallet and a magnet to ensure the closure of the valve after operation. Regular maintenance, inspection, and surveillance requirements for operating and cleaning these valves ensure their integrity.

These valves have stainless steel seats that are rust resistant and easily maintained.

Pressure Suppression Pool

The pressure suppression pool serves both as a heat sink for postulated transients and accidents and as a source of water for the emergency core cooling systems.

The suppression pool receives energy in the form of steam and water from the reactor pressure relief valve discharge piping or from the drywell vent system downcomers, which discharge under the water. The steam is condensed within the suppression pool. The condensed steam and any water carryover cause an increase in pool volume and temperature. Energy is removed from the suppression pool when the RHR system is operating in the suppression pool cooling mode. Section 5.4.7 further describes the function of the RHR system in the suppression pool cooling mode.

The suppression pool is the primary source of water for the core spray system, the high pressure coolant injection (HPCI) system and the low pressure coolant injection (LPCI) mode of the RHR system. The suppression pool is the secondary source of water for the reactor core isolation cooling (RCIC) system. The initial source of water for HPCI and RCIC (normal lineup) is the Condensate Storage Tank.

Pressure Suppression Pool Water Cleanup System

The pressure suppression pool (torus) water cleanup system is described in Section 9.5.10. The system provides a means of draining, cleaning, and storing the pressure suppression pool water when necessary to perform maintenance on the pressure suppression chamber. The system utilizes the condensate demineralizer for cleaning the water and the condensate storage tanks and/or the condenser hotwell for storing the cleaned water. A removable spool piece is used to join the torus and the torus water cleanup system. During plant operation, this spool piece is removed and a blind flange is installed at the torus drain outlet.

Penetrations - General

Containment penetrations have the following design characteristics:

1. They are designed for the same pressure and temperature conditions as the drywell and pressure suppression chamber.

2. They are capable of withstanding the forces caused by the impingement of the fluid from the rupture of the largest local pipe or connection without failure.

3. They are capable of accommodating the thermal and mechanical stresses that may be encountered during all modes of operation without failure.

4. They are capable of withstanding the maximum reaction that the pipe to which they are attached is capable of exerting.

The number and size of these penetrations are shown in Table 6.2-2. The locations of the penetrations are indicated in Figures 6.2-2 and 6.2-3.

Pipe Penetrations

Two general types of pipe penetrations are provided: (1) those that must accommodate thermal movement as shown by Figure 6.2-4 and (2) those that experience relatively little thermal stress as shown by Figures 6.2-5 and 6.2-6. Figure 6.2-7 shows a typical instrument penetration.

Some piping penetrations, such as those used for the steam lines, have provisions for thermal movement between the pipe and the containment shell. The process line is attached to a triple flued-head fitting as shown in Figure 6.2-8. This fitting is then attached to the containment shell through a double expansion bellows that permits relative movement between the process line and the containment vessel through a multiple-head fitting. This fitting is a one-piece forging with integral flues and is designed to meet all requirements of ASME Code, Section III, Subsection B. The forging is radiographed and ultrasonically tested as specified by this Code. The guard pipe and flued head are designed to the same pressure requirements as the process line. A guard pipe is installed between the process line and the bellows to prevent damage to the bellows in the unlikely event of a process line rupture. The pipe is guided through pipe supports at the end of the penetration assembly to allow movement parallel to the penetration and to limit pipe reactions of the penetration to allowable stress levels. Where necessary, the penetration assemblies are anchored outside the containment to limit the movement of the line relative to the containment.

In lines where thermal movement is not a problem, such as the cold piping, ventilation pipes, and instrument line penetrations, the pipe is generally welded directly to the sleeves. In some cases, where stress analyses indicate the need, double flued-head fittings are used. Bellows and guard pipes are not necessary in these designs, because the thermal stresses are small and are accounted for in the design of the weld joint.

Electrical Penetrations

Figure 6.2-9 shows typical electrical penetration structural components and assembly details. All penetrations are sealed, with provisions for periodic leak testing. The penetration

canisters were factory assembled and tested, with the number of field welds held to a minimum. Some low voltage power and control penetrations have been replaced. In lieu of canisters, these penetrations use a modular design. The number of field welds was also held to a minimum for these penetrations.

Traversing Incore Probe Penetrations

Traversing incore probe (TIP) guide tubes pass from the reactor building through the primary containment. Penetrations of the guide tubes through the primary containment are sealed by brazing that meets the requirements of ASME Code, Section VIII. These seals also meet the intent of Section III of the Code even though the Code has no provisions for qualifying the procedures.

Personnel and Equipment Access Locks and Hatches

One combination personnel access lock/equipment lock (X-1) is provided for access to the drywell. The personnel lock has two gasketed doors in series, with each door designed and constructed to withstand the drywell design differential pressure. The doors are mechanically interlocked to ensure that at least one door is locked at times when primary containment is required. The locking mechanisms are designed so that a tight seal will be maintained when the doors are subjected to either internal or external pressure. The seals on this access opening are capable of being tested for leakage. The personnel access lock is bolted onto an equipment insert barrel approximately 12 ft in diameter, which in turn is provided with double testable seals and is welded to the drywell shell. The personnel access lock can be completely removed by an overhead monorail to increase the size of the opening should a larger access be required.

A personnel access hatch (X-4) with double, testable seals is provided in the drywell head. This hatch is bolted in place. One 12-ft-diameter equipment access hatch with double, testable seals is also provided (X-2). This hatch is bolted in place.

Personnel and equipment hatches are sized and located with full consideration of service required, accessibility for maintenance, and periodic testing programs. A 2-in. minimum gap is maintained around the barrel of the personnel and equipment hatches as they pass through or enter into the concrete shield wall.

A control rod drive (CRD) removal hatch (X-6) with double, testable seals is provided. This hatch is bolted in place and permits the removal of the drive mechanisms when required.

Access to the Pressure Suppression Chamber

Access to the pressure suppression chamber is provided at two locations, penetrations N-200A and N-200B. These are two 4-ft-diameter manhole entrances with double-gasketed bolted covers connected to the chamber by 4-ft-diameter steel pipe inserts. These access ports will be bolted closed when primary containment is required and will be opened only when the primary coolant temperature is below 212°F and the pressure suppression system is not required to be operational.

Access for Refueling Operations

The top head portion of the drywell vessel is removed during refueling operations. The head is held in place by bolts and is sealed with a double seal arrangement. The head is bolted closed when primary containment is required and will be opened only when the primary coolant temperature is below 212°F and the pressure suppression system is not required to be operational.

The double seal on the head flange provides a method for determining the leaktightness after the drywell head has been replaced.

6.2.1.1.2.4 Primary Containment System Design Details

Chicago Bridge and Iron Company designed, fabricated, furnished, installed, and tested the containment vessel and connecting vent piping, including bellows, jet deflectors, penetration sleeves, vessel supports, and other appurtenances. This was accomplished in accordance with Bechtel Corporation specifications developed for compliance with the codes and standards described in Section 6.2.1.1.1.4.

The information presented in this section pertaining to the detailed design of the pressure containment system was taken from CB&I's Certified Stress Report, which is on file at the DAEC.

Figures 6.2-1 and 6.2-10 through 6.2-14 show the drywell shell stretchout and penetration locations. Figures 6.2-15 through 6.2-43 show the details of the containment vessel and major components for which stresses have been listed in Section 6.2.1.1.3. Section 6.2.1.4 describes the leak rate tests of the containment.

The pressure suppression containment system consists of a drywell; a pressure suppression chamber, which stores a large volume of water; and a connecting vent system between the drywell and the water pool.

Materials, design, fabrication, inspection, and testing are in accordance with ASME Code, Section III, Subsection B, with all applicable addenda published to Summer 1968 and Code Cases 1177, 1330, and 1413.

The material for the shell of the drywell, suppression chamber, and interconnecting vent system is ASME SA-516, Grade 70 fabricated to SA-300. The Charpy V-notch impact tests of the material were conducted as specified in N-330, at a maximum test temperature of 0°F. This impact test temperature is based on a lowest service metal temperature of 30°F. The minimum impact energies were as specified in Tables N-221 and N-222, ASME Section III.

The drywell is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion. The bolted top closure is 27 ft 2 in. in diameter and is made with a double tongue and groove seal having a test connection between, which will permit periodic checks for tightness without pressurizing the entire vessel.

Jet deflectors are provided at the inlet of each vent pipe to prevent possible damage to the pipes or bellows assemblies from a jet force that might accompany a pipe break in the drywell and to prevent overloading any single vent.

The free flow area around the periphery of the jet deflector plate is equal to 1.4 times the area of the 4 ft 9 in. diameter vent duct (1.4 x 2290 = 3210 in.^{2}). The deflectors project approximately 2 ft into the drywell. The vent pipes are enclosed with sleeves and are provided with two-ply expansion bellows to accommodate differential motion between the drywell and suppression chamber.

During erection, the drywell vessel was supported on a steel skirt that was attached to the vessel at elevation [redacted]

After the initial leak rate and overpressure testing, the drywell was embedded in concrete to elevation [redacted], thereby providing uniformity in the support by following the contour of the vessel. An embedment transition is provided for the shell from elevation [redacted] to elevation [redacted] (see detail A on Figure 6.2-1). The embedment transition is filled with sand and covered with an 18 gauge galvanized steel plate which is sealed to the drywell shell. Any leakage into the area above the cover plate is directed into the Torus Room basement via four 4-inch drain lines. The transition area is provided with four 2-inch sand-filled drain lines.

The suppression chamber is a steel pressure vessel in the shape of a torus below and encircling the drywell. Inside the suppression chamber, also in the shape of a torus, is the vent system distribution header. Projecting downward from the header are 48 downcomer pipes that terminate below the water surface of the pool. Connecting to the vent header are eight vent lines from the drywell. Columns extending from and attached to the bottom of the suppression chamber support the vent header and downcomers and also resist the upward reaction from the

downcomers during blowdown. The columns are pinned at the top and bottom to accommodate the differential horizontal movement between the header and the suppression chamber.

A set of seven 18-in. vacuum breakers relieves pressure from the suppression chamber through the vent lines to the drywell to prevent a significant pressure differential between the drywell and suppression chamber. A location is provided for an eight vacuum breaker, but it is blank flanged. These vacuum breakers also prevent a backflow of water from the suppression pool into the vent system and prevent excessive water level oscillation within the downcomer pipes. Two 20-in. vacuum breakers are provided from the reactor building to the torus to prevent an external pressure on the containment greater than 2 psi (see Table 6.2-1).

There are six safety relief valve (SRV) vent lines (10 in. in diameter) extending into the center of the torus and terminating below the pool water level in tee connections (the T-quenchers). The discharge from these tees is horizontal in two directions along the torus centerline.

Access to the pressure suppression chamber from the reactor building is through two manholes with double-gasketed bolted covers with a test connection between, which can be tested for leakage.

Access to the drywell is through the equipment hatch, through the equipment/personnel air lock (both 12 ft in diameter), and through the double-gasketed drywell head, with a 24-in. manhole, all of which have provisions for individual leak testing.

The pressure suppression chamber is supported on 16 pairs of equally spaced columns. These supports transmit vertical loading to the reinforced-concrete foundation slab of the reactor building. Lateral loads due to an earthquake are transmitted to the foundation by four symmetrically placed earthquake ties.

The dimensions of the drywell and pressure suppression system are given in Table 6.2-6.

Coatings qualified for use inside primary containment (i.e., safety related, Service Level I) are qualified and controlled under the DAEC Protective Coatings Program (DAECPCP). In the case of Service Level I coatings system laboratory testing, irradiation and simulated Design Basis Accident (DBA) testing are included in the qualification process.

The suppression pool contains demineralized water with no inhibitors or additives. The circulating water system contains chlorine and sulfuric acid as discussed in Sections 9.2.4 and 10.4.5.

6.2.1.1.2.5 <u>Vacuum Relief System</u>

The primary containment is designed for an external pressure not more than 2 psi greater than the concurrent internal pressure. Automatic vacuum relief devices are used to prevent any unacceptable pressure differential.

There are two groups of vacuum breakers: the torus-to-drywell group, which is connected to the vent header inside the torus and prevents drywell pressure from being significantly less than torus pressure; and the reactor building-to-torus group, which prevents the torus pressure from being significantly lower than building pressure.

Reactor Building-Torus Group

A vacuum breaker and an air-operated butterfly valve are located in series on each of two lines that run from the reactor building to a common line (20-in. diameter) that penetrates the torus. The butterfly valve is actuated by a differential pressure. The vacuum breaker is self-actuating, and it can be locally operated for testing purposes.

The vacuum breaker system as shown in Figure 6.2-44 is of adequate size to prevent pressure in either the drywell or the pressure suppression chamber from exceeding their negative design pressure (2 psi) as a result of the most-rapid-cooldown transient that can occur during normal operation or postulated accident condition assuming the failure of a single valve to open.

Suppression Chamber-Drywell Group

Vacuum breaker valves are located on the vent header within the airspace of the suppression chamber. These valves prevent excessive water-level variations in the submerged portion of the vent downcomer lines. The total cross-sectional area of the vacuum breaker system is sized on the basis of the Bodega[1] pressure suppression system tests. The capacity is adequate to limit pressure differential between the suppression chamber and the drywell during postaccident drywell cooling operations to a value that is within the suppression system design values.

System Operation

The primary containment vacuum protection system actually consists of two separate systems. The internal torus-drywell system consists of seven 18-in. inside diameter (ID) swing check valves that relieve a negative pressure differential between the torus and the drywell. These valves are mounted on the torus-drywell vent header inside the torus. The second system is the torus-reactor building system consisting of two 20-in.-ID swing check valves mounted on the torus.

The most-rapid-cooldown transient that places the greatest demand on the torus-drywell vacuum relief valves is post-LOCA drywell spray operation. This transient consists of LOCA blowdown that displaces 100% of the primary containment noncondensibles into the torus. Such a condition leaves saturated steam in the drywell; this steam is then condensed by drywell spray

at the maximum containment spray rate of 7200 gpm. To calculate this transient conservatively, the drywell spray water was assumed to remain at the pre-LOCA temperature, resulting in a conservatively high condensation rate inside the drywell. The resulting makeup flow requirement is 100 1bm/sec into the drywell through these valves. If a pressure differential of 2 psid is then assumed for the torus-drywell vacuum relief systems, with one valve failed, the resulting flow capability is 385 1bm/sec. Therefore, sufficient vacuum relief capacity exists to meet the drywell maximum makeup requirements as defined above and prevents the differential pressure across the vent system from exceeding 2 psid as the drywell pressure drops below the torus pressure and the torus is pressurized with post-LOCA noncondensibles. The torus-drywell vent system has been evaluated for a negative pressure differential of 2 psid without exceeding allowable stress levels.

The maximum positive pressure differential across the torus-drywell vent system occurs during LOCA blowdown. This differential reaches a maximum value of approximately 17 psid as the peak drywell pressure reaches 45.7 psig. The design of the vent system has been evaluated for an internal pressure of 30 psig without exceeding allowable stress levels.

The most-rapid-cooldown transient that would place the greatest demand on the torus-reactor building vacuum relief valves would be an inadvertent containment spray operation while the drywell is at the 135°F average operating temperature.

Since the containment spray has a 2-psig nominal spray interlock to prevent spray operation at or below 2 psig, spray initiation is assumed at some pressure slightly above 2 psig. The spray then cools the drywell atmosphere to the spray temperature (70°F), causing the pressure to fall to -0.635 psig, which is well above the primary containment design negative pressure of 2 psig.

Cooldown transients that could produce an internal pressure of -2.0 psig or more would involve cooling after reactor shutdown. Because of the large masses of steel, concrete, and reactor water at temperatures in excess of 135°F, the normal cooldown time will take weeks. This will place a very small demand on the torus-drywell vacuum relief valves, which will be met with one of the 18-in. valves. Flow capacity of a torus-reactor building vacuum breaker with a 2-psid differential is 31.6 1bm/sec with one valve failed closed.

The torus-drywell vacuum breaker valves are provided with a counter-balanced pallet and a magnet to ensure the closure of the valve after operation. These valves are tested for proper setting and bypass leakage before installation. The seat surfaces are stainless steel to preclude corrosion on these surfaces and to minimize leakage. These valves are equipped with limit switches to indicate the fully open and fully closed position. A pneumatic cylinder is provided to allow remote testing of these valves by opening them and checking position lights. Since these valves are bolted in place and no welding will be performed after the valves have been tested, the seats should be installed in the same condition as tested. Should a torus-drywell valve require service, it may be removed and tested during reactor shutdown.

The reactor building-torus vacuum breaker valves are also equipped with a magnet and a counter-balanced pallet to ensure closure after operation. Limit switches are provided to indicate the fully open or fully closed position. A device allows these valves to be manually opened. These valves can be tested periodically by closing the downstream butterfly valve and evacuating the space between those valves.

The excessive water level variations referred to in Section 6.2.1.1.2.5 are a result of the water drawn up the vent system by a negative pressure differential across the vent system. The torus-drywell vacuum breakers prevent the torus water from being drawn up more than 13.8 in. This distance corresponds to the set pressure of these valves.

Testing

Each vacuum breaker is tested in accordance with the Technical Specifications. The torus-to-drywell vacuum breaker is cycled open and closed and is verified open and closed at the time of valve cycling.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Introduction

A complete set of design calculations for the drywell, suppression chamber, interconnecting elements, nozzle reinforcements, and access openings has been prepared by CB&I and is on file at the DAEC. The analyses have taken into consideration all of the design loads combinations shown in Tables 6.2-4, 6.2-5, 6.2-7, and 6.2-8. The maximum stresses computed are all within the indicated allowable limits.

6.2.1.1.3.2 Drywell Design - Primary Membrane Stresses

The drywell is designed by membrane theory, which is based on the principle that the thin shell resists the imposed loads by direct stresses only. To resist earthquake loads, the stabilizer assembly is provided at elevation [redacted] to transfer the seismic load on the internal structure through the shell and into the external concrete shield wall.

The seismic load on the shell and appurtenances is resisted jointly by the shell and by the stabilizer.

The shell acts as a beam of variable cross section fixed at the embedment level (elevation [redacted]) and simply supported at the stabilizer level (elevation [redacted]). The stabilizer assembly is designed for loads due to seismic and jet forces on the internal structure in addition to a stay force on the drywell shell. The magnitude of the forces is accommodated in the gap between the male and female parts of the stabilizer assembly. The stresses induced in the shell from the stay force are extremely small, and they do not govern the design of the shell.

6.2.1.1.3.3 Drywell Design - Maximum Primary Membrane Stresses in the Shell

The maximum primary general membrane stresses in the shell result from the combination of an internal pressure of 56 psig, the dead load of the shell and appurtenances, and lateral and vertical seismic loads, which is Case 7, Table 6.2-7, the accident condition. The internal pressure load causes most of the stress.

The maximum primary membrane stress shown in Table 6.2-9 of 16.18 ksi is less than the 17.5 ksi allowed by the Code. It occurs in the knuckle portion of the drywell. Other stresses computed at other points along the drywell are also shown in Table 6.2-9.

Case 1 shown in Table 6.2-7 is for the overload test conducted at a pressure of 70 psig, which is higher than the design internal pressure of 56 psig. Since this condition and pressure were temporary, an increase in the allowable membrane stress was allowed.

In addition to maximum stresses computed for the cylindrical and spherical portions of the drywell, stresses have been computed on the elliptical top closure head of the vessel, taking into account the effect of jet forces, since this portion of the vessel is not backed up by concrete. The maximum stress on the head has been found to be 29.69 ksi and results from jet forces combined with the design internal pressure of 56 psig. The design specification allowance for this loading combination is 30.33 ksi (0.9 F_y at 300°F).

6.2.1.1.3.4 Drywell Design - Discontinuity Stresses

Drywell discontinuity stresses at embedment have been accounted for and stress values included in the CB&I certified stress report. The following gives the actual and allowable stresses at these discontinuities:

Location	Maximum Actual Stress	Allowable Stress
Drywell embedment at flooded condition	22.07 ksi	F_y = 38.0 ksi

6.2.1.1.3.5 Drywell Design - Expansion of the Drywell Containment Vessel and Jet Forces

Design pressure for the drywell permits a relatively thin-walled steel vessel. However, the vessel has relatively little capability to resist concentrated jet forces. However, such loads are readily accepted by the massive concrete shield that surrounds the vessel. Accordingly, the space between the steel drywell vessel and the concrete shield outside has to be sufficiently small so that, although local yielding of the steel vessel can occur under concentrated forces, yielding to an extent causing rupture will be prevented. Space has been provided to allow the drywell to expand when in its stressed condition so that it can function as a pressure vessel independent of the surrounding concrete. In addition, the vessel is subjected to thermal

expansion caused by operating or possible accident condition temperatures significantly higher than ambient. Jet impingement force stresses are summarized in Table 6.2-10.

To ensure that a steel shell could deflect up to 3 in. locally without failure as a result of a concentrated load, CB&I has conducted a series of tests on a steel plate formed to simulate a portion of the drywell vessel. The tests were satisfactory and also provided data on loading required to produce a given deflection and the strain at various points of the shell. In performing these tests, permanent deformation was not considered as failure.

6.2.1.1.3.6 Drywell Design - Flooded Condition

The primary containment was analyzed for its ability to withstand loading from postaccident flooding of the drywell.

Under this condition, the drywell is flooded with water to elevation [redacted] Other loads, such as internal pressure, temperature, live loads, and jet forces, are not combined with the hydrostatic load because these loads will not occur simultaneously with flooding. However, the vessel was analyzed for the OBE loads combined with the hydrostatic loads.

Table 6.2-9 summarizes the stresses in the shell under the flooded condition and earthquake.

6.2.1.1.3.7 Drywell Design - Buckling Considerations

The drywell shell must be able to resist the compressive stresses resulting from the external pressure, the dead load of the shell and appurtenances, the live load on the access hatch and beam loads, the gravity loads on the weld pads, plus the seismic loads. These loads produce biaxial compressive stresses of varying magnitude at different points along the drywell shell.

The worst condition for drywell buckling is during the refueling condition, Case 6, Table 6.2-7, combined with stresses due to DBE seismic loading. The maximum compressive stress occurs at the drywell embedment and has a stability ratio of 0.58.

6.2.1.1.3.8 Drywell Design - Stabilizer Shear Lugs

Eight stabilizer mechanisms are designed to transfer the reaction due to seismic loads or seismic plus jet loads acting on the drywell, reactor, and shield into the building (at elevation [redacted]). These loads are shown in Table 6.2-4.

Each stabilizer mechanism is composed of four components: (1) the connection between the reactor stabilizer and the drywell shell, (2) the male lug, (3) the female lug, and (4) the concrete shear connectors. The geometry of the stabilizer mechanism allows for radial and vertical movements due to pressure and temperature. Computed stresses in the stabilizer mechanism are compared to either the AISC or ASME Code allowables depending on the component being analyzed. All components and welds that are attached directly to the drywell

shell satisfy the ASME Code. The stresses in the remaining components are compared to AISC allowables. The allowed and computed stresses are summarized in Table 6.2-11.

6.2.1.1.3.9 Suppression Chamber Design - Primary Membrane Stresses

The suppression chamber is supported on 16 pairs of equally spaced columns located on the inner and outer perimeters. Although the principal stresses computed on the suppression chamber were circumferential, detailed analyses have been performed to determine the magnitude of localized stresses at the points of column and downcomer supports and vents to determine the need for and to provide additional stiffeners and reinforcing as required. The computed stresses are summarized in Tables 6.2-12 and 6.2-13.

Because of the complexity of the analysis involved in the determination of maximum stresses under various loads and load combinations, CB&I set up a computer program for each of the major loading combinations. These combinations were the initial and final condition at ambient temperature at the time of the acceptance test, and the accident condition at 281°F. In addition, the flooded condition was analyzed. The CB&I calculations for the suppression chamber, including the printout sheets for the computer program, are included in the certified stress report.

6.2.1.1.3.10 Suppression Chamber Design - Accident Condition

The maximum primary membrane stresses in the shell and ring girder result from a combination of downcomer thrusts of 21,000 lb each, internal pressure of 56 psig at 281°F, the load of the 61,500 ft^3 of water in the suppression pool, lateral and vertical seismic loads, and vent thrusts of 56 psig at 281°F.

The maximum primary membrane stresses in the shell and ring girder result from a combination of loads as shown in Table 6.2-8; the principal stresses are shown in Table 6.2-12. The maximum actual stresses in the columns from the combination of axial compression and bending are calculated to be 0.821 and 0.567 of the allowable stress for the outside and inside columns, respectively.

Stresses are determined at critical points along the girder. The maximum stresses, 11.76 ksi acting in the plane of the shell and 15.82 ksi, acting in the ring girder flange, are for the accident condition and the ASME Code allowables of 17.5 ksi.

6.2.1.1.3.11 Suppression Chamber Design - Flooded Condition (Ring Section and Supports)

For the water level at elevation [redacted] in the drywell for the flooded condition, a computer analysis showed that the maximum stresses in the support ring are 13.8 ksi in the plane of the shell and 19.74 ksi in the ring girder flange, which are below the allowable of 38.0 ksi.

The outside and inside column stresses were investigated. The maximum stress due to a combination of axial compression and bending was calculated to be 0.521 and 0.391 of the allowable stress for the outside and inside columns, respectively.

The design of rods, column connections, plates, etc., have been analyzed for the flooded condition with earthquake, and the stresses are less than the code-allowable stresses.

6.2.1.1.3.12 Suppression Chamber Design - Header, Downncomer, and Vent Pipes

These components of the suppression chamber were analyzed and adequately sized for plate thickness and reinforcements as required and are in conformance with the ASME Code.

6.2.1.1.3.13 Containment System Design - Summary

All possible loads, as well as their combinations, have been taken into consideration, and the maximum stresses computed are all within the design specifications and the ASME Code allowable stresses.

6.2.1.1.3.14 Penetration Nozzle Design

CB&I designed the penetration nozzles. The shell stresses, caused by loads on the nozzles, at the nozzle neck-to-shell junction were analyzed by the methods outlined in Welding Research Council Bulletin 107. A computer program was written to perform the calculations outlined in the computation forms for spherical and cylindrical shells.

The size and thickness of the nozzle neck and necessary reinforcements are computed from requirements listed in Section III, Subsection B, of the ASME Code. The attachments are designed to provide the strength required by the ASME Code. The computed stresses and allowable stresses are summarized in Table 6.2-14.

6.2.1.1.3.15 Vacuum Breaker Design

NRC Generic Letter 83-08 identified the need for additional analysis of vacuum breakers due to a chugging phenomenon observed during model tests in which a Loss-of-Coolant Accident was simulated. In response to that generic letter, force functions were developed which simulate the anticipated hydrodynamic loads, and stress analyses were performed using those loads. References 35 and 36 (and their attachments) document the DAEC analysis and commitments. These analyses indicate the potential for overstressing certain components of the originally-installed vacuum breakers. Consequently, DAEC committed to replace certain components of the vacuum breakers such that stresses predicted by the analysis will be less than code-allowable stresses. Reference 37 documents NRC acceptance of the analyses.

6.2.1.2 Containment Subcompartments

See Section 6.2.1.1.

6.2.1.3 Mass and Energy Release Analysis for Postulated LOCAs

6.2.1.3.1 General

The primary containment and its associated safeguards systems are designed to accomplish the following four principal functions:

1. To accommodate the transient pressures and temperatures associated with the equipment operation and/or failures within the containment.

2. To accommodate and mitigate the effects of a postulated metal-water reaction subsequent to a postulated design-basis LOCA.

3. To provide a high-integrity barrier against the leakage of fission products associated with equipment failures.

4. To provide containment protection against damaging effects of internally generated missiles and movement of water.

These factors are considered in the following evaluation of the integrated primary containment system.

6.2.1.3.2 Primary Containment Characteristics Following a Design-Basis Accident

To establish a design basis for the pressure suppression containment with regard to pressure and temperature rating and steam-condensing capability, the maximum rupture size of the reactor primary system must be defined. For this design, an instantaneous, circumferential rupture with double-ended flow of one recirculation line was selected as a basis for determining the maximum gross drywell pressure and the condensing capability of the pressure suppression system.

In establishing the containment design, circumferential pipe ruptures were assumed with sufficient distance separation to allow full potential flow from each end of the pipe. Pipeline flow restrictions were not considered in establishing rupture flow rates. Because the assumed initial rupture rate and the accompanying reactor depressurization is so rapid, progressive failure of the piping is not a limiting factor in the containment design.

The design pressure was established on the basis of the Bodega Bay pressure suppression tests.[1]

The choice of 281°F for the design temperature of the primary containment vessel was a result of the containment LOCA response calculations. The drywell temperature response curve (see PSAR Figure 14.0.36) shows a peak temperature of 281°F, which quickly decays to a much lower value. These containment response calculations were determined from experimental data measured during the Bodega Bay experiment.

The ability of the containment to handle temperature transients in excess of 281°F is discussed in Sections 6.2.1.3.4 and 6.2.2.3.1. The temperature effects on safety-related electrical equipment are discussed in Section 3.11.

The parameters having the greatest effect on drywell design pressure are the ratio of pipe break area to total vent area, the vent submergence below the water level in the suppression pool, the initial system pressure, and the final equilibrium pressure in the pressure suppression chamber.

Enough water is provided in the suppression pool to accommodate the initial energy that can be released into the drywell from the postulated pipe failure. The suppression chamber is sized to contain this water, plus the water displaced from the reactor primary system (less the 1,955 cubic feet hold-up on the Drywell floor prior to spill over into the suppression pool via the vent system) together with the free air initially contained in the drywell.

The containment design parameters listed in Table 6.2-1 are concerned primarily with the effects on the primary containment caused by the blowdown immediately following the postulated double-ended rupture of the recirculation piping.

6.2.1.3.3 Primary Containment Response to a Design-Basis Accident

The original FSAR containment analysis considered the following four scenarios, referred to as Cases 1-4.

- Case 1) All ECCS equipment operating, with containment spray
- Case 2) One RHR loop with two pumps operating, with containment spray
- Case 3) Loss-of-offsite power, with containment spray
- Case 4) Loss-of-offsite power, with no containment spray.

Case 4 was shown to be the most limiting scenario for peak containment pressure and temperature and has been used as the bounding event for evaluating containment response to the design basis accident. However, in order to maximize key parameters in the predicted containment response, for use as inputs to other evaluations, such as ECCS Net Positive Suction Head (NPSH) (Section 1.8.1) or Equipment Qualification (EQ) (Section 3.11), different inputs, models, and assumptions have been used. See Chapter 15 for a more detailed discussion of each evaluation of containment response.

6.2.1.3.3.1 Containment Capability with Respect to Metal-Water Reactions

If Zircaloy in the reactor core is heated to temperatures above approximately 2000°F in the presence of steam, a chemical reaction occurs in which zirconium oxide and hydrogen are formed. This is accompanied with an energy release of approximately 2800 Btu/lb of zirconium reacted. The energy produced is accommodated in the suppression chamber pool. The metal-water reaction is explicitly accounted for in the decay heat curves used as input to the containment analyses (Section 15.0).

6.2.1.3.3.2 Depressurization Response

The original FSAR discussion has been deleted. See Chapter 15 for a discussion of current analytical models for long-term containment response, including the depressurization period.

6.2.1.3.4 Containment Response to Smaller Breaks

The response of the containment to breaks less than the double-ended blowdown of a recirculation line has also been considered. In addition, various sizes of steamline breaks have also been evaluated. See Chapter 15.2 for the detailed discussion.

6.2.1.3.5 Primary Containment Bypass Leakage

The primary containment is constructed in such a manner that it can be verified that at the calculated peak containment pressure resulting from the design-basis accident, the DBA leakage rate is not in excess of that used to calculate the radiological consequences of that accident in Section 15.2. See Section 6.2.6 for additional details.

In addition, all external paths of potential bypass leakage (such as the purge and vent system) have been reviewed. Every path has at least two isolation valves in the leakage path. These valves are high-quality containment isolation valves. They are all normally closed, essentially leaktight valves. See Section 6.2.4 for additional details.

The DAEC containment has been examined to determine what bypass leakage between the drywell and wetwell can be tolerated. The basis for determining tolerable bypass leakage is the containment maximum internal pressure of 56 psig. The allowable bypass leakage capacity ($A/\sqrt{K}$) is a function of primary system break area. (A is the area of the leakage flow path and K is the total geometric loss coefficient associated with A.)

For the DAEC containment, the maximum allowable leakage capacity was determined in the original FSAR analysis to be equal to $A/\sqrt{K} = 0.11\ ft^2$. Typically, the geometric loss factor would be 3 or greater; thus, the maximum allowable leakage area would be ~$0.2\ ft^2$. This corresponds to a 6-in. line.

Primary system breaks less than ~0.2 ft^2 will not result in rapid primary system depressurization, and some operator action is required to terminate the pressure rise in the containment. When calculating the allowable leakage capacities shown in Figure 6.2-54, it was assumed that the following sequence of events occurs. Immediately after the small primary system break, there would be a fairly rapid rise in containment pressure as the noncondensible gases in the drywell are washed over the suppression chamber. During this portion of the transient, it is assumed that the plant operators think everything is "normal" in that they do not yet realize that a leakage path exists. With no bypass leakage, the maximum pressure that can occur in the DAEC suppression chamber is < 25 psig. This is the pressure that would result if all of the noncondensible gases initially in the containment are carried over to the wetwell free space. For the allowable leakage calculations, it was assumed that the plant operators realize a leakage path exists only when the suppression chamber pressure reaches 35 psig. It was further assumed that following this, there is a 10-min delay before any action is taken to terminate the transient.

The corrective action taken 10 min after the pressure has exceeded 35 psig is assumed to take 5 min to be effective. At that time, the containment pressure would be equal to the design pressure if the allowable leakage had occurred. For the calculations, the specific nature of the corrective action taken after 10 min was not defined. The operators have several options available to them. If the source of the leakage is undefined, they could depressurize the primary system via either the main condenser or relief valves.

If the source of leakage is a malfunctioning vacuum breaker, then the operators would be alerted by the control room vacuum breaker position indicators. In this event, the operators would attempt to close the open valve by exercising it with the remote actuator. This action, together with the force acting on the valve disk as a result of the flow that is occurring, would in all probability close the valve.

See Section 6.2.6.3.5 for a discussion of periodic testing to confirm bypass leakage is within limits. See Section 15.2 for the evaluation of containment response assuming the maximum allowable bypass leakage.

6.2.1.3.6 Primary Containment Integrity Protection

A detailed analysis has been conducted to delineate which systems or portions of systems are essential in mitigating the consequences of a pipe rupture within the drywell. Four general criteria were established to determine essential systems in ensuring both primary containment integrity and the core cooling capability as follows:

1. Maintain the ability to scram the reactor.

2. Maintain the ability to isolate the reactor vessel and primary containment.

3. Maintain the ability to initiate and operate the core cooling systems.

4. Maintain physical integrity of the drywell liner and torus shell.

A rupture was assumed to be a nonmechanistic one occurring anywhere inside the drywell, and the subsequent recovery assumed a single active component failure in one of the systems that was required to function. The result of this study provided a list of which systems or combination of systems had to be protected from the effects of a given rupture.

The following five inherent design features minimize the chance of a rupture occurring that causes unacceptable damage:

1. From conservative piping design using proven engineering practice, the proper choice of piping materials and loadings (Chapter 3), and conservative quality control standards and procedures for piping, fabrication, and installation (Chapter 17), it is most unlikely that pipes will catastrophically fail.

2. The structures, including primary containment, are conservatively designed as discussed in this section and Chapter 3. The primary containment vessel (drywell) is completely enclosed in a reinforced-concrete structure having a thickness of 4 to 7 ft. This concrete structure serves as a radiological shield for the reactor system, a structural member to limit the movement of the liner, and as a mechanical barrier for the protection of the liner and reactor systems against potential missiles generated external to the primary containment.

3. A dimensionally controlled gap is provided to permit the growth of the liner due to temperature and pressure. A nominal gap of 2 in. is used up to the drywell head; the liner may expand or deform this distance without suffering a "tear." This feature has also been evaluated in areas subjected to a jet force and determined to be adequate. Since concrete is not available at the vent openings, deflection plates have been put across these openings for jet protection.

4. If a pipe leak should occur, means for detecting even small leaks are available so that proper action can be taken before they develop into appreciable breaks (see Section 6.2.1.3.5).

5. The design provides for considerable system redundancy to optimize the reliability of accomplishing essential functions. The drywell design has used this concept, and a study was made to ensure that the independence of redundant systems is maintained. For example, the automatic depressurization system (ADS) valves have been separated as much as possible, and the HPCI steam line has been routed as far away from the ADS valves as possible.

Where separation and structural interference were not adequate to protect an essential system from a pipe movement, the offending pipe was restrained. This resulted in restraints

being placed on the HPCI steam line, the feedwater lines, the main steam lines, the recirculation lines, and the safety relief valve vent lines. Evaluation showed that other lines either cannot reach or cannot penetrate the drywell liner, or they cannot strike components whose loss would prevent any of the four basic criteria from being accomplished.

This evaluation was predicated on several central assumptions as follows:

1. All pipes were considered susceptible to circumferential (or longitudinal) failure at any location along that portion of its length that is subjected to unisolable reactor pressure during normal operation.

2. Pipe runs separated from the pressure vessel by a check valve that seats with reactor pressure were not considered as potential sources of sustained pipe movement (or jet spray) since the check valve will seat rapidly on an upstream failure.

3. A line of a given size and schedule will not cause a line of equal size and schedule to fail to perform its function, should the first line strike the second.

4. A given pipe rupture will generate only one additional rupture. The consequences of a cascading rupture sequence are indeterminate and of such a low probability within this highly unlikely event as to be unrealistic.

The drywell has been designed to withstand the jet forces discussed in Section 6.2.1.1.3.5. Separation and interference concepts were used to provide maximum assurance that no jet could incapacitate a sufficient number of redundant components to violate one of the four criteria previously mentioned.

The design of the valves used in the plant precludes any component from becoming a missile. Other potential missiles have been investigated and either eliminated as sources or oriented away from the containment. All thermowells are directed toward the biological shield around the reactor.

The design of the piping inside the drywell optimizes the use of restraints, given the type and size of the primary containment. Additional restraints are not necessary, would significantly limit access for inservice inspection and maintenance, and would decrease the structural safety factors presently existing in plant design. Detailed aspects of the analytical techniques are discussed in Section 3.6.

6.2.1.3.7 Capabilities of Penetrations

The containment penetrations are designed to withstand the normal containment environmental conditions that may prevail during plant operation and to retain their integrity during all postulated accidents.

Pipe lines that penetrate or open into the containment shell, and which are capable of exerting a reaction force due to line thermal expansion or containment movement that cannot be restrained by the containment shell, are provided with a bellows expansion seal. These lines are anchored outside the containment to limit the movement of the line relative to the containment. The bellows accommodates the relative movement between the pipe and the containment shell.

Pipe lines that penetrate the containment where the reactive forces can be restrained by the containment shell are provided with full-strength attachment welds between the pipe and the containment shell. These penetrations are designed for long-term integrity without the use of a bellows seal.

A personnel access lock is provided with interlocked double doors so that access may be made to the containment while the reactor primary system is pressurized. Double doors are provided to ensure that containment integrity is effective while access is being made.

Access hatches are sealed in place, using flexible double seals to ensure leaktightness. These openings are closed at all times when containment is required.

Inspection and surveillance provide additional assurance of the integrity and functional performance of the penetrations. For this reason, provisions are made to leak test individually all containment electrical penetrations, the personnel access lock, the access hatches, and those pipe penetrations having bellows seals. This can be accomplished without pressurizing the entire containment system.

6.2.1.3.8 Primary Containment Isolation

See Section 6.2.4.3.

6.2.1.3.9 Primary Containment Flooding

The primary containment system is designed for the conditions associated with flooding the containment. The capability for flooding the primary containment is provided by the containment spray mode of the two independent RHR subsystems whereby water may be taken from the condensate storage tanks or the suppression pool and injected into the drywell. An emergency source of water is also available by using the RHR service water system to inject river water into either RHR discharge header.

6.2.1.3.10 Pressure Suppression Pool Water Storage

On the basis of the accident analyses presented in Chapter 15, the quantity of water stored in the suppression pool is sufficient to condense the steam from a design-basis accident and to provide water for the emergency core cooling systems. The suppression chamber is subject to the pressure associated with the storage of 58,900 ft^3 of water distributed uniformly within the vessel during normal operation. Under the accident conditions, the suppression

chamber is designed for 61,500 ft^3 of water plus the containment design pressure and dynamic effects of air and steam flow through the vent lines.

6.2.1.4 Inspection and Testing

6.2.1.4.1 Containment Leakage Testing

The containment vessel was tested by CB&I for its structural integrity by an overload test specified in ASME Code, Section III, N-713 and for leakage by the reference chamber method as described in the American Nuclear Society's publication ANS 7.60.

Tests showed that the leakage rate for the vessel was less than the 0.2% weight per day leakage rate limit as specified in the containment vessel specification (i.e., 0.086 wt % per day).

The containment vessel was again tested for leaktightness after all the equipment was installed in the drywell and connected to the penetrations.

Refer to Section 6.2.6 for a discussion of containment leakage testing.

6.2.1.4.2 Surveillance

The DAEC performs a general visual surveillance inspection of interior and exterior surfaces of the 8 vent pipes, the vent header, and the 48 downcomer pipes during each refueling outage. This visual inspection is primarily for the purpose of ascertaining whether there is degradation of paint or rusting of vent system metal above the suppression pool water line. The water line shall be the line of contact of water and the shell at the time of inspection. An engineering evaluation of degradation documented during the inspection will be performed before resuming power operation.

Whenever there is indication of relief valve operation with the temperature of the suppression pool reaching 200°F or more, an external visual inspection of the suppression chamber shall be conducted before resuming power operation.

Each of the torus-to-drywell vacuum breakers has two "closed" and one "open" position indicator lights, which are located on a control room panel. These lights are observed in accordance with Technical Specifications to ensure that the vacuum breakers are closed. This ensures the plant operating personnel that there can be no back-leakage through the valves.

The valve position indicating lights consist of one closed position indicating light and one open position indicating light operated by a different switch from the closed light. In addition, each valve is equipped with a magnetic latch that will maintain the valve in the closed position unless a Δp of 0.5 psi exists.

Each vacuum breaker will be tested in accordance with the Technical Specifications.

Figure 6.2-58 shows design details of a torus-to-drywell vacuum breaker. Each breaker is equipped with an opening test device and a permanent magnet, positive closing latch.

Drywell-to-suppression pool leakage can only be caused by missile damage to the vent system, fabrication errors during construction of the vent system, vacuum breaker back-leakage, gross rusting of the vent system, or physical damage to the vent system as a result of blowdown forces. These subjects are discussed in more detail below.

Missile Damage

Each of the eight vent pipe openings in the drywell has a deflector in the opening to protect the vent system from jet impingement forces and missiles that could originate from the drywell. The suppression chamber does not have any rotating or moving equipment able to generate a missile.

Fabrication Errors

The vent system is designed, built, and given the same nondestructive examination and quality assurance as the primary containment vessel itself. Containment pressure response shows that the highest pressure differential to which the vent system could be subjected during the design-basis accident does not exceed about 45 psi; however, the vent system is designed and constructed for a maximum differential pressure of 62 psi.

The maximum tolerable vent system leakage area has been analyzed. The analysis outlines the operator action required to control and isolate the largest primary system break (which will not result in a rapid primary system depressurization) coincidental with the maximum allowable leakage area. This leakage area corresponds to the area of a 6-in. pipe. Thus, any fabrication errors of this magnitude would be visually detectable. The vent system has successfully completed a thorough nondestructive examination pressure/leakage test.

Vacuum Breaker Back-Leakage

The vacuum breaker position indication and positive closing features are discussed above. If it could not be verified that every torus-to-drywell vacuum breaker was closed, the plant would go through an orderly shutdown.

Rusting

A visual examination of the vent system is conducted as described above.

Blowdown Forces

The vent system has been designed to withstand the blowdown forces as a result of the design-basis accident. Therefore, the structural integrity of the vent system will always remain intact and no leakage as a result of blowdown damage can occur.

The other sources of blowdown into the suppression pool are from the six safety/relief vent lines. Each line extends into the center of the torus and terminates below the pool water level in a tee connection. The discharge from each tee is horizontal in two directions.

This vent pipe discharge was analyzed to determine if the jet blowdown force was dissipated before striking any targets. For conservatism, the analysis neglected the effects of water in the suppression pool. The conclusion was that the jets from the tee are dissipated before striking any targets. Therefore, the effect of this normal blowdown on the torus vent system does not exceed established structural design criteria.

6.2.1.5 Instrumentation Requirements

Suppression pool water temperature indicators and recorders are described in Section 7.5.1.2.6. The signals to the redundant torus water temperature recorders are also isolated and averaged. The average signal is then displayed on a digital recorder and indicator on panel 1C03 in the Control Room.

In addition, to meet the requirements of NUREG-0661, the DAEC has a suppression pool temperature monitoring system to measure suppression pool bulk temperature. The suppression pool temperature monitoring system utilizes eight temperature sensors which are seismically qualified and are located in Quality Group B thermowells. The thermowells are located around the suppression pool, both inboard and outboard, at a height just below the minimum water level (Figure 6.2-3).

Suppression pool water level is continuously monitored and displayed in the control room on redundant recorders and indicators. The system has a range of 1.5 to 16 ft which envelopes the NUREG-0737, Item II.F.1.5, requirements of from below the ECCS suppression pool suction line inlets, to 5 ft above the normal water level. Both the recorder and indicator loops have a system accuracy of 6% of full scale. In the event of a LOCA, monitoring of suppression pool level will provide the operator with an indication of the inventory of the suppression pool heat sink. Instrumentation is provided to monitor containment water level and display it in the control room on redundant recorders and indicators. The system has a range of 0 to 98 ft, where 0 ft. is the bottom of the torus and 23 ft. 3 3/4 in. is the bottom of the drywell.

Instrumentation requirements for containment atmosphere temperature; pressure; humidity; radioactive particulate, halogen, and noble gas activities; and oxygen and hydrogen concentration are monitored as discussed in Section 6.2.5.5. Postaccident containment radioactive particulate, halogen, and noble gas sampling is discussed in Section 12.3.4.2.3.

6.2.1.6 Mark I Containment Program

6.2.1.6.1 Background

The Mark I Owners Group was formed as a result of the April 1975 request by the NRC for the purpose of obtaining additional information on the design of the Mark I containments used with the GE-designed boiling water reactor (BWR) nuclear steam supply systems. Since its formation, Iowa Electric has been an active member of the Mark I Owners Group and followed closely the development of the program conclusions. General Electric and Iowa Electric have outlined both short- and long-term evaluation programs to be followed.

General Electric was retained as the Mark I Containment Owners Group Project Manager. Bechtel was retained by GE as a consultant for the purpose of structural evaluation. Teledyne Materials Research (TMC) was retained by GE to perform an overview function for load development, structural evaluation, and structural criteria establishment. NUTECH was retained by the Owners Group in November 1975 to act as the utility group's technical representative and to keep the utilities informed of program progress on a continuing basis.

The initial task for the Mark I Owners Group during the short-term program was evaluating the integrity of the containment vent system and vent system supports assuming most probable loads, with the governing criterion being the maintenance of containment functions and ECCS piping. The results of this effort, which concluded that the vent system integrity would be maintained when subjected to the most probable pool swell loads, are documented in the five volume Short-Term Program (STP) report, which was submitted to the NRC in September 1975,[15] and subsequent addenda.

To supplement the general studies being conducted by GE and its consultant Bechtel for the Mark I Owners Group, Iowa Electric retained NUTECH as an independent consultant. NUTECH has conducted a parallel evaluation of the structural integrity of the vent systems for the DAEC when subjected to the most probable pool swell loads and has confirmed the work done on behalf of the Mark I Owners Group as it relates to this unit.

Subsequent to the submittal of the STP report, an Addendum 1 to that report was prepared and submitted to the NRC in December 1975.[16] Documented in that addendum were analyses of stresses in the relief valve discharge piping when subjected to pool swell impact and drag loads. This addendum provided the basis for concluding that the integrity of the relief valve discharge piping was assured.

Also included in Addendum 1 was documentation of the structural integrity testing of a representative vent line bellows assembly when subjected to pool swell loads. Since the bellows assemblies on the DAEC are located outside the torus and as such are not subjected to pool swell impact loads, this test was not required to demonstrate the integrity of the DAEC bellows. Nevertheless, the observed behavior demonstrates the inherent reserve capacity for welded steel

structural components to maintain their leak-tight integrity even when subjected to large deformations.

6.2.1.6.2 Mark I Containment Modifications

6.2.1.6.2.1 Short-Term Program

The following three design and procedural modifications were made as part of the Short-Term Program.

Torus Support Column Anchorage

The torus support columns were modified to add some uplift resistance capacity as a stop-gap effort. The modifications significantly increased safety margins by restricting upward movement while maintaining lateral movement capabilities.[17]

Drywell-Suppression Pool Delta P

The DAEC installed a differential pressure control system, which provided a positive differential pressure between the drywell and torus regions of the containment. This differential pressure reduced the height of the water leg in the downcomers and thereby reduced potential LOCA hydrodynamic loads on the pressure suppression pool.[18] For further details see Section 6.2.5.2. After the 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.

Rework of Safety/Relief Valve Setpoints

The DAEC modified the topworks of the two low-setpoint safety/relief valves such that the two low-setpoint relief valves would discharge to bays in the suppression pool not adjacent to each other.[19] Adjusting the setpoints so that adjacent valves would not lift together reduced potential individual torus support column loads.

6.2.1.6.2.2 Long-Term Program

The Mark I Owners Group status summary report submitted to the NRC on June 29, 1981[20], included the DAEC Mark I containment long-term modification program. On July 12, 1983, by Reference 21, Iowa Electric reported to the NRC that all plant modifications and structural reassessments required to meet the acceptance criteria of NUREG-0661[22] for the DAEC had been completed. The final volume (Volume 6) of the DAEC Plant Unique Analysis Report (PUAR) for the Mark I Containment was submitted to the NRC on June 30, 1983 (Reference 23). Volumes 1 through 5 of the DAEC PUAR were submitted to the NRC on December 30, 1982 (Reference 24). The NRC reviewed the PUAR and reported in Reference 25 that the NRC concluded that acceptable safety margins have been established for all pool

dynamic loads under LOCA and safety/relief valve discharge loads and that the established margins for structural integrity under LOCA conditions are acceptable.

The following modifications were completed as part of the DAEC Mark I containment long-term program.

Suppression Chamber Downcomer Shortening

The drywell-to-suppression chamber vent system downcomers were shortened so as to reduce the minimum downcomer submergence from 4 to 3 ft. Small- and large-scale load evaluation tests have demonstrated that reduced downcomer submergency reduces torus downforce and upforce and vent header impact that can occur during the pool-swell phase of a postulated LOCA.

The intent of downcomer submergence is to ensure condensation effectiveness and prevent steam bypass to the suppression chamber airspace. General Electric has performed a functional assessment of reducing the downcomer minimum submergence from a nominal 4.0 to 3.0 ft (GE NEDE-21855-P, dated June 1978). The report addresses condensation effectiveness, thermal stratification, seismic-induced waves, post-LOCA pool waves, and post-LOCA draw-down. Results presented in the report show that condensation effectiveness can still be maintained with a submergence of 2 ft and that the 3.0 ft dimension is conservative and allows for normal tolerances in determining minimum water level. The conclusion is that on the basis of existing information 3.0 ft downcomer submergence can be safely implemented in the Mark I containment system. The reduced submergence is obtained by reducing the length of the downcomers, not by reducing the water volume. The minimum water volume as listed in the Technical Specifications was not changed.

Safety/Relief Valve T-Quenchers

T-quenchers were installed at the termination of all six SRV discharge lines within the suppression chamber pool. In-plant testing of the T-quencher device was conducted as part of the Mark I Program at the Monticello Nuclear Generating Plant and reported in GE Report NEDE-21864-P, dated July 1978. The testing demonstrated significantly lower hydrodynamic loads on the containment as a result of quencher installation, but less than desired thermal mixing in the suppression pool. Holes were added to one end cap of each T-quencher to promote circular mixing of the pool. The T-quenchers provide a reduction in torus shell pressures by a factor of 4, a reduction in submerged structures loads, an improvement in steam condensation, and a raising of the temperature threshold for condensation instability.

Torus Support Modification

The modification to the torus support consisted of reinforcing the existing torus support column connection flange welds and the addition of a web and base plate assembly beneath the torus. This added assembly is welded to both the torus support column and the torus shell.

The purpose of this modification is to reinforce the containment suppression chamber supports in order to increase the margins of safety. The addition of the reinforcement will increase the capacity of the torus supports for containment loadings.

The reinforcement of the suppression chamber supports was performed in accordance with the requirements of ASME Sections III and XI. The attachment of the reinforcement is to a "butter" layer previously deposited on the torus shell rather than attaching directly to the shell.

Suppression Chamber Anchorage

The suppression chamber anchorage was modified to accommodate newly-defined hydrodynamic loads resulting from LOCA and/or safety/relief valve discharge events. The new stiffeners and base plate brackets were added to the suppression chamber saddles and column supports and additional anchor bolts were installed to transmit uplift loads from the suppression chamber columns and saddles to the reactor building foundation.

RHR Elbow and Support

The purpose of this modification is to promote mixing of suppression pool water during an extended steam blow down through SRV discharge lines. T-quenchers were installed at the termination of all six SRV discharge lines within the suppression pool. Additional mixing of the pool will be obtained with RHR flow if the discharge through RHR test lines is also directed in a circular direction.

The addition of an elbow reducer to the RHR return line increases the flow resistance of the loop. However, calculations have been performed to ensure that the system can accommodate additional head loss. The decrease in total flow rate has been estimated from the RHR pump characteristic curve to be approximately 150 gpm/pump or less than 2% of the nominal flow rate. Sufficient system margin exists to compensate for loss by valve adjustments if necessary.

The modification was performed in accordance with the requirements of ASME Section XI and ANSI B31.1, the original code of construction. Attachments to the torus shell and the ring girder comply with the requirements of ASME Section III.

Suppression Chamber External Piping Penetrations

Reinforcements in the form of insert plates, support arms, and gusset plates were added to existing suppression chamber piping penetrations to increase the capability of these penetrations to resist the postulated dynamic loads due to LOCA and safety/relief valve discharge events.

Suppression Chamber Internal Torus Attached Piping Supports

Suppression chamber internal small bore and large bore torus attached piping and pipe supports were modified and new pipe supports were added to increase the capacity of the piping and pipe supports to resist the dynamic loads due to LOCA and safety/relief valve discharge events.

Internal Catwalk and Ring Beam Structures

The suppression chamber internal catwalk and ring beam structures were modified to increase their capacity to withstand the increased postulated dynamic loads due to LOCA and safety/relief valve discharge events.

Safety/Relief Valve Discharge Piping Vent Lines

The safety/relief valve discharge piping vent line penetrations, elbow support beams, and T-quencher support beams were modified to increase their capacity to resist the increased postulated hydrodynamic loads resulting from LOCA and safety/relief valve discharge events.

Suppression Chamber External Torus Attached Piping

Existing suppression chamber small bore and large bore torus attached piping and piping supports outside the torus were modified and new pipe supports were added. These modifications increase the capacity of the piping and pipe supports to resist the postulated dynamic loads due to LOCA and safety/relief valve discharge events.

6.2.1.6.2.3 ECCS Pump Suction Strainer Modifications

NRC Bulletin 96-03 requested that the DAEC evaluate the effects of post LOCA debris on the performance of the ECCS systems drawing a suction from the torus. The results of the evaluations showed a need to enhance the suction strainers on the RHR and Core Spray systems.

The existing conical strainers were replaced with alternate geometry stacked disc strainers supplied by General Electric. The new strainers are significantly larger than the original strainers and required reevaluation of torus structural loading in the area of the four penetrations associated with RHR (2) and Core Spray (2). Analyses were performed using the rules of the original MARK I program.

Specific analyses performed include: 1) development of the submerged structure loads as defined in the original MARK I program, 2) evaluation of the RHR and CS strainers, piping, piping supports, equipment, valves, and suppression chamber penetrations, and 3) evaluation of operational loads of the ECCS Strainers. The analyses are documented in Volume 7 to the Plant Unique Analysis Report.

Based on the analyses, modifications to the two RHR and two CS external torus penetrations were performed to strengthen the existing support reinforcement. Additional modification were made to five piping supports located on the A and B RHR piping and the A Core Spray piping.

The final modification was the installation of a connection assembly inside the torus. This was accomplished by removing the existing flange and replacing it with an assembly that is fastened to the penetration stub by bolting. The strainers are bolted to this assembly.

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6.2.1.6.2.4 Hardened Containment Vent System Modification

As a consequence of the nuclear accident at Fukushima Dai-ichi nuclear power plant, the NRC issued Order EA-12-050 requiring that licensees of Mark I and Mark II containments implement requirements for a more reliable hardened containment venting system to provide means for controlling containment pressure and preventing core damage following an event that causes a loss of heat removal systems (e.g., an extended loss of electrical power). Subsequently, NRC Order EA-13-109 was issued to the affected plants which provided the hardened containment vent system (HCVS) functional requirements, quality standard requirements, and programmatic requirements. As a result of the order, a new containment hardened wetwell vent system was installed. The HCVS consists of a 10 inch diameter pipe that connects to Torus nozzle N-230A and provides a vent path from the wetwell airspace to the environment that bypasses secondary containment and the standby gas treatment system.

The vent line consists of two sealed closed primary containment isolation valves (CV-4360 and CV-4361), a safety related rupture disk which provides a zero leakage barrier to unfiltered release (PSE-4362), a temperature element and indicator that is used to verify the vent is in operation, and a radiation monitor that is used to verify the vent is in operation. The indications and controls for the system are located in the main control room at panel 1C014. The vent line runs from the Torus penetration, through the southwest corner room, up the south reactor building stairwell, and eventually discharges at an elevated release point above the reactor building roof.

Primary containment isolation valves CV-4360 and CV-4361 are pneumatically operated valves that require two manual operator actions to open. Locked closed manual isolation valve V43-0642 prevents pneumatic pressure from being supplied to the valve operators. Solenoid valve SV-4360B is normally open and vents the actuators for CV-4360 and CV-4361. SV-4360A is normally closed and provides an additional isolation barrier in conjunction with V43-0642 to prevent the valve operators from pressurizing. Therefore, to open the valves, key-locked hand switch HS-4360 must be taken to open in addition to manually opening locked closed isolation valve V43-0642.

The instrumentation and controls for the HCVS are powered by an uninterruptible DC power supply which is charged by 1B15. This power supply is capable of providing at least 24 hours of power in the event of an extended loss of AC power.

2016-003 Rupture disk PSE-4362 is set such that the expected pressure in the piping downstream of CV-4361 (outboard PCIV) during a LOCA will not cause the disk to rupture and is set below the primary containment pressure limit to protect the containment in a beyond design basis event. Valves CV-4360 and CV-4361 are specified to be Class VI shutoff valves, and therefore provide the highest degree of isolation capabilities for control valves and the lowest amount of leakage. The rupture disk provides a zero leakage barrier between the primary containment and the environment by preventing any small amount of leakage past CV-4360 and CV-4361 from bypassing secondary containment and the standby gas treatment system. A connection is provided between outboard valve CV-4361 and rupture disk PSE-4362 that can be used for either purging the vent line of hydrogen and oxygen to prevent a detonation, or for applying pressure to the rupture disk PSE-4362. This function may be used only by taking key-lock hand switch HS-4362 to OPEN and by opening locked closed manual isolation valve V43-0642. The purge/rupture line will use a set of Nitrogen bottles as the pressure source, which are located in the CRD repair room. The use of the purge/rupture function will only be used as directed by the Emergency Operating Procedures.

The DAEC Emergency Operating Procedures and Severe Accident Management Procedures will control the use of the HCVS in response to primary containment threatening event.

As a result of the implementation of NRC Order EA-13-109, the existing hardened containment vent which was mandated by NRC Generic Letter 89-16, has been abandoned.

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 short-term temperature rise through blowdown remains within the design limit of 50°F (see Section 15.2). 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).

Because SPC mode of RHR is one of the primary mechanisms for decay heat removal following a postulated accident, it was included within the scope of Generic Letter 2008-01 (Ref. 44 and 45). However, because the pump suction piping of SPC mode is common to LPCI, no unique evaluations were required for this mode of RHR to ensure that the suction piping is maintained sufficiently full of water to perform its intended safety function. And, because the discharge piping for SPC mode is common with the full flow test mode of the RHR pumps, these piping sections are dynamically vented following maintenance that drains the system and during periodic surveillance tests of the pumps.

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 procedure set forth in Section 6.2.2.2.2.2 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 <u>Design Standards</u>

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 Operator Use of Containment Spray

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 atmosphere temperature in excess of 281°F persisted. This ensured that the wall never exceeded 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 preserve HPCI and/or RCIC as sources for reactor coolant makeup.

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 performed because of high ambient temperatures in the upper elevations of the drywell, which 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). Each of the six 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 RPV is pressurized 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 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.

Containment Spray piping was included in the Scope of Generic Letter 2008-01 (Ref. 44 and 45). Because the Containment Spray suction piping is common with other modes of RHR, such as LPCI and Suppression Pool Cooling, no unique actions were required for this mode of RHR to assure that this piping is maintained sufficiently full of water to support system operation. For the discharge side piping, those sections not common to LPCI and Suppression Pool Cooling were uniquely evaluated. Because the discharge piping terminates in ring spargers that are open inside the Drywell and Torus, which are intentionally not maintained with water by design, those piping sections are considered exempted from the Generic Letter scope. The discharge piping between the inboard containment isolation valves and the common sections of piping with the other RHR modes (LPCI and Suppression Pool Cooling) are not vulnerable to gas intrusion, even though the Primary Containment is inerted with nitrogen and slightly pressurized during power operation, because the outboard sections of the discharge piping are maintained at a higher pressure than the Primary Containment during power operation by the Keep Fill pump. Thus, it is not likely that gas (nitrogen) will accumulate in the Containment Spray discharge piping in those areas that are intended to contain water, i.e., outboard of the Containment Spray isolation valves. In addition, this section of piping has high point vents (Drywell) and/or is dynamically vented (Torus) as part of filling and venting operations after maintenance and periodic full flow testing of the RHR pumps.

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 Action 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 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 [redacted] 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.

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 (Reference Chapter 15).

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.

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 Chapter 15.2.

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 50.67.

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 LOCA will be below the guideline values stated in 10 CFR 50.67 and RG 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors." The secondary containment function is not required to keep radiological doses within regulatory limits during a Fuel Handling Accident. The refueling accident analysis is described in Chapter 15. Although operability of the secondary containment systems may be relaxed during refueling and core alternations, outage risk management procedures require planning to consider normal or contingency methods to restore secondary containment in the event of a refueling accident to further limit the radiation released.

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. Analysis of the design basis refueling accident (fuel handling accident) performed using the assumptions and methodology in Regulatory Guide 1.183 "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors" determined that this function is not required to keep radiological doses within regulatory limits. Although operability of the secondary containment systems may be relaxed during refueling and core alterations, outage risk management procedures require planning to consider normal or contingency methods to restore secondary containment in the event of a refueling accident to further limit the radiation released.

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. Analysis of the design basis refueling accident (fuel handling accident) performed using the assumptions and methodology in Regulatory Guide 1.183 "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors" determined that the secondary containment function is not required to keep radiological doses within regulatory limits. Although operability of the secondary containment systems may be relaxed during refueling and core alterations, outage risk management procedures require planning to consider normal or contingency methods to restore secondary containment in the event of a refueling accident to further limit the radiation released.

The secondary containment system uses four different features to mitigate the consequences of a postulated LOCA (pipe break inside the drywell) and to reduce the consequences of 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. 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. These three signals were installed to initiate isolation from the limiting design basis accident in the reactor building. Analysis of the refueling accident is described in Chapter 15. Automatic isolation and initiation of secondary containment functions is not needed to maintain radiological doses within regulatory limits. If operable, the reactor building isolation and control system will minimize the dose consequences. If these automatic systems are inoperable, 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 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, 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 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 accident. 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 in Section 15.2.2, In addition, the impact of the instrument line break on Equipment Qualification (EQ) in the Reactor Building has been evaluated and found to be negligible.

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 50.67.

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.

6.2.4.2.5 Containment Purge and Vent Valves

6.2.4.2.5.1 Description

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 Control Room 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 Control Room 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 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 at the containment design pressure (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.

As part of the original evaluation of purge/vent valve operability conducted under post-TMI actions (NUREG-0737, Item II.E.4.2), a dose assessment was performed using the old accident source term (TID-14844). This assessment looked at offsite dose consequences assuming the purge/vent valves were open at the beginning of the event and closed in response to an isolation signal using their design stroke time. This assessment concluded that the resulting thyroid dose at the exclusion area boundary (EAB) was well below the 10 CFR 100.11 guidelines. As part of conversion to the Alternate Source Term (AST) (10 CFR 50.67), this evaluation was not re-performed, as the radionuclide release from the fuel to the coolant is assumed to not occur for 120 seconds into the event. Thus, even if open at the beginning of the event for normal inerting/de-inerting operations, these valves would be closed well before the beginning of the coolant release and would not contribute to offsite dose consequences, other than as part of overall primary-to-secondary containment leakage (10 CFR 50, Appendix J), which is accounted for in the AST dose assessments. As discussed in UFSAR 6.2.5, purge/vent valve operation is not expected during any design basis event for combustible gas control, but only in response to beyond design basis (severe) accidents. Thus, it is not expected that the purge/vent valves would be re-opened later in the post-LOCA event response. Therefore, this

release pathway is not expected to significantly contribute to post-accident dose consequences and need not be explicitly modeled.

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.

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 for combustible gas control following a “beyond design basis” or “severe” accident.

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 or below 4% by volume during normal operation.

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 9 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 9 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

In September 2003, the NRC revised 10CFR50.44, "Standards for Combustible Gas Control for Nuclear Power Reactors." This rule change reflects the position that only combustible gas generated by a "beyond-design-basis accident" (i.e., a severe accident) is a risk-significant threat to containment integrity, provided that Mark I containments are inerted at the start of the accident. The revision to 10CFR50.44 eliminates requirements that previously pertained to design-basis accidents.

The containment inerting system maintains the containment during normal operation at an atmosphere oxygen level of 4% by volume and may preclude reaching the flammability concentration level of 5% following a beyond design basis accident by adding nitrogen to the containment to dilute the oxygen concentration.

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 monitoring system, when manually operated, provides "post-accident" indication of containment hydrogen and oxygen concentration to the operator in the control room. Continuous indication of hydrogen concentration is not required during normal operations. If an indication is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of safety injection. The monitoring system 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. However, redundancy is no longer required.

The high-pressure storage portion of the CAD system is "abandoned-in-place" up to the isolation valves at the drywell. 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.

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 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.

6.2.5.2 System Design

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 severe accident, 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.

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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 at an elevated release point above the reactor building roof via the containment hardened vent system, which bypasses the secondary containment and the standby gas treatment system. Venting will only be an option when directed by the Emergency Response Organization using the Severe Accident Management Guidelines (SAMG's) and will be administratively controlled. 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.

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.

6.2.5.2.3 Containment Atmosphere Dilution System

The Containment Atmosphere Dilution (CAD) system was removed from service per License Amendment No. 265. In this interim "abandoned-in-place" status, only the primary containment isolation function is being maintained.

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; however, such redundancy is not required. An indication of the hydrogen concentration can determine whether or not the flammability limit is exceeded, and that the dilution system is needed to control the oxygen concentration. There are sample points in the torus and the drywell. The two analyzers are completely redundant and designed to be functional, reliable and capable of continuously measuring the concentration of hydrogen and oxygen in the containment atmosphere following a significant beyond design basis accident for combustible gas control and accident management, including emergency planning.

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 Design Evaluation

The NRC has revised 10CFR50.44, "Standards for Combustible Gas Control for Nuclear Power Reactors." This revision reflects the position that only combustible gas generated by the fuel cladding metal-water reaction resulting from a "beyond-design-basis" or "severe" accident is a risk-significant threat to containment integrity, provided that Mark I containments are inerted at the start of the accident. The revision to 10CFR50.44 eliminates requirements that previously pertained to design-basis accidents. However, the limiting condition for operation with respect to oxygen concentration in containment is 4.0% by volume as stated in the Technical Specifications was retained.

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 accident, 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 20 lb-moles of oxygen initially present (assuming containment inerted to 4% of oxygen) it can be seen that the oxygen in the primary coolant 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% flammability 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% flammability 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.

Hydrogen gas additions due to zinc-steam reactions (e.g., with coating system containing zinc) 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. During severe (beyond design basis) accident conditions, Emergency Operating Procedures (EOPs) may require that sodium pentaborate be injected into the reactor, via the Standby Liquid Control System, to ultimately increase the pH in the suppression pool to minimize fission product volatization from the pool. However, this slightly basic pH will not lead to significant corrosion and combustible gas production.

The post-accident containment atmosphere will be monitored for combustible gas accumulation by the hydrogen-oxygen monitoring systems for the drywell and torus. Manual override of system isolation and initiation of nitrogen addition will take place from the control room 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. Containment pressure gauges and oxygen and hydrogen sensors are available to monitor containment conditions.

Although the hydrogen-oxygen analyzers are each 100% redundant including sampling points, analyzers, power supply, and remote-control capability (see Figure 6.2-65), they are no longer required to be, per License Amendment No. 254. 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 (Reference 29 through 34). 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 generic 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 suppression 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 results of this generic analysis, the overall conclusion is that the assumption of uniform concentration in the containment is reasonable.

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)

$$V = \frac{F_o^1}{\ell} - \frac{F_o^1}{K}\left[\frac{3x^2 - \ell^2}{6\ell^2} - \frac{2}{\pi}\sum_{n=1}^{\infty}\frac{(-1)^n}{n^2} e^{-kn^2\pi^2 t/\ell^2} \cos(n\pi X/\ell)\right]$$

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 event 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 event 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 assumptions relative to metal-water reaction and radiolysis 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 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 combustible gas control is available.

In the unlikely event that the standby gas treatment system should be used for containment purge 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. The effects of moisture on the adsorber's ability to capture gaseous activity are accounted for by performing testing at a relative humidity of 95%. Moisture or steam additions to the air stream will be reduced by an upstream moisture eliminator. 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 after a severe accident.

Nitrogen concentrations either higher or lower than normal air concentrations will have no effect on standby gas treatment system operation or efficiency.

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 an accident.

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 and vent valves and are contained in the Technical Specifications.

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.

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* Per License Amendment # 254, determination of hydrogen and oxygen concentration is no longer an "essential" parameter and not required to meet Reg. Guide 1.97 Category I requirements.

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 7.5.1.2.

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.

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. A separate oxygen analyzer is installed on the 'B' Primary Containment Radiation Monitoring Panel. This instrument verifies atmosphere conditions of the drywell and torus remain inert with the Primary Containment H_2O_2 Analyzer Panels in standby.

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 severe accident 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 placed in service as directed by Emergency Operating Procedures.

The hydrogen-oxygen analyzer systems are designed to be functional, reliable and capable of continuously measuring the concentration of hydrogen-oxygen in the containment atmosphere following a significant beyond design basis accident for combustible gas control and accident management, including emergency planning.

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.

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.

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 original containment response analysis 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 sealed 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 <u>General</u>

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 during each regularly scheduled refueling outage before the pressurization of the primary system. This test maybe

performed at any convenient time during a refueling outage provided no further work is performed on vacuum breakers.

The test involved pressurizing the drywell by approximately 1 psi with respect to the wet-well; 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 $A/\sqrt{K} = 0.11\ ft^2$. 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 during each regularly scheduled refueling outage and before the pressurization of the primary system. This test may be performed at any convenient time during a refueling outage provided no further work is performed on vacuum breakers.

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 during each refueling outage; during this test, there are no energy dumps to the pool, and a constant temperature situation exists in the suppression chamber.

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.

6.2.7 GENERIC LETTER (GL) 96-06

On September 30, 1996, the NRC issued Generic Letter (GL) 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," requesting information and actions regarding the following safety-significant issues:

1. Cooling water systems serving the containment air coolers may be exposed to the hydrodynamic effects of waterhammer during either a loss-of-coolant accident (LOCA) or a main steam line break (MSLB).
2. Cooling water systems serving the containment air coolers may experience two-phase flow conditions during postulated LOCA and MSLB scenarios.
3. Thermally induced overpressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident-mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage.

The DAEC provided its response to the GL by letters dated October 30, 1996, January 28, 1997, June 30, 1998, and February 22, 2002. The NRC provided its evaluation of the DAEC's response by letters dated May 4, 1999 and March 29, 2002. In the May 4, 1999 letter, the NRC stated that the DAEC's corrective actions provide an acceptable resolution for the issue of thermally induced pressurization of piping runs penetrating the containment. In the March 29, 2002 letter, the NRC provided its safety evaluation concluding that the occurrence of a waterhammer event, such as could affect plant safety as postulated in GL 96-06, is highly unlikely at DAEC and that the DAEC containment air cooler design does not give rise to a safety concern involving two-phase flow. The DAEC's resolution of the issues is described below.

Thermally Induced Pressurization

Four piping sections that penetrate containment were determined to be susceptible to thermally induced pressurization during design basis accident conditions:

- Residual Heat Removal (RHR) shutdown cooling line between motor-operated valves MO-1908 and MO-1909

The RHR shutdown cooling line was modified. The modification consisted of a bypass line with a check valve which vents the section of pipe between MO-1908 and MO-1909 back to the upstream pipe. The bypass line prevents the pressure in the isolated section of pipe from being higher than the reactor coolant system pressure. This provides overpressure protection for the isolated section of pipe and containment isolation valves MO-1908 and MO-1909.

- Condensate demineralized water supply to the drywell between manual valves V09-0065 and V09-0111

The line is pressurized for leak rate testing of containment isolation valves V09-0111 and V09-0065 and is left in the drained condition. Procedural restrictions were placed in the appropriate Operating Instruction to ensure that the line is drained after use.

- Drain line from the drywell equipment drain sump between check valves V37-0001 and V37-0003 and control valve CV-3728, and

- Drain line from the drywell floor drain sump between check valves V37-0017 and V37-0019 and control valve CV-3704.

The drywell equipment and floor drain sumps were modified. The modification consisted of the installation of an expansion chamber in each system. The expansion chamber provides an air volume to accommodate the thermal expansion of the water trapped in the isolated sections of the pipe.

Water Hammer and Two-Phase Flow

For steam to form within the drywell coolers, the internal pressure would have to exceed the set pressure of the relief valves. These valves have a minimum set pressure of 220 psig. The water temperature would have to exceed a temperature of 396 °F for steam to form at this pressure. Therefore, steam would not form within the drywell coolers following a LOCA unless additional failures, such as an isolation or relief valve sticking open, were to occur.

If well water flow were to be lost for a sustained period of time, under certain single-failure conditions, the drywell coolers might drain. The DAEC's procedures were revised to ensure that waterhammer would not occur under these conditions when well water flow is being restored.

Regarding the potential occurrence of two-phase flow conditions within containment air coolers that might affect the assumptions used for heat removal during design-basis accidents, the DAEC containment air coolers are not relied upon to mitigate design-basis accidents and would likely be isolated. Therefore, this aspect of the GL 96-06 does not give rise to a safety concern at DAEC.

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Table 6.2-1

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.)
Drywell floor water hold-up before spill over to suppression pool		1,955 ft^3
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 6.2-2

PRIMARY CONTAINMENT PENETRATION SCHEDULE

Penetration Number	Number Required	Pipe Schedule or Wall Thickness	Sleeve or Line Size	Description
Drywell				
X-1	1	--	12 ft 0 in. I.D.	Equipment hatch/personnel lock
X-2	1	--	12 ft 0 in.	Equipment hatch
X-4	1	--	24 in. I.D.	Head access hatch
X-5A through H	8	--	5 ft 6 in. I.D.	Vent line
X-6	1	1.5 in.	24 in.	Control rod drive removal hatch
X-7A through D	4	2 in.	36 in.	Main steam line
X-8	1	80	18 in.	Condensate drain
X-9A and B	2	2 in.	36 in.	RPV feedwater
X-10	1	80	18 in.	Steam to RCIC turbine
X-11	1	1.5 in.	28 in.	Steam to HPCI turbine
X-12	1	2 in.	36 in.	RHR suction (Recirculation)
X-13A and B	2	2 in.	36 in.	RHR return to recirculation (LPCI)
X-14	1	1.125 in.	20 in.	Instrumentation
X-15	1	1.125 in.	20 in.	Reactor water cleanup supply
X-16A and B	2	1.5 in.	26 in.	Core spray
X-17	1	1.125 in.	20 in.	Spare, with decommissioned head spray piping in place, inside drywell.
X-18	1	80	6 in.	Spare
X-19	1	80	6 in.	Floor drain sump
X-20	1	80	3 in.	Demineralized water supply
X-21	1	80	3 in.	Service air

PRIMARY CONTAINMENT PENETRATION SCHEDULE

Penetration Number	Number Required	Pipe Schedule or Wall Thickness	Sleeve or Line Size	Description
Drywell (continued)				
X-22	1	80	10 in.	Nitrogen supply
X-23A and B	2	80	12 in.	Well cooling water supply
X-24A and B	2	80	12 in.	Well cooling water return
X-25	1	80	18 in.	Drywell vent
X-26	1	80	18 in.	Drywell purge inlet
X-28	1	80	12 in.	RPV level and pressure, pressure above core
X-29	1	80	12 in.	RPV level and pressure, pressure above core, drywell liquid level
X-30	1	80	12 in.	Main steam flow
X-31	1	80	12 in.	Recirculation loop pressure, drywell pressure
X-32	1	80	12 in	Recirculation loop flow, drywell pressure, recirculation pump seal, N_2 compressor suction
X-33	1	80	12 in.	Recirculation loop flow and pump seal water pressure
X-34	1	80	12 in.	Main steam flow
X-35A through D	4	80	1-1/2 in.	TIP drives and purge
X-36	1	80	16 in.	CRD return
X-37A through D	90	160	1 in.	CRD insert
X-38A through D	90	160	1 in.	CRD withdraw
X-39A and B	2	80	10 in.	Containment spray

PRIMARY CONTAINMENT PENETRATION SCHEDULE

Penetration Number	Number Required	Pipe Schedule or Wall Thickness	Sleeve or Line Size	Description
Drywell (continued)				
X-40A and B	2	80	12 in.	Jet pump instrument flow, below and above core pressure, drywell pressure, postaccident sample
X-40C and D	2	80	12 in.	Jet pump instrument flow, below and above core pressure, drywell pressure, postaccident sample
X-41	1	80	3 in.	Recirculation loop sample
X-42	1	80	4 in.	Standby liquid control
X-43	1	1.5 in.	30 in.	Spare
X-44	1	1.5 in.	26 in.	Spare
X-45	1	2 in.	36 in.	Spare
X-46	1	80	12 in.	CAMS return, instrumentation
X-47	1	80	10 in.	Spare
X-48	1	80	10 in.	Equipment drain sump
X-49	1	80	12 in.	Recirculation loop differential pressure RCIC steam supply
X-50	1	80	12 in.	Drywell pressure, oxygen sample
X-51	1	80	12 in.	HPCI differential pressure, drywell pressure and level
X-52	1	80	12 in.	Recirculation loop differential pressure and HPCI steam supply
X-53	1	80	6 in.	Spare
X-54	1	80	12 in.	Reactor building cooling water, out

PRIMARY CONTAINMENT PENETRATION SCHEDULE

Penetration Number	Number Required	Pipe Schedule or Wall Thickness	Sleeve or Line Size	Description
Drywell (continued)				
X-55	1	80	12 in.	Reactor building cooling water, in
X-56	1	80	12 in.	Recirculation loop flow and RCIC steam supply, d/p, CAMS supply
X-57	1	80	12 in.	Recirculation loop pressure and flow
X-58A through H	8	--	16 in.	Stabilizer access ports
X-100A through G	7	80	10 in.	Neutron monitoring
X-101A through D	4	80	10 in.	Power to recirculation pump
X-102	1	80	10 in.	Main steam flow
X-103	1	80	10 in.	Reactor vessel thermocouples
X-104A through D	4	80	10 in.	CRD position indicators
X-105A through D	4	80	10 in.	Power and control
X-106A through E	5	80	10 in.	Power and control
X-107	1	80	8 in.	Containment level, Reactor Vessel level, spare
X-108	1	80	8 in.	Containment level, Reactor Vessel level, spare
Torus				
N-200A and B	2	--	48 in. I.D.	Access hatch
N-201A through H	8	--	4 ft 9 in.	Vent line
N-202A through H	8	80	18 in.	Vacuum breakers to drywell

PRIMARY CONTAINMENT PENETRATION SCHEDULE

Penetration Number	Number Required	Pipe Schedule or Wall Thickness	Sleeve or Line Size	Description
Torus (continued)				
N-203A and B	2	80	1 in.	Spare
N-205	1	80	18 in.	Torus vent
N-206A through D	4	80	1 in.	Liquid level indicator and drywell liquid level
N-207A through H	8	80	1 in.	Vent line drain
N-208A through F	6	80	10 in.	Relief valve discharge
N-209A through D	4	80	1 in.	Air and water temperature and drywell liquid level
N-210A and B	2	80	12 in.	RHR test
N-211A and B	2	80	4 in.	Suppression pool spray
N-212	1	80	8 in.	RCIC turbine exhaust steam
N-213A and B	2	80	8 in.	Torus drain and level
N-214	1	1.218 in.	20 in.	HPCI turbine exhaust steam
N-215	1	80	1 in.	Spare
N-216	1	80	4 in.	Spare
N-217	1	80	2 in.	Core spray relief return
N-218	1	80	2 in.	Core spray relief return
N-219	1	80	10 in	RHR relief, HPCI exhaust vacuum breaker
N-220	1	80	18 in.	Torus purge inlet
N-221	1	80	2 in.	Spare
N-222	1	80	2 in.	HPCI condensate

Table 6.2-2

PRIMARY CONTAINMENT PENETRATION SCHEDULE

Penetration Number	Number Required	Pipe Schedule or Wall Thickness	Sleeve or Line Size	Description
Torus (continued)				
N-223	1	100	8 in.	RHR relief
N-224	1	--	6 in.	RCIC suction
N-225A and B	2	--	24 in.	RHR suction
N-226	1	--	14 in.	HPCI suction
N-227A and B	2	--	12 in.	Core spray
2012-011 N-229A, B, C, F, and G	5	80	1 in.	Vacuum breaker actuating nitrogen, CAMS
N-229D and E	2	80	1 in.	Spare
N-229H	1	80	1 in.	Postaccident liquid sample return
2016-003 N-230A	1	80	12 in.	Hardened Containment Vent
N-230B	1	80	12 in.	Vacuum breaker position indicator
N-231	1	80	20 in.	Vacuum breaker, reactor building
N-232A through H	8	--	1 in.	Suppression pool temperature monitor system thermowells
N-233A through H	8	--	1 in.	Suppression pool temperature monitor system thermowells

Table 6.2-3

PRIMARY CONTAINMENT MATERIAL STRESSES (ksi)

Material Code Designation	Minimum Ultimate Tensile	Minimum Yield (Ambient)	Code Allowable Tensile to 650°F	Notes
Plate:				
ASME-SA516 GR 70 fabricated to SA300	70	38	17.5	Yield at 300°F = 33.7 ksi includes drywell to torus vent pipes
ASME-SA240 TP304	75	30	13.75	Yield at 300°F = 22.0 ksi
Pipe:				
ASME-SA333 GR 1	55	30	13.75	Yield at 300°F = 26.6 ksi
or ASME-SA333 GR 6	60	35	15.0	Yield at 300°F = 31.0 ksi
ASME-SA312 TP304	75	30	18.75	
Forgings:				
ASME-SA350 LF1	60	30	15	
ASME-SA350 LF2 (code case 1431)	70	0	17.5	
ASME-SA105 GR 2	70	36	17.5	
Bolting:				
ASME-SA193 B7	125	105	25	Through 2-1/2 in.Ø
or ASME-SA320 L43	125	105	25	Through 4.in.Ø
ASME-SA193 B8	75	30	12	
ASME-SA194 GR 4	--	--	--	Specification Reg. proof test

Table 6.2-3

PRIMARY CONTAINMENT MATERIAL STRESSES (ksi)

Material Code Designation	Minimum Ultimate Tensile	Minimum Yield (Ambient)	Code Allowable Tensile to 650°F	Notes
Structural:				
ASTM-A36	58	36	22	Not to be used for pressure part nor within 4 in. of pressure part
ASTM-A53 GR B	58	35	15	
ASTM-A106 GR B	58	35	15	
ASTM-A307 GR B	--	--	10	AISC Shear
ASTM-A514	105-135	100	--	
ASME-SA516 GR 70	70	--	17.5	

Table 6.2-4

GENERAL DRYWELL DESIGN CONDITIONS

Design Pressures

Internal	- maximum	62 psig at 281°F
	- design	56 psig at 281°F
	- operating	<2 psig at 150°F
External	- maximum	2 psig at 281°F
	- design	2 psig at 281°F
	- operating	<2 psig at 150°F

Earthquake

Horizontal (See curves in Figure 6.2-72)	
Vertical (reviewed for 0.108g)	5.3%g

Weight of Compressible Material

None

Bellows Loads

Inside	- operating	↑60 lb/in.
	- refueling	0
Outside	- operating	↓30 lb/in.
	- refueling	↑125 lb/in.

Loads To Be Transferred Through Drywell

At bottom of drywell elevation = [redacted]

Vertical	- normal	6,400,000 lb
	- refueling	6,510,000 lb
Horizontal		1,000,000 lb
Moment		480,000,000 in.-lb

At stayed elevation = [redacted]
(maximum at any one stabilizer)

Without jets	200,000 lb
With jets	275,000 lb

Wind (prior to construction of the reactor building)

In accordance with ASCE paper 3269, "Wind Forces on Structures"

Table 6.2-4

GENERAL DRYWELL DESIGN CONDITIONS

Top of Refueling Water

To be at elevation [redacted]

Miscellaneous Live Loads

Personnel lock floor	5,500 lb
Equipment access opening	80,000 lb
Upper beam seats	766,800 lb
Lower beam seats	640,000 lb

Weights of all appurtenances are estimated weights and may be heavier than the actual weights.

Jet Forces

Location:

On spherical part of drywell (2.19 ft^3 subject to jet force)	393 kip (maximum)
On cylindrical part and sphere transition to cylinder (1.80 ft^3 subject to jet force)	325 kip (maximum)
On closure head (0.18 ft^3 subject to jet force)	32.6 kip (maximum)
Steam and/or water temperature	300°F
Shell temperature	150°F

Stabilizer Loads

Seismic force	200 kip
Seismic plus jet forces	275 kip
Seismic plus flooded condition	200 kip

NOTE: The vessel was designed and analyzed for the conditions included in this table, in accordance with the Bechtel specification.

Table 6.2-5

GENERAL SUPPRESSION CHAMBER DESIGN CONDITIONS

Design Pressures	
Internal - maximum	62 psig at 281°F
- design	56 psig at 281°F
- operating	<2 psig at 50-150°F
External - maximum	2 psig at 281°F
- design	2 psig at 281°F
- operating	<2 psig at 50-150°F
Earthquake	
Horizontal (reviewed for 0.30g)	12%g
Vertical (reviewed for 0.108g)	5.3%g
Water Volumes	
Normal operating	58,900 ft^3
Accident and test	61,500 ft^3
Catwalks	
Live load	75 lb/ft^2
Jet Forces	
Downcomer (24-in. diameter)	21 kip (maximum)

NOTE: Weights of appurtenances are estimated weights and may be more than actual weight.

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[1]
Vertical load, seismic	X	X	X	X	X	X	X	X	X	E or E[1]
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 loads						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.

Table 6.2-8

SUPPRESSION CHAMBER LOADING COMBINATIONS

CB&I Case Number

Loads	(1) Overload Test	(2) Final Test	(3) Construction	(4) Normal Operating	(5) Accident	(6) Flooding	Load Symbol[a]
Dead load, vessel and attachments	X	X	X	X	X	X	D
Suppression pool water	X	X		X	X	X	D
Pressure (psi)							
Positive	70	56		2	56		R
Negative				2	2		R
Seismic							
Vertical	X	X	X	X	X	X	E or E'
Lateral	X	X	X	X	X	X	E or E'
Vent thrusts	X	X		X	X		R
Contained air	X	X					D
Live loads on catwalks and platforms			X	X			D
Jet forces on downcomer pipes					X		R

[a] Used to indicate load combinations in Tables 6.2-9 through 6.2-14.

Table 6.2-9

DRYWELL MEMBRANE STRESSES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stresses (ksi) σt	Maximum Stresses (ksi) $\sigma 1$	Location
The vessel is bulb shaped and houses the primary nuclear reactor vessel, the coolant recirculation lines, pumps, etc. In case of operating accident, the vessel must contain the steam released within the drywell and conduct this steam to the suppression chamber.	ASME Code, Section III, Including Code Cases 1330, 1177, and 1413, and addenda as of summer 1968 Vessel Class B		Primary general membrane PM = 17.5 at 281°F	Circumferential	Meridional	
		D + R + E		8.75		Head
		D + R + E		6.32	3.15	Cylinder
	Stress intensities and limits are defined per ASME Code, Section III, paragraph N-413					
Structural steel plate material is ASME SA-516 to SA-300; minimum service temperature is 30°F, with Charpy impact requirements at a maximum 0°F.		D + R + E		16.18		Knuckle at [redacted]
	End conditions are found with methods described in Ref. 30	D + R + E		15.46		Sphere

Table 6.2-9

DRYWELL MEMBRANE STRESSES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stresses (ksi) σt	Maximum Stresses (ksi) $\sigma 1$	Location
Seismic design load includes load due to vertical acceleration equal to 5.3%g. For other design criteria, see Table 6.2-4.		D + R + E'	Yield 33.7 at 300°F	16.3		Knuckle at [redacted]
After an accident, the drywell may be flooded up to el. 854 ft 6 in.; stresses shall be below yield point.		D + R + E' D + R + E'		15.99 10.84	13.51 6.96	Sphere Embedment at [redacted]
Accident load (R) includes pressure and temperature in the primary containment.		D + E + Flood	Yield 38.0 at ambient Ultimate 70.0 Critical buckling 24.47 (meridional)	22.07	9.75	Embedment at [redacted]

NOTE: For simplicity, only additive stresses are shown.

Table 6.2-10

JET IMPINGEMENT FORCE STRESSES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress(ksi)	Maximum Stress (ksi)	Reference	Location
A jet force is assumed to occur in any direction within the drywell.	Find maximum load on shell prior to breaking	D + R	30.33	29.25	Ref. 24 (Case 20)	Personnel lock door
The force is calculated as 1250 psi pressure acting on the area equal to the cross section of ruptured pipe.		D + R	30.33	29.69	Ref. 24 (Case 20)	Top closure head
The jet impingement force is considered to act coincidentially with the design internal pressure and 150ºF shell temperature.		Experimental test in 1964	CB&I experimental investigation proved that 3/4-in.-thick plate can deform 3 in. without failure.			Spherical shell and lower cylinder
Temperature of the shell and welds is assumed to be 300ºF if hit directly by jet.		D + R D + R	30.33 27.90	28.78 26.86	Ref. 25	Cylindrical shell Upper spray header pipe
Local thermal effects and dynamic jet effects are disregarded.		D + R D + R	21.70 30.33	20.60 30.21		Upper spray header weld Upper spray header support

Table 6.2-10

JET IMPINGEMENT FORCE STRESSES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stress (ksi)	Reference	Location
There is a 2-in. gap between drywell shell and backup concrete.		D + R	27.90	22.18		Upper spray header inlet pipe
	Yield taken from ASME Code, Section III, Table N-424, at pertinent temperature	D + R	27.90	26.70		Lower spray header pipe
Material is ASME SA-516, Grade 70, to SA-300 or SA-514 where noted.	Assume shear-type failure of weld and its stress equal to 7/10 of parent material	D + R	21.70	20.67		Lower spray header weld
		D + R	30.33	28.56		Lower spray header support
For the load combination D + R + E, the effect of E is insignificant when compared with the effect of the jet impingement force.						

Table 6.2-11

DRYWELL STABILIZER SHEAR LUG STRESSES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stresses (ksi)	Location
		Male Lug			
The stabilizer mechanism transfers into building the reaction due to seismic loads or seismic plus jet loads acting on the drywell, reactor, and shield; or seismic, plus flooding of the drywell.	ASME Code, Section III, including addenda as of Summer 1968, Vessel Class B	D + E	B = 18.0 (plate) C = 18.0 (weld)	B = 8.2 (plate) C = 9.6 (weld)	Stabilizer shear lug for drywell at [redacted]
		D + R + E	B = 36.0 C = 31.9	B = 11.2 C = 12.5	
The geometry of the stabilizer allows for radial and vertical movements due to pressure and temperature.	Ref. 30, Case 22 for plate	D + E + Flood	B = 36.0	B = 16.4	

Table 6.2-11 Sheet 2 of 2

DRYWELL STABILIZER SHEAR LUG STRESSES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stresses (ksi)	Location
		Female Lug			
Materials for components attached to drywell are ASME SA-516, Grade 70, to SA-300, per ASME Code, Section III; those for concrete anchors are A-36 per AISC-1963.	σ_C = combined stress	D + E	C = 19.0 (plate)	C = 6.8	
			C = 11.4 (weld)	C = 5.9	
	$\sqrt{(\sigma_B+\sigma_T)^2+(\sigma_S)^2}$ where: B = bending stress	D + R + E	C = 38.0	C = 8.9	
	T = tensile stress		C = 22.8	C = 7.8	
	S = shear stress	D + E + Flood	C = 38.0	C = 24.7	
			C = 22.8	C = 21.5	

Table 6.2-12

STRESSES IN TORUS SHELL AND SUPPORTS

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stresses (ksi)	Location
The vessel is in the shape of a torus supported on 32 columns and is located below the drywell; 8 vent pipes connect the drywell and the torus. The torus contains a large amount of water for condensation of accident steam.	ASME Code, Section III, and addenda as of Summer 1968, Vessel Class B	D + R + E	F_t = 17.50	f_t = 17.30	Torus top shell
		D + R + E	F_t = 17.50	f_t = 17.50	Torus bottom shell Torus bottom shell
		D + Flood	F_y = 38.00	f_t = 16.90	Torus outside column
		D + R + E	F_a = 17.83	f_a = 10.80	
		D + E + Flood	F_a = 21.60	f_b = 4.25	Torus outside column
		D + E + Flood	F_a = 36.00	f_a = 17.84	Torus outside column
		D + E + Flood	F_b = 36.00	f_b = 0.90	Torus outside column
Structural steel plate material is ASME SA-516 to SA-300. Minimum service temperature is 30□F, with Charpy impact requirements at a maximum of 0□F.	Columns per AISC Section 1.6.1, 6th Edition, 1963	D + R + E	F_t = 17.50	f_t = 15.82	Ring girder flange
		D + R + E	F_t = 17.50	f_t = 11.76	Ring girder shell Ring girder flange
		D + E + Flood	F_t = 38.00	f_t = 19.74	

Table 6.2-12

STRESSES IN TORUS SHELL AND SUPPORTS

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stresses (ksi)	Location
		D + E + Flood	$F_t = 38.00$	$f_t = 13.81$	Ring girder shell
		D + E	$F_a = 11.57$	$f_a = 0.91$	Header supporting column
After an accident the drywell, vent system, and torus may be flooded up to el. [redacted] Stresses in shell shall be below yield point.		D + R + E	$F_c = 13.75$	$f_c = 7.15$	
		D + R + E	$F_{bear} = 19.20$	$f_{bear} = 14.00$	Pin header supporting columns
			$F_b = 18.00$	$f_b = 10.55$	
			$F_v = 9.60$	$f_v = 3.96$	
Support column material is ASTM A-36.		D + R + E	$F_t = 17.50$	$f_t = 13.40$	Vent header

Table 6.2-13

DRYWELL STABILIZER SHEAR LUG STRESSES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stresses (ksi)	Location
The saddles, located below the torus at 90□ intervals, are oriented so that either set of two opposite saddles will withstand an assumed 0.12g horizontal seismic acceleration (E).	Ref. 26	D + E	F_v = 14.40	f_v = 3.07 (shear)	Pin
		D + E	F_b = 27.00	f_b = 4.06 (bending)	
		D + E	F_t = 18.96	f_t = 5.87 (tension)	2-1/4-in.Ø anchor bolt
		D + E	F_s = 15.80	f_s = 4.62	1-1/2-in. thick upper plate weld
		D + E	F_s = 15.80	f_s = 4.62	1-1/2-in. thick lower plate weld
Materials: Concrete, ACI 318-63 (f'= 4000 psi at 28 days)					
Pin, ASTM A-105, Gr II (F_y = 36 ksi)		D + E	F_c = 1.0	f_c = 2.32	Concrete bearing
Bolts, ASTM Designation A-36		D + E + Flood	F_v = 28.8	f_v = 6.91	Pin
Plates, ASTM Designation A-36		D + E + Flood	F_b = 54.0	f_b = 9.13	Pin

Table 6.2-13

DRYWELL STABILIZER SHEAR LUG STRESSES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Stress (ksi)	Maximum Stresses (ksi)	Location
Vertical seismic load is carried by supporting columns, not by saddles.		D + E + Flood	$F_t = 36.0$	$f_t = 13.11$	2-1/4-in.Ø anchor bolt
		D + E + Flood	$F_s = 21.01$	$f_x = 8.85$	1-1/2-in. thick upper plate weld
Assume accident condition for water volume (61,500 ft^3).		D + E + Flood	$F_s = 21.01$	$f_s = 10.38$	1-1/2-in. thick lower plate weld
Maximum stress may not exceed normal code-allowable values.		D + E + Flood		$f_c = 5.22$	Concrete bearing

Table 6.2-14

MAXIMUM STRESSES IN DRYWELL PENETRATION NOZZLES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Total Stress (ksi)	Maximum Stresses (ksi)	Elevation Penetration And Service
Pipe penetration for process lines must accommodate thermal movement and must resist relatively high thermal stress; therefore, expansion bellows are required. The process lines are anchored outside the containment to limit the movement relative to the containment. This design assures integrity of the penetration (see Figure 6.2-2).	Welding Research Council Bulletin	D + R	52.5	37.66	[redacted] X-7A through X-7D, primary steam
		D + R	52.5	37.46	[redacted] X-9A through X9B, primary feedwater
The penetration nozzle is welded to the drywell. The process line, which passes through the nozzle, is free to move axially, with the two-ply bellows joint accommodating the movement. A guard pipe, which surrounds the process line, is designed to protect the bellows should the process line fall within the penetration. The two-ply expansion joint permits periodic leak testing of the bellows during normal operation of the plant by pressurizing the annular gap between the two plies.		D + R	52.5	37.76	[redacted] X-11, HPCI steam to turbine
		D + R	52.5	37.48	[redacted] X-12 RHR supply
		D + R	52.5	37.22	[redacted] X-13 A and B, RHR system return

Table 6.2-14 Sheet 2 of 2

MAXIMUM STRESSES IN DRYWELL PENETRATION NOZZLES

Description/Criteria	Methods of Analysis	Load Combination	Maximum Allowable Total Stress (ksi)	Maximum Stresses (ksi)	Elevation Penetration And Service
The design of the penetration takes into account the simultaneous stress associated with internal pressure, thermal expansion, dead loads, seismic loads, and loads associated with loss-of-coolant accident. Restraint lugs on the guard pipe are provided to transfer any load associated with random failures of the process line directly to the vessel without causing any bending moment stresses. The penetration nozzle design takes into account the jet force loading resulting from the failure. Structural steel plate material is ASME SA-516-70 to SA-300. Maximum allowable total stress is 3 S_m.		D + R	52.5	37.23	[redacted] X-14, cleanup supply
		D + R	52.5	35.68	[redacted] X-16 A and B, core spray
		D + R	52.5	37.23	[redacted] X-17, RPV head spray

Table 6.2-15
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Table 6.2-16
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Table 6.2-17
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Table 6.2-18

PRIMARY CONTAINMENT ATMOSPHERE COOLING SYSTEM DESIGN PARAMETERS

Parameter	Normal	Maximum[a]
Average Drywell air/N_2 temperature	≤135°F	135°F
Recirculation pump motor area temperature	≤128°F	128°F
Leaving air/N_2 temperature from recirculating pump motor cooling units	≤101°F	104°F
Average Entering air/N_2 temperature to cooling units	≤135°F	148°F
Average Leaving air/N_2 temperature from cooling units	75°-95°F	84°-98°F
Average Leaving air/N_2 temperature from induction cooling units	106°F	117°F
Average Cooling water supply temperature	≤54°F	≤54°F
Cooling water return temperature	88°-100°F	95°-112°F
Drywell heat load	3.2×10^6 Btu/hr	3.53×10^6 Btu/hr
Total cooling capacity of units	5.13×10^6 Btu/hr	5.85×10^6 Btu/hr
Total fan capacity of cooling units	102,000 cfm	106,300 cfm
Total cooling air/N_2 circulation flow	118,200 cfm	122,500 cfm
Total fan brake	134[b]hp	140 hp
Drywell temperature 10 hr after shutdown	105°F	105°F

[a] As a result of the extra load from a scram of the control rod drives.

[b] Total system fan horsepower for one fan per cooling unit. The six original units have two fans. The two retrofitted units each have a single fan.

Table 6.2-19
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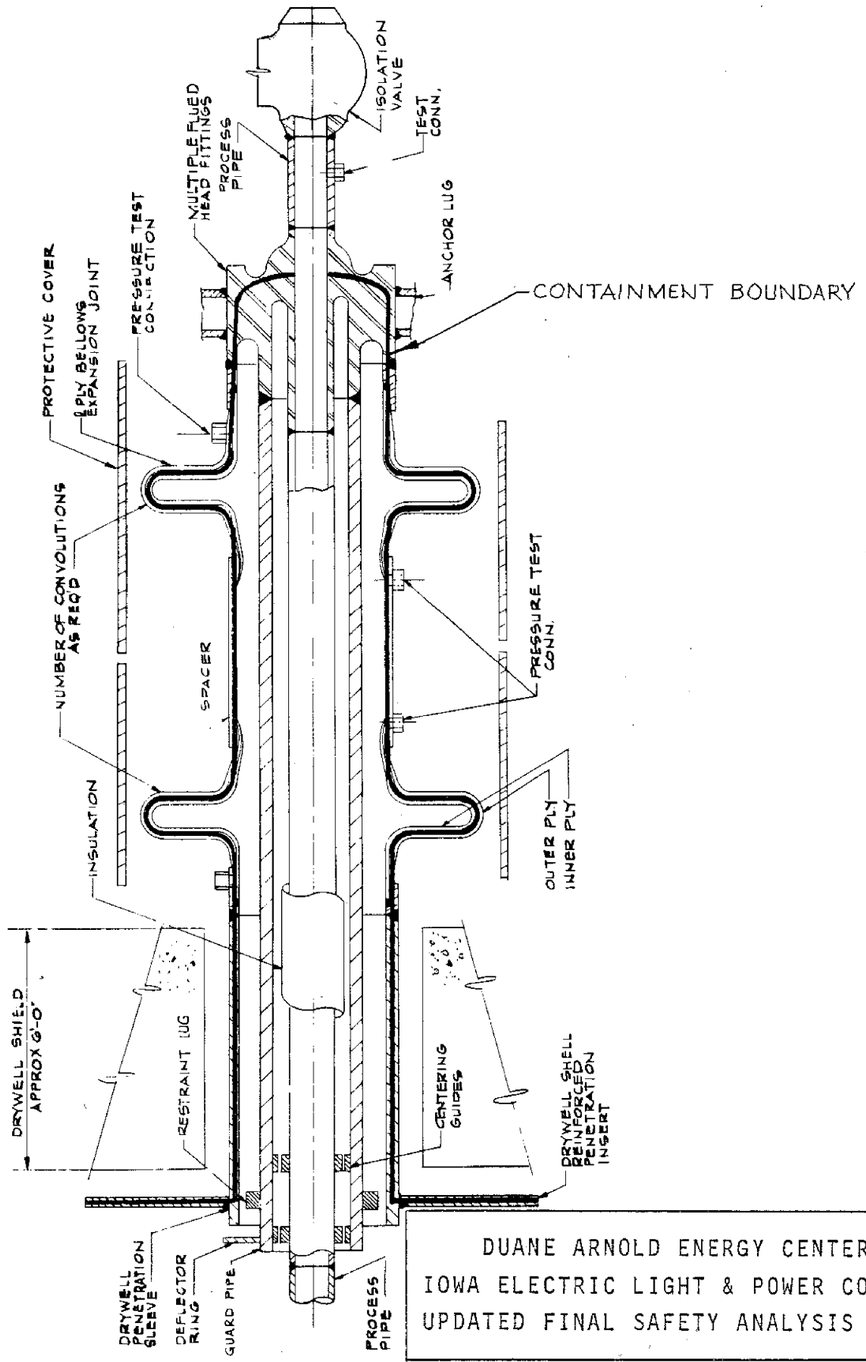
[redacted]



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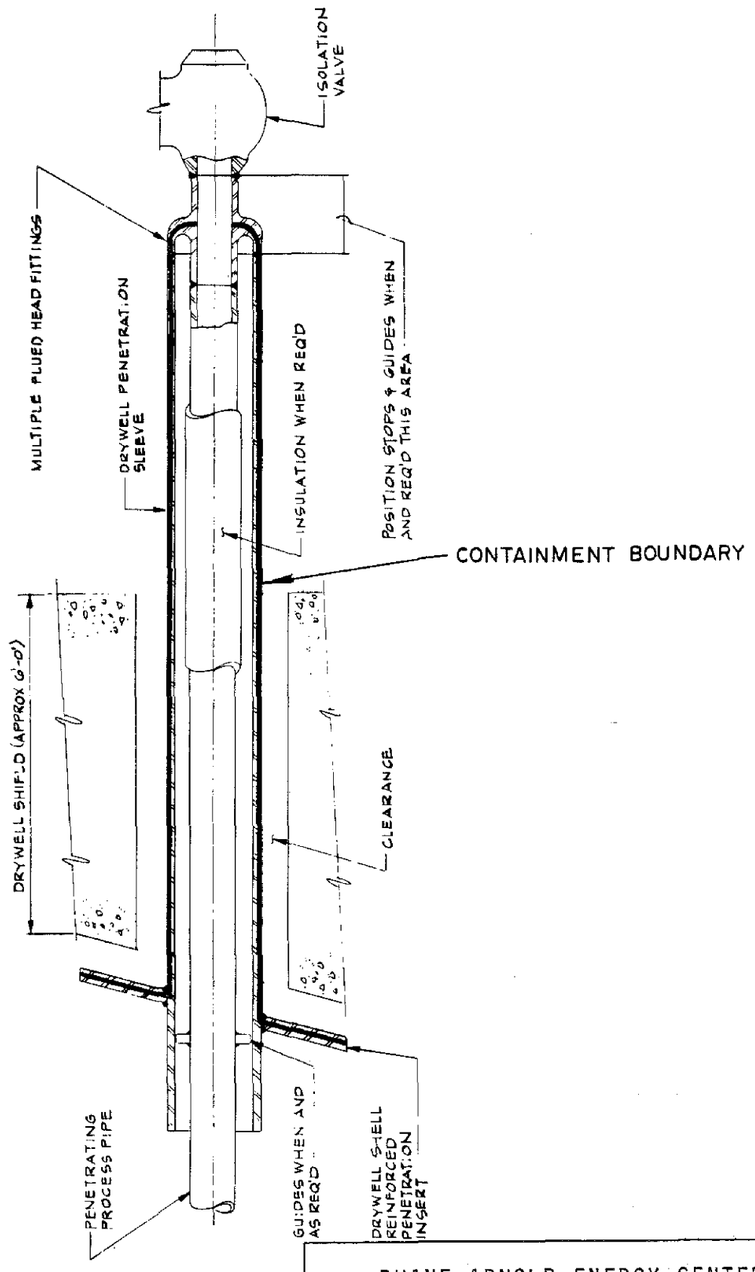
Typical Piping Penetration/Containment Boundary

Figure 6.2-4



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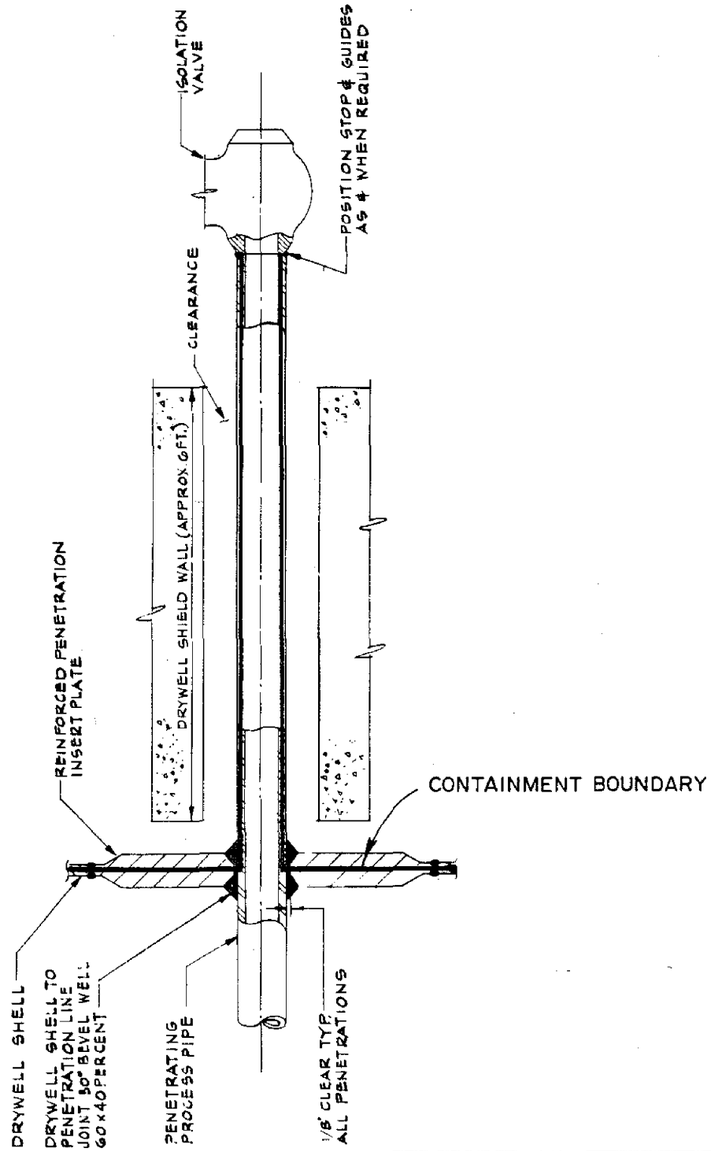
Typical Piping Penetration/Containment Boundary

Figure 6.2-5



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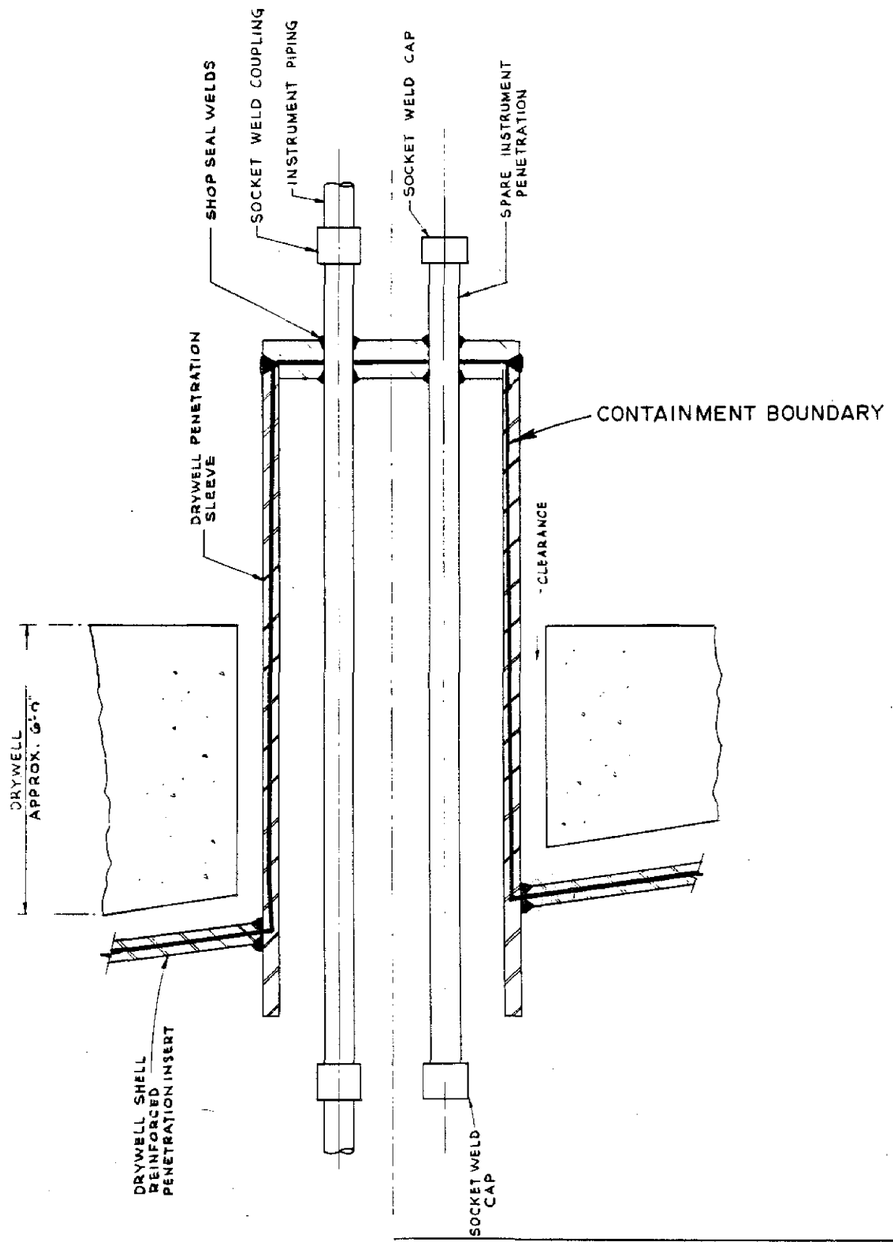
Typical Piping Penetration/Containment Boundary

Figure 6.2-6



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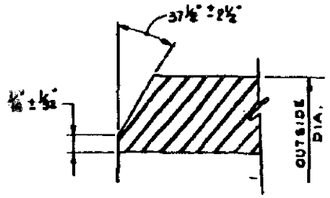
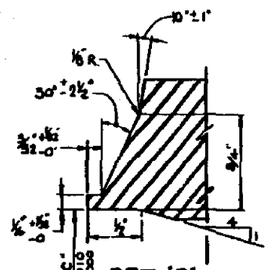
Typical Instrument Penetration/Containment Boundary

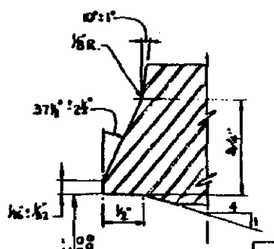
Figure 6.2-7



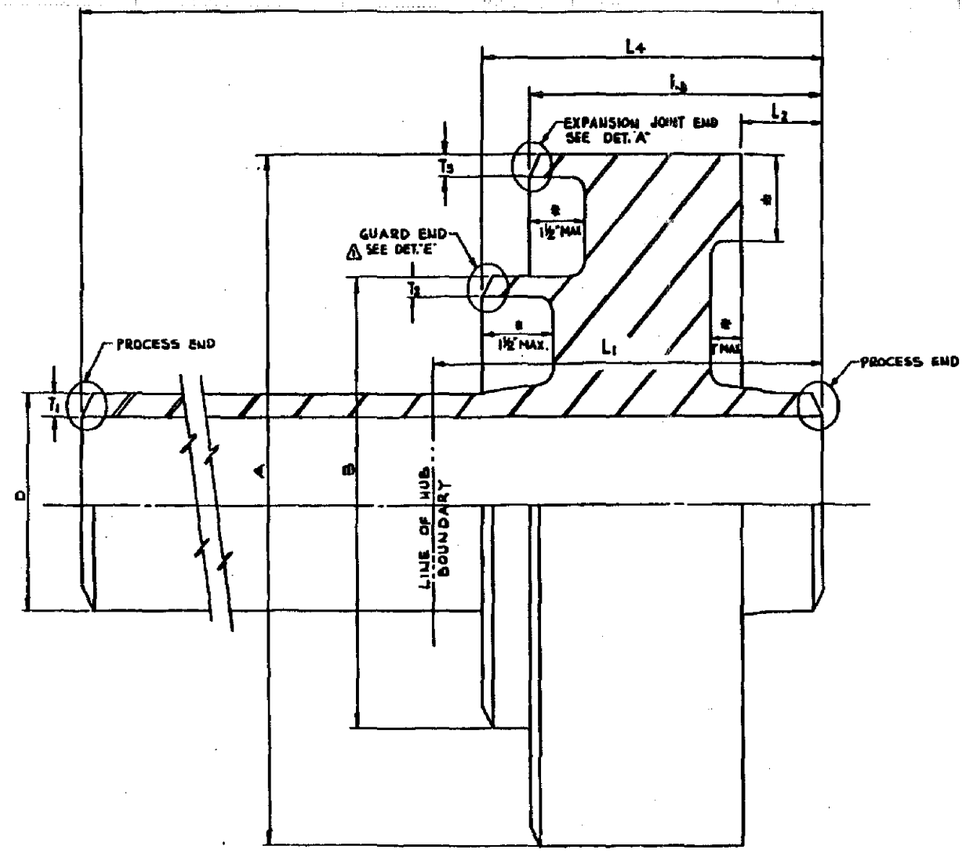
DET. "A"
WELD END PREP.



DET. "B"
WELD END PREP.

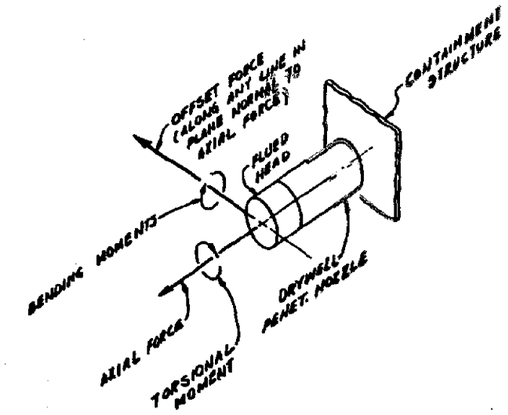


DET. "E"
WELD END PREP.
⚠



FLUED HEAD – CLASS I

SUBJECT TO INSERVICE INSPECTION ASME CODE SECT. XI



NOTE:
1. DIMENSIONS MARKED THUS ✱ TO BE DETERMINED BY MANUFACTURER.
2. MANUFACTURER SHALL SHOW WEIGHT OF FINISHED ITEMS ON HIS SHOP DRAWINGS.

PENET. NO.	SERVICE	QTY	FLUED HEAD: NOM. SIZE SLVE × GUARD × PIPE	MATERIAL ⚠	CODE ASME SECT II/III	O.D. "A"	O.D. "B"	O.D. "D"	L_1	L_2	L_3	L_4	L_5	NOM. WALL THK. T_1	T_2	T_3	PROCESS PIPE: DESIGN PRESS PSIG	HYDRO TEST	DESIGN TEMP °F	AXIAL FORCE LBS.	BENDING MOMENT FT. LBS.	OFFSET FORCE LBS	TORSIONAL MOMENT FT. LBS	PIPE CLASS	PROC. END WELD DET.	PROC. END "C" DIM.	GUARD END WELD DET.	GUARD END "C" DIM.	CHARPY IMPACT TEMP. °F
X-9A&B	FEEDWATER	2	36"×26"×16"	SA-105-GR. II	CLASS I	36"	26"	16"	16"	5"	14"	15½"	13'-1"	.844	1.000	.375	1295	NOT BY FLUED HEAD MANUFACTURER	573	313,000	1,023,000	313,000	1,023,000	DLA-2	B	14.482	⚠	14.209	-20°
X-10	STEAM TO RCIC TURBINE	1	18"×12"×4"			18"	12.75	4.5	15"	4"	10"	11½"	14'-5"	.337	.406		1240			24,000	51,000	24,000	51,000	DLA-4	A	–		11.498	0°
X-11	STEAM TO HPCI TURBINE	1	28"×20"×10"			28"	20"	10.75	13"		10"	11½"	15'-5"	.594	.812		1240			134,000	323,000	134,000	323,000	DLA-3	B	9.669		10.538	0°
X-12	RHR & SHUT DOWN SUPPLY (SUCT)	1	36"×28"×18"			36"	28"	18"	16"		13"	14½"	13'-8"	.938	1.000		1265			388,000	1,441,000	388,000	1,441,000	DLA-4		16.317		⚠ 16.109	0°
X-13A	RHR & SHUT DOWN RETURN (DISCH.)	1	36"×28"×20"			34"	28"	20"	16"	1½"	13"	14½"	14'-1	1.031	1.000		1438			545,000	1,935,000	545,000	1,935,000	DLA-6		18.155		24.309	0°
X-13B		1	36"×28"×20"							1½"					1.000					545,000	1,935,000	545,000	1,935,000	DLA-5		18.155		24.309	0°
X-15	R.W. CLEAN-UP SUPPLY	1	20"×12"×4"	SA-182-F316		20"	12.75	4.5	13"	4"	10"	11½"	16'-2"	.337	.406		1261			22,000	36,000	22,000	36,000	DCA-6	A	–		11.498	—
X-16A&B	CORE SPRAY PUMP DISCH.	2	26"×18"×8"	SA-105-GR. II		26"	18"	8.625	13"		10"	11½"	15'-3½"	.500	.750		1240			85,000	174,000	85,000	174,000	6-DLA-7 8-DLA-8	B	7.709		16.146	0°
X-17	RPV HEAD SPRAY	1	20"×12"×4"			20"	12.75	4.5	13"		10"	11½"	13'-10"	.337	.406		1240			22,000	31,000	22,000	31,000	DLA-5	A	–		11.498	0°

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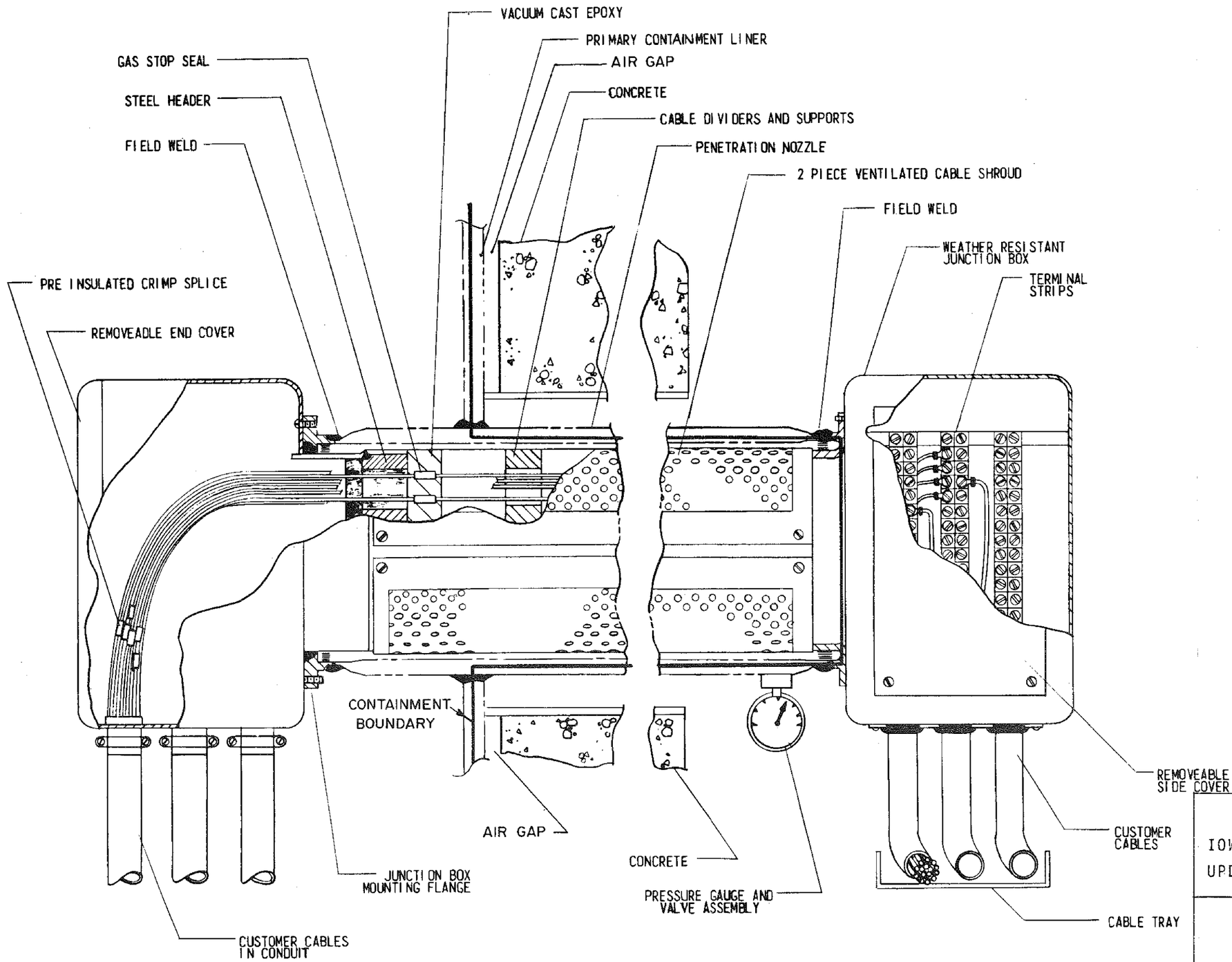
TYPICAL TRIPLE FLUED HEAD FITTING

FIGURE 6.2-8



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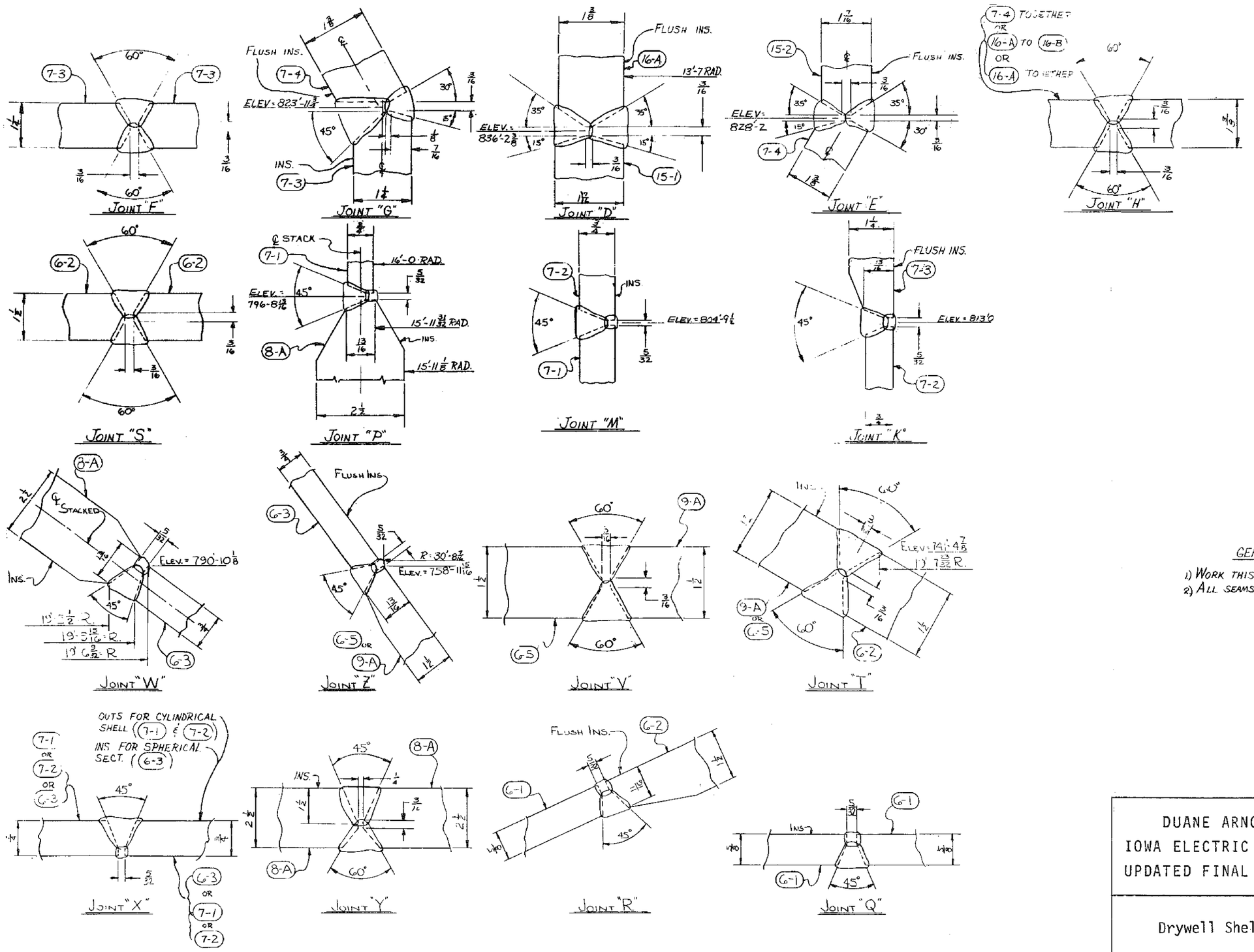
Typical Electrical Penetration/Containment Boundary

Figure 6.2-9

[redacted]



GENERAL NOTES

1) WORK THIS DWG. WITH DWG. #3.
2) ALL SEAMS ON THIS DWG TO BE 100% RADIOGRAPHED.

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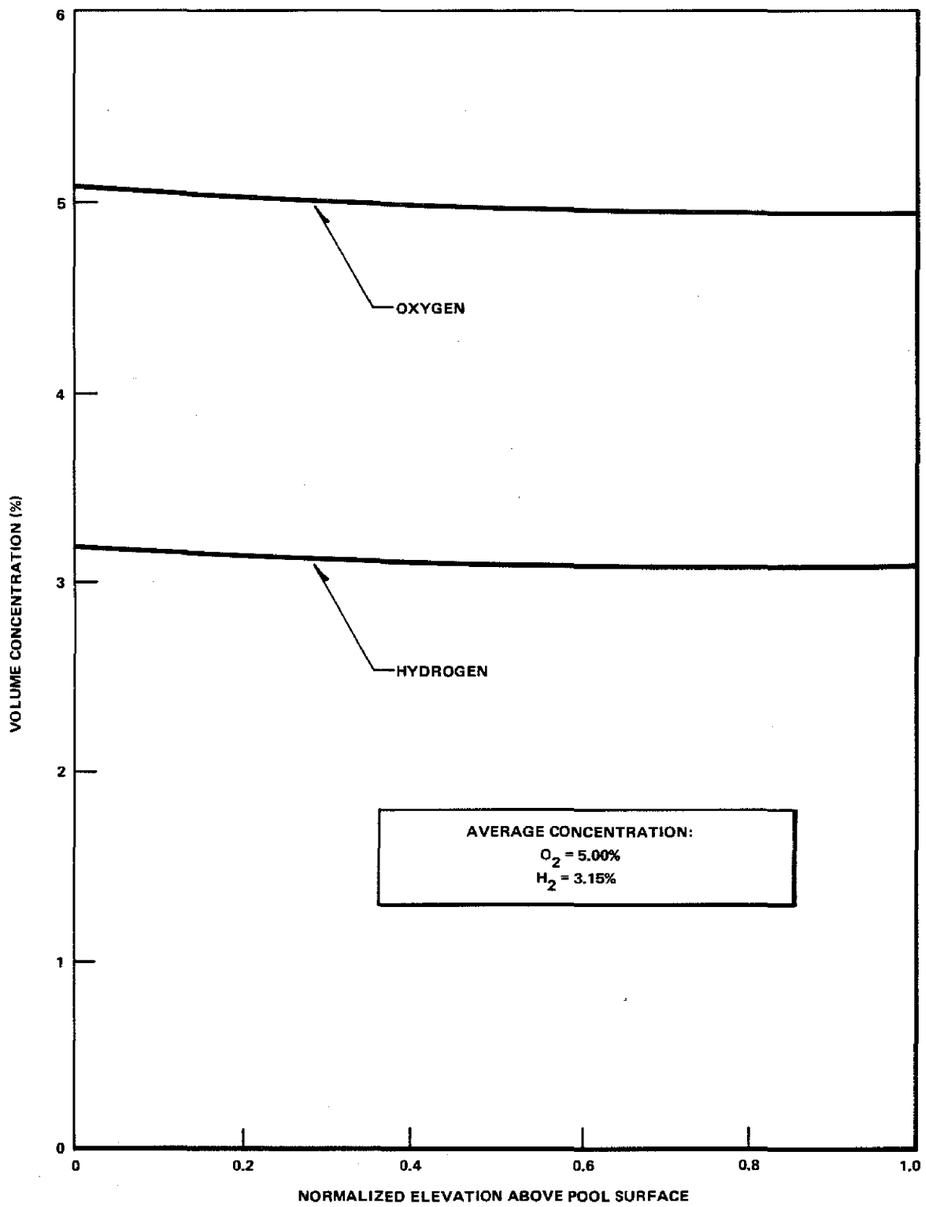
Drywell Shell Field Joint Details

Figure 6.2-16

[redacted]



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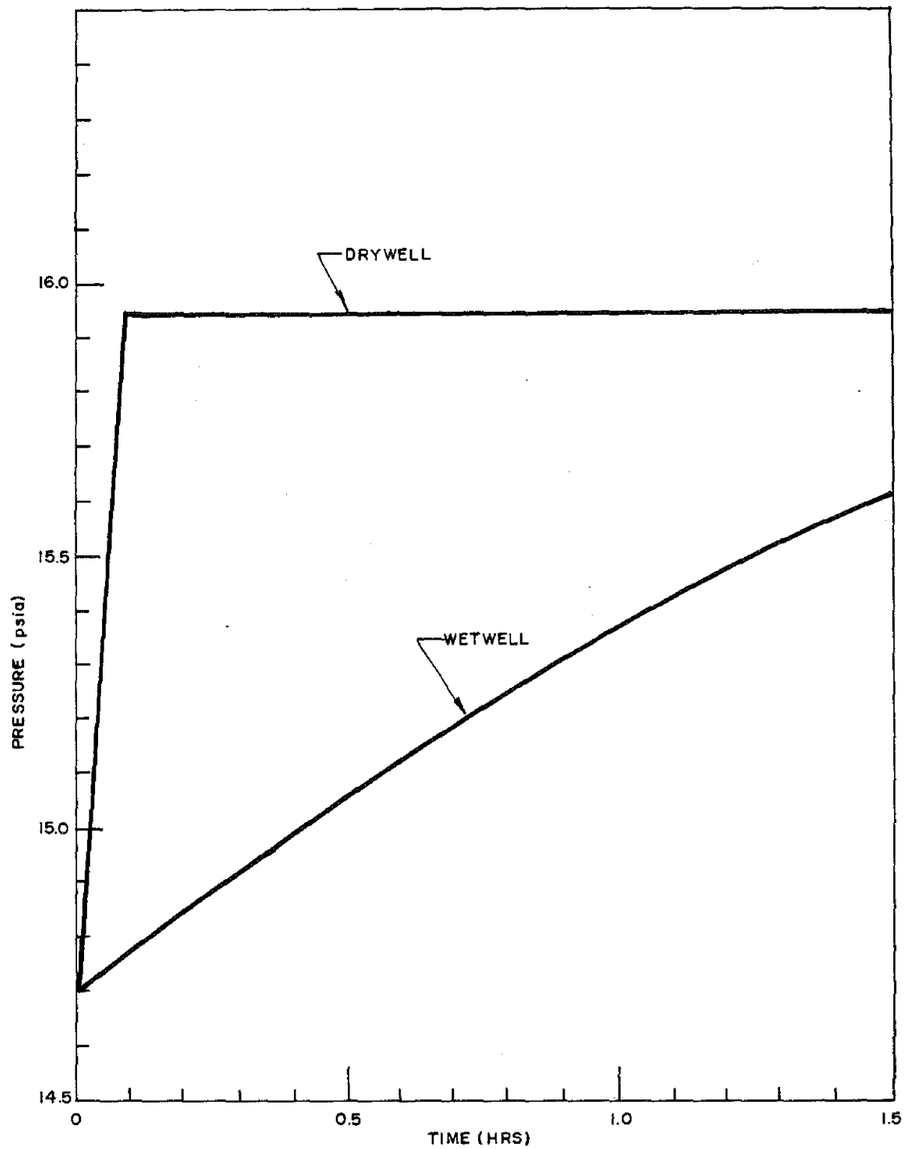
Maximum Hydrogen and Oxygen Concentration Gradients in Suppression Chamber

Figure 6.2-66



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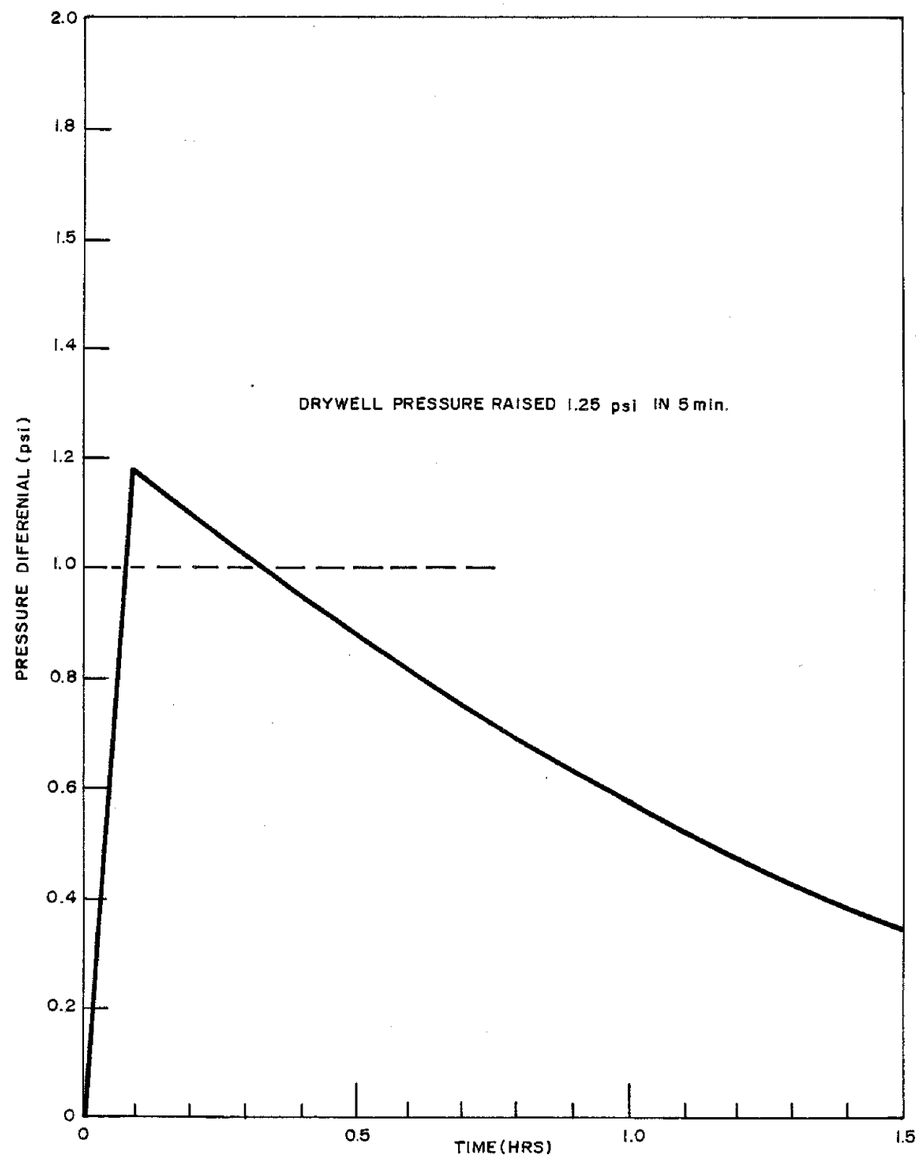
Proposed Drywell/Wetwell
Leak Test Response -
Leak Equivalent to a 1 Inch Orifice

Figure 6.2-70



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Proposed Drywell/Wetwell Leak Test
Pressure Differential Transient Leak
Equivalent to a 1 In. Orifice

Figure 6.2-71

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 were performed (Reference 12) that demonstrated margin was available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. See Section 15.0 for current values used in the LOCA analysis. 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 (Chapter 15.2.1), 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 8.3-1. (Note: These are the original design values. Sensitivity studies were performed (Reference 12) that demonstrated margin was available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. See Section 15.0 for current values used in the LOCA analysis.

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.

As discussed in Section 1.8.1, the low pressure ECCS pumps must rely upon containment (wetwell) pressure for meeting Net Positive Suction Head (NPSH) requirements at elevated suppression pool temperatures, as shown in Figure 5.4-15(a). However, there are limitations on the containment pressure that can be credited for satisfying these NPSH requirements (Fig. 5.4-15(b)).

Requirements for net positive suction head at the centerline of the pump suction nozzles for each pump are given in Figures 6.3-1 (HPCI), 6.3-2 (core spray), and 6.3-3, Sheets 1 and 2 (LPCI). Pump characteristic curves are given in Figures 6.3-4 (HPCI), 6.3-5 (core spray), and 6.3-6 (LPCI).

As part of the plant's review for Generic Letter 2008-01 (Ref. 15 and 16), CS, RHR, and HPCI system suction and discharge piping designs were evaluated for potential sources of gas accumulation. Walkdowns of these piping systems were conducted that confirmed plant as-built configurations were consistent with design drawings/specifications with respect to proper locations for vent valves and piping slope. Plant procedures were reviewed for potential enhancements to preclude unacceptable voiding in these piping systems upon return to service from maintenance or re-alignment to standby readiness conditions from secondary modes of operation. Filling and venting operations were found to the highest potential risk for unacceptable gas accumulation. Procedure upgrades were made, including the addition of ultrasonic testing (UT) inspections of identified piping high points to verify proper filling and venting as part of return to service, and instructions to write Corrective Action Program (CAP) documents whenever voiding is detected.

6.3.2.2.1 High-Pressure Coolant Injection System

The HPCI system consists of a steam turbine that drives a constant-flow pump, system piping, valves, controls, and instrumentation. Figure 7.3-10, Sheets 1 through 3, are the HPCI flow control diagrams and Figure 6.3-1 is the HPCI process diagram. Figure 6.3-7, Sheets 1 and 2, is the HPCI piping and instrumentation diagram.

The principal HPCI system equipment is installed in the reactor building. The turbine-pump assembly is located in a shielded area to ensure that personnel access to adjacent areas is not restricted during the operation of the HPCI system. Suction piping comes from the condensate storage tank and the suppression pool. Injection water is piped to the reactor feedwater pipe at a T-connection. Steam supply for the turbine is piped from a main steam header in the primary containment. This piping is provided with an isolation valve on each side of the drywell barrier. Remote controls for valve and turbine operation are provided in the main control room. The controls and instrumentation of the HPCI system are described, illustrated, and evaluated in detail in Section 7.3.1.1.2.

The HPCI system is provided to ensure that the reactor is adequately cooled to meet the design bases in the event of a small break in the nuclear system and a loss of coolant that does not result in rapid depressurization of the reactor vessel. The HPCI system permits the nuclear plant to be shut down while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which either LPCI operation or core spray system operation maintains core cooling.

If a LOCA occurs, the reactor scrams on the receipt of a low water level signal from the reactor or a high-pressure signal from the drywell. The HPCI system starts when the water level drops to a preselected height above the core, or if high pressure exists in the primary containment. The HPCI system automatically stops when it receives a signal of high water level in the reactor vessel.

The HPCI system is designed to pump water into the reactor vessel for a wide range of pressures in the reactor vessel. Two sources of water are available. Initially, the system uses demineralized water from condensate storage. Approximately 75,000 gal of the 400,000 gal condensate storage are held in reserve for the HPCI system and the RCIC system. System demands on condensate storage other than the HPCI system and RCIC system will draw from an elevated tank connection with the exception of the core spray outlet, which is connected to the RCIC penetration by two locked-closed valves (see Figure 7.3-3). This isolation arrangement is in accordance with the established HPCI/RCIC system design requirements. This tank connection is set at a level so that approximately 75,000 gal will be below the intake and unavailable to these other systems. Both the HPCI system and RCIC system connect separately to the condensate storage tank near the bottom. Should the condensate storage tank be drawn down to a low level, automatic transfer to the suppression pool occurs. Water from either source is pumped into the reactor vessel via the feedwater sparger, causing mixing with the hot water or steam in the reactor pressure vessel.

To ensure positive suction head to the pump, the pump is located below the level of the condensate storage tank and below the water level in the suppression pool. Pumps meet net positive suction head (NPSH) requirements by providing adequate suction head and adequate suction line size.

The HPCI system turbine-pump assembly and piping are located so as to be protected from the physical effects of design-basis accidents, such as pipe whip and high temperatures; the equipment is located outside the primary containment.

The feedwater spargers in the reactor vessel are used for high-pressure coolant injection. Each sparger is mounted to the inside reactor vessel surface. The thermal sleeve is welded to the feedwater nozzle on one end and connected to the sparger by a slip fit on the other end. Therefore, the feedwater sparger is removable. The spargers are mounted in the vessel at one elevation to distribute the feedwater in a symmetrical pattern about the vessel axis. Each sparger is supported by the thermal sleeve and a bracket mounted to each end of the sparger. Provision is made for the differential expansion between the stainless steel sparger and carbon steel vessel. Radial differential expansion is taken up by the slip fit of the sparger connection into the vessel nozzle thermal sleeve. Tangential differential expansion is taken up by tangential slots cut in the bracket mounted to each end of the feedwater sparger bracket. The sparger is analyzed with the thermal sleeve welded into the nozzle. In addition, pressure differentials, jet reactions, and earthquake loading are all added; these stresses within the sparger are all within the allowable stresses given in the ASME Code, Section III, for Class 1 vessels.

The presence of a steam bubble near the normally closed injection valve (MO2312) to the feedwater system (See Figure 6.3-18 for a simplified representation of the energy transport mechanisms) has been analyzed for potential effects, with the overall conclusion that the pressure transients due to the collapse of the steam bubble are structurally acceptable and do not challenge the ability of the HPCI system to perform its design safety functions. This analysis encompasses a range of steam bubble sizes, with the largest predicted steam bubble nearly filling the horizontal piping run immediately upstream of MO2312. The loads from the steam bubble collapse transient are included in the applicable piping analyses, which conclude that all pipe stresses and support components meet design basis allowable limits. Thus, the HPCI pump discharge piping is adequately filled to support performance of the HPCI system design safety functions when the standy readiness pressure in the HPCI pump discharge piping at MO2312 is not less than the pressure provided by the static head from a ≥ 8 feet CST level.

While the presence of a steam bubble near MO2312 does not adversely affect the HPCI system, capability is provided for the Condensate Service Water system to provide a "high pressure" keep fill for the HPCI pump discharge piping near MO2312 that minimizes the conditions for this steam bubble near MO2312 at operating power levels. The connection flow path from the Condensate Service Water system to the HPCI pump discharge piping incorporates series check valves to preclude diversion of HPCI flow or inadvertent pressurization of the Condensate Service Water system in the event of one check valve failing to close. A pressure relief valve is provided for the "closed volume" upstream of MO2312 to preclude over pressurization from the thermal expansion of water (e.g., during plant startup to normal full power operation).

HPCI is also vented at its high points to remove accumulation of non condensable gases. Venting may be performed if either the "high pressure" or "low pressure" keep fill systems are in operation. In the event that neither the "high pressure" nor "low pressure" keep fill systems are in operation, CST tank level is monitored in the control room at ≥ 8 ft to ensure an adequate water level is available in the CST tanks to allow for acceptable venting.

Steam from the reactor drives the HPCI system turbine. Decay heat and stored heat generate steam, which is extracted from a main steam header upstream of the main steam line isolation valves. The two HPCI system isolation valves in the steam line to the HPCI system turbine are normally open to keep piping to the turbine at elevated temperatures and to permit rapid startup of the HPCI system. Signals from the HPCI system control system open or close the turbine stop valve.

To prevent the HPCI system steam supply line from filling with water, a condensate drain pot is provided upstream of the turbine stop valve. The drain pot normally routes condensate to the main condenser, but on a receipt of an HPCI system initiation signal or loss of control air pressure, isolation valves on the condensate line shut automatically.

Two devices control turbine power: (1) a speed governor limits turbine speed to its maximum operating level and (2) a control governor with an automatic speed setpoint control is positioned by a demand signal from a flow controller to maintain constant flow over the pressure range of HPCI system operation. When the governor is in the test mode, it can be operated manually; however, it is automatically repositioned by the demand signal from the flow controller if system initiation is required.

As reactor steam pressure decreases, the HPCI system turbine throttle valve opens wider; this permits the passage of the steam flow required to provide necessary pump flow.

Exhaust steam from the HPCI system turbine is discharged to the suppression pool. A drain pot at the low point in the exhaust line collects condensate that is discharged to the suppression pool or bypassed to the barometric condenser.

The HPCI system turbine gland seals are vented to the HPCI system barometric condenser, and part of the water from the HPCI booster pump is routed through the condenser for cooling purposes. Noncondensible gases from the barometric condenser are exhausted through the standby gas treatment system.

The system piping is designed in accordance with the requirements stated in Chapter 3. The HPCI system equipment, piping, and support structures are designed as Seismic Category I equipment.

The system is managed and inspected for aging effects, including corrosion, erosion, and material fatigue.

The startup of the HPCI system is completely independent of ac power. For startup to occur, only dc power from the plant batteries and steam extracted from the nuclear system are required.

Various operations of the HPCI system components are summarized as follows: The HPCI system controls automatically start the system and are designed to bring it to design flow rate within 30 sec from the receipt of a low water level signal from the reactor vessel or a high-pressure signal from the primary containment (drywell), however the licensing basis LOCA analysis (Chapter 15.2.1) conservatively assumes that design flow is achieved within 45 sec.

The HPCI system turbine is shut down automatically (with the exception of the Manual Push button) by any of the following signals:

1. Turbine overspeed - This prevents damage to the turbine and the turbine casing.

2. Reactor vessel high water level - This indicates that core-cooling requirements are satisfied.

3. HPCI system pump low suction pressure - This prevents damage to the pump due to loss of flow.

4. HPCI system turbine exhaust high pressure - This indicates a turbine or turbine control malfunction.

5. Automatic isolation signal.

6. Manual push button.

7. Low steam inlet pressure.

If an initiation signal is received after the turbine is shut down, the system is capable of automatic restart if no shutdown signals exist.

Because the steam supply line to the HPCI system turbine is part of the nuclear system process barrier, certain signals automatically isolate this line, causing the shutdown of the HPCI system turbine. Automatic shutoff of the steam supply is described in Section 7.3.1.1. However, the automatic depressurization system and the low-pressure systems of the emergency core cooling systems act as backup, and automatic shutoff to the steam supply does not negate the ability of the emergency core cooling systems to satisfy the safety objective.

In addition to the automatic operational features of the system, it also provides for remote manual startup, operation, and shutdown (provided initiation or shutdown signals do not exist). All automatically operated valves are equipped with a remote manual functional test feature.

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 (nominal) 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 30 days without makeup and still provide for actuations of the ADS safety/relief valves. 2018-010

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. The system design head flow characteristics are shown in Table 6.3-1. (Note: These are the original design values. Sensitivity studies were performed

(Reference 12) that demonstrated margin was available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. See Section 15.0 for current values used in the LOCA analysis.

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.

As discussed in detail in Section 1.8.1, an analysis has been performed to demonstrate, under worst-case accident conditions, that adequate Net Positive Suction Head (NPSH) is available to the Core Spray pumps. The results of this analysis are shown in Figure 5.4-15(a). However, there are limitations on containment overpressure that can be credited for satisfying NPSH requirements (Fig. 5.4-15(b)).

The RHR/core spray keep fill pump maintains system discharge piping sufficiently 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 and the Core Spray 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 (Section 15.2.1) 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 keep fill pump maintains system discharge piping sufficiently 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 6.3-4a, 6.3-4b, 6.3-4c, 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 were performed (Reference 12) that demonstrated margin was available to relax these performance requirements while still meeting the acceptance criteria of 10CFR50.46. See Section 15.0 for current values used in the LOCA anaylsis.

6.3.2.2.7 ECCS Actuation Parameters

See Section 15.0 for current values used in the LOCA analysis.

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.

4. Condition 4

   a. RHR pumps A, B, and D operating.
   b. Recirculation loop B broken.
   c. RHR pumps A. B, and D injecting into recirculation loop B.

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 4 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 four 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, 3, and 4 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 13 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 engineered safety features are designed for identified and evaluated hazards and component failure modes. The design instituted to minimize the failure of the emergency core cooling systems to complete their specified functions are outlined in Section 6.3.1.

In addition, it should be noted that the plant Technical Specifications delineate surveillance and operational requirements that ensure that the plant is operated and maintained in a reliable, safe manner.

The intent of all NRC Design Criteria with regard to the emergency core cooling systems are met. Examination of each NRC Design Criterion has established the following:

1. NRC Design Criteria do not require Class 1 passive component failure protection for fluid systems (i.e., failure protection of pipes, valves, pumps, etc., is not required).

2. It does require the design

    a. To provide safety functions assuming a failure of a single active component.

    b. To provide safety systems that will not share active components and will not share other features or components unless it can be demonstrated that (1) the capability of the shared feature or component to perform its required function can be readily ascertained during reactor operation, (2) the failure of the shared feature or component does not initiate a LOCA, and (3) the capability of the shared feature or component to perform its required function is not impaired by the effects of a LOCA and is not lost during the entire period this function is required following the accident.

    c. To perform its required function and not be impaired by the effects of a LOCA.

    d. To provide heat removal systems that prevent the containment from exceeding its design pressure.

The DAEC design meets all the above criteria under the single active component failure criteria. Attention to passive failures of Class 1 pressure components is not a requirement; however, provisions are made for mitigating the effects of non-Class 1 system or equipment failures upon Class 1 equipment.

6.3.2.5.2 HPCI and LPCI System Reliability

The consideration of active failures affecting high-pressure coolant injection and low-pressure coolant injection systems primarily depends on system pumps and valve availability. For this reason, single-failure analyses assuming several modes of pump failure and inadequate flow of cooling water have been made by the DAEC.

6.3.2.5.3 ECCS Power Supply Reliability

The ECCS power supply has been designed to consider single failures of dc power equipment. To maximize ECCS equipment availability, a GE study was made to identify any failures resulting from flood and the outage of electrical equipment.

Power supplies for all applicable ECCS equipment were reviewed by GE to determine the effect of a dc power failure. Table 6.3-5 indicates which power supplies are used for this ECCS equipment. Table 6.3-6 is a listing of available equipment given a dc power failure in either Division 1 or Division 2. No equipment loss due to water spillage is expected because the recirculation line break occurs inside containment. All ECCS equipment is located outside containment. Table 6.3-6 does not distinguish between recirculation loop discharge breaks and suction breaks because this distinction does not affect equipment availability.

This review concluded that the plant design assumptions, which were used as the basis for GE's study, reflect the worst ECCS availability combinations for a dc power failure at the DAEC. Based on these conclusions, it was agreed that the conclusions reached by GE[2] relative to a loop selection logic systems are applicable to the DAEC.

6.3.2.6 Protection Provisions

Protection provisions are included in the design of the ECCS. Protection is afforded against missiles, pipe whip, and flooding. Also accounted for in the design are thermal stresses, loadings from a LOCA, and seismic effects.

The ECCS is protected against the effects of pipe whip that might result from piping failures up to, and including, the design-basis LOCA. This protection is provided by separation, pipe whip restraints, and energy-absorbing materials. These three methods are applied to provide protection against damage to ECCS piping and components that otherwise could result in a reduction of ECCS effectiveness to an unacceptable level. See Section 3.6 for the criteria on pipe whip.

Among other preventive measures, procedures are incorporated to minimize possible passive failures.

As described in Section 5.4.7, the core spray and RHR pump discharge piping is maintained sufficiently full of water by a keep fill pump that takes suction from and recirculates to the suppression pool. Accordingly, hydraulic forces that could cause system damage resulting from system initiation with the pump discharge lines not sufficiently 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.

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.

In the evaluation of adequate ECCS pump NPSH (Section 1.8.1), it is assumed that operator action to throttle the pump flow back to rated conditions occurs at 30 minutes after injection begins.

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. See Section 15.0 for the current methods used in the analysis.

The 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. (Section 15.2) 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 Section15.2.

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 large 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).

The foregoing discussion is intended to show generic trends only. See Section 15.2 for the current evaluation of emergency core cooling systems performance during a LOCA required by 10CFR50.46.

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.

The HPCI, LPCI, core spray, and automatic depressurization systems are tested periodically to ensure that the emergency core cooling systems will operate (see the Technical Specifications).

6.3.4.1 ECCS Performance Tests

Preoperational tests of the emergency core cooling systems were conducted during the final stages of plant construction before initial startup (see Chapter 14). These tests ensured

correct functioning of all controls, instrumentation, pumps, piping, and valves. System reference characteristics, such as pressure differentials and flow rates, were documented during the preoperational tests and were used as base points for measurements obtained in subsequent operational tests.

Specific ECCS tests were performed on the core spray system with respect to core spray distribution effectiveness and the structural integrity of the HPCI pumps with postulated water ingestion from the steam turbine steam supply line. Descriptions and results of these tests are in Sections 6.3.4.1.1 and 6.3.4.1.2, respectively.

6.3.4.1.1 Preoperational Core Spray Tests

Core spray distribution tests on the DAEC full-scale mockup were completed. The spray distribution system described below will ensure spray distribution over the core so that each fuel bundle will receive in excess of the minimum flow necessary for adequate cooling.

The recommended nozzle pattern is a combination of 0.75-in. VNC 12/13 and SPRACO 3101 nozzles. Each spray sparger consists of 52 VNC nozzles and 52 SPRACO nozzles alternately spaced around the header. These two groups of spray discharges are aimed at different inclination angles to optimize the distribution of spray. Effects of flow, updraft, and inclination angle tolerances were also investigated. These tests are discussed below.

VNC Nozzle Discharges

One-half of the spray discharges on each spray header for the DAEC final core spray configuration are 0.75-in. VNC stainless steel elbows of the cast pattern (ESCO, Inc.). The shaft in the center of the discharge end of the VNC nozzle holds a deflector plate that increases the angle of the cone of spray. These VNC nozzles give a very soft spray with a wide discharge angle and coarse droplets.

SPRACO Nozzle Discharges

The other half of the spray discharges on each spray header are SPRACO 3101 nozzles. The SPRACO nozzles supply flow mainly to the middle fuel bundles of the core. Since the SPRACO nozzle has a flat, rectangular fan-shaped discharge pattern, it is necessary to control the twist of the nozzle about its axis. The twist determines how the discharge rectangle intercepts the core.

Aiming Angles

The optimum aiming angles for the VNC and SPRACO nozzles on both the upper and lower spray header are given in Table 6.3-7. These angle settings are the results of extensive testing and ensure the adequate distribution of spray over the core.

Figures 6.3-10 and 6.3-11 illustrate the spray distribution over the core at rated design flow of 3020 gpm for the upper and lower spray headers, respectively. Aiming sensitivity tests (including inclination) indicate that a variation of ±2 degrees from the recommended case have near-negligible effects on the spray distribution. Therefore, a tolerance of ±1 degree was established on all aiming angles.

Flow Rate Effects

The core spray system is rated at 3020 gpm at a vessel pressure of 113 psid (i.e., the difference in pressure between the reactor vessel and the torus). All nozzle and aiming evaluation tests were run at this flow rate. To determine system performance at other flows, tests were run at 4300 and 2500 gpm. These results are shown in Figures 6.3-12 and 6.3-13 for upper and lower headers. System flows below the design value of 3020 gpm will result in a reduction of flow to the center of the core. At flows greater than design flow, the distribution remains adequate. A flow-restricting orifice limits core spray flow to 4300 gpm.

Updraft Effects

The test facility used to determine core spray distribution is capable of simulating updraft (air) during core spray operation. Earlier single-channel tests showed that air and steam updrafts, when compared on a mass flow basis, produced predictable effects on the amount of core spray entering a channel. These single-channel tests demonstrated that the effect of an air updraft of 7.5 fps is representative of 380 lb/hr per channel of steam updraft. This is greater than the most conservative calculation for hot-channel updraft for the DAEC. Full-scale air updraft tests show that adequate spray distribution is maintained for both the high and low headers even at this excessive updraft value. Figure 6.3-14 shows the effect of updraft for the lower header.

Minimum Channel Flow Rate

The original test program (for the initial core) performed to determine the effectiveness of the reactor core spray was conducted using a 36-rod electrically heated test section. These tests were run using a range of coolant flow rates from 1.8 to 2.8 gpm per bundle. The effect of flow rate over this range was almost negligible, indicating that 1.8 gpm per bundle did not represent the lower limit of flow for effective bundle cooling. However, since this was the lowest flow rate tested at that time, the minimum acceptable bundle spray rate was set at 1.8 gpm per bundle or 0.05 gpm per fuel rod. Appropriately increasing the minimum flow per rod to account for the higher linear heat generation rate of the DAEC and factoring in the 49-rod bundle design resulted in a required minimum flow of 3.25 gpm per bundle. All of the core spray distribution tests conducted with the recommended aiming angles indicate that the minimum bundle flow rate of 3.25 gpm is satisfied and that most of the core is far in excess of this value.

More recent core spray effectiveness tests are documented in Reference 6.

6.3.4.1.2 Preoperational HPCI Turbine Tests

A test program with two test series was conducted to prove the structural integrity of the HPCI unit (Terry turbine, Model type CCS) for the following cases:

1. Water ingestion during HPCI quick startup.

2. Water ingestion during HPCI normal operation.

The tests were conducted using subcooled water and steam as the driving force. The amount of water used in the test series was varied from 50 to 600 gal, which was established from the conservative assumption that the HPCI steam line was full of water. The behavior of the turbine under the test conditions was recorded through the constant monitoring of the inlet and outlet pressures and temperatures, the position of the control valve, and the rotation speed of the turbine. See Figures 6.3-15 through 6.3-17 for arrangements and results for these tests.

Following both series of tests, the HPCI turbine was completely disassembled and all parts were inspected for possible damage or deterioration. After the reassembly of the turbine, a no-load running test was conducted to detect any degradation of turbine performance.

From the results of the tests it was concluded that

1. The test conditions to which the Terry turbine were subjected were as least as severe as any that could result in an operating GE BWR; in fact, the tests represent a more severe condition than any that could occur in a GE BWR.

2. The turbine showed signs neither of damage nor any permanent performance degradation.

3. The tested turbine is typical for the type then installed in the HPCI system of the 1967 product line GE BWR.

These test results are representative for the DAEC.

6.3.4.2 <u>Reliability Tests and Inspections</u>

6.3.4.2.1 General

The average reliability of a standby (nonoperating) safety system is a function of the duration of the interval between periodic functional tests. The factors considered in determining

the periodic test interval of the ECCS are the desired system availability (average reliability), the number of redundant functional system success paths, the failure rates of the individual components in the system, and the schedule of periodic tests (simultaneous versus uniformly staggered versus randomly staggered). For this system, the above factors are used to determine safe test intervals by the methods described in Reference 7.

All of the active components of the HPCI, core spray, and LPCI systems are designed so that they may be tested during normal plant operation (with the exception of the recirculation valves). The full-flow test capability of each ECCS injection system is provided by test lines back to their suction sources. The full-flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed in the power generation mode. In addition, each individual valve may be tested during normal plant operation. Input jacks are provided, and by racking out the injection valve breaker, each ECCS loop can be tested for response time.

All of the active components of the automatic depressurization system, except the check valves for the ADS accumulator, and the safety relief valves and their associated solenoid valves are designed so that they may be tested during normal plant operation.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3. The safeguard power system, which supplies electrical power to this system if offsite power is unavailable, is tested as described in Section 8.3. Testing is specified in the Technical Specifications. Visual inspections of all the ECCS components outside the primary containment can be made at any time during power operation. Components inside the primary containment can be visually inspected only during periods of access to the primary containment. When the reactor vessel is open, the spargers and other reactor vessel internals can be inspected.

6.3.4.2.2 HPCI Testing

The HPCI system can be tested at full flow with condensate storage tank water at any time during plant operation, except when the reactor vessel water level is low; when the condensate level in the condensate storage tank is below the reserve level; or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the HPCI system is being tested, the system valves align automatically to the injection mode. However, while injection to the vessel would occur during the test, actual flowrate could be less than required by Technical Specifications, but would remain within analyzed limits.

A design flow functional test of the HPCI system over the operating pressure and flow range is performed by pumping water from the condensate storage tank and back through the full flow test return line to the condensate storage tank. The HPCI system turbine pump is driven at its rated output by steam from the reactor. The suction valves from the suppression pool and the discharge valves to the feedwater line remain closed. These two valves are tested separately to ensure their operability. The HPCI system is tested in accordance with the Technical Specifications.

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 (Reference 9 and Reference 11).

6.3.4.2.3 ADS Testing

The ADS valves are tested in accordance with the Technical Specifications. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence, but excludes actual valve actuation. Each individual ADS valve is manually actuated.

During plant operation, the automatic depressurization system can be checked as discussed in Section 7.3.

6.3.4.2.4 Core Spray Testing

The core spray pumps and valves are tested periodically during reactor operation. With the injection valve closed and the return line open to the suppression pool, full flow pump capability is demonstrated. The injection valve and the check valve are tested in a manner similar to that used for the LPCI valves. The portion of the core spray system outside the drywell may be inspected for leaks during tests. The Core Spray system is tested in accordance with the Technical Specifications.

The core spray spargers and the segment of core spray piping inside the reactor pressure vessel are visually inspected during each refueling outage in accordance with IE Bulletin 80-13 or in accordance with the guidelines endorsed by the BWR Vessel and Internals Project (BWRVIP).

6.3.4.2.5 LPCI Testing

Each LPCI loop can be tested during reactor operation. The LPCI system is tested in accordance with Technical Specifications. During plant operation, this test does not inject cold water into the reactor, because the injection line check valve is held closed by vessel pressure, which is higher than the pump pressure. The injection line portion is tested with reactor water when the reactor is shut down, and when a closed system loop is created. This prevents unnecessary thermal stresses.

To test a LPCI pump at rated flow, the test line valve to the suppression pool is opened, the pump suction valve from the suppression pool is opened (this valve is normally open), and the pumps are started using the remote manual switches in the main control room. Correct operation is determined by observing the instruments in the main control room.

If an initiation signal occurs during the test, the LPCI system aligns to the operating mode. The valves in the test bypass lines close automatically to ensure that the LPCI pump discharge is correctly routed to the RPV.

6.3.5 INSTRUMENTATION REQUIREMENTS

Design details and logic of the instrumentation for the emergency core cooling systems are discussed in Section 7.3.

6.3.5.1 HPCI Actuation Instrumentation

The actuation of the HPCI system is provided automatically when one of two conditions occur: reactor vessel low water level or primary containment (drywell) high pressure. Reactor vessel low-low water level is monitored by four indicating-type multicircuit level switches that sense the difference between the pressure due to a constant reference column of water and the pressure due to the actual height of water in the vessel. Primary containment pressure is monitored by four pressure switches that are mounted on instrument racks outside the drywell but inside the reactor building. Pipes that terminate in the reactor building allow the switches to sense pressures within the drywell interior.

System controls function to provide makeup water flow to the reactor vessel until the amount of water delivered to the reactor vessel is adequate. The HPCI system then automatically shuts down. Controls for remote manual startup, operation, and shutdown are located in the main control room. Once actuated to ensure proper functioning, RPV steam must power the HPCI turbine-driven pump. Instrumentation installed to detect steam flow is necessary to indicate steam flow status.

6.3.5.2 ADS Actuation Instrumentation

The automatic depressurization system is automatically actuated by signals from instrumentation monitoring reactor water level. Reactor vessel low water level signals actuate a time-delay circuit. In addition to the time-delay circuit, core spray or RHR pumps must be running to initiate reactor vessel blowdown. The automatic depressurization system can also be manually actuated from the main control room. Automatic actuation can be prevented from the control room during the time-delay by placing the ADS timer reset switches in the override position.

6.3.5.3 Core Spray Actuation Instrumentation

Automatic start of both pumps is initiated by the instrumentation signals generated by either reactor vessel low ("low-low-low") water level or drywell high pressure (one-out-of-two-twice logic for either signal). In addition, the core spray can be manually actuated from the main control room.

6.3.5.4 LPCI Actuation Instrumentation

Low-pressure coolant injection is automatically actuated by the RPV low water level or high drywell pressure. In addition, low pressure coolant injection can be manually actuated from the main control room.

The low-pressure core cooling portion of the emergency core cooling systems consists of three subsystems: core spray A, core spray B, and low-pressure coolant injection. Therefore, it should be understood that the LPCI subsystem by itself is not required to meet all the requirements of IEEE 279, since it is backed up by the two core spray subsystems.

To the extent practicable, the LPCI subsystem has been designed to meet IEEE 279. The loop selection sensing instrumentation for break detection and valve selection is arranged so that the failure of a single device or circuit to function on demand will not prevent the correct selection of the loop for injection.

The control system reliability is compatible with, and more reliable than, the controlled equipment (injection valve). Those single failures that could cause improper loop selection (i.e., selected short circuits that pick up specific relays) will not disable the core spray function. It is concluded, therefore, that the failure of the loop selection scheme to, in itself, fully comply with reactor protection system standards does not constitute a violation of IEEE 279 insofar as the low-pressure core cooling function is concerned.

Refer to Section 7.3.2 and to General Electric Topical Report[8] for further discussion and details.

REFERENCES FOR SECTION 6.3

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3. Deleted

4a. Deleted

4b. Deleted

4c. Deleted

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12. General Electric Company, Sensitivity of the Duane Arnold Center Safety Systems Performance to Fundamental System Parameters, MDE-282-1285, February, 1986.

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16. Letter, R. Anderson (NextEra Energy) to USNRC, "Nine-Month Supplemental (Post Outage) Response to NRC Generic Letter 2008-01," NG-09-0327, April 27, 2009.

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%	25%[c]	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 Chapter 15.0.
[b] psid = pounds per square inch differential between reactor vessel and primary containment or reactor vessel and pump suction.
[c] Sensitivity study was done for (n-1) ADS valves. See Chapter 15.0.

Table 6.3-2
Deleted

Table 6.3-3

RHR (LPCI) PUMP NET POSITIVE SUCTION HEAD FOR CONDITIONS 1, 2, 3, AND 4

Parameter[a]	RHR Injection Pumps				Comment
	A	C	B	D	
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 Sheet 2 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
Core spray system I test bypass valve	MO-2112	1B34 (ac)		1D11 (dc)	
Core spray system II test bypass valve	MO-2132		1B44 (ac)		1D21 (dc)
Core spray system I outboard valve	MO-2115	1B34 (ac)		1D11 (dc)	
Core spray system II outboard valve	MO-2135		1B44 (ac)		1D21 (dc)
Water supply pump	1P-117A	1B9 (ac)		1D11 (dc)	
Water supply pump	1P-117B		1B20 (ac)		1D21 (dc)
Water supply pump	1P-117C	1B9 (ac)		1D11 (dc)	
Water supply pump	1P-117D		1B20 (ac)		1D21 (dc)
Traveling screen drive motor A	1F-36A	1B91 (ac)		1B91 (ac)	
Traveling screen drive motor B	1F-36B		1B21 (ac)		1B91 (ac)
Traveling screen wash pump A	1P-112A	1B91 (ac)		1D11 (dc)	
Traveling screen wash pump B	1P-112B		1B21 (ac)		1D21 (dc)
Screen wash pump nozzle shutoff valve	MO-2902	1B91 (ac)		1B91 (ac)	
Screen wash pump nozzle shutoff valve	MO-2903		1B21 (ac)		1B21 (ac)
Screen wash water strainer	1S-85A	1B91 (ac)		1B91 (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 Sheet 3 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
Screen wash water strainer	1S-85B		1B21 (ac)		1B21 (ac)
Screen wash water strainer valve	MO-2910A	1B91 (ac)		1B91 (ac)	
Screen wash water strainer valve	MO-2910B		1B21 (ac)		1B21 (ac)
Emergency service water pump	1P-99A	1B32 (ac)		1D11 (dc)	
Emergency service water pump	1P-99B		1B42 (ac)		1D21 (dc)
Emergency service water pump solenoid valve	SV-1956A	1B32 (ac)		1D11 (dc)	
Emergency service water pump solenoid valve	SV-1956B		1B42 (ac)		1D21 (dc)
Emergency service water pump solenoid valve	SV-2080	1B32 (ac)		1D11 (dc)	
Emergency service water pump solenoid valve	SV-2081		1B42 (ac)		1D21 (dc)
Well water inlet to coolers valve	MO-2039A	1B32 (ac)		1B32 (ac)	
Well water inlet to coolers valve	MO-2039B		1B42 (ac)		1B32 (ac)
Well water return valve	MO-2077	1B32 (ac)		1D11 (dc)	
Well water return valve	MO-2078		1B42 (ac)		1D21 (dc)
RHR pump	1P-229A	1A3 (ac)		1D13 (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.

Table 6.3-5 Sheet 4 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 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)	
2016-006	RHR loop B minimum flow bypass valve	MO-1935		1B44 (ac)		1D23 (dc)
2016-006	RHR loop A 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 Sheet 5 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
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.

Table 6.3-5 Sheet 6 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
RHR loop B discharge to LPCI valve (inboard)	MO-1905	1B44A (ac)	1B44A (ac)	1D13 (dc)	1D23 (dc)
RHR loop A discharge to LPCI valve (outboard)	MO-2004	1B34A (ac)	1B34A (ac)	1D13 (dc)	1D23 (dc)
RHR loop B discharge to LPCI valve (outboard)	MO-1904	1B44A (ac)	1B44A (ac)	1D13 (dc)	1D23 (dc)
RHR loop A test isolation valve	MO-2005	1B34 (ac)		1D13 (dc)	
RHR loop B test isolation valve	MO-1932		1B44 (ac)		1D23 (dc)
RHR loop A test to torus valve	MO-2006	1B34 (ac)		1D13 (dc)	
RHR loop B test to torus valve	MO-1933		1B44 (ac)		1D23 (dc)
RHR loop A test to torus valve	MO-2007	1B34 (ac)		1D13 (dc)	
RHR loop B test to torus valve	MO-1934		1B44 (ac)		1D23 (dc)
RHR cross loop header valve	MO-2010	1B34 (ac)		1B34 (ac)	
RHR loop A maintenance isolation valve	MO-2069	1B34 (ac)		1B34 (ac)	
RHR loop B maintenance isolation valve	MO-1989		1B44 (ac)		1B44 (ac)
RHR loop A drain to torus valve	MO-2038	1B34 (ac)		1D13 (dc)	
RHR loop B drain to torus valve	MO-1970		1B44 (ac)		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.

Table 6.3-5 Sheet 7 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
RHR loop A drain to recirculation valve	MO-2036	1B34 (ac)		1D13 (dc)	
RHR loop B drain to recirculation valve	MO-1967		1B44 (ac)		1D23 (dc)
RHR heat exchanger A shell inlet valve	MO-2029	1B34 (ac)		1B34 (ac)	
RHR heat exchanger B shell inlet valve	MO-1939		1B44 (ac)		1B44 (ac)
RHR heat exchanger A shell outlet valve	MO-2031	1B34 (ac)		1B34 (ac)	
RHR heat exchanger B shell outlet valve	MO-1941		1B44 (ac)		1B44 (ac)
RHR loop A heat exchanger bypass valve	MO-2030	1B34 (ac)		1D13 (dc)	
RHR loop B heat exchanger bypass valve	MO-1940		1B44 (ac)		1D23 (dc)
RHR heat exchanger A vent valve	MO-2044A	1B34 (ac)		1B34 (ac)	
RHR heat exchanger A vent valve	MO-2044B	1B34 (ac)		1B34 (ac)	
RHR heat exchanger B vent valve	MO-1949A		1B44 (ac)		1B44 (ac)
RHR heat exchanger B vent valve	MO-1949B		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 Sheet 8 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
RHR PP 1P-229A shutdown cooling valve	MO-2011	1B34 (ac)		1B34 (ac)	
RHR PP 1P-229B shutdown cooling valve	MO-1912		1B44 (ac)		1B44 (ac)
RHR PP 1P-229C shutdown cooling valve	MO-2016	1B34 (ac)		1B34 (ac)	
RHR PP 1P-229D shutdown cooling valve	MO-1920		1B44 (ac)		1B44 (ac)
RHR PP 1P-229A suction valve	MO-2012	1B34 (ac)		1B34 (ac)	
RHR PP 1P-229B suction valve	MO-1913		1B44 (ac)		1B44 (ac)
RHR PP 1P-229C suction valve	MO-2015	1B34 (ac)		1B34 (ac)	
RHR PP 1P-229D suction valve	MO-1921		1B44 (ac)		1B44 (ac)
RHR service water pump	1P-22A	1A3 (ac)		1D13 (dc)	
RHR service water pump	1P-22B		1A4 (ac)		1D23 (dc)
RHR service water pump	1P-22C	1A3 (ac)		1D13 (dc)	
RHR service water pump	1P-22D		1A4 (ac)		1D23 (dc)
RHR loop B heat exchanger service water discharge valve	MO-1947		1B44 (ac)		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.

Table 6.3-5 Sheet 9 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
RHR loop A heat exchanger service water discharge valve	MO-2046	1B34 (ac)		1D13 (dc)	
HPCI room cooling unit	1V-AC-14A	1B34 (ac)		1B34 (ac)	
HPCI room cooling unit	1V-AC-14B		1B44 (ac)		1B44 (ac)
RHR room cooling unit	1V-AC-11		1B44 (ac)		1B44 (ac)
RHR room cooling unit	1V-AC-12	1B34 (ac)		1B34 (ac)	
RHR service water pump room air supply fan	1V-SF-56A	1B36 (ac)		1B36 (ac)	
RHR service water pump room air supply fan	1V-SF-56B		1B46 (ac)		1B46 (ac)
RHR service water pump room air supply solenoid valve	SV-7538A	1B36 (ac)		1B36 (ac)	
RHR service water pump room air supply solenoid valve	SV-7538B		1B46 (ac)		1B46 (ac)
RHR service water pump room air supply solenoid valve	SV-7539A	1B36 (ac)		1B36 (ac)	
RHR service water pump room air supply solenoid valve	SV-7539B		1B46 (ac)		1B46 (ac)
RHR service water pump room air supply solenoid valve	SV-7536	1B36 (ac)		1B36 (ac)	
RHR service water pump room air supply solenoid valve	SV-7537		1B46 (ac)		1B46 (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 Sheet 10 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
Intake structure main supply fan	1V-SF-50	1B91 (ac)		1D11 (dc)	
Intake structure main supply fan	1V-SF-51		1B21 (ac)		1D21 (dc)
Intake structure unit heater	1V-UH-52A		1B21 (ac)		1B21 (ac)
Intake structure unit heater	1V-UH-52C		1B21 (ac)		1B21 (ac)
Intake structure unit heater	1V-UH-52E		1B21 (ac)		1B21 (ac)
Intake structure unit heater	1V-UH-52G		1B21 (ac)		1B21 (ac)
Intake structure unit heater	1V-UH-52B	1B91 (ac)		1B91 (ac)	
Intake structure unit heater	1V-UH-52D	1B91 (ac)		1B91 (ac)	
Intake structure unit heater	1V-UH-52F	1B91 (ac)		1B91 (ac)	
Intake structure unit heater	1V-UH-52H	1B91 (ac)		1B91 (ac)	
Reactor recirculating pump discharge bypass valve	MO-4629	1B34A (ac)	1B34A (ac)	1D13A (dc)	1D23 (dc)
Reactor recirculating pump discharge bypass valve	MO-4630	1B44A (ac)	1B44A (ac)	1D13 (dc)	1D23 (dc)
Reactor recirculating pump discharge valve	MO-4627	1B34A (ac)	1B34A (ac)	1D13 (dc)	1D23 (dc)
Reactor recirculating pump discharge valve	MO-4628	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.

Table 6.3-6 Sheet 1 of 4

ESSENTIAL EQUIPMENT AVAILABLE FOLLOWING LOSS OF DC POWER

Equipment Description	Loss of Division 1 dc Power	Loss of Division 2 dc Power
Auto depressurization valve	SV-4400	SV-4400
Auto depressurization valve	SV-4402	SV-4402
Auto depressurization valve	SV-4405	SV-4405
Auto depressurization valve	SV-4406	SV-4406
Core spray (CS) pump	1P-211B	1P-211A
CS system suction valve	MO-2120	MO-2100
CS system main isolation valve	MO-2146	MO-2147
CS system inboard isolation valve	MO-2137	MO-2117
CS system minimum flow bypass valve	MO-2124	MO-2104
CS system test bypass valve	MO-2132	MO-2112
CS system outboard isolation valve	MO-2135	MO-2115
Water supply pump	1P-117B	1P-117A
Water supply pump	1P-117D	1P-117C
Traveling screen drive motor	1F-36B	1F-36A
Traveling screen wash pump	1P-112B	1P-112A
Screen wash pump nozzle shutoff valve	MO-2903	MO-2902
Screen wash water strainer	1S-85B	1S-85A
Screen wash strainer valve	MO-2910B	MO-2910A
Emergency service water pump	1P-99B	1P-99A
Emergency service water pump valve	SV-1956B	SV-1956A

Table 6.3-6 Sheet 2 of 4

ESSENTIAL EQUIPMENT AVAILABLE FOLLOWING LOSS OF DC POWER

Equipment Description	Loss of Division 1 dc Power	Loss of Division 2 dc Power
Emergency service water pump valve	SV-2081	SV-2080
Well water inlet to coolers valve	MO-2039B	MO-2039A
Well water return valve	MO-2078	MO-2077
RHR pump	1P-229B	1P229A
RHR pump	1P-229D	1P-229C
RHR shutdown cooling isolation valve	MO-1909	MO-1908
RHR discharge to waste isolation valve	MO-1937	MO-1936
RHR loop minimum flow bypass valve	MO-1935	MO-2009
RHR sample line valve	SV-1973	SV-1972
RHR sample line valve	SV-2052	SV-2051
HPCI to RHR pressure reduction valve	SV-1963	SV-2033
HPCI to RHR pressure reduction valve	SV-1964	SV-2034
RHR to RCIC pressure reduction valves	SV-1966	SV-2037
RHR containment spray valve	MO-1902	MO-2000
RHR containment spray regulating valve	MO-1903	MO-2001
RHR discharge to LPCI	MO-2003	MO-2003
RHR discharge to LPCI	MO-1905	MO-1905
RHR discharge to LPCI	MO-2004	MO-2004

Table 6.3-6 Sheet 3 of 4

ESSENTIAL EQUIPMENT AVAILABLE FOLLOWING LOSS OF DC POWER

Equipment Description	Loss of Division I dc Power	Loss of Division 2 dc Power
RHR discharge to LPCI	MO-1904	MO-1904
RHR test isolation valve	MO-1932	MO-2005
RHR test to torus valve	MO-1933	MO-2006
RHR test to torus valve	MO-1934	MO-2007
RHR cross loop header valve		MO-2010[a]
RHR loop maintenance isolation valve	MO-1989	MO-2069
RHR drain to torus valve	MO-1970	MO-2038
RHR to RCIC isolation valve	MO-1967	MO-2036
RHR heat exchanger inlet valve	MO-1939	MO-2029
RHR heat exchanger outlet valve	MO-1941	MO-2031
RHR heat exchanger bypass	MO-1940	MO-2030
RHR heat exchanger vent valve	MO-1949A	MO-2044A
RHR heat exchanger vent valve	MO-1949B	MO-2044B
RHR pump suction header valve	MO-1912	MO-2011
RHR pump suction header valve	MO-1920	MO-2016
RHR pump suction from torus	MO-1913	MO-2012
RHR pump suction from torus	MO-1921	MO-2015
RHR service water pump	1P-22B	1P-22A
RHR service water pump	1P-22D	1P-22C

[a] Valve MO-2010 is key locked in the open position and provides the flowpath for LPCI system operation of either Division 1 or Division 2.

Table 6.3-6 Sheet 4 of 4

ESSENTIAL EQUIPMENT AVAILABLE FOLLOWING LOSS OF DC POWER

Equipment Description	Loss of Division 1 dc Power	Loss of Division 2 dc Power
RHR heat exchanger service water discharge valve	MO-1947	MO-2046
HPCI room cooling unit	1V-AC-14B	1V-AC-14A
RHR room cooling unit	1V-AC-11	1V-AC-12
RHR service water pump room fan	1V-SF-56B	1V-SF-56A
RHR service water pump room supply valve	SV-7538B	SV-7538A
RHR service water pump room supply valve	SV-7539B	SV-7539A
RHR service water pump room supply valve	SV-7537	SV-7536
Intake structure main supply fan	1V-SF-51	1V-SF-50
Intake structure unit heater	1V-UH-52B	1V-UH-52A
Intake structure unit heater	1V-UH-52D	1V-UH-52C
Intake structure unit heater	1V-UH-52F	1V-UH-52E
Intake structure unit heater	1V-UH-52H	1V-UH-52G
Reactor recirculating pump discharge bypass valve	MO-4629	MO-4629
Reactor recirculating pump discharge bypass valve	MO-4630	MO-4630
Reactor recirculating pump discharge valve	MO-4627	MO-4627
Reactor recirculating pump discharge valve	MO-4628	MO-4628

Table 6.3-7

CORE SPRAY NOZZLE INCLINATION SETTINGS

	Upper Header	Upper Header
1. Nozzle - SPRACO 3101		
Inclination (with reference to the plane perpendicular to vessel axis)	-4°	-4°
2. Nozzle - 3/4-in. VNC 12/13		
Inclination (with reference to the plane perpendicular to vessel axis)	-25°	-16°
3. Tolerance		
All angle settings	±1°	±1°

MODE F - SHUTDOWN COOLING (SEE NOTE 3-14)

RX PRESS 0 PSIG

POSITION-○	16	38	39	40A/B	41A/B	5A/B	6A/B	7A/B	17A/B	18A/B	8A/B	9A/B	10A/B	11A	11B	12B	13B	14B	15B	16	24A/B	25A/B
FLOW-GPM	—	9,600	9,600	4,800	←								→	4,800	9,600	←		→	9,600	—	4,800	4,800
PRESS-PSIA	14.7																			14.7		
TEMP° F	—	125	←					→	125	116.6	←							→	116.6	—	85	93.4
MAX PRESS DROP-FEET						.TDH 365.			.ΔP= 25.2.												.ΔP= 173.	

DUTY PER HX 20.1 x 10^6 (2 HX OPERATING) RHRSW

MODE G - LPCI INJECTION (SEE NOTE 3)

RX PRESS 0 PSIG

POSITION-○	1	2B	3B	4B	5B&D	6B&D	7B	8B	9B	10B	11B	12B	13B	14B	15B	16
FLOW-GPM	—	13,000	13,000	13,000	6,500	6,500	13,000	←						→	13,000	—
PRESS-PSIA	14.7															14.7
TEMP° F	—	130	←											→	130	—
MAX PRESS DROP-FEET						.TDH= 252.										

MODE H - FULL FLOW TEST

POSITION-○	1	2B	3B	4B	5B&D	6B&D	7B	8B	9B	10B	11B	12B	22B	35B	26B	1
FLOW-GPM	—	9600	9600	9600	4,800	4,800	9,600	←						→	9600	—
PRESS-PSIA	14.7															14.7
TEMP° F	—	AMB.	←											→	AMB	—
MAX PRESS DROP-FEET						.TDH= 365.										

MODE J - MINIMUM FLOW

RX PRESS 135 PSIG

POSITION-○	16	38	39	40A	41A	5A	6A	48A	26A	1		1	2A	3A	4A	5A	6A	48A	26A	1
FLOW-GPM	—	250	←					→	250	—		—	250	←				→	250	—
PRESS-PSIA	150									14.7		14.7								14.7
TEMP° F	—	358	←					→	358	—		—	125	←				→	125	—
MAX PRESS DROP-FEET						.SOH= 97/2600			→							.SOH= 97/2600			→	

TABLE 1 - VALVE POSITION CHART SEE NOTE 8

MODES	F004	F006	F052	F051	F048	F003	F017	F015	F020	F016	F021	F028	F027	F024	F023	F022	F019	F031	F011	F054	F026	F025	F018	F046	F009	F009	STRAINER A	STRAINER B
A	O				O		O	O	O																		P	P
B	O				O		O	O	O																		P	P
C1	O			O		O				O	O	O	O											T			—	P
C2	O			O		O				T	O	O	T											T			—	P
D1		T	T														T	O-T	O-T	O-T				T			—	—
D2		T	T														T		O	O				T			—	—
D3 (CONT'D)	O			O		O					O		T											T				
E		O			O	T/O	O	T/O	O						O									T	O	O	—	—
F		O			O		O	T	O	O														T	O	O	—	—
G	O					O		O	O	O																	—	P
H	O					O						O		T													CLEAR	CLEAR
J	O																								O	O	CLEAR	—

NOTE: F022 & F023 ARE DE-ENERGIZED SHUT.

O - VALVE OPEN
T - VALVE THROTTLED
P - STRAINER PLUGGED WITH DEBRIS IN ACCORDANCE TO CAL-M98-002 AND CAL-M97-007.
T-C - VALVE THROTTLED OR CLOSED
O-T - VALVE OPENED OR THROTTLED
BLANK SPACE INDICATES VALVE IS CLOSED

TABLE 3 - LIMITING LINE LOSSES

MODES	POSITION - ○
A	6-15
B	NONE
C1	13-20-21 & 22-23-1
C2	1-2-5
D1	16-46-27 & 34-35-26-1 & 36-37
D2	27-36
D3 (CONT'D)	NONE
E	19-44
F	16-38-41
G	1-2-5
H	12-22-35-26-1
J	6-48

MODE A - LPCI INJECTION

Rx PRESS 20 PSIG

POSITION-○	1	2A	3A	4A	2B	3B	4B	5ABC	6ABC	7A	8A	9A	10A	11A	7B	8B	9B	10B	11B	12B	13B	14B	15B	16
FLOW-GPM	—	9600	9600	9600	4800	←		→	4,800	9,600	←		→	9600	4800	←	→	4800	14,400	←		→	14,400	—
PRESS-PSIA	14.7																							34.7
TEMP° F	—	130/75	←																			→	130/75	—
MAX PRESS DROP-FEET		←						.TDH= 365.				.ΔP= 20.					.ΔP= 5.					.ΔP= 145.		

SEE NOTE 5

MODE B - LPCI INJECTION (SEE NOTE 13)

Rx PRESS 20 PSIG

POSITION-○	1	2A	3A	4A	5A&C	6A&C	7A	8A	9A	10A	11A	11B	12B	13B	14B	15B	16
FLOW-GPM	—	12,200	12,200	12,200	6,100	6,100	12,200	←							→	12,200	—
PRESS-PSIA	14.7																34.7
TEMP° F	—	130/75	←												→	130/75	—
MAX PRESS DROP-FEET		←				.TDH= 280.										→	

MODE C-1 - CONTAINMENT SPRAY (SEE NOTE 14)

RHRSW

POSITION-○	1	2B	3B	4B	5B&D	6B&D	7B	17B	18B	8B	9B	10B	11B	12B	13B	19	20B	21	22B	23B	1	24B	25B
FLOW-GPM	—	7200	7200	7200	3,600	3600	7,200	←						→	7200	6840	6840	6,840	—	360	360	—	4800	4800
PRESS-PSIA	14.7																	14.7			14.7		
TEMP° F	—	165	←				→	165	154.8	←						→	154.8	—	154.8	154.8	—	95	110.2
MAX PRESS DROP-FEET		←				.TDH= 415.												→					
		←																			→		

DUTY PER HX 36.6 X 10^6 (1 HX OPERATING) RHRSW

MODE C-2 - CONTAINMENT SPRAY (SEE NOTE 3, 14 & 18)

RHRSW

POSITION-○	1	2B	3B	4B	5B	6B	7B	17B	18B	8B	9B	10B	11B	12B	13B	19	20B	21	22B	23B	1	24B	25B
FLOW-GPM	—	4800	←										→	4800	4560	4560	4,560	—	240	240	—	4,800	4800
PRESS-PSIA	19.7																	19.7			19.7		
TEMP° F	—	197	←				→	197	175.6	←						→	175.6	—	175.6	175.6	—	95	116.4
MAX PRESS DROP-FEET		←				.TDH= 365.												→					
		←																			→		

DUTY PER HX 51.3 X 10^6 (1 HX OPERATING) RHRSW
HISTORICAL VALUE SEE NOTE 18

MODE D-1 - STEAM CONDENSING (SEE NOTE 11 & 15)

RX PRESS 1000 PSIG

POSITION-○	16	46	27	28A/B	29A/B	30A/B	17A/B	18A/B	31A/B	32A/B	33A/B	34A/B	35A/B	26A/B	1	36	37	24A/B	25A/B
FLOW #/HR	—	8.44 x 10^4	8.44 x 10^4	4.22 x 10^4	←								→	4.22 x 10^4	—	8.44 x 10^4	8.44 x 10^4	2.4 x 10^4	2.2 x 10^4
PRESS-PSIA	1014.7				214.7										14.7		64.7		
TEMP° F	546	←	→	546	388	388	388	140	←				→	140	—	140	140	95	114
MAX PRESS DROP-PSI		←	ΔP=800	→	←					ΔP=200				→			→		
					←						ΔP=125								

DUTY PER HX 45.7 X 10^6 (2 HX STEAM CONDENSING)

MODE D-2 - STEAM CONDENSING (SEE NOTE 11 & 15)

RX PRESS 1000 PSIG

POSITION-○	16	46	27	28A	29A	30A	17A	18A	31A	32A	33A	34A	36	37	24A	25A
FLOW #/HR	—	59.2 x 10^6	←										→	59.2 x 10^3	2.4 x 10^6	2.4 x 10^6
PRESS-PSIA	1014.7				214.7									64.7		
TEMP° F	546	←	→	546	388	388	388	140	←				→	140	95	121.8
MAX PRESS DROP-PSI		←	ΔP=800	→	←								→			
									ΔP=125							

DUTY PER STEAM CONDENSING HX 642 X 10^6 (1 HX OPERATING) RHRSW

MODE D-2 CONT'D.

RHRSW

POSITION-○	1	2B	3B	4B	5B	6B	7B	17B	18B	8B	9B	10B	11B	12B	22B	35B	26B	1	24B	25B
FLOW-GPM	—	4,800	←														→	4,800	4,800	4,800
PRESS-PSIA	14.7																	14.7		
TEMP° F	—	120	←				→	120	114.8	←							→	114.8	95	100.2
MAX PRESS DROP-FEET		←				.TDH= 365.												→		

DUTY PER POOL COOLING HX 12.6 X 10^6 (1 HX OPERATING) RHRSW

MODE E - SHUTDOWN COOLING (SEE NOTE 14)

RX PRESS 35 PSIG (SEE NOTE 10)

POSITION-○	16	38	39	40A/B	41A/B	5A/B	6A/B	7A/B	17A/B	18A/B	8A/B	11A	11B	12B	13B	14B	15B	16	24A/B	25A/B
FLOW-GPM	—	9600	9600	4800	←			→	4800	4800	4800	4800	4800	9600	9600	9,600	9,600	—	4,800	4800
PRESS-PSIA	50																	50		
TEMP° F	—	281	←					→	281	240	←					→	240	—	85	126
MAX PRESS DROP-FEET		←				.TDH= 365.											→			

DUTY PER HX 98.5 X 10^6 (2 HX OPERATING)

MODES:

A. ACCIDENT W/RECIRC LINE BREAK IN SIDE I WITH THREE PUMP OPERATION (20 PSIG)(LPCI) } NOTE 16
B. ACCIDENT W/RECIRC LINE BREAK IN SIDE I WITH TWO PUMP OPERATION (20 PSIG)(LPCI) } NOTE 16
C-1 POST ACCIDENT CONTAINMENT SPRAY W/HEAT REJECTION WITH TWO PUMP OPERATION (NORMAL SUPPRESSION POOL TEMPERATURE) (CONTAINMENT SPRAY) } NOTE 16
C-2 POST ACCIDENT CONTAINMENT SPRAY W/HEAT REJECTION WITH ONE PUMP OPERATION (PEAK SUPPRESSION POOL TEMPERATURE) (CONTAINMENT SPRAY) } NOTE 16
D-1 REACTOR ISOLATION - 2 HX STEAM CONDENSER. (½ HR.)
D-2 REACTOR ISOLATION 1 HX STEAM CONDENSER & 1 HX POOL COOLING. (1½ HR) } NOTE 15
E. NORMAL SHUTDOWN AFTER BLOWDOWN TO MAIN CONDENSER. (SEE NOTE 9)(SHUTDOWN COOLING)
F. CONTINUATION OF NORMAL SHUTDOWN FROM PLANT MODE E. (0PSIG) & FUNCTIONAL TEST FOLLOWING SHUTDOWN. (SHUTDOWN COOLING)
G. ACCIDENT W/RECIRC LINE BREAK IN SIDE I WITH TWO PUMP OPERATION. (0 PSIG) } NOTE 16
H. R.H.R. SYSTEM TEST DURING PLANT OPERATION.
J. MINIMUM FLOW BYPASS MODE.

NOTES:

2. PIPING DESIGNER SHALL FILL IN THE EMPTY DATA BLANKS BASED ON HIS PIPING LAYOUT AND SUBMIT TO APED FOR INFORMATION. IF SIDE I AND SIDE II ARE NOT SYMMETRICALLY ARRANGED, VALUES FOR BOTH SHALL BE SUBMITTED.
3. THE MINIMUM PUMP NPSH AVAILABLE MAY OCCUR DURING MODE C-2, F OR G
4. ELEVATIONS ARE NOT INCLUDED IN Δ.P. VALUES GIVEN. ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.
5. DASHED LINES INDICATES FLOW DOES NOT PASS THROUGH THESE POINTS.
6. SERVICE WATER CROSS-TIE SHALL BE SIZED TO FLOW 3120 GPM. (SEE SH. NO.2)
7. LINE SHALL BE SIZED BASED ON FLOW SHOWN ON FUEL PROCESS DIAGRAM.
8. TABLE 1 INDICATES VALVE POSITIONS DURING VARIOUS MODES OF OPERATION.
10. SHUTDOWN OPERATION MAY BE INITIATED AT A MAXIMUM REACTOR VESSEL PRESSURE OF 135 PSIG.
11. THE MAXIMUM CONDENSATE RETURN TEMPERATURE TO RCIC PUMP DURING MODES D-1 AND D-2 SHALL NOT EXCEED 140°F. } NOTE 15
12. THE HEIGHT OF WATER IN THE SHUTDOWN COOLING SUBSYSTEM PIPING, INCLUDING THE HEAT EXCHANGERS AND PUMPS, SHALL NOT EXCEED 110,000 LBS. AT 70° TO PREVENT DILUTION OF STANDBY LIQUID CONTROL NEUTRON ABSORBER BELOW MINIMUM REQUIREMENTS.
13. TOTAL FLOW CAN BE LESS THAN SHOWN, PROVIDED THE COMBINED CORE SPRAY AND RHR FLOW EQUALS 14,400 GPM MINIMUM.
14. PER POINTS CHARGE AND BEAND, THE RHRSW FLOW REQUIREMENTS WERE REDUCED FROM 2100 gpm PER PUMP TO 2070 gpm PER PUMP FOR A TOTAL OF 4280 gpm PER RHR HEAT EXCHANGER. SEE DCP 1426 AND HCGE-30051-A, ANALYSIS OF REDUCED RHR SERVICE WATER FLOW AT THE DUANE ARNOLD ENERGY CENTER.

LEGEND:
RX PRESS. - REACTOR VESSEL PRESSURE
SOH - SHUTOFF HEAD

REFERENCE DOCUMENTS: MFL ITEM NO.
1. RHR SYS P&ID - - - - - - - - - - - - E11-1010

NOTES CONT'D:
15. STEAM CONDENSING REMOVED DURING CYCLE 30 REFUELING OUTAGE BY DCP-1450.
16. STRAINER HEADLOSS FOR NPSH IS DEFINED IN CAL-M97-007.
17. FOR ACCIDENT W/RECIRC LINE BREAK IN SIDE I @ PRESSURE AT 20 PSIG AND 1 PUMP OPERATION THROUGH RHR HEAT EXCHANGER, REFER TO CAL-MC-040J FOR REQUIRED AND EXPECTED RHR FLOW RATES.
18. THE VALUES OF PARAMETERS AND RESULTS FROM ANALYSES FOR EACH RHR HEAT EXCHANGER USED IN THE ACCIDENT ANALYSES IS CONTAINED IN THE UFSAR CHAPTER 15 ACCIDENT ANALYSIS.

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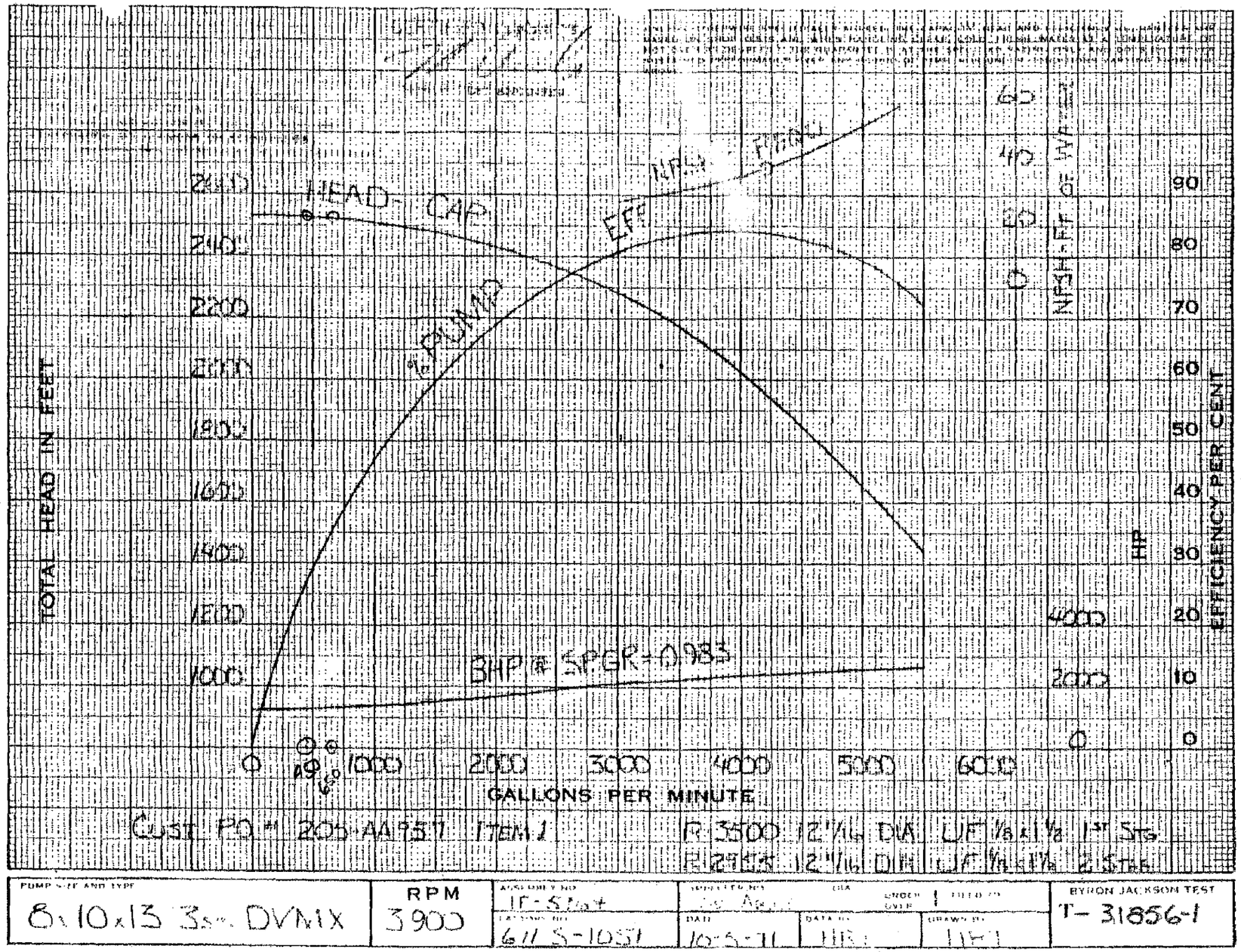
RESIDUAL HEAT REMOVAL SYSTEMS, PROCESS FLOW DIAGRAM

FIGURE 6.3-3, SHEET 1



PUMP SIZE AND TYPE	RPM	ASSEMBLY NO				BYRON JACKSON TEST
8x10x13 3st DVMIX	3900	1F-5[illegible]				T-31856-1
		611 S-1051	DATE 10-5-71	DATA BY [illegible]	DRAWN BY [illegible]	

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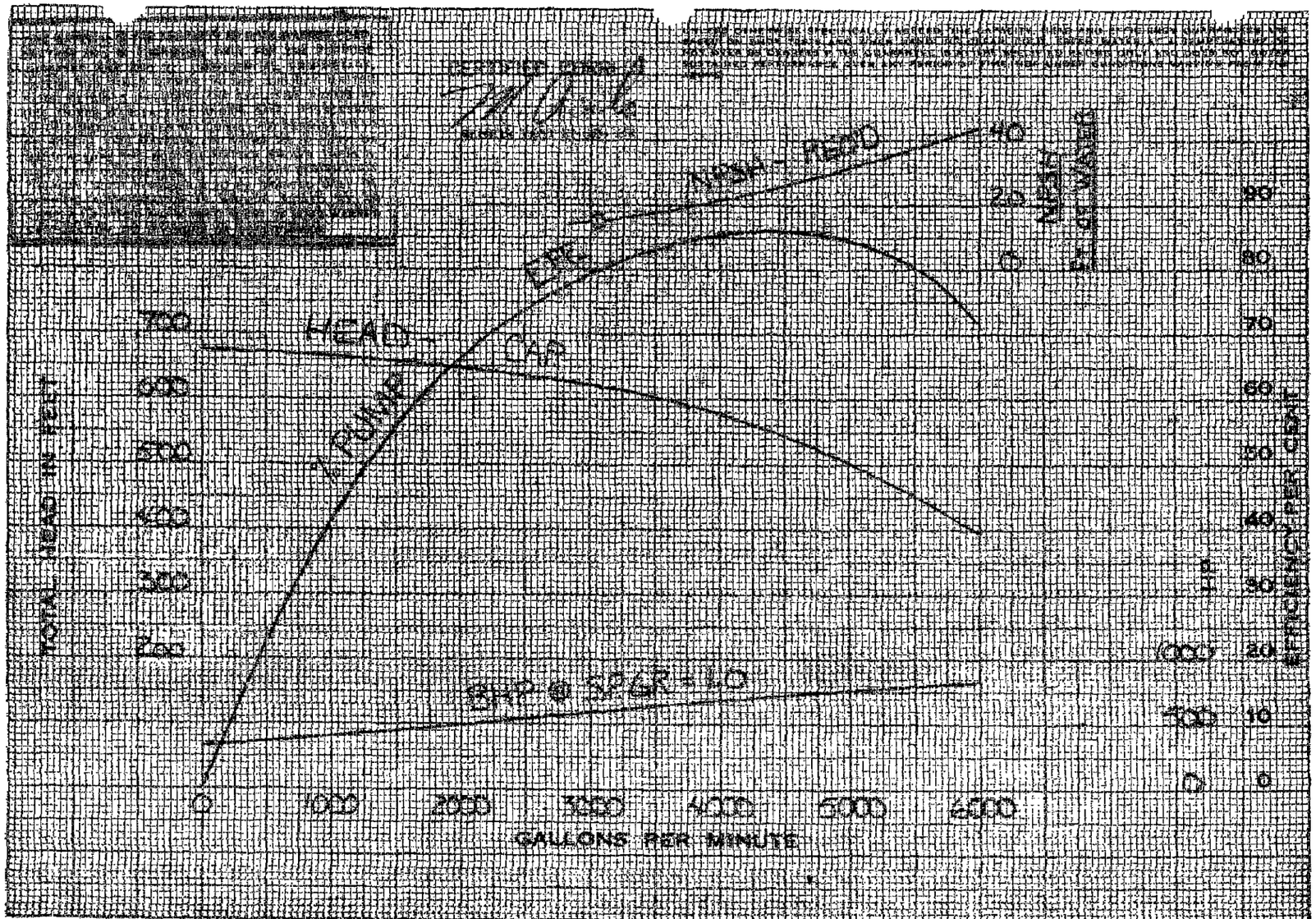
HPCI MAIN PUMP, PUMP CURVE @ 3900rpm

FIGURE 6.3-4A

BYRON . CKSON



PUMP SIZE AND TYPE	RPM	ASSEMBLY NO. / FACTORY NO.	IMPELLER NO. / DATE	DIA / DATA BY	FILED TO / DRAWN BY	BYRON JACKSON TEST
10x10x14 1/2 DVS	3100	1E-5955 / 691-S-1050	R-3636 / 10-2-71	14 1/2" UNDER / HRT	HRT	T-31855-1

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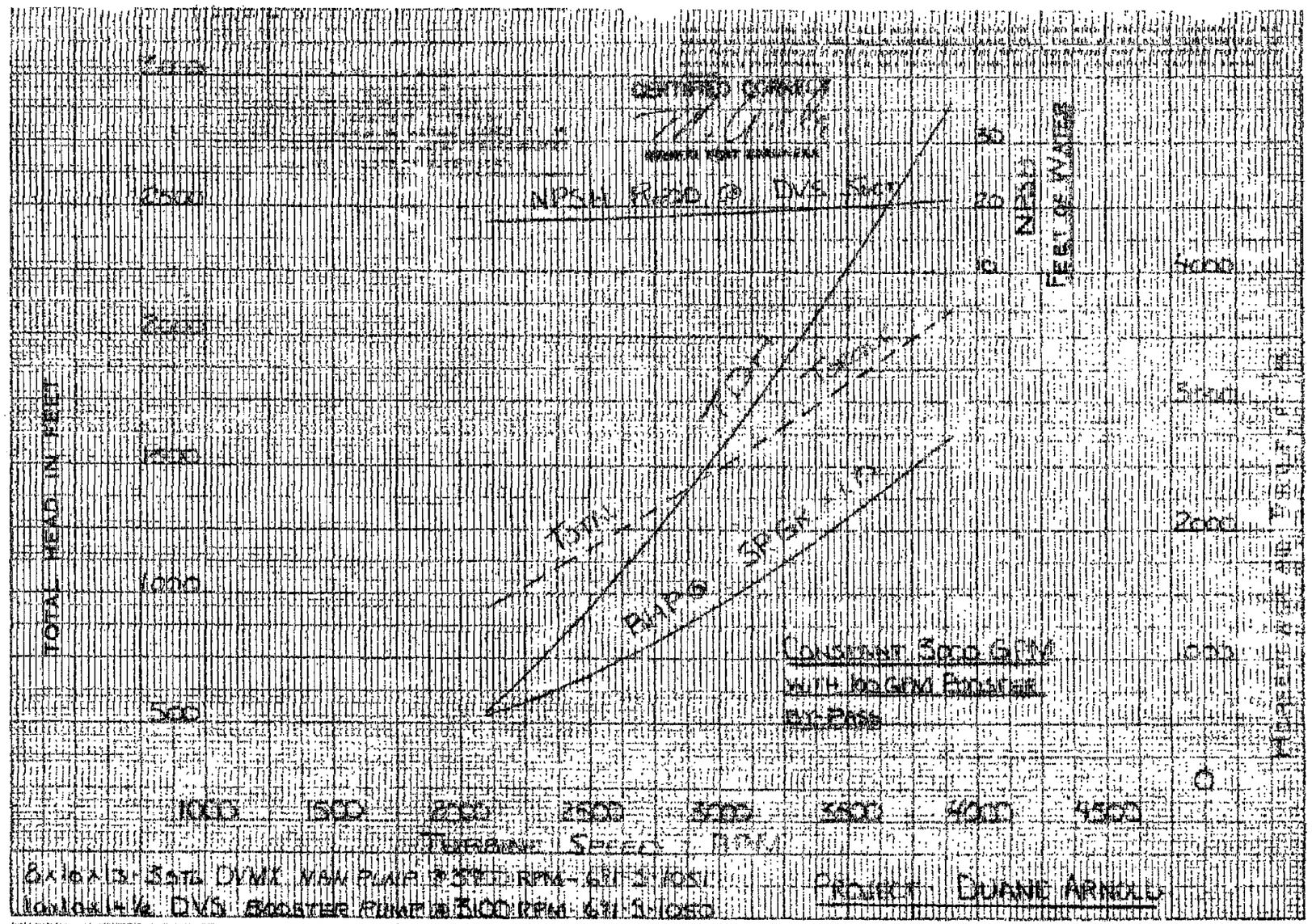
HPCI BOOSTER PUMP,
PUMP CURVE @ 3100rpm

FIGURE 6.3-4B

BYRON JACKSON.



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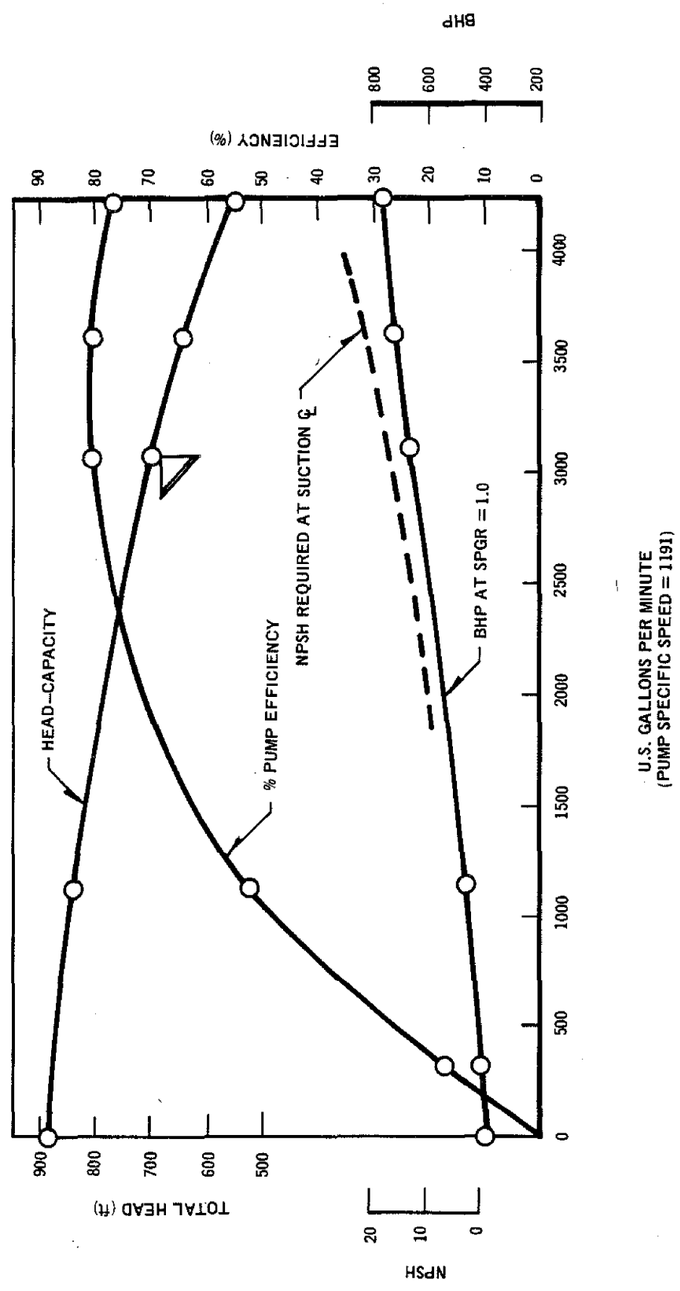
HPCI PUMP ASSEMBLY TDH vs
TURBINE SPEED @ 3000gpm

FIGURE 6.3-4C



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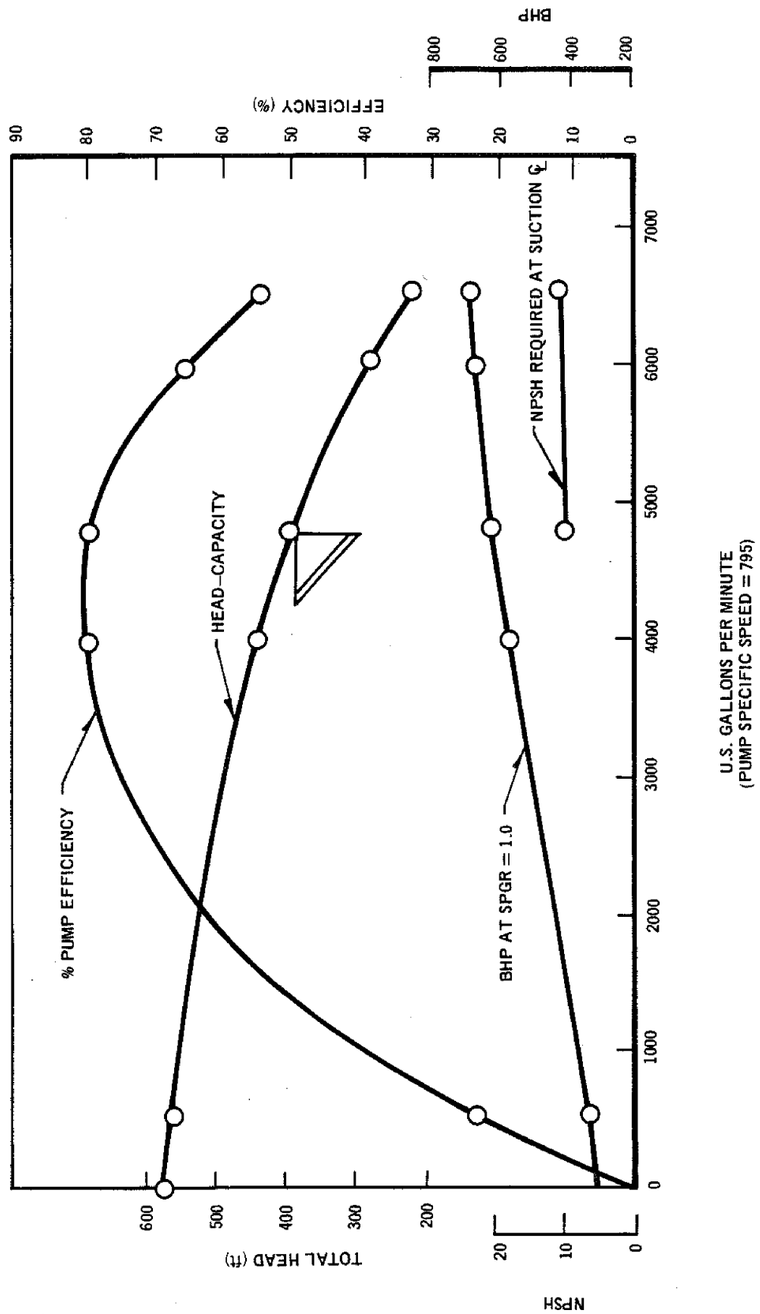
Core Spray Pump Curves

Figure 6.3-5



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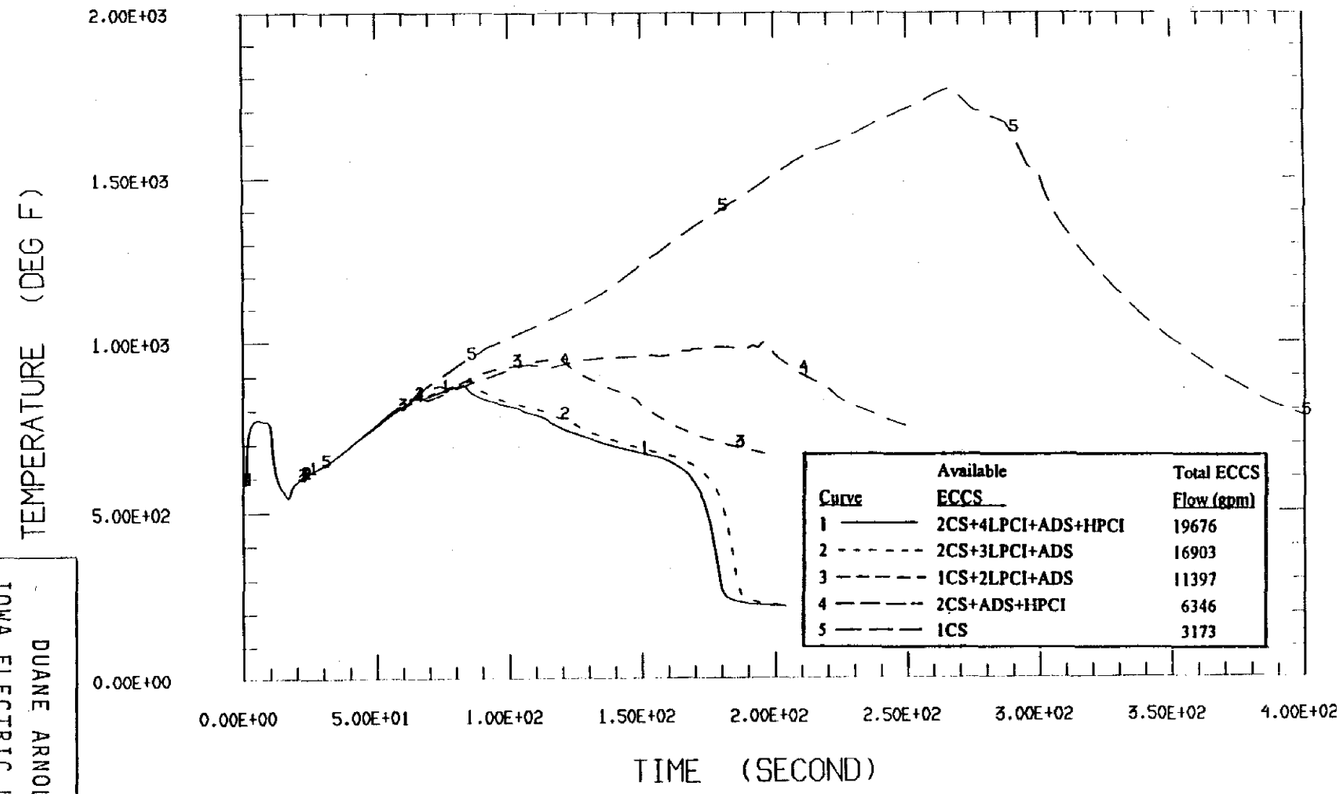
LPCI Pump Curves

Figure 6.3-6



Note: Typical plant response. See Section 15.3 for current analysis of actual PCT values.

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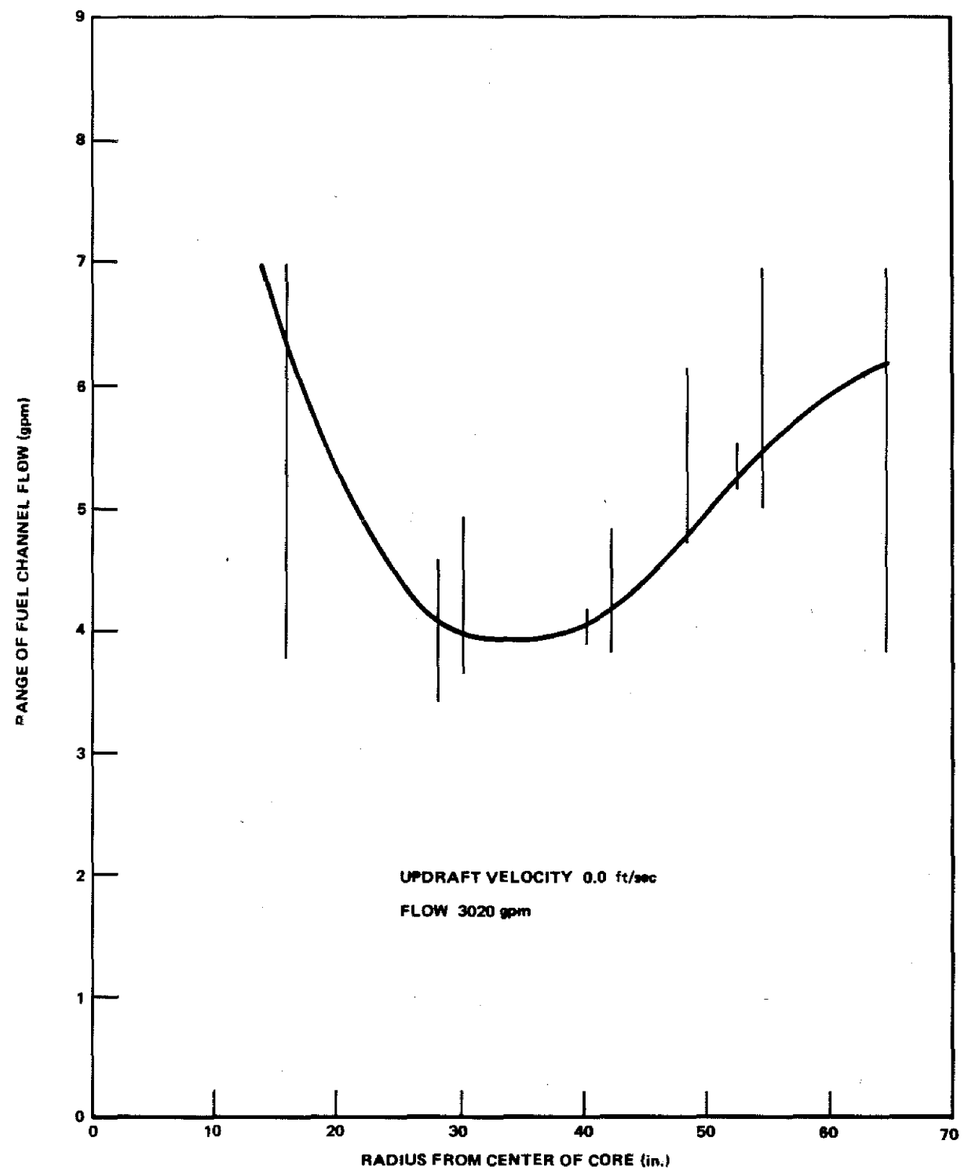
Emergency Core Cooling Systems
Performance Capability
Figure 6.3-9



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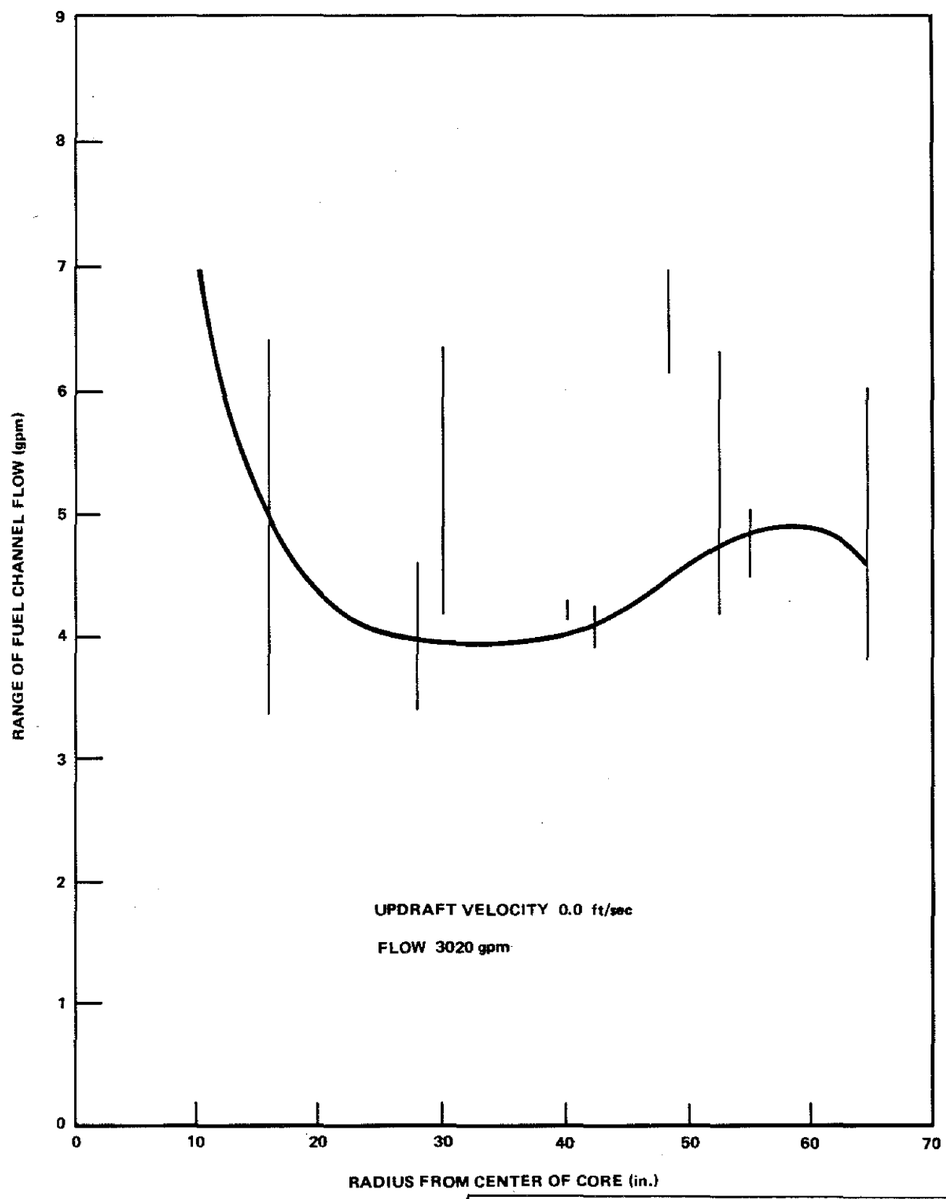
Base Case Data Range Upper Header

Figure 6.3-10



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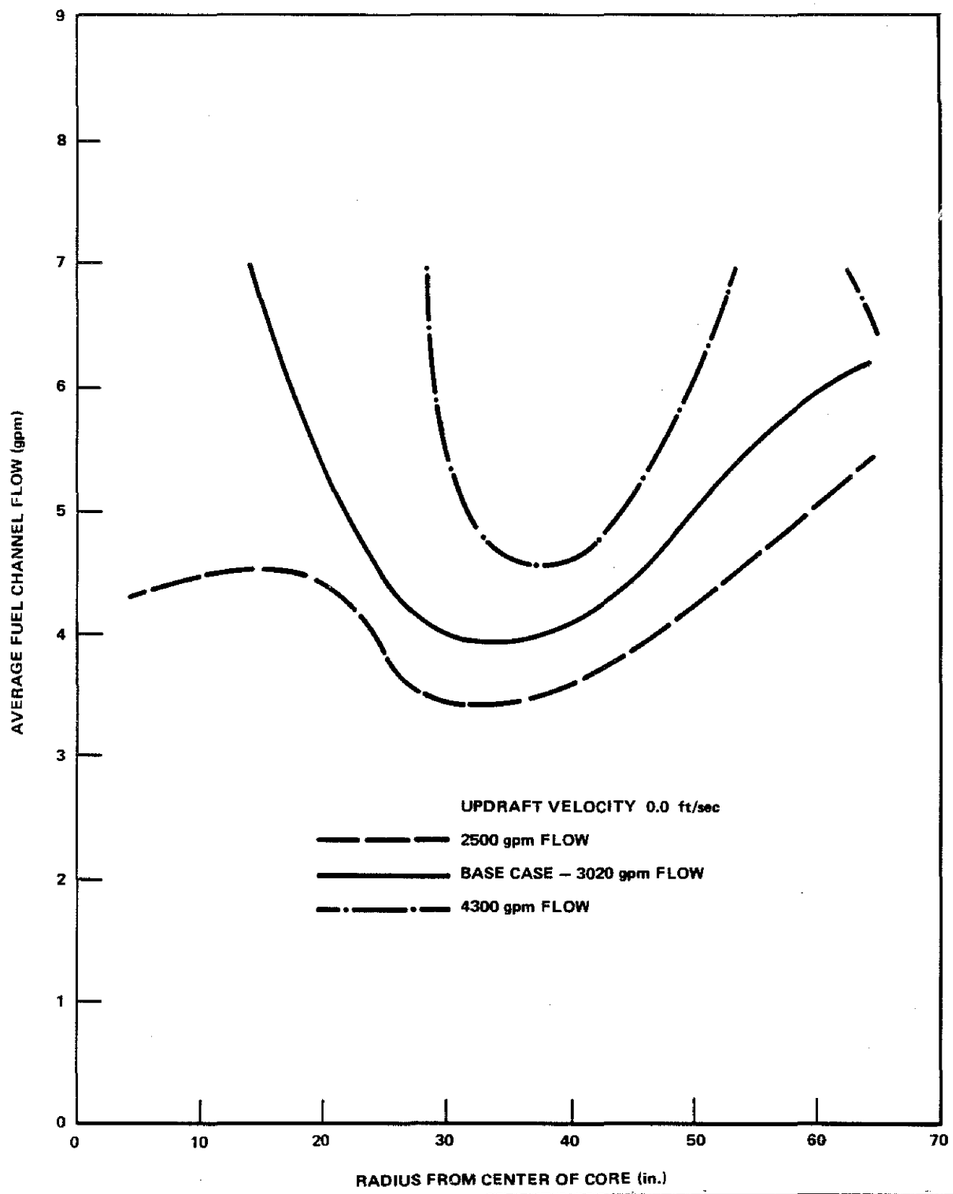
Base Case Data Range Lower Header

Figure 6.3-11



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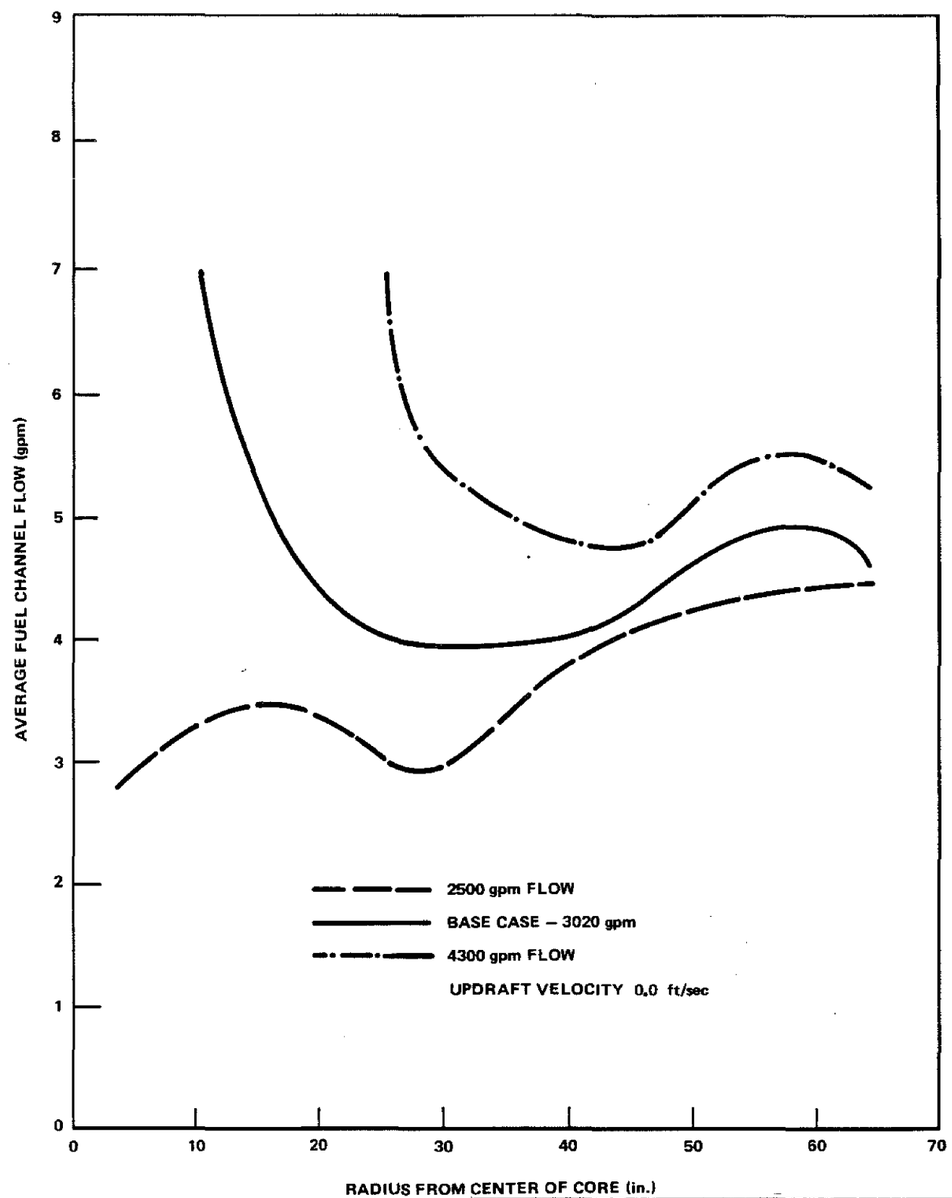
Effect of Flow Upper Header

Figure 6.3-12



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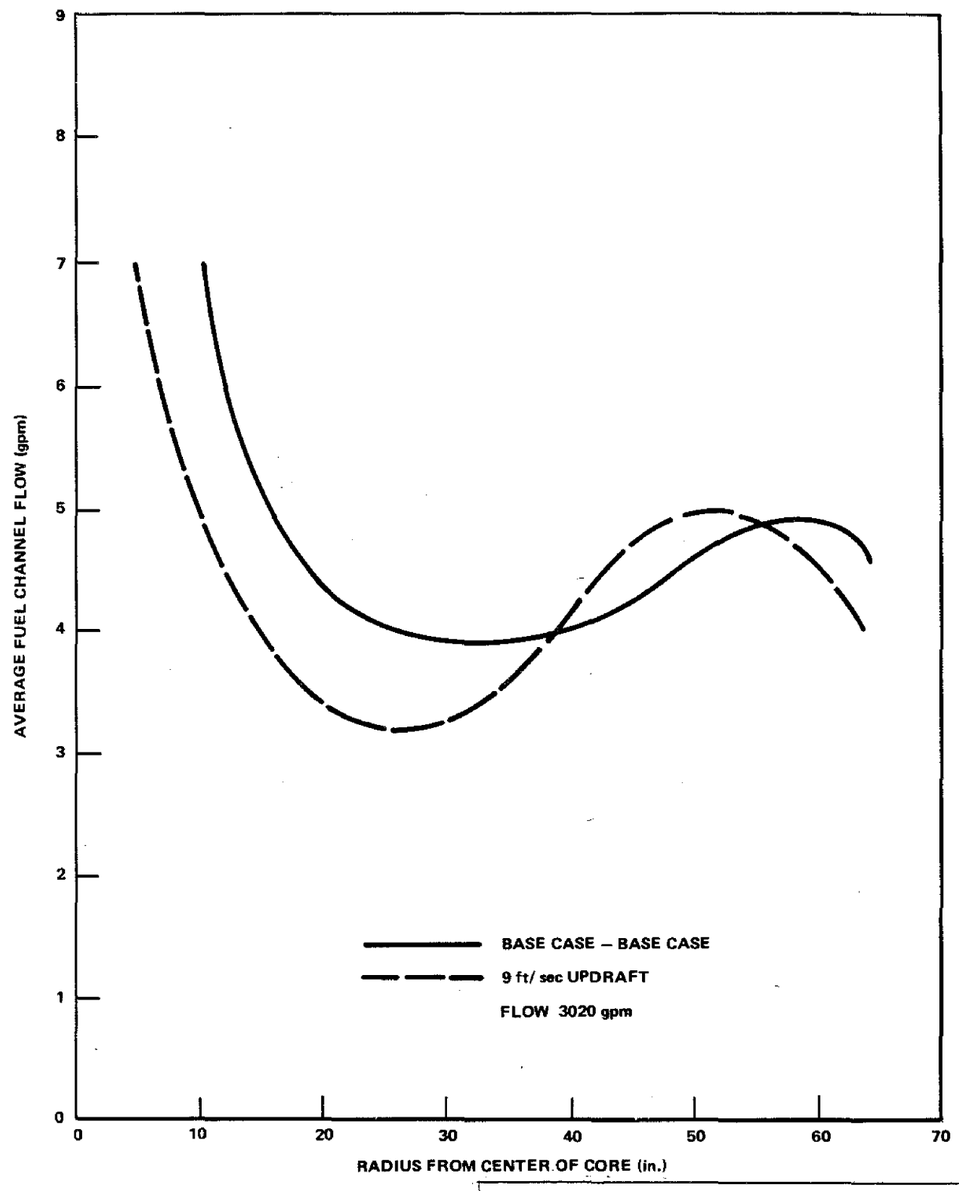
Effect of Flow Lower Header

Figure 6.3-13



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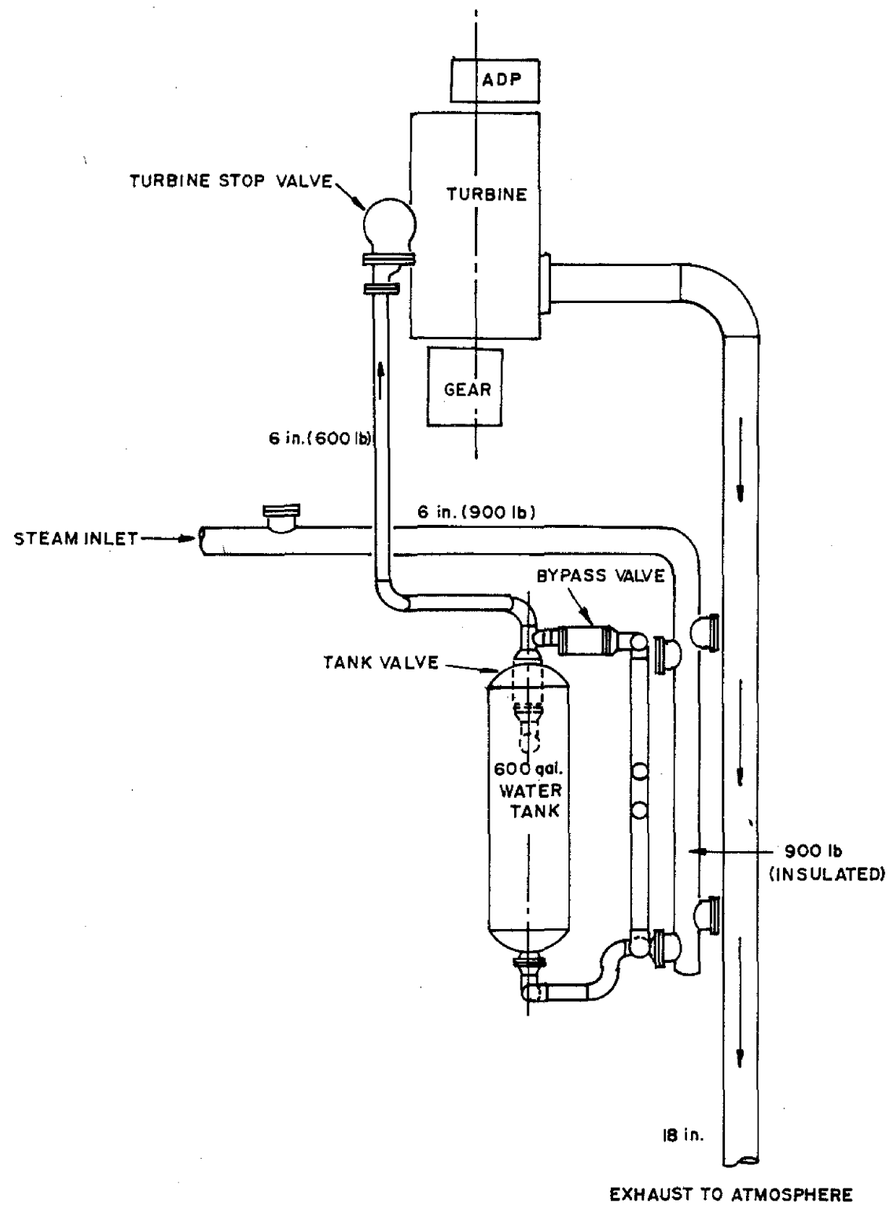
Effect of Updraft Lower Header

Figure 6.3-14



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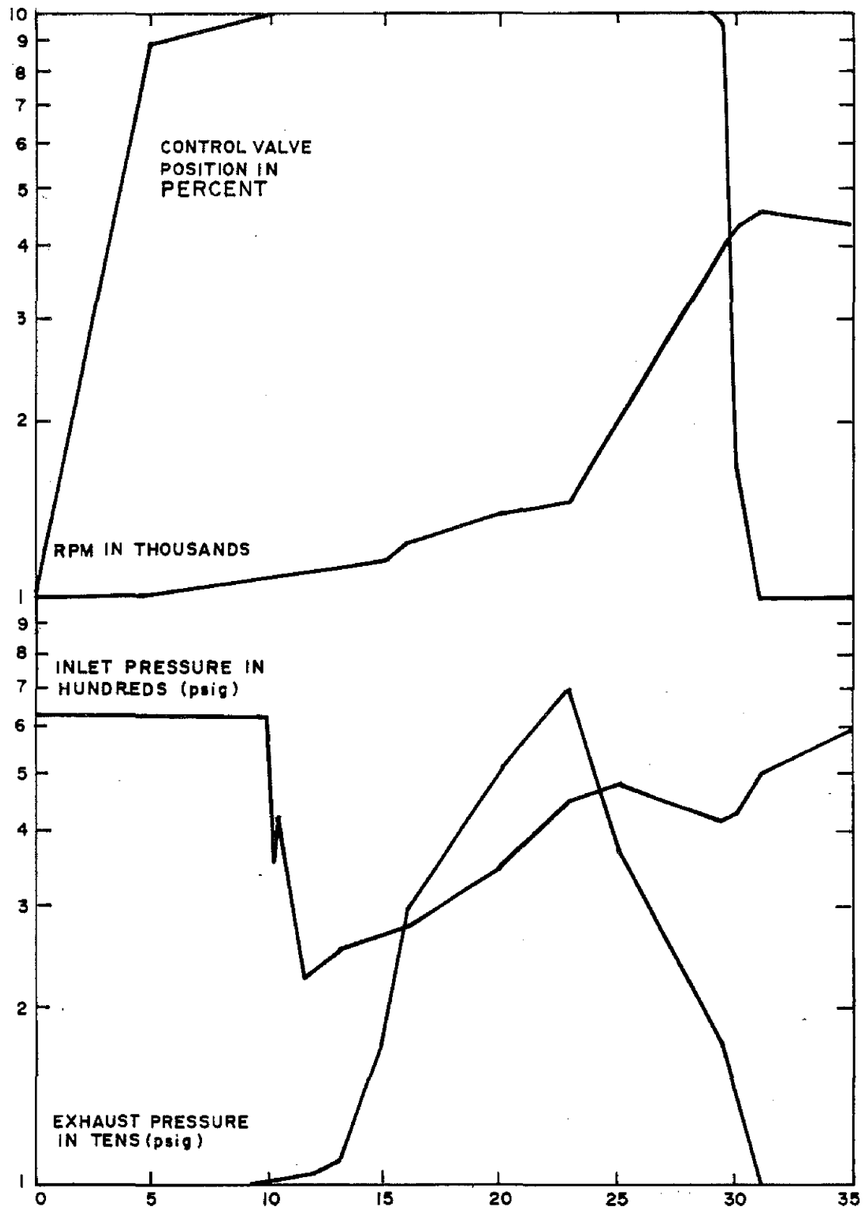
HPCI Turbine Water Injection Test Loop

Figure 6.3-15



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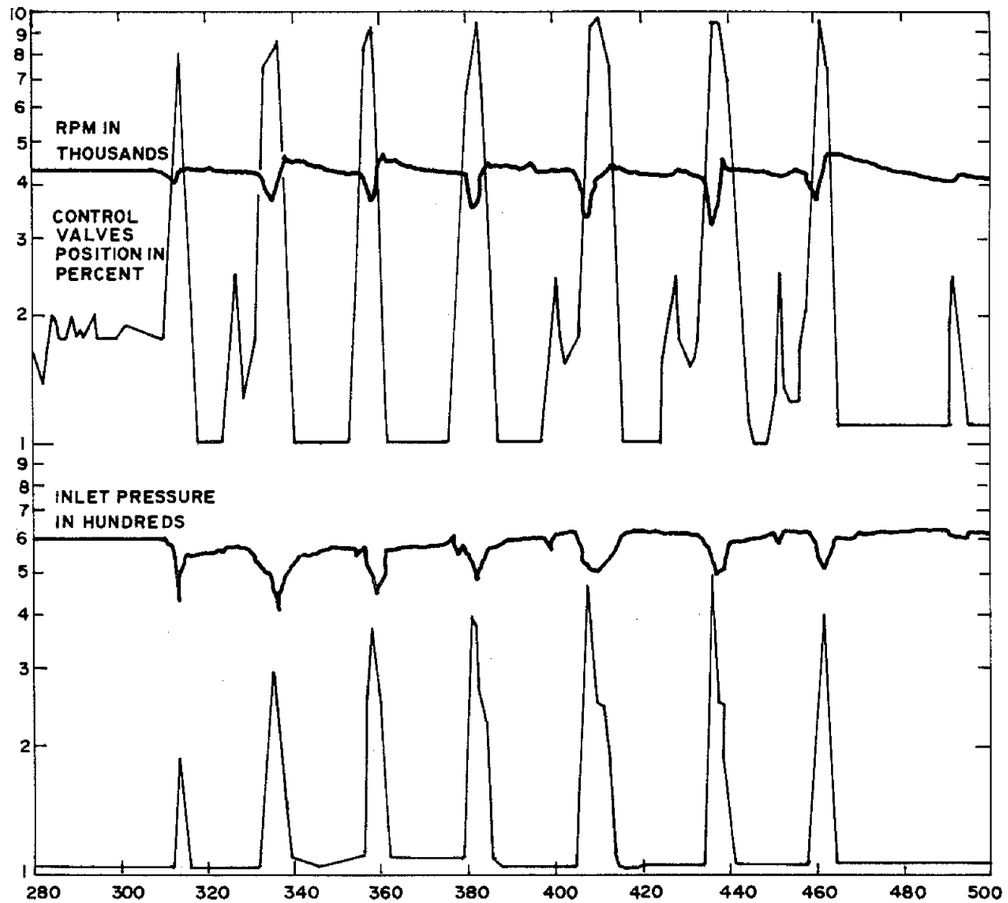
HPCI Turbine Water Injection Tests -
600 Gallon Startup Test

Figure 6.3-16



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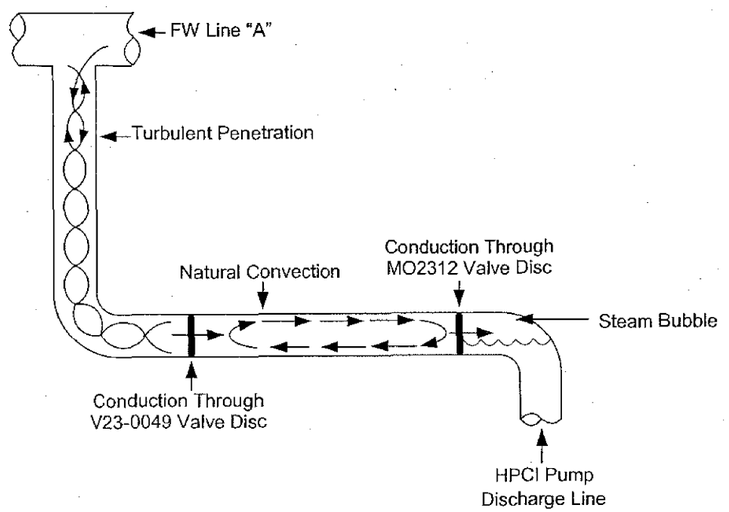
HPCI Turbine Water Injection Tests -
600 Gallon Injection Test

Figure 6.3-17



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Energy Transport Mechanisms for
Equilibrium HPCI Steam Bubble
Figure 6.3-18

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

[redacted] The control building houses the control room and associated auxiliaries, essential switchgear rooms, battery rooms, cable spreading room, computer room, and HVAC equipment room. It does not include the battery room corridor. 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 [redacted] The ventilation system that provides control room airflow also supplies the remainder of the control building, including the essential switchgear and battery rooms (elevation [redacted]), the cable spreading areas above and below the control room, and the HVAC equipment room (elevation [redacted]). 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.

The ventilation air returning from each essential switchgear room can be isolated by bubble tight smoke dampers installed in each room's return duct. The smoke dampers automatically close upon detection of smoke by the duct mounted smoke detector or on a loss of power event. This isolation function will prevent the propagation of smoke from an essential switchgear room to the control room.

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 Total Effective Dose Equivalent (TEDE).

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 TEDE or its equivalent to any part of the body resulting from access and occupancy for the duration of the accident condition are consistent with10 CFR50.67.

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 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 for the Main Steam pathway. 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 analysis was performed of the 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 (including the inboard MSIV drain line) and without the MSIV-LCS (Reference 15.2). This analysis demonstrates that doses remain within the guidelines of 10CFR50, Appendix A, (General Design Criterion 19) for the control room and 10CFR 50.67.

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. [redacted]
2011-016 [redacted] Additionally, six hydril 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 [redacted] 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 [redacted] 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.

6. Chemicals used in the circulating water chemical addition system are stored in four chemical tanks on [redacted]

All of the chemicals are liquids at a temperature of 100°F, non-volatile and do not represent a threat to control room habitability.

Oxygen can also be an explosive hazard. At the DAEC, a [redacted] It is injected into the offgas system and condensate pump suctions. The location meets NFPA separation criteria for proximity to combustibles. The effects of increased oxygen concentration entering safety related air intakes was evaluated and the results show that separation distances are extremely conservative. Therefore, oxygen does not impose a threat to control room habitability.

6.4.4.3.2 Survey of Offsite Chemical Hazards

A survey of potentially toxic and explosive chemicals stored within 5 miles of the DAEC plant was conducted. The following chemicals in this category were identified:

1. Anhydrous ammonia.
2. Propane.
3. Gasoline/fuel oil/diesel oil.
4. Dynamite (TNT).

Anhydrous ammonia has toxic properties. The latter three chemicals are principally fire and explosive hazards.

Section 2.2 describes industrial, transportation, and military facilities and lists local farms and industries, locations of bulk storage facilities, and local transportation of potentially hazardous chemicals within 5 miles of the DAEC.
The evaluation of the survey results is presented below.

1. The only chemical stored offsite that presents a potential toxicity threat to control room habitability is anhydrous ammonia (ammonia gas). Ammonia is used as a fertilizer during a 2-week period of spring planting in central Iowa. The anhydrous ammonia storage nearest to the site is a 2-ton tank on the Stodola farm 1.8 miles from the plant.

   Table C-2 of Regulatory Guide 1.78 permits relief from considering hazardous chemicals as a threat to control room habitability if the chemical is stored in quantities below a given weight at a given distance from the plant site. Using this weight-distance criterion of Regulatory Guide 1.78 and also considering the infrequent storage of ammonia at the Stodola farm, anhydrous ammonia does not present a threat to DAEC control room habitability.

2. The remaining chemicals listed in this section are fire and explosive hazards and would not pose a toxicity threat to control room inhabitants. Although a review of explosive hazards in the site vicinity is not specifically related to control room habitability, Standard Review Plan Sections 2.2.1, 2.2.2, and 2.2.3 require the evaluation of potential offsite accidents that could present a hazard to the plant. A summary of potentially explosive chemicals within 5 miles of the site is therefore included for completeness in responding to NUREG-0737, Item III.D.3.4.

A review of the storage quantities and distances from the site of potential fire and explosive chemicals was conducted using the review criteria of Regulatory Guide 1.91, Evaluations of Explosions Postulated To Occur on Transportation Routes near Nuclear Power Plants. This guide describes the concept of "TNT equivalence" as a method of standardizing the blast effect of various chemicals at various distances from the plant. Briefly, solid and liquid chemicals with explosive properties are assumed to have a 1:1 weight equivalence to TNT unless the chemical is known to have a greater explosive force than TNT. For gaseous chemicals with explosive properties, a 1:2.4 weight equivalence is assumed, such that 1 lb of gas is equivalent to 2.4 lb of TNT.

Each of the fire and explosive chemicals listed in this section is stored in either the liquid or solid state within 5 miles of the DAEC site. A 1:1 weight equivalence to TNT was assumed for gasoline, and a 2.4:1 weight equivalence was assumed for propane, assuming the propane is vaporized on release. The chemicals, quantities, and distances from the site are as follows:

Chemical	Amount Stored or Transported	Distance from the DAEC (miles)
Liquid propane	1,900 gal	0.9 (Bull farm)
Liquid Propane	30,000 gal	3.2 (Palo)
Gasoline	30,000 gal	3.2 (Palo)
Dynamite	10,000 lb (in truck)	3.2 (Palo)
[redacted]	[redacted]	[redacted]

The TNT equivalency of each of the above chemicals was calculated and entered into Regulatory Guide 1.91, Figure 1, along with the distance value, to determine if any explosive risk to the site existed as a result of the detonation of these materials at their storage location. The conclusion reached using this approach is that none of the chemicals present an explosion hazard to the DAEC from their storage locations.

The second aspect to consider for a fire and explosive hazard is the potential transport of these chemicals through the atmosphere to the plant site. All explosive chemicals except propane have vapor pressures under 10 torr and are therefore excluded from further evaluation per the criteria of Regulatory Guide 1.78 for toxic chemicals.

In the case of propane, the analysis concluded that a cloud release of propane at a distance of 3.2 miles would result in a propane concentration at the control building air intake of 0.13% by volume in air. At this concentration, propane is neither a fire nor asphyxiant hazard to the control room.

6.4.4.3.3 Survey Conclusions

The original surveys in Sections 6.4.4.3.1 and 6.4.4.3.2 concluded that chlorine was the only hazardous chemical within 5 miles of the DAEC that might present a threat to control room habitability.

As a result of the conclusion that onsite chlorine releases pose a potential threat to control room habitability at the DAEC, the onsite storage of chlorine has been eliminated.

Subsequent to the original survey of onsite and offsite hazardous chemicals, an evaluation of the effects of a CARDOX system actuation into the Cable Spreading Room has been performed and is discussed in Section 6.4.4.5.

6.4.4.4 Comparison with NRC Licensing Criteria

NUREG-0737, Item III.D.3.4, states that the following NRC licensing documents address control room habitability:

1. General Design Criterion 19, "Control Room."

2. Regulatory Guide 1.78, Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release.

3. Regulatory Guide 1.95, Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release.

4. Standard Review Plan, Section 6.4, "Habitability Systems."

5. Standard Review Plan, Sections 2.2.1, 2.2.2, and 2.2.3.

6. Murphy and Campe paper of August 1974, Meeting General Design Criterion 19.

A review was conducted to determine the degree of conformance of the DAEC design to each of the above documents. The results of this review are summarized below:

1. General Design Criterion 19, Control Room. The DAEC design satisfies General Design Criterion 19. Section 3.1 describes General Design Criterion 19 compliance and refers to Section 12.3.2 for a description of control room radiation protection.

2. Regulatory Guide 1.78 (see also Section 1.8). The DAEC design does not fully meet the positions of Regulatory Guide 1.78. Principal differences between the plant design and this guide include the following:

   a. Chlorine was the only hazardous chemical analyzed in the FSAR, whereas the guide requires that all hazardous chemicals that could exist in quantity within 5 miles of the plant site be evaluated for potential impact on control room habitability. (See Section 6.4.4.5 for a discussion of the effects of a CARDOX system actuation on Control Room Habitability.)

   b. Equipment to detect the presence of hazardous chemicals in the control room air supply and a means of automatically initiating systems designed for the protection of the control room on detection are required by the guide. The DAEC presently has no equipment for automatic protection of the control room or control building following the detection of hazardous chemicals.

   c. DAEC emergency procedures do not presently address hazardous chemical releases, as required by the guide.

3. Regulatory Guide 1.95 (see also Section 1.8). The DAEC design does not fully meet the positions of Regulatory Guide 1.95. Principal differences between the plant design and this guide include the following:

   a. The guide defines six types of control rooms, with corresponding maximum chlorine storage requirements for each type. Each of the six control room types includes chlorine detectors located in the fresh air inlets for the initiation of control room isolation. Because the DAEC design does not provide for automatic control room isolation, the DAEC control room meets none of the defined control room types in the guide.

   b. The guide requires periodic control room leakage testing by the pressurization of the control room. Because the DAEC control room is not separately isolable, the pressurization of the room is not possible.

   c. As in Regulatory Guide 1.78, this guide requires emergency procedures for chlorine releases. These are not presently developed for the DAEC.

4. Standard Review Plan, Section 6.4. The DAEC design differs from the acceptance criteria in Standard Review Plan Section 6.4. Principal differences between the plant design and the Standard Review Plan include the following:

   a. The DAEC "emergency zone" includes not only the control room elevation of the control building, but also the remaining three building elevations not requiring operator occupancy under accident conditions. The Standard Review Plan limits the emergency zone to those spaces requiring operator occupancy.

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.

Item		Response
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.
	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 [redacted]

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.

Item		Response
2 (cont.)	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.
	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.

Item		Response
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
2011-016 Hydrogen	2 (tube trailers)	176,000 ft^3
Nitrogen	1	9300-gal cryogenic tank
Carbon dioxide	1	10-ton tank
Sulfuric acid	1	20,000-gal tank
Circulating water	2	2000-gal tank
treatment chemicals	1	2000-gal tank
(3)	1	1000-gal tank

Subsequent to the above response, two additional storage containers were found on the DAEC site and moved to the south warehouse area. Tank capacity is 1000 gallons for the gasoline and 500 gallons for the fuel oil 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.

Item	Response
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.

6.4.7 TECHNICAL SUPPORT CENTER

The Technical Support Center (TSC) is provided with shielding and an air cleanup system to assure habitability under postulated accident conditions, as discussed in Sections 12.3.2 and 9.4.9. Area radiation monitors are also provided and are described in Section 12.3.3.3.3. Evaluation of radiological dose to TSC personnel during accident conditions is discussed in Chapter 15.2.

No toxic gas protection features are required, as discussed in the preceding sections.

Radiological analysis similar to the analysis described in Section 6.4.4.2 for the control room was used to calculate the effects of the allowable MSIV leakage rate in terms of TSC doses. Table 6.7-1 shows that calculated TSC doses exposure for the BWROG radiological analysis for the DAEC. Regulatory limits and the calculated doses from radiological analysis from above, 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 the elimination of the LCS)

results in an acceptable increase in the dose exposure previously calculated for the TSC. The revised LOCA doses remain within the guidelines of 10CFR50, Appendix A, (General Design Criterion 19) for the TSC and 10CFR 50.67.

REFERENCES FOR SECTION 6.4

1. U.S. Nuclear Regulatory Commission, Clarification of TMI Action Plan Requirements, NUREG-0737, Washington D.C., 1980.

2. U.S. Nuclear Regulatory Commission, NRC Action Plans Developed as a Result of the TMI-2 Accident, NUREG-0660, Washington, D.C., 1980.

3. Letter from Larry D. Root, Iowa Electric, to Harold R. Denton, NRC, Subject: Responses to NUREG-0737 Items Requiring Response by January 1, 1981, dated December 31, 1980 (Serial No. LDR-80-393).

4. Letter from Larry D. Root, Iowa Electric, to Harold R. Denton, NRC, Subject: NUREG-0737, Item III.D.3.4, dated March 24, 1982 (Serial No. LDR-82-082).

5. Letter from Domenic B. Vassallo, NRC, to Duane Arnold, Iowa Electric, Subject: NUREG-0737, Item III.D.3.4, Control Room Habitability, dated April 19, 1982.

6. Letter from Clyde Y. Shiraki, NRC, to Lee Liu, Iowa Electric, Subject: Control Room Habitability Evaluation, dated August 2, 1991

7. Letter (NG-91-3254) from Daniel L. Mineck, Iowa Electric, to Thomas E. Murley, NRC, Subject: Response to Request for Additional Information Regarding DAEC's Control Room Habitability Evaluation, dated October 28, 1991

8. Letter (NG-92-2091) from David Wilson, Iowa Electric, to A. B. Davis, NRC, Licensee Event Report 92-004, dated April 21, 1992

Table 6.4-1
Deleted

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 ENGINEERED SAFETY FEATURES FILTER SYSTEMS

Filter systems required to perform a safety-related function following a design-basis accident are discussed or referenced in this section. These filter systems are associated with the control room, the emergency switchgear rooms, the battery rooms, the standby diesel-generator room, the fuel storage pool, and the reactor building spaces associated with residual heat removal, reactor core isolation cooling, high-pressure coolant injection, and core spray.

The subject filters are contained within the following systems:

1. Standby gas treatment system (SGTS), Figure 6.2-61.

2. Reactor building ventilation system, Figure 9.4-3 (spaces associated with residual heat removal, reactor core isolation cooling, high-pressure coolant injection, core spray, and the spent-fuel pool).

3. Turbine building ventilation system, Figure 9.4-5 (standby diesel-generator room).

4. Control room ventilation system, Figure 9.4-7 (control room, emergency switchgear rooms, and battery rooms).

The standby gas treatment system is discussed in Section 6.5.3.3.

The reactor building ventilation system is discussed in Section 9.4.2 and 9.4.6.2.

The turbine building ventilation system is discussed in Section 9.4.3 and 9.4.6.2.

The control room ventilation system is discussed in Sections 9.4.4, 9.4.6.2, and 6.4.4.

6.5.2 CONTAINMENT SPRAY SYSTEM

The DAEC containment spray system is provided for heat removal purposes and is not relied on to perform a fission product removal function following a design-basis accident. Containment spray is discussed in Section 6.2.2.2.2.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

The primary containment forms a barrier to prevent the escape of radioactive material released as a result of a design-bases accident. The secondary containment system is a second barrier that surround the primary containment and retains any airborne

radioactive gases or particles that leak from the primary containment. The secondary containment system provides holdup, filtration, and controlled, elevated release of low-level airborne radioactive materials.

6.5.3.1 Primary Containment

The primary containment system is discussed in detail in Section 6.2. It is designed to provide an extremely low leakage boundary for the retention of any radioactive material released.

The safety objective of the system is to provide the capability, in conjunction with other safeguard features, 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 CFR50.67.

Isolation valves for the primary containment are provided to maximize the retention of radioactive materials within the primary containment should they be released from the reactor to the containment during the course of an accident. Chapter 15 demonstrates the effectiveness of the primary containment system as a radiological barrier.

Following the design-basis accident, the vent system connecting the drywell to the pressure suppression chamber conducts flow from the drywell to the suppression chamber without excessive resistance and distributes this flow into the pool. The pressure suppression pool condenses the steam portion of this flow and releases the noncondensible gases and gaseous fission products to the pressure suppression chamber gas space.

Isolation valves for the primary containment 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.

6.5.3.2 Secondary Containment

The secondary containment system of the DAEC is discussed in detail in Section 6.2.

The system consists of four subsystems: The reactor building, the reactor building isolation and control system, the standby gas treatment system, and the offgas stack.

The standby gas treatment system is discussed in Section 6.5.3.3, while the rest of the subsystems of the secondary containment system are described in Section 6.2.3.

The secondary containment system serves as the containment barrier during reactor refueling and maintenance operations when the primary containment is open and as an additional barrier when the primary containment is functional. The secondary containment system is designed to provide holdup, filter treatment, and an elevated release point for any fission or activation products released to it.

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 50.67 and RG 1.183. The secondary containment is designed to accomplish this by providing a filtered, elevated release of airborne radioactive materials.

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

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.

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. The second feature is a low-leakage containment volume. The third feature is the removal of particulates and iodines by filtration before release. The fourth feature is the exhausting of the secondary containment atmosphere through an elevated release point. (See Section 6.2.3.2.1)

Analysis of the design basis refueling accident (fuel handling accident) performed using the assumptions and methodology in Regulatory Guide 1.183 “Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors” determined that the secondary containment function is not required to keep radiological doses within regulatory limits. The refueling accident analysis is described in Chapter 15. Although operability of the secondary containment systems may be relaxed during refueling and core alterations, outage risk management procedures require planning to consider normal or contingency methods to restore secondary containment in the event of a refueling accident to further limit the radiation released.

6.5.3.3 Standby Gas Treatment System

The standby gas treatment system, which is a subsystem of the secondary containment, consist of two identical parallel air filtration assemblies located at elevation

[redacted] of the reactor building (Figure 6.2-61). The assemblies are separated by a Seismic Category I concrete wall and completely enclosed within a Seismic Category I structure. Each of the filtration assemblies has full capacity. With the reactor building isolated, each train can hold the building at a subatmospheric pressure of 0.25 in. of water.

The physical arrangement of the standby gas treatment system is such that redundant units are physically separated by both space and structural components in the reactor building. The physical arrangement of instrumentation and controls is discussed in Section 7.3.

The standby gas treatment system dampers are designed to fail to positions that provide open flow paths through the filter trains. The dampers are arranged such that a loss of air, a loss of dc power, or a failure of a logic channel will not prevent exhausting all reactor building areas through one of two filter trains.

The standby gas treatment system is protected from overpressurization by a relief damper installed in the standby gas treatment system suction ductwork. The relief damper is actuated within 0.1 sec when the differential pressure between the suction ductwork and the secondary containment exceeds 10 in. of water.

The mode of operation of each standby gas treatment filter train is controlled by a switch from the control room. In order to facilitate maintenance and testing and allow manual mode selection, the switch has the following positions:

MANUAL: This position allows direct operation and testing of the filter train.

AUTO: This is the normal switch position for both standby gas treatment filter trains. Upon the receipt of an initiation signal, the fans automatically start and dampers operate.

During normal operation, the isolation dampers of the reactor building ventilation system are open, and the required supply and exhaust fans to the various areas are operating. The reactor building ventilation shaft to standby gas treatment dampers are closed and the filter trains are not operating. In this condition, the standby gas treatment trains are in AUTO unless maintenance requirements temporarily place one train out of service.

Upon receiving the required initiation signal, all normal reactor building ventilation is isolated, both standby gas treatment system filter trains start, all standby gas treatment isolation dampers open, and each fan draws air from the isolated reactor building.

In order to achieve the design differential pressure as rapidly as possible and reduce the possibility of exfiltration, both trains start initially. After the operation of each train is verified by flow indicators in the control room, the control room operator

switches one train to MANUAL and then back to AUTO. In this condition, the train will not start unless low flow in the operating train occurs.

The air discharge rate of the running fan may be adjusted by operating personnel in the control room using the information provided by the flow indicators and inlet vane damper control located in the control room.

The safety evaluation and the inspection and testing requirements for the standby gas treatment system are described in this chapter.

Each train has a maximum flow rate of 4000 cfm. Automatically operated exhaust fan inlet vane controls maintain the required flow rate set by the flow controller. The flow controller can be set to a maximum value of 4000 cfm. The secondary containment leaktightness is maintained such that 4000 cfm is adequate to establish 0.25 in. of water subatmospheric pressure. The filtration system has a capability of removing in excess of 99% of the iodine in the air stream with 10% of the iodine in the form of
2013-009 methyl iodide. The effects of moisture on the adsorber's ability to capture gaseous activity are accounted for by performing testing at a relative humidity of 95%. HEPA filters having an efficiently of 99.97% for particles greater than 0.3 1m are located upstream and downstream of the iodine adsorber in each train.

The HEPA filters are constructed with aluminum separators, cadmium plated steel frames, fiberglass-asbestos filter media, and a fire-resistant rubber-base sealant compound. The sealant will withstand an accumulated radiation exposure of at least 1 x 10^8 rads at a continuous operating temperature of 250°F. This radiation exposure is approximately two orders of magnitude greater than the exposure that could be accumulated by the upstream HEPA filter of the standby gas treatment system, assuming that it collects the particulate leaking from the primary containment as a result of a LOCA releasing the hypothetical TID-14844 fission product source term.

Two electric heaters (a constant heater and variable heater) are provided in the
2013-009 standby gas treatment system (between the demister and the prefilter), but are not required
2015-007 to operate. Power to the heaters, and their controls, is isolated by open circuit breakers and pulled fuses.

The efficiency of both the upstream and downstream HEPA filters of the standby gas treatment system has been tested with dioctylpthalate (DOP). Based on a maximum expected upstream DOP air concentration of 40 1g/l and a maximum test duration of 1 min at 4000 cfm, approximately 0.1 g of DOP is deposited per test on the filter bank. Testing and operating experience at numerous laboratories and operating facilities indicates that increased HEPA filter operating temperatures with design limits cause no measurable losses of DOP from the filters. In addition, DOP particles are not readily removed from air streams by charcoal beds with a thickness of less than 6 in. Experimental work performed at Savannah River Laboratory and Oak Ridge National Laboratory has demonstrated that the presence of DOP in impregnated charcoal filter

beds has no measurable effect on iodine retention or on the charcoal ignition temperature and does not promote significant iodine conversion to organic forms.

The activated carbon iodine filter is a high-efficiency deep-bed type with a 6 in. layer of charcoal, activated for trapping elemental iodine and radioiodine in the form of organic compounds.

The deep-bed filter in each train contains approximately 1224 lbs.net effective, 2500 lbs. total of potassium iodide impregnated, activated charcoal.

Each lot of new charcoal is tested to ensure that its quality meets design requirements. A representative sample from each lot is shown to be capable of removing at least 99% of methyl iodide. Tests are run in accordance with ASTM D3803-1989.

The filter unit consists of six individual charcoal beds connected in parallel to a common inlet plenum. Each charcoal bed is contained and formed by a rectangular-shaped perforated metal inlet enclosure within an outer perforated metal enclosure. These enclosures form the inlet and outlet boundaries, respectively, of the beds. The perforated metal inlet enclosure is completely submerged within the bed of charcoal.

The minimum thickness of charcoal between the inlet and outlet perforated screen metal boundaries of each bed is 6 in.

The beds are of all-welded construction and have all welds that are critical to "bypass" minimized and readily accessible for routine postinstallation inspection and testing.

The inlet stream (perforated metal) is completely contained and submerged within the bed of charcoal to completely eliminate any change of bypass. The charcoal bed is completely restrained, and its restrained configuration is such that settling, vibration, and/or shock loads such as might be associated with seismic loads cannot alter or diminish the design bed thickness and therefore endure localized higher velocities and promote channeling.

No charcoal-to-metal interface within the bed and parallel to the direction of flow exists so as to completely eliminate any channeling along the interfaces.

The charcoal beds have provisions for easily obtaining representative samples from any portion of the bed.

The high-efficiency charcoal filter unit is supplied complete with a system that ensures a convenient method of filling and/or changing the bed charcoal.

The charcoal fill-and-change system includes a draft blower HEPA filter so that the charcoal filter unit and change system is at a negative pressure during filling and changing operations. All penetrations to the filter bed that are required to be open during

changing operations have a positive inflow of air to promote cleanliness and to eliminate the potential escape of radioactively contaminated particulate to the surroundings.

The charcoal bed is equipped with an overfill hopper to ensure that the design bed thickness will be maintained.

The filter is constructed so the air flow through the carbon bed is essentially in a horizontal plane. The minimum depth of each carbon bed is 6 in.

To test for charcoal filter bypass, Refrigerant-11 or equivalent is introduced into a test distribution header upstream of the filter bank. A gas chromatography having an electron-capture detector is connected through a switching valve to a sampling device located immediately downstream of the adsorptive filter bank to be tested. The concentration of the Refrigerant in the duct downstream of the filter is checked by scanning while the Refrigerant concentration is approximately 50 ppm upstream of the filter at maximum rated air flow. A maximum concentration of 0.03 ppm is allowable downstream of the filter.

The effective face area of the filter is approximately 100 ft^2, large enough so that the maximum superficial gas velocity through the carbon bed will not exceed 40 fpm at the maximum design fan air flow of 4000 scfm (one or both units operative).

2013-001 An analysis of the maximum charcoal filter temperatures following a postulated LOCA has been performed. The calculated temperature increase due to fission product heating is less than 16°F at 1000 cfm. If air flow in a filter train is lost because of fan failure, a small bypass flow (less than 250 cfm) will be diverted through the inoperative train. This flow will be sufficient to hold the temperature increase in the charcoal bed to less than 40°F. This bypass air flow provision will prevent iodine desorbtion or charcoal ignition (at temperatures greater than 640°F). In addition, a water deluge spray is provided for each charcoal filter in the standby gas treatment system to prevent charcoal overheating or ignition.

The reactor building ventilation supply and exhaust fans are tripped, the normal reactor building ventilation is isolated, and both trains of the standby gas treatment systems are started on the receipt of a signal that indicates that either a fuel-handling accident or a LOCA have taken place. (Automatic reactor building isolation and SBGT initiation are not required for the refueling accident, see Section 15.2). Any of the following conditions is sufficient to initiate this action: the detection of high radiation in the refueling floor ventilation exhaust duct or in the reactor building exhaust duct; high drywell pressure; offgas vent pipe high-high radiation; or low reactor water level. The system can also be manually started from the control room. On the receipt of any one of these signals, each damper required for reactor building isolation and standby gas treatment system initiation is designed to go to its required position within 10 sec, except as noted in Table 9.4-2. The reactor building ventilation supply and exhaust fans trip and the SGTS fans start immediately. The SGTS fans will be up to speed in less than 10 sec after the receipt of a start signal.

When system flow has been verified, one train is manually stopped and placed in a standby condition. Cross-connections between the filter trains are provided to maintain the required decay heat removal cooling air flow on the charcoal filters in the inactive train. The system discharges to the offgas stack. The standby gas treatment system is powered from independent emergency service portions of the auxiliary power distribution system.

On the isolation of the secondary containment, the ventilation supply is shut off, and the exhaust is simultaneously redirected to the standby gas treatment system. It is expected that flow in the standby gas treatment system will continue during fan startup because of the inertia of the air flow in the lines. In any event, reverse flow during the fan startup period is prevented by check valves in the SGTS ducting.

2016-003 Drywell and torus purge exhaust can also be directed to the standby gas treatment system for processing before release up the offgas stack (Section 6.2.5). However, the Hardened Wetwell Vent, installed in accordance with NRC Order EA-13-109, intentionally bypasses the SGTS before discharging to an elevated release point above the reactor building roof (see 6.2.1.6.2.4). The HPCI and RCIC systems barometric condenser discharge is also routed to the standby gas treatment system. The function of the reactor building heating and ventilation system is discussed in Section 9.4.2.

The effectiveness of the standby gas treatment system is monitored by the offgas stack radiation monitoring system. This system is described in Section 11.5.3. Instrument sensitivity is given in Table 11.5-1. Iodine samples can be taken from the offgas sample stream by the use of filters that are subsequently analyzed in a laboratory for iodine content.

All the requirements of IEEE 279-1971 are satisfied for the standby gas treatment system.

2013-009 Test and sample analysis requirements of the HEPA filters and charcoal adsorbers are specified in the Technical Specifications. The standby gas treatment system pressure drop and air distribution are tested as specified in the Technical Specifications to demonstrate system performance capability. Performance testing is as specified in the Technical Specifications.

6.5.4 Ice Condenser as a Fission Product Cleanup System

The DAEC does not have an ice condenser.

6.6 INSERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS

Inservice inspection of Class 2 and 3 components will comply with the requirements of 10 CFR 50.55a(g) and ASME B&PV Code, Section XI. The edition and addenda of the Code will be as agreed on by the DAEC and the NRC for each inspection period. The 1989 Edition is applicable for the current inspection interval scheduled to end on October 31, 2006.

The engineering and design effort associated with the DAEC predates the availability of Section XI of the ASME Code. However this Code, including addenda through the Winter 1972 Addenda, was used as a guide in the preparation of the DAEC inservice inspection plan for Nuclear Class 2 components, and maximum access has been provided within the limits of drywell design.

A preservice inspection was not performed at the DAEC on Nuclear Class 2 and 3 components because it was not required at the stage of DAEC construction when it would have been used. For these components, shop and in-plant examination records of components and welds serve as a basis for comparison with inservice inspection data.

The initial inservice inspection of Class 2 components for the DAEC was conducted in accordance with the plant Technical Specifications that were based on the ASME Code, Section III, 1971 Edition through the Winter 1972 Addenda, as approved by the NRC. Inservice inspections before June 1, 1978, were conducted in accordance with these Technical Specifications since Iowa Electric received Facility Operating License DPR-49 before May 1, 1976. This course of action was in full compliance with the amended inservice inspection requirements (10 CFR 50.55a(g)(4)(v)). Inservice inspection of Class 3 components was commenced on June 1, 1978.

Documentation and records of examination procedures, schedules, and inspection reports concerned with preoperational and inservice inspection will be 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 of the preservice base examination data and inservice inspection records of tests performed. Documentation includes corrective action reports and repair procedures where required. Originals of all inservice inspection records are maintained in a central location.

Reporting will be in accordance with the ASME Code, Section XI, Article IWA-6000. References 5.2-10 and 5.2-11 summarize the first ten-year ISI interval.

6.6.1 COMPONENTS SUBJECT TO EXAMINATION

The Nuclear Class 2 pressure-containing components and piping that are considered for inservice inspection include the two RHR heat exchangers and their appurtenances, and RHR piping, pumps, and valves, major portions of the ECCS, CRD hydraulic system, and main steam lines from the outermost containment isolation valves up to but not including the turbine stop and bypass valves.

Components and appurtenances that are to be subjected to non-destructive examination in and around the RHR heat exchangers include the following:

1. Circumferential butt welds.

2. Nozzle-to-vessel welds.

3. Integrally welded support welds.

4. Longitudinal seam welds.

The examination program assumes that examinations can be performed without unloading the reactor core solely for the purpose of conducting examinations.

Class 2 components or systems to be inspected are identified in the Duane Arnold Energy Center third 10-year inservice inspection plan submitted to the NRC by Reference 2. The inservice inspection plan is based on Table IWC-2500-1 of ASME Code Section XI.

The DAEC will submit a report to the NRC at the end of each 10-yr inspection interval defining the examination categories that could not be completed because of scheduling. Examination categories that could not be completed because of accessibility/limitations require an approved relief request from the NRC.

The Nuclear Class 3 inservice inspection program includes the following systems:

1. RHR service water.

2. Steam lines from six main steam safety relief valves to the torus.

3. Emergency service water system.

4. River water supply system.

6.6.2 ACCESSIBILITY

Access for inspection has been provided within the limits of the plant and system design. For many areas, volumetric and surface examinations will require the removal of a portion of the permanent insulation.

6.6.3 EXAMINATION TECHNIQUES AND PROCEDURES

6.6.3.1 Class 2 Components

The examination procedures used for inservice inspection will include ultrasonic, magnetic particle, liquid penetrant, and visual techniques. All examinations will be conducted in accordance with ASME Code Section XI. Examining personnel will be qualified in accordance with Subarticle IWA-2300.

The type of inservice inspection planned for each component depends on location, accessibility, and type of expected defect. Direct visual examination is planned wherever possible since it is fast and reliable. Surface inspections are planned where practical, and where added sensitivity is required. Ultrasonic testing or radiography are used where defects can occur in concealed surfaces.

Visual examinations will be used to determine the general condition of the part, component, or surface examined, including such conditions as scratches, wear, cracks, corrosion, erosion, or evidence of leakage.

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.

6.6.3.2 Class 3 Components

The Class 3 inservice inspection program requires visual examination of components for evidence of leakage, structural distress, or corrosion when the system is undergoing either a system inservice test, component functional test, or a system pressure test. Supports and hangers for components exceeding 4-in. nominal pipe size will be examined visually to detect any loss of support capability and evidence of inadequate restraint. Inspection requirements will be in accordance with the Inservice Inspection Plan.

6.6.4 INSPECTION INTERVALS

The inservice inspection interval for the examination program is 10 yr. The extent of Nuclear Class 2 examinations during the third 10-yr interval is as indicated in the DAEC Inservice Inspection Plan[2]. The actual individual inspections will generally be performed during refueling outages and will be adjusted to the load factor of the unit to minimize outage time directly required for inspection.

The first 40-month inspection period ended June 1, 1978, based on commercial operation beginning on February 1, 1975.

The first 10-yr inservice inspection interval ended October 31, 1985, having been extended 9 months as a result of a continuous refueling and repair outage that lasted 9 months from June 1978 to March 1979.

The second 10-yr inservice inspection interval ended on November 1, 1996. The interval was divided into three inspection periods ending on March 1, 1989; July 1, 1992; and November 1, 1996.

The third 10-yr inservice inspection interval commenced November 1, 1996 and is scheduled to end on October 31, 2006.

The inspection schedule for Class 2 components will be in accordance with Subarticle IWC-2400 and for Class 3 components in accordance with Subarticle IWD-2400.

6.6.5 EXAMINATION CATEGORIES AND REQUIREMENTS

Examination categories and requirements for Class 2 components are indicated in Reference 2, which are correlated with Table IWC-2500-1 of Section XI of the ASME Code. Exempted Class 2 components are in accordance with Subarticles IWC-1220. Examination requirements for Class 3 components are in accordance with Subarticle IWD-2500 of Section XI of the ASME Code.

Requests for relief are submitted where it is impossible or impractical to examine or test an applicable Class 2 or 3 component or system.

6.6.6 EVALUATION OF EXAMINATION RESULTS

The results of the examinations are evaluated in compliance with the appropriate portions of ASME Code, Section XI. Repairs, if required, will also comply with Section XI or NRC-approved alternate.

6.6.7 SYSTEM PRESSURE TEST

Near the end of each inspection interval, the following will be subjected to a pressure test in accordance with the Inservice Inspection Plan.

1. RHR and RHR service water systems.

2. Core spray system.

3. HPCI system.

4. CRD hydraulic system.

5. Emergency service water system.

6. River water supply system.

Components will be subjected to normal operating pressure by the operation of system pumps or by remote pressurization. During the pressure test, components will be inspected for leakage without the removal of insulation.

6.6.8 AUGMENTED INSERVICE INSPECTION TO PROTECT AGAINST POSTULATED PIPING FAILURES

The use of augmented inservice inspection as related to the prevention of pipe rupture at the containment boundary is discussed in Section 5.2.4.

REFERENCES FOR SECTION 6.6

1. Letter from Richard W. McGaughy, Iowa Electric, to Harold Denton, NRC, Subject: Duane Arnold Energy Center Second 10-Year Inservice Inspection Plan, dated May 1, 1985.

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

6.7 MAIN STEAM ISOLATION VALVE LEAKAGE TREATMENT PATH

6.7.1 BACKGROUND OF MSIV-LEAKAGE CONTROL SYSTEM

During DAEC's construction permit stage, the NRC identified their concern regarding radiological exposures which could result from leakage from the primary containment which might bypass the secondary containment and the associated filtering systems in the event of an accident. Of particular interest was the possible leakage paths through the Main Steam Isolation Valves (MSIVs). This particular concern was based on BWR plants observing variances with MSIV leakage rates.

The DAEC addressed the concern with a complete study evaluating the path of the fission products from the reactor vessel through the main steam lines to the turbine stop valves. The study also encompassed effects such as diffusion, natural convection and condensation, with respect to the transportation mechanism. The results of the study concluded that the two hour radiological exposure (as defined in 10 CFR 100) from the MSIV leakage was indeed nonexistent and that the thirty day low population zone dose was well below the 10 CFR 100 Guidelines. (The plant's original licensing basis. The current licensing basis is 10CFR 50.67).

The Main Steam Isolation Valve Leakage Control System (MSIV-LCS) was proposed and installed. The MSIV-LCS was designed to collect MSIV leakage following a design basis loss of coolant accident (LOCA) and process it through the Standby Gas Treatment System. The system provided additional assurance that the radioactivity, which may leak from the primary containment as a consequence of MSIV leakage, would not bypass the secondary containment in the event of an accident

In 1982 the BWR Owners Group (BWROG) formed a Main Steam Isolation Valve Leakage Committee to identify and resolve the causes of high MSIV leakage rates. The BWROG then formed a follow-on MSIV Leakage Closure Committee in 1986 to address alternate actions to resolve on-going, but less severe MSIV leakage problems and to address the limited capability of MSIV-LCS.

As a resolution to the MSIV-LCS concerns, 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, the 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, and the total main steam pathway, which includes the 4 main steam lines and the inboard MSIV drain line, is limited to 200 scfh. 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).

6.7.2 DESIGN BASES

The design bases of the MSIV Leakage Treatment Path are established to ensure safe and efficient operation and to fulfill the NRC's requirements of minimizing radiological releases under accident conditions. The design bases are as follows:

The MSIV Leakage Treatment Path is established after a design-basis LOCA, with MSIVs isolated and indications of fuel damage.

The leakage path and isolation boundaries are established from the Control Room, by manual operator action.

MSIV leakage rate limits are 100 scfh per valve, and the total main steam pathway, which includes the 4 main steam lines and the inboard MSIV drain line, is limited to 200 scfh per Technical Specifications.

Offsite power is unavailable.

The leakage treatment path and isolated boundary systems shall be "seismically rugged" and will remain functional during and after a seismic event.

Radiological releases shall be limited by 10 CFR 50.67 and 10 CFR 50 Appendix A (General Design Criterion 19) guidelines.

The MSIV Leakage Treatment Path shall comply with the applicable requirements of the ASME Section XI and Augmented Programs.

Equipment will comply with requirements of the Environmental Qualification Program (10 CFR 50.49)

6.7.3 LEAKAGE TREATMENT PATH DESCRIPTION

The MSIV Leakage Treatment Path is designed to mitigate the release of fission products following a LOCA. This is accomplished by directing MSIV leakage to the main condenser via the outboard main steam drain line. The volume and surface area of the condenser provides holdup time and plate-out surface for fission products. Other steam systems connected to Main Steam are isolated to ensure that leakage is processed through this path. The leakage treatment path and isolation boundaries are shown in Figure 6.7-1. The MSIV Leakage Treatment Path is established by operator action following a design-basis LOCA, with MSIVs isolated and indications of fuel failure. All operations are performed from the Control Room.

MO1043 and MO1044 are opened to establish the primary leakage path to the main condenser. Both MOVs are provided with essential power from 1B37 to assure that they can be opened with a coincident loss of offsite power. An alternate drain path is available to convey

MSIV leakage to the isolated condenser if either MOV fails to open. The alternate drain path consists of the bypass line around MO1043 via CV1064, and the bypass around MO1044 via FO1051. CV1064 is a "fail open" valve and FO1051 is a normally open path. Consequently, if either primary MOV failed to open as required, the second drain path would be available to convey MSIV leakage to the main condenser.

The steam systems connected to Main Steam are isolated to ensure that leakage is directed to the main condenser. MO1362A and MO1362B are closed to isolate the offgas and steam jet air ejector systems. MO1169 and MO1170 are closed to isolate the turbine steam seal system. MO1054 and MO1055 are closed to isolate the second stage reheat system. These six MOVs are provided with essential power from 1B37.

6.7.4 SAFETY ASSESSMENT

6.7.4.1 Safety Evaluation

The implementation of the new leakage treatment path required revision of the DAEC Technical Specifications (TS). The allowable leak rate specified in TS was increased from 11.5 scfh for any one MSIV to 100 scfh for any one MSIV with a total maximum pathway leakage of 200 scfh through all four main steam lines (including the inboard MSIV drain line). The MSIV leakage control system (LCS) requirements have been deleted from the TS. This TS change has been evaluated and documented in accordance with 10 CFR 50.90 and 50.59, and reviewed and approved by the NRC (Reference 2).

6.7.4.2 Seismic Verification

The MSIV Leakage Treatment Path uses the main steam piping, main steam drain lines, and main condenser as an alternate method of processing MSIV leakage. Because certain main steam piping and components were not designed as Seismic Category I items, detailed evaluations and seismic verification walkdowns were performed to demonstrate that the main steam system piping and equipment that constitute the alternate treatment path are seismically rugged and meet General Design Criterion 2 of Appendix A to 10 CFR Part 50 with regard to seismic adequacy. The seismic adequacy of these piping and equipment systems at the DAEC was confirmed by comparing them to a detailed earthquake experience database as discussed in Section 6.7 of NEDC-31858P Revision 2 (Reference 1), and performing engineering walkdowns and evaluations using seismic capability engineers.

Seismic evaluations for piping, supports, and equipment associated with the MSIV leakage treatment path were based on new floor response spectra generated for the turbine building. The seismic response of the turbine building design basis earthquake (DBE) was based on the original seismic building model, a NUREG 0098 ground response spectrum, and a soil-structure interaction(SSI) analysis.

The purpose of the SSI analysis was to obtain a more realistic seismic response for the turbine building due to the ground motion of the DAEC DBE. The DAEC DBE is a "Housner" type spectrum with a peak ground acceleration of 0.12g. The methodology for determining the new floor response spectra for the turbine building and performing seismic evaluations of non-seismic piping supports and equipment was consistent with the seismic margins assessment methodology described in Reference 1 of EPRI Report NP-6041-SL. That is, seismic evaluations of non-seismic components were based on 1) a conservative design ground motion, 2) realistic (median centered) response, and 3)conservative allowables or capacities. This approach results in a high confidence of low probability of failure. The methodology used for this application is not an endorsement for the use of the experienced-based methodology for other applications at the DAEC.

The DAEC has concluded that the main steam lines, main steam drain lines, condenser, and applicable interconnecting piping and equipment are well represented by the earthquake experience data demonstrating good seismic performance, are confirmed to exhibit excellent resistance to damage from a DBE, and have been shown to have substantial margin for seismic capability. Therefore they are seismically adequate to withstand the DAEC DBE and maintain pressure retaining integrity. This capability of the alternate MSIV leakage treatment system to withstand the effects of the safe shutdown earthquake and continue to perform its intended function (treatment of MSIV leakage) satisfies the intent of the seismic requirement of Appendix A to 10 CFR 100. The DAEC therefore concluded that the proposed method for MSIV leakage treatment is seismically adequate to serve as an acceptable alternative to the previously installed LCS.

6.7.4.3 Radiological Analysis

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 the four main steam lines (including the inboard MSIV drain line) and without the MSIV LCS. The radiological dose methodology developed by GE for the BWROG is documented in Appendix C of Reference 1. This analysis was updated during DAEC implementation of the Alternative Source Term Methodology defined in 10CFR 50.67 and guidelines of RG 1.183. See Chapter 15.2.1 for details of the MSIV leakage path contribution to total dose consequences.

References for Section 6.7

1. NEDC-31858P Revision 2 BWROG Report for Increasing MSIV Leakage Rate Limits and Elimination of Leakage Control Systems, September 1993.

2. NG-94-2629, RTS-232: Increase in Allowable MSIV Leakage Rate and Deletion of the MSIV Leakage Control System, dated August 15, 1994.

3. Amendment No. 207 to Facility Operating License No. DPR-49, Duane Arnold Energy Center (TAC No. M90155), dated February 22, 1995.

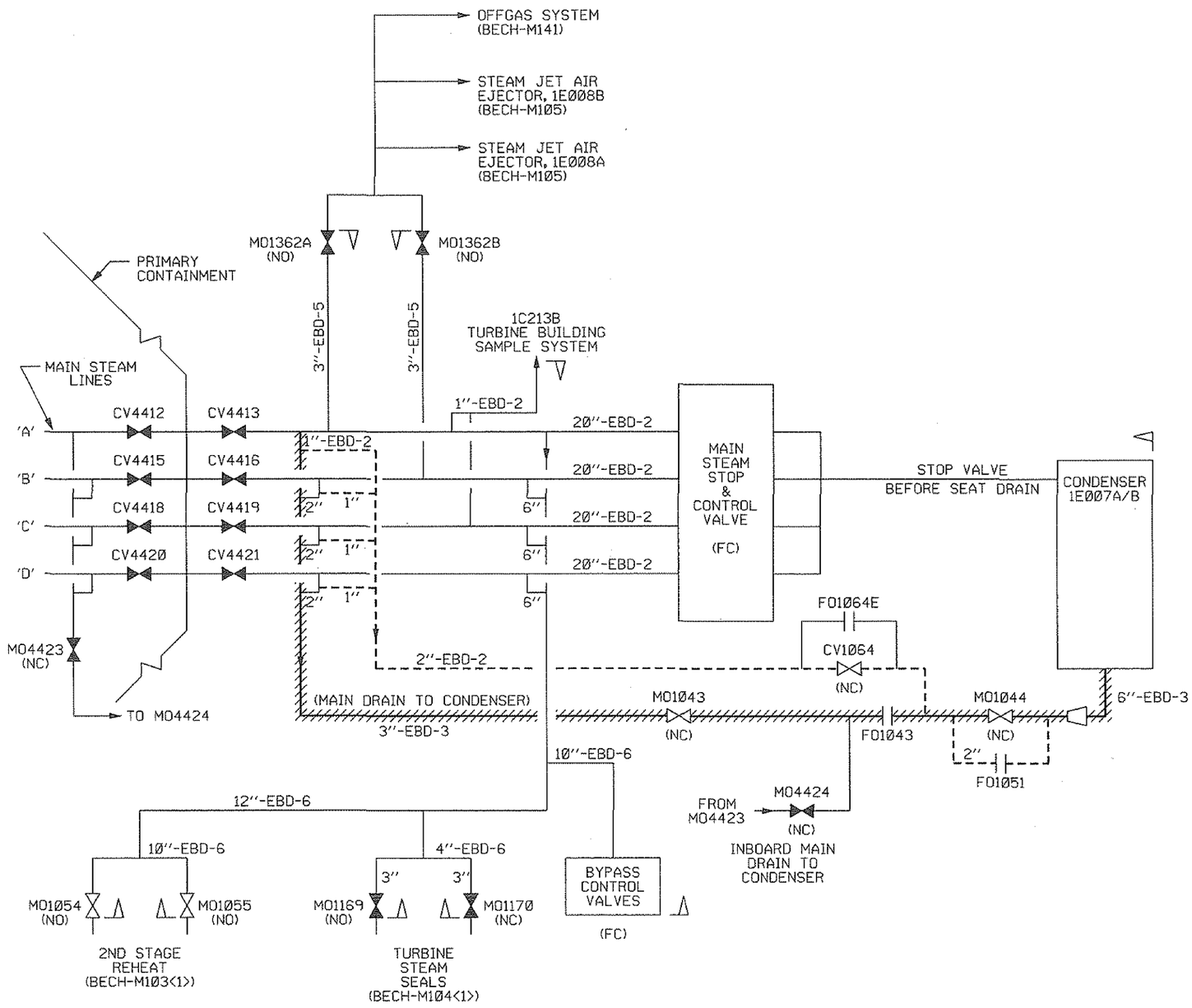
4. NG-94-4632, DAEC, Docket No. 50-331, Operating License No. DPR-49, Response to NRC RAI on MSIV Leakage Control System Technical Specification Amendment Request (RTS 232), dated December 21, 1994.

5. NG-95-0089, DAEC, Docket No. 50-331, Operating License No. DPR-49, Request for Technical Specification Change, RTS 232, Increase in Allowable MSIV Leakage Control System, dated January 20, 1995.

6. Amendment No. 276 to Facility Operating License No. DPR-49, Duane Arnold Energy Center (TAC Nos. ME0873/0874, dated March 31, 2010 (ADAMs ACCESSION NO.: ML100621169).

Table 6.7-1

Deleted



NOTES:

1. ESSENTIAL POWER IS PROVIDED TO THE FOLLOWING VALVES: M01362A, M01362B, M01169, M01170, M01043, M01044, M01054, M01055
2. LINE UP DEPICTS A POST LOCA LINE UP, OPERATOR ACTION IS REQUIRED TO POSITION THE FOLLOWING VALVES: M01362A, M01362B, M01169, M01043, M01044, CV1064, M01054, M01055
3. MAIN STEAM LINES BETWEEN THE MSIV UP TO THE STOP VALVE, INCLUDING BRANCH LINES 3" AND LARGER HAVE BEEN SEISMICALLY ANALYZED.
4. ALL CONNECTING BRANCH LINES SUCH AS HPCI, RCIC, EQUALIZING HEADER DRAIN, (2" AND UNDER), VENTS AND INSTRUMENTATION TAPS ARE NOT DEPICTED BUT WERE INCLUDED IN THE EDE SEISMIC ADEQUACY EVALUATION.

NO = NORMALLY OPEN

NC = NORMALLY CLOSED

FC = FAILED CLOSED

= SEISMIC ADEQUACY WALKDOWN BOUNDARY

= PRIMARY DRAIN PATH

= ALTERNATE DRAIN PATH

REFERENCE DRAWINGS:

1. BECH-M103<1>,<2>
2. BECH-M104<1>
3. BECH-M105<1>
4. BECH-M114
5. BECH-M122
6. BECH-M124
7. BECH-M141
8. BECH-M149
9. DI-646, 683, 692
10. IP0I-3

DUANE ARNOLD ENERGY CENTER
NEXTERA ENERGY DUANE ARNOLD, LLC
UPDATED FINAL SAFETY ANALYSIS REPORT

MSIV LEAKAGE TREATMENT PATH
AND ISOLATION BOUNDARIES

FIGURE 6.7-1