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CHAPTER 5

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

This chapter describes those systems and components that form the major portions of the nuclear system process barrier. These systems and components contain or transport the fluids coming from or going to the reactor core.

Section 5.3 describes the reactor vessel and the various fittings with which other systems are connected to the vessel. The major safety considerations for the reactor vessel are concerned with the ability of the vessel to function as a radioactive material barrier. Various combinations of loading are considered in the vessel design. The vessel meets the requirements of various applicable codes and criteria. To reduce the probability of the fracture of any component or piping in the reactor coolant pressure boundary that could initiate a loss-of-coolant accident (LOCA), provisions to prevent brittle fracture are applied over the entire boundary.

The reactor recirculation system pumps coolant through the core. The adjustment of the core coolant flow rate changes reactor power output, thus providing a means of following plant load demand without adjusting control rods. The recirculation system is designed with sufficient fluid and pump inertia so that fuel thermal limits cannot be exceeded as a result of recirculation system malfunctions. The arrangement of the recirculation system is designed so that a piping failure cannot compromise the integrity of the floodable inner volume of the reactor vessel.

The nuclear system pressure relief system is designed to protect the nuclear system process barrier from damage due to overpressure. To accomplish overpressure protection, six pressure-operated relief valves are provided to discharge steam from the nuclear system to the primary containment. The nuclear system pressure relief system also acts to automatically depressureize the nuclear system in the event of a LOCA in which the high-pressure coolant injection (HPCI) system fails to deliver rated flow. The depressurization of the nuclear system in this situation allows low-pressure emergency core cooling systems to supply enough cooling water to adequately cool the fuel. Only some of the pressure relief valves used for overpressure protection are arranged to effect automatic depressurization.

The main steam line flow restrictors are venture-type flow devices. One restrictor is installed in each main steam line close to the reactor vessel but downstream from the pressure relief and safety valves. The restrictors are designed to limit the loss of coolant resulting from a main steam line break outside the primary containment.

Two main steam line isolation valves are installed on each main steam line. One valve on each line is inside the primary containment, the other outside. These vales act automatically to close off the nuclear system process barrier in the event a pipe break occurs downstream of the valves. This action limits the loss of coolant and the release of radioactive materials from the nuclear system. In the event that a main steam line break occurs inside the primary containment, the closure of the isolation valve outside the containment acts to seal the primary containment itself.

The reactor core isolation cooling (RCIC) system includes a turbine-pump driven by reactor vessel steam. Under certain conditions, the system automatically starts in time to prevent conditions requiring the operation of any of the emergency core cooling systems. The system provides the ability to cool the core during a reactor isolation in which feedwater flow is not available.

The residual heat removal (RHR) system includes a number of pumps and heat exchangers that can cool the nuclear system under a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. The RHR system allows the removal of decay heat whenever the main heat sink (main condenser) is not available. One operational mode of the RHR system is low-pressure coolant injection (LPCI). LPCI operation is an engineered safeguard for use during a LOCA; this operation is described in Section 6.3. Another mode of RHR system operation allows the removal of heat from the primary containment following a LOCA (Section 6.2.2).

The reactor water cleanup (RWCU) system functions to maintain the required purity of reactor coolant by circulating coolant through a system of filters and demineralizers.

Section 5.2.5 discusses the detection of leakage through the reactor coolant pressure boundary. Limits on nuclear system leakage inside the primary containment are established so that appropriate action can be taken before the nuclear system process barrier is threatened by a crack large enough to propagate rapidly.

Figure 5.1-1, Sheets 1 and 2, are piping and instrumentation diagrams of the reactor coolant system.

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

The classifications of components and systems that comprise the reactor coolant pressure boundary are given in Section 3.2. ASME Boiler and Pressure Vessel (B&PV) Code compliance is also given in Section 3.2.

The fracture or notch toughness properties and the operating temperature of ferritic materials of the reactor coolant pressure boundary are controlled to ensure adequate toughness when the system is pressurized to more than 20% of the design pressure. Such assurance is provided by maintaining a material service temperature at least 60°F above the nil-ductility transition (NDT) temperature. Further interpretations and requirements are as follows:

1. Charpy V-notch tests are performed to demonstrate that the material meets the minimum impact test temperature. Test specimens are prepared and tested in accordance with the general provisions of N331 and N332 of Section III of the ASME Code. The test temperature is 60°F below the minimum service temperature at which 20% of design pressure can be applied for each pipeline or pressure component.

2. Piping and equipment having a nominal wall thickness of 0.5 in. or less are not tested provided that the material is normalized or has been fabricated to fine-grain-melting practice or is made of austenitic stainless steel.

3. Impact testing is required on components or piping within the boundary having a service temperature of 250°F or less.

4. Impact testing is not required on components or piping within the boundary whose rupture could not result in a loss of coolant exceeding the capability of normal makeup systems to maintain adequate core cooling for the duration of a reactor shutdown and orderly cooldown.

5. Field welds and shop welds in material 0.5 in. thick or less are normalized unless the welding procedure has been qualified by impact testing in accordance with item 1 above.

6. These criteria apply to piping and equipment of the reactor coolant pressure boundary and do not apply to related components such as anchors, anchor bolts, hangers, suppressors, and restraints.

5.2.1 COMPLIANCE WITH CODES AND CODE CASES

5.2.1.1 Compliance with 10 CFR 50.55a

Inservice inspection of Class 1 components is performed in accordance with the Inservice Inspection Plan. Inservice testing of Class 1 pumps and valves is performed in accordance with the Inservice Testing Program.

5.2.2 OVERPRESSURIZATION PROTECTION

5.2.2.1 Design Bases

To design the pressure protection for the nuclear boiler system, extensive analytical computer models, representing all essential dynamic characteristics of the system, are used.. These models include the hydrodynamics of the flow loop, the reactor kinetics, the thermal characteristics of the fuel and its transfer of heat to the coolant, and all the principal controller features such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand. These are represented with all their principal nonlinear features in models that have evolved through extensive experience and favorable comparison of analysis with actual BWR test data.

Included in this model are components of the reactor vessel overpressure protection system. Dual safety/relief valves and spring safety valves are simulated in a nonlinear representation. The model thereby allows full investigation of the various valve characteristics: response time, valve capacity, and actuation setpoint. Typical capacity characteristics as modeled are represented in Figures 5.2-1 and 5.2-2 for both the safety/relief valve and the spring safety valve types. The associated bypass valve, turbine control valve, and main steam isolation valve characteristics are also represented fully in the model.

Safety/relief valve setpoints and minimum design capacities are selected, based on operational transients. The safety/relief valve nominal setpoints and design capacities as modeled are given in Table 5.2-1.

The high-pressure setpoint of the spring safety valves is tied directly to the design overpressure limit allowed by the code. The spring safety valve nominal setpoint is 1240 psig, which is less than the 1250 psig vessel design pressure.

The design task is to establish the minimum high-pressure safety valve capacity to satisfy the design criteria. In the case of the dual-purpose safety/relief valves, the valves qualify as safety valves at setpoints coincident with the relief setpoints.

5.2.2.2 Design Evaluation

See Appendix 5B.

5.2.2.2.1 Power Uprate Overpressure Protection Evaluation

The closure of all main steam isolation valves with flux scram is evaluated as part of the reload licensing analyses for each operating cycle to determine the adequacy of the nuclear

system overpressure protection system. This was chosen as the limiting isolation event. The code safety and the safety/relief valve setpoints were as indicated in Table 5.2-1. All safety/relief valves were assumed to be in service. The summary of the results of the analysis is presented in Section 15.1.2.3.2.

Generic studies show that a maximum pressure increase of 20 psi would result for a main steam isolation valve closure event with a single safety/relief valve failing to open. Therefore, for a single safety/relief valve failure the maximum pressure at the bottom of the vessel would still have margin to the ASME vessel code limit.

5.2.2.3 Piping and Instrumentation Diagrams

See Figure 5.1-1.

5.2.2.4 Equipment and Component Data

5.2.2.4.1 Safety Valves

There are two Dresser Maxiflow safety valves located on the main steam lines within the drywell between the reactor vessel and the first isolation valve. They are spring loaded, flat seated, reaction type. The inlet connections are 6-in., 1500-lb special-facing flanges. The outlet connections are 8-in., 150-lb raised-face flanges per ANSI B16.5. The set pressure and capacity are given in Table 5.2-1.

5.2.2.4.2 Safety/Relief Valves

There are six Target Rock safety/relief valves, all of which are located on the main steam lines within the drywell between the reactor vessel and the first isolation valve.

The inlet connections for the Target Rock safety/relief valves are 6-in., 1500-lb special-facing flanges. The outlet connections are 10-in., 300-lb raised-face flanges per ANSI B16.5. The safety/relief valves are designed, constructed, and marked as described in Section 5.4.13.

Each safety/relief valve consists of three main sections. The pilot valve section is a relatively small, self-actuated relief valve, integral with the main valve, which provides pressure sensing and main valve control functions. The main element of this pilot valve is a precision-machined spring bellows, the expansion of which accurately controls the main valve. It is actuated by externally supplied nitrogen pressure to a diaphragm. The main valve section is a hydraulically operated, reverse-seating globe valve which, when actuated by the pilot valve, provides the pressure relief function by opening to discharge nuclear system steam to the suppression pool.

A typical sequence of operation for overpressure relief self-actuation can be described as follows (refer to Figures 5.2-9 and 5.2-10):

1. In the closed position (Figure 5.2-9), the bellows is mechanically extended a slight amount by the preload spacer to provide a preload force on the pilot disk. This seats the pilot valve tightly and prevents reverse leakage by low system pressures or high backpressures. The main valve disk is tightly seated by the combined forces exerted by the main valve preload spring and the system internal pressure acting over the area of the main valve disk. In the closed position, the static pressures will be equal in the valve body and in the chamber over the main valve piston. This pressure equalization is made possible by leakage through the piston orifice.

2. As system pressure increases, the preload force on the pilot disk is reduced to zero as the bellows is extended farther and the disk is held closed by the internal pressure acting over the pilot valve seat area. This hydraulic seating force, which is significantly greater than the initial preload, increases with increasing system pressure and discourages leakage or "simmering" at pressures near the valve set pressure.

3. As system pressure further increases, bellows expansion reduces the abutment gap between the stem and the disk yoke. When the stem abuts against the yoke, further pressure increase reduces the net pilot seating force to zero and lifts the first-stage pilot valve from its seat.

4. Once the pilot valve starts to open, the hydraulic seating force is eliminated, resulting in a net increase in the force tending to open the pilot valve. This increase in net force produces the "popping" action during pilot valve opening (Figure 5.2-10).

5. The opening of the first-stage pilot valve admits fluid to the operating piston of the second-stage valve, causing it also to open.

6. The opening of the second-stage pilot valve vents the chamber over the main valve piston to the downstream side of the valve. This venting action creates a differential pressure across the main valve piston almost equal to the system pressure and in a direction tending to open the valve. The main valve piston is sized so that the resulting opening force is greater than the combined preload and hydraulic seating force. Therefore, opening the pilot opens the main valve.

7. As in the case of the pilot valve, once the main valve disk starts to open, the hydraulic seating force is reduced, causing a significant increase in opening force and the characteristic full-opening or “popping” action.

8. When the pressure has been reduced sufficiently to permit the pilot valve to close, the leakage of system fluid past the main valve piston repressurizes the chamber over the piston, eliminates the hydraulic opening force, and permits the preload spring to close the valve. Once closed, the additional hydraulic seating force due

to system pressure acting on the main valve disk seats the main valve tightly and prevents leakage.

The nitrogen-powered diaphragm-operated valve also displaces the second-stage piston, which in turn controls the main valve as shown in Figures 5.2-9 and 5.2-10. Using this system, the relief valve can be remotely opened by supplying pressure on the diaphragm of this actuator.

The relief valves are installed so that each valve discharge is piped through its own uniform diameter discharge line to a point below the minimum water level in the primary containment suppression pool to permit the steam to condense in the pool. Water in the line above suppression pool water level would cause excessive pressure at the relief valve discharge when the valve again opened. For this reason, a vacuum relief valve is provided on each relief valve discharge line to prevent drawing water up into the line from steam condensation following the termination of relief valve operation.

Four of the six relief valves are used for automatic depressurization and are equipped with a nitrogen accumulator and check valve arrangement. These accumulators are provided to 2018-010 ensure that the valves perform their required safety function following the failure of the nitrogen supply to the accumulators, and they are sized to contain sufficient nitrogen for a 30-day period following a design-basis LOCA. See Section 6.3.2.2.2. The two non-automatic depressurization system relief valves are also each connected to one of the automatic depressurization system nitrogen accumulators such that all six relief valves have a Seismic Category I Safety Class 2 nitrogen supply. The two non-automatic depressurization system relief valves are so configured to operate automatically in the low-low set mode (Section 5.4.13.2).

The automatic depressurization feature of the nuclear system pressure relief system serves as a backup to the HPCI system under LOCA conditions. If the HPCI system does not operate and one of the LPCI or core spray pumps is running, the nuclear system is depressurized sufficiently to permit the LPCI and core spray systems to operate to protect the fuel barrier. Depressurization is accomplished through automatic opening of some of the relief valves to vent steam to the suppression pool. For small-line breaks when the HPCI system fails, the nuclear system is depressurized in sufficient time to allow the core spray or LPCI systems to provide core cooling to prevent any fuel cladding melting. For large breaks, the vessel depressurizes rapidly through the break without assistance. The signal for the relief valves to open and remain open is based on simultaneous signals from (1) reactor vessel low water level, and (2) one core spray or LPCI pump running, after a 2 minute timer expires.

A manual depressurization of the nuclear system can be effected in the event the main condenser is not available as a heat sink after reactor shutdown. The steam generated by core decay heat is discharged to the suppression pool. The relief valves are operated by remote manual controls from the main control room to control nuclear system pressure.

The number, set pressures, and capacities of the relief valves and safety valves are shown in Table 5.2-1.

5.2.2.5 Mounting of Pressure Relief Devices

The inlet and connections are described in Section 5.2.2.4.1 for the Dresser safety valves and in Section 5.2.2.4.2 for the Target Rock safety/relief valves.

5.2.2.6 Applicable Codes and Classification

The spring safety and the safety/relief valves have been designed, constructed, and marked in accordance with ASME Code, Section III, 1968 Edition, Article 9 (with 1969 Summer Addenda for the spring safety valves and with 1968 Winter Addenda for the safety/relief valves) for the following operating conditions:

1. Fluid: steam with less than 1% moisture.

2. Pressure: 0 to 1020 psig.

3. Ambient temperature: 135°F normal, 150°F maximum.

5.2.2.7 Material Specification

Material specifications are discussed in Section 5.4.13.

5.2.2.8 Process Instrumentation

See Figure 5.1-1.

5.2.2.9 System Reliability

As stated in Appendix 5B, various combinations of proper valve operation provide adequate vessel overpressure protection subsequent to the severe main steam isolation valve closure transient assuming a scram initiated by high neutron flux or high vessel pressure. Table 5.2-2 summarizes the safety valve scram system availability that has been calculated on the basis of the combination of valves required to provide a minimum of a 25-psi margin below the ASME Code limit of 1375 psig. The availability of flux scram is greater than 0.99999, while with pressure scram it is 0.9993 for an interval between tests of 2 yr when the system has six safety/relief valves and two spring safety valves.

A failure-to-open rate of 1.1 failures per million operating hours was assigned to the dual-purpose safety/relief valves, and a failure-to-open rate of 0.01 failure per million operating hours was assigned to the spring safety valves. The downtime, or period that the valve would be unavailable for service if it failed, was determined to be dominated by the period between testing. The effects of these differences in downtime were included in the availability calculations.

General Electric availability goals applied to the DAEC over-pressure protection system require that a minimum availability of 0.99999 be provided for the flux scram condition as well as capability for success with scram initiation emanating from pressure. These goals have been applied to the results of this analysis, and since the availability of all cases exceeds these goals, the probability of successful pressure protection is ensured.

5.2.2.10 Testing and Inspection

The base castings of each valve have been 100% radiographed in accordance with ASTM Standards E71, E94, E142, E186, and E280.

All pressure-containing bolting has been magnetic particle examined in accordance with ASTM E138.

Capacity certification tests have been conducted in accordance with Article 9, Section III of the ASME Code. Valves were tested before installation and are bench checked periodically during plant shutdown for the proper setpoint in accordance with the ASME Code and Technical Specification requirements.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

5.2.3.1 Material Specifications

A review of reactor coolant system pressure boundary piping was completed in 1978 to determine if ASME Class 1 and 2 pressure boundary piping, safe ends, and fitting material, including weld metal, met the material selection, testing, and processing guidelines set forth in NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping." The detailed results of the review are contained in References 2 and 3.

In general, the results of the NUREG-0313 conformance review were as follows:

1. Conforming material. All stainless steel safe ends and stainless steel safe-end extensions are conforming material. All contain less than 0.035% carbon and were solution annealed. Inconel welds join the stainless steel safe ends to the nozzles. Class 1 pressure boundary piping except that identified below in items 2 and 3 are conforming, and all Class 2 piping is conforming.

2. Partial nonconformance but not service sensitive. The following systems are nonconforming and nonservice sensitive in accordance with the guidelines of NUREG-0313, Revision 1.

    a. Recirculation system except the bypass pipe.

    b. RHR stainless steel transition spools to the recirculation system.

c. Liquid level control (reactor vessel).

d. Instrumentation piping (reactor vessel).

Stainless steel pipe and fittings in the above systems contain greater than 0.035% carbon, and the welds have not been solution annealed; therefore, they are nonconforming. All pipe and fittings have been solution annealed. The selection of welds for augmented inservice inspection on item "a" and "b" systems will be those most susceptible for intergranular stress-assisted corrosion cracking based on the stress rule index number.

3. Partial nonconformance and service sensitive. The following do not conform to the criteria as stated in NUREG-0313, Revision 1, and are considered to be service sensitive:

   a. Recirculation system bypass.

   b. Core spray spools that connect carbon steel pipe to stainless steel safe-end extensions at the reactor pressure vessel nozzles.

   c. CRD hydraulic return spool that connects carbon steel pipe to the reactor pressure vessel nozzle.

   d. RWCU systems.

   The stainless steel pipe and fittings in the above systems contain greater than 0.035% carbon, and the welds have not been solution annealed. All pipe and fittings have been solution annealed. Augmented inservice inspection has been done on the above systems in accordance with the guidelines of NUREG-0313, Revision 1.

The only components within the DAEC reactor coolant pressure boundary fabricated outside the United States were the RHR and core spray pumps by Byron Jackson-Canada (Canadian-B.J.). The pumps were purchased from Byron Jackson-United States (U.S.-B.J.) and designed within the United States. The fabrication was done by Canadian-B.J. to fabrication and quality control instructions and procedures issued by U.S.-B.J. Canadian-B.J. was fully qualified to fabricate RHR and core spray pumps with adequate machining, handling, and welding equipment. Canadian-B.J. had qualified fabrication and quality control organizations. U.S.-B.J. was responsible for ensuring and documenting the required quality level. RHR and core spray pumps for other nuclear power plants have been fabricated by Canadian-B.J. [redacted]

5.2.3.2 Compatibility with Reactor Coolant

The recirculation system piping, valves, and pump casings are covered with thermal insulation having an average maximum heat-transfer transfer rate of 65 Btu/hr-ft^2 with the system at rated operating conditions. Most of the insulation is of the fiberglass type with a metal jacket and is prefabricated into components for field installation. Removable insulation is provided at various locations to allow periodic inspection of the insulated equipment.

5.2.3.3 Fabrication and Processing of Ferritic Materials

The fracture or notch toughness properties and the operating temperature of ferritic materials in systems that form the reactor coolant and primary containment pressure boundaries are controlled to ensure adequate toughness when the system is pressurized to more than 20% of the design pressure. Such assurance is provided by maintaining a material service temperature of at least 60°F above the NDT temperature for the reactor coolant pressure boundary and 30°F above the NDT temperature for the primary containment boundary. Where reactor coolant pressure boundary piping penetrates the containment, the fracture toughness temperature requirements of the reactor coolant pressure boundary materials apply. Materials to be impact tested shall be tested by the Charpy V-notch method in accordance with ASME Code, Section III. Other requirements are as follows:

1. Reactor coolant pressure boundary. Impact testing is not required on materials having a minimum service temperature of 250°F when pressurized at more than 20% of design pressure.

   Impact tests are not required for bolting, including nuts whose nominal bolt size is 1-in. in diameter or less; bars whose cross-sectional area does not exceed 1 square inch; materials whose section thickness is less than 0.5 in.; piping, valves, and pumps whose nominal inlet pipe is 6 in. in diameter and less, regardless of thickness; austenitic stainless steels; and nonferrous materials.

   Charpy V-notch specimens are in accordance with ASTM A-370, Figure 11, Type A; the specimens are also tested in accordance with A-370.

   Impact testing is not required on components or piping within the pressure boundary whose rupture could not result in a loss of coolant exceeding the capability of normal makeup systems to maintain adequate core cooling for the duration of a reactor shutdown and orderly cooldown.

   Impact test criteria do not apply to non-pressure-retaining components such as anchors, anchor bolts, hangers, suppressors, and restraints.

2. Extension of Containment Pressure Boundary

   The containment boundary extends to and includes the first stop or stop check

valve outside containment. Impact testing is not required for materials where the nominal pipe size is 4 in. or less (6 in. or less after July 1, 1971) or where the section thickness is 0.5 in. or less.

The design specification states the test temperature at which the material shall meet the impact test values listed in Tables A.1, A.2, and A.8 of ASME Code, Section III.

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

All sensitized austenitic stainless steel has been replaced on the DAEC pressure vessel, except for the jet pump riser brace pads and recirculation inlet thermal sleeve attachment buildups. These exceptions are fabricated from weld metal with controlled ferrite content. Austenitic stainless steel used in other component parts of the reactor coolant pressure boundary including relief and safety valves is fully annealed to preclude sensitization.

Stainless steel with deliberate additions of nitrogen for enhancing the material strength has not been used.

All high points on nonflowing parts of the reactor coolant system have been vented to prevent gas entrapment.

None of the component materials of the reactor coolant pressure boundary or emergency core cooling system (ECCS), except as noted above, and none of the component materials of the systems required for reactor shutdown are furnace sensitized and, therefore, they are not susceptible to intergranular attack.

For a few reactor internals that are not water quenched, the following procedure was used.

For the acceptable qualification of a process other than water quenching, thermocouples were used on test coupons to verify the cooling rate from 1800 to 800°F. The test coupons or demonstration samples are of the maximum thickness of the processed material. The demonstration samples were examined metallographically and accepted on the basis of conformance to well-documented solution-heat-treated microstructures.

Filler metals, including consumable inserts, for austenitic stainless steel welds and weld overlays were selected and controlled to produce welds that contain a measurable amount of ferrite. Magnetic methods were used to test for ferrite in each completed production weld.

Welders and welding procedures were qualified in accordance with ASME Code, Section IX, and in the case of some reactor internals, qualifications were done per engineering-approved alternatives to Section IX (Section 3.3.4).

Welding processes are limited to 110,000 J/in., and the interpass temperature is limited to 350°F to avoid local sensitization of stainless steel.

Reference 4 prescribes practices and requirements for the manual and automatic welding of austenitic stainless steel piping using heat sink techniques during welding. Heat sink welding is defined as the practice of water cooling a weld joint during metal deposition, as described in the specification. It is applicable for both shop and field welds.

5.2.3.5 Intergranular Stress Corrosion Cracking

During the 1985 refueling outage, a comprehensive program addressing intergranular stress corrosion cracking (IGSCC) in the reactor coolant recirculation system was implemented.

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

IGSCC is controlled by a hydrogen water chemistry (HWC) system, described in Section 9.3.5, which injects hydrogen into the feedwater. The hydrogen is carried into the reactor, where it reduces the concentration of dissolved oxygen in the reactor coolant. To enhance the effectiveness and efficiency of HWC in mitigating IGSCC in the reactor vessel internals, noble metal is injected as described in Section 9.3.7.

To satisfy the requirements of NRC Generic Letter 88-01, an augmented IGSCC examination program is in effect for austenitic stainless piping welds.

5.2.3.5.1 Mechanical Stress Improvement Process (MSIP)

During RFO 22 (Fall 2010), RRE-F002, RRG-F002, and RRH-F002 nozzle to safe-end welds underwent the Mechanical Stress Improvement Process. The recirculation inlet piping was compressed near the nozzle to safe end weld, removing the tensile stresses and creating favorable compressive stresses at the weldment. This process was performed on N2E, N2G and N2H. MSIP is a patented design process that mitigates cracks caused by IGSCC and prevents new cracks from forming.

5.2.4 INSERVICE INSPECTION AND TESTING OF REACTOR COOLANT PRESSURE BOUNDARY

5.2.4.1 Introduction

A preservice inspection of Nuclear Class 1 components was conducted to ensure freedom from defects greater than code allowance; in addition, this served as a reference base for future inspections. Prior to operation, the reactor coolant system as described in Article IS-120 of

Section XI of the ASME Code was inspected to ensure that the system was free of gross defects. In addition, the facility was designed such that gross defects should not occur throughout the life of the plant. The preservice inspection program was based on the 1971 Section XI of the ASME Code for inservice inspection. This inspection plan was designed to reveal problem areas (should they occur) before a leak in the coolant system could develop. The program was established to provide reasonable assurance that no LOCA would occur at the DAEC as a result of leakage or breach of pressure-containing components and piping of the reactor coolant system, portions of the emergency core cooling systems, and portions of the auxiliary systems-associated with the reactor coolant system.

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

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

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

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

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

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

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

The DAEC Inservice Inspection Program for the third 10-yr interval addresses the requirements of ASME Code, Section XI, 1989 Edition, subject to limitations and modifications as stated in 10CFR50.55a(b)(2). This third 10-yr interval began November 1, 1996 and ended on November 1, 2006. Results of inservice inspections and exceptions to the ASME Code are summarized in References 10 through 26.

The DAEC Inservice Inspection Program for the fourth 10-year interval addresses the requirements of the 2001 Edition through 2003 Addenda of the American Society of Mechanical Engineers (ASME), subject to the limitations and modifications of 10 CFR 50.55a(b)(2). This fourth 10-year interval began on November 1, 2006. Results of inspections and exceptions to the ASME Code are summarized in References 25 and 26.

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

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

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

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

5.2.4.2 Program Purpose and Objectives

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

The required ensurance is provided by conducting the following:

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

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

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

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

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

5.2.4.3 Examination Techniques

5.2.4.3.1 Nondestructive Examination

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

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

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

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

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

5.2.4.3.2 Pressure Tests for Nuclear Class 1 Components

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

5.2.4.4 Nondestructive Testing (NDT) Operator Qualification

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

5.2.4.5 Class 1 System Boundaries and Accessibility

The Nuclear Class 1 systems and their associated boundaries that are inspected during the operating lifetime of the plant are delineated below. Primary consideration is given to the reactor coolant system, portions of the auxiliary systems associated with the reactor coolant system, and portions of the emergency core cooling systems.

5.2.4.5.1 Reactor Coolant System Boundary

The reactor coolant system contains primary reactor coolant at operating pressure during normal reactor operations and is considered to include the reactor pressure vessel, the recirculation system, the reactor coolant system safety and relief valves, and the main steam and feedwater piping systems extending out to and including the first containment isolation valve outside containment.

5.2.4.5.2 Reactor Coolant Associated Auxiliary Systems

Associated reactor auxiliary systems in which reactor coolant is diverted from the reactor coolant system either continuously or intermittently in support of normal reactor operation are the RWCU and RCIC systems out to and including the first containment isolation valve outside the primary containment.

5.2.4.5.3 Emergency Core Cooling Systems

Emergency core cooling system boundaries include the RHR, core spray, and HPCI systems connected to the reactor coolant system and extend out to and include the first containment isolation valve outside the primary containment.

5.2.4.5.4 Nuclear Class 1 Examination Exclusions

According to Subarticle IWB-1220 in Section XI of the ASME Code, certain small components and piping welds may be excluded on the premise that the amount of fluid lost in the event of a failure can be replenished by the normal makeup systems. The makeup systems can maintain inventory in the case of a water- or steam-line break in a line having an inside diameter of approximately 1 and 2 in., respectively. Visual examination of these welds will be conducted while performing the code-required pressure tests.

When it is impossible or impractical to meet certain code requirements, requests for relief are made pursuant to 10 CFR 50.55a(g)(5)(iii).

5.2.4.5.5 Nuclear Class 1 Component Accessibility

Areas of the reactor vessel outside diameter above the sacrificial shield, including the closure head, are accessible for volumetric and visual examinations by removing insulation panels. Removable plugs in the sacrificial shield and removable panels in the insulation area are also provided in the core region of the vessel, the bottom head, and around each nozzle (see Figure 5.2-11). These removable plugs and panels provide access to examine the nozzle-to-nozzle welds, nozzle-to-piping welds, portions of vessel welds in the core and bottom head regions, and the support skirt weld. In addition to the removable plugs and panels provided, the reactor vessel insulation is designed as a standoff structure spaced 5.5 to 6 in. from the reactor vessel, as shown in Figure 5.2-12. To minimize personnel exposure to high-radiation levels, this annulus could be used as access to the reactor vessel welds with suitable remotely operated, mechanized ultrasonic devices.

The piping welds subject to inspection in the systems are made accessible by removable insulation.

Interior surfaces and components below the reactor core are not made accessible by normal refueling operations. Portions of this region will be visually examined when maintenance operations provide access.

The 2-in. drain nozzle and line within the array of control rod hydraulic system housings are not accessible for volumetric examination; visual examination is performed.

The primary containment penetrations contain some piping welds that, in general, are not accessible for volumetric examination. Visual examination from outside the containment for evidence of leakage is performed in accordance with the Inservice Inspection Plan.

Visual examination of recirculation pump internal surfaces is performed when a pump or valve is disassembled for maintenance in accordance with the Inservice Inspection Plan.

5.2.4.5.6 Nuclear Class 1 Pressure-Containing Components and Piping

The Nuclear Class 1 pressure-containing components and piping that are considered for inservice inspection and examination include the reactor pressure vessel and its appurtenances, primary pressure piping, pumps, and valves.

Components and appurtenances that are subjected to nondestructive examination in and around the reactor pressure vessel include the following:

1. Reactor pressure vessel shell welds.

2. Closure head welds and flange ligaments.

3. Reactor vessel nozzle and penetration welds.

4. Closure studs and nuts.

5. Integrally welded vessel support welds.

6. Reactor vessel flange ligaments.

Welds in pressure-retaining piping, as indicated in Section 5.2.4.5 (subject to exclusions in Sections 5.2.4.5.4 and 5.2.4.5.5) will be examined. The piping is listed below and is schematically represented in Figure 5.2-13:

1. Main steam lines.

2. Reactor feedwater lines.

3. Reactor recirculation lines.

4. RHR system lines.

5. Core spray system lines.

6. HPCI system lines.

7. RCIC system lines.

8. Standby liquid control system lines.

9. Two-inch instrument lines below normal water level and 2-in. liquid control core ΔP line.

10. Two-inch drain line.

5.2.4.6 Detail of Access Provisions and Examination Schedules

The access provisions and examination schedules are discussed below according to code categories. This information is condensed and presented in the DAEC Inservice Inspection Program.

1. Reactor Vessel and Closure Head

    a. Longitudinal and Circumferential Welds in the Core Region

    The design of the sacrificial shield and of the standoff insulation has provided an annulus of 5.5 to 6 in. between the vessel and the insulation. Access to welds in the core region has also been provided by installing removable panels in the insulation and removable plugs in the sacrificial shield as shown in Figure 5.2-11. This access will be used when conditions warrant unloading the core and in the absence of remote examination equipment.

    Examinations are conducted in accordance with the Inservice Inspection Plan.

    b. Pressure-Containing Welds in Shell, Bottom Head, and Closure Head

    Weld seams above the sacrificial shield on the vessel and on the closure head are accessible for manual ultrasonic examination by removing insulation panels. The remainder of the vessel shell seams are available for examination as described in this section. The bottom head-to-vessel weld in the plenum around the support skirt is accessible for manual ultrasonic testing examination by removing insulation panels with access through the sacrificial shield. The meridional weld inside the support skirt and outside the array of CRD mechanisms is accessible through manholes within the support skirt.

    Examinations are conducted in accordance with the Inservice Inspection Plan.

    c. Vessel-to-Flange and Head-to-Flange Welds

    Access is provided to these welds from the flange faces during refueling and through removable insulation panels around the closure head and the vessel. Examinations are conducted in accordance with the Inservice Inspection Plan

    d. Primary Nozzle-to-Vessel Welds and Nozzle Inside Radiused Sections

    Access to the nozzle-to-vessel welds and nozzle blend radii is from the vessel outside diameter and is obtained through removable sections in the sacrificial shield and/or removable insulation panels. Manual ultrasonic techniques are planned during the earlier examination intervals. However, because of radiation levels, it may become necessary to adopt remotely operated equipment. The required access is available. Examinations are conducted in accordance with the Inservice Inspection Plan.

e. Vessel Penetrations Including CRD Penetrations, CRD Housing Welds, and Incore Monitor Housing Penetrations.

Examinations are conducted in accordance with the Inservice Inspection Plan.

f. Primary Nozzle-to-Dissimilar Metal Piping Welds

Examinations are conducted in accordance with the Inservice Inspection Plan.

g. Closure Studs, Nuts, Washers, Bushings, and Ligaments Between Threaded Stud Holes

Examinations are conducted in accordance with the Inservice Inspection Plan.

h. Integrally Welded Vessel Supports

The vessel skirt-to-vessel weld is accessible through openings in the sacrificial shield and removable panels in the insulation. Examinations are conducted in accordance with the Inservice Inspection Plan.

i. Interior Surfaces and Internals and Integrally Welded Internal Supports

The examinations for this category will be performed visually. The steam dryer and standpipe assembly are removed during refueling and will be examined under water during the refueling period.

Examinations are conducted in accordance with the Inservice Inspection Plan.

2. Piping Pressure Boundaries

a. Dissimilar Metal Welds in Piping Systems (Other than on Vessel Nozzles)

Access to the piping welds is obtained through removable insulation. Examinations are conducted in accordance with the Inservice Inspection Plan.

b. Pressure-Retaining Bolting

Bolting within the piping systems is less than 2 in. in diameter, and thus only visual examination is required. Examinations are conducted in accordance with the Inservice Inspection Plan.

c. Pressure-Containing Welds in Piping

Welds within the piping systems are accessible through removable insulation. Examinations are conducted in accordance with the Inservice Inspection Plan.

d. Piping Supports and Hangers

Removable insulation provides access to supports and hangers in the piping systems. Examinations are conducted in accordance with the Inservice Inspection Plan.

3. Pumps Pressure Boundary

a. Pressure-Containing Welds in Pump Casings

There are no pumps with pressure-containing welds.

b. Pump Casings

The two recirculation pumps are in this category. Examinations are conducted in accordance with the Inservice Inspection Plan.

c. Dissimilar Metal Piping Welds

There are no dissimilar metal pressure boundary welds on the recirculation pumps.

d. Pressure-Retaining Bolting

Examinations are conducted in accordance with the Inservice Inspection Plan.

e. Pressure-Retaining Bolting Under 2 In.

Examinations are conducted in accordance with the Inservice Inspection Plan.

f. Pump Supports and Hangers

Examinations are conducted in accordance with the Inservice Inspection Plan.

4. Valve Pressure Boundary

   a. Valve Body Welds

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

   b. Valve Bodies

      Examinations are conducted in accordance with the Inservice Inspection Plan.

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

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

   d. Pressure-Retaining Bolting Larger than 2 in.

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

   e. Pressure-Retaining Bolting Under 2 in.

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

   f. Valve Supports and Hangers

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

5.2.4.7 Nuclear Class 1 Preoperational Examinations

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

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

5.2.4.8 Inservice Inspection of Shock Suppressors (Snubbers)

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

5.2.4.9 Documentation and Records

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

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

5.2.5 DETECTION OF LEAKAGE THROUGH REACTOR COOLANT PRESSURE BOUNDARY

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

5.2.5.1 Safety Design Bases

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

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

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

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

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

5.2.5.2 Description

5.2.5.2.1 General

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

The DAEC design includes a nuclear system leak detection, isolation, processing, and makeup system. This system (made up of many normal station operational subsystems) provides for leakage control capability. This capability includes the following:

1. Identifying the reactor building (or reactor primary system) leakage sources.

2. Efficiently isolating and controlling the sources.

3. Effectively removing the residual leakage water (before and after isolation).

4. Conveniently replacing the leakage liquid and/or restoring the source system function.

These functions are accomplished under normal operation or postaccident conditions in a manner in which normal (10 CFR 20) or accident (10 CFR 50.67) offsite dose limits do not exceed established values and in a manner in which the core and the containment cooling continuity is not impaired or negated.

The leakage considered here is limited to that water or steam released from the nuclear system process barrier inside the primary containment. Leakage inside the drywell is treated separately from leakage elsewhere in the plant because the drywell contains a high concentration of nuclear system piping and is totally inaccessible during reactor operation.

If a leak occurs, the drywell will contain the released matter that will be present in the liquid, gaseous, and vapor phases. This will result in the collection of water in the sumps, a possible increase in drywell temperature, pressure, and relative humidity, an increase in the air-conditioning heat load, and an increase in the radioactivity of the drywell atmosphere. The closed limited volume of the drywell enhances the detection sensitivity.

5.2.5.2.2 Leakage Sources

Total leakage within the drywell is divided into two classifications--identified and unidentified--depending on whether the drywell equipment drain sump (identified) or the drywell floor drain sump (unidentified) receives the fluid:

Identifiable Leakage (Equipment Drain Sump)

Identifiable leakage into the equipment drain sump is composed of normal seal and valve packing leakage and does not represent a safety consideration so long as the leakage is small compared to the available reactor coolant makeup capacity.

Most valves and pumps in the nuclear system inside the drywell are equipped with double seals; leakage through the primary seal is piped to the equipment drain sump.

Leakage from the main steam relief and safety valves is identified by downstream temperature sensors that read out in the main control room. Relief valve discharge is directed to the suppression pool.

Unidentifiable Leakage (Floor Drain)

The unidentifiable leakage is composed of all leakage from the reactor primary system that is not defined as identifiable leakage. This unidentified leakage is collected in the drywell floor drain sump. Vapor that is condensed by the drywell ventilation system will drain to this sump.

The sump systems and input sources are indicated on Figure 11.2-2.

5.2.5.2.3 Leak Detection Methods

The following six methods are used to detect leakage in the primary containment:

1. Equipment drain sump flow.
2. Floor drain sump flow.
3. Drywell ventilation system cooling water temperature.
4. Drywell pressure.
5. Drywell temperature.
6. Drywell atmosphere radioactivity.

Instrumentation is provided for the primary containment sumps having a capability to detect steam leakage of 0.5 gpm within a 45-min period. The response time depends on the amount of background leakage but will not exceed the interval between pumping cycles. The higher the leak rate the shorter the response time. Alarms are provided to annunciate leakage.

The alarm setpoints will be adjustable from 0 to 5 gpm for the floor drain sump (unidentified leakage) and 0 to 25 gpm for the equipment drain sump (identified leakage), thus giving the capability of having alarm annunciation set at or below the license limit and providing immediate response when the preselected rate is reached or exceeded.

The unidentified leakage rate is the portion of the total leakage rate received in the drywell sumps that is not identified. A threat of significant compromise to the nuclear system process barrier exists if the barrier contains a crack that is large enough to propagate rapidly (i.e., critical crack). An allowance for leakage that does not compromise barrier integrity and is not identifiable is made for normal plant operation. The unidentified leakage rate limit for the DAEC is established at the 5-gpm rate to allow time for corrective action before the process barrier could be significantly compromised. This 5-gpm unidentified leakage rate is substantially lower than the calculated flow from a subcritical crack in a primary system pipe. The experimental as well as mathematical background is summarized below.

Critical Crack Length

Both the GE[6] and the BMI[7] test results indicate that formulas for theoretical fracture mechanics do not predict critical crack length, but that satisfactory empirical expressions may be developed to fit test results. A simple equation (for axially oriented through-wall cracks) that fits the data in the range of normal design stresses (for carbon steel pipe) is

$l_c = \frac{15{,}000\ D}{\sigma_\eta}$ (see data correlation on Figure 5.2-14)

l_c = critical crack length, in.

D = mean pipe diameter, in.

σ_η = nominal hoop stress, psi

Crack Opening displacement

The theory of elasticity predicts a crack-opening displacement of

$$w = \frac{2l\sigma}{E}$$

where

l = crack length

σ = applied nominal stress

E = Young's modulus

Measurements of crack-opening displacement made by BMI show that local yielding and bending greatly increases the crack opening displacement as the applied stress σ approaches the failure stress σ_f . A suitable correction factor for plasticity effects is

$$C = \sec [\pi\sigma/2\sigma_f]$$

The crack opening area is given by

$$A = C\pi wl/4$$

or

$$A = \frac{\pi l^2 \sigma}{2E} \sec [\pi\sigma/2\sigma_f]$$

For a given crack length of l, $\sigma_f = 15{,}000\ D/l$.

Leakage Flow Rate

The maximum flow rate for the blowdown of saturated water at 1000 psi is 55 lb/sec-in.^{2}, and for saturated steam the rate is 14.6 lb/sec-in.[a] (Reference 8). Friction in the flow passage reduces this rate, but for cracks leaking at 5 gpm (0.7 lb/sec) the effect of friction is small. The required leak size for 5-gpm flow is

$$A = 0.0126\ \text{in.}^2 \text{ (saturated water)}$$
$$A = 0.0475\ \text{in.}^2 \text{ (saturated steam)}$$

Figure 5.2-15 shows general relationships between crack length, leak rate, stress, and line size using the mathematical model described above. The asterisks in the figure denote conditions at which the crack-opening displacement is 0.1 in., at which time instability is imminent. This provides a realistic estimate of the leak rate to be expected from a crack of critical size. In every case, the leak rate from a crack of critical size is significantly greater than the 5-gpm criteria.

From the mathematical model described above, the critical crack length and the 5-gpm crack length have been calculated for representative BWR pipe sizes and pressure (1050 psi). Results are tabulated as follows.

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

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

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

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

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

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

5.2.5.2.3.1 Equipment Drain and Floor Drain Sumps

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

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

The pump control and alarm function is as follows.

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

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

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

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

5.2.5.2.3.2 Drywell Ventilation

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

5.2.5.2.3.3 Drywell Pressure, Temperature and Radioactivity

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

The drywell atmosphere radioactivity detector provides a backup indication to the drywell sump system of increased nuclear system leakage. The drywell environment is continuously sampled from three locations that are chosen to provide both a representative gas mixture and an indication of the location of the leakage. The lines used for the oxygen sampling system are also used for the drywell atmosphere radioactivity detector in order to take advantage of existing piping, penetrations, and isolation capabilities. The piping runs to the detector are as short and as straight as possible to minimize the particulate deposition and are constructed of stainless steel to minimize chemical reactions.

The drywell atmosphere radioactivity detector is designed so that steam leakage rates as low as 1 gpm can be detected. However, their sensitivity is directly proportional to the radioactive source term in the reactor coolant during normal operation. With high fuel integrity (lower source term), the time to detect small leaks can be long. Therefore, these detectors are only used as a back-up monitor for reactor coolant system leakage.

The sampled air undergoes three separate processes in which the radioactive noble gas, halogen, and particulate content is determined. This system is thus a three-channel monitoring system. The processed air is returned to the drywell.

2011-006 The readings for each channel are fed into a recorder so that a permanent record of the drywell atmosphere radioactivity is maintained. The system will alarm locally and in the control room to indicate system failure or alarm conditions. No automatic action is initiated by the system.

5.2.5.3 <u>Safety Evaluation</u>

5.2.5.3.1 General

The different drywell parameters that are discussed in Section 5.2.5 provide diverse methods for determining if an increased leak rate exists within the drywell. The allowable leakage rates have been based on the predicted and experimentally determined behavior of cracks in pipes, the ability to make up coolant system leakage, the normally expected background leakage due to equipment design, and the detection capability of the various drywell monitors.

Based on the behavior of cracks, a 5-gpm leak rate limit has been assigned to unidentified leaks and a 25-gpm leak rate limit for the total of unidentified and identified leaks. Experience has shown that normal leak rate is 4 gpm into the equipment drain sump and 0 to 0.5 gpm into the floor drain sump. The Technical Specifications limit is 5 gpm unidentified leakage, 25 gpm total leakage, and a 2 gpm increase in unidentified leakage within 24 hours. In addition, DAEC Technical Specifications state that a reactor shutdown must be initiated if the unidentified drywell leakage is observed to increase by 2 gpm in any 24-hr period.

The sump working capacities and pump discharge capacities are large enough to accept the design leak rates. The sump working capacity is the amount of water between the low-level pump trip and the high-high-level alarm point. The equipment drain sump (approximate working capacity, 450 gal) and the floor drain sump (approximate working capacity, 225 gal) are drained by two 50-gpm pumps. This pump capacity permits one pump in each sump to remove the design total leakage because of the possibility that most of the leakage could flow into one sump.

5.2.5.3.2 Behavior of Cracks

The behavior of cracks in piping systems has been experimentally and analytically investigated as part of an NRC-sponsored Reactor Primary Coolant System Rupture Study (the Pipe Rupture Study). Analysis using the data obtained in this study has shown that there is a high probability that a leaking crack can be detected before it grows to a dangerous or critical size because of mechanically or thermally induced cyclic loading, or stress corrosion cracking, or some other mechanism characterized by gradual crack growth. Earthquake and normal vibration stresses are considered in the determination of the critical crack size. For the crack size that gives a water leakage of 15 gpm, the probability of rapid propagation was calculated to be 10^{-4} . The crack area corresponding to a 15-gpm leak is approximately 1.8 x 10^{-4} ft^2.

The Technical Specification unidentified leakage rate has been set at 5 gpm to provide further conservatism.

5.2.5.3.3 Total Leakage Rate Limit

The criterion for establishing the total leakage rate limit is based on the makeup capability of the CRD and RCIC systems and is independent of the feedwater system, normal ac power, and the emergency core cooling systems. The CRD system supplies 42 gpm into the reactor vessel; the RCIC system can supply 425 gpm through the feedwater sparger to the reactor vessel. The total leakage rate limit is set at less than 0.1 of this value or 25 gpm.

5.2.5.3.4 Drywell Leak Detection

The sump-fill timer and pump-out timer for both the equipment drain sump and floor drain sump are set to alarm at levels that provide adequate separation from expected leak rates to avoid spurious alarms but low enough to indicate significant leaks. Exact leak rates can be determined from the flow indications in the control room, and any increase beyond the normal leak rate will be apparent to control room personnel.

The drywell ventilation system consists of several coolers, each with a separate heat load. The calculated well water differential temperature is 30° to 45°F depending on the cooler in question. It is therefore reasonable to assume that a 5°F rise in outlet temperature is detectable.

If one assumes the following, one can determine that, for a given size break, steam and water are equally detectable although four times as much reactor water is lost through a water break.

1. A 5°F rise in cooler outlet water temperature is detectable by control room personnel.

2. Normal cooler heat load is 740,000 Btu/hr.

3. A 1000-psig blowdown of saturated steam or water.[9]

4. Fifty percent of the water and 100% of the steam become airborne.

The alarms associated with the cooler air and water outlet provide additional indication should a sudden increase in leak rate occur.

Drywell temperature and, to some extent, drywell pressure are controlled by the drywell ventilation system. As the heat load on the cooling coil is increased, the average drywell temperature will increase. If this temperature exceeds the setpoint, an alarm will occur. The combination of increased temperature and increased absolute humidity causes the drywell pressure to increase. A small increase in pressure above the setpoint will actuate an alarm; a 2-psig increase indicates a larger leak and is used to initiate a scram, nuclear steam supply isolation and ECCS (including HPCI, LPCI and CS). Low reactor water level will also indicate larger leaks and initiate a scram and isolation.

If the drywell ventilation system is assumed to be saturated so that the steam or water from a leak does not condense, there will be an increase in drywell temperature, pressure, and relative humidity with respect to time, providing an indication of the sensitivity of these parameters.

The drywell atmosphere radioactivity detector serves as a reliable backup to the other methods of leak detection. It is anticipated that the particulate detector will be the primary indication of leakage, with the halogen and noble gas detectors serving as indications of the drywell environment if drywell venting is required. These detectors, in conjunction with an isotopic analysis, can be used to indicate whether the detected leak is from a steam or water system.

The detector units are shielded to minimize the effect of background activity and thereby increase the detection sensitivity. The individual units have the capability of being tested for reaction to a source and calibrated. Since the background contamination and deposition--chemical reaction effects--cannot be predetermined, and since it is an increase in detected values that indicates a leak, the alarm points will be determined by operator experience; the setpoints will be low enough to provide the quickest indication without receiving spurious alarms.

It is expected that this system will provide at least an order of magnitude reduction in the leak size that can be detected and will also reduce the time delay in sensing the condition.

5.2.5.4 Inspection and Testing

The nuclear system leak detection system is an operational system in daily use. Testing of these systems are specified in the DAEC Technical Specifications.

REFERENCES FOR SECTION 5.2

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

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

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20. Letter from K. Peveler, IES Utilities, to NRC, Subject: DAEC Inservice Inspection Report, dated July 15, 1998 (NG-98-1244).

21. Letter from K. Peveler, IES Utilities, to NRC, Subject: DAEC Inservice Inspection Report, dated February 28, 2000 (NG-00-0319).

22. Letter from K. Putnam, NMC, to NRC, Subject: DAEC Inservice Inspection Report, dated August 15, 2001 (NG-01-0975).

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Table 5.2-1

NUCLEAR SYSTEM SAFETY AND RELIEF VALVES

Valve Type	Number of Valves	Set Pressure (nominal) [a] (psig)	Capacity at 103% of Set Pressure (each) (lb/hr)
Relief	1	1110	853,000
	1	1120	860,000
	2	1130	868,000
	2	1140	876,000
Total[b]	6 (4)		
Safety	2	1240	642,000
Relief (low-low set function)	1	1030 open 910 close	
	1	1035 open 915 close	

[a] Nominal setting +3% tolerance is assumed in the transient analyses in Chapter 15 for the
Relief mode of the S/RV and SSVs. For the LLS function, these represent the nominal trip setpoint (NTSP), the Analytical Limits used in the transient and accident analyses can
be found in Chapter 15.0

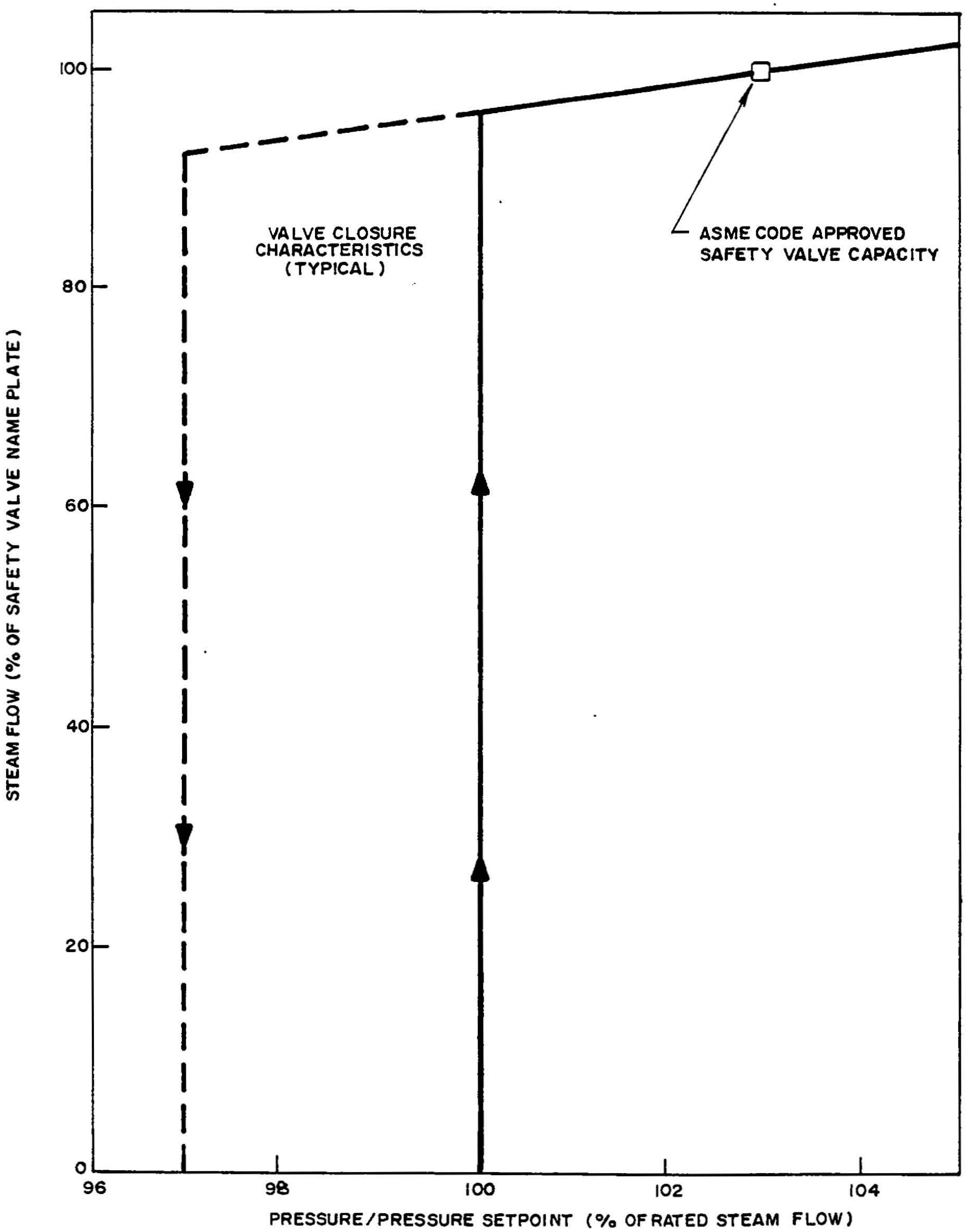
[b] The number in parentheses indicates the number of relief valves that serve in the automatic depressurization capacity.

Table 5.2-2

SAFETY VALVE SCRAM AVAILABILITY

Scram	Availability[a]
Flux Five of six dual plus Zero of two spring valves or Four of six dual plus One of two spring valves or Four of six dual plus Two of two spring valves	>0.99999
Pressure Six of six dual plus Zero of two spring valves or Five of six dual plus Two of two spring valves	>0.99930

[a] Two-year interval between tests.



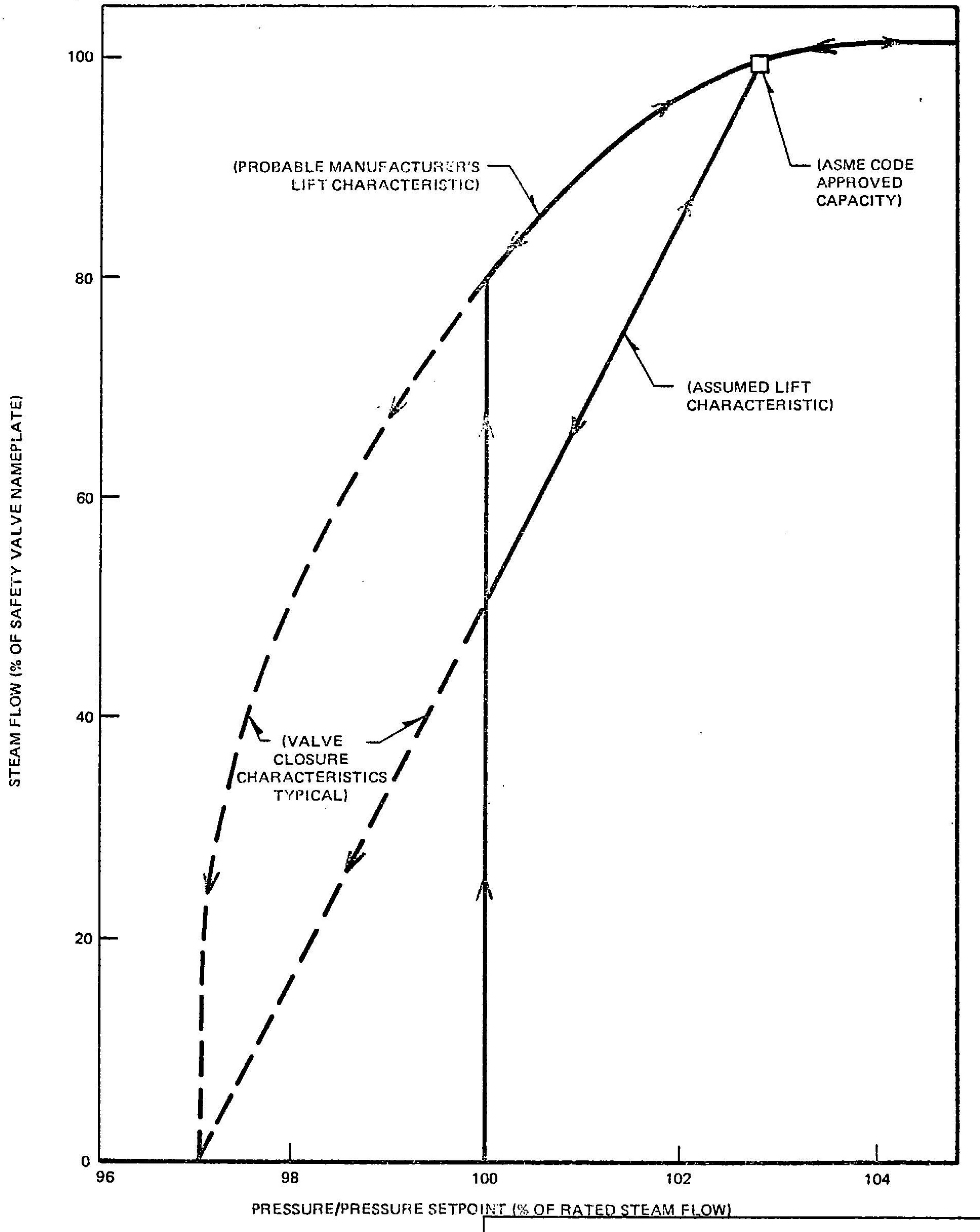
DUANE ARNOLD ENERGY CENTER

IES UTILITIES, INC.

UPDATED FINAL SAFETY ANALYSIS REPORT

Typical Dual Relief/Safety Pop
Valve Capacity Characteristics

Figure 5.2-1

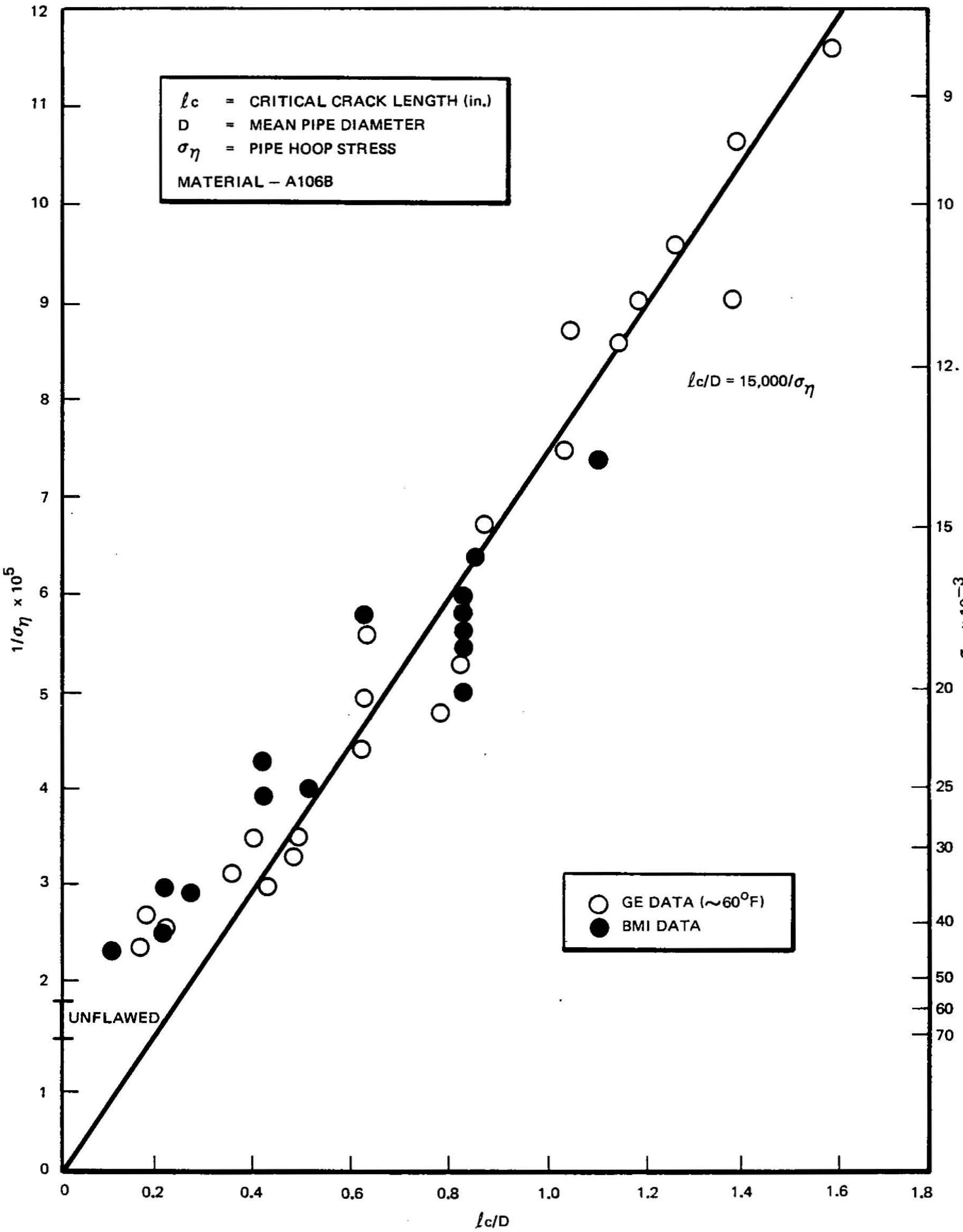


DUANE ARNOLD ENERGY CENTER
IOWA ELECTRIC LIGHT & POWER COMPANY
UPDATED FINAL SAFETY ANALYSIS REPORT

Typical Spring Loaded Safety Valve Capacity Characteristics

Figure 5.2-2

[redacted]



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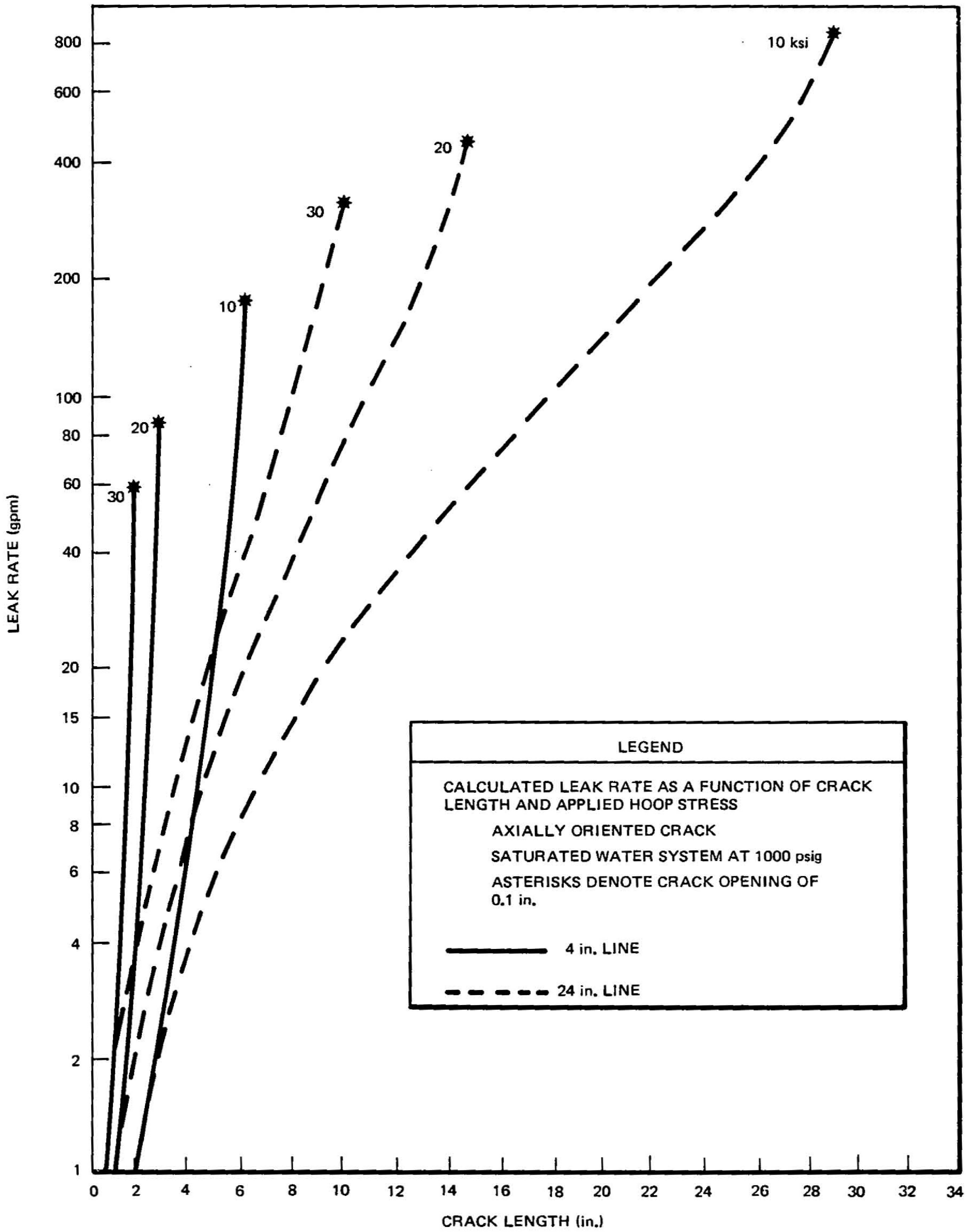
IOWA ELECTRIC LIGHT & POWER COMPANY
UPDATED FINAL SAFETY ANALYSIS REPORT

Axial Through-Wall Crack Data Correlation

Figure 5.2-14



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UPDATED FINAL SAFETY ANALYSIS REPORT

Calculated Leak Rate as a Function of Crack Length and Applied Hoop Stress

Figure 5.2-15

5.3 REACTOR VESSELS

5.3.1 REACTOR VESSEL MATERIALS

5.3.1.1 Material Specifications

The reactor vessel design objective is to provide a volume in which the core can be submerged in coolant, thereby allowing power operation of the fuel. The design of the reactor vessel and appurtenances provides the means for the attachment of pipelines to the reactor vessel and the means for the proper installation of vessel internal components.

The power generation design bases are as follows:

1. The location and design of the external and internal supports provided as an integral part of the reactor vessel are such that stresses in the reactor vessel and supports due to reactions at these supports are within applicable ASME Code limits. (See Chapter 3 and Appendix 5A for specific design criteria.)

2. The reactor vessel design lifetime is 60 years.

3. The design of the reactor vessel and appurtenances allows for the accomplishment of a suitable program of periodic inspection and surveillance.

The safety design bases are as follows:

1. The reactor vessel and appurtenances are designed to withstand adverse combinations of loadings and forces resulting from operation under abnormal and accident conditions.

2. To minimize the possibility of brittle fracture failure of the nuclear system process barrier, the following are required: (1) the initial ductile-brittle transition temperature of materials used in the reactor vessel is known by reference or established empirically and (2) expected shifts in the transition temperature during design service life because of neutron flux are determined and employed in the reactor vessel design.

The reactor vessel is a vertical, cylindrical pressure vessel with hemispherical heads of welded construction. The reactor vessel is designed and fabricated for a useful life of 60 years based on the specified design and operating conditions. The vessel is designed, fabricated, inspected, tested, and stamped in accordance with the 1965 ASME Code, Section III, and applicable requirements for Class A vessels as defined therein and in the interpretation of the ASME Code up to but not including the Winter 1967 Addenda according to the following list. General Electric comments with regard to 34 criteria proposed by the AEC were transmitted on March 13, 1968, to Harold C. Price. The positions indicated by these comments were used in the design and fabrication of the DAEC unit.

1. Charpy impact tests per N-331.2 of the Winter 1967 Addenda were furnished for vessel studs.

2. All full-penetration pressure-carrying welds were ultrasonically examined using the angle-beam method described by N-625 of the Winter 1967 Addenda.

3. The changes to Article 4 - "Design," by the Winter 1967 Addenda were included.

4. The addition of Appendix IX, "Quality Control and Nondestructive Examination Methods," was included.

5. ASME Code Case 1441-1 was included as an option for design analysis.

The nuclear steam supplier's (GE) purchase specifications supplement the requirements of the codes and encompass the means whereby the design objective is satisfied.

The reactor pressure vessel was fabricated by the Chicago Bridge & Iron Company (CB&I). Material for the vessel was purchased by CB&I. Site assembly of the vessel is described in Appendix 5A.

The reactor vessel and its supports are designed in accordance with the loading criteria of Chapter 3 and Appendix 5A. The materials used in the design and fabrication of the reactor pressure vessel are shown in Table 5.3-1.

The cylindrical shell and bottom hemispherical head of the reactor vessel are fabricated of low-alloy steel plate that is clad on the interior with stainless steel weld overlay. The plates and forgings are ultrasonically tested and magnetic particle tested over 100% of their surfaces after forming and heat treatment. The preheat of vessel plate and forgings is maintained during welding until the weld joints are postweld heat treated. Full-penetration welds are used in all joints that retain design pressure, including nozzles throughout the vessel with the exception of nozzles less than 3-in. nominal size incore penetrations and CRD penetrations.

Although little corrosion of plain carbon or low-alloy steels occurs at temperatures of 500 to 600°F, higher corrosion rates occur at temperatures around 140°F. The 0.125-in. minimum thickness stainless steel cladding provides the necessary corrosion resistance during reactor shutdown and also helps maintain water clarity during refueling operations. Since the vessel head is exposed to a saturated steam environment throughout its operating lifetime, stainless steel cladding is not required over its interior surfaces. Exterior exposed ferritic surfaces of pressure-containing parts have a minimum corrosion allowance of 1/32 in. The interior surfaces of the top head and all carbon and low-alloy steel nozzles exposed to the reactor coolant have a corrosion allowance of 1/16 in. The vessel shape is designed to minimize coolant retention pockets and crevices.

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

Site assembly of the reactor vessel is described in Appendix 5A.

5.3.1.3 Special Methods for Nondestructive Examination

See Sections 5.2.4.3 and 5.4.3.5.4.

5.3.1.4 Special Controls for Ferritic and Austenitic Stainless Steels

Furnace sensitization of austenitic stainless steel has been avoided. Austenitic stainless steel is considered to be furnace sensitized if it has been heated by means other than welding within the range of 800 to 1800°F, regardless of subsequent cooling rate. Such parts that are subsequently solution annealed are not considered to be sensitized.

The austenitic stainless steel castings were specified to contain a minimum of 5% ferrite.

The specifications for reactor vessel beltline ferritic materials did not include any additionally imposed limits on residual elements. The specifications did include requirements on grain size that were intended to reduce sensitivity to irradiation embrittlement in service.

5.3.1.5 Fracture Toughness

5.3.1.5.1 Compliance With 10 CFR 50, Appendix G

A major condition necessary for full compliance with Appendix G is satisfaction of the requirements of the Summer 1972 or later addenda to Section III of the ASME Code. This is not possible with components that were purchased to earlier ASME Code requirements. (The reactor pressure vessel was manufactured to pre-1972 ASME Code requirements, as described in Section 5.3.1.1.)

Ferritic materials complying with 10 CFR 50, Appendix G, must have both drop-weight tests and Charpy V-notch tests with the Charpy V-notch specimens oriented transverse to the principal material working direction to establish the reference temperature RT_{NDT}. The Charpy V-notch tests must be evaluated against both an absorbed energy and a lateral expansion criteria. The maximum acceptable RT_{NDT} must be determined in accordance with the analytical procedures of the ASME Code Section III, NB-2300. Appendix G of 10 CFR 50 requires a minimum of 75 ft-lb upper-shelf Charpy V-notch energy for unirradiated beltline materials and at least 50 ft-lb upper-shelf energy at the end of life.

By comparison, materials for the reactor pressure vessel were qualified by drop-weight tests and longitudinally oriented Charpy V-notch tests, generally at only one temperature, confirming that the material nil-ductility transition temperature (NDT) was at least 60° below the lowest service temperature. There was no upper-shelf Charpy V-notch energy requirement on the beltline materials. The bolting materials were qualified to a 30 ft-lb Charpy V-notch energy requirement at 60°F below the minimum preload temperature.

From the above comparison it can be seen that the fracture toughness testing performed on the reactor pressure vessel materials cannot be shown to comply directly with the requirements of ASME Code Section III NB-2300. However, Paragraph III.A of 10 CFR 50, Appendix G, states that an approved method may be used to demonstrate equivalence of pre-1972 ASME Code fracture toughness data with post-1972 ASME Code requirements. The method used to develop RT_{NDT} values to current requirements is described in Section 5.3.1.5.2.

5.3.1.5.2 Method of RT_{NDT} Evaluation

For the purpose of setting the operating limits, the RT_{NDT} was determined from the toughness test data taken in accordance with requirements of the ASME Code, Section III, and the GE reactor pressure vessel purchase specification to which the reactor pressure vessel was designed and manufactured. These toughness test data, Charpy V-notch and drop-weight NDT, were analyzed to establish compliance with the intent of 10 CFR 50, Appendix G. Because all toughness testing needed for strict compliance was not required at the time of reactor pressure vessel procurement, some toughness results are not available. To substitute for this absence of certain data, toughness property correlations were derived for the vessel materials in order to operate upon the available data to give a conservative estimate of RT_{NDT}, in compliance with the intent of 10 CFR 50, Appendix G, criteria. These toughness correlations vary, depending upon the specific material analyzed, and were derived from the results of Welding Research Council Bulletin 217, "Properties of Heavy Section Nuclear Reactor Steels," and from toughness data for other BWR reactors.

In the case of vessel plate material (SA-533 Grade B, Class 1), the predicted limiting toughness property is either NDT or transverse Charpy V-notch 50 ft-lb temperature minus 60°F, whichever is greater. As a matter of practice where NDT results are missing, NDT is estimated as the longitudinal Charpy V-notch 35 ft-lb transition temperature. However, for the DAEC vessel plates, "no break" drop-weight information was available at purchase specification temperatures, so the NDT was conservatively taken as 10°F below the "no break" test temperature. The transverse Charpy V-notch 50 ft-lb transition temperature was estimated from longitudinal Charpy V-notch data in the following manner. The lowest longitudinal Charpy V-notch energy, if below 50 ft-lb, was adjusted to derive a longitudinal Charpy V-notch 50 ft-lb transition temperature by adding 2°F/ft-lb to the test temperature. If the actual data equaled or exceeded 50 ft-lb, the test temperature was used. Once the longitudinal 50 ft-lb temperature was derived, an additional 30°F was added to account for the orientation change from longitudinal 50 ft-lb to transverse 50 ft-lb.

For forgings (SA-508, Class 2), the predicted limiting property is the same as for vessel plates and the RT_{NDT} was estimated in the same way.

For the vessel weld metal the predicted limiting property is the Charpy V-notch 50 ft-lb transition temperature minus 60°F, as BWR materials experience indicates that drop-weight NDT values are typically -50°F or lower. The Charpy V-notch 50 ft-lb temperature was derived in the same way as for the vessel plate material, except the 30°F addition for orientation effects was omitted since there is no principal working direction in weld metal. NDT values were not available, so the RT_{NDT} was taken as the transverse Charpy V-notch 50 ft-lb transition temperature minus 60°F.

For the vessel weld heat-affected zone material, the RT_{NDT} was assumed to be the same as for the base material. ASME Code weld procedure qualification test requirements and postweld heat treatment data indicate that this assumption is valid.

For bolting material, the current ASME Code requirements define the lowest service temperature (LST) as the temperature at which transverse Charpy V-Notch (CVN) energy of 45 ft-lb. and 25 mils lateral expansion (MLE) were achieved. If the required Charpy results are not met, or are not reported, but the CVN energy reported is above 30 ft-lb., the requirements of the ASME Code Section III, Subsection NB-2300 at construction are applied, namely that the 30 ft-lb. test temperature plus 60°F is the LST for the bolting materials. Charpy data for the Duane Arnold closure studs indicates the materials did not meet the 45 ft-lb., 25 MLE requirement at 10°F, but the CVN energy was greater than 30 ft-lb. Thus, the higher of the LST and the RT_{NDT} +60°F determines the boltup limit in the closure flange region.

5.3.1.5.3 Calculated Values of Initial RT_{NDT}

The methods in Section 5.3.1.5.2 were used to calculate initial RT_{NDT} values for the core beltline plates and welds, closure flange region, nozzles and other discontinuities, and lowest service temperature for the closure bolting material. The calculation methods conservatively estimate RT_{NDT} in order to meet the intent of 10 CFR 50, Appendix G, criteria. The beltline plate RT_{NDT} is +40°F, based on the NDT for shell ring number one. The weld metal RT_{NDT} of -50°F was calculated by adjusting Charpy V-notch data. The value of NDT for the reactor vessel nozzles is 40°F. The highest RT_{NDT} value for the nozzles is 74°F for N15, Drain Nozzle. The upper vessel shell plate material at 14°F represents the limiting initial RT_{NDT} for the closure flange region, and the LST of the closure studs is 70°F; therefore, the bolt-up temperature value used is 74°F.

The DAEC pressure-temperature operating limits in the Technical Specifications have been analyzed by GE and meet the requirements of 10 CFR 50, Appendix G, revised December, 1995.

In addition to Technical Specifications to conform to 10 CFR 50, Appendix G, the test specimen withdrawal requirements have been modified to conform to 10 CFR 50, Appendix H and the Boiling Water Reactor Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP). See Section 5.3.1.6.

5.3.1.6 Material Surveillance

5.3.1.6.1 DAEC-Specific Material Surveillance Program

NOTE: The following information regarding the previous DAEC plant-specific program is included for information and is HISTORICAL. See Section 5.3.1.6.2 for a discussion of the current integrated surveillance program.

The material surveillance test program uses a series of Charpy V-notch impact specimens and tensile specimens from the base metal of the reactor vessel, weld heat-

affected zone metal, and weld metal from a reactor steel joint that simulated a welded joint in the reactor vessel. The specimens and neutron monitor wires were placed near core midheight adjacent to or near the reactor vessel wall as access permits, so that the neutron exposure is similar to that of the vessel wall. The specimens were installed at startup or just before full-power operation. Selected groups of specimens are removed at intervals over the lifetime of the reactor and are tested to compare mechanical properties with the properties of control specimens that are not irradiated.

The DAEC-specific surveillance program for the reactor vessel is described in Reference 3 and in the following paragraphs. Additional information is provided in References 4, 5 and 6.

This surveillance program did not conform identically to ASTM E-185-66 or its revision, ASTM E-185-70, "Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels."

The following is a comparison of the DAEC surveillance program with those portions of ASTM E-185-70 that the DAEC program did not totally coincide with. Referenced paragraph numbers correspond to paragraph numbers in ASTM E-185-70.

<u>Test Material (Paragraph 3.1)</u>

The test specimens were taken from a plate sample of the same heat as the wall plates in the reactor core region. The sample plate was welded with the same material and by the same procedure as a butt weld in the core region.

<u>Fabrication History (Paragraph 3.1.1)</u>

The test plate represents all of the fabrication processes to which the vessel plate was subjected except for forming, which has an insignificant effect on the vessel plate properties.

<u>Test Specimens (Paragraph 3.1.2)</u>

Test specimens were taken from the test plate to represent the base metal, heat-affected zone, and weld material. The plate material was not tested before selection since this pretesting would have imposed a large material and test cost on the surveillance program. The weld procedures and materials duplicated actual fabrication. The specimens were located vertically in the highest fluence area. Circumferentially, the specimens were located where access dictates, not necessarily at the highest fluence. One extra baseline set of specimens has been retained as spares. All specimens are identified, and complete documentation is available.

<u>Chemical Composition (Paragraph 3.1.3)</u>

Since specimens were taken from each heat of actual plate material, the chemical analysis of this material is on record.

Type of Specimens (Paragraph 3.2)

The surveillance test specimens conform to ASTM E-185-70 requirements, except that the heat-affected zone impacts have the notch at the fusion line instead of 1/32 in. away. The weld material tensile specimen is oriented parallel to the weld. All other specimens are oriented parallel to the plate-rolling direction, transverse to the weld. The impact notch is perpendicular to the plate surface.

Number of Specimens (Paragraph 3.3)

The number and types of specimens used in this surveillance program are given in Table 5.3-2. There are equal numbers of base metal, heat-affected zone, and weld specimens. For the establishment of the baseline, the program was based on 12 impact specimens per test set, since experience indicated that this quantity was adequate.

Correlation Monitors (Paragraph 3.4)

Correlation monitors were not used since this was a surveillance program, not a research and development program.

Location of Specimens (Paragraph 4.1)

The specimens were located as close as possible to the zone of highest fluence. The test plate duplicated the vessel material, and the specimens were placed as close as practical to the vessel wall to best duplicate the vessel wall conditions.

Accelerated or Reduced Irradiation (Paragraph 4.2)

Accelerated exposures were not used.

Thermal Control Specimens (Paragraph 4.3)

Thermal controls were part of earlier test programs, and after reviews of results, the controls have been discontinued.

Test Capsules (Paragraph 4.4)

The BWR is essentially a constant-temperature system; therefore, no temperature monitoring was employed. The specimens were hermetically sealed in an inert gas environment in a thin-wall stainless steel capsule that is not buoyant and does not present any problems in removing the irradiated capsules. All specimens were encapsulated in tight containers, and tensile specimens had aluminum spacers to keep gamma heating as close as possible to vessel wall conditions. If it became necessary, the out-of-reactor spare specimens could have been encapsulated and placed in a wall basket as a replacement for one group of the initial in-reactor specimens.

Corrosion-Resistant Reactor Vessel Materials (Paragraph 4.5)

The vessel wall and all test specimens are low-alloy ferritic steel.

Significance (Paragraph 5.1)

Dosimeters were a part of the specimens to measure flux. Irradiation-induced temperature was of no consequence and was not measured. The evaluation of the radiation spectrum is a development, rather than a surveillance function.

Neutron Flux Dosimeters (Paragraph 5.2)

Iron, nickel with known cobalt content, and copper were used as flux monitors. One of each was included in each impact specimen capsule. In addition, one separate removable flux dosimeter was included.

Tension Tests and Notched Bar Impact Tests (Paragraphs 6.7, 7.1, and 7.2.1)

The tension test methods recommended by GE were not in complete conformance with ASTM E-184.

The surveillance program and test interpretation are based on 30 ft-lb Charpy impact. This data would indicate significant changes in NDT temperature if any occurred.

The tensile and impact capsules were placed in three baskets, fastened to a holder, and suspended from a bracket on the reactor vessel inner wall approximately 120 degrees apart.

There are 37 spare impact specimens and 12 tensile out-of-reactor spare specimens.

The surplus base metal is approximately 12 by 21 by 4-11/16 in. The surplus weld sample plate is approximately 6 by 33 by 4-11/16 in. The surplus plates, if it becomes necessary, can be made into specimens with the following dimensions:

Charpy V-notch specimen - 2.1 by 0.39 by 0.39 in.
Tensile specimen - 0.25 in. in diameter by 3 in. long

In addition to the capsule dosimeter, one basket had a special holder with a capsule containing iron and copper dosimeter wire. This special dosimeter could be removed independently of the surveillance samples.

5.3.1.6.2 Intregrated Surveillance Program and Test Results

Withdrawal Schedule

Test specimens of the reactor vessel base, weld and heat affected zone metal were installed in the reactor vessel adjacent to the vessel wall at the core midplane level at the

start of operation. A withdrawal of specimens was performed in accordance with the following:

Withdrawal Period (Approx. effective full power years)	Estimated Max. Fluence @ 1/4 T (10^{18} nvt> 1 MeV)
6	0.7
15	1.2

Future specimen withdrawal is in accordance with the Boiling Water Reactor Vessel and Internals Project Integrated Surveillance Program.

The program for implementation of the scheduling, withdrawal, and testing of the material surveillance specimens is governed and controlled by the Boiling Water Reactor Vessel and Internals Project (BWRVIP) BWRVIP-86-A, "BWR Vessel and Internals Project Updated, BWR Integrated Surveillance Program (ISP) Implementation Plan" (Reference 11). The BWRVIP Integrated Surveillance Program (ISP) complies with the requirements of 10 CFR 50, Appendix H. The specimens will be pulled in accordance with the test matrix included in BWRVIP-86-A.

A neutron fluence calculation methodology which has been approved by the NRC staff and conforms with U.S. Nuclear Regulatory Commission Regulatory Guide 1.190, "Calculation and Dosimetry Methods for Determining 'Pressure Vessel Neutron Fluence", will be used for the determination of neutron fluence values for the DAEC.

First Surveillance Capsule

The first surveillance capsule at the 288° location was withdrawn after 5.9 effective full power years (Cycle 7) for testing. It contained 24 Charpy V-notch specimens, six tensile specimens and six flux wires. The test results are presented in Reference 3. These results are superceded by those results of the Second Surveillance Capsule which is summarized below and contained in Reference 6.

Second Surveillance Capsule

The second surveillance capsule at the 36° location was removed at approximately 14.7 EFPY in October 1996 (end of Cycle 14). The capsule contained 9 flux wires for neutron fluence measurement and 36 Charpy and 8 tensile test specimens for material property evaluations. The flux wires were evaluated to determine the fluence experienced by the test specimens. Charpy V-Notch impact testing and uniaxial tensile testing were performed to establish the properties of the irradiated surveillance materials.

The 36° azimuth position surveillance capsule was removed and shipped to VNC. The flux wires and Charpy V-Notch and tensile test specimens removed from the capsule were tested according to ASTM E185-82. The methods and results of the testing are presented in Reference 6. This evaluation was re-performed to incorporate ASME Code Case N-640 and revised fluence (Reference 7). The fluence was calculated in accordance

with GE Licensing Topical Report NEDC-32983P, which has been approved by the NRC in Reference 8. The evaluation was used to generate Pressure-Temperature Limit Curves (Reference 9). The significant results of the evaluation are below:

a. The second surveillance capsule contained 9 flux wires: 3 copper (Cu), 3 nickel (Ni), and 3 iron (Fe). There were 36 Charpy V-Notch specimens in the capsule: 12 each of plate material, weld material, and heat affected zone (HAZ) material. The 8 tensile specimens removed consisted of 3 plate, 2 weld, and 3 HAZ metal specimens.

b. The curves of irradiated and unirradiated Charpy specimens established the 30 ft-lb shifts. After the first capsule specimens were tested, the weld material showed a 2.5°F shift and a 2.7 ft-lb increase in USE (2.7% increase). The plate material showed a 41.8°F shift and a 0.7 ft-lb increase in USE (0.4% increase). The HAZ materials showed a 2.9°F shift and a 8.2 ft-lb increase in USE (7.1% increase). After the second capsule specimens were tested, the weld material showed a 16.1°F shift and a 3.4 ft-lb decrease in USE (3.4% decrease). The plate material showed a 77°F shift and a 12.2 ft-lb decrease in USE (10.5% decrease).

c. The measured shifts of 77°F for the plate material and 16.1°F for weld material, for a fluence of 1.1×10^{18} n/cm^2, were within the Reg. Guide 1.99, Rev. 2 range predictions ($\Delta RT_{NDT} \pm 2\sigma$) of 15°F to 83°F and -44°F to 68°F for plate and weld material, respectively. The best estimate chemical composition for the surveillance materials was used for this calculation.

d. The irradiated tensile specimens were tested at room temperature, reactor operating temperature (550°F), and at 185°F for the additional base and HAZ weld specimens. Unirradiated and first capsule testing results were available for comparison.

e. The peak RPV ID fluence used in the P-T curve evaluation is 4.17E18 n/cm^2 for the entire plant life. This fluence applies to the lower-intermediate plates and longitudinal welds. The fluence is adjusted for the lower plates and longitudinal welds and the girth weld based upon an attenuation factor of 1.18; hence, the peak ID surface fluence for these components is 3.55E18 n/cm^2. Similarly, the fluence is adjusted for the N2 (Recirculation Inlet) Nozzle based upon an attenuation factor of 5.46; hence the peak ID surface fluence used for this component is

7.64E17 n/cm^2. The same method is applied to the N16 (Instrumentation) Nozzle, which has an attenuation factor of 3.7, resulting in a peak ID surface fluence of 1.13E18 n/cm^2.

f. The adjusted reference temperature (ART=Initial RT_{NDT} + Δ RT_{NDT} + Margin) was predicted for beltline materials, based on the methods of Reg. Guide 1.99, Rev. 2.

g. An update of the beltline material USE values at 32 EFPY was performed using the Reg. Guide 1.99, Rev. 2 methodology. The Equivalent Margin Analyses demonstrate that the 10CFR50, Appendix G safety requirements are satisfactorily met for the DAEC.

h. P-T curves were developed with incorporation of ASME Code 1995 edition with 1996 addenda including Cases N-640 methodology and with current evaluation and the effect of extended power uprate for three reactor conditions: pressure test (Curve A), core not critical heatup and cooldown (Curve B), and core critical operation (Curve C) which are valid for up to 32 EFPY of operation. The P-T curves are beltline (N2 Recirculation Inlet Nozzle) limited above 240 and 230 psig for Curve A for 25 and 32 EFPY, respectively, and above 30 psig for Curve B for both 25 and 32 EFPY. The P-T curves as shown in Figure 5.3-1 include a set of A curves established at heatup/cooldown rate of 20 °F/hr. The P-T curves as shown in Figure 5.3-1 include a set of B and C curves evaluated at a heatup/cooldown rate of 100 °F/hr.

i. The requirement of 10 CFR50 Appendix G deal with vessel design life conditions and with limits of operation designed to prevent brittle fracture. Based on the evaluation of current analysis (Extended Power Uprate), the following conclusions are made:

The values of ART and USE for the reactor vessel beltline materials are expected to remain within the limits of Reg. Guide 1.99, Rev. 2 and Appendix G of 10CFR50 (<200°F and >50 ft-lbs, respectively) for at least 32 EFPY of operation.

5.3.1.7 <u>Reactor Vessel Fasteners</u>

The vessel top head is secured to the reactor vessel by studs, nuts, and bushings that are designed to be tightened with a stud tensioner. The vessel flanges are sealed by two concentric Inconel-718 seal rings designed for no detectable leakage through the inner or outer seal at any operating condition including the following:

1. Cold hydrostatic pressure test at the design pressure.

2. Heating to operating pressure and temperature at a maximum rate of 100°F/hr. To detect the lack of seal integrity, a 1-in. vent tap is provided in the area between the two seal rings, and a monitor line is attached to the tap to provide an indication of leakage from the inner seal ring seal. A 1-in. tap is also provided in the area outside the outer seal ring for use in monitoring leakage.

5.3.2 OPERATING PRESSURE AND TEMPERATURE LIMITS

Operating limits curves are required for the Technical Specifications for three reactor conditions: (a) system hydrostatic and leakage tests, (b) non-nuclear heatup or cooldown, and (c) core critical operation. The curves are established by requirements of Section III, Appendix G, of the ASME Code and by 10 CFR 50, Appendix G. Figure 5.3-1 shows all three operating limits curves, including irradiation shift of the core beltline region curves to their positions at end of life (32 full power years).

5.3.2.1 Irradiation Effects on Core Beltline

The beltline contains the N2 Recirculation Inlet Nozzle and the N16 Instrumentation Nozzle, which represents a slight extension beyond the core region. This is determined by the location on the vessel where the fluence exceeds $1x10^{17}$ n/cm^2. An evaluation of ART for all beltline plates, the N2 and N16 Nozzles, and several beltline welds was made for 32 EFPY.

Estimated maximum changes in RT_{NDT} as a function of the end-of-life (32 full power years) fluence at the one-quarter thickness (1/4 T) depth of the vessel beltline materials are listed below.

Flux densities at the 288 and 36 degree surveillance capsule locations in the reactor pressure vessel were evaluated by testing flux wires removed with the surveillance capsule after Cycles 7 and 14 respectively.

The relationship between the capsule location and the peak flux location at the 1/4 T depth was determined by a combination of two-dimensional and one-dimensional flux distribution computer analyses.

The transition temperature shift due to irradiation was calculated in accordance with Regulatory Guide 1.99, Revision 2, taking into account the data from the surveillance testing. The results for the core beltline materials are tabulated below:

	Plate	N16	N2	Weld
Limiting material chemistry	0.15% Cu, 0.65% Ni	0.18% Cu 0.85%Ni	0.18% Cu 0.84%Ni	0.03% Cu, 0.91% Ni
End-of-life transition temperature shift	130.5°F	89.1°F	79.2°F	56.3°F
Initial reference temperature	10°F	40°F	40°F	-50°F
End-of-life adjusted reference temperature	140.5°F	129.1°F	119.2°F	6.3°F
1/4 T Fluence (n/cm^2)	3.19E+18	8.63E+17	5.85E+17	3.19E+18

Since the predicted end-of-life adjusted reference temperatures are below 200°F, provisions to permit thermal annealing of the reactor pressure vessel in accordance with Paragraph IV.B of 10 CFR 50, Appendix G, are not required.

5.3.2.2 Temperature Limit for Boltup and Pressurization

The minimum temperature for boltup and pressurization of 74°F was established by adding 60°F to the RT_{NDT} for the limiting closure flange region. The 60°F added to the RT_{NDT} for boltup and pressurization is a requirement of the ASME Code applicable to the original reactor pressure vessel design work. However, Appendix G of the 1995 ASME Code with 1996 Addenda, Section XI requires a minimum permissible temperature of RT_{NDT} for boltup and pressurization up to 20% of hydrotest pressure (Paragraph G-2222c). The 60°F added to the RT_{NDT} is extra margin included because the closure flange region stress analysis assumes a 0.24-in. flaw (which is detectable) instead of a 1/4 T flaw. In the case of the core critical operation curve C in Figure 5.3-1, 10 CFR 50, Appendix G, Table 1 requires a minimum permissible temperature of (RT_{NDT} + 60°F) or 74°F.

The minimum temperature for boltup prior to pressurization must be 74°F or greater. Boltup at 74°F satisfies the requirements of the original code of construction and exceeds the 1995 ASME Code with 1996 Addenda requirements. A sufficient number of studs may be partially tensioned to seal the closure flange O-rings for the purpose of raising reactor water level above the closure flanges, in order to assist in warming the flanges and adjacent shells to a minimum temperature of 74°F before they are stressed by the full intended bolt preload.

5.3.2.3 Temperature Limits for System Hydrostatic or System Leakage Tests

The fracture toughness analysis for system pressure tests results in the curve labeled A shown in Figure 5.3-1. The N2 Recirculation Inlet Nozzle is the limiting material for the beltline region for 32 EFPY. The beltline pressure test P-T curves are calculated in the same manner as the Feedwater Nozzle pressure test P-T curves, using the N2-specific geometry. The initial RT_{NDT} for the N2 Recirculation Inlet Nozzle materials is 40°F. The generic pressure test P-T curve is applied to N2 Nozzle curve by shifting the P vs. ($T\text{-}RT_{NDT}$) values for the Feedwater Nozzle to reflect the ART value for the N2 Nozzle (119.2°F).

5.3.2.4 Temperature Limits for Non-Nuclear Heatup/Cooldown

The fracture toughness analysis for non-nuclear heatup and cooldown results in Curve B shown in Figure 5.3-1. The N2 Recirculation Inlet Nozzle is the limiting material for the beltline region for 32 EFPY. The beltline core not critical P-T curves are calculated in the same manner as the Feedwater Nozzle core not critical P-T curves, using the N2-specific geometry. The initial RT_{NDT} for the N2 Recirculation Inlet Nozzle

materials is 40°F. The generic core not critical P-T curve is applied to the N2 Nozzle curve by shifting the P vs. (T-RT_{NDT}) values for the Feedwater Nozzle to reflect the ART value for the N2 Nozzle (119.2°F). The Curve B analysis assumes a normal heatup or cooldown rate of 100°F/hr and it also includes the effects of cold water injections into the nozzles and other operational transients. The resulting temperature gradients and thermal stress effects are included.

5.3.2.5 Temperature Limits for Core Critical Operation

10CFR50, Appendix G, Table 1 requires that core critical P-T limits be 40°F above any Curve A or B limits when pressure exceeds 20% of the pre-service system hydrotest pressure. Curve B is more limiting that Curve A, so limiting Curve C values are at least Curve B plus 40°F for pressures above 312 psig.

10CFR50, Appendix G, Table 1 indicates that the allowed initial criticality at the closure flange region is (RT_{NDT} + 60°F) at pressures below 312 psig. This requirement makes the minimum criticality temperature 74°F, based on an RT_{NDT} of 14°F. In addition, above 312 psig the Curve C temperature must be at least the greater of RT_{NDT} of the closure region + 160°F or the temperature required for the hydrostatic pressure test (Curve A at 1035 psig.) This requirement does not cause a temperature shift in Curve C at 312 psig due to the presence of the N2 Nozzle discontinuity.

5.3.2.6 Operating Procedures

For most reactor operating conditions, coolant pressure and temperature are at saturation conditions, which are well into the acceptable operating area (to the right of the P-T curves). The operations where P-T curve compliance is typically monitored closely are planned events, such as vessel boltup, leakage testing and startup/shutdown operations, where operator actions can directly influence vessel pressures and temperatures.

The most severe unplanned transients relative to the P-T curves are those that result from SCRAMs, which sometimes include recirculation pump trips. Depending on operator responses following pump trip, there can be cases where stratification of colder water in the bottom head occurs while the vessel pressure is still relatively high. Experience with such events has shown that operator action is necessary to avoid P-T curve exceedance, but there is adequate time for operators to respond.

In summary, there are several operating conditions where careful monitoring of P-T conditions against the curves is needed:

- Head flange boltup
- Leakage test (Curve A compliance)
- Startup (coolant temperature change of less than or equal to 100°F in one hour period heatup)

- Shutdown (coolant temperature change of less than or equal to 100°F in one hour period cooldown)
- Recirculation pump trip, bottom head stratification (Curve B compliance)

The average rate of reactor coolant temperature change during normal heatup and cooldown is limited to 100°F in any 1-hr period Figure 5.3-1, Curves B & C. During emergency and faulted conditions, the cooling rates may exceed this value as a result of rapid blowdown due to postulated valve malfunctions or rupture accidents.

A record is maintained of the actual reactor vessel transients that occur versus the design number of transients listed in Table 5.3-7. The record is updated at the end of each fuel cycle.

5.3.3 REACTOR VESSEL INTEGRITY

This section contains information about vessel integrity that may not be contained in other sections. It describes some of the considerations in achieving reactor vessel safety and describes factors contributing to vessel integrity.

5.3.3.1 Design

The reactor vessel design pressure of 1250 psig is determined by an analysis of margins required to provide a reasonable range for maneuvering during operation, with additional allowances to accommodate transients above the operating pressure (1025 psig at the level of the top head flange) without causing the operation of the safety valves. The design temperature for the reactor vessel (575°F) is based on the saturation temperature of water corresponding to the design pressure.

To withstand external and internal loadings while maintaining a high degree of corrosion resistance, a high-strength low-alloy steel is used as a base metal with an internal cladding of stainless steel applied by weld overlay. The use of the ASME Code, Section III, Class A, pressure vessel code design criteria ensures that a vessel designed, built, and operated within its design limits has an extremely low probability of failure due to any known failure mechanism.

Reactor vessel data are contained in Tables 5.3-5 and 5.3-6. The reactor vessel is designed for a 60-year life. The reactor vessel is also designed for the transients that could occur during the 60-year life as indicated in Table 5.3-7.

Extensive tests have established the magnitude of changes in the NDT temperature as a function of the integrated neutron dosage. Figure 5.3-2 presents pertinent test data for SA-302B/SA-533B Class 1 steel and plots the change in ductile to brittle transition temperature as a function of integrated neutron flux (nvt). The 30 ft-lb refers to the energy absorbed by the Charpy V-notch sample at the test (transition) temperature. The upper two curves apply to thick-walled pressure vessels, and the lower curve is for the wall thickness range representative of this reactor vessel .

Detailed stress analyses have been made on the reactor vessel for both steady-state and transient conditions with respect to material fatigue. The results of these transients are compared to allowable stress limits. Requiring the coolant temperature in an idle recirculation loop to be within 50°F of the operating loop temperature before a recirculation pump is started ensures that the changes in coolant temperature at the reactor vessel nozzles and bottom head region are acceptable.

Heating and cooling transients throughout plant life at uniform rates of 100°F/hr were considered in the temperature range of 100 to 549°F and were shown to be within the requirements for stress intensity and fatigue limits of Section III of the ASME Code (1971 Edition including Summer 1972 Addenda).

The coolant in the bottom of the vessel is at a lower temperature than that in the upper regions of the vessel when there is no recirculation flow. This colder water is forced up when recirculation pumps are started. This will not result in stresses that exceed ASME Code, Section III limits when the temperature differential is not greater than 145°F.

The minimum temperature of the fluid retained by a component can be used as a conservative estimate of metal temperature in evaluating the margin from the temperature at which the NDT properties were measured. Additional margin can usually be shown by calculating the temperature of the metal for the condition and area of concern.

During operation when pressure depends on temperature, brittle failure of the vessel is not possible until the neutron fluence of the reactor vessel reaches a value of the order of 10^{20} nvt. This value is approximately 20 times the maximum neutron fluence conservatively calculated during the lifetime of the DAEC plant.

5.3.3.2 Materials of Construction

In addition to the minimum requirements of the ASME Code, the following precautions are taken and tests made either to ensure that the initial NDT temperature of the reactor vessel material is low or to reduce the sensitivity of the material to irradiation effects:

1. The material is selected to produce as fine a grain size as practical. It is an objective to maintain a grain size of five or finer.

2. Drop-weight impact tests are performed on each heat and heat treatment charge of all low-alloy steel plate material in its as-fabricated condition.

3. Drop-weight impact tests are made on the weld metal, the heat-affected zone of the base metal, and the base metal of the weld test plates simulating seams. If different welding procedures are used for nozzle welds, drop-weight tests of similarly prepared coupons are made. The NDT temperature test criteria for the weld and heat-affected zone of the base material are the same as for the unaffected base metal.

4. The actual NDT temperature of the plates opposite the center of the reactor

   core is determined. In other areas, it is sufficient to demonstrate that the two drop-weight test specimens do not break at 10°F above the design NDT temperatures. The area of the vessel opposite the core is fabricated entirely of plate and is not penetrated by nozzles nor are there any other structural discontinuities in this area that would act as stress risers.

The head and vessel flanges are low-alloy steel forgings. The sealing surfaces of the reactor vessel head and shell flanges are weld overlay clad with austenitic stainless

steel similar to the vessel that consists of a minimum of two layers and minimum of 0.25 in. total thickness after all machining, including the area under seal grooves. The first layer is deposited with a composition equivalent to ASTM A-371, Type ER309, and subsequent layers have a composition equivalent to ASTM A-371, Type ER308, except that the carbon content does not exceed 0.035% at the finished surface.

The vessel nozzles (Figure 5.3-3) are low-alloy steel forgings made in accordance with ASTM A-508 as modified by ASME Code Case 1332, Paragraph 5. Nozzles of 3 to 9 in. nominal size or larger are full-penetration welded to the vessel. Nozzles of less than 3-in. nominal size may be partial penetration welded as permitted by ASME Code, Section III. Nozzles that are partial-penetration welded are nickel-chromium-iron forgings made in accordance with ASME SB-166 or SB-167 as modified by Code Case 1420.

The reactor vessel including all nozzles was reviewed for compliance with Paragraph N-331, Ductile-Brittle Transition Tests, Section III, ASME Code, 1965 Edition plus addenda through Summer 1967 Addenda. It was determined that the vessel and its components, with the exception of the feedwater nozzle safe end, met the code criteria.

The materials for the feedwater nozzles and safe ends were ordered on the basis of a 100°F lowest service metal temperature. The ASME Code requires all material to have impact tests 60°F below the lowest service metal temperature. The code requirements for Charpy V-notch energy on the A-508 Class 2 nozzle is 30-ft-lb average for three test specimens. The Charpy V-notch energy requirement for the A-508 Class 1 safe ends is 20 ft-lb average for three test specimens.

The 90°F water steady-state flow case was determined to be the governing normal service condition for the original design of these nozzles because of a thermal sleeve design that exposed the safe end and nozzle to a bypass flow of 90°F water. Therefore, the original design did not meet the ASME Code requirements, since the impact tests were performed at +40°F based on 100°F water, instead of +30°F based on +90°F water.

In addition to the governing normal service condition described above, feedwater nozzles N4C and N4D were also evaluated for the abnormal condition of RCIC injection. The conservative conditions assumed for this evaluation were 200-gpm flow per nozzle of 40°F water for an indefinite time. RCIC flow would probably be switched from the 40°F condensate storage supply to the 100°F RHR system within 30 min, but for this analysis, it was assumed the RCIC flow would continue to be from the condensate storage supply. The initial warm leg of water in the feedwater and RCIC piping was also conservatively neglected.

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

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

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

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

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

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

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

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

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

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

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

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

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

5.3.3.2.1 Shroud Support

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

5.3.3.2.2 Reactor Vessel Support Assembly

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

The reactor vessel is supported on a steel cylinder that is welded to the bottom of the reactor vessel and extends down and through the drywell shell and is embedded in the

reactor building mat. After the erection of the reactor vessel, a concrete pedestal is added, which is constructed monolithically with the steel support cylinder.

5.3.3.2.3 Vessel Stabilizers

The lateral loads from the vessel stabilizers and shield wall are transmitted to the drywell stabilizers by rigid struts extending from the top of the shield wall to the drywell stabilizers.

The vessel stabilizers are connected between the reactor vessel and the top of the shield wall surrounding the vessel to provide lateral stability for the upper part of the vessel. Four stabilizer brackets are attached by full-penetration welds to the reactor vessel at evenly spaced locations around the vessel below the flange. Each vessel stabilizer consists of a gusset plate attached to the top of the shield, a clevis (a U-shaped piece of metal with ends perforated to receive a pin) pinned to the stabilizer bracket, and a spring-loaded drawbar between them. Two stabilizers are attached to each bracket and apply tension in opposite directions. The stabilizers are evenly preloaded with tensioners to the values of the residual loads shown in Table 5.3-5. The stabilizers are designed to permit radial and axial vessel expansion, to limit horizontal vibration, and to resist seismic and jet reaction forces.

5.3.3.2.4 Refueling Bellows

The refueling bellows form a seal between the reactor vessel and the surrounding primary containment drywell to permit flooding of the space (reactor well) above the vessel during refueling operations. The refueling bellows assembly (see Figure 5.3-3) consists of a Type 304 stainless steel bellows, a backing plate, a spring seal, and a removable guard spring. The backing plate surrounds the outer circumference of the bellows to protect it and is equipped with a tap for testing and for monitoring leakage. The self-energizing spring seal is located in the area between the bellows and the backing plate and is designed to limit water loss in the event of a bellows rupture by yielding to make a tight fit to the backing plate when subjected to full hydrostatic pressure. In the event that refueling bellows leakage is in excess of 5 gpm, an alarm will annunciate in the control room. The guard ring attaches to the assembly and protects the inner circumference of the bellows. The guard ring can be removed from above to inspect the bellows. The assembly is welded to the reactor bellows support skirt flange and the reactor well seal bulkhead plate. The reactor bellows support skirt is welded to the reactor vessel shell flange (see Figure 5.3-3), and the reactor well seal bulkhead plate bridges the distance to the primary containment drywell wall. A bellows seal of similar design forms a seal between the outside of the drywell and the outer portion of the reactor well. Six watertight hinged covers are bolted in place for normal refueling operation. For normal operation, these covers are opened and removable air supply ducts and air return ducts permit the circulation of ventilation air in the region above the reactor well seal bulkhead plate.

5.3.3.2.5 Control Rod Drive Housings

The CRD housings are inserted through the CRD penetrations in the reactor vessel bottom head and are welded to the stub tubes extending into the reactor vessel (Figure 5.3-3). Each housing transmits a number of loads to the bottom head of the reactor. These loads include the weight of a control rod and control rod drive, which are bolted to the housing from below (see Section 4.6), the weight of a control rod guide tube, one fuel support piece, and the fuel assemblies that rest on the top of the fuel support piece (see Section 3.9.5). The housings are fabricated of Type 304 austenitic stainless steel.

5.3.3.2.6 Control Rod Drive Housing Supports

The CRD housing support is designed to prevent a nuclear transient in the unlikely event there is a CRD housing failure. This device consists of a grid structure below the reactor vessel from which housing supports are suspended. The supports allow only slight movement of the control rod drive or housing in the event of failure.

The CRD housing support is treated in detail in Section 3.9.4.

5.3.3.2.7 Incore Neutron Flux Monitor Housings

The incore neutron flux monitor housings are inserted up through the incore penetrations in the bottom head of the reactor vessel and are welded to the inner surface of the bottom head (Figure 5.3-3). An incore flux monitor guide tube is welded to the top of each housing (see Section 3.9.5). Either a source range monitor/intermediate range monitor drive unit or a local power range monitor is bolted to the seal ring flange at the bottom of the housing (see Section 7.6).

5.3.3.2.8 Reactor Vessel Insulation

The reactor vessel insulation has an average maximum heat-transfer rate of approximately 80 Btu/hr-ft^2 at the operating conditions of 550°F for the vessel and 135°F for the outside air. Insulation thicknesses vary in different regions of the vessel up to 4 in. maximum.

The cylindrical shell insulation is supported at three levels. The upper level supports have close-in insulation above them and standoff permanently installed insulation below them down through the intermediate support level to the lower support level. The lower supports have removable, hanging, standoff insulation below them.

The top head insulation consists of vertical cylindrical sections, a flat annular ring, and a disk closing off the top of the smallest vertical cylinder. This insulation is mounted on a steel frame for easy removal as an assembly. The bottom head insulation is in the form of a disk and is permanently installed.

Liquids containing chlorides are not used on any austenitic stainless steel parts of the insulation at any time.

5.3.3.3 Fabrication Methods

Quality control methods were used during the fabrication and assembly of the reactor vessel and appurtenances to ensure that the design specifications are met (see Chapter 17 and Appendix 5A) .

The fabrication test program was carried out by the reactor vessel vendor on material representative of the formed, heat-treated, and fully fabricated vessel. Tests of base metal and welded joint were performed, and the results were reported during the early stages of vessel construction. Tensile specimens from the shell plate material are prepared for various thickness levels of the plate material. These specimens are tested at various temperatures per ASTM Specifications E-8 and E-21 to determine tensile strength, yield strength, elongation, and reduction of area. Charpy V-notch impact specimens are prepared from base metal and tested per ASTM Specification E-23, Type A, to establish curves for determining the transition temperature at which 30 ft-lb of absorbed energy result in ductile fracture for various thickness levels of the plate material.

The quality control program for the field-fabricated DAEC reactor vessel was a continuing program involving the surveillance of GE, Iowa Electric, and the CB&I. The design and fabrication of the reactor vessel is of the highest quality practicable with current technology. The reactor vessel was designed, analyzed, independently checked, fabricated, and inspected in accordance with ASME Code, Section III, for Class A nuclear vessels.

5.3.3.4 Inspection Requirements

Refer to Section 5.2.4.

5.3.3.5 Shipment and Installation

Field fabrication of the reactor vessel is discussed in Appendix 5A.

5.3.3.6 Operating Conditions

The reactor coolant system was cleaned and flushed before fuel was loaded initially. During the preoperational test program, the reactor vessel and reactor coolant system were given a hydrostatic test in accordance with code requirements at 125% of design pressure. The vessel temperature is maintained at a minimum of 60°F above the NDT temperature before pressuring the vessel for a test. A pressure test in accordance with the Inservice Inspection Plan is made following each removal and replacement of the reactor vessel head. Other preoperational tests include calibrating and testing the reactor vessel flange seal ring leakage detection instrumentation, adjusting reactor vessel

stabilizers, checking all vessel thermocouples, and checking the operation of the vessel flange stud tensioner.

During the startup test program, the reactor vessel temperatures were monitored during vessel heatup and cooldown to ensure that thermal stress on the reactor vessel was not excessive during startup and shutdown.

5.3.3.7 Inservice Surveillance

For the inservice inspection program for the DAEC vessel, see Section 5.2.4.

REFERENCES FOR SECTION 5.3

1. L. C. Hsui, An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident (LOCA), NEDO-10029, 1969.

2. General Electric Company, Duane Arnold Energy Center Reactor Pressure Vessel Fracture Toughness Analysis to 10 CFR 50, Appendix G, May 1983, NEDC-30839, December 1984.

3. General Electric Company, Duane Arnold Energy Center Reactor Pressure Vessel Surveillance Materials Testing, NEDC-31166-1, Revision 1, 1986.

4. NEDO-32205, "BWR Owners' Group Topical Report on Upper Shelf Energy Equivalent Margin Analysis", dated March 21, 1994.

5. Letter from J. Franz (IES) to T. Murley (NRC) dated July 30, 1993, NG-93-2800, Response to Request for Additional Information Regarding Response to Generic Letter (GL) 92-01, Revision 1, "Reactor Vessel Structural Integrity."

6. General Electric Company, Duane Arnold RPV Surveillance Materials Testing and Analysis, GE-NE-B1100716-01, Revision 0, July 1997.

7. General Electric Company, Pressure-Temperature Curves for Duane Arnold Energy Center, GE-NE-A22-00100-08-01-R2, Revision 2, August 2003.

8. Letter, S. A. Richards, USNRC to J. F. Klapproth, GE-NE, "Safety Evaluation for NEDC-32983P, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation (TAC No. MA9891)", MFN 01-050, September 14, 2001.

9. Amendment No. 253 regarding Pressure and Temperature Limit Curves, dated August 25, 2003.

10. Not Used

11. Boiling Water Reactor Vessel and Internals Project (BWRVIP) BWRVIP-86-A, "BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan", EPRI Technical Report 1003346, dated October 2002.

12. Not Used.

13. Not Used.

14. Letter to Mr. Carl Terry, BWRVIP Chairman, from Mr. William H. Bateman, Nuclear Regulatory Commission, dated December 16, 2002, subject: ‘NRC Staff Review of BWRVIP-86-A, “BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan.”’

Table 5.3-1 Sheet 1 of 3

REACTOR PRESSURE VESSEL MATERIALS

Component	Form	Material	Specification (ASTM/ASME)
Heads, shell	Rolled plate	Low alloy steel	SA533, Grade B, Class 1
Closure flange	Forged rings	Low alloy	A508, Class 2, cc 1332
Cladding (excluding flange seal surface)	Weld overlay	Austenitic stainless steel	SA371 Type ER309, Type ER308 (and finished surface carbon content 0.08% maximum)
Nozzles	(See additional pages of this table)		
CRD stub tubes	Tubes	Inconel	SB167, cc 1420
CRD housings	Pipe	Austenitic stainless steel	SA312, Type 304 (tubing and piping); SA182, Grade F, Type 304 (flanges)
Incore housings	Pipe	Austenitic Stainless steel	SA213, Type 304 (tubing and piping); SA182, Grade F, Type 304 (flanges)

Table 5.3-1 Sheet 2 of 3

REACTOR PRESSURE VESSEL MATERIALS

Nozzle Number	Component	Specification (ASTM/ASME)	Code Case
N1A/B	Recirculation outlet		
	Nozzle	SA-508, Class 2	([a])
	Safe end	SA-336, F8	
N2A/H	Recirculation inlet		
	Nozzle	SA-508, Class 2	([a])
	Safe end	SB-166	
	Safe end extension	SA-336, F8	
	Thermal sleeve	SB-168	
	Thermal sleeve extension	SA-240, Type 304L	
N3A/D	Steam outlet		
	Nozzle	SA-508, Class 2	([a])
	Safe end	A-508, Class 1	([b])
N4A/D	Feedwater		
	Nozzle	SA-508, Class 2	([a])
	Safe end	SA-508, Class 1	([b])
	Safe end extension	SA-508, Class 1	([b])
	Thermal sleeve	SB-166	
	Thermal sleeve extension	SA-336, F8	
N5A/B	Core Spray		
	Nozzle	SA-508, Class 2	([a])
	Safe end	SB-166	
	Safe end extension	SA-336, F8	
	Thermal sleeve	SA-336, F8	
N6A/B	A - blind flanged		
	B - head instrumentation		
	Nozzle	SA-508, Class 2	([a])
	Flange	SA-508, Class 1	([b])
N7	Vent		
	Nozzle	SA-508, Class 2	([a])
	Flange	SA-508, Class 1	([b])

Note: For these cases, liquid penetrant was allowed in lieu of magnetic particle inspection on inside diameters less than 4 in.

[a] Code Case 1332-3, Paragraph 5.

[b] Code Case 1332-4, Paragraph 1.

Table 5.3-1 Sheet 3 of 3

REACTOR PRESSURE VESSEL MATERIALS

Nozzle Number	Components	Specification (ASTM/ASME)	Code Case
N8A/B	Jet pump instrumentation		
	Nozzle	SA-508, Class 2	([a])
	Safe end	SA-336, F8	
N9	CRD hydraulic system return		
	Nozzle	SA-508, Class 2	([a])
	Safe end	SA-336, F8	
N10	Core ΔP and liquid control		
	Nozzle	SA-508, Class 2	([a])
	Safe end	SA-336, F8	
N11A/B	2-in. instrumentation		
N12A/B	Nozzle	SA-508, Class 2	([a])
N16A/B	Safe end	SA-336, F8	
N13	1-in. seal leak detection		
N14	Nozzle	SB-166	
	Pipe extension	A-508, Class 1	([b])
N15	Drain		
	Nozzle	SA-508, Class 1	([b])
	Pipe extension	SA-508, Class 1	([b])

Note: For these cases, liquid penetrant was allowed in lieu of magnetic particle inspection on inside diameters less than 4 in.

[a] Code Case 1332-3, Paragraph 5.

[b] Code Case 1332-4, Paragraph 1.

Table 5.3-2

NUMBER OF SPECIMENS BY SOURCE

Specimen	Base	Weld	Heat-Affected Zone	Suggested Withdrawal Period[a]	Actual Specimen Withdrawal[a]
Unirradiated baseline tested					
C[b]	14	12	12	--	--
T[c]	3	3	0	--	--
In-reactor					
C	12	12	12	15	14.7
T	3	2	3	15	14.7
C	8	8	8	6	5.9
T	2	2	2	6	5.9
C	8	8	8	32	
T	2	2	2	32	
RC[d, f, g]	16	8	12	9	
RT[e, f, g]	3	3	0	9	
Out-of-reactor spares					
C	11	13	13	--	--
T	3	3	6	--	--

[a] Effective full power years.
[b] C is standard Charpy V-notch impact bar.
[c] T is 1/4 in. gauge diameter tensile specimen.
[d] RC is Reconstituted Charpy V-notch impact bar.
[e] RT is Reconstituted 0.113 inch minimum diameter tensile specimen.
[f] Reconstituted specimens fabricated from ten specimens removed at the end of cycle 7 (5.9 effective full power years) and re-installed at the beginning of cycle 9. Therefore, this set of reconstituted specimens does not reflect the irradiation effects of cycle 8.
[g] These reconstituted reactor specimens were re-installed for augmented testing and/or plant life extension testing and are not required to meet the material surveillance test program.

Table 5.3-3

Deleted

Table 5.3-4

Deleted

Table 5.3-5
REACTOR VESSEL DATA

Parameter	Value
Reactor vessel	
Inside diameter, in. (min)	183
Inside length, ft-in.	66 - 4
Design pressure and temperature, psig at ºF	1250 at 575
Reactor vessel support	
Design horizontal seismic shear, kip	680
Design seismic moment, ft-kip	15,400
Vessel nozzles (number), in.	
Recirculation outlet (two)	30 to 22
Steam outlet (four)	20
Recirculation inlet (eight)	10
Feedwater inlet (four)	10
Core spray inlet (two)	8
Instrument (two)	6
Control rod drive (89)	6
Jet pump instrumentation (two)	4
Vent (one)	4
Instrumentation (six)	2
CRD hydraulic system return (one)	2-1/2
Core differential pressure and standby liquid control (one)	2
Drain (one)	2
Incore flux instrumentation (30)	2
Head seal leak detection (two)	1
Vessel stabilizers	
Design seismic load (per stabilizer), kip	200
Design preload (per stabilizer), kip	215
Weights, lb	
Vessel	716,200
Top head	99,800
Operating weight	1,797,000

Table 5.3-6

REACTOR VESSEL ATTACHMENTS

Item	Quantity
Internal attachments	
Guide rod bracket	2
Steam dryer support bracket	4
Dryer holddown bracket	4
Feedwater sparger bracket	8
Jet pump riser support pad	2 each, 8 places
Core spray bracket	2 each, 4 places
Surveillance specimen bracket	2 each, 3 places
External attachments	
Stabilizer bracket	4
Top head lifting lug	4
Insulation support - vessel support skirt	18
Insulation support bracket - cylindrical shell	12 each, 3 elevations
Thermocouple pad	2 each, 28 places
Name plate pad	1
Reactor bellows support skirt flange	1

Table 5.3-7
REACTOR VESSEL TRANSIENT DESIGN

Type of Cycle	Number of cycles
Bolt up/Unbolt	45
Hydrostatic pressure test	49
Startup/Shutdown at100ºF/h	212[b]
Scram (to hot standby and return to power)	150
Loss of feedwater heaters	6
Feedwater heaterbypass	16
Improper start of a cold recirculation loop	5
Sudden start of pump in cold recirculation loop	2
CRD Isolation	3
Single CRD scram	3
125% design hydrostatic pressure test	1[a]

[a] APED A41-003 shows 3 cycles for this type of cycle, however, only 1 cycle has occurred. This test is no longer performed.

[b] Involves "aborted startup cycle (Cold Shutdown to Hot Standby and return to Cold Shutdown) i.e. 36 cycles, is conservatively analyzed as equivalent to a startup shutdown cycle since both involve a heatup and cooldown of the RPV. (176 cycles + 36 cycles = 212 cycles).

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 RECIRCULATION PUMPS

There are two recirculation pumps manufactured by Byron Jackson Pump Division, Borg-Warner Corporation. Each recirculation pump is a single-stage, variable-speed, vertical, centrifugal pump equipped with mechanical shaft seal assemblies. The pump is capable of stable and satisfactory performance while operating continuously at any speed corresponding to a power supply frequency range of 11.5 to 57.5 Hz. For loop startup, each pump operates at a speed corresponding to a power supply frequency of 11.5-16 Hz with the main discharge gate valve closed and the 4-in. bypass valve open.

The recirculation pump shaft seal assembly consists of two individual seals built into a cartridge or cartridges that can be readily replaced without removing the motor from the pump. The seal assembly is designed to require minimum maintenance over a long period of time, regardless of whether the pump is stopped or is operating at various speeds with water at various pressures and temperatures. Each seal is designed for a life of 1 year based on a 90% probability factor. Each individual seal in the cartridge is capable of sealing against pump design pressure so that any one seal can adequately limit leakage in the event that the other seal should fail. The pump shaft passes through a breakdown bushing in the pump casing to reduce leakage in the event of a gross failure of both shaft seals. Provision is made for monitoring the pressure drop across each individual seal as well as the cavity temperature of each seal. The seal leakage is piped to a flow switch with alarm on high leakage.

Each recirculation pump motor is a variable-speed ac electric motor that can drive the pump over a nominal controlled range of 330 RPM to 1710 RPM, approximately 20% to 102.5% pump speed. The motor is designed to operate continuously at any speed within the power supply frequency range of 11.5 to 57.5 Hz. Electrical equipment is designed, constructed, and tested in accordance with the applicable sections of the NEMA Standards.

Each recirculation pump motor has two oil level switches, one for the upper bearing and one for the lower bearing. During abnormal operation (high or low oil level), alarms actuate in the control room and in the reactor building. The control room alarm is used to identify the affected pump. The reactor building alarm is used to determine the affected bearing and whether the indication is high or low oil level.

A variable-frequency ac motor-generator (M-G) set located outside the drywell supplies power to each recirculation pump motor. The pump motor is electrically connected to the generator and is started by engaging the variable-speed coupling between the generator and the motor. Minimum speed corresponds to a frequency of 11.5 Hz-16Hz. Minimum speed is set by the scoop tube positioner electrical stops and is 20-28% speed.

The combined rotating inertias of the recirculation pump and motor, M-G set, and the variable speed coupling are chosen to provide a slow coastdown of flow following a loss of power to the drive motors, so that the core is adequately cooled during the transient. The effective inertias of these devices are specified in the following form, which takes into account the torque and speed conditions on each rotating shaft.

$$\sum\left[\frac{Inertia(lb-ft^{2})\times speed(radians/\sec)}{g(ft/\sec^{2})\times torque(ft/lb)}\right]_{all\,shafts}$$

The recirculation pumps are classified as machinery and as such are specifically exempt from the jurisdiction of any section of the ASME Code or the U.S. Standard Code for Pressure Piping. The Standards of the Hydraulic Institute are applicable to the testing and performance of the pump and as such provide little or no guidance in the areas of casing quality and structural integrity.

To ensure that the pump casing can withstand a pressure equivalent to that inside the reactor vessel, the pump casing has been designed in accordance with the ASME Code, Section III, Class C, and ANSI B31.1.0, as far as these codes can be applied.

The design objective for the recirculation pump casing and valve bodies is a useful life of 60 years, accounting for corrosion, erosion, and material fatigue.

The pump drive motor, impeller, and wear rings are designed for as long a life as is practicable. The design objective is to provide a unit that will not require removal from the system for rework or overhaul at intervals of less than 5 yr.

The recirculation pump characteristics are given in Figure 5.4-1.

Additional data on jet pump parameters and characteristics are found in Table 5.4-1 and in General Electric's Topical Report APED-5460.

An analysis[1] has been conducted to show that a recirculation pump decoupler is not needed to protect the recirculation pump motor from destructive overspeed conditions in the unlikely event of a LOCA.

The recirculation pump motor was assumed to be instantaneously seized in the transient analysis presented in Chapter 15, and the result showed that there was no damage to the fuel barrier.

In accordance with NUREG-0737, Item II.K.3.25, the DAEC type recirculation pumps were tested to determine the consequences of a loss-of-cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of offsite power for at least 2 hr.

A description of the tests is given in Reference 1c. The test results showed that the seal leakage rates are acceptable following loss-of-cooling to the pump seals. Therefore, no modifications to the seal cooling for recirculation pumps were required as a result of NUREG-0737, Item II.K.3.25.

5.4.2 STEAM GENERATORS (PWR)

This section is not applicable to BWRs.

5.4.3 REACTOR COOLANT PIPING

5.4.3.1 Design Bases

The objective of the reactor recirculation system is to provide a variable rate of coolant flow to the reactor core so that a proper thermal margin is maintained during normal reactor operation.

The power generation design bases are the following:

1. The reactor recirculation system provides adequate fuel thermal conditions over the full range of reactor power operation.

2. The reactor recirculation system is designed to minimize maintenance situations that would require core disassembly and fuel removal.

The safety design bases are the following:

1. The reactor recirculation system is designed so that adequate fuel barrier thermal margin is ensured following recirculation pump system malfunctions.

2. The reactor recirculation system is designed so that the failure of piping integrity does not compromise the ability of the reactor vessel internals to provide a refloodable volume.

3. The reactor recirculation system is designed to maintain pressure integrity during adverse combinations of loadings and forces resulting from operation during abnormal, accident, and special event conditions.

5.4.3.2 <u>Description</u>

Isometric drawings of the piping of the reactor coolant system (and the emergency core cooling system) are shown as Figure 5.4-2, Sheets 1 through 42. The drawings show the arrangement of piping fittings, connections, valves, hangers, restraints, and penetrations.

The reactor recirculation system consists of the two recirculation pump loops external to the reactor vessel that provide the driving flow of water to the reactor vessel jet pumps (see Figures 5.4-3 and 5.4-4). Each external loop contains one variable-speed, motor-driven recirculation pump and three motor-operated gate valves for pump maintenance and isolation. Each pump discharge line contains a venturi-type flow meter nozzle. The recirculation loops are a part of the nuclear system process barrier and are located inside the drywell containment structure. The jet pumps are reactor vessel internals and their location and mechanical design are discussed in Section 3.9.5.4.1. A summary of the characteristics of the reactor recirculation system is presented in Table 5.4-1.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by mixing with incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant exits from the vessel and passes through the two external recirculation loops to become the driving flow for the jet pumps. The two external recirculation loops each discharge high-pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pumps at the suction inlet and is accelerated by the driving flow. The driving and driven flows are mixed in the jet pump throat section resulting in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing section (see Figure 5.4-5). The adequacy of the total flow to the core is discussed in Section 4.4. Jet pump operating experience has shown that the design is sound and that jet pump operation is stable and predictable.

A recirculation pump is started at slow speed with the main discharge valve closed. Pump speed is not increased until after the main valve has been opened. It is not intended that a recirculation loop that has been allowed to cool would be placed in service again with the nuclear system hot. The only valid reason for closing both the pump discharge valve and the suction valve is to prevent leakage out of that portion of the recirculation loop between the valves (e.g., excessive leakage through a faulty pump mechanical seal). A leak of this nature cannot be repaired without shutting the plant down to permit access to the drywell; the nuclear system would, in all probability, be cooled before the leak is repaired.

Since the removal of reactor recirculation system valve internals requires the unloading of the nuclear fuel, the valves are provided with high-quality back seats to permit stem packing renewal with the system full of water. The design objective of the back seats and trim design is to minimize the need for the maintenance of the valve internals.

The feedwater flowing into the reactor vessel annulus during operation provides subcooling for the fluid passing to the recirculation pumps, thus determining the additional net positive suction head (NPSH) available beyond that provided by the pump location below the reactor vessel water level. If feedwater flow is below 20%, the recirculation pump speed is automatically limited. This limit is chosen to prevent pump cavitation even for operation with the suction pressure available only from the reactor vessel water column above the pump.

During the life of the plant, recirculation pumps can be operated during nuclear system heatup for hydrostatic tests. At this time, they act in conjunction with any contribution from reactor core decay heat to raise nuclear system temperature above the limit imposed on the reactor vessel by NDT temperatures considerations so that the hydrostatic test can be conducted.

Decontamination connections are provided in the piping on the suction and discharge side of the pump as shown in Figure 5.4-4 to permit flushing and decontamination of the pump and adjacent piping. These inlet connections are arranged for convenient and rapid connection of temporary piping. The piping low-point drain is used during flushing or decontamination to conduct crud away from the piping low point and is also designed for the connection of temporary piping. An in-pipe electrochemical corrosion potential (ECP) monitor is installed on the ‘A’ side recirculation line suction decontamination flange. The monitor replaces the blind flange at the connection.

The recirculation system piping is of all-welded construction and is designed and constructed to meet the requirements of ANSI B31.1.0, the additional requirements of GE design and procurement specifications, and applicable state regulations. The system is classified as Group A as described in Chapter 3. The suction and discharge pipes are welded to the pump casing. The requirements of Section III of the ASME Code for Class C vessels are used as a guide in calculating the thickness of pressure-retaining parts of the recirculation pumps. The casings and forgings are fabricated from austenitic stainless steel.

The intent of using Section III of the ASME Code and ANSI B31.1.0 with added GE requirements for the recirculation system is to design piping systems of quality equivalent to the reactor pressure vessel to which it is attached.

The reactor recirculation system, except for the M-G sets, is designed as Seismic Category I equipment (see Chapter 3) to resist sufficiently the response motion at the installed location within the supporting structure for the DBE with the pump assumed filled with water for the analysis. Vibration snubbers at the top of the motor and at the bottom of the pump casing are designed to resist the horizontal reactions.

The recirculation piping, valves, and pumps are supported by constant support hangers to avoid the use of piping expansion loops that would be required if the pumps were anchored. In addition, the recirculation loops are provided with a system of restraints designed to limit pipe motion so that reaction forces associated with any split or circumferential break do not jeopardize containment integrity. This restraint system provides adequate clearance for normal thermal expansion movement of the loop. The spacing between limit stops is set on the basis that a split pipe retains its structural load-resisting characteristics. Impact loading is not considered on limit stops since possible pipe movement is limited to slightly more than the clearance required for thermal expansion movement.

Sway braces are not used on the recirculation piping loop because vibration analyses have been performed to show that the vibration-induced stress levels are insignificant. Also, measurements have been taken on several plants, including [redacted] which confirm these analyses.

The vibration of the recirculation piping of a previous system was analyzed and designed as described below.

5.4.3.2.1 Vibrations

Vibration analyses were performed on the piping system of a representative reactor coolant recirculation system to determine the effects of excitation internal to the system. Because of the insignificant vibration-induced stress levels and the geometric similarity between plants, analyses are not performed on each individual plant, but on the GE standard product line models. This unit is a standard GE plant model designation 183T368.

Outlined below are the principal assumptions and results and a discussion of a preliminary analysis applicable to the DAEC plant:

1. Reactor coolant recirculation system piping system model: Two-dimensional lumped mass system with 1% structural damping. Auxiliary lines were excluded.

2. Excitation: Excitation was taken as that from pump motor unbalance, sinusoidally varying, with a variable peak amplitude. Mechanical excitation, 5.83 to 27.83 cps.

3. Results:

   a. Natural frequencies

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

   b. Peak deflection is 0.0002 at 8.308 cps.

   c. Maximum vibration, induced stress is 30 psi.

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

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

5.4.3.2.2 Method of Vibration Control

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

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

5.4.3.2.3 Reactor Coolant System Venting

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

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

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

A description of the construction, location, size, and power supply for these valves is provided in Sections 5.2.2 and 5.4.13.

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

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

5.4.3.3 Safety Evaluation

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

The DAEC is licensed to operate with one recirculation loop not in operation (single-loop operation). Single-loop operation has been analyzed and found to be acceptable for the DAEC (Reference 22). Single-loop operation primarily affects the probability of an inadvertent startup of an idle recirculation pump transient evaluated in Chapter 15. As specified in plant procedures, the idle loop is required to be electrically isolated prior to continued single-loop operation in order to minimize the probability of such an event. The water temperature and chemistry in the inactive loop are maintained by leaving the suction and discharge (or bypass) valves open. The LPCI loop selection logic will close these valves during a LOCA in order to prevent degradation in LPCI flow. Analyses have been performed (References17, and 22) that demonstrate that the acceptance criteria of 10CFR50.46 are still met if the recirculation discharge bypass valve remains open in the selected loop.

The reactor recirculation system piping and pump design pressures are based on peak steam pressure in the reactor dome plus the static head above the lowest point in the recirculation loop and appropriate pump head allowances. Actual values of design pressures for piping and related equipment pressure parts are chosen in accordance with applicable codes.

An analysis of the recirculation system has been done to determine the potential for damage due to water hammer. Since the recirculation system is filled with water, and is self-venting by configuration, the area of most concern is the potential for damage due to pressure waves caused by rapid changes in flow velocity.

The recirculation system maximum valve closure time of 30 sec is much too slow to cause water hammer. If instantaneous seizure of the recirculation pump should occur, the stoppage of the impeller does not result in a large instantaneous change in flow velocity as would be required for water-hammer effects to occur. This is because a large, open flow area still exists through the pump impeller when it is stopped.

When the pump seizes, it changes from a device that aids the flow of water to a device that impedes its flow. Two pressure waves are sent out from the pump, which modify the flow. The wave that travels up the suction pipe is a compression wave, while the wave traveling down the discharge pipe is a rarefaction wave. The evaluation of the pressure waves, using equations of the form "DP = rCDV", results in a wave strength of less than 200 psi. That is, the pressure in the suction pipe is less than 200 psi above normal operating pressure, while the pressure in the discharge pipe is less than 200 psi below normal operating pressure. This change in pressure is within the design capability of the piping system.

Since there is no further energy input to the system after the pump seizes, any conceivable combination of pressure wave reinforcement in the piping system caused by reflections from valves, elbows, orifices, etc., cannot exceed the strength of the original wave from which they were subdivided.

On the basis of the above discussion, water-hammer effects in the recirculation system are negligible.

The rapid depressurization of the reactor vessel following a LOCA would not create temperature changes or pressure surges in the piping systems of any pipe stress significance. The flow transient in the recirculation system from pump trip and coastdown following a LOCA is essentially the same as that of a pump trip during preoperational testing.

5.4.3.4 Inspection and Testing

Quality control methods are used during the fabrication and assembly of the reactor recirculation system to ensure that the design specifications are met. Inspection and testing are carried out as described in Chapters 3, 14, and 17. The reactor coolant system is thoroughly cleaned and flushed before fuel is loaded initially.

During preoperational testing, the reactor recirculation system is given a hydrostatic test at 125% of reactor vessel design pressure. A pressure test in accordance with the Inservice Inspection Plan is made following each removal and replacement of the reactor vessel head. Other preoperational tests on the reactor recirculation system include checking proper operation of the valves, operating pumps, and M-G sets and checking flow control transient operation.

During startup testing, the horizontal and vertical motions of the reactor recirculation system piping and equipment are observed and adjustments of supports are made, as necessary, to ensure that components are free to move as designed. Nuclear system responses to recirculation pump trips at rated temperatures and pressures are elevated during the startup tests, and the plant power response to recirculation flow control is determined.

Inservice inspection is considered in the design of the reactor recirculation system to ensure access for the inspection of selected components. For details of Class 1 inservice inspection, see Section 5.2.4. Inservice inspection of Class 2 and 3 components is described in Section 6.6.

5.4.3.5 Inlet Nozzle Safe-End Replacement

5.4.3.5.1 Introduction

On May 1, 1978, the DAEC began to monitor a slowly increasing rate of leakage from an unidentified source in the drywell. On June 14, 1978, the leak rate increased from about 1 to 3 gpm. On June 17, 1978, an automatic scram occurred during the weekly control valve testing because of problems in reactor protection system relays associated with the testing. Although the leak rate was within the Technical Specification limit of 5 gpm (for leakage from an unidentified source), advantage was taken of the unplanned shutdown to deinert the containment and identify the source of the leakage.

During the inspection of the reactor coolant system piping, a through-wall crack was found in one of the eight recirculation system inlet nozzle safe ends (Nozzle N2A). The safe ends are transition pieces that join the 10-in. recirculation system piping to the inlet nozzles on the reactor vessel and the thermal sleeve to the jet pumps.

The purpose of the reactor recirculation system is to provide forced circulation of water through the reactor core. Forced circulation permits a higher specific power than natural circulation and permits the control of flow distribution to all channels. The recirculation system consists of two separate, parallel pump loops that operate simultaneously but independent of each other. Each loop consists of a variable-speed, motor-driven recirculation pump, two motor-operated gate valves (for isolation of the pumps), eight jet pumps, and piping and instrumentation. The recirculation system, which is part of the primary system pressure boundary, is located inside the drywell containment structure. The jet pumps are located inside the reactor vessel, between the core shroud and vessel wall. Each of the recirculation pumps withdraws water from the reactor vessel annulus area through a 22-in. suction line and discharges the water into a 16-in. manifold containing four 10-in. riser pipes per recirculation loop. Each riser penetrates the reactor vessel and supplies water to two jet pumps. The jet pumps mix the high-velocity water from the recirculation system with water in the annulus and circulates this through the core. As noted above, the leak was in one of the 10-in. riser pipes at the point where the piping connects to the reactor vessel, specifically in the safe end of nozzle N2A. These safe ends contained an area in which a machining error was repaired by welding during the original manufacture.

At the time the facility was shut down on June 17, 1978, the leak rate through the crack was about 3 gpm. The leaking water was collected in the containment structure drain system and was then pumped to the plant's radioactive waste treatment system for processing. There was no release of radioactivity to the environment as a result of the crack.

Ultrasonic testing and radiographic examinations were performed to determine the crack extent in the leaking safe end and to check the other seven safe ends. The DAEC reported that linear ultrasonic testing indications in excess of code limits were recorded on five safe ends (including the leaking one); later discussion revealed that the ultrasonic testing data showed indications, interpreted as originating from cracks, from all eight safe ends. Based on the initial nondestructive examination results, the DAEC decided to replace all eight safe ends with an improved design.

5.4.3.5.2 Failure Analysis

Nondestructive tests of all eight safe-end segments, after they were removed from the vessel, showed all to be cracked at the safe-end to thermal sleeve weld, 360 degrees around the inside surface. Two segments, N2A and N2E, were selected for destructive examination. Segment N2A, with the leaking through-wall crack, was sent to the Southwest Research Institute (SRI) where work proceeded under the direction of Iowa Electric. Segment N2E was chosen because the original ultrasonic testing results had identified cracking that extended around the entire inner circumference and, by subsequent ultrasonic testing, slag indications were identified. It was examined at the Battelle Columbus Laboratories under the direction of the NRC.

Both laboratories reached the same conclusion regarding both the nature and the mechanism of the cracking. Briefly, it was observed that (1) the cracking was entirely on the safe-end side of the crevice formed by the welding of the thermal sleeve to the safe end, originating near the crevice tip; (2) the cracks began in the weld heat-affected zone; (3) the cracks propagated entirely by intergranular stress corrosion with an absence of evidence of mechanical fatigue; (4) the weld repair on the outside surface of the safe end was not involved in crack initiation and had little to do with the later states of cracking; (5) the cracks did encircle the safe-end inside diameter (at the crevice) around the full 360 degrees; and (6) there were a significantly large number of particles on the fracture surface that were compounds high in sulphur from an as-yet unidentified source.

Although some small cracks were observed in the vicinity of the slag inclusions examined metallographically at Battelle, neither the slag nor the tears played a role in the N2E safe-end cracking. The extensive evidence assembled at both laboratories supported the conclusion that the cause of failure was intergranular stress corrosion cracking.

In their examination of the safe ends, both SRI and Battelle detected sulfur contamination. Additional investigations were conducted at both laboratories to determine whether the sulfur contamination was associated with sulfur segregation at grain boundaries of the initial Inconel matrix or whether it resulted from progressive concentration in the fractures by transport mechanisms from other sources in the system. While the sulfur ion species was not conclusively identified, extensive analysis by Battelle using selective grain boundary etching techniques revealed no evidence of sulfur segregation at grain boundaries. The sulfur was probably from other sources in the system. SRI concluded that if a sulfur species were entrapped from the environment it could lead to acidification of the crevice and contribute to cracking. The Energy Dispersive X-Ray analysis of crud deposits and pH values (approximately four to six; indicated by qualitative litmus tests within the fractures) tend to further support this conclusion. Battelle was unable to make a quantitative evaluation of the extent of the contribution of sulfur to the cracking.

5.4.3.5.3 Description of Replacement Design

The existing eight cracked recirculation inlet nozzle safe ends were replaced with redesigned safe ends and thermal sleeve adapters. The safe ends were fabricated from SB-166 (Alloy 600) material, also known as Inconel-600. They function as transition pieces between the stainless steel reactor recirculation piping and the carbon steel reactor vessel nozzles and as attachment points for the internal thermal sleeves that carry the recirculation flow to the jet pump risers.

The new safe-end design removes the thermal sleeve attachment weld from the primary pressure boundary and eliminates the sharp crevice in the high residual tensile stress area. In the new design, the thermal sleeve is welded to the safe end at a point away from the pressure boundary wall. The new safe-end design improves the inservice inspection access at the nozzle attachment end by maintaining longer straight inside and outside surfaces, thus simplifying ultrasonic angle-beam examinations.

5.4.3.5.4 Installation

The installation of the new assemblies involved five separate welds at each safe end. Before installation, each weld was mocked up to demonstrate reproducibility of welding and dimensional control of weld shrinkage. Because the root of the production weld between the thermal sleeve and the safe end could not be examined after welding to confirm that complete fusion was achieved, the mockup weld was sectioned, etched, and examined. Although it was observed that the backing ring deformed against the thermal sleeve creating a crevice-like condition, the joint is not located on the primary pressure boundary of the safe-end; therefore, if the condition were to induce intergranular stress corrosion cracking, the pressure boundary integrity would be unaffected.

The installation procedure consisted of machining weld preps on the reactor vessel nozzle and thermal sleeve using witness marks to obtain accurate dimensional tolerances between the safe end and the thermal sleeve adapter. The weld prep on the vessel nozzle was made on the existing nickel-chromium-iron weld butter to avoid dissimilar metal field welding during installation and the necessity for postweld heat treatment. The weld root pass was made with a consumable insert in place, thus minimizing the likelihood of forming a crevice through incomplete penetration. While the root pass of the nozzle to safe-end weld was being laid down, the annular region between the weld joint and the thermal sleeve was flushed with an inert gas mixture. The inert gas was used as a precaution against the formation of oxide inclusions on the inside diameter surface. After completing the weld, the two small (<0.25 in. diameter) chamfered purge gas holes in the thermal sleeve adapter were seal welded.

After the adapter to thermal sleeve and safe end to nozzle welds were completed, the weld gap at the root of the thermal sleeve adapter to safe end was measured. The thermal sleeve was then positioned to compensate for the weld shrinkage before welding, thereby minimizing the net residual tensile stress at the joint. Once the safe end and thermal sleeve were welded in place, the closure spool piece was templated and machined for fitup, and the final two closure welds were made.

All safe-end welds were subjected to radiographic, liquid penetrant, and ultrasonic examinations in accordance with Section XI of the ASME Code. The results of the radiographic and liquid penetrant examinations were evaluated in accordance with the acceptance criteria set forth in Section III of the ASME Code. The ultrasonic examinations performed after welding were done with the test sensitivity increased beyond the ASME Code requirements, and the results were recorded to serve as detailed baseline comparisons for future inservice inspections.

5.4.3.5.5 Structural and Mechanical Design

Analyses of the recirculation inlet nozzle replacement safe end and thermal sleeve adapter for all loads, including seismic and thermal transient loadings, were performed in accordance with Section III of the ASME Code, 1965 Edition, with addenda through Summer 1967. The analyses also make use of the simplified elastic-plastic analysis rules of NB 3228.2 of the 1977 ASME Code.

The recirculation inlet nozzle safe end and thermal sleeve adapter were analyzed using an axisymmetric finite-element computer model to obtain the maximum thermal gradients through the section during the postulated plant operational transients. The results of the thermal analysis were used in a similar axisymmetric finite-element computer model to obtain the maximum thermal stress intensities. The applied piping loads from the original piping analysis, in conjunction with the internal pressure, were used in a shell of revolution computer program to obtain the primary stress intensities. The results of these analyses were combined for appropriate ASME Code evaluations. In addition, for the fatigue evaluation, stress concentration factors were applied to the areas where local geometric discontinuities exist.

An additional analysis, not required for ASME Code evaluation, was performed to determine the residual welding stresses in the area of the thermal sleeve adapter to safe-end weld. The method used incorporates transient thermal analysis of a point heat source moving through a body, followed by an axisymmetric, elastic-plastic stress evaluation of the resulting temperature distributions. The analysis was performed as a time history employing actual welding parameters such as weld heat input, travel speed, and number of passes and employing a temperature-dependent material stress-strain relation. The analysis predicted a compressive residual stress in the region of the weld where the potential for a crevice existed. Compressive residual stresses will reduce the susceptibility to stress corrosion cracking. An analysis of weld residual stress was also performed for the original thermal sleeve to safe-end weld. The results of the analysis showed a high-tensile residual stress developed in the crevice region where cracks initiated. Since the initiation of intergranular stress corrosion cracking depends on a relatively high (with respect to the yield strength) tensile stress, the residual stress analysis of the original design helps to explain the observed cracking. By comparison, the analysis of the safe end to thermal sleeve weld in the replacement design suggested the cracking will not be a problem since the compressive weld residual stress will result in a lower net tensile stress when combined with the other loadings.

Recognizing that the weld joining the thermal sleeve adapter to the safe end may include a crevice-like configuration in the heat-affected zone, an evaluation was performed to determine the potential safety effect of assuming a complete circumferential fracture of this weld that would separate the thermal sleeve from the safe end. The evaluation showed that the thermal sleeve could move radially inward toward the vessel approximately 2 in. Yielding would occur in the jet pump riser elbows and the riser brace. The maximum stress in the diffuser would be below the normal allowable value. Other than the localized elbow and brace yielding, no damage would be expected on the reactor vessel or internals, and the primary pressure boundary integrity would not be compromised.

The separation of the sleeve would cause some recirculation flow to leak into the vessel through the thermal sleeve annulus, reducing the flow through the jet pumps. Flow in the two affected jet pumps would drop to approximately 76% of rated flow, resulting in a reduction in core flow of approximately 3%. The reduction in jet pump flow would be detected in the control room by the core flow measurement indicators, and reactor shutdown would be required by the Technical Specifications.

5.4.3.5.6 Evaluation

The analyses, design, fabrication, and installation of the recirculation nozzle inlet safe end and thermal sleeve adapter replacements are in accordance with accepted criteria as stated below. The structural loads including dynamic, static, and thermal loadings applied by the attached piping and the acceptance criteria for the appropriate loading conditions are in accordance with the appropriate portions of the FSAR. The allowable stress limits for the combined loading conditions are in accordance with Section III of the ASME Code.

The safe-end and thermal sleeve adapter replacements are fabricated from Alloy 600, the same type of material as the original safe ends. A review of BWR operating experience showed that the safe-end cracking at the DAEC was the first example of intergranular stress corrosion cracking in Alloy 600 exposed to the BWR water environment. Moreover, because the original safe end to thermal sleeve weld joint created a relatively long, sharp crevice, the cracking actually occurred under unusual environmental considerations indigenous to the stagnant, contaminated, crevice conditions in an area of high residual stress. At other areas, there was no sign of distress at the welds, heat-affected zones, or base metal exposed to circulating water on any of the metallographic sections made during failure analysis. Furthermore, laboratory tests have shown that very high tensile stresses (above yield) and tight crevice conditions, both of which were present in the original design, are significant factors in initiating stress corrosion cracking in Alloy 600. Examples of operating plants constructed with Alloy 600 recirculation riser safe ends are the DAEC [redacted]

Chicago Bridge & Iron was the BWR vessel constructor for the DAEC, [redacted] Chicago Bridge & Iron was the sole vendor and was responsible for reactor pressure vessel design and fabrication. [redacted] are more recent plants for which CB&I is the responsible reactor pressure vessel vendor for design and fabrication.

The new safe-end design has removed from the primary pressure boundary the weld that caused both the tight crevice and the high residual stresses in the original design. There is reasonable assurance that stress corrosion cracking will not occur in the pressure boundary of the new design. Although the annulus region between the safe end and the thermal sleeve will restrict fluid flow, the machined gap will allow enough circulation to prevent the buildup of detrimental chemical species as would occur in a tight crevice.

The thermal, stress, and fatigue analyses of the recirculation inlet nozzle replacement safe end and adapter are documented by CB&I.[2]

5.4.3.5.7 Leak Detection

As discussed in Section 5.4.3.5.1, the leakage from the cracked safe end was detected when it was less than 1 gpm. On June 14, 1978, the leakage increased from 1 to 3 gpm and remained essentially constant at this rate until the plant was shut down on June 17, 1978. As discussed in Section II.A of the report forwarded by Iowa Electric's letter of December 8, 1978, "the increased leakage was immediately observed by six independent methods." The Technical Specifications for the DAEC required that the facility be shut down if reactor coolant leakage into the primary containment from unidentified sources exceeds 5 gpm. The Technical Specifications for the DAEC require that the sump and air sampling systems (two of the systems for monitoring leakage) be operable during reactor power operation and that reactor coolant leakage be checked by the sump and air sampling system and recorded periodically. In Sections III.A.2 and III.A.3 of the December 1978 report, the adequacy of the Technical Specifications with respect to reactor coolant leakage is discussed. All reactor systems generally have a small amount of unidentified leakage, primarily from packing gland weepage from the hundreds of packed valves in containment. The leakage is usually lowest following startup from a refueling outage, since during the extended outages the packing glands are generally inspected and tightened. The total leakage generally increases toward the end of each fuel cycle. A review of DAEC operating experience showed that total leakage in containment from valve packing has reached about 3 gpm on several occasions; leakage from this source is not a significant concern.

5.4.3.5.8 Inspections

Preservice inspection of the recirculation nozzle safe end was performed on both the wrought material and the attachment welds in accordance with the ASME Code, Section III. The wrought material was both liquid penetrant and ultrasonically inspected. The attachment welds were radiographed except the thermal sleeve to safe-end weld, which was liquid penetrant tested.

Inservice inspections are those required by ASME Code, Section XI.

5.4.4 MAIN STEAM LINE FLOW RESTRICTORS

The main steam line flow restrictors limit the loss of water from the reactor vessel before main steam line isolation valve closure in case of a main steam line rupture outside the primary containment.

5.4.4.1 Design Bases

1. The main steam line flow restrictor is designed to limit the loss of coolant from the reactor vessel following a steam line rupture outside the primary containment to the extent that the reactor vessel water level does not fall below the top of the core within the time required to close the main steam line isolation valves.

2. The main steam line flow restrictor is designed to withstand the maximum pressure difference expected across the restrictor following complete severance of a main steam line.

5.4.4.2 Description

One main steam line flow restrictor (shown in Figure 5.4-7) is provided for each of the four main steam lines. The restrictor is a complete assembly welded into the main steam line between the reactor vessel and the first main steam line isolation valve and downstream of the main steam line safety relief valves. The restrictor limits the coolant flow rate from the reactor vessel in the event of a main steam line break outside the primary containment to the maximum (choke) flow. The restrictor assembly consists of a venturi-type nozzle insert welded into a carbon steel pipe. The venturi-type nozzle insert is constructed of all austenitic stainless steel and is held in place with a full-penetration circumferential weld. The restrictor assembly is self-draining (low-point pockets are internally drained to the steam line).

The flow restrictor is designed and fabricated in accordance with ANSI B31.1.0. In addition to those requirements, the following additional requirements have been imposed:

1. Materials are limited to the following ASTM specifications:

    a. Stainless steel

        Forgings - A182, A336, A403.
        Castings - A451, Grade CPF8
        Plate - A240.

    b. Carbon steel

        Forgings - A105, Grade II; A234, Grade WPB; A350, Grade GRLFI; A508, Class I.
        Castings - A216, Grade WBC; A352, Grade LCB.
        Plate - A285, A516.
        Tubular - A155, Class I, Grade 70; A106-B, A333, Grade I; A524, Grade I or 2.

2. One-hundred percent radiography of all girth and longitudinal welds.

3. Surface examination of all welds.

4. Radiography and surface examination of any pressure-containing cast parts.

5. Ultrasonic test of any pressure-containing tubular products, plate, and forgings.

6. Surface examination of forgings and plate base material for non-pressure-containing components.

The detail design and the vibration analysis of the flow restrictor is done by the supplier. The analysis is available for audit. The analysis of the flow restrictor is described below.

It was assumed that steam flow will excite the fluid in the cavity behind the cone to oscillate at the natural frequencies of the cavity filled with steam. This oscillation is assumed to be capable of exciting the steam flow limiter cone and/or steam line. The problem is thus reduced to determining whether or not such oscillation will cause structure fatigue. The results of the analysis show that the fundamental frequency of the steam-filled cavity is about 150 Hz, while the lowest natural frequency of the cone is 567 Hz. Based on past experience, the lowest frequency for the steam line is about 10 Hz.

The lowest frequency of the steam-filled cavity was estimated by a formula in Reference 3, while that of the cone was computed via the SABOR-Free Program. It can be concluded from the frequency determinations that the vibration of the steam flow restrictor would not cause structural fatigue in the pipe.

Materials of analysis equivalent to ISI-304 or 316 in the following ASTM specifications were used except where furnace sensitization of the material was unavoidable, in which case, material with analysis equivalent to ISI-304 was used. Austenitic stainless steel is considered to be furnace sensitized if it has been heated by means other than welding, within the range of 800 to 1800°F regardless of subsequent cooling rate. When heated to temperatures above 1800°F, the austenitic stainless steel was cooled through the range 1800 to below 800°F within 5 min to minimize sensitization.

General Electric has received in a letter from the ASME Boiler and Pressure Vessel Committee dated August 19, 1969, a statement that the main steam line flow restricting orifice "...will not violate the intent of Section I."

Preinstallation inspection and testing was in accordance with the specified ASME Code, Sections I, III, and IX. The container pipe is also designed and fabricated in accordance with ANSI B31.1.0 and with the specified ASME Code Sections I, III, and IX. The flow restrictor has no moving parts, and the mechanical structure of the restrictor can withstand the velocities and forces under main steam line break conditions where maximum differential pressure is 1375 psi.

The ratio of the venturi throat diameter to a steam-line diameter is approximately 0.5. This results in less than a 10-psi pressure difference at design flow. This design limits the steam flow in a severed line to 170% of its rated flow at 1025-psig inlet pressure, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used in the measurement of steam flow to initiate the closure of the main steam line isolation valves in the event that the steam flow exceeds preselected operational limits.

5.4.4.3 Safety Evaluation

In the event of a main steam line break outside the primary containment, steam flow rate is restricted in the venturi throat by a two-phase mechanism similar to the critical flow phenomenon in gas dynamics. This limits the steam quantity flow rate, thereby reducing the reactor vessel coolant blowdown. The probability of fuel failure and its consequences are therefore decreased.

An analysis of the steam-line rupture accident (Chapter 15) shows that the core remains covered with water and that the amount of radioactive materials released to the environs through the main steam line break does not exceed the radiation exposure guidelines of 10 CFR 50.67.

Pressure surges caused by a two-phase mixture impinging on the flow restrictor result in stresses that do not exceed code allowable limits. There is adequate margin in the code for withstanding the pressure load due to impact pressure from the possible oncoming two-phase mixture predicted during main steam line break accident condition.

Tests were conducted by GE on an idealized scale model to determine final design and performance characteristics of the flow restrictor, including maximum flow rate of the restrictor corresponding to the accident conditions, irreversible losses under normal plant operating conditions, and discharge moisture level. The tests showed that the flow restrictor operation at critical throat velocities is stable and predictable. Unrecovered differential pressure across the scale model restrictor is consistently about 10% of the total nozzle pressure differentials, and the restrictor performance is in agreement with the ASME Power Test Code Supplement PCT-19.5, Part 4, 1959 Edition. Although the full-size restrictors have a slightly different hydraulic shape than the idealized model, the results for the test corresponding to the accident condition and discharge moisture level are still valid.

5.4.4.4 Inspection and Testing

Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing program is planned.

5.4.5 MAIN STEAM LINE ISOLATION SYSTEM

5.4.5.1 Design Bases

Two isolation valves, one on each side of the primary containment barrier, in each of the main steam pipes close automatically to

1. Prevent damage to the fuel barrier by limiting the loss of reactor coolant in case of a major leak from the steam piping outside the primary containment.

2. Limit the release of radioactive materials by closing the primary containment barrier in case of a major leak from the nuclear system inside the primary containment.

The main steam line isolation valves, individually or collectively

1. Close the pipelines within the time established by design-basis accidents to limit the release of reactor coolant or radioactive materials.

2. Close the pipelines at a speed slow enough so that simultaneous (inadvertent) closure of all steam lines (with direct scram) will not induce a more severe transient on the nuclear system than the closure of the turbine stop valves while the bypass valves remain closed.

3. Close the steam line when required despite single failure in either valve or the attached controls to provide a high level of reliability for the safety function.

4. Use separate energy sources, as the motive force, to independently close the redundant isolation valves in the individual steam line.

5. Use local stored energy to close at least one isolation valve in each steam line without relying on the continuity of any variety of electrical power for the motive force to achieve closure.

6. Be able to close the steam lines during or after seismic loadings to ensure isolation.

7. Be testable during normal operating conditions, to demonstrate that the valves will function.

5.4.5.2 Description

Two isolation valves are welded in a horizontal run of each of the four main steam lines with one valve as close as possible to the primary containment barrier inside and the other just outside the barrier. The valves, when closed, form part of the nuclear system process barrier for openings outside the primary containment and part of the primary containment barrier for nuclear system breaks inside the containment.

The main steam lines isolate on a low-low-low reactor water level. The main steam isolation valves do not close on high drywell pressure since high drywell pressure alone is not indicative of a LOCA. They remain open to remove heat from the reactor and isolate when one of the following occurs:

1. Low-low-low reactor water level.
2. High steam flow.
3. High steam tunnel temperature.
4. Low main steam line pressure (in run mode).
5. Main condenser low vacuum.
6. High turbine building temperature.

The description and testing of the controls for the main steam line isolation valves are included in Sections 7.3.1 and 7.3.4, respectively.

A drawing of the main steam isolation valve is shown in Figure 5.4-8.

Each valve is a 20-in. globe valve having a Y-pattern body, the main disk moving in a line 45 degrees upward from the horizontal center line. The valve is of reduced port design in that the main valve seat diameter is smaller than the connecting pipe inside diameter. At 102.6% rated flow, the pressure drop across a fully open valve is 10.5 psi. The normal steam flow and pressure aid in closing the valve and holding it closed.

The main disk, guided at the sides by stellited-disk guides integral with the valve body, has a hard-faced seal surface at the bottom that mates with the hard-faced valve seat when the valve is closed. The main disk forms a union that encloses the lower end of the valve stem. The valve stem penetrates the bonnet through a stuffing box that has replaceable packing rings and a junk ring. The nitrogen cylinder and an oil dashpot are mounted in tandem on a common shaft. This shaft is connected to the upper end of the valve stem through a union. The union serves as a seat to the spring flange. The cylinder and dashpot assembly is supported by four tie rods that use the valve bonnet as their support. These four tie rods act as guides for stacks of helical springs. The springs are fitted between the nitrogen cylinder mounting plate and the spring flange.

The stem disk is welded to the valve stem. The connection includes a belleville washer to maintain a preload on the connection. The main disk is welded to the piston assembly to reduce the possibility of separation of the main disk from the assembly.

The bottom end of the valve stem is a chamfered stem disk that mates with a hard-faced seat in the middle of the main disk. This stem disk serves as a pilot valve. Pressure is balanced across the main disk when the stem disk is off its seat. The nitrogen cylinder can lift the main disk with a differential pressure of 200 psi in the flow direction against the main disk.

For sealing purposes when the valve is fully opened, a shoulder at an appropriate location along the valve stem is chamfered to mate with the hard face at the bottom of the bonnet. When the main disk is fully lifted, this shoulder is in the backseated position and, therefore, leakage through the stem packing is blocked. The bonnet, which is bolted to the valve body, has provisions for seal welding in case leaks develop across the body bonnet seal joint after the valve has accumulated extensive service.

The main disk is guided at the top to provide support when it is off its seat. Running clearances permit the disk to align with the seat in the body. Force from the valve actuation is applied through the valve stem to the bottom of the disk so that the possibility of cocking the disk is minimized. Body guide pads and a high disk/piston center of gravity also help to minimize the possibility of disk tilting.

The nitrogen cylinder is used to operate the isolation valve. The opening and closing of the valve is affected by the admission of nitrogen to the bottom and top, respectively, of the nitrogen cylinder. This is accomplished through the control unit that is attached to the nitrogen cylinder and contains the pneumatic, ac, and dc control valves. The valve-operating nitrogen is supplied to the control system from the plant nitrogen system through a check valve. There is a control room alarm to alert the operator of low nitrogen pressure from the liquid supply tank. An accumulator is connected to the system between the check valve and the control valve to provide backup operating nitrogen. The valve pilot system and the accumulator are piped in such a way that when one or both pilots are energized, the accumulator pressurizes the valve operator to overcome the closing force exerted by the spring to open the main valve. When both pilots are deenergized, as in a two-channel trip or manual switch in the closed position, the accumulator pressure is switched to pressurize the opposite side of the valve operator and help the spring close the valve. With the exception of the inboard MSIVs, the pressures from the accumulator and the spring force can each independently close the valve when the containment is at peak post-LOCA pressures. In this instance, the combined forces available from the springs and the pneumatic actuator are required to close the valve when the containment is pressurized.

To ensure inboard MSIV closure at peak drywell pressures, the plant operating procedures instruct the control room operators to declare the MSIV(s) inoperable and take the appropriate actions per Technical Specifications and close an inboard MSIV prior to its accumulator pneumatic pressure degrading to the point where there is insufficient stored energy to close at the containment peak accident pressure. Thus, inboard MSIV closure is assured.

The accumulator volume is adequate to close the valve for up to one hour after supply nitrogen to the accumulator has failed. The supply line to the accumulator is large enough to satisfy demands resulting from normal valve operation and system leakage.

The hydraulic (oil) dashpot functions as an hydraulic buffer and is used to control the speed with which the isolation valve is closed. Oil is displaced from one side of the dashpot piston to the other through the hydraulic return line alongside the dashpot; the rate at which it is displaced, and thus the rate at which the valve can be closed, is controlled by the speed control valves in this return line. Increasing the flow through this line decreases the time it takes to close the isolation valve, and vice versa. In this way, the valve closing time is adjustable between 3 and 10 sec.

Each of the four spring guide shafts contains two stacks of springs that are compressed when the valve is open. These springs expand when nitrogen pressure is either vented or lost from under the nitrogen cylinder piston, and thus exert a downward force against the spring seat member that pushes the valve stem and disk down to close the valve. There are spring guides installed on each guide shaft that prevent scoring during normal operation and binding should one of the springs break. The spring seat member is also closely guided on the support shafts and rigidly holds onto the stem to offset any eccentric force being applied in case of a broken spring.

Either manual or automatic signals can be sent to the pneumatic control system for each isolation valve. The control system consists of the following:

1. Normal opening and closing components: nitrogen and spring operated, four-way spool valve, an ac solenoid valve, and a dc solenoid valve.

2. Exercising components: three-way spool valve and solenoid valve.

All control system components except the nitrogen storage tank and the check valve are bolted to a subplate that is fastened to the nitrogen cylinder mounting plate on each isolation valve.

The control power available is 120 V ac, 60 Hz, and 125 V dc.

Remote manual switches in the control room enable the operator to open or close at normal speed (3 to 10 sec) or at slow speed (45 to 60 sec) for exercising and testing. Position-indicating lights actuated by limit switches on each isolation valve give the control room operator valve full-open, full-closed, and partially closed display. Pairs of switches at 90% open and 90% closed valve positions are actuated by the motion of the spring seat member. The 90% open switches turn off the open lights for purposes of valve testing and initiate reactor scram if three of four main steam lines isolate (for the closure of one valve in each main steam line, see Section 7.2.)

The isolation valve is designed to pass saturated steam at 1250 psig and 575°F with a moisture content of approximately 0.25%, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The estimated operating cycles per year is 100 cycles during the first year and 50 cycles per year thereafter. In addition to minimum wall thickness required by applicable codes, a corrosion allowance of 0.120 in. minimum is added.

Design specification for normal operating conditions are 150°F maximum, 100% relative humidity, and radiation field of 15 rad/hr gamma and 25 rad/hr neutron plus gamma, which are all continuous for the design life. The valves are also designed to operate at the abnormal condition of 340°F. The inboard valves are not exposed to these maximum conditions continuously, and the outboard valves are in much less severe ambient conditions.

In the event that the main steam line breaks downstream from the isolation valve, the steam flow quickly increases to 170% of rated flow. The flow is limited from further increase by the venturi flow restrictor installed upstream of the inboard isolation valve. During approximately the first 75% of closing, the isolation valve has little or no effect in reducing flow because the flow is restricted by the venturi. During the last 25% of valve closure travel, flow is reduced by the isolation valve as a function of the valve area versus travel characteristic.

The main steam line valves are designed to Seismic Category I requirements. The valve assembly is manufactured to withstand the design-basis seismic forces applied at the mass center assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are considered to act simultaneously and are added directly. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress is as set forth in the applicable codes. The parts of the main steam isolation valves that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as described in Section 3.2.2. The control valves and other equipment provided in the valve assembly are designed, manufactured, and shop tested in accordance with applicable industry standards for the specified service.

In the above discussion on valve operation, nitrogen is used to operate the main steam isolation valves.

The main steam isolation valve leakage treatment path is described in Section 6.7.

5.4.5.3 Safety Evaluation

The safety objectives of the main steam isolation valves are to limit the release of radioactive material by closing the nuclear system process barrier and the primary containment barrier and to limit the loss of reactor coolant in case of a major steam leak outside the primary containment.

In a direct-cycle nuclear power plant, the reactor steam goes to the turbine and other equipment outside the reactor containments. Radioactive materials in the steam are released to the environs through process openings in the steam system or can escape from accidental openings. A large break in the steam system can void the water from the reactor core faster than it is replaced by feedwater.

The analysis of a complete sudden steam-line break outside the primary containment is described in Chapter 15.2.1.5. It shows that the fuel barrier is protected against a loss of cooling if main steam isolation closure takes as long as 10.5 sec (10-sec valve closure time plus up to 0.5 sec for the break detection instrumentation to initiate valve closure after the break or 9-sec valve closure time plus approximately 1.5 sec for the leak detection instrumentation to initiate valve closure). The calculated radiological effects of the radioactive material assumed to be released with the steam are shown to be within the guide values for such an accident. Thus, the safety design basis is shown to be satisfied.

Although plant safety analyses assume that no fuel rod perforations would occur for a 10-sec main steam isolation valve closure time, it should be noted that the DAEC Technical Specifications incorporate a valve closure time of 5 sec.

The shortest closing time (approximately 3 sec) of the main steam isolation valves is also shown to be satisfactory by Section 15.1.2.3.1. The switches on the valves initiate reactor scram when several valves are more than 10% closed. The pressure rise in the system from stored and decay heat may cause the nuclear system relief valves to open briefly, but the rise in the fuel cladding temperature will be insignificant. The transient is less severe than that from sudden closure of the turbine stop valves (in approximately 0.1 sec) coincident with postulated failure of the turbine bypass valves to open (Section 15.1.2.2.2). No fuel damage results.

The ability of this 45-degree Y-design globe valve to close a few seconds after a steam-line break, under conditions of high-pressure differentials and fluid flows, with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of tests in dynamic test facilities. Dynamic tests with a 1-in. valve show that the analytical method is valid. A full-size, 20-in. valve has been tested in a range of steam-water blowdown conditions simulating postulated accident conditions. The description, results, and evaluations of these tests have been issued as a report for inclusion in the NRC file of topical reports on GE BWRs.[5]

The maximum DAEC main steam line isolation valve (MSIV) leakage rate for any one MSIV is 100 scfh with a total maximum pathway leakage rate of 200 scfh through all four main steam lines (including the inboard MSIV drain line).

The main steam isolation valve leakage treatment path is described in detail in Section 6.7.

Materials for the valve sealing surfaces can withstand impact loadings from closing even in the event that the hydraulic buffer is inoperative. The spring guides, the guiding of the spring seat member on the support shafts, and rigid attachment of the seat member to the stem ensure that the valve closes when only spring driven. Three sets of springs, or two opposite sets, will close the valve. The nitrogen cylinder alone or with the remaining springs will close the valve even if a spring set jams, since the springs are not attached to the spring seat member. The binding of the valve poppet in the guides is prevented by making the poppet in the form of a cylinder longer than its diameter and by applying the stem force near the bottom of the poppet. Clearance is provided between the poppet and its guides so that some cocking of the poppet or warpage of the seat can be tolerated and still achieve a seal.

Two redundant isolation valves are provided in each steam line so that either can perform the isolation function, and either can be tested for leakage after closing the other. The inside valve and the outside valve and their control systems are separated physically. Considering the redundancy, the mechanical strength, the closing forces, and the leakage tests performed, the main steam isolation valves satisfy the safety design basis to limit the release of reactor coolant or radioactive materials, within the margins evaluated in Chapter 15.

The isolation valves and their installation are designed as Seismic Category I equipment for inclusion of seismic loadings, as delineated in Section 3.9.

The design of the isolation valve for seismic loading is discussed in Section 5.4.5.2. The design has been analyzed for earthquake loading. These loads are small compared with the pressure and operating loads the valve components are designed to withstand. The cantilevered support of the nitrogen cylinder, hydraulic cylinder, springs, and controls is the key area. The increase in loading at the joints between the support shafts and the valve bonnet caused by the specified earthquake loading is negligible.

Electrical equipment associated with the isolation valves that must operate in an accident environment is limited to the wiring, solenoid valves, and position switches on the isolation valves. The design and purchase specifications for the environment are given in Table 5.4-2.

The gamma and neutron radiation during nuclear system operation is 15 rad/hr and 25 rad/hr, respectively. The valves are capable of operation within specified limits, except regarding variance in closing speed from superimposed backpressure resulting from emergency ambient conditions during 0.5 hr (total) exposure to emergency ambient conditions A and B (per Table 5.4-2), and shall remain closed during the continuance of emergency ambient conditions.

The operation of the valves in the normal operating conditions and postulated accident environments is ensured by the requirements of the purchase specifications, review and approval of equipment design and vendor drawings, extensive control of materials, fabrication procedures, fabrication tests, non-destructive examinations, shop tests, preoperational and startup tests of the installed valves, and prescribed periodic inspections and tests during the plant life.

5.4.5.4 Inspection and Testing

The following specified hydrostatic, leakage, and stroking tests, as a minimum, are performed by the valve manufacturer in shop tests.

Each valve is tested at rated pressure and temperature (1000 psig and 545°F) and no flow to verify capability to close between 3 and 10 sec. The valve is stroked several times and the closing time recorded. The valve is closed by the air cylinder and springs and may also be closed by the springs only. The closing time is usually slightly greater when closed by springs only.

Adjustability of the closing time of each valve between 3 and 10 sec is tested at rated pressure and no flow. The valve is stroked several times at the fastest setting, intermediate setting, and slowest setting. Closing times are recorded.

Valves are shop tested at atmospheric pressure and room temperature to verify closing time and adjustability of closing time.

Leakage with the valve seated and back seated is measured. Seat leakage is measured in the shop by pressurizing the upstream side of the valve. The specified maximum seat leakage, using cold water at 1875 psig, is 40 cm^3/hr. There must be no visible leakage from either set of stem packing (subsequently modified to a single stem packing configuration - this section retained for historical reference) at design pressure. The valve stem is operated a minimum of three times from the closed to open position, and the packing leakage must still be zero by visual examination.

Each valve is hydrostatically tested at MSS-SP-61 specified test pressure (2380 psig) with cold water.

During valve fabrication, extensive nondestructive tests and examinations were made, including radiographic, liquid penetrant, or magnetic particle examinations of casting, forgings, welds, hard facings, and bolts.

The main steam isolation valves may be tested during plant operation and tested and inspected during refueling outages. The test operations are listed below.

The main steam isolation valves may be tested and exercised individually to the 90% open position because the valves still pass rated steam flow when 90% open. The main steam line isolation valves may be tested and exercised individually to the fully closed position if reactor power is not greater than 76% of rated power (1460 MWt) assuming all four steamlines are in operation. If the plant is operating on only three streamlines, this testing is limited to < <41 % power (780 MWt).

During reactor shutdowns for refueling, the main steam isolation valves are tested and visually inspected.

Leakage from the valve stem packing may become suspect during reactor operation from measurements of leakage into the primary containment, or from observations or similar measurements in the secondary containment. During shutdown while the nuclear system is pressurized, the leak rate through the packing may be observed during visual examination performed during inservice pressure testing.

Leakage rate testing of the main steam isolation valves is performed as discussed in Section 6.2.6 and the Technical Specifications.

A program to test the function and closure time of main steam line isolation valves under simulated accident conditions was conducted by GE. Three specific programs were conducted. The first included small scale tests to observe the phenomenon of high speed steam being stopped by valve closure; the second was a full-scale test where the steam flow rate through the valve was increased over normal flow; and the third included tests for the simulated accident situation where the valve was subjected to conditions of high steam flow with water entrainment. The results of these tests satisfactorily demonstrated the required performance characteristics of the steam-line isolation valves. The test program results were submitted to the NRC as a GE topical report.[5]

5.4.6 REACTOR CORE ISOLATION COOLING SYSTEM

5.4.6.1 Design Bases

The RCIC system provides makeup water to the reactor vessel following a reactor vessel isolation to ensure adequate core cooling.

The RCIC system provides core cooling during reactor shutdown by pumping makeup water into the reactor vessel in case of a loss of flow from the feedwater system and is activated in time to preclude conditions that lead to inadequate core cooling.

The safety* design bases are as follows:

1. The system operates automatically to maintain sufficient coolant in the reactor vessel so that the integrity of the radioactive material barrier is not compromised.

2. Piping and equipment, including support structures, are designed to withstand the effects of an earthquake without a failure that could lead to a release of radioactivity in excess of the values in published regulations.

3. Equipment necessary for operation of the RCIC System is designed as Class 1E to improve its reliability.

The power generation design bases are as follows:

1. The system operates automatically to provide makeup capacity sufficient to prevent the reactor vessel level from dropping to the top of the core.

2. Provision is made for remote manual operation of the system by an operator.

3. To provide a high degree of assurance that the system will operate when necessary, the power supply for the system is from immediately available energy sources of high reliability.

4. To provide a high degree of assurance that the system will operate when necessary, provision is made so that periodic testing can be performed during plant operation.

5.4.6.2 Description

The RCIC system consists of a steam-turbine-driven pump unit and associated valves and piping capable of delivering makeup water to the reactor vessel. A summary of the design requirements of the turbine-pump unit is shown in Table 5.4-3. Schematic diagrams are shown in Figures 5.4-9 and 5.4-10.

2014-011 * While no credit for RCIC system operation is assumed during any design basis accident, credit is taken for RCIC operation during transients and certain Special Events in Chapter 15.

The steam supply to the turbine comes from the reactor vessel. The steam exhaust from the turbine dumps to the suppression pool. The pump can take suction from either of two sources: condensate storage tank or the suppression pool. The pump discharges either to the feedwater line or to a full-flow test line to the condensate storage tank. A minimum flow bypass line to the suppression pool is provided. The makeup water is delivered into the reactor vessel through a connection to the feedwater line and is distributed within the reactor vessel through the feedwater sparger.

Cooling water for the RCIC system turbine lube-oil cooler and barometric condenser is supplied from the discharge of the pump (see Figure 5.4-9).

Following any reactor shutdown, steam generation continues as a result of heat produced by the radioactive decay of fission products. Initially, the rate of steam generation can be as much as approximately 6% of rated flow and is augmented during the first few seconds by delayed neutrons and some of the residual energy stored in the fuel. The steam normally flows to the main condenser through the turbine bypass or, if the condenser is isolated, to the suppression pool. The fluid removed from the reactor vessel can be entirely made up by the feedwater pumps or partially made up by flow from the CRD system that is supplied by the CRD supply pump. If makeup water is required to supplement these primary sources of water, the RCIC system turbine-pump unit either starts automatically on the receipt of a reactor vessel low ("low-low") water level signal (see Figure 5.4-11) or is started by the operator from the control room by remote manual controls. The RCIC system delivers its design flow within 30 sec after actuation. To limit the amount of fluid leaving the reactor vessel, the reactor vessel low-low-low water level signal also actuates the closure of the main steam isolation valves.

The RCIC system has a makeup capacity sufficient to prevent the reactor vessel water level from dropping to the top of the core. The pump suction is normally lined up to the condensate storage tank. The total capacity of the condensate storage system is sufficient to allow the operation of the RCIC system for 8 hrs after shutdown assuming that none of the steam generated in the reactor vessel can be returned to the reactor vessel as condensate. The reserve capacity of the condensate storage system is sufficient to allow the operation of the RCIC system for the required 4 hour coping period for a station blackout (SBO) event (Section 15.3.2). Systems that use the condensate storage tank other than HPCI and RCIC systems take suction from the tank at a higher elevation, thus ensuring that the availability of the reserve storage is not jeopardized (see Section 6.3). A low-level alarm from the condensate storage tank is also provided in the control room and is energized when the level in the storage volume falls to the minimum required to meet the design requirements of the RCIC system.

The backup supply of cooling water for the RCIC system is the suppression pool. The turbine-pump assembly is located below the level of the condensate storage tank and below the minimum water level in the suppression pool to ensure positive suction head to the pump. Pump

NPSH requirements are met by providing adequate suction head and adequate suction line size. A low condensate storage tank level trip is provided to provide automatic RCIC switchover from the condensate storage tank to the suppression pool. The low-level trip opens the suppression pool suction valves. The sensors used for switchover are the existing safety-grade condensate storage tank low-water level elements in the high pressure coolant injection system. These sensors and their associated circuitry meet the criteria of IEEE Standard 279-1971, Sections 4.9 and 4.10, and are designed and tested to meet the same seismic design criteria as was used for the RCIC system. In addition, the sensors are environmentally qualified to the same criteria as was used in the original design of the HPCI and RCIC system. The RCIC switchover design is such that no single failure within any equipment added to accomplish the automatic switchover of RCIC will interfere with operation of the HPCI system or interfere with the transfer of HPCI suction from the condensate storage tank to the suppression pool. The logic of the switchover is such that the condensate storage tank suction valve is not closed until the suppression pool suction valves are fully open. Valve position indication for the above suction valves is provided in the control room.

For a particular mode of operation, available RCIC pump NPSH is minimized when the water source container pressure and water level are at a minimum and the water source temperature is at a maximum. Considering RCIC pump suction from the suppression pool and condensate storage tank, during minimum available pump NPSH conditions as stated above, the available RCIC pump NPSH is at a minimum when suction is taken from the suppression pool. The value of this minimum available NPSH is 25.8 ft, which corresponds to the design flow requirements of the RCIC system shown in Table 5.4-3.

The maximum water temperature in the suppression pool during RCIC operation is 140°F for continuous operation and 170°F for periods of short duration. The normal water temperature in the condensate storage tanks is approximately 100°F. The elevation of the minimum water level in the suppression pool is [redacted] and the elevation of the minimum water level in the condensate storage tanks is [redacted] compared to an RCIC pump suction elevation of [redacted] The minimum pressure in the suppression pool is 14.7 psia, and the pressure in the condensate storage tanks is atmospheric. Therefore, the minimum available NPSH when suction is taken from the suppression pool is less than that when suction is taken from the condensate storage tanks, since the difference in friction loss, minimum pressure and temperature difference between these two conditions is negligible compared to the difference in water-level elevation (24 ft).

The minimum available RCIC pump NPSH of 25.8 ft exists when suction is taken from the suppression pool, which is at a temperature of 170°F, a water-level elevation of [redacted] and a backpressure of 14.7 psia. This value corresponds to the design flow requirements of the RCIC system shown in Table 5.4-3 and exceeds the required RCIC pump minimum NPSH of 20 feet.

Throughout the period of RCIC system operation, the exhaust from the RCIC system turbine is condensed in the suppression pool, which results in a slow temperature rise

(approximately 3°F/hr) in the pool. RHR system heat exchangers are used to cool the suppression pool if necessary.

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

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

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

Again, as stated earlier, although the RCIC system is not assumed to perform a safety function in mitigating any design basis accident, it is credited for assisting in the mitigation of transients and other special events as discussed in Chapter 15, such as a Loss-of-Feedwater event with concurrent HPCI failure (NUREG-0737, Item II.K.3.44) and Station Blackout (SBO).

5.4.6.3 Safety Evaluation

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

The potential for steam void formation (which could cause water hammer) due to leakage through the system discharge valves has been considered. During the normal plant operation, any back leakage of reactor coolant into the RCIC system cannot cause significant steam void formation in the discharge piping. Thus, there is no significant potential for water hammer upon RCIC system startup due to back leakage. RCIC operability is ensured by verifying the RCIC discharge piping is sufficiently full of water per venting the system at its high points. Venting may be performed for verification if RCIC suction is aligned to the CST. 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 at all times.

5.4.6.4 Inspection and Testing

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

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

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

where

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

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

$$\Delta P_t = \Delta P_{3xflow} \left(\Delta P_m\right) \left[\frac{W_{max}}{W_{test}}\right]^2$$

where

ΔP_t = trip setpoint required

ΔP_m = measured ΔP (steady state)

ΔP_{3xflow} = ΔP change corresponding to 300% flow

W_{max} = maximum steam flow required in any mode per process diagrams

W_{test} = steam flow required in test mode per process diagrams

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

$$\Delta P_{\max} = \Delta P_{3xflow}\left(\Delta P_{test}\right)\left(\frac{\rho_{test}}{\rho_{\max}}\right)\left(\frac{W_{\max}}{W_{test}}\right)$$

In which:

ΔP_{max} = Analytical limit required for 300% steam flow

ΔP_{test} = Differential pressure measured during steady state testing

ρ_{max} = Steam density for process diagram Mode A conditions

ρ_{test} = Steam density for measured reactor pressure

W_{max} = Maximum steam flow (Mode A of system process diagram)

W_{test} = Steam flow from test mode of system process diagram

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

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

5.4.7 RESIDUAL HEAT REMOVAL SYSTEM

5.4.7.1 Design Bases

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

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

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

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

The safety design bases are as follows:

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

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

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

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

The power generation design bases are as follows:

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

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

5.4.7.2 Description

5.4.7.2.1 General

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

The major subsystems are:

1. Low Pressure Coolant Injection (LPCI).

2. Containment spray.

3. Suppression pool cooling.

4. Shutdown cooling.

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

The minor functional subsystems are:

1. Fuel pool cooling.

2. Reactor vessel draining.

3. Suppression pool draining.

4. Reactor or containment flood with RHR service water.

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

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

The main system pumps are sized on the basis of the flow required during the LPCI mode of operation, which is the mode requiring the maximum flow rate. The service water pumps are sized to cause the pressure at the cooling water outlet of the RHR system heat exchangers to be greater than the pressure of the reactor coolant at the inlet of the heat exchangers during the

shutdown cooling mode of operation. This criterion ensures that in case of a leak in the tubes of the heat exchanger, the radioactive coolant does not leak into the service water.

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

2016-008 Figure 5.4-12 indicates the RHR heat exchanger duties for the principal modes of operation. 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.

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

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

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

Maintaining the core spray and RHR pump discharge lines downstream of the pump discharge check valves sufficiently full of water is important, as possible water hammer and consequent damage to the piping system may result if these lines are not sufficiently full of water. An RHR/core spray fill pump shown in Figure 5.4-14 is provided for this purpose. In the process of circulating water from and back to the suppression pool via the RHR pump suction line and the RHR minimum flow bypass line, this fill pump maintains water pressure in the
2016-014 discharge lines. Each discharge line is monitored by a low-pressure switch and alarm. The pressure switches which monitor the LPCI and core spray lines are functionally tested quarterly and calibrated once per operating cycle. The possibility of defeating the Automatic Depressurization System low-pressure core cooling interlock by inadvertently pressurizing these lines above the interlock pressure setpoint with this fill system does not exist because the maximum pressure that the fill pump is able to produce is lower than that pressure which

activates the pressure switch in the Automatic Depressurization System low-pressure core cooling interlock. The fill pump discharge into the RHR and Core Spray systems is downstream of the RHR and Core Spray system pump discharge check valves while the Automatic Depressurization System low-pressure core cooling interlock instruments are located upstream of the RHR and Core Spray system pump discharge check valves. System pressure is allowed above the keep-fill pressure, due to recent pump operation or other events which may pressurize the piping above the keep-fill normal pressure, in standby readiness conditions. This is acceptable due to the locations of the fill pump discharge into the RHR and Core Spray systems and the locations of the Automatic Depressurization System low-pressure core cooling interlock instruments.

As part of the plant's review for Generic Letter 2008-01 (Ref. 24 and 25), 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 be 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.

To assure that the RHR system will not be drained in the event that it is automatically isolated from the Reactor Coolant System, valve MO-1937 is interlocked to close upon occurrence of an isolation of the RHR system when the control switch is in the "shutdown cooling" position.

Two separate RHR Shutdown Cooling Suction low pressure switches supply the PCIS logic with reactor high-pressure isolation signals. The two RHR suction pressure switches are different to provide diversity.

RHR system equipment is designed in accordance with Seismic Category I criteria (see Chapter 3) to resist sufficiently the response motion at the installed location with the supporting building from the DBE. The main system pumps are assumed to be filled with water for the seismic analysis.

The system piping and main system pumps are designed, constructed, and hydrostatically tested in accordance with the requirements of Chapter 3. The pumps are also performance tested in accordance with the Standards of the Hydraulic Institute for centrifugal pumps. The shell side of the heat exchangers is designed in accordance with ASME Code, Section III, Class C vessels

and TEMA Class C, and the tube side is designed in accordance with Section VIII and TEMA Class C. The provisions of the Winter Addenda of 1966, Paragraph N2113, apply.

In response to an NRC letter of February 23, l980, concerning LWR primary coolant system pressure isolation valves, a review was conducted of the DAEC valve arrangements with respect to Event V isolation valve configurations within the Class I boundary of the high-pressure piping connecting nuclear boiler system piping to low-pressure piping. While the DAEC does not have either of the two Event V isolation valve configurations discussed in the letter, the DAEC core spray system and RHR system valve arrangements are similar enough to warrant further consideration. A review of the design features and testing program was completed for these two systems. The following is a brief discussion of the DAEC core spray system and RHR valving arrangement, pressure monitoring and control features, and periodic testing performed to ensure that the possibility of an Event V type accident is minimized.

The core spray and RHR shutdown cooling system containment isolation valve arrangement consists of a single check valve on each line inside containment and two motor-operated valves on the high-pressure carbon steel (Schedule l00) piping. The piping upstream of the motor-operated valves is low-pressure (Schedule 40) carbon steel piping. Each low-pressure line is provided with (l) a pressure relief valve and (2) a pressure switch or switches and high-pressure annunciators in the control room to monitor the system pressure and permit the detection of leakage from the nuclear boiler system into the core spray or RHR system piping outside containment. The core spray system pressure relief valves discharge to the suppression pool, and the RHR system relief valves discharge to the open (floor) radwaste system. These design features are shown in Table 5.4-5, and the valve arrangement is depicted in Figures 5.4-l2 and 5.4-14.

Continuous surveillance is accomplished for the single check valve inside containment and normally closed motor-operated valve outside containment by the pressure switches and high-pressure annunciators located in the control room as discussed above. All of the containment isolation motor-operated valves listed in Table 5.4-5 are cycled periodically to ensure valve operability. In addition, all of the core spray system containment isolation valves are subjected to the periodic Type C isolation valve pressure tests in accordance with the requirements of the Technical Specifications.

Based on the pressure surveillance instrumentation and pressure-relieving equipment provided for each DAEC line having a valve arrangement similar to the Event V configurations, plant procedure revisions or plant equipment modifications are not necessary for containment integrity reliability.

During power operation, reactor coolant system leakage past V19-0149 and V20-0082 can result in a reactor coolant system operating pressure of approximately 1000 psig on the reactor side of LPCI isolation valves MO-1905 and MO-2003. Based on BWR operating experience, motors can be overloaded during attempts to open if a high differential pressure

exists across a motor-operated valve. Therefore, the capability of equalizing pressure across MO-1905 and MO-2003 during power operation is provided.

Radiation monitoring of the RHR system and associated emergency service water system piping is discussed in Chapter 11.

5.4.7.2.2 Shutdown Cooling

The shutdown cooling subsystem is an integral part of the RHR system and is placed in operation during a normal shutdown and cooldown. The initial phase of nuclear system cooldown is accomplished by dumping steam from the reactor vessel to the main condenser with the main condenser acting as the heat sink. When nuclear system temperature has decreased to the value where the steam supply pressure is not sufficient to maintain the turbine shaft gland seals, vacuum in the main condenser cannot be maintained and the RHR system is placed in the shutdown cooling mode of operation. The shutdown cooling subsystem completes cooldown to 125°F in ~27 hrs and maintains the nuclear system at 125°F so that the reactor can be refueled and serviced. Although the original design specification of 20 hours is not met following extended power uprate, this is an operational issue and does not pose a safety concern.

Reactor coolant is pumped by the RHR system main system pumps from one of the recirculation loops and discharged through the RHR system heat exchangers where cooling takes place by transferring heat to the service water. Reactor coolant is returned to the reactor vessel through the recirculation loop discharge piping.

During a nuclear system shutdown and cooldown, when the shutdown cooling subsystem is initially placed in operation, decay heat levels can be high and the operation of both RHR system heat exchangers may be required to remove the heat. When the decay heat level has decreased sufficiently, the entire shutdown cooling load can be shifted to one RHR system heat exchanger leaving the other available for any other cooling loads.

As part of the plant’s review for Generic Letter 2008-01 (Ref. 24), the operating procedures for the RHR system were reviewed for placing the system into Shutdown Cooling mode and for restoration back into the primary ECCS function (LPSCI mode). When being aligned for SDC mode, the suction piping, pump(s), and a portion of the discharge piping are back-flushed and warmed prior to placing it into service. This evolution should remove any potential voids that might have accumulated since the last use of the SDC mode. The discharge section of piping is common with the ECCS function, thus, it is part of the piping connected to the keep fill system, which precludes unacceptable gas voiding, in conjunction with a proper initial fill and vent. Restoration from SDC mode to standby readiness includes direction to pressurize RHR piping with Condensate Service Water, which precludes unacceptable gas voiding, in conjunction with a proper initial fill and vent.

5.4.7.2.3 Suppression Pool Cooling Subsystem

The suppression pool cooling subsystem of the RHR system is discussed in Section 6.2.2.

5.4.7.2.4 Containment Spray Subsystem

The containment spray subsystem of the RHR system is discussed in Section 6.2.2.

5.4.7.2.5 Condensing Mode, Reactor Core Isolation Cooling System

This mode has been disabled.

5.4.7.2.6 Low-Pressure Coolant Injection

The LPCI subsystem is an integral part of the RHR system. It operates, in combination with the Core Spray system, to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a LOCA so that the core is sufficiently cooled to preclude excessive fuel clad temperatures and subsequent energy release due to a metal-water reaction. A detailed discussion of the requirements and response of the equipment that operates during low-pressure coolant injection for a LOCA may be found in Chapter 6. Section 7.3 discusses the requirements and response of the controls and instrumentation of low-pressure coolant injection during a LOCA.

In general, LPCI operation involves restoring the water level in the reactor vessel to a sufficient height for adequate cooling after a LOCA. The LPCI subsystem operates in conjunction with the HPCI system, the nuclear system pressure relief system, and the core spray system to achieve this goal. The HPCI system is a high-head, low-flow system that pumps water into the reactor vessel when the nuclear system is at high pressure. If the HPCI system fails to deliver the required flow of cooling water to the reactor vessel, the automatic depressurization feature of the nuclear system pressure relief system functions to reduce nuclear system pressure so that low-pressure coolant injection operates to inject water into the pressure vessel. Low-pressure coolant injection is a low-head, high-flow function and delivers rated flow to the reactor vessel when the differential pressure between the reactor vessel and primary containment is 20 psid or less. Low-pressure coolant injection is designed to reflood the reactor vessel to at least two-thirds core height and to maintain this level. After the core has been flooded to this height, the capacity of one RHR system main system pump is more than sufficient to maintain the level.

During LPCI operation, the main system pumps take suction from the suppression pool and discharge to the reactor vessel into the core region through one of the recirculation loops. Instrumentation is provided to detect the undamaged path for the injection of LPCI flow (see Section 7.3). Any spillage through a break in the lines within the primary containment returns to the suppression pool through the pressure suppression vent lines. A minimum flow bypass line to the suppression pool is provided so that the pumps are not damaged if operating with the discharge valves shut.

Service water flow to the RHR system heat exchangers is not required immediately after a LOCA because heat rejection from the containment is not necessary during the time it takes to flood the reactor. Power for the main system pumps normally comes from an auxiliary ac power bus, but if this source is not available, power can be obtained from the standby ac power source.

5.4.7.2.7 Residual Heat Removal System Intertie

To provide a source of water if any postaccident flooding of the primary containment is required, a crosstie exists from the RHR service water system to the discharge piping on the shell side of an RHR system heat exchanger. This connection is provided with redundant valving appropriate to a primary containment penetration. The valves are remotely operable from the control room. This connection provides access to a large source of water for postaccident flooding of the primary containment. The pair of service water pumps that provides this function can add water to either recirculation loop through the cross-connection between the piping of each RHR system loop. A keylock switch with an amber light provides the capability to control MO-1947 and MO-2046 (RHRSW Heat Exchanger Discharge Valves) in an emergency if the respective RHRSW pumps are not operating. This allows alternate sources of makeup to be used to flood the primary containment.

5.4.7.3 Safety Evaluation

Since the LPCI and containment cooling subsystems act with other emergency core cooling systems to satisfy the safety objective, they are properly evaluated in conjunction with the other emergency core cooling systems. This safety evaluation is in Chapter 6. The safety evaluation of the controls and instrumentation of the LPCI subsystem is in Section 7.3.

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 Section Head (NPSH) is
2014-006 available to the RHR pumps. The results of this analysis are shown in Figure 5.4-15 Sheet 1. However, there are limitations on containment overpressure that can be credited for satisfying
2014-006 NPSH requirements (Fig. 5.4-15 Sheet 2).

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

5.4.7.4 Inspection and Testing

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

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

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

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

5.4.8 REACTOR WATER CLEANUP SYSTEM

5.4.8.1 Design Bases

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

The power generation design bases are as follows:

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

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

5.4.8.2 Description

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

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

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

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

The filter-demineralizer units are pressure precoat-type filters using finely ground mixed ion-exchange resins. Spent resins are not regenerable and are sluiced from each filter-demineralizer unit to the cleanup phase separator storage tanks for dewatering, decay, and disposal. A strainer is installed on the outlet of each filter-demineralizer unit to prevent resins from entering the reactor coolant recirculation system in the event of a resin support failure. Each strainer is provided with an alarm that is energized by high differential pressure. A bypass line is provided around the filter-demineralizer units for bypassing the units when necessary.

Additional design features are provided to eliminate possible sources of resin introduction into the reactor vessel. They are as follows:

1. Venting of the piping on the holding pump discharge lines is controlled by automatic sequencing of valves by the control logic.

2. Valve interlocks that prohibit the initiation of backwash without the proper valve lineup.

3. Valve interlocks that prohibit de-isolation of the RWCU system without the proper valve lineup.

4. Automatic isolation of the RWCU filter-demineralizers in the event of low or no flow.

5. A white light for each holding pump to indicate pump trip.

Relief valves and instrumentation are provided to protect the equipment against overpressurization and the resin against overheating. The system is automatically isolated for the reasons indicated when signaled by any of the following occurrences:

1. High temperature downstream of the nonregenerative heat exchanger. To protect the ion-exchange resin from damage due to high temperature.

2. Reactor vessel low ("low-low") water level. To protect the core in case of a possible break in the RWCU system piping and equipment.

3. Standby liquid control system actuation. To prevent removal of the boron by the ion-exchange resin.

4. High differential flow of the cleanup system. To protect against a possible break in the RWCU system piping and equipment.

5. High cleanup system ambient temperature. To protect against a possible break in the cleanup system carrying high-temperature water.

6. High differential temperature across the systems inlet and outlet ventilation ducts. To protect against a possible break in the RWCU system piping and equipment.

Flow is maintained through each filter-demineralizer by its own holding pump in the event of low flow or loss of flow. Sample points are provided in the influent header and effluent line of the filter-demineralizer units. The influent sample point is also used as a normal source of reactor coolant samples. Sample analysis provides an indication of the effectiveness of the filter-demineralizer units.

5.4.8.3 Inspection and Testing

Because the RWCU system is normally in operation during the operation of the nuclear plant, satisfactory operation is demonstrated without the need for any special inspection or testing.

5.4.9 MAIN STEAM LINES AND FEEDWATER PIPING

5.4.9.1 Design Bases

The power generation objective of the main steam lines is to conduct steam from the reactor vessel through the primary containment to the steam turbine. The power generation objective of the feedwater lines is to provide the piping path for delivery of water back to the reactor vessel.

The power generation design bases are as follows:

1. The main steam and feedwater lines are designed with suitable accesses to allow inservice testing and inspections.

2. The main steam lines are designed to conduct steam from the reactor vessel over the full range of reactor power operation.

3. The feedwater lines are designed to conduct water to the reactor vessel over the full range of reactor power operation.

The safety design basis is as follows:

The main steam and feedwater lines are designed to accommodate operational stresses, such as internal pressures, without a failure that could lead to a release of radioactivity in excess of the guideline values in published regulations.

5.4.9.2 Description

The feedwater piping is designed to conduct water from sources outside the primary containment to the reactor vessel. The general requirements of the feedwater system are covered in Section 7.7 and Section 10.4.7. All main steam and feedwater piping are classified according to service and locations. The materials used in piping are in accordance with the applicable design code and supplementary requirements. A diagram of the main steam and feedwater piping is shown in Figure 5.1-1, Sheet 1.

The main steam lines meet Seismic Category I requirements up to but not including the turbine stop and control valves.

The reheater steam lines and turbine bypass lines also meet Seismic Category I requirements.

The nuclear piping for the DAEC main steam line, reheater steam line, turbine bypass lines, and all branch lines 2.5 in. or larger in diameter, is designed in accordance with ANSI B31.1.0 and the applicable Code Cases N-2, 7, 9, and 10 with the following exceptions to the nuclear code cases applied to branch line valves larger than 2.5 in. in diameter:

1. Comply with the positive sealing requirements for bonnet and stem leaks as specified in Code Case N-2. Conventional valve design in accordance with ANSI valve standards is provided.

2. Provide full radiography of valve pressure boundary castings because Code Case N-2 makes this a requirement only for cast austenitic materials. The imposition of this requirement on the standard carbon steel valves employed in most of the systems, other than Class 1, creates a doubt as to acceptability because of standard manufacturing practices for this valving application. This is because these valves for such low-pressure/low-temperature systems in a BWR are standard-shelf-type valves that have conformed with ANSI (formerly ASA) standards for many years and as such the body castings are not amenable to passing a Class 1 radiography inspection. Dye penetrant or magnetic particle inspection of the body castings is employed inside and out to achieve a full-surface inspection. The carbon steel valves employed in Class 2 systems receive a shop hydrostatic test in accordance with the applicable standards and codes.

For operational and functional reasons, the turbine stop valves are 100% volumetrically examined by GE.

The main steam line down through the turbine stop and control valves and including the turbine steam leads up to the turbine inlet has been subjected to a seismic analysis. Branches connecting to the main steam line of a size, configuration, and/or mass that may have a significant contribution have also been included, such as piping to the steam bypass valve chest. The analysis of these lines encompasses the piping and inline components (principally valves) between anchor points. The downstream anchor point has been chosen to include the first valve downstream of the second main steam line isolation valve. This includes the consideration of all branch lines 2.5 in. or larger in diameter.

1. The analysis uses a multidegree-of-freedom dynamic model in accordance with the requirements of Chapter 3.

2. The turbine building is designed to Uniform Building Code Zone 1 as a minimum. However, in order to determine the end displacements and seismic forces on the

main steam piping, analyses were performed to determine needed response spectra at the pipe anchor points.

A simplified lumped mass mathematical model similar to the one described in Section 3.7.2.1.2. employing response spectra inputs to simulate earthquake response of the turbine building was used to determine the response of the main steam line support system for an OBE. After determining the response of the support system, a response spectra diagram was prepared to show relative response motion acceleration and velocity as a function of the main steam piping system frequencies.

The forces induced by the earthquake loading in the main steam piping were included with other operating loads to properly design the pipe supports and anchors.

5.4.9.2.1 Materials

1. Seamless pipe is ASTM A-106, Grade B. Rolled and welded pipe is ASTM A-155, Class 1, Grade KC 70.

2. Certification in writing is required from the manufacturer that all pipe, fittings, flanges, bolting materials, valves, and welding wire meet applicable material specifications along with Mill test reports.

5.4.9.2.2 Fabrication and Erection

One-hundred percent radiography is required on all butt welds.

5.4.9.2.3 Feedwater Nozzle Instrumentation

The inner blend radius of the four DAEC feedwater nozzles were instrumented with resistance temperature detectors during the scheduled refueling outage that began in April 1977. The instrumentation was removed in 1980. The purpose of the instrumentation was to record the temperature cycling experienced by each feedwater nozzle from the mixing of feedwater and reactor downcomer water. This cycling had caused feedwater nozzle cracking at other BWRs.

The DAEC feedwater nozzle/thermal sleeve/sparger design is unique. The feedwater nozzle thermal sleeve is welded to the nozzle safe end; therefore, it is expected that the feedwater nozzles would experience less thermal cycling and thus significantly less cracking than at other BWRs with a similar period of operation (Reference 6).

The feedwater nozzle temperature cycling recorded during the May 1977 startup was significantly less than that recorded for other BWRs that have a slip fit between the thermal sleeve and safe end. Large thermal cycles do not occur at the DAEC at low feedwater temperatures. The peak to peak temperature cycling was seen to be between 59 and 82°F for all

conditions with the feedwater temperature greater than 200°F. At lower feedwater temperatures, the cycling is reduced except during a turbine trip transient.

The total nozzle corner cumulative usage factor due to rapid cycling is 0.012. This value is low enough so that feedwater nozzle cracking due to fatigue should not occur. Should cracking due to another mechanism occur, then the cracks will propagate slower than at other BWRs because of the smaller thermal cycles experiences at the DAEC. In the event of cracking the hypothetical failure mode is predicted to be a "leak before break" mode as discussed in GE report NEDE 21480.

Additional detail on the feedwater nozzle instrumentation is contained in the GE report identified as Reference 6.

5.4.9.3 Safety Evaluation

Differential pressures on reactor internals under the assumed accident conditions of a ruptured steam line are limited by the use of flow restrictors (Section 5.4.4) and the use of four main steam lines. All main steam and feedwater piping is designed as described in Chapter 3.

A dynamic analysis of the main steam piping system was made, using a time history of the maximum forces created by instant closure of the turbine stop valve. The dynamic analysis was made for several typical BWR plants. The results of this analysis show that the pressure waves created by turbine stop valve closure do not cause significant stresses in the nuclear steam supply (NSS) shutoff system portion of the main steam piping, less than 2% of the overall stress.

When the safety and relief valves (Section 5.4.13) open, dynamic forces act on the piping system during the short period of time while steam is being accelerated through the piping system. A dynamic analysis of the DAEC main steam piping system was made, using a time history of the loads created by valve opening. The magnitude of the forces was estimated by determining the change in momentum in each section of straight pipe with a linear increased valve flow rate. The stresses caused by relief valve flow are appropriately combined with those caused by earthquake, deadweight, and pressure, and the total is less than 1.2 S_h, which is allowed by ANSI B31.1.0.

Systems that have been identified as containing components that can introduce rapid pressure/velocity fluctuations of the flowing media have been reviewed and analyzed as necessary.

As a result of a turbine stop valve trip, a pressure wave is generated in the steam line, which causes a dynamic response of the system. A conservative assumption of an instantaneous stop valve closure is made, and the magnitude of the pressure wave is calculated by $\Delta p = \rho C \Delta V$. For the main steam, RCIC, and HPCI systems, $\Delta p < 150$ psi.

A computer system is used to predict the time-dependent response of the system to the dynamic loads. The validity of this computer program was confirmed by actual measurements made during preoperational testing of a previous plant.

5.4.9.4 Inspection and Testing

Nondestructive examinations prior to initial plant startup of pressure boundary weldments were performed on the main steam line and on branch lines larger than 2.5 in. nominal diameter up to the first branch valve.

All circumferential and longitudinal full-penetration welds on piping, valves, and fittings up to and including the turbine stop valves were fully examined by radiography. Accessible surfaces of each weld were examined by either liquid penetrant or magnetic particle methods.

All branch connection welds larger than 4 in. were fully examined by radiography. Accessible surfaces of all branch connection welds were examined by either liquid penetrant or magnetic particle methods.

Fillet welds, socket welds, and attachment welds such as supports, lugs, anchors, and guides were examined on all accessible surfaces by either liquid penetrant or magnetic particle methods.

Seamless pipe was ultrasonically examined by the angle-beam method. Plate for welded pipe, including fittings, was ultrasonically examined by the straight-beam method.

Castings for pressure-retaining components were fully examined by radiography. All castings for pressure-retaining components were examined on all accessible surfaces by either liquid penetrant or magnetic particle methods.

Forgings for pressure-retaining components were ultrasonically examined by angle-beam and/or straight-beam methods and by the liquid penetrant or magnetic particle methods. Forged fittings were examined by the liquid penetrant or magnetic particle methods.

Access for inspection is provided for that portion of the main steam line between the reactor vessel and the outermost isolation valve. In addition, for that portion of the main steam line downstream of the second isolation valve (although it was not Iowa Electric practice to perform scheduled inspection of steam lines in power-producing facilities), inspections have been performed visually and with appropriate testing when a steam line has been operated beyond its design. The same practice will be continued for the DAEC steam lines. In order to allow inspection when necessary, essentially 100% access is provided for the main steam lines and branch connections 2.5 in. in diameter or larger.

Further details on inservice inspection are described in Section 5.2.4.

As part of startup testing, vibration monitoring of main steam lines and feedwater piping was performed to confirm acceptable performance. For further details, see Section 14.2.14.

5.4.10 PRESSURIZER

Not applicable to BWRs.

5.4.11 PRESSURIZER RELIEF DISCHARGE SYSTEM (PWRs)

Not applicable to BWRs.

5.4.12 VALVES

The main steam isolation valve characteristics and the turbine stop valve characteristics used in transient analyses are given in Figures 7.3-8 and 7.2-7.

In response to a request from the AEC's Division of Compliance, the minimum wall thickness for "valves important to nuclear safety" has been verified and documented.

5.4.13 SAFETY AND RELIEF VALVES

5.4.13.1 Design Bases

The safety objective of the nuclear system pressure relief system is to prevent overpressurization of the nuclear system (Section 5.2.2); this protects the nuclear system process barrier from failure that could result in the uncontrolled release of fission products. In addition, the automatic depressurization feature of the nuclear system pressure relief system acts in conjunction with the emergency core cooling system for reflooding the core following small breaks in the nuclear system process barrier; this protects the reactor fuel barrier (uranium dioxide sealed in cladding) from failure due to overheating that could result in the uncontrolled release of fission products from the reactor fuel barrier.

In addition to the above objective of the pressure relief system, Reference 7 indicates that the existing systems at the DAEC are sufficient to vent noncondensible gases from the RCS and therefore meet the requirements of NUREG-0737, Item II.B.1, "Reactor Coolant System Vents." The primary means of venting noncondensible gases from the reactor pressure vessel are the four power-operated, safety-grade automatic depressurization system safety/relief valves. Additional RCS venting occurs at the HPCI and RCIC system turbine exhausts. See Section 5.4.3.2.3 for further information on this subject.

The operational objective of the nuclear system pressure relief system is to prevent the opening of the spring-loaded safety valves during normal plant isolations and load rejections. As

part of the Mark I containment program (Section 6.2.1.6.2). Also, as part of the Mark I containment program (Section 6.2.1.6.2), to minimize loads on the torus due to S/RV discharges into the suppression pool, T-Quenchers were added to the S/RV discharge lines.

Two of the SRVs are equipped to provide the LLS function. The LLS logic (Section 7.6.5) causes the LLS valves to be opened at a lower pressure after reactor pressure has exceeded the scram setpoint and any SRV has opened at its normal steam pilot setpoint, and stay open longer, so that reopening more than one SRV is prevented on subsequent actuations. This mitigates the induced loads on the containment and the thrust loads on the SRV discharge lines by increasing the time between subsequent SRV actuations.

The safety design bases are as follows:

1. The nuclear system pressure relief system prevents the overpressurization of the nuclear system to prevent the failure of the nuclear system process barrier because of pressure.

2. The nuclear system pressure relief system provides automatic nuclear system depressurization for small breaks in the nuclear system occurring with the assumed failure of the HPCI system so that the LPCI and the core spray systems can operate to protect the fuel barrier.

3. The safety/relief valve discharge piping is designed to accommodate forces resulting from relief action and is supported for reactions due to flow at maximum relief valve discharge capacity so that system integrity is maintained, (e.g., T-Quenchers, LLS Logic).

4. The nuclear system pressure relief system is designed for testing prior to nuclear system operation and for periodic verification of the operability of the nuclear system pressure relief system.

The power generation design bases are as follows:

1. The nuclear system safety/relief valves prevent the opening of the spring-loaded safety valves during normal plant isolations and load rejections.

2. The nuclear system safety/relief valves do not discharge to the primary containment drywell.

3. The safety/relief valves will properly reclose following a plant isolation or load rejection so that normal operations can be resumed as soon as possible.

5.4.13.2 Description

The primary system safety valves are sized to limit the primary system pressure, including transients, to the limits expressed in ASME Code, Section III. No credit is taken for a scram initiated directly from the isolation event or for power-operated relief valves, sprays, or other power-operated pressure-relieving devices. Thus, the probability of failure of the turbine-generator trip scram or main steam isolation valve closure scram is conservatively assumed to be unity. Credit is taken for subsequent indirect protection system action, such as neutron flux scram and reactor high-pressure scram, as allowed by the ASME Code. Credit is also taken for the dual safety/relief valves in their ASME Code qualified mode of safety operation. Sizing on this basis is applied to the most severe pressurization transient, as described in Section 15.1.2.3.

The above-described basis is used to determine the minimum safety valve capacity that conforms to the ASME Code limits. General Electric engineering design practice produces a safety valve capacity that exceeds the minimum code requirement, thus providing additional design margin.

The rated capacity of the spring safety valves and dual safety/relief valves, including any limitations imposed by the systems connected to the discharge side, is sufficient to prevent a rise in pressure within the vessel of more than 10% above the design pressure at design temperature, in compliance with Paragraph N910.3 of Article 9, Section III of the ASME Code.

The pressure settings of all safety/relief valves are significantly below the vessel design pressure. No safety valve has a setting that exceeds 105% of vessel design pressure. This complies with Paragraph N910.4 of Article 9, Section III of the ASME Code.

In determining the pressure settings and discharge capabilities, full account is taken of the pressure drop on both the inlet and discharge sides of the valves in compliance with Paragraph N910.5 of Article 9, Section III of the ASME Code. Spring safety valves discharge directly into the drywell and have no restrictions. The safety/relief valves discharge into the pressure suppression pool through a discharge pipe on each valve. This piping is designed to achieve sonic velocity of discharge through the valve so that relieving capacity is independent of losses in the discharge piping.

The spring safety and safety/relief valves are installed on horizontal runs of the four main steam lines inside the primary containment. See Figure 5.4-17.

There are no stop valves or similar-type devices installed between the vessel and the safety and safety/relief valves, in accordance with Paragraph N-910.7 of Article 9, ASME Code, Section III.

Criteria for the design and installation of safety and safety/relief valves include the following:

1. Discharge tees are provided on safety valves to equalize the discharge thrust force.

2. The discharge tees are oriented to ensure no deleterious effects resulting from steam impinging on equipment.

3. Flanges are installed to ensure that the valve installation will meet vertical tolerances.

4. Clearance of at least 6 in. is provided between valves and other equipment.

5. Clearance is provided between header and bottom of flange for bolt removal when valve is installed.

6. Flatness tolerance for surface of groove is provided on the safety and relief valve flanges.

7. A large flange rating of l500 lb was provided for structural stability instead of a pressure rating of 900 lb for pressure temperature rating.

8. A larger pipe schedule of l60 was used for structural stability instead of Schedule 80 required for pressure temperature.

9. The discharge piping on the safety/relief valves provides an equalization of the discharge thrust forces for steady-state flow.

For analysis, the special loadings listed below are considered in addition to the usual design loads such as weight, pressure, temperature, and earthquake:

1. The jet force exerted on the safety/relief and safety valves during the first few milliseconds when the valve is open (steady-state flow has not yet been established). With steady-state flow, the dynamic flow reaction forces will be self-equalibrated by the safety/relief valve discharge piping or the tee at the safety valve discharge.

2. The dynamic effects of the kinetic energy of the piston disk assembly when it impacts on the base casting of the valve.

The nuclear system pressure relief system includes two safety and six safety/relief valves located on the main steam lines within the drywell between the reactor vessel and the first isolation valve (see Table 5.2-1). The safety valves provide protection against the overpressure of the nuclear system (Section 5.2.2) and discharge directly to the interior space of the drywell. The safety/relief valves, which discharge to the suppression pool, provide the following four main protection functions:

1. Overpressure relief operation. The valves are opened to limit the pressure rise and prevent spring safety valve opening.

2. Overpressure safety operation. The valves augment the spring safety valves by opening (self-actuated operation only) in order to prevent nuclear system overpressurization.

3. Depressurization operation. The required valves are opened automatically or manually by indirectly operated devices as part of the protection system for small line breaks.

4. Low-Low set operation. The required valves are controlled automatically to minimize the thrust loads on the discharge lines and induced loads on the containment by increasing the time between subsequent valve actuations.

The main steam lines, in which the safety/relief and safety valves are installed, are designed, installed, and tested in accordance with the applicable codes as discussed in Section 3.2. The safety and safety/relief valves are distributed among the four main steam lines so that a single accident cannot completely disable a safety, relief, or automatic depressurization function. See Figure 5.1-1, Sheet 1, for schematic location and layout details of the valves and piping.

The safety valves are spring-loaded valves that are designed, constructed, and marked with data in accordance with ASME Code, Section III, Article 9, and in accordance with ANSI B31.1.0 and B16.5. Popping-point tolerance (pressure at which valve "pops" wide open) is in accordance with ASME Code, Section I, Paragraph PG-72.3. The material on the pressure side of the valve disk, in contact with the steam, is stainless steel. The valves are designed for operation with saturated steam containing less than 1% moisture and are designed to have a response as described in the following paragraphs.

The safety/relief valves are Target Rock pilot-operated valves that are designed, constructed, and marked with data in accordance with the ASME Code, Section III, Article 9, and in accordance with ANSI B31.1.0 and B16.5. Existing simmer margins are 85 psi (one valve), 95 psi (one valve), 105 psi (two valves), and 115 psi (two valves) (Reference 11). Popping-point tolerance is in accordance with ASME Code, Section I, Paragraph PG-72 (c). Each valve is self-actuating at the set-relieving pressure, but may also be actuated by indirectly operated devices to permit remote manual or automatic opening at lower pressures. For depressurization operation, each safety/relief valve is provided with a power-actuated device capable of opening the valve at any steam pressure above 100 psig and capable of holding the valve open until the steam pressure decreases to about 50 psig. The control system for the actuator is described in Section 7.3. Pressure-containing parts of the valve body are fabricated of ASTM A216, Grade WCB. The safety/relief valve is designed for operation with saturated steam containing 1% moisture or less. The relieving pressures for overpressure relief and safety operating modes are adjustable between 1060 and 1160 psig with a maximum backpressure of 40% of the set pressure. The elapsed time between the initiation of the signal to the power

actuator and actual valve movement shall not exceed 0.4 sec; the time between initiation of the signal to the power actuator and full opening of the valve shall not exceed 0.45 sec.

The safety/relief valves are installed so that each valve discharge is piped through its own uniform diameter discharge line to a point below the minimum water level in the primary containment suppression pool to permit the steam to condense in the pool. Water in the line above suppression pool water level would cause excessive pressure at the relief valve discharge when the valve again opened. For this reason, a vacuum relief valve is provided on each relief valve discharge line to prevent drawing water up into the line because of steam condensation following the termination of relief valve operation. The safety/relief valves are located on the main steam line piping, rather than on the reactor vessel top head, primarily to simplify the discharge piping to the pool and to avoid the necessity for removing sections of this piping when the reactor head is removed for refueling. In addition, the safety/relief valves, as well as the safety valves, are more accessible during a quick shutdown to correct possible valve malfunctions when located on the steam lines.

Reference 8 describes an analytical model that predicts the water rise in a safety/relief valve discharge line after closure of the safety/relief valve. The model is applicable to discharge lines ending in either a ramshead or a T-quencher. The model can be used to size discharge line vacuum breakers.

Before valve actuation, the discharge line contains air at the containment pressure and temperature between the valve and the suppression pool water surface elevation. The remaining portion of the line is submerged and filled with water. When the valve is actuated, steam flows into the discharge line and begins compressing the air. As the steam flow and air compression continue, the water column is accelerated and is eventually expelled from the line, followed by a flow of air and then steam into the suppression pool. This steam flow continues until the valve is closed.

The following discussion summarizes the sequence of events in the discharge line following valve closure. The model accounts for all these effects.

1. At first, the pressure is higher than the static pressure external to the valve discharge into the pool. Steam continues to blow out and no water enters the line.

2. The pressure in the discharge line drops below the static pressure of the water at the discharge. Water flows into the discharge device. Turbulence and sprays that result from this early water motion lead to a very high steam condensation rate, which in turn causes the pressure of the steam at the interface to drop to near the vapor pressure of the inflowing water.

3. The water accelerates rapidly until fluid friction limits the velocity. (At this time, the inertia of the water is small.)

4. Steam continues to condense and the pressure in the line continues to drop. The vacuum breaker starts to open.

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

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

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

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

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

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

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

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

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

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

5.4.13.3 Safety Evaluation

The ASME Code requires overpressure protection for each vessel designed to meet Code Section III. The code permits a peak allowable pressure of 110% of vessel design pressure (1375 psig for a 1250-psig vessel). The code specifications for safety valves additionally require that the lowest safety valve setpoint be at or below vessel design pressure (1250 psig) and the highest

safety valve setpoint be at or below 105% of vessel design pressure (1313 psig). The safety/relief valves are set to open by self-actuation (overpressure safety function) in the range (nominal) from 1110 to 1140 psig, and the safety valves are set to operate at 1240 psig (nominal). These settings satisfy the ASME Code specifications for the setpoints of the safety valves.

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

For the DAEC plant, the transient produced by the closure of all main steam line isolation valves represents the most severe abnormal operational transient resulting in a nuclear system pressure rise when direct scrams are ignored. The required safety valve capacity is determined by analyzing the pressure rise from such a transient. The analysis (Section 15.1.2.3) indicates that the design valve settings and capacities (see Table 5.2-1) are capable of maintaining adequate margin below the peak ASME Code allowable pressure in the nuclear system (1375 psig). The safety valve capacity in conjunction with safety/relief valve capacity limits the peak nuclear system pressure at the bottom of the vessel. The resulting margin to the ASME Code limit ensures adequate protection against excessive overpressurization of the nuclear system process barrier even for this hypothetical reactor isolation event.

The safety/relief valves are designed to relieve energy from the nuclear system rapidly enough to prevent the operation of the safety valves during pressure transients that are reasonably expected to occur during the lifetime of the plant. The relief valve capacity is determined by analyzing the pressure rise accompanying the transients produced by a turbine trip without bypass and a load rejection without bypass initiated from turbine-generator design conditions. See Section 15.1.2.

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

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

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

Although no common failure mode has been identified that would prevent the pressure relief valves from opening during plant transient events, such a case is presented in the Enrico Fermi Unit

2 FSAR. It was shown that for the plant safety/relief and safety valve arrangement at Fermi Unit 2 the ASME Code limit for the reactor coolant pressure boundary would not be exceeded.

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

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

5.4.13.4 Inspection and Testing

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

1. Hydrostatic test at ANSI B16.5 specified test pressure with cold water.

2. Set pressure test: valve pressurized with saturated steam with the pressure rising to the valve set pressure; the specified set pressure is verified when the valve opens.

3. Each valve is subjected to an "air-under-water" seat leakage test following the set pressure test.

4. Safety/relief valve response time verification test.

During the preoperational test program, the valves were installed as received from the factory. The setpoints were adjusted, verified, and indicated on the valves by the vendor. Proper manual and automatic actuation of the safety/relief valves was verified, and the operation of the vacuum breaker valves was checked.

It is recognized that it is not feasible to test the safety and safety/relief valve setpoints while the valves are in place or during normal plant operation. The valves are mounted on 6-in. diameter 1500-lb primary service rating flanges so that they may be removed for maintenance or bench checks and reinstalled during normal plant shutdowns. The external surface and seating surface of all safety/relief valves and safety valves are visually inspected when the valves are removed for maintenance or bench checks.

The demonstration of safety and relief setpoints will occur only with the plant shutdown and will be done according to ASME Code, Section XI provisions. The test schedule is specified by the Inservice Testing Program.

In response to NUREG-0737, Item II.D.1, the BWR Owners Group established a test program (Reference 12) to demonstrate that safety/relief valves would open and reclose under all expected flow conditions. The test program was based on an evaluation of expected operating conditions determined through the use of analyses of accident and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. In October 1981, the Owners Group published a test report (Reference 13) documenting the results of the prototypical safety/relief valve tests conducted in accordance with the accepted test program. The tests were performed by the General Electric Company for the BWR Owners Group at the Wyle Laboratory in Huntsville, Alabama. The test report, which was reviewed by the NRC staff, describes the test facility, the basis for the test conditions and valve selection, the instrumentation and its accuracy, and analyzes the results with respect to valve operability, piping and support loads, and the applicability of the test results to the in-plant safety and relief valves. Subsequent NRC staff review of the test results generated six plant-specific questions which required resolution. Reference 14, representing the Duane Arnold Energy Center response to the six plant-specific questions, was submitted for NRC staff review on December 14, 1982.

The NRC staff has completed its review of the information concerning testing of safety/relief valves and has concluded that NUREG-0737, Item II.D.1, is resolved for the DAEC. The basis for the conclusion is as follows:

- The DAEC, with concurrence by the NRC staff, developed an acceptable relief and safety valve test program designed to qualify the operability of the prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. The subsequent tests were successfully completed under operating conditions which by analysis bounded the most probable maximum forces expected from anticipated design-basis events. The generic test results showed that the valves functioned correctly and safely for all steam and water discharge events specified in the test program and that the pressure boundary component design criteria were not exceeded. Analysis and review of the test results and the DAEC justifications indicated the direct applicability of prototypical valve and valve system performance to the inplant valves and systems intended to be covered by the generic test program.

- Thus, the requirements of Item II.D.1 of NUREG-0737 have been met and, thereby, ensure that the reactor primary coolant pressure boundary will have, by testing, a low probability of abnormal leakage (General Design Criterion 14) and that the reactor primary coolant pressure boundary and its associated components (piping, valves, and supports) have been designed with sufficient margin such that design conditions are not exceeded during relief/safety valve events (General Design Criterion 15).

- Further, the prototypical tests and the successful performance of the valves and associated components demonstrated that this equipment has been constructed in accordance with high quality standards (General Design Criterion 30).

5.4.14 COMPONENT SUPPORTS

All components in the pipe suspension systems supplied by GE were designed to the codes in effect at the times the various purchase orders were placed. The design, materials, and fabrication of parts were in accordance with Power Piping Code, ANSI B31.1, and the Standard MSS-SP58, as applicable. The suspension system was designed in accordance with the criteria listed in Table 5.4-7. Those criteria apply to both variable and constant support hangers and to seismic restraints.

All seismic restraint and/or snubber locations are specified after an appropriate seismic analysis determines their necessity. The required location and type of restraint is then sent to a restraint supplier for the development of design details. These details are carefully reviewed to ensure that the location, function, and overall design are compatible with the seismic analysis.

The seismic supports and restraints for recirculation and steam piping (Seismic Category I portion of piping) are not determined in the field. The seismic supports and restraints are located in accordance with the seismic analysis that is performed before installation.

When the seismic supports and restraints are installed, a field representative reviews the installation to ensure compliance with the assumptions of the analysis.

Operability and surveillance requirements for safety-related snubbers are contained in the Technical Requirements Manual.

REFERENCES FOR SECTION 5.4

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1a. Letter from D. B. Vassallo, NRC, to Duane Arnold, Iowa Electric, Subject: Resolution of NUREG-0737, Item II.K.3.25, Effect of Loss of AC Power on Pump Seals, with enclosures, dated December 1, 1982.

1b. [Not Used]

1c. Performance of the CAN2A Recirculation Pump Seal Cartridge During a Station Blackout, by D. B. Rhodes of AECL Research, AR 97-1418.01.

2. Chicago Bridge & Iron Company, Stress Report, Recirculation Inlet Nozzle Safe End Replacement, Duane Arnold Nuclear Plant, 1978.

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4. [Not Used].

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

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

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

17. General Electric Company, Duane Arnold Energy Center SAFER/GESTR-LOCA Loss of Coolant Accident Analysis, Engineering Report, GENE-637-034-1093, October 1993.

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

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

21. [Not Used.]

22. General Electric Report, Safety Analysis Report for Duane Arnold Energy Center Extended Power Uprate, NEDC-32980P, May 2001.

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Table 5.4-1

Sheet 1 of 2

DESIGN CHARACTERISTICS OF THE REACTOR RECIRCULATION SYSTEM

Parameter	Value
External loops	
Number of loops	2
Pipe sizes (nominal outside diameter), in.	
Pump suction	22
Pump discharge	22
Discharge manifold	16
Recirculation inlet line	10
Design pressure, psig/design temperature, °F	
Suction piping	1150/562
Discharge piping	1325/562
Pumps	1500/575
Operation at warranted conditions[b, c]	
Recirculation pump	
Flow, gpm	28,800 (28,035) [29,410]
Flow. lb/hr	11.05×10^6 (10.61×10^6) [11.12×10^6]
Total developed head, ft	520 (527) [580]
Suction pressure (static), psig	1030 (1039) [1038]
Available NPSH[a] (minimum), ft	350 (464) [440]
Water temperature, °F	522 (532) [533]

[a] Includes velocity head.
[b] Extended Power Uprate values in parentheses.
[c] Increased Core Flow (105%) values in brackets [ ].

Table 5.4-1

DESIGN CHARACTERISTICS OF THE REACTOR RECIRCULATION SYSTEM

Parameter	Value
Pump motor output (minimum), HP	3180 (3365) [3979]
Flow velocity at pump suction, fps	30.2 (29.4) [30.8]
Drive motor and power supply	
Frequency of (at warranted), Hz	56
Frequency (operating range), Hz	11.5 to 57.5
Total required power to M-G sets	
kW/set	3120 (3100) [3494]
kW total	6240 (6200) [6988]
Jet pumps	
Number	16
Total jet pump flow, lb/hr	49.0×10^6 [51.5×10^6]
Throat inside diameter, in.	6.1
Diffuser inside diameter, in.	14.0
Nozzle inside diameter, in. (representative)	2.95
Diffuser exit velocity, fps	17.4
Jet pump head, ft	82.2

Table 5.4-2

MAIN STEAM ISOLATION VALVE DESIGN SPECIFICATIONS

Parameter	Normal	Emergency[a]	
		A	B
Temperature	150°F maximum	340°F maximum	340°F maximum
Pressure	0 to 2 psig	-2 to 56 psig	-2 to 35 psig maximum
Relative humidity	100%	100%	100%
Duration	Continuous	45 sec	1 hr

[a] Total duration is the sum of the separate durations.

Table 5.4-3

PUMP DESIGN DATA OF THE RCIC SYSTEM TURBINE

Parameter	Value
Pump	
Number required	1
Capacity, %	100
Design temperature, °F	40 to 140
Design pressure, psig	1500
NPSH (minimum), ft	20
Developed head, ft	
At 1135 psia reactor pressure	2800
At 165 psia reactor pressure	525
Flow rate, gpm	
Injection flow	400
Cooling water flow	16
Total pump discharge	416
Turbine	
Number required	1
Capacity, %	500
Steam inlet pressure (saturated), psia	150 to 1120
Turbine exhaust pressure, psia	15 to 64

Table 5.4-4

DESIGN DATA OF THE RHR SYSTEM EQUIPMENT*	
Parameter	Value
Main system pumps	
Number required	4
Capacity per pump, %	33-1/3
Design temperature, °F	360
Design pressure, psig	450
Design conditions per pump at 20 psid	
Discharge flow, gpm	4800
Discharge head, ft	360
Operating conditions per pump	
Discharge flow, gpm	0-5700
Discharge head, ft	750-120
Differential pressure, psid	295-0
Number required	2
Shell-side fluid	Reactor water
Tube-side fluid	Service water
Design pressure, psig	450
Design temperature, °F	40 to 400
Pressure drop at design condition, shell and tube sides, psi	10
Design conditions	
Shell-side flow, gpm	4800
Inlet temperature, shell side, °F	125
Heat exchanger duty, Btu/hr	20.1×10^6
RHR Service Water Temperature	85ºF
RHR Heat Exchange K-Factor per Loop in Containment Cooling Mode	142 Btu/sec-ºF
RHR Heat Exchanger K-Factor per Loop during the Loss of Offsite Power Event	135 Btu/sec-ºF
Key: psid = pound per square inch difference between reactor vessel and drywell	

*See Chapter 15.0 for values of parameters used in accident analyses.

Table 5.4-5

CORE SPRAY AND RHR SYSTEM CONTAINMENT ISOLATION VALVES AND ASSOCIATED PRESSURE PROTECTION DESIGN FEATURES

Line Number (high/low pressure)	Check Valve Number (inside containment)	MOV Numbers (outside containment) [a]	Pressure Relief Valve Number [b]	Pressure Switch Used to Detect Leakage [c]
		Core Spray System		
8”-DLA-7 8”-EBB-17/ 10”-GBB-13	V-21-72	MO-2117 MO-2115	PSV-2109	PS-2116
8”-DLA-8 8”-EBB-18/ 10”-GBB-14	V-21-73	MO-2137 MO-2135	PSV-2129	PS-2136
		RHR System		
20”-DLA-5 20”-DBB-1/ 20”-GBB-4	V-20-82	MO-2003 MO-2004	PSV-2057	PS-2040A PS-2040B
20”-DLA-6 20”-DBB-2/ 20”-GBB-3	V-19-149	MO-1905 MO-1904	PSV-1975	PS-1955A PS-1955B

Key: MOV = motor operated valve

[a] All motor-operated valves are located outside containment on the high pressure 600-psig or 900 psig piping.

[b] All pressure relief valves are located on the low-pressure 300-psig piping upstream of the containment isolation valves.

[c] All pressure switches are located on the low-pressure piping upstream of the motor-operated valves. Annuniciators are provided on control room panel 1C03 to indicate high pump discharge pressure.

Table 5.4-6

DESIGN DATA OF THE RWCU SYSTEM EQUIPMENT

Main cleanup recirculation pumps

Number	2
Capacity (each), %	107 (at rated pump speed)
Flow rate (each), lb/hr	83,000 (at ~93% rated pump speed)
Design temperature, °F	564
Design pressure, psig	1400

Heat Exchangers

	Regenerative	Non-Regenerative
Reactor coolant flow rate, lb/hr	83,000	83,000
Shell-side design pressure, psig	1,400	150
Shell-side design temperature, °F	564	370
Tube-side design pressure, psig	1,400	1,400
Tube-side design temperature, °F	564	564

Filter-Demineralizers

Number required	2
Capacity (each), %	50
Flow rate (each), lb/hr	41,500
Effluent conductivity, μmho max.	0.1
Effluent pH	6.5 to 7.5
Effluent insoluble, ppb, measured as residue on 0.45-μm filter paper	10
Design temperature, °F	150
Design pressure, psig	1400

Table 5.4-7

COMPONENT SUPPORT DESIGN CRITERIA

Ambient Conditions

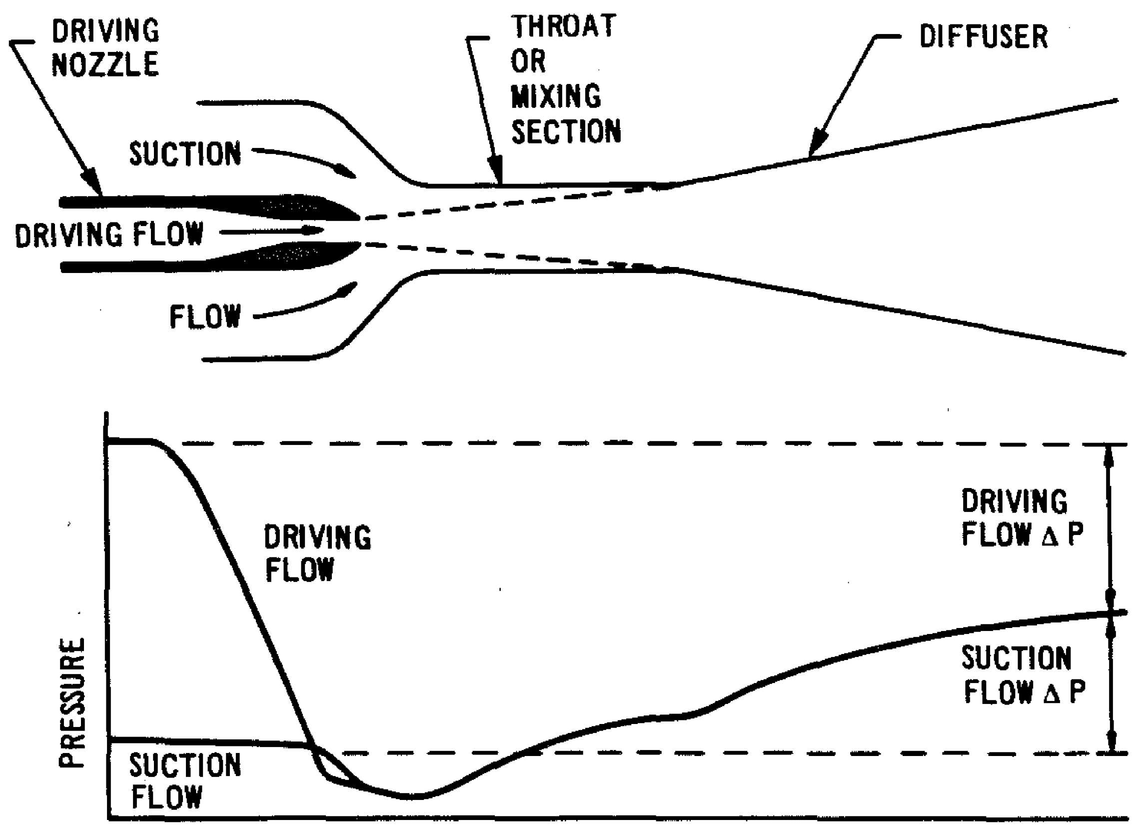
Temperature	70°F (before initial startup) 135°F normal/150°F maximum during operation and shutdown
Relative humidity	40% (during operation) 95% (during shutdown)
Relation	100 R/hr (3.5×10^7 R/40 yr)

Load Combinations	Primary Membrane Stress Limits
weight + thermal expansion + OBE	S[a]
weight + thermal expansion + DBE	$0.9\ S_y$
weight + thermal expansion + DBE + pipe rupture	

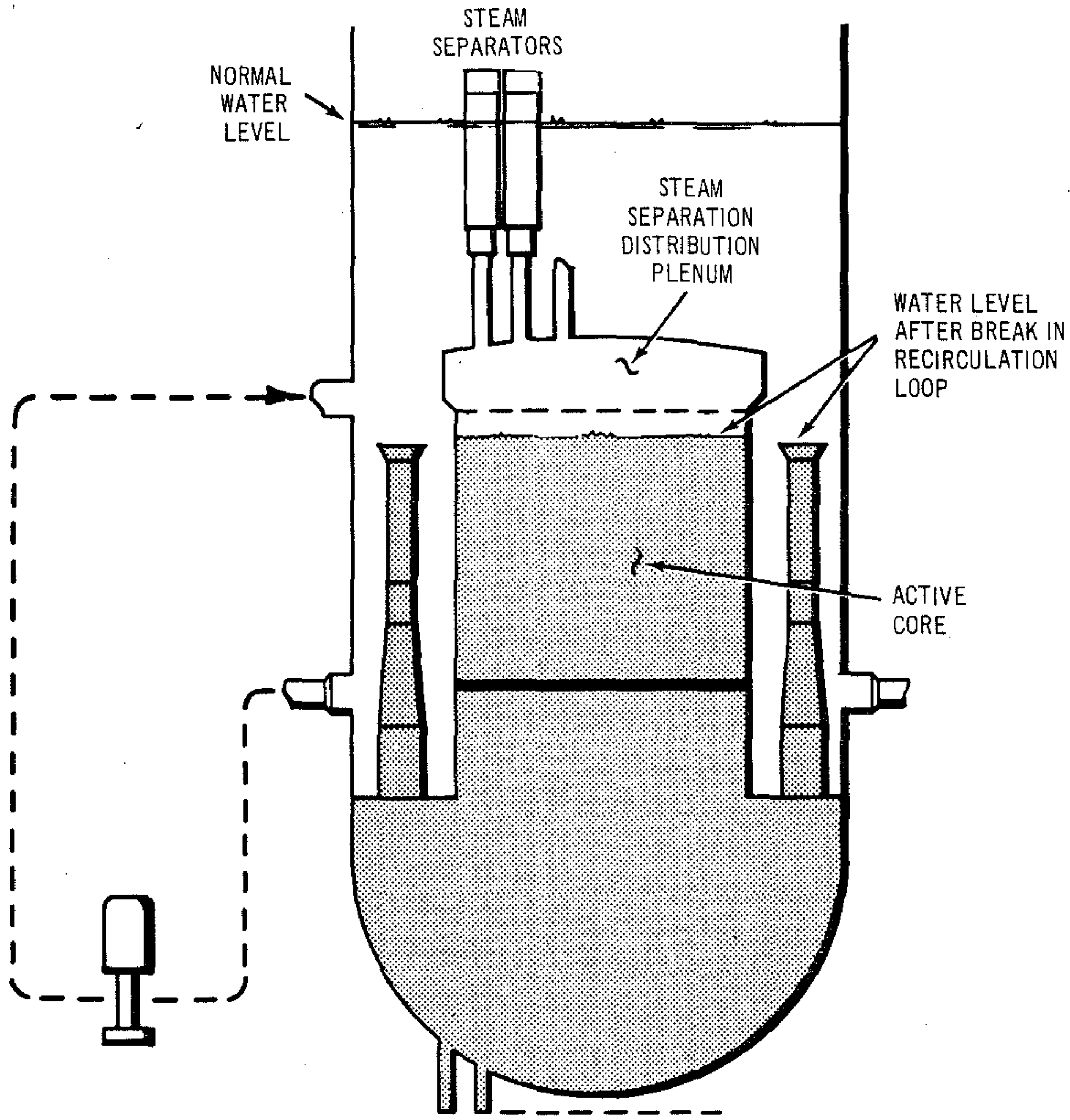
Key: OBE = operating-basis earthquake
DBE = design-basis earthquake
[a] (S is allowable stress for material under consideration as specified in SP-58)

[redacted]

[redacted]



DUANE ARNOLD ENERGY CENTER IOWA ELECTRIC LIGHT & POWER COMPANY UPDATED FINAL SAFETY ANALYSIS REPORT
Jet Pump - Operating Principle Figure 5.4-5



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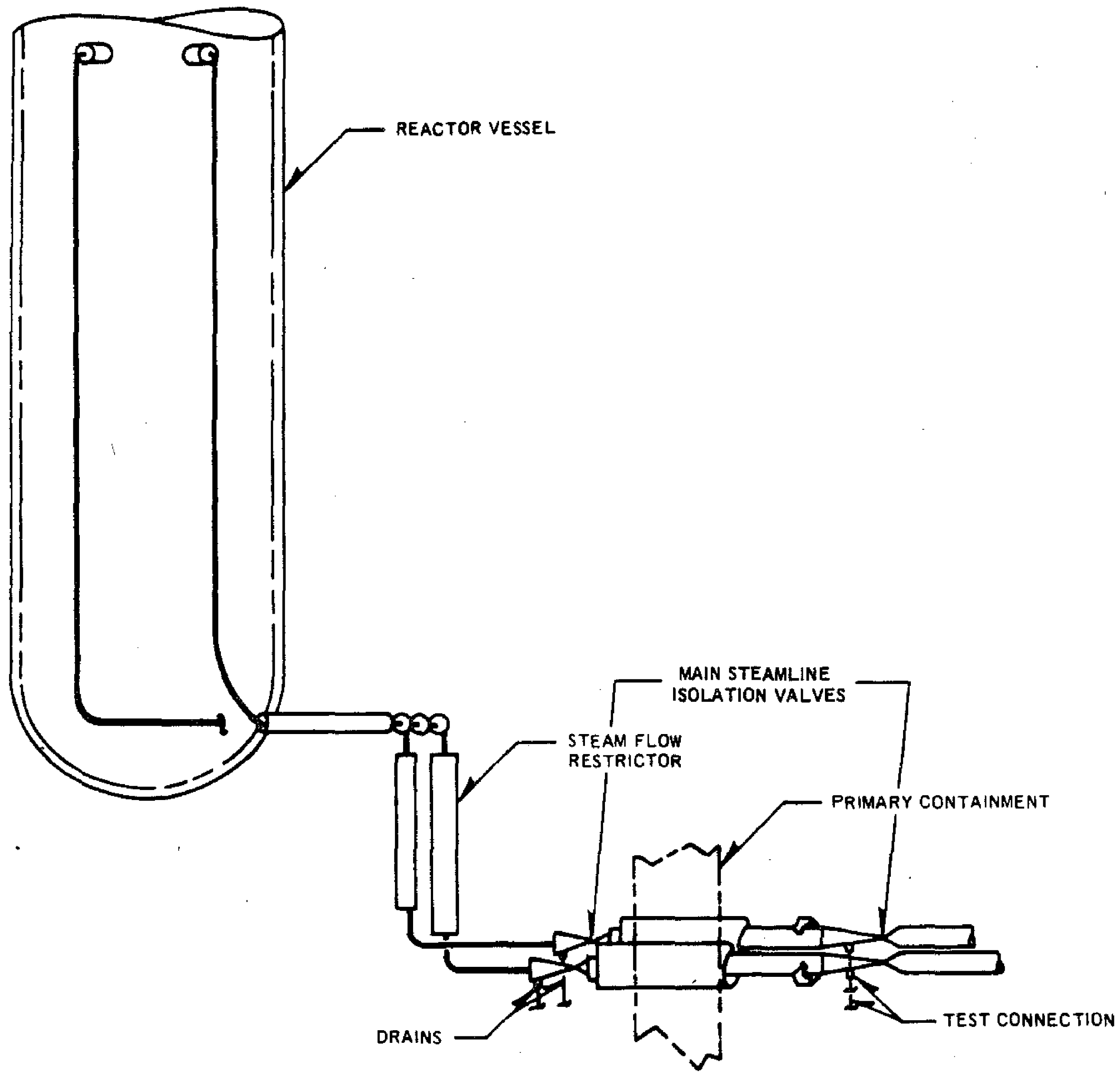
Recirculation System Core Flooding Capability

Figure 5.4-6



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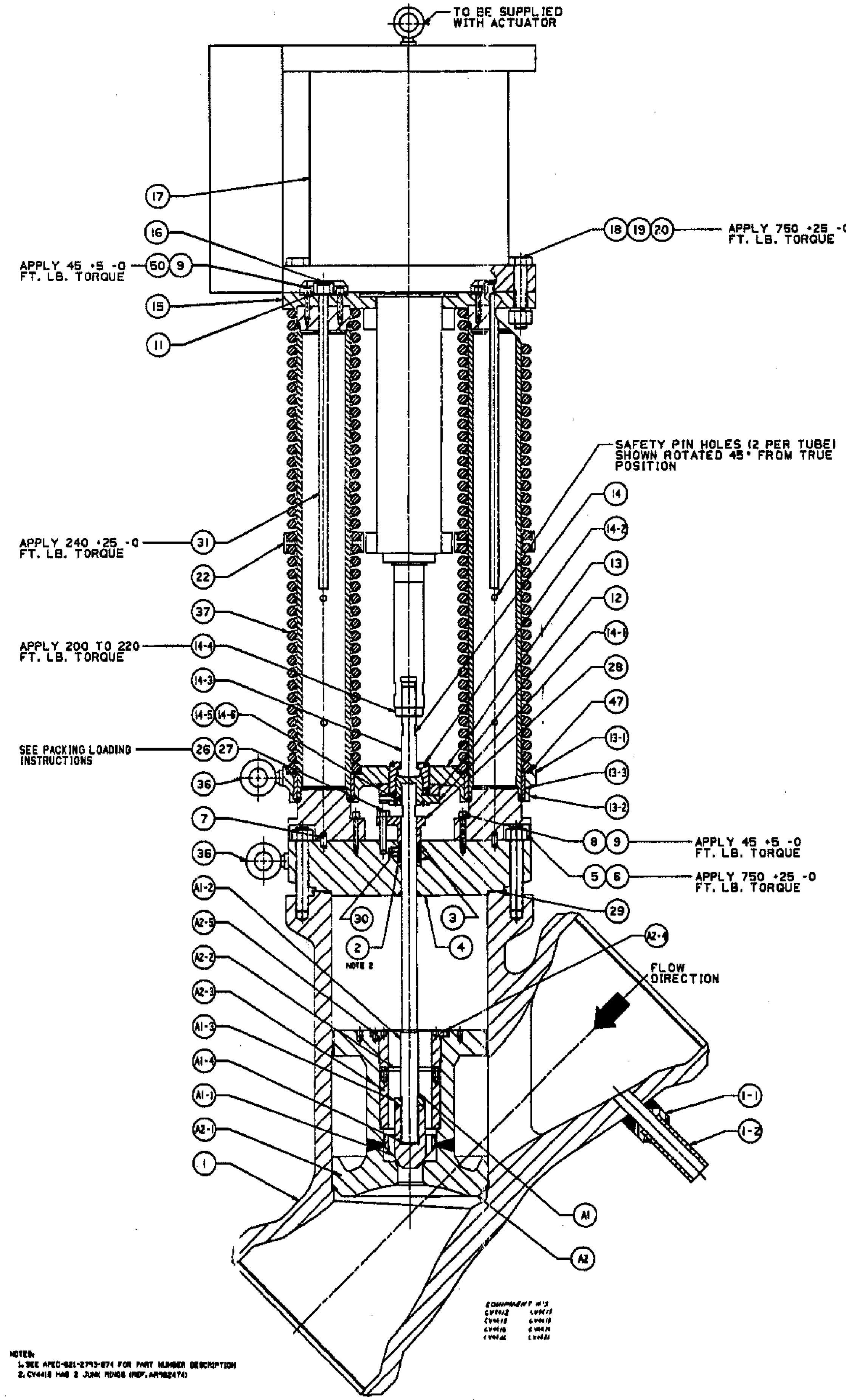
Main Steam Line Flow
Restrictor Location

Figure 5.4-7



NOTES:
1. SEE APED-B21-2793-074 FOR PART NUMBER DESCRIPTION
2. CV4418 HAS 2 JUNK RINGS (REF. AR962474)

D	1985-3	6	01/26/90	BR 02-20-90	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
C	1985-2	3	01/25/90	BR 01-29-90	SLA 02-08-90	RB 02-08-90	SLA 02-08-90	SLA 02-08-90	RDN 02-08-90	RLB 02-08-90
B	1985-1	1	10/25/89	BR 11-27-89	BR 11-28-89	WAR 11-28-89	SLA 11-28-89	SLA 11-28-89	RDN 11-28-89	RLB 11-28-89
A	1985	1	10/25/89	BR 11-21-89	BR 11-22-89	WAR 11-22-89	SLA 11-22-89	SLA 10-31-89	RDN 11-22-89	RLB 11-22-89
0	——	0	9-28-89	BR 10-26-89	BR 10-30-89	WAR 10-30-89	SLA 10-31-89	SLA 10-31-89	RDN 10-31-89	RLB 10-31-89
REV	ADCN NO.	DW REV	B/M DATE	DWN / DATE	CHK'D / DATE	APV'D / DATE	PROJ ENG/DATE	ENG SUPV/DATE	P.E. MGR/DATE	Q.A. MGR/DATE

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MAIN STEAM LINE ISOLATION VALVE

FIGURE 5.4-8

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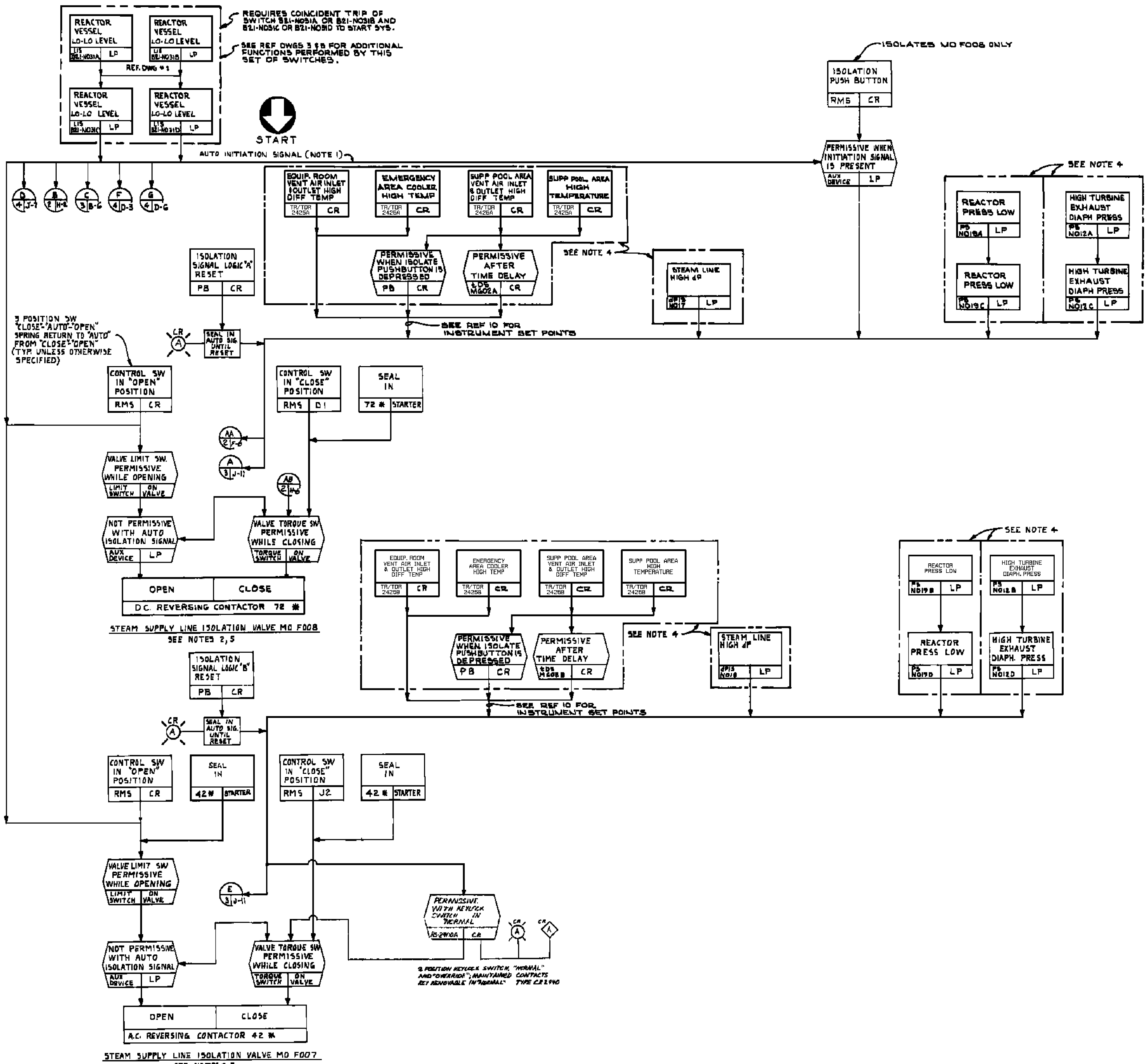
[redacted]



F.C.F. 238X121CA (DUANE ARNOLD) E51-1030

DUANE ARNOLD
MPL# E51-1030

NOTES:

1. THE RCIC SYS IS ARRANGED FOR TEST OF PUMP AT FULL FLOW & ALL VALVES FOR OPEN & CLOSE CAPABILITY AT ANY TIME EXCEPT WHEN INITIATION SIGNAL OR AUTO ISOLATION SIGNAL IS ACTIVATED. IN EVENT THE INITIATION SIGNAL OCCURS WHILE TEST IS UNDERWAY THE SYSTEM AUTOMATICALLY RETURNS TO STARTUP MODE.
2. ALL POWER FOR OPERATION OF D.C.VALVE MOTORS SHALL ORIGINATE FROM A PLANT D.C. BUS. POWER FOR AC OPERATED VALVES SHALL ORIGINATE FROM AN EMERGENCY A.C. BUS.
3. ALL EQUIPMENT & INSTRUMENT PREFIXED BY SYSTEM NO. (E51) UNLESS OTHERWISE NOTED.
4. ISOLATION SIGNAL SWITCHES SHALL BE OF THE TYPE THAT CLOSE CONTACTS FOR THE SPECIFIED ISOLATION EVENT. WHERE AUXILIARY RELAYS ARE USED IN THE ISOLATION CHANNELS THEY SHALL BE POWERED FROM THE STATION BATTERIES.
5. AUXILIARY RELAYS & DEVICES NOT SHOWN ON FUNCTIONAL CONTROL DIAGRAMS EXCEPT WHERE REQUIRED TO CLARIFY FUNCTION.
6.
7. FURNISHED WITH TURBINE.
8. AN ALTERNATE SOURCE OF EMERGENCY AC POWER SHALL BE PROVIDED TO THE INSIDE ISOLATION VALVE MO-F007 (SEE REF 1).
9. THE RCIC SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH "PROPOSED CRITERIA FOR NUCLEAR POWER PLANT PROTECTION SYSTEM IEEE - 279", INSOFAR AS PRACTICABLE.
10. ALL MOTORS SHALL BE PROTECTED BY THERMAL OVER-LOAD TRIPS AND BREAKER SHORT CIRCUIT CURRENT PROTECTIVE TRIPS.
11. REMOTE SHUTDOWN
12.) INDICATING LIGHTS AT RSP SHALL INDICATE VALVE POSITION WHEN TRANSFER SWITCH IS IN EMERGENCY OPERATION AND AT THIS TIME THE CR LIGHTS WILL NOT FUNCTION. THIS IS TYPICAL FOR MO-F045 (MO-2404).

REFERENCE DOCUMENTS:	MPL ITEM NO.
1. NUCLEAR BOILER P&ID	B21-1010
2. NUCLEAR BOILER MISC SYS FCD	B21-1030
3. RHR SYSTEM FCD	E11-1030
4. CORE SPRAY SYSTEM FCD	E21-1030
5. HPCI SYSTEM FCD	E41-1030
6. RCIC SYSTEM P&ID	E51-1010
7. LOGIC SYMBOLS	A41-1030
8. TURBINE CONT SYS & ELEC WIRING	VPF-
9. REAC WATER CLEANUP SYS P&ID	G31-1010
10. LEAK DETECTION SYS	A61-4040
11. ELEC EQUIP SEPARATION FOR SAFEGUARD SYSTEM	A61-4050

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REACTOR CORE ISOLATION COOLING SYSTEM

FIGURE 5.4-11 SHEET 1

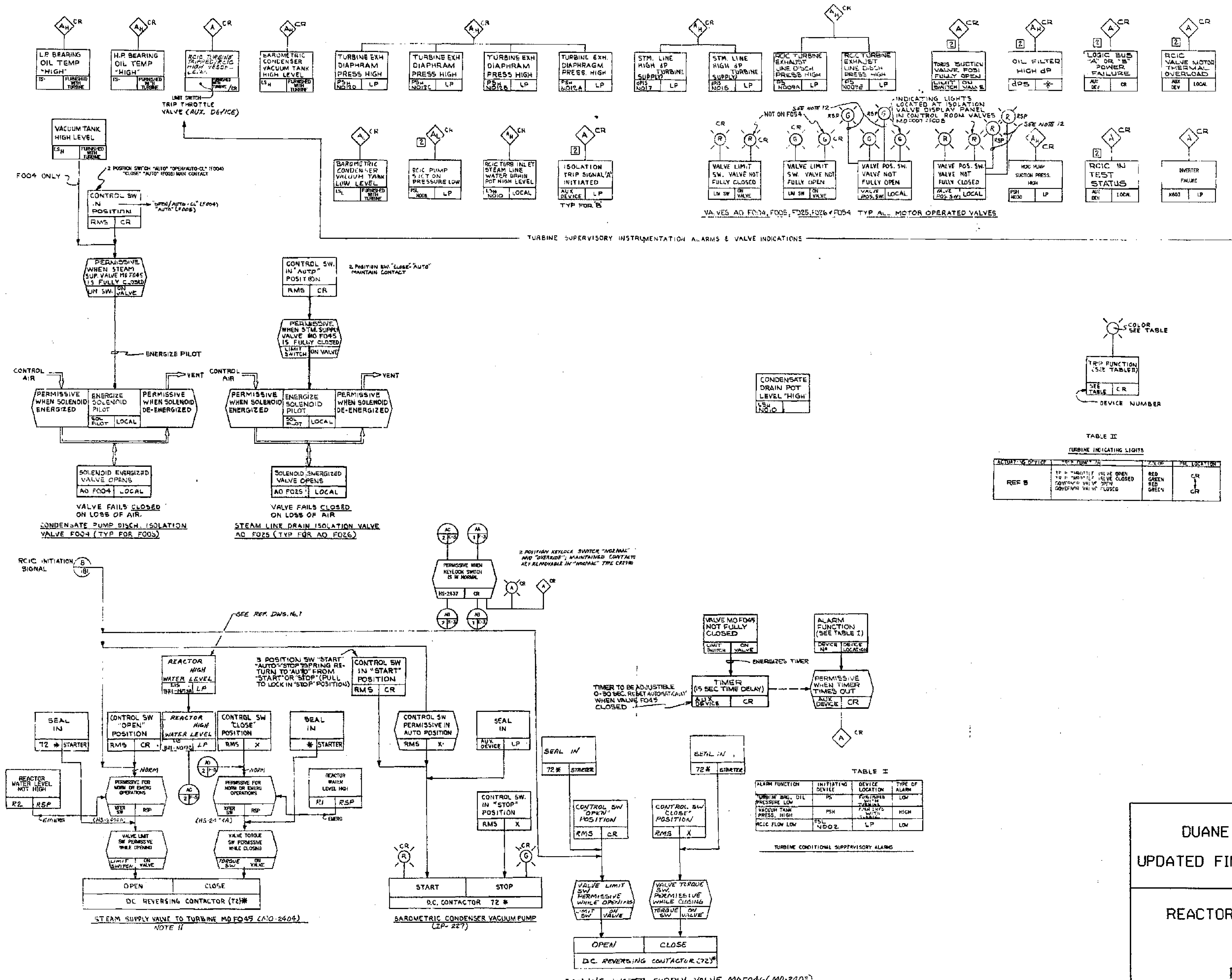

TABLE II

TURBINE INDICATING LIGHTS

ACTUATING DEVICE	TRIP FUNCTION	COLOR	PNL LOCATION
REF 8	TRIP THROTTLE VALVE OPEN TRIP THROTTLE VALVE CLOSED GOVERNOR VALVE OPEN GOVERNING VALVE CLOSED	RED GREEN RED GREEN	CR CR

TABLE I

ALARM FUNCTION	INITIATING DEVICE	DEVICE LOCATION	TYPE OF ALARM
TURBINE BRG. OIL PRESSURE LOW	PS	FURNISHED WITH TURBINE	LOW
VACUUM TANK PRESS. HIGH	PSH	FURNISHED WITH TURBINE	HIGH
RCIC FLOW LOW	FSL N002	LP	LOW

TURBINE CONDITIONAL SUPPERVISORY ALARMS

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REACTOR CORE ISOLATION COOLING SYSTEM

FIGURE 5.4-11 SH. 2

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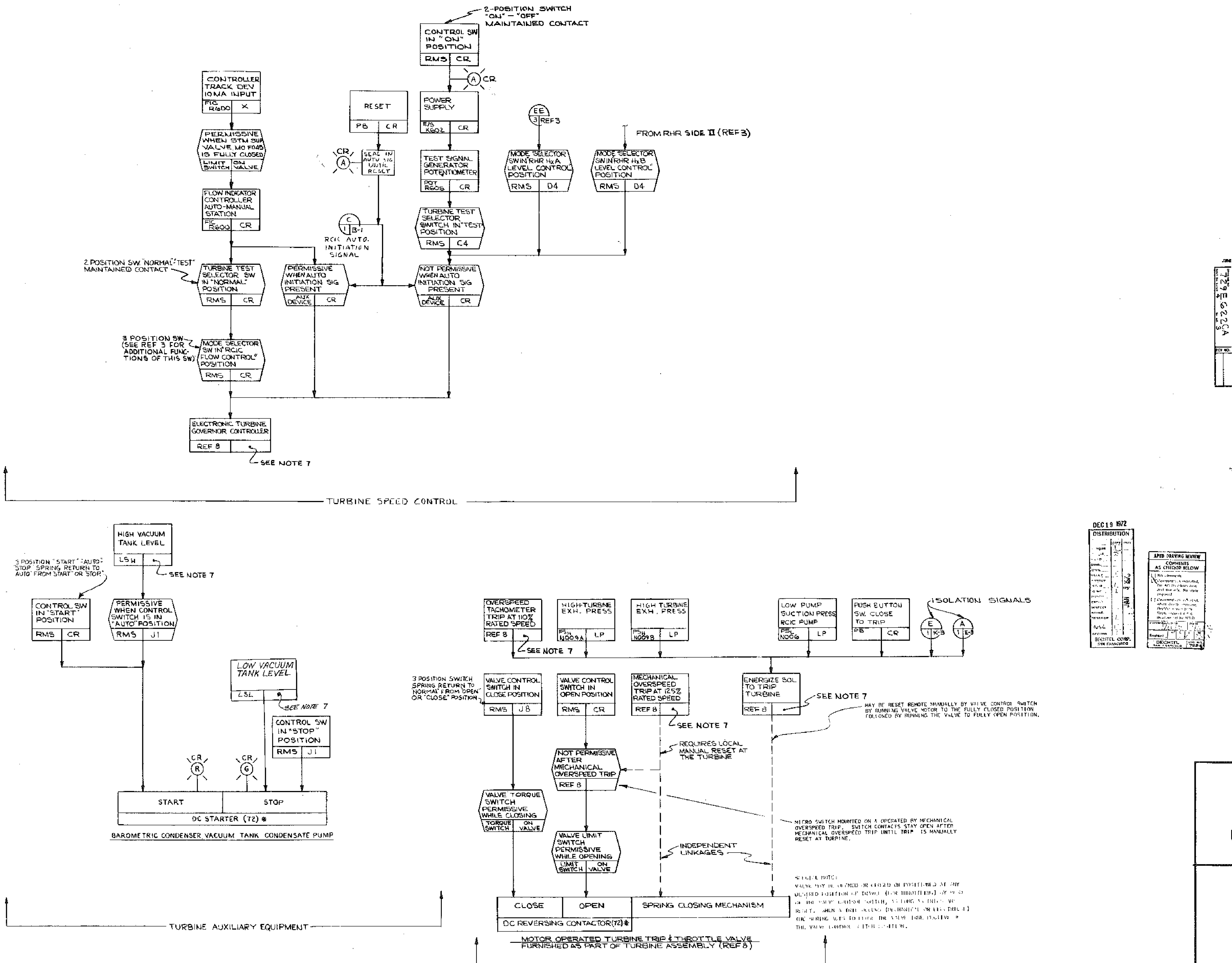

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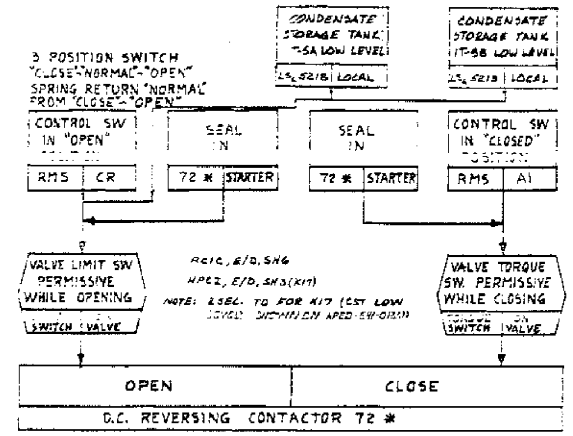
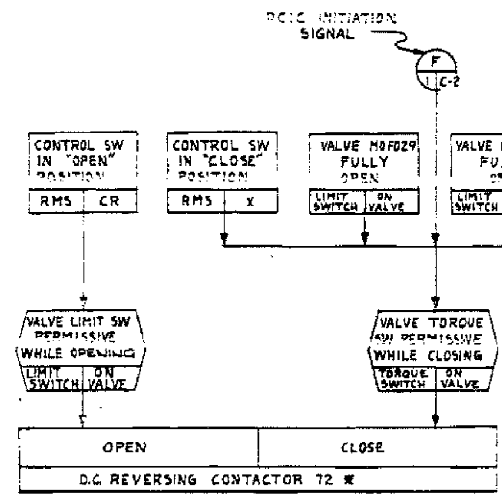
FCD, Reactor Core Isolation Cooling System

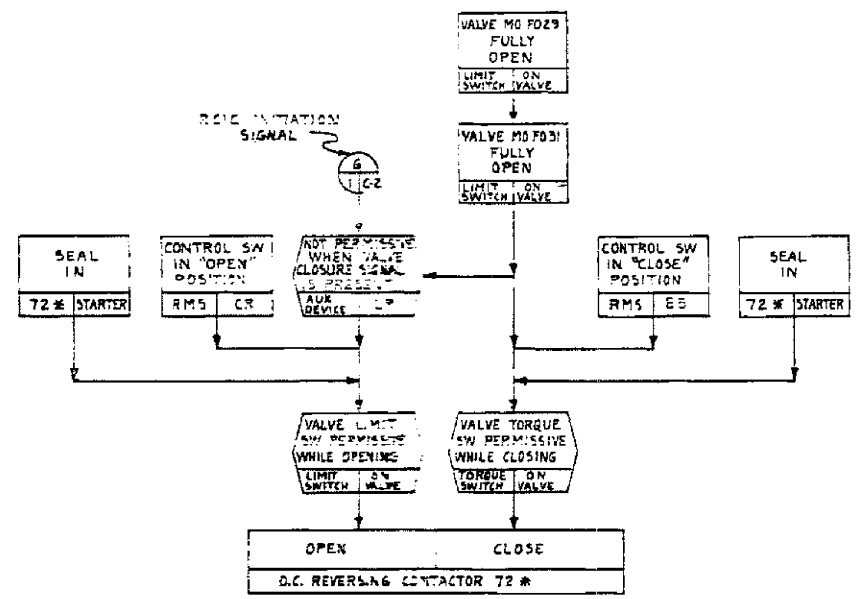
Figure 5.4-11, Sheet 3



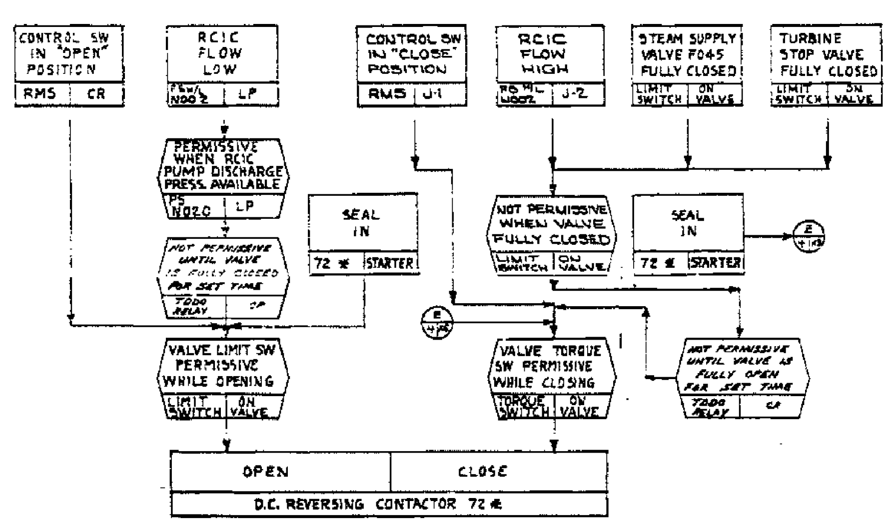
PUMP SUCTION FROM SUPPRESSION CHAMBER VALVE MO F029
(TYP FOR VALVE MO F031) NOTE 5



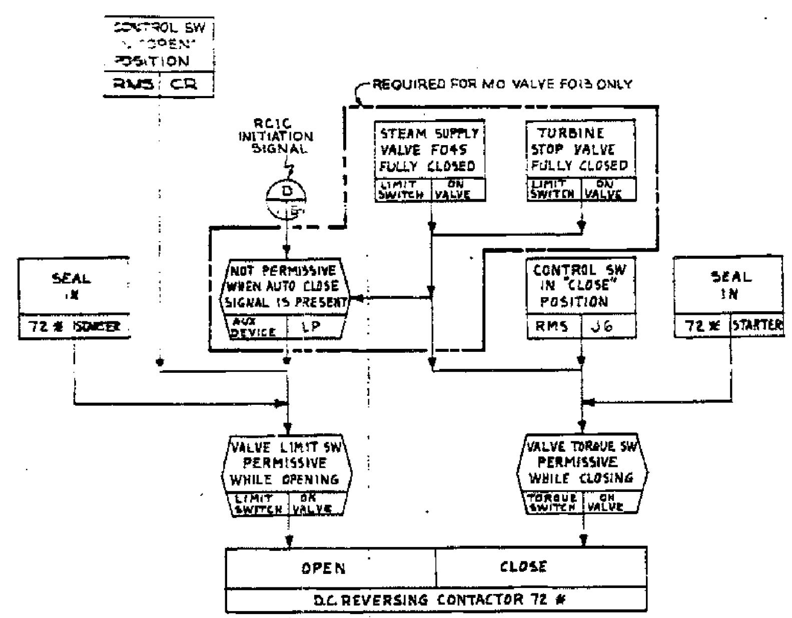
VALVE MO F022 TEST BYPASS TO CONDENSATE STORAGE TANK
(THROTTLING TYPE VALVE) NOTE 5



PUMP SUCTION FROM CONDENSATE STORAGE TANK VALVE MO F010
NOTE 5



MINIMUM FLOW BYPASS TO SUPPRESSION CHAMBER VALVE MO F019
NOTE 5



PUMP DISCHARGE VALVE MO F013
(TYP FOR PUMP DISCH. VALVE MO F012)
NOTE 5

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REACTOR CORE ISOLATION COOLING SYSTEM

FIGURE 5.4-11 SH. 4

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						X	X	X	X	X	X	X	X	X	X	X	X	X	14.7		X	X
TEMP° F	—	125	←					→	125	116.6	←							→	116.6	—		85	93.4
MAX PRESS DROP-FEET	←					.TDH=	365.		.ΔP=	25.2.										→		.ΔP=	17.3.

DUTY PER HX 20.1 × 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					X	X	X	X	X	X	X	X	X	X	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	—	9,600	9,600	9,600	4,800	4,800	9,600	←						→	9600	—
PRESS-PSIA	14.7	X	X	X	X	X	X	X	X	X	X					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	X	X	X	X	X			X	14.7		14.7							X	14.7
TEMP° F	—	358	←					→	358	—		—	125	←				→	125	—
MAX PRESS DROP-FEET	←					.SOH=	575/690			→		←				.SOH=	575/690			→

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	4,800	←	→	4800	14,400	←		→	14,400	—
PRESS-PSIA	14.7	X	X	X	X	X	X	X																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	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	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	—	7,200	7,200	7,200	3,600	3,600	7,200	←					→	7,200	6,840	6,840	6,840	—	360	360	—		4,800	4,800
PRESS-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	X	X				14.7			14.7		X	X
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	←										→	4,800	4560	4560	4,560	—	240	240	—		4,800	4,800
PRESS-PSIA	19.7					X	X	X	X	X	X	X	X	X	X	X	X	19.7	X	X	19.7		X	X
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 10^6	2.4 X 10^6
PRESS-PSIA	1014.7			X	214.7	X	X	X	X	X	X				14.7		64.7		X	X
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	←										→	59.2 x 10^3		2.4 x 10^6	2.4 x 10^6
PRESS-PSIA	1014.7	X	X		214.7		X	X						64.7		X	X
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 64.2 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	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	14.7		X	X
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	9,600	4,800	←		→	4,800	<4800	<4800	4,800	4,800	9,600	9,600	9,600	9,600	9,600					—	4,800	4800
PRESS-PSIA	50	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X					50	X	X
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)

TABLE 1 - VALVE POSITION CHART

SEE NOTE 8

MODES	F004	F006	F052	F051	F047	F048	F003	F017	F015	F050	F016	F021	F028	F027	F024	F023	F022	F019	F053	F011	F054	F026	F073	F075	F078	F068	F008	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/C	C/O	C/O				T			—	—
D2			T	T															T		O	O				T			—	—
D2 (CONT'D)	O				O		O						O		T											T				
E		O			O	T-C	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	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
D2 (CONT'D)	NONE
E	19-44
F	16-38-41
G	1-2-5
H	12-22-35-26-1
J	6-48

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 - 2HX STEAM CONDENSER. (½ HR.)
D-2 REACTOR ISOLATION 1HX 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 POOL 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 WEIGHT OF WATER IN THE SHUTDOWN COOLING SUBSYSTEM PIPING, INCLUDING THE HEAT EXCHANGERS AND PUMPS, SHALL NOT EXCEED 150,000 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. FOR POINTS 24A&B AND 25A+B, THE RHRSW FLOW REQUIREMENTS WERE REDUCED FROM 2400 gpm PER PUMP TO 2040 gpm PER PUMP FOR A TOTAL OF 4080 gpm PER RHR HEAT EXCHANGER. SEE DCP 1236 AND NEDE-30051-P, ANALYSIS OF REDUCED RHR SERVICE WATER FLOW AT THE DUANE ARNOLD ENERGY CENTER.

LEGEND:

RX PRESS = REACTOR VESSEL PRESSURE

SOH = SHUTOFF HEAD

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

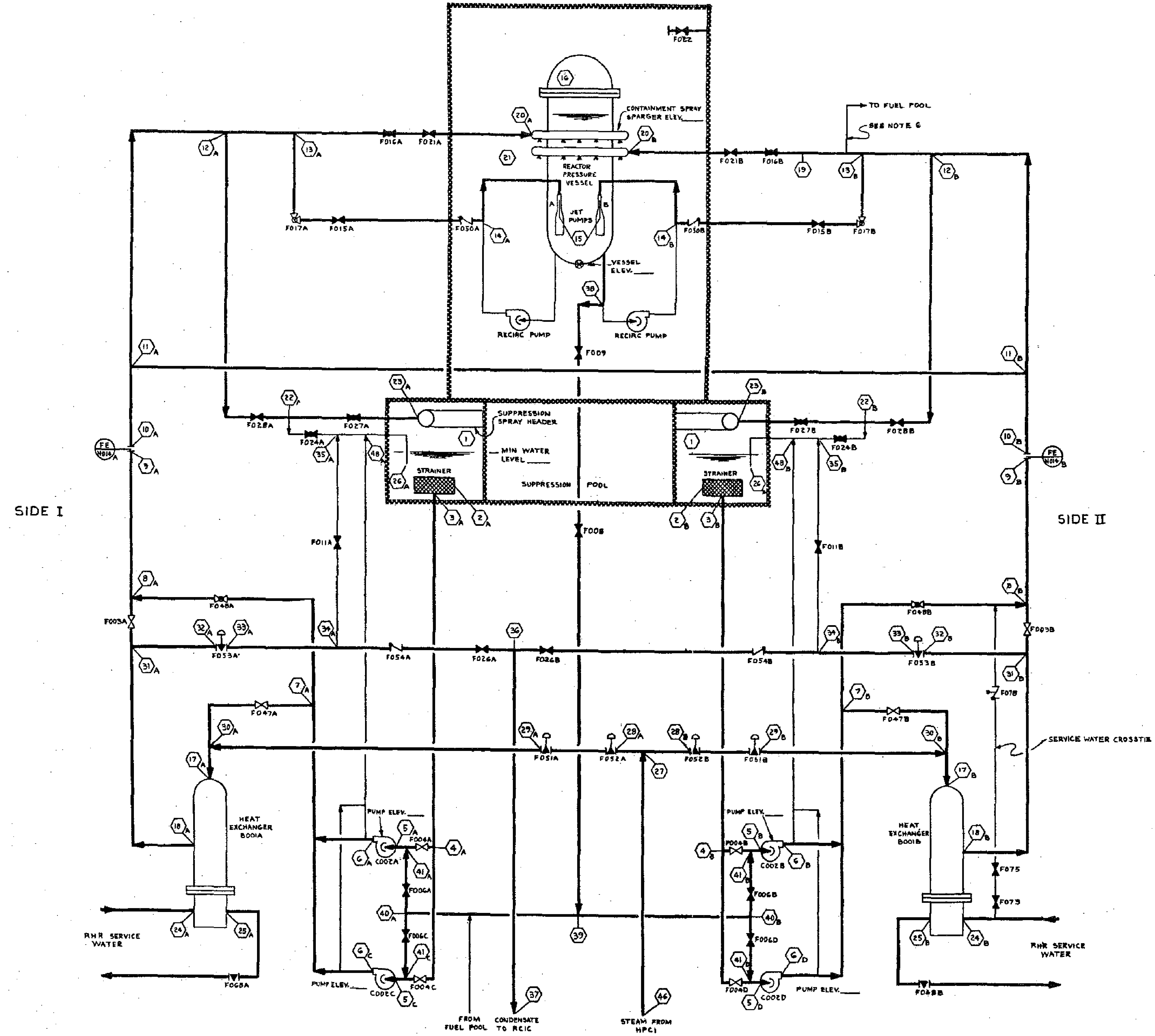
NOTES CONT'D:

15. STEAM CONDENSING REMOVED DURING CYCLE 9/10 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 1 (Rx 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.

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

RESIDUAL HEAT REMOVAL SYSTEMS, PROCESS FLOW DIAGRAM

FIGURE 5.4-12, SHEET 1



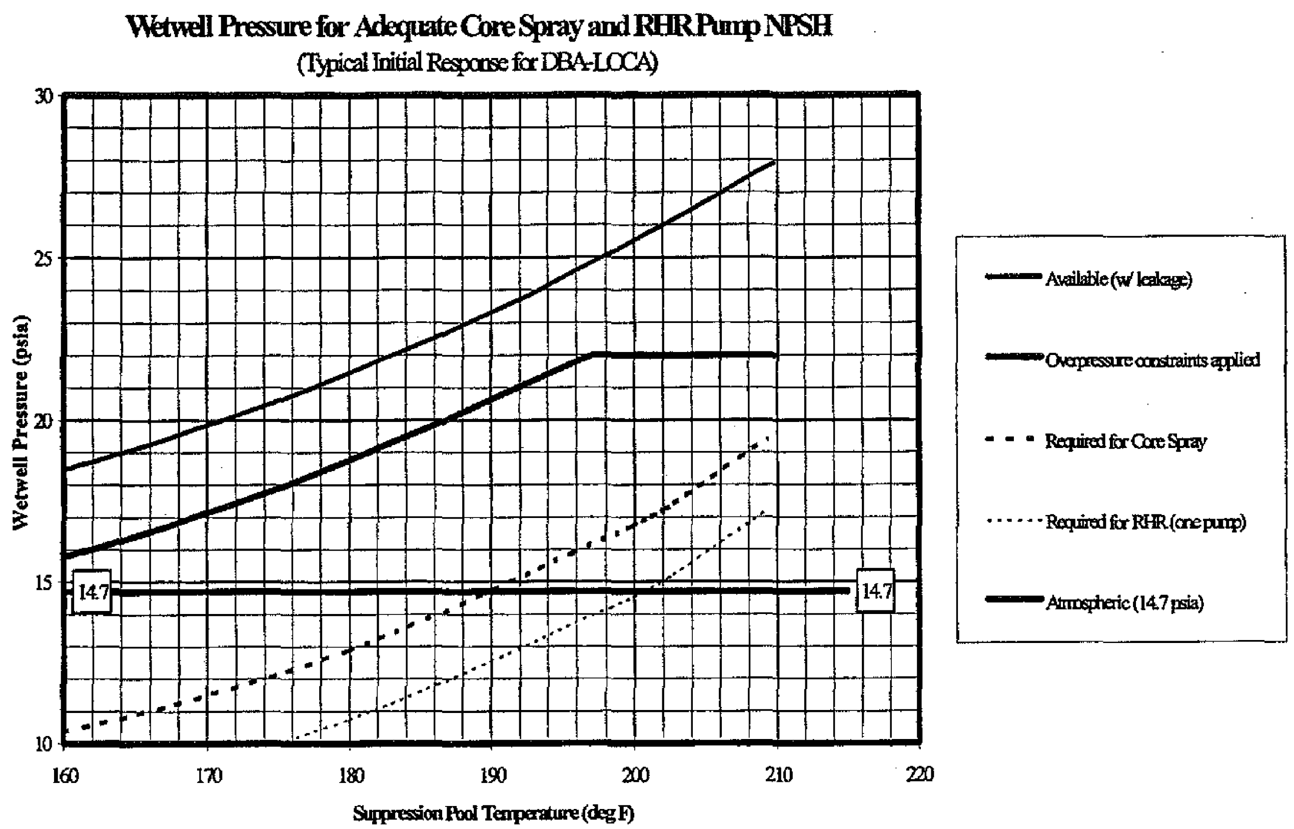
APED-E11-008<2> REV. 4

DUANE ARNOLD ENERGY CENTER
IES UTILITIES
UPDATED FINAL SAFETY ANALYSIS REPORT

RESIDUAL HEAT REMOVAL SYSTEM
PROCESS FLOW DIAGRAM

FIGURE 5.4-12 SH. 2

REVISION 17 - 10/03



NOTE: Wetwell pressure may only be credited for NPSH up to 36 hours after reactor shutdown.

DUANE ARNOLD ENERGY CENTER

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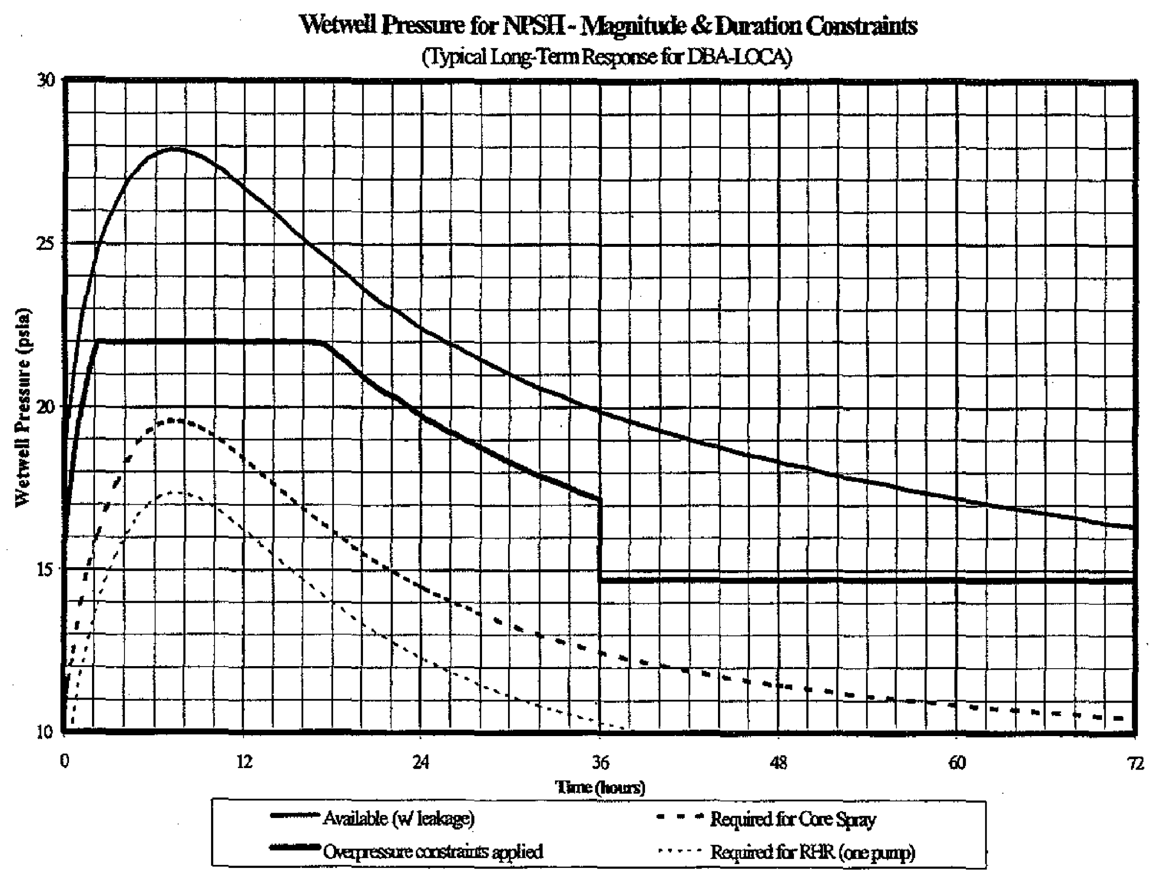
UPDATED FINAL SAFETY ANALYSIS REPORT

Licensing Basis Overpressure Allowance for Core Spray and RHR Pump NPSH (Wetwell Pressure vs. Time)

Figure 5.4-15 Sheet 1



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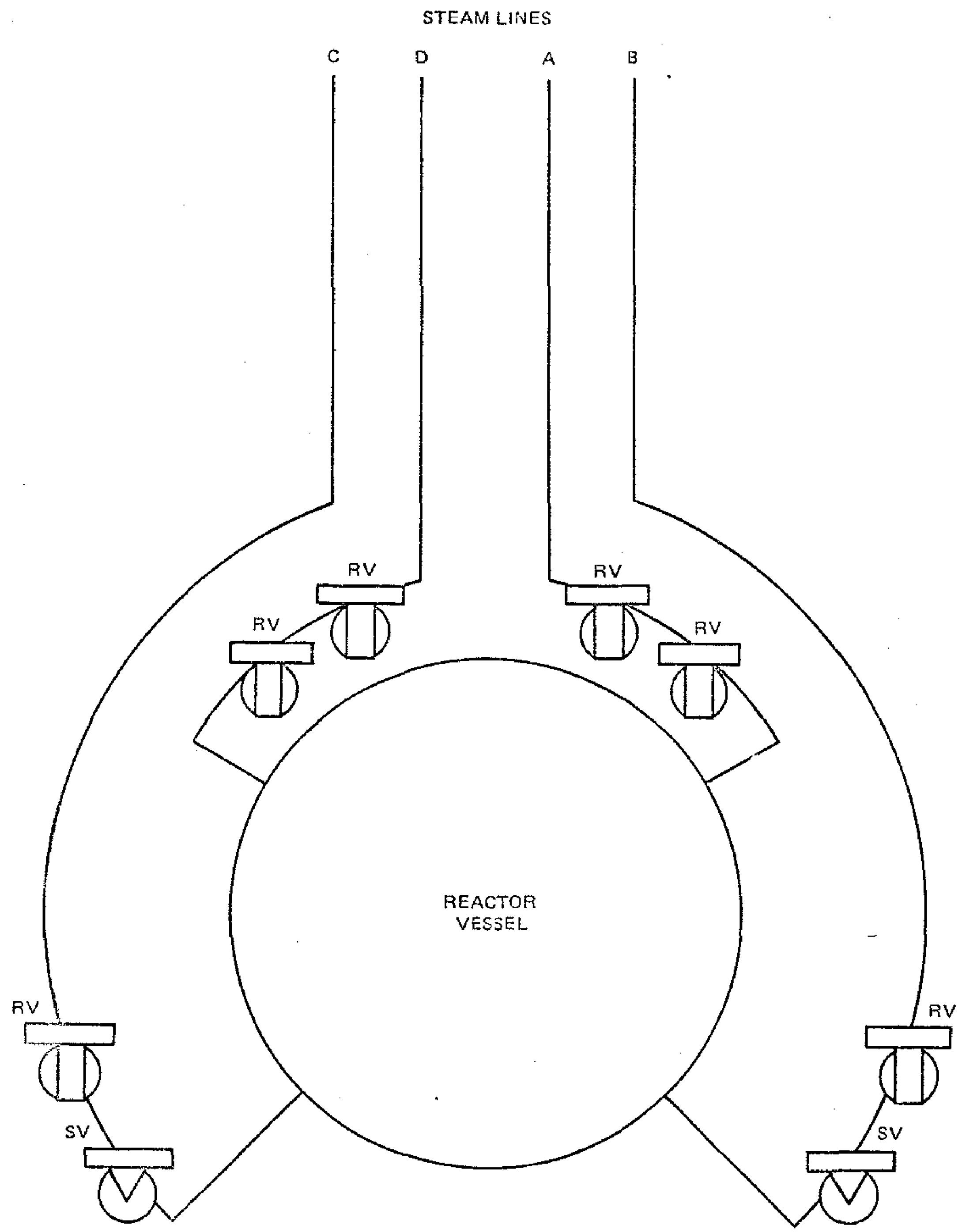
IES UTILITIES, INC.

UPDATED FINAL SAFETY ANALYSIS REPORT

Licensing Basis Overpressure Allowance for Core Spray and RHR Pump NPSH (Wetwell Pressure vs. Suppression Pool Temperature)

Figure 5.4-15 Sheet 2



DUANE ARNOLD ENERGY CENTER
IOWA ELECTRIC LIGHT & POWER COMPANY
UPDATED FINAL SAFETY ANALYSIS REPORT

Safety Relief/Safety Valve
Location Schematic Plan View

Figure 5.4-17

5A: SITE ASSEMBLY OF THE REACTOR PRESSURE VESSEL

TABLE OF CONTENTS

5A: SITE ASSEMBLY OF THE REACTOR PRESSURE VESSEL

LIST OF FIGURES

APPENDIX 5A

SITE ASSEMBLY OF THE REACTOR PRESSURE VESSEL

5A.1 SCOPE

The reactor pressure vessel is discussed in Section 5.3. That discussion covers the operational and safety requirements but does not cover the assembly of the vessel.

A feasibility study of shipping an assembled reactor pressure vessel to the Palo, Iowa, site led to the conclusion that the reactor pressure vessel should be site assembled. The site-assembled vessel for the DAEC was furnished in a manner similar to those furnished for [redacted] and the schedule of operations was similar to the ones for those vessels.

This appendix discusses the technical and safety considerations pertinent to a site-assembled reactor pressure vessel.

Site assembly of the reactor vessel involves some machining, welding, heat treatment, and testing operations at the plant site that in the past have been performed in the vendor's fabrication shop. A significant portion of the vessel was fabricated in the shop just as though the vessel were to be completely assembled and tested before shipping. Major subassemblies were assembled in the shop to the degree consistent with shipping capability, but final assembly took place at the plant site. A field shop area was established at the site to complete work on subassemblies. The complete assembly of the reactor vessel at the site was done in place. Assembly at the plant site, therefore, was a matter of setting up equipment to perform some of the operations usually performed in the vendor's shop.

Based on the experience gained in the site assembly of the [redacted] reactor pressure vessels, it was evident that site-assembled vessels can be constructed in accordance with specification requirements without compromise. The techniques and site-assembly procedures that were developed for the [redacted] vessel proved satisfactory, and modifications to these procedures were not necessary. The quality assurance and control programs functioned well on the site-assembled DAEC Unit 1 vessel.

The overall evaluation of the reactor vessel site assembly is covered in detail under the categories of design, fabrication and assembly, quality control, inspection, and testing.

Chicago Bridge & Iron Company (CB&I) fabricated the site-assembled vessel.

5A.2 DESCRIPTION

5A.2.1 GENERAL

Chicago Bridge & Iron performed the various operations of reactor vessel fabrication and assembly at the shop, the field shop set up at the site, and in place at the final reactor vessel location.

The materials for the reactor vessel were ordered, received, and inspected in routine fashion. The specifications and suppliers for these materials are the same as those used to supply materials for other reactor pressure vessels that have been fabricated by CB&I. The adequacy of the CB&I quality control has been established, and a description of the quality control program in effect for this plant can be found in Chapter 17.

The bottom head plates, shell, and top head plates were shop formed, on heavy pressing equipment. The bottom head was shop assembled from subassemblies and was shipped to the site in one piece. The bottom head was postweld heat treated, radiographed, overlay welded, and heat treated as required. The control rod housing holes were rough bored in the shop. Some of the vessel penetration nozzles in the bottom head subassembly were shop installed.

Several shell rings compose the cylindrical shell portion of the vessel. Each ring was shipped to the site in two sections. After forming, associated heat treatment, and initial sizing, the two sections of each ring were temporarily welded to permit the application of the weld overlay with automatic equipment in the shop. The temporary longitudinal weld was cut, the overlay removed from the joint, and the joint prepared and sized for final welding in the field shop area. The nozzle penetrations were installed in the ring sections in the shop as far as practicable. All radiographs and postweld heat treatments were performed as required. The top head of the vessel was fabricated in the shop and shipped to the site in one assembly similar to the bottom head configuration. The head closure flanges were shipped directly to the site as rough-machined integral ring sections.

The field shop area at the site was equipped with stress-relieving furnaces, a storeroom, a toolroom, radiographic equipment, a darkroom, preheating and welding equipment, and lifting and handling equipment. The main derrick swung over this area to pick up the reactor vessel components and set them in final position on a support skirt in the drywell structure.

The following operations were performed in the field shop area:

1. The half rings of the shell sections were welded into full rings and the cladding completed over the welds.

2. Welds were heat treated and radiographed as required; the weld overlay was applied and heat treated.

A suitable environment was made around all welding and heat-treating operations in the field shop area. Igloo-type weather enclosure structures [redacted] sites were used to protect the work from adverse weather conditions. Similarly, the welders and work on the vessel were protected in position during all welding and heat-treating operations by modular-type circular weather enclosures suitably covered with a temporary roof.

Figure 5A.2-1 illustrates a typical field stress relief of a longitudinal weld on a shell ring. Figure 5A.2-2 shows a similar setup in place on the vessel to stress relieve a girth seam weld. Indicators and controls were provided to maintain temperatures within the range of 1100 to 1175°F.

The top head flange was machined, and the stud holes were drilled in the field shop area. A temporary support skirt was attached to the head to permit these operations. The setup shown in Figure 5A.2-3, in which the work remains stationary while the machine revolves about it, was used in machining the flanges.

The drilling of the top head flange holes was done with the equipment setup that was developed for the [redacted] project similar to that shown in Figure 5A.2-4. This operation closely resembles an actual shop setup and was done, as was the machining, under a weather hood to minimize the effects of weather conditions.

The reactor vessel subassemblies were assembled in place. The bottom head and stub skirt were set in the drywell. Next, the No. 1 shell ring was hoisted into place, fitted and welded to the bottom head, back clad, and stress relieved (see Figure 5A.2-5). With the completion of welding shell ring No. 1 to the bottom head, shell ring No. 2 was hoisted into place and joined to ring No. 1 (see Figure 5A.2-6). When overlay welding and stress relief of this closure seam was completed, boring bar equipment, guide templates and ventilation equipment was installed for boring the close tolerance control rod penetration holes. The machining equipment and techniques were similar to those used for the [redacted] project. A temporary bulkhead was built to protect operations inside the reactor vessel as subsequent rings were set, welded, and stress relieved.

The vessel flange was set in place, leveled, and welded to Ring No. 4 (Figure 5A.2-7). This flange was drilled and tapped by using the same equipment under the same careful machine alignment control as was used on the head flange. Ring Nos. 3 and 4 were then set in position and welded and related operations performed.

Boring the control rod drive (CRD) penetrations in the bottom head was accomplished in a manner similar to that used for the [redacted] reactor vessels as shown in Figure 5A.2-8. The boring bar guide templates were made in a machine shop on a precision boring mill. They were attached to the bottom head and vessel support skirt and aligned for the high degree of accuracy required for these penetrations by using optical devices. Temperature-controlled ventilation equipment was used because the success of this operation was dependent

on keeping the reactor vessel shell and templates at a common temperature. The work was done by skilled personnel in an environment equivalent to, if not better than, that of the CB&I shop. After the stub tubes were installed, the machining was completed on the lower head. Chicago Bridge & Iron hydrostatic tests have been completed and the CRD housings have been installed.

There are many key operations in the previous discussion that were not detailed because of their repetitive nature and the number of variations in which they may occur. These are (1) intermediate interstage tempering after welding, (2) "final" post-weld treatment of some individual welds, and (3) the various inspection steps. These three operations were interspersed throughout the sequence as required by the ASME Code, GE, and CB& I. General Electric required that CB&I prepare a detailed fabrication sequence that met GE approval. The entire detailed fabrication procedure was reviewed by GE for proper type and sequence of operations required to achieve the built-in quality that is considered necessary for a nuclear reactor pressure vessel.

With the vessel design and quality (Chapter 17) established at the predetermined level by the ASME Code and by GE specifications, the various manufacturing operations were performed as necessary to meet those requirements whether the operations were performed in the shop, in the field shop, or in place at the final reactor vessel location. To complete the reactor vessel, a combination of both shop and site fabrication and assembly was required. The major difference between the assembly of this vessel and those assembled in the shop was the increased quantity of work performed at the site.

The construction of the reactor vessel in the field has some advantages over a shop-assembled vessel with respect to the placement of the vessel on its foundation. With the vessel being final assembled in place, the initial parts of the vessel are placed on the foundation, and the vessel is built up in its final location. Since the initial placement includes only the lower head assembly, equal loading on supports and true plumb alignment can be ensured. While true plumb alignment is not essential to reactor operation, it greatly facilitates the installation of the critical portions of the internal structure that must be carefully aligned with the CRD penetrations in the bottom head. Final boring of the CRD penetrations in place means that the attitude of the penetrations relative to plumb are controlled by a machining operation rather than as a function of the placement of the premachined penetrations of the shop-fabricated component. The use of specially fabricated fixtures to support boring apparatus above and below the vessel bottom head results in an accuracy equivalent to that associated with usual shop boring operation on a horizontal boring mill.

5A.2.2 PRACTICES

All practices for the site assembly fall into one of four acceptable categories when an apparent difference between shop practice and site assembly is scrutinized closely in context with the GE specification. These categories are as follows:

1. Practices that have been proved and used to a limited extent on shop-fabricated-and-assembled reactor primary vessels and that are intended to be used more generally on a site-assembled reactor vessel.

2. Practices that have been proved and widely used in the fabrication of other vessels and that are fully applicable for use on a reactor vessel.

3. Practices that will be conducted in the field the same as in the shop.

4. Practices that will continue to be conducted in the shop without change.

It is apparent from these categories that there are no new or novel practices required for site assembly of the reactor vessel. Furthermore, the manufacturers and distributors of plate, forgings, bar tubular products, and bolting and welding materials for vessel components for both shop and field are all selected from the same group of qualified vendors. The purchase specifications for the reactor vessel material are approved by GE as has always been the practice.

5A.2.3 FORMING AND FABRICATION OPERATIONS

The forming of the vessel components was done in the shop because the heavy equipment involved in forming the shell and head components virtually dictated this approach. The vessel was fabricated from high-strength, low-alloy materials that were heat treated at high temperatures above 1500°F to austenitize and then quenched in water. Because of the requirement for a high- temperature furnace (over 1500°F) and for large water-quenching facilities, the availability of the process equipment favors the high-temperature heat treatment being performed either at the mill or in the shop. The material for the DAEC reactor vessel was high-temperature heat treated at the mill. The material was preheated at the shop to 800°F and formed while at temperatures in the range of 400 to 800°F. After the material was formed and welded in the shop, low-temperature postweld heat treatment and intermediate-temperature postweld heat treatment at temperatures up to 1175°F were performed. Low-temperature postweld heat treatment and intermediate-temperature postweld heat treatment were also performed in the field after joining the vessel components. The only difference in postweld heat treatment between the shop and site-assembled reactor vessel is that more local postweld heat cycles may be expected in the field than are used in the shop. Local postweld heat treatment has been used in the shop and field where facilities and size limitations have required doing so. The ASME Code, Section III specifically permits local postweld heat treatment, and since both the code and GE have well-developed standards that do not change between shop and field, no change in quality level occurs as a result of the increased number of local postweld heat treatments.

Local postweld heat treatment consists essentially of heating a circumferential band of the vessel that encompasses the weld joints being postweld heat treated. The permissible temperatures, times, and rates are the same for both local and total postweld heat treatment. The difference between local and total postweld heat treatment is the presence of a thermal gradient between the heated band and the cold section. General Electric standards for an acceptable local

postweld heat-treatment procedure are based on the fabricator providing a detailed written plan that pays particular attention to (1) the type of furnace, furnace controls, and insulation to provide an inherently stable operation that is easily controlled; (2) operating procedures, heating and cooling rates, and temperature gradients in all directions to meet code requirements and to meet GE requirements for the control of thermal stresses to avoid warpage and distortion; and (3) sufficient instrumentation of proper type, quality, and location to measure accurately the progress and acceptability of the operation within the specified tolerances.

Total postweld treatment of some subcomponents at the site was done. A furnace was built in the field shop area that differed in shape from a shop furnace but met all the functional and technical requirements of a shop furnace (Figure 5A.2-9). This technique has been used in the field on other types of vessels and on the reactor vessels for the [redacted] power stations. The methods and techniques of postweld heat treatment of the site-assembled vessel therefore represent nothing unique in pressure vessel construction and have been used by pressure vessel vendors for many years.

The welding and weld cladding of the vessel was performed with conventional processes involving conventional, manual, and automatic welding equipment. The major differences between shop and site welding consist of the following:

1. Possible variations in the experience of field welders. This factor is potentially encountered with any new vessel fabricator and was controlled by instruction, practice, performance qualification tests, supervision, and inspection so that the development of experience was obtained while maintaining an adequate quality level. It should be noted that most of the welders working on the DAEC vessel at the site had prior field experience on other BWR nuclear reactor pressure vessels.

2. More manual welding "out of position," that is, other than the flat welding position. This is a matter of degree since some major parts of all reactor vessels are manually welded out of position. Out-of-position welding was minimized where practical, but where not practical, the welding procedures and joint designs and field supervision were of a nature that provide good quality welds.

3. The shop and the site have different methods of protection from the weather; however, the equivalent of shop conditions was provided in the field where required, at least in localized work areas. The weather protection for the site-assembled reactor vessel weldment was more elaborate than normally provided for field welding where preheat and postweld heat treatment requirements may have been less stringent.

4. The field storage, drying facilities, and handling of coated electrodes and submerged arc welding flux were equal to shop facilities in the control of the moisture content of the welding material. Field practice is well developed in this regard.

All welding was performed by ASME Code qualified boilermakers, qualified by CB&I. Longitudinal seams were welded manually with the metallic shielded arc process. Head plate

seams and closure welds in position on the vessel were hand welded, using the metallic shielded arc process.

Any required machining of penetrations and mating surfaces in the field was performed by built-up boring equipment that attaches to the vessel and that is guided by accurately machined templates in contrast to the huge boring mills usually associated with large shop equipment in which the work is brought to the machine. This approach to machining is not new in reactor vessel construction and has been used in the past on other vessels, including the vessel supplied for the [redacted] power station. It has been demonstrated as an acceptable method for construction of larger vessels. Portable, built-up boring equipment has also been used extensively in shipyard construction for machining gun turrets. The tolerances obtainable with this approach to machining depend on the method of attaching the tooling to the vessel, the accuracy of the templates, the flexure of the boring arm, the tool characteristics, the skill of the machinist, the accuracy of the reference point, and the effect of subsequent operations. Most of the effect of this approach to machining was handled by good tooling design. The major difference between shop and site construction is that (1) machinist skill is provided in the field and (2) site sequence and accessibility for short, inflexible boring arms and equal tool pressure may require a shift in tolerances from one location to another in any given dimensional system. However, this does not result in a major shift of the overall envelope within a given system because system tolerances are set by the requirements of the completed vessel and not by the equipment of the fabricator. System tolerance envelopes can be relaxed only by changing the design requirements and are independent of shop or site facilities.

5A.2.4 SUPERVISION

The need for adherence to written procedures and dimensional requirements of the reactor vessel is apparent to the site erection crew. Highly qualified and experienced site field supervisors direct the work of the craftsmen and instruct them regarding the importance of their role in the quality and procedure of the job.

5A.3 DESIGN BASES AND EVALUATION

5A.3.1 GENERAL

The design of the site-assembled reactor vessel is the same as the design for a shop-fabricated-and-assembled reactor vessel. The same quality factors and design margins are applied since the requirements for material and process inspection and control and acceptance criteria are identical in both cases and are equal to or better than requirements of ASME Code, Section III. Various aspects of the vessel design are summarized below.

5A.3.2 FUNCTIONAL DESIGN

The principal functional design requirements of the reactor vessel are (1) to provide a high-integrity barrier to contain the reactor coolant and prevent the leakage of radioactive materials during the 40-year service life of the plant and (2) to support and maintain proper alignment of the reactor core, control rods, and control rod drives during all modes of reactor operation. These requirements are equally applicable to both site-assembled and shop-assembled vessels.

5A.3.3 DETAILED DESIGN

The same detailed design is used for the site-assembled vessel as for a shop-assembled vessel except for the installation of nozzle safe ends and for weld preps for field welding. The stainless steel nozzle safe ends will not be welded on until the vessel is heat treated. Heat treating of the nozzle safe ends would cause sensitization of the stainless steel that can be avoided in this manner. There is no need to make any special design allowance for plate sizes, seam weld locations, nozzle locations, or tolerances for site assembly.

The reactor vessel parts meet the requirements of ASME Code, Section III, for trueness to form and fit-up. These are the same tolerances applicable to a shop-assembled vessel. Plate for the shell and heads are ASME SA-533, Grade B, Class 1. Low-alloy steel forgings for nozzles and flanges are ASME SA-508, Class 2. All material used meets the requirements of Article 3 of Section III of the ASME Code.

5A.3.4 CODE DESIGN

The site-assembled vessel is designed to the requirements of the ASME Code, Section III, Class A reactor vessel.

5A.3.5 REACTOR PRESSURE VESSEL STRESS REPORT

The stress analysis for the DAEC reactor vessel has been performed in accordance with the certified General Electric Purchase Specification and Section III of the ASME Code.

The stress results for the various components of the DAEC reactor vessel are summarized in calculation APED-B11-232, latest revision, hereby incorporated by reference. For each reactor pressure vessel component, the calculated stress intensities for each stress category (primary membrane stress intensity, local membrane plus bending stress intensity, and primary plus secondary stress intensity range) are compared with the appropriate Section III, ASME Code allowable. The fatigue usage factors are also calculated, where appropriate, and compared to the code allowable limit.

5A.4 SURVEILLANCE AND TESTING

5A.4.1 QUALITY CONTROL

General Electric requirements for inspection and quality control are the same for both shop and field, but they may be expected to differ somewhat in the method of achievement for the same end result (see Chapter 17).

With site assembly, the attention of fewer people is directed more entirely to the pressure vessel under construction. However, there is more formal documentation of specific detailed operations such as found in a shop. Therefore, special effort and emphasis are directed toward maintaining controls in the field that are equivalent to shop practices where each operational step is detailed on a document sheet called a "traveler." The traveler contains formal automatic work stops and checkoffs for inspection, and, in addition, automatically incorporates the details of the approved written procedures. Means are provided in the field for a quality control system, instruction and diligence, to provide the equivalent of shop practice. This provides the assurance of working to approved written procedures and also ensures that proper inspections and quality control are performed at the required times.

As there are fewer field personnel than shop personnel, the field personnel used may be less specialized and somewhat broader in coverage than their counterparts in the shop. In this manner, the areas of supervision, inspection, and quality control are properly and adequately covered. Therefore, some field quality control procedures for dimensional, welding, and materials control are more specific than required for reactor vessels in the shop where standard practices and chain of command are well established. With all of the responsible people paying attention to one vessel, the inspection and quality control function at the site is equivalent to that in the shop.

The reactor vessel was fabricated and assembled in accordance with the GE quality control plan for a BWR vessel. This plan is a formal document that defines the quality control and inspection requirements to the supplier. The plan requires complete access for GE surveillance of all work on the vessel and defines many mandatory witness points for materials, testing, heat treatment, welding, and nondestructive testing.

The identical plan is applied for shop- and field-assembled vessels. Chicago Bridge & Iron was required to develop written procedures for welding, heat treating, radiography, and several other operations. The detailed drawings and procedures were reviewed and approved by GE prior to use by CB&I.

The quality control program is designed to positively ensure that only approved drawings and procedures are used at all times and places, both in the shop and at the site. Emphasis is placed on detailed planning and process control to ensure that the quality is built-in step by step.

When defects do occur, a thorough analysis is performed to determine the cause, and appropriate corrective action must be taken. The resident quality control representative reports all defects to the GE Quality and Design Engineers on a current basis. This results in additional investigation at the shop or site (see Chapter 17).

In summary, the GE quality program plan consists of a thorough and independent verification by technically competent people during all phases of vessel assembly. General Electric places the full burden of quality proof on CB&I and is confident that this approach gives positive assurance of quality in accordance with specifications and the ASME Code.

The only difference between a field-assembled vessel and a shop-assembled vessel is that quality control representatives are assigned at the site as well as in the CB&I shops.

5A.4.2 EXAMINATION

Considering the five major methods of examination given to vessel material (visual, magnetic particle, liquid penetrant, ultrasonic, and radiographic), the only difference between shop and site inspection may be the method of radiography and the processing of radiographic films.

Shop radiography of vessel sections consists of a combination of X-ray and gamma ray; however, more gamma-ray radiography was used on the DAEC site-assembled vessel than is used on most shop-fabricated-and-assembled vessels because the high-energy X-ray equipment used in the shop is not readily transportable and set up at the site. Therefore, gamma-ray radiography with a relatively large, high-energy, isotope source of cobalt 60 was used more extensively in this application. Radiography procedures using the gama-ray source have been developed and tested, and adequate sensitivity has been demonstrated.

Ultrasonic examination of the welds supplemented the radiography and was similar to the method presently used by CB&I both in the shop and in the field.

Although GE requires the approval of all inspection procedures, they also require particular attention to gamma-ray procedures. Emphasis was placed on developing an average sensitivity that is better than the required ASME Code minimum sensitivity, so that even with the larger size of the gamma-ray focal spot and the potentially greater amount of scatter (because of longer exposure times), films that had better than marginal sensitivity could be produced.

The radiographic procedures may also potentially involve less sophisticated film processing and handling techniques in the field, but high-quality field processing of radiographic film has been demonstrated.

5A.4.3 VESSEL TESTING

The code-required hydrostatic testing of the completed site-assembled vessel is performed with temporary covers on the penetrations, much as is the practice with shop-fabricated vessels. In addition to the ASME Code test, a design pressure test to verify the leaktightness of the head closure seal was performed to fulfill one of the many additional requirements imposed before GE would accept the DAEC reactor vessel. This test was performed with the temporary covers in place.

REFERENCES FOR SECTION 5A.5

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

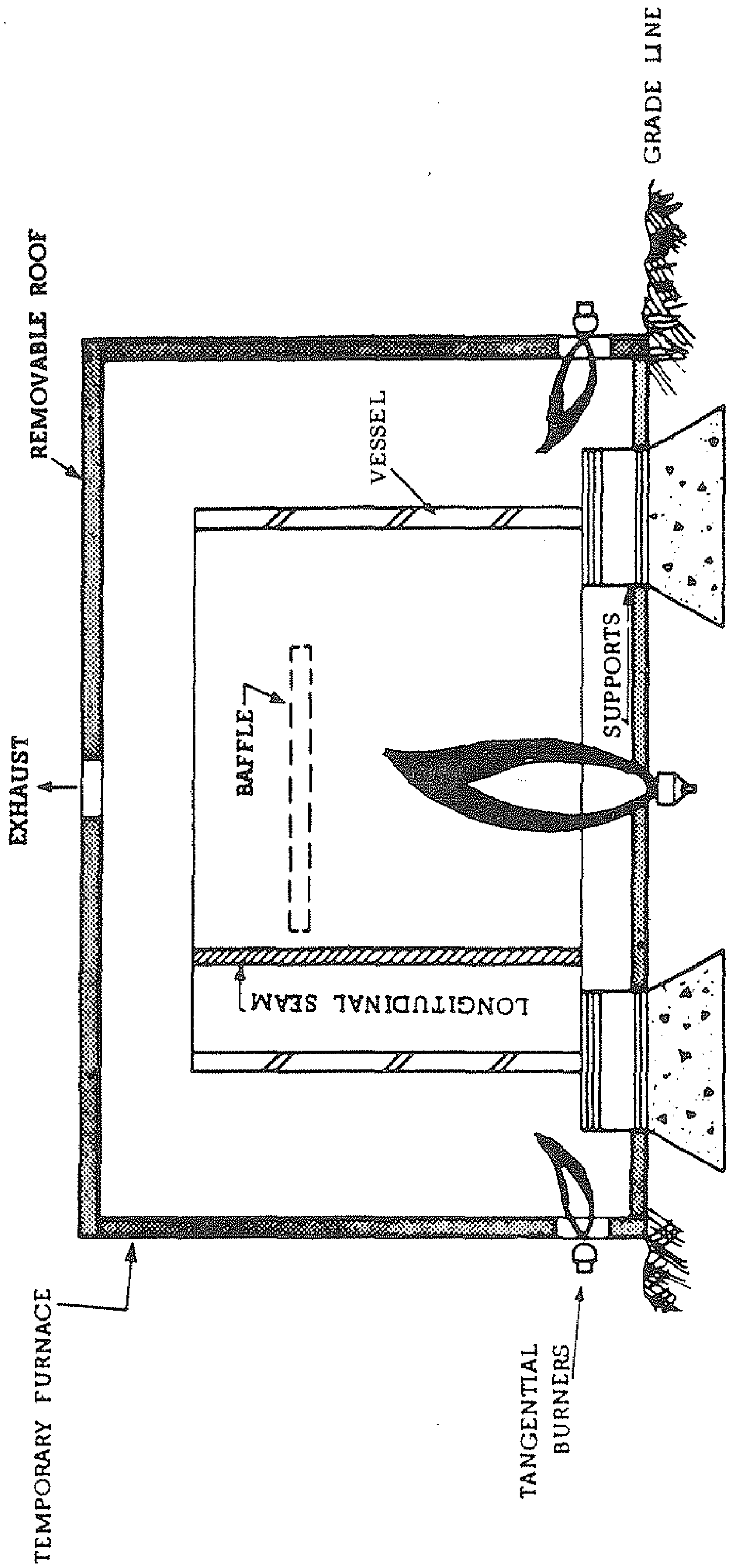
2. K. R. Wichman, A. G. Hooper, and J. L. Mershon, "Local Stresses in Spherical and Cylindrical Shells due to External Loadings," Welding Research Council Bulletin 107, 1965.

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

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

5. APED-B11-236, Revision 0, "Reactor Vessel Tensioning Optimization Stress Report Duane Arnold Energy Center."

6. APED-B11-232, Latest Revision, "Stress Report – Reactor Vessel," Incorporated by Reference in Section 5A.3.5.



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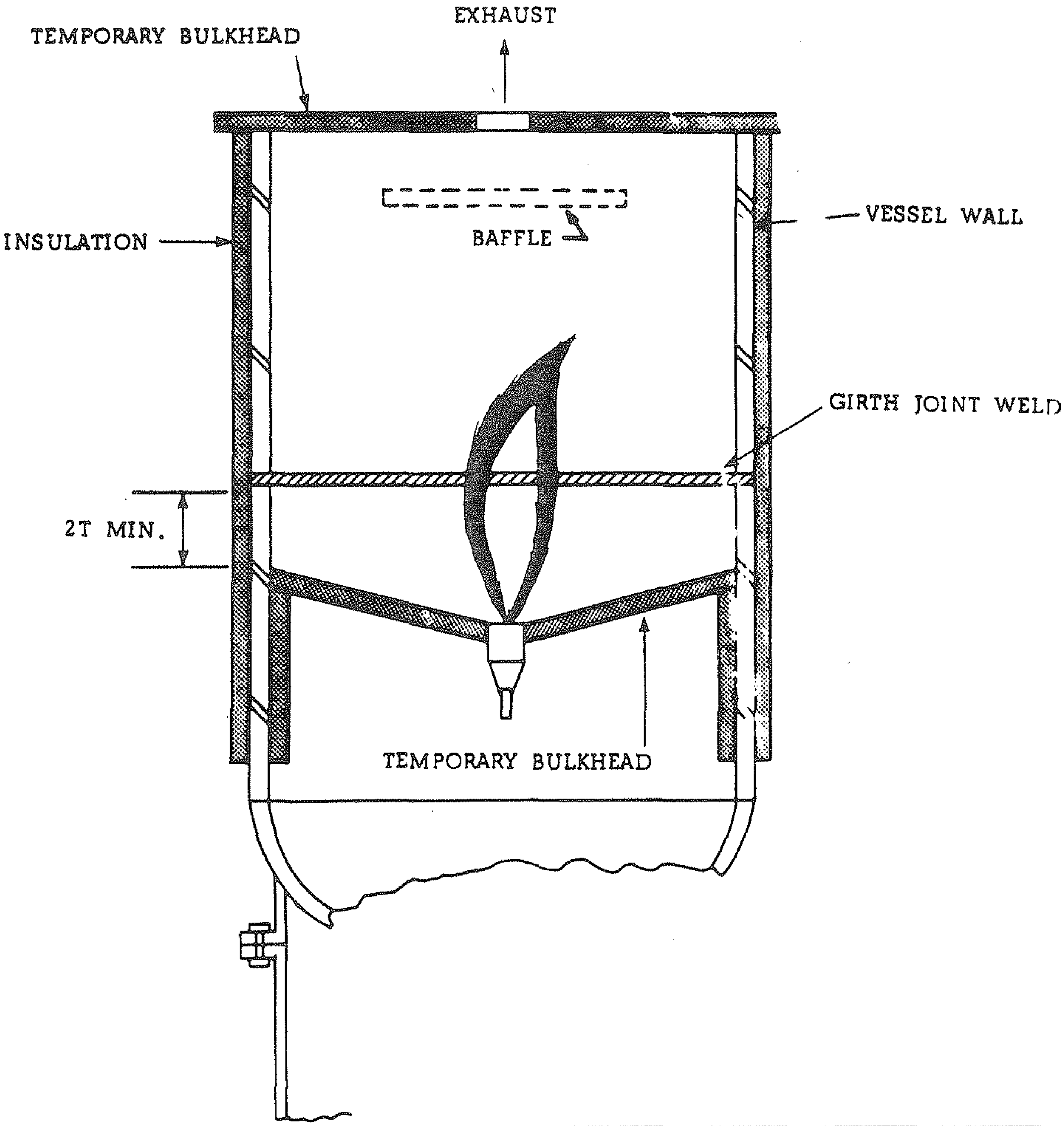
Reactor Pressure Vessel - Site Assembled - Post Weld Heat Treat - Longitudinal Weld

Figure 5A.2-1



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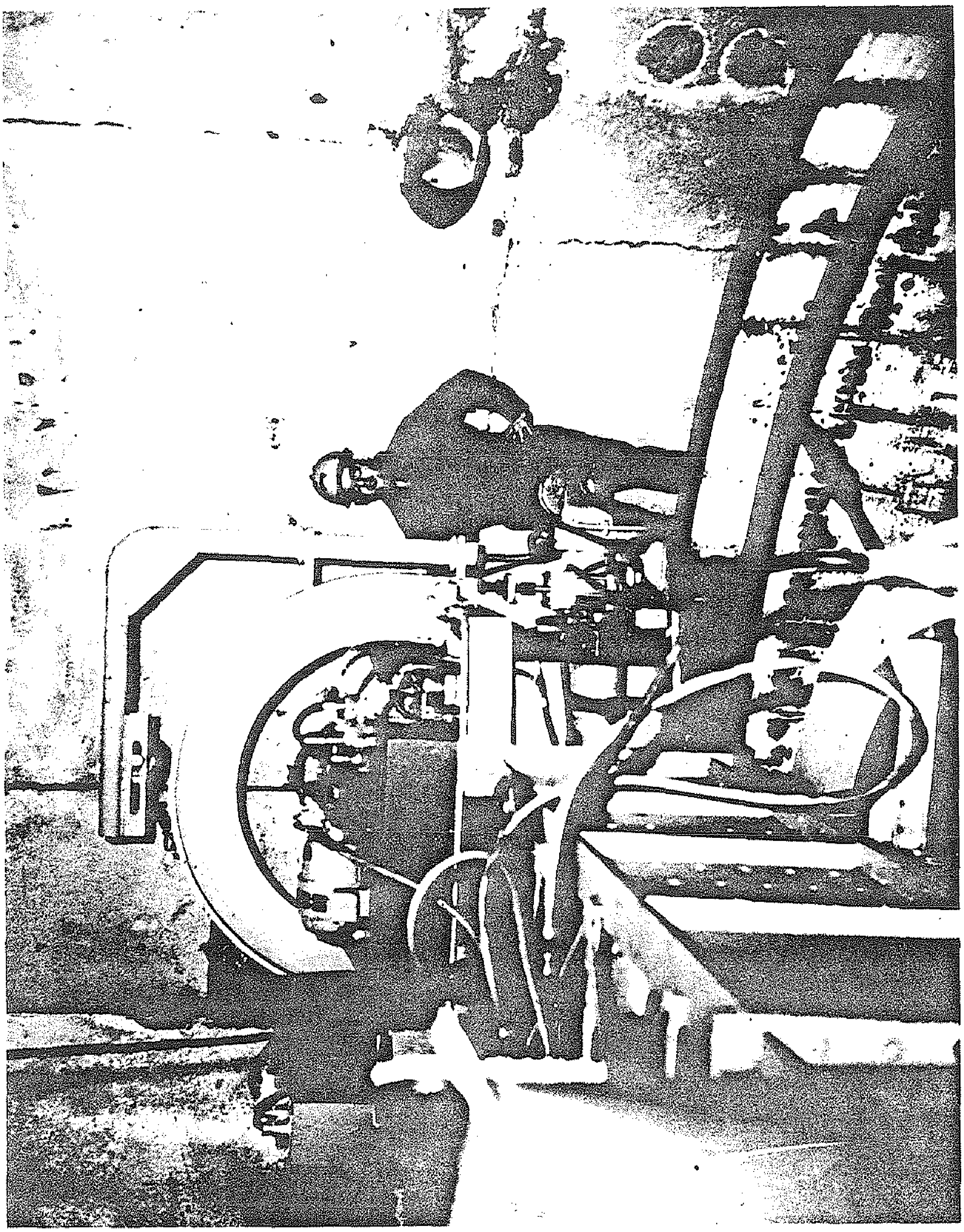
Reactor Pressure Vessel - Site Assembled - Post Weld Heat Treat - Girth Weld

Figure 5A.2-2



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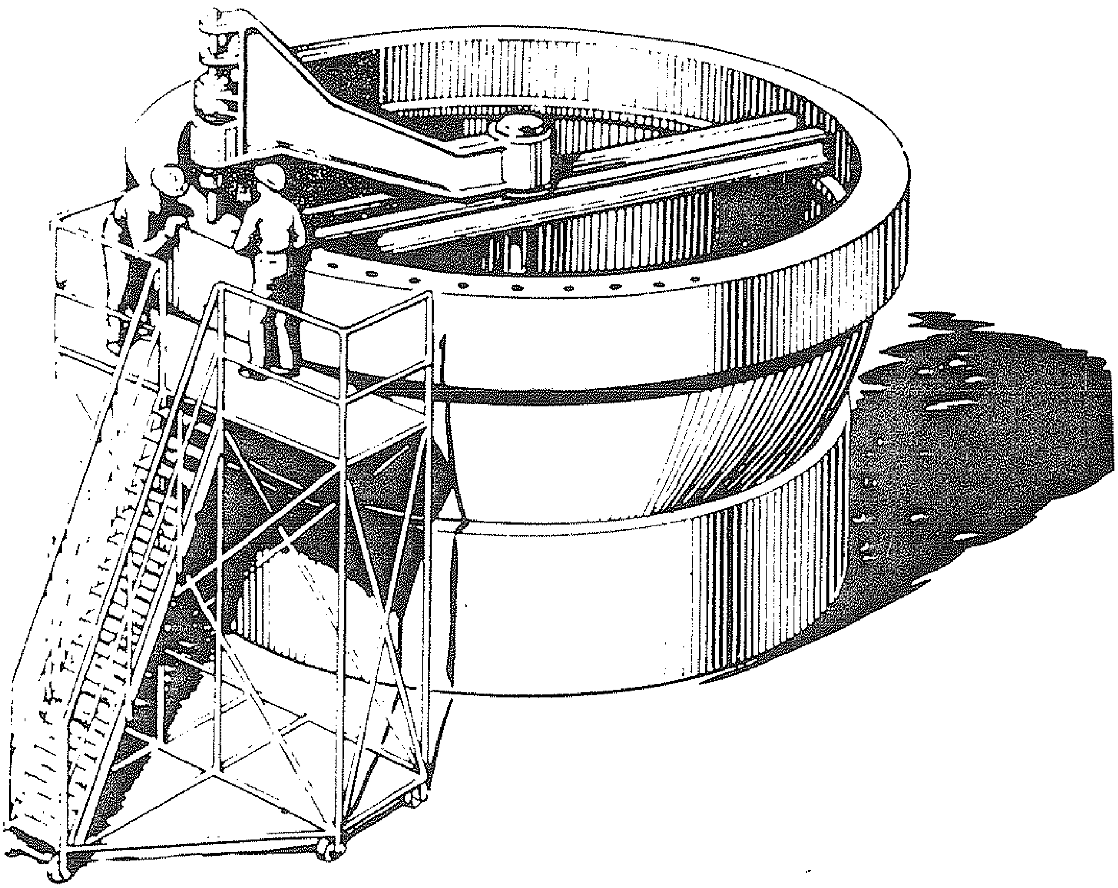
Reactor Pressure Vessel - Site Assembled - Vessel Flange Machining

Figure 5A.2-3



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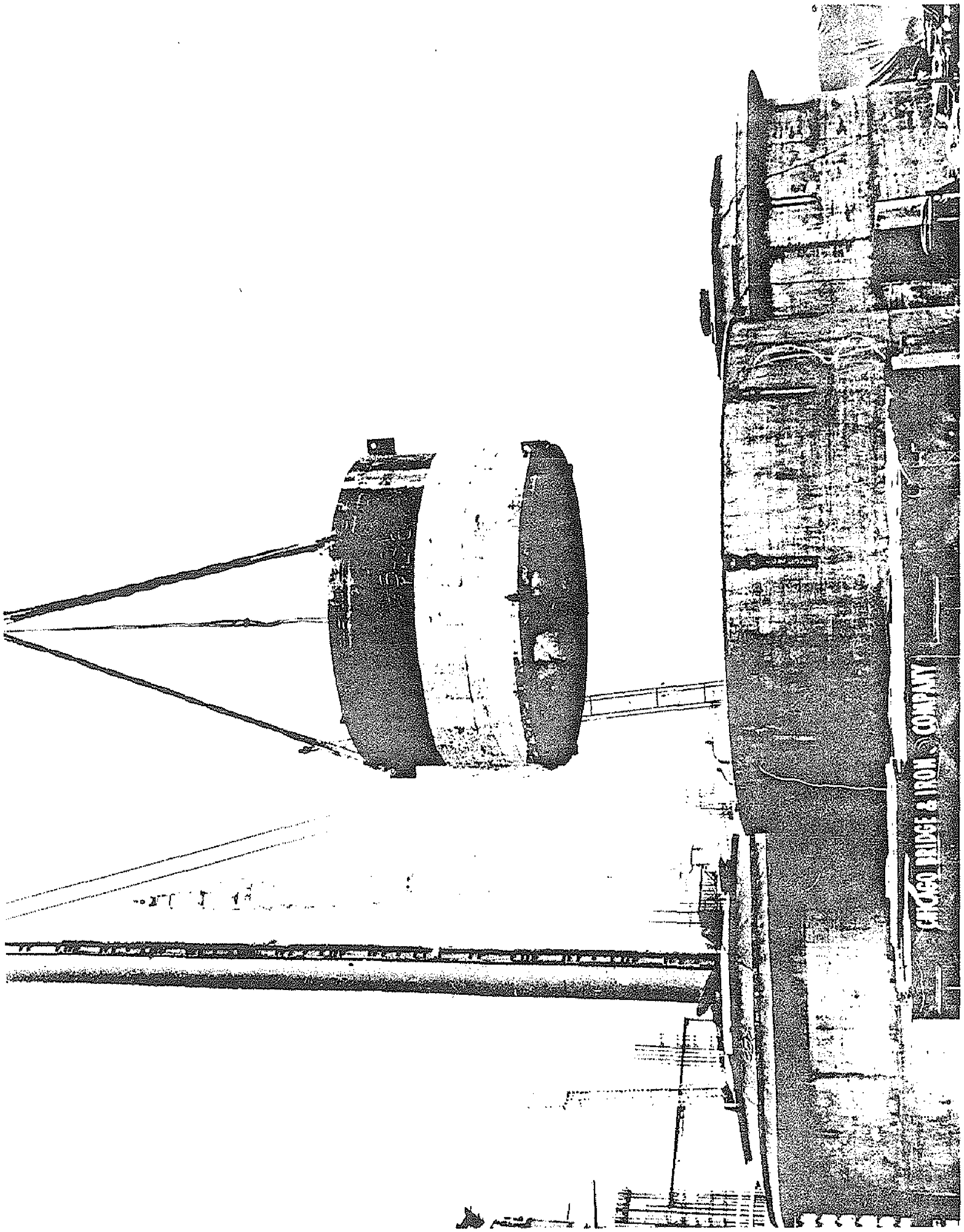
Reactor Pressure Vessel - Site Assembled - Top Head Flange Hold Drilling

Figure 5A.2-4



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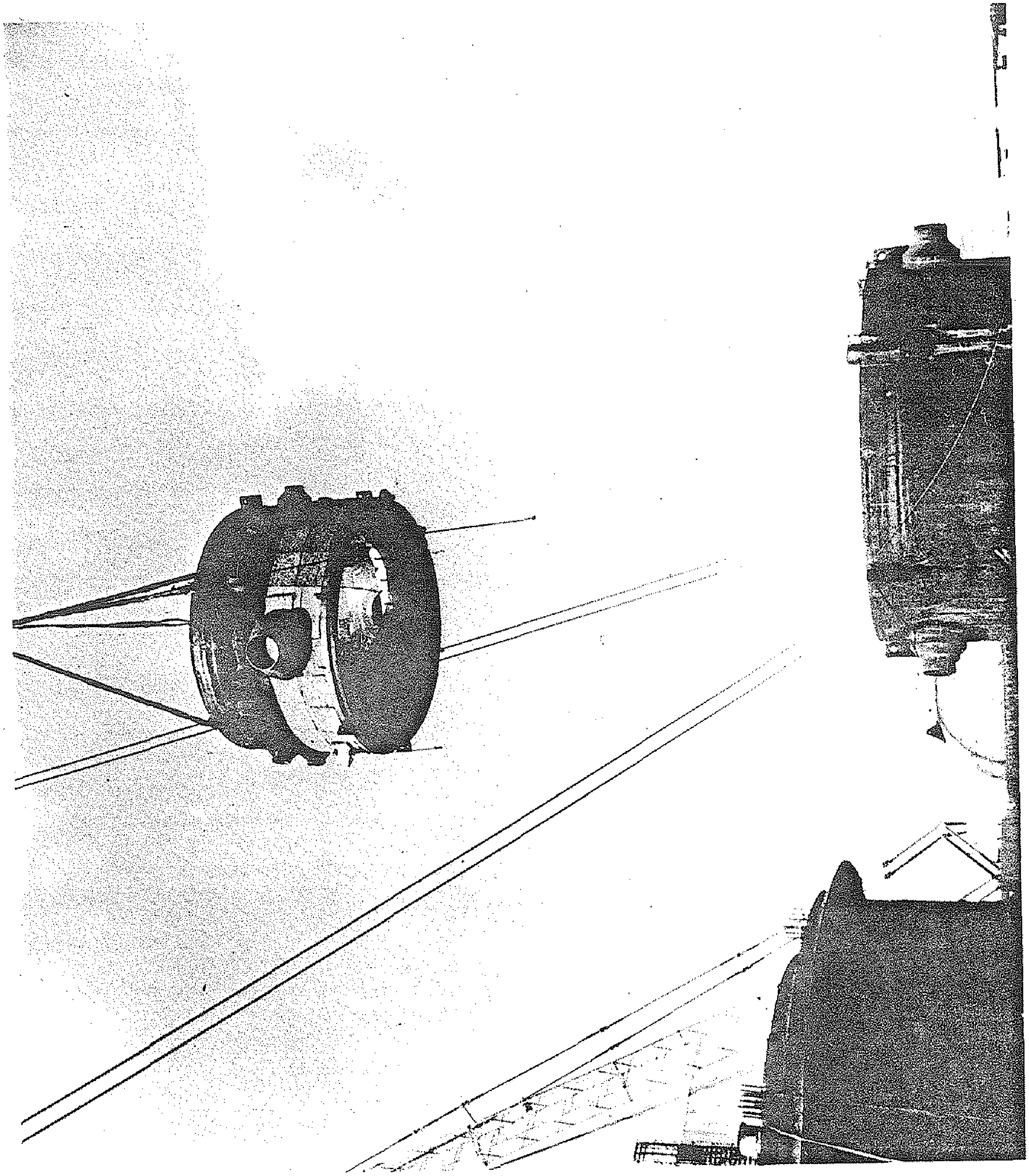
Reactor Pressure Vessel - Site Assembled - No. 1 Shell Ring

Figure 5A.2-5



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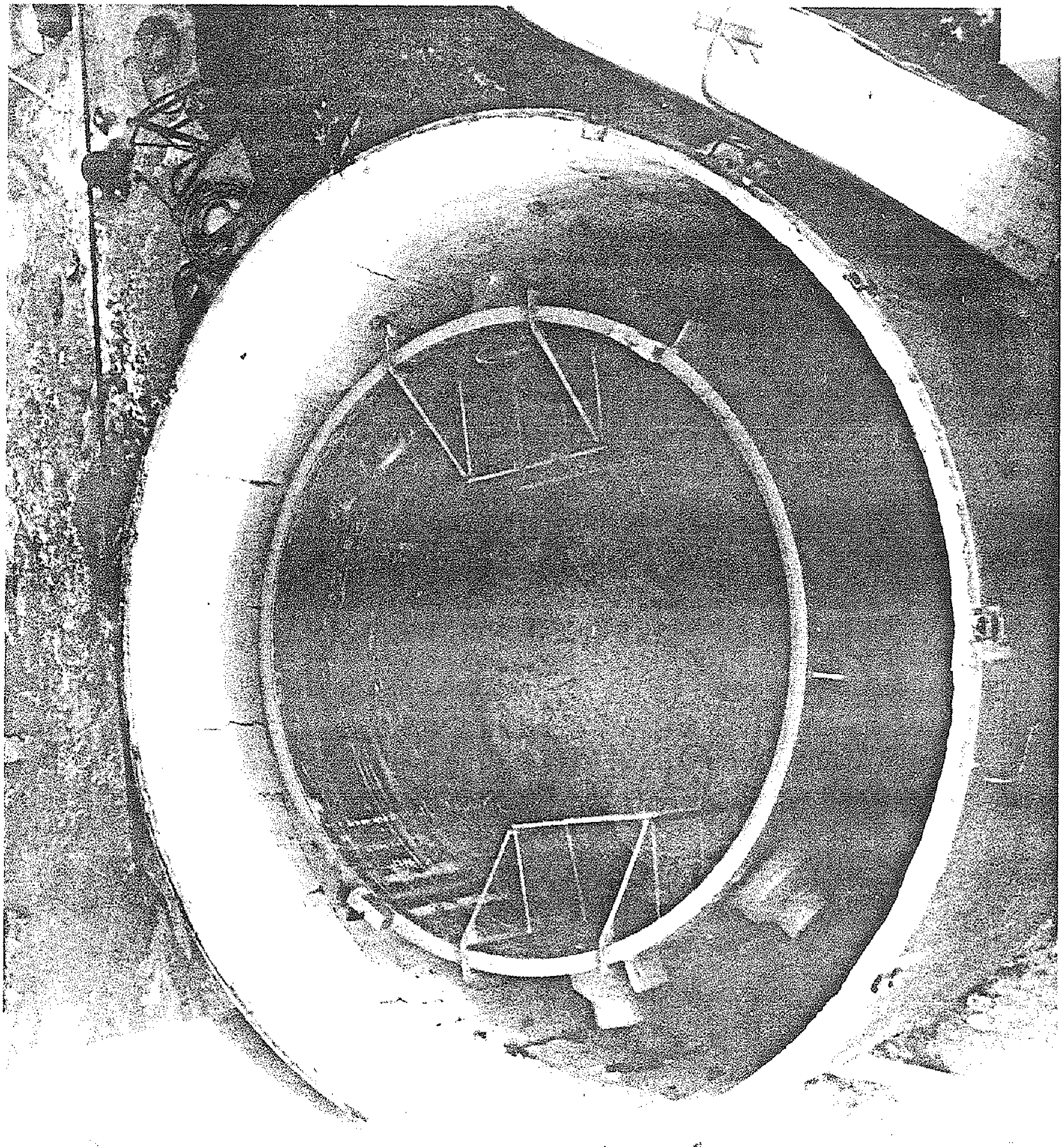
Reactor Pressure Vessel - Site Assembled - No. 2 Shell Ring

Figure 5A.2-6



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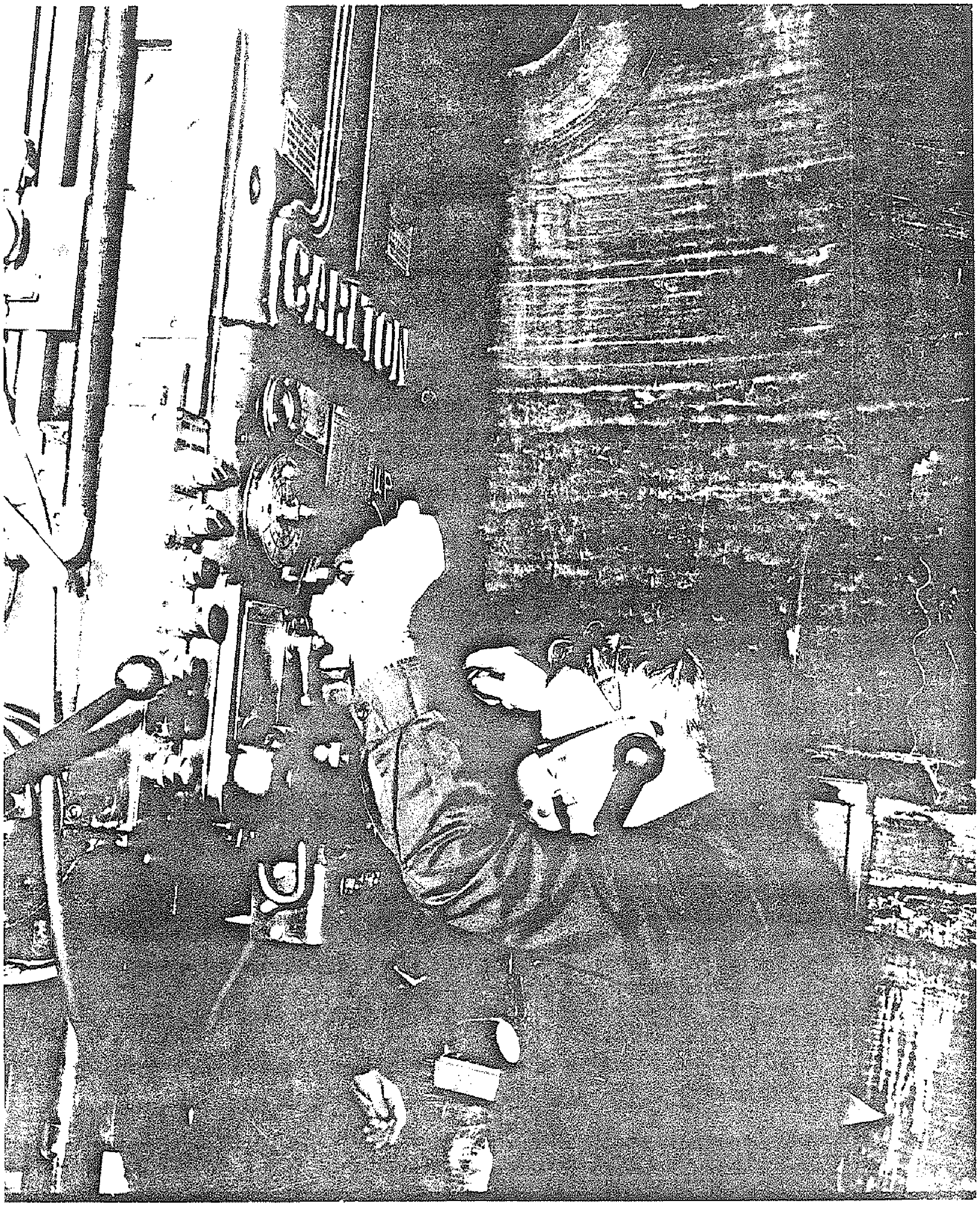
Reactor Pressure Vessel - Site Assembled - No. 4 Shell Ring

Figure 5A.2-7



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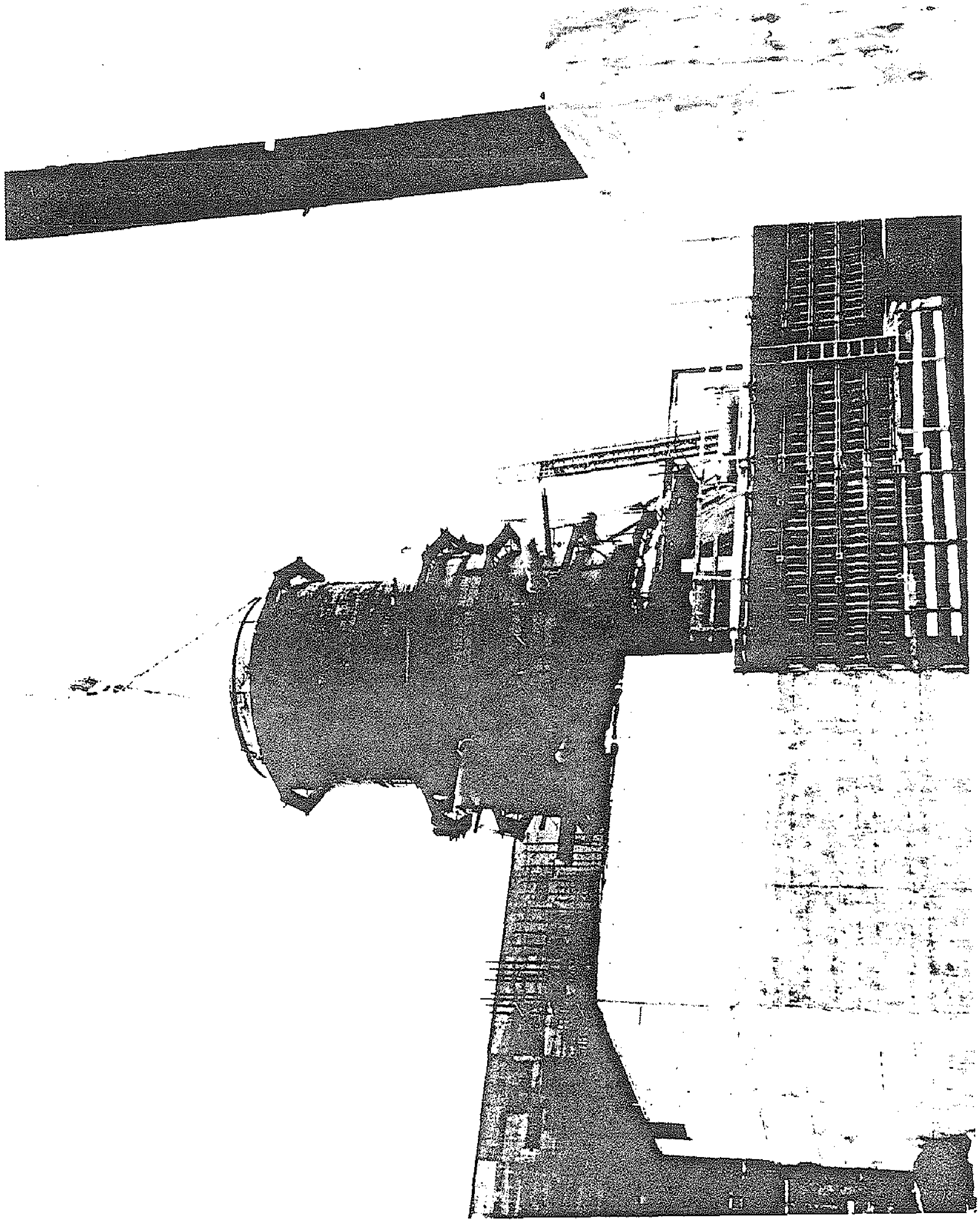
Reactor Pressure Vessel - Site Assembled - Drilling Control Rod Holes in Bottom Heat

Figure 5A.2-8



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Reactor Pressure Vessel - Site Assembled - Placing Heat Treating Furnace in Vessel

Figure 5A.2-9

5B: Over Pressurization Protection

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5B: Over Pressurization Protection

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Appendix 5B: Over Pressurization Protection

5B.1 Design Evaluation

To determine the required steam-flow capacity of the safety valves, a parametric study was performed with the following assumptions:

1) The plant is operating at the turbine-generator design condition with a vessel dome pressure of 1025 psig, a steam flow of 7.17×10^6 lb/hr, and a reactor thermal power of 1658 MW.

2) The reactor experiences the worst pressurization transient. Both the closure of all main steam isolation valves and a turbine trip (without bypass response) produce severe transients. The evaluation of the final plant configuration has shown that the main steam isolation valve closure is slightly more severe when credit is only taken for backup scrams; therefore, it is used as the design-basis event for overpressure protection.

3) Direct reactor scram based on main steam isolation valve position switches (valve closure) - failed.

4) Various total capacities of dual safety/relief valves were used. These valves functioned properly and were considered to be part of the total safety valve capacity requirement with a nominal lowest setpoint of 1080 psig. This satisfied the ASME Code requirement that the lowest safety valve be set at or below the vessel design pressure of 1250 psig.

5) The design basis takes credit for high neutron flux scram, although the analysis also shows the adequacy of the valves even with high vessel pressure scram, as a backup to high flux scram.

6) Various safety valve total capacities were used with a 1240-psig nominal setpoint, which satisfies ASME Code, Section III requirements that the highest safety valve setpoint be less than 105% of vessel design pressure (1.05 x 1250 = 1313 psig).

7) Both the dual safety/relief valves and the spring safety valves were assumed to have 1% (high) error in pressure setpoint throughout the study.

Under Section III of the ASME Code, the peak allowable pressure is 110% of vessel design pressure or 1375 psig at the vessel bottom. Design specifications for safety/relief valve and spring safety valve capacities, based on the rated steam flow and the above parametric studies, were 61.9% and 10%, respectively. The six safety/relief valves have a combined capacity of 68.4%. Two spring safety valves are required to meet the specified 10% capacity and have a combined capacity of 18.7%.

Figure 5B.1-1 shows the nominal peak vessel bottom pressures attained when the turbine trip without bypass and main steam isolation valve closure transients are terminated by various modes of reactor scram, in the order in which they would occur. Notice that when direct scrams are ignored, the main steam isolation valve closure transient is the more severe of the two transients. Safety/relief and spring safety valve capacities for this comparison are 68.4% and 18.7%, respectively, representative of the six safety/relief valves and two spring safety valves. The pressure attained with neutron flux scram is considerably lower than that attained with pressure scram. Vessel bottom pressure transients for each of the foregoing reactor high-pressure events are presented in Figure5B.1-2. The cases with direct (trip or position) scrams are designed to avoid lifting the spring safety valves.

Using the overpressure protection system consisting of six dual-purpose safety/relief valves and two spring safety valves, analyses were performed to determine the effects on the pressure transient of various combinations of valve failures.

5B.1.1 Valve Position Switch Scram (Direct)

With this protection system functioning as expected, the turbine trip without bypass transient is more severe than the main steam isolation valve closure transient. Figure 5B.1-3 shows the peak vessel bottom pressure attained during such a transient with one, two, or three safety/relief valves functioning properly in combination with zero, one, or two spring safety valves. As shown, vessel overpressure protection, with a minimum margin of 25 psi, exists if three relief valves in combination with no safety valves or two relief valves in combination with two safety valves function properly. Furthermore, vessel overpressure protection is maintained below code limits if two relief valves in combination with no safety valves or one relief valve in combination with two safety valves function properly.

5B.1.2 High-Neutron-Flux Scram

A main steam isolation valve closure transient when terminated by a high-neutron-flux scram causes the peak neutron flux to reach its scram setpoint about 1.24 sec after a main steam isolation valve position switch scram would have been initiated. Figure 5B.1-4 shows the peak vessel bottom pressures attained during such a transient with three, four, or five safety/relief valves functioning properly in combination with zero, one, or two spring safety valves. As shown, vessel overpressure protection, with a minimum margin of 25 psi, exists if five relief valves in combination with no safety

valves or four relief valves in combination with two safety valves function properly, Vessel pressure is maintained below code limit when four relief valves in combination with no safety valves or three relief valves in combination with two safety valves function properly. This case, using an indirect reactor scram, demonstrates compliance with the requirements of Section III of the ASME Code.

5B.1.3 High Vessel Pressure Scram

The General Electric (GE) design gives even more vessel overpressure protection by providing enough valves to adequately cover the case in which reactor scram is initiated by high vessel pressure, reached at approximately 1.70 sec after a valve position switch scram would have occurred. As shown in Figure5B.1-5, adequate vessel overpressure protection, with a minimum margin of 25 psi, exists if six relief valves in combination with no safety valves or five relief valves in combination with two safety valves function properly.

5B.1.4 Summary of Analyses

Figure 5B.1-6 summarizes the results of the analyses using relief capacity as the independent parameter. Also shown is the main steam line isolation valve closure with valve position switch scram.

The evaluations described in Section 5B.1.2 assume the use of Dresser safety/relief valves, which were replaced with equivalent Target Rock valves in 1977. The safety implications of the replacement were evaluated with the conclusion that the modification did not represent an undue risk to public health and safety.

The only discernable effect on the transient and safety analyses concerned a slight (3.6%) reduction in valve capacity, which led to a 4-psi peak steam-line pressure increase for the transient of turbine trip without bypass and a 5-psi peak vessel bottom pressure increase for the transient of main steam isolation valve closure. Data for the Target Rock valves are given in Tables 5.2-1 and 5.2-2.

5B.1.5 Sensitivity to Safety Valve Failure

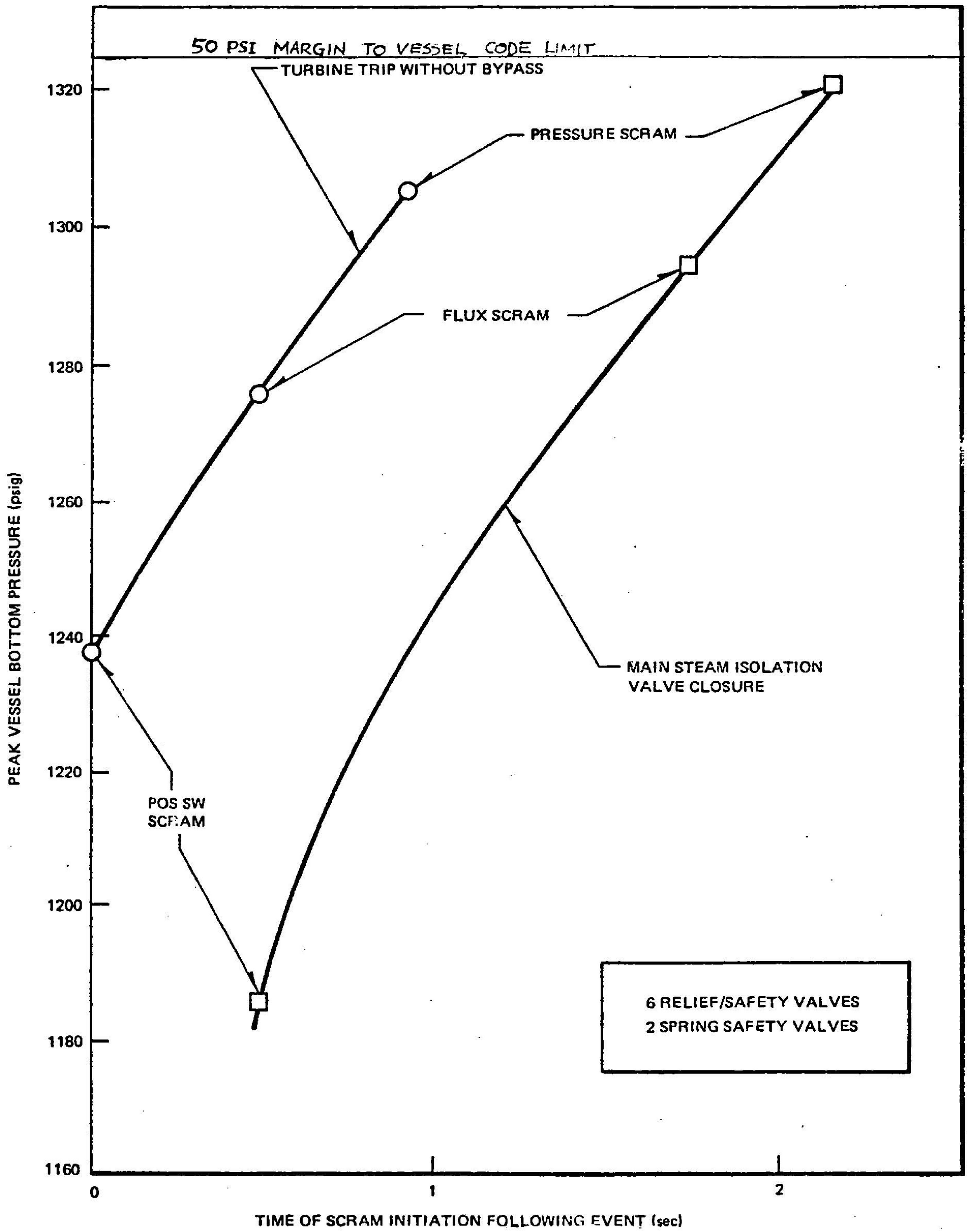
A study of a typical high-power-density BWR was conducted to show the sensitivity of peak vessel pressure to valve operability. This study is applicable to the DAEC reactor and is supplemental to previous overpressure protection analyses.
safety valve is approximately 20 psi. To further substantiate this study, a safety analysis assuming plugged bypass flow holes was submitted on June 10, 1975, and showed a sensitivity of 19 psi for a flux scram with one inoperable relief valve.

Rather than perform a DAEC plant-specific analysis based on the failure of a safety valve with high-flux scram, reference is made to a generic analysis provided in a GE letter to the NRC (Ivan F. Stewart to Victor Stello, Jr.) dated December 23, 1975. The results provided in this letter are described below.

The design of safety/relief valves for GE reactors is based on the requirements of Section III of the ASME Code, which has been adopted by the NRC as part of the requirements in the Code of Federal Regulations (10 CFR 50.55a). It is GE's interpretation that this code does not require the failure of a qualified safety/relief valve in addition to the failure of the direct safety-grade position scram and is therefore not considered to be part of the licensing basis for reactor vessel overpressure protection. Furthermore, the consideration of the failure of the direct safety-grade position scram by itself requires multiple equipment failures. The probability of an overpressurization event with these multiple equipment failures is so low that such an event should be considered, as a minimum, an "emergency" condition. Therefore, the application of the emergency limit under these assumed failure conditions would be appropriate.

In determining the required safety/relief valve capacity, GE conservatively assumes the failure of all direct safety-grade position scrams in the analysis. The GE analysis conservatively relies on indirectly derived signals (high neutron flux) from the reactor protection system, and although this condition could appropriately be classified as an emergency condition, GE conservatively applies the “upset" code requirements rather than the emergency limits.

In summary, the sensitivity study shows that several valves have to fail in order to violate the emergency limit. General Electric considers the failure of the direct position scram and subsequent shutdown by high-neutron-flux scram, with all safety-relief valves operable, to satisfy the code requirements and to be an appropriate licensing basis for reactor vessel overpressure protection.



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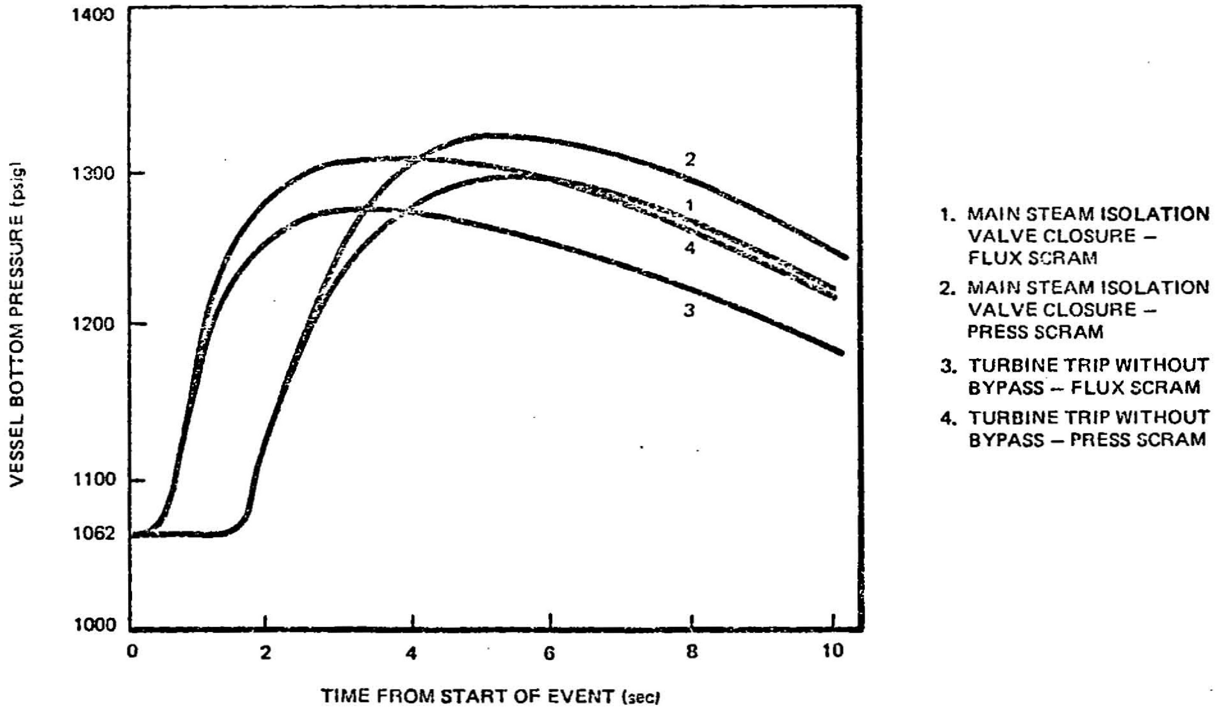
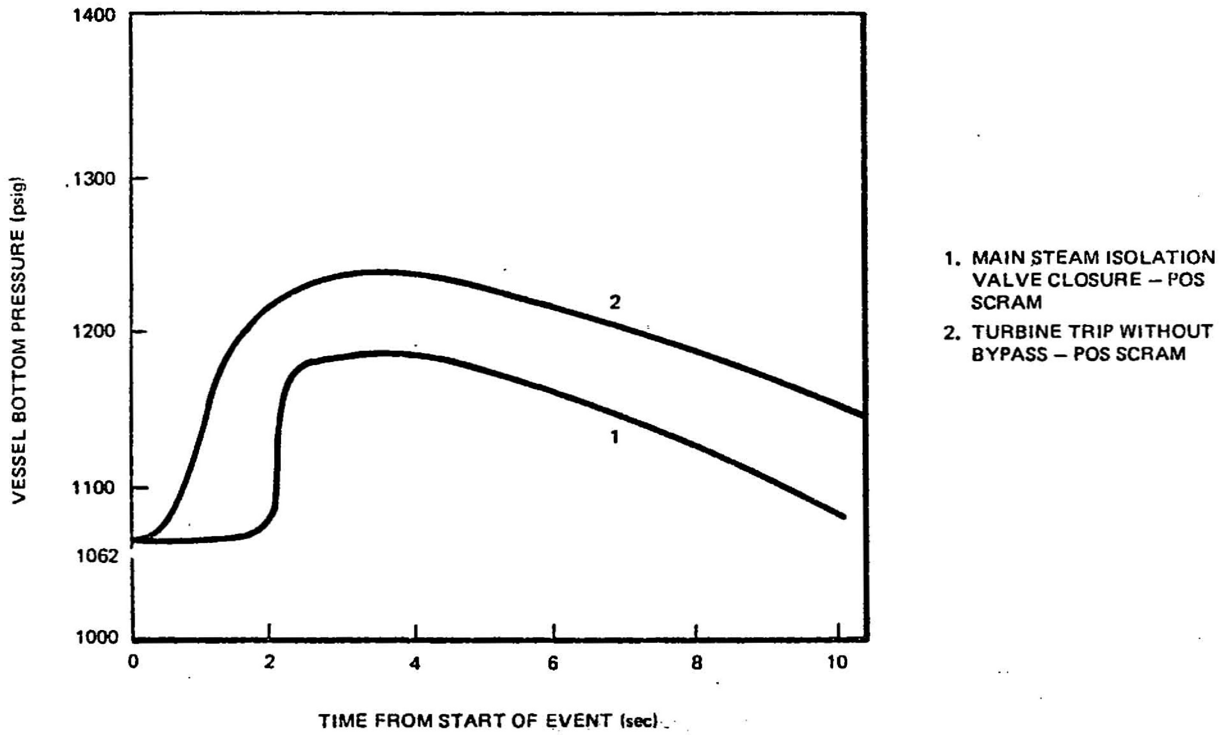
Effect of Various Scram Times on Peak Vessel Pressure

Figure 5B.1-1





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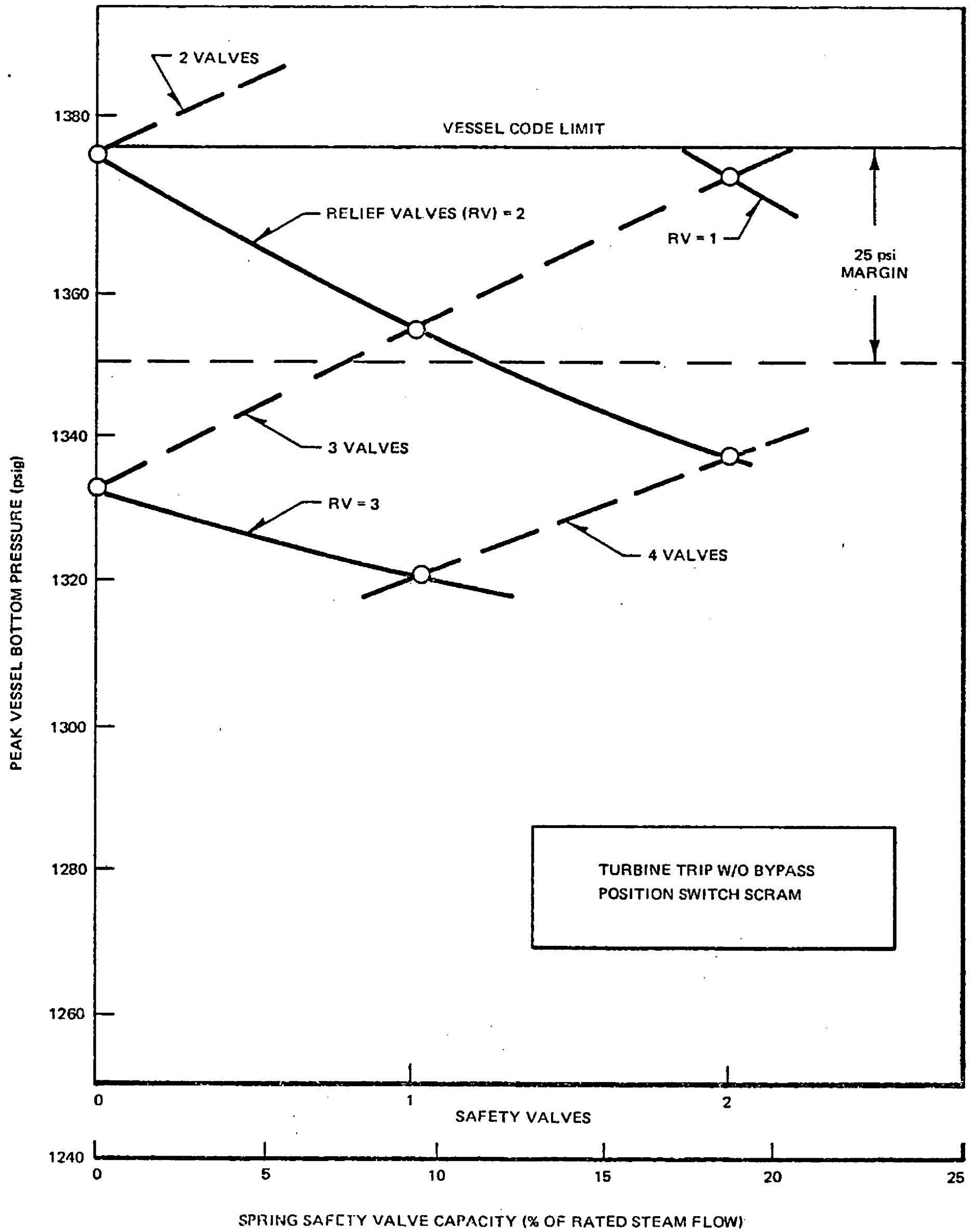
Comparison of High Pressure Vessel Transients

Figure 5B.1-2



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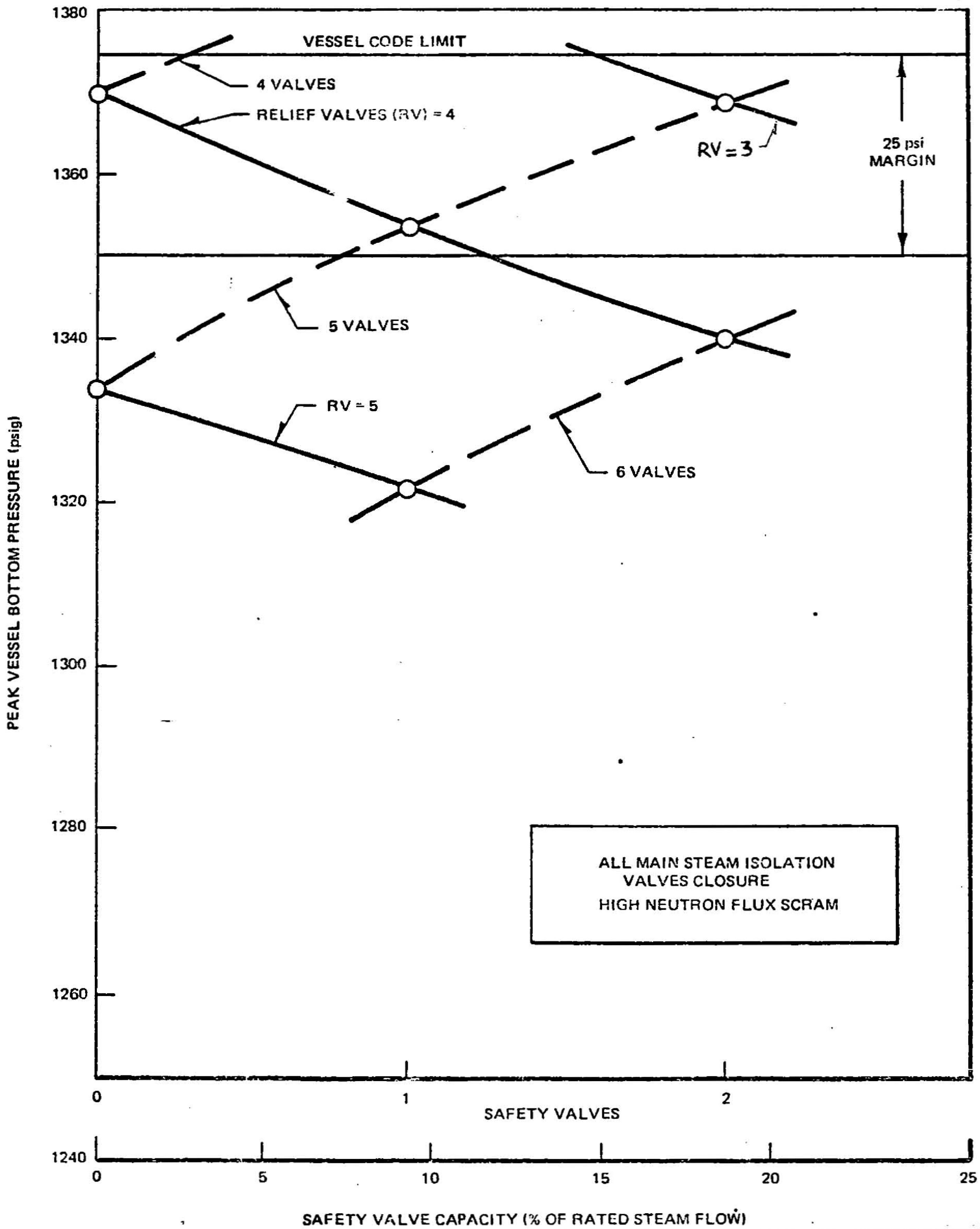
Effect on Peak Vessel Pressure of Various Valve Failures with Turbine Generator Trip Scram following a Turbine Trip without Bypass

Figure 5B.1-3



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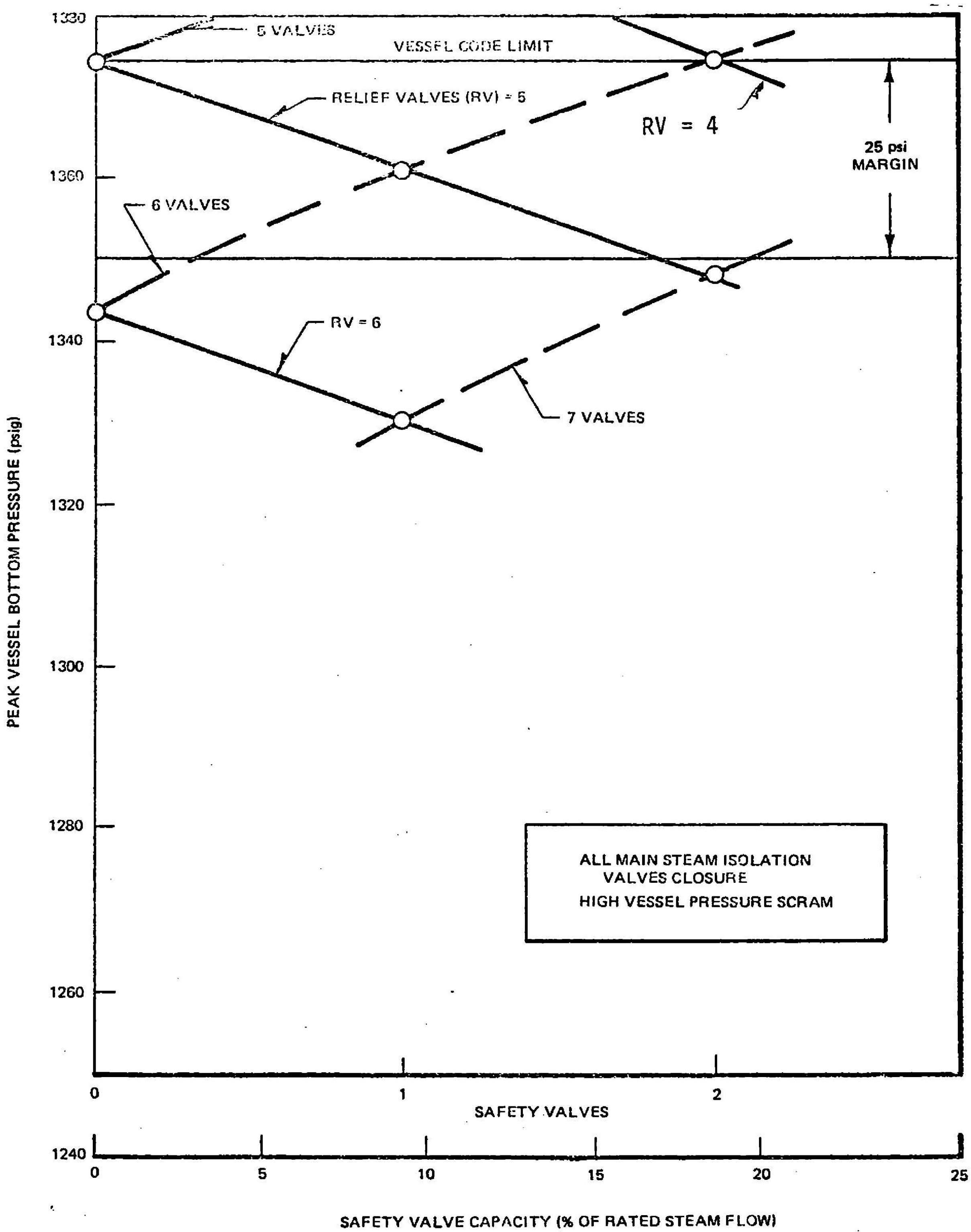
Effect on Peak Vessel Pressure of Various Valve Failures with High Neutron Flux Scram following MSIV Closure

Figure 5B.1-4



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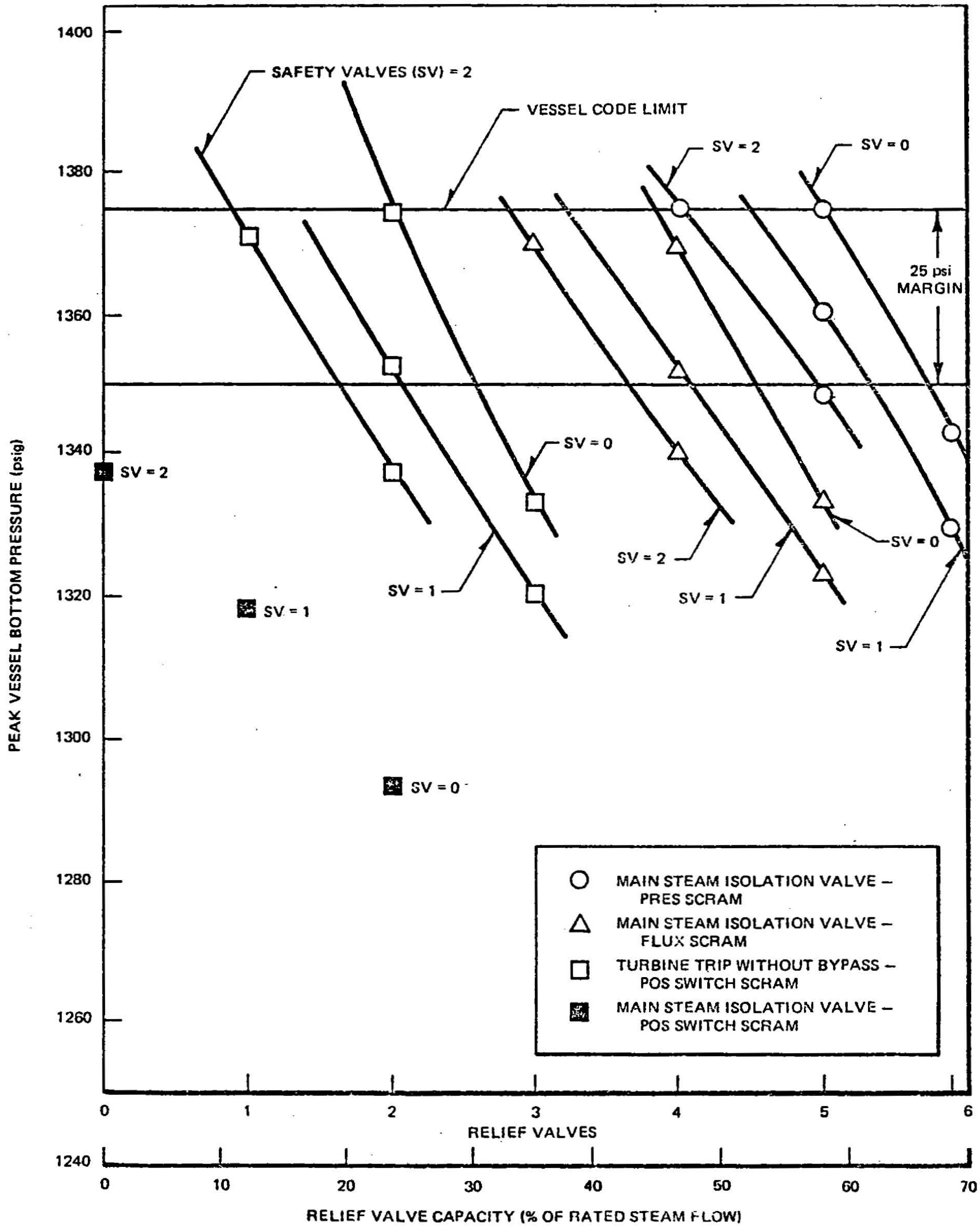
Effect on Peak Vessel Pressure of Various Valve Failures with High Vessel Pressure Scram following a MSIV Closure Figure 5B.1-5



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Peak Vessel Pressure versus Relief/Safety Valve Capacity

Figure 5B.1-6