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IV - REACTOR COOLANT SYSTEM

1.0 SUMMARY DESCRIPTION

This section describes those systems and components that form the major portions of the Reactor Coolant Pressure Boundary (RCPB). These systems and components contain or transport the fluids coming from or going to the reactor core.

The "Reactor Vessel and Appurtenances Mechanical Design" section 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 structural loading are considered in the vessel design, and the vessel meets the requirements of the applicable codes and criteria. The possibility of brittle fracture is considered, and suitable limits are established that avoid conditions where brittle fracture is possible. Reactor vessel fatigue analyses are discussed in Section III.

The Reactor Recirculation System pumps coolant through the core. 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 in order 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 RCPB from damage due to overpressure. To accomplish overpressure protection a number of pressure-operated relief valves are provided that can discharge steam from the nuclear system to the primary containment. The Nuclear System Pressure Relief System also acts to automatically depressurize the nuclear system in the event of a loss of coolant accident in which High Pressure Coolant Injection (HPCI) fails to restore water level. The depressurization of the nuclear system allows low pressure Emergency Core Cooling Systems (ECCS) to supply enough cooling water to adequately cool the fuel. Only some of the valves used to provide overpressure protection are arranged to effect automatic depressurization.

The Main Steam Line Flow Restrictors are venturi-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. The coolant loss is limited so that reactor vessel water level remains above the top of the core during the time required for the main steam line isolation valves to close. This action protects the fuel barrier.

Two Main Steam Line Isolation Valves (MSIV) are installed on each main steam line. One valve in each line is located inside the primary containment, the other outside. These valves act automatically to close off the RCPB 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, 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. The system provides the ability to cool the core during a reactor shutdown in which feedwater flow is not available.

The Residual Heat Removal (RHR) system includes a number of pumps and heat exchangers that can be used to cool the nuclear system under a variety of situations. During normal shutdown and reactor servicing, RHR removes residual and decay heat. One operational mode of RHR is low pressure coolant injection (LPCI). LPCI operation is an Engineered Safety Feature (ESF) for use during a loss of coolant accident; this operation is described in Section VI "ECCS". Another mode of RHR operation, Suppression Pool Cooling or Containment Spray, allows the removal of heat from the primary containment following a loss of coolant accident.

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.

The "Nuclear System Leakage Rate Limits" section establishes the limits on nuclear system leakage inside the primary containment so that appropriate action can be taken before the RCPB is threatened by a crack large enough to propagate rapidly.

Four steam lines are utilized between the reactor and the turbine, which permit turbine stop valve and primary steam isolation valve tests during plant operation with a minimum amount of load reduction. In addition, differential pressures on reactor internals under assumed accident conditions of a broken steam line are limited. Feedwater lines provide water to the reactor vessel entering near the top of the vessel downcomer annulus. Drains are provided at the low point of each main steam line, at the reactor vessel bottom head, at the relief valves, and on each side of the recirculation pumps. A vent is provided in the Reactor Vessel top head which permits the removal of noncondensibles from the head area.

High Energy Line Break (HELB) effects and the description of the pipe break study performed are described in USAR Chapter IV, Section 12.0.

2.0 REACTOR VESSEL AND APPURTENANCES MECHANICAL DESIGN

2.1 Safety Objective

The safety objective of the reactor vessel and appurtenances, in conjunction with other safety systems, is to provide a barrier to the release of radioactive materials when operated within the range of conditions considered by the Station Safety Analysis (see USAR Chapter XIV).

2.2 Safety Design Bases

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

2. To minimize the possibility of brittle fracture failure of the RCPB, the following shall be required: (1) the initial ductile-brittle transition temperature of materials used in the reactor vessel was known by reference or established empirically; (2) expected shifts in transition temperature during design service life due to environmental conditions, such as neutron flux, was determined and employed in the reactor vessel design; (3) operation margins to be observed with regard to the transition temperature have been designated for each mode of operation.

3. The reactor vessel and appurtenances are designed so that failure of piping integrity does not compromise the ability to provide a refloodable volume.

2.3 Power Generation Objective

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 reactor vessel appurtenances design provides the means for the attachment of pipelines to the reactor vessel and the means for the proper installation of vessel internal components.

2.4 Power Generation Design Bases

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 ASME Code limits.

2. The reactor vessel design lifetime is 40 years.

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

2.5 Description

General:

With regard to the welding materials used in the fabrication of the Reactor Coolant System, no electroslag welding materials were used within the RCPB.[105]

Although no nitrogen strengthened grades of SS (304N or 316N) were used in the piping or other pressure retaining components,[1] piping and components made with 304NG or 316NG have been used as replacements. These grades of SS do contain trace amounts of nitrogen specifically to recover the decrease in alloy strength due to the reduction in carbon content.

2.5.1 Reactor Vessel

The reactor vessel is a vertical cylindrical pressure vessel with hemispherical heads of welded construction. Table IV-2-1 provides typical reactor vessel data; General Electric Drawing 197R576, Sheet 1 presents the reactor vessel assembly. The reactor vessel is designed and fabricated for a useful life of 40 years based upon the specified design and operating conditions. The vessel is designed, fabricated, inspected, tested and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section III (1965 Edition and January, 1966, addenda), its interpretations, and applicable requirements for Class A Vessels as defined therein. The reactor vessel and its supports are designed in accordance with the loading criteria of USAR Appendix C. The materials used in the design and fabrication of the reactor pressure vessel are shown in Table IV-2-2.

The cylindrical shell and bottom hemispherical head of the reactor vessel are fabricated of low alloy steel plate which is clad on the interior with stainless steel weld overlay. The plates and forgings were ultrasonically tested and magnetic particle tested over 100% of their surfaces after forming and heat treatment. Preheat of vessel plate and forgings were maintained during welding until the weld joints were post-weld-heat treated. Full penetration welds were used at all joints, including nozzles, throughout the vessel except for nozzles of less than 3-inch nominal size and CRD stub tubes.

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 stainless steel cladding provides the necessary corrosion resistance during reactor shutdown and also helps maintain water clarity during refueling operations. Exterior exposed ferritic surfaces of pressure-containing parts have a minimum corrosion allowance of 1/16-inch. All carbon and low alloy steel nozzles exposed to the reactor coolant have a corrosion allowance of 1/16-inch. The vessel is designed to limit coolant retention pockets and crevices.

The nil-ductility transition temperature (NDTT) is defined as the temperature below which ferritic steel fractures in a brittle rather than a ductile manner. A similar expression is the reference temperature of nil-ductility transition, RT_{NDT}, which is defined as the temperature 60°F below the index temperature corresponding to 50 ft-lbs Charpy V-Notch energy. The NDTT and RT_{NDT} values increase as a function of neutron exposure at integrated neutron exposures greater than about 1 x 10^{17} nvt with neutrons of energies in excess of 1 Mev. The material NDTT dictates the minimum operating temperature at which the reactor vessel can be pressurized. One way to control the material NDTT is by selecting fine-grained steels and by using advanced fabrication techniques to minimize radiation effects. The as-fabricated initial RT_{NDT} for all carbon and low alloy steel used in the main closure flanges and the shell and head materials connecting to these flanges is limited to a maximum of 20°F as determined by ASTM E208. For all other carbon and low alloy steel pressure containing materials and the vessel support skirt material, the as-fabricated initial RT_{NDT} is no higher than 40°F. A grain size of five or finer, as determined by the method in ASTM E112, is the objective of the fabrication technique. Detailed information on brittle fracture considerations is provided in USAR Section IV-2.6.2.

The vessel top head is secured to the reactor vessel by studs and nuts which are designed to be tightened with a stud tensioner. The vessel flanges are sealed by two concentric Inconel seal-rings designed for no detectable leakage through the inner or outer seal at any operating condition including: a) cold hydrostatic pressure test at the full design pressure; b) heating to operating pressure and temperature at a maximum rate of 100°F/hr. To detect lack of seal integrity, a 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 tap is also provided in the area outside the outer seal-ring for use in monitoring leakage.

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 which consists of a minimum of two layers and a minimum of 0.25 inch total thickness after all machining, including the area under the seal grooves. The first layer is deposited with a composition equivalent to ASTM A371, Type ER309, and the second layer has a composition equivalent to ASTM A371, Type ER308, except that the carbon content does not exceed 0.08%.

Thermocouple pads are located on the exterior of the vessel. At each thermocouple location, two pads are provided - an end pad to hold the end of a thermocouple and a clamp pad equipped with a set screw to secure the thermocouple. Table IV-2-3 presents the quantities of the reactor vessel's internal and external attachments.

TABLE IV-2-1

TYPICAL REACTOR VESSEL DATA

Reactor Vessel	
Inside Diameter, inches (min.)	218
Inside Length, ft.	69.3
Design Pressure and Temperature	1250 psig/575°F
Vessel Nozzles (No. and size)	
Recirculation Outlet	2 - 28"
Steam Outlet	4 - 24"
Recirculation Inlet	10 - 12"
Feedwater Inlet	4 - 12"
Core Spray Inlet	2 - 10"
Control Rod Drive	137 - 6"
Jet Pump Instrumentation	2 - 4"
Vent	1 - 4"
Instrumentation	6 - 2"
Control Rod Drive Hydraulic System Return (Capped)	
Core Differential Pressure and Liquid Control	1 - 2"
Drain	1 - 2"
In-Core Flux Instrumentation	43 – 2"
Head Seal Leak Detection	2 - 1″
Spare Top Head Nozzle	2 - 6"
Estimated Weights (lbs) *	
Bottom Head	122,000
Vessel Cylinder	822,000
Vessel Flange	41,000
Support Skirt	20,000
Internals Support	15,000
Nozzles	17,000
Control Rod Drive Housings	68,000
Stub Tubes	6,000
In-Core Flux Monitor Housings	3,000
Total Vessel without Top Head	1,114,000
Top Head	135,000
Total Vessel	1,249,000

*refer to calculation NEDC 97-088 Attachment 4 if more detailed weight information is required.

TABLE IV-2-2

REACTOR PRESSURE VESSEL MATERIALS

Component	Form	Material	Spec.(ASTM/ASME)
Heads, shell	rolled plate	low alloy steel	SA533 Gr B cc 1339-2
Closure flange	forged rings	low alloy steel	SA508 C1 2 cc 1332-3
Cladding	weld overlay	austenitic stainless steel	SA371 type ER309-type ER308 (and carbon content < 0.08 w/o)
Nozzles	forged shapes	low alloy steel	SA508 C1 2 cc 1332-3
Control rod drive stub tubes	Tube	Ni-Cr-Fe	SB167 cc 1336
Control rod drive housing	Pipe	austenitic stainless steel	---
In-core housing	Pipe	austenitic stainless steel	---
Vessel support skirt cylinder	rolled plate	carbon steel	SA516 Grade 70
Shroud support	rolled plate	Ni-Cr-Fe	SB168
Nozzle thermal sleeves	Pipe	austenitic stainless steel	SA312/376 Type 304
Nozzles for instrument penetrations	Forging	Ni-Cr-Fe	SB166 cc 1336
Vessel support skirt forging (welding to bottom head)	Forging	low alloy steel	SA336

TABLE IV-2-3

REACTOR VESSEL ATTACHMENTS

Internal Attachments	Quantity
Guide Rod Bracket	2
Steam Dryer Support Bracket	4
Dryer Holdown Bracket	4
Feedwater Sparger Bracket	8
Jet Pump Riser Support Pads	1 ea; 20 places
Core Spray Bracket	4
Surveillance Bracket	6
External Attachments	
Stabilizer Bracket	4
Top Head Lifting Lug	4
Insulation Support Brackets	12 ea; 2 places
Thermocouple Pad	32

2.5.1.1 RPV Nozzles

The vessel nozzles (General Electric Drawing 919D690BC, Sheet 3) are low alloy steel forgings made in accordance with ASTM A508. Nozzles of 3-inch nominal size or larger are full penetration welded to the vessel. Nozzles of less than 3-inch nominal size may be partial penetration welded as permitted by ASME Code, Section III.

The vessel top head nozzles are provided with flanges with small groove facing. The drain nozzle is of the full penetration weld design. The recirculation inlet nozzles located as shown in General Electric Drawing 197R576, Sheet 1, feedwater inlet nozzles and core spray inlet nozzles have thermal sleeves similar to those shown in the detail of General Electric Drawing 919D690BC, Sheet 3.

Nozzles connecting to stainless steel piping have "safe ends" of stainless steel of types which are compatible with the material of the mating pipe. Nozzles for connecting carbon steel piping (except the top head nozzles which are unclad) are clad through at least the thickness of the vessel wall or one-half the diameter of the nozzle bore, whichever is less.

During replacement of the feedwater spargers[52] in 1980 the stainless steel cladding was removed from the feedwater nozzles to reduce thermal stresses and crack initiation. Stainless steel cladding was originally installed for corrosion protection of the carbon steel nozzle and to minimize rust accumulation in the reactor vessel water, but experience has shown that cladding on the feedwater nozzles is unnecessary because the area of exposed base metal is relatively small.

Moreover, there are deleterious effects from the use of feedwater nozzle cladding. The cladding would experience larger amplitude metal temperature fluctuations than the carbon steel base metal and higher stresses caused by these fluctuations. In 1980, when new feedwater spargers with concentric thermal sleeves were installed (see USAR Section III-3.4), the feedwater nozzles were bored out to a depth that exposed undamaged base metal. The net effect of cladding removal and consequent reduction in thermal stresses is to prolong the time to crack initiation and increase the number of plant startup and shutdown cycles required to grow fatigue cracks to the limiting depth as specified by the applicable ASME Code requirements. The decrease in the crack growth rate results from the elimination of the stresses due to differential thermal expansion of the stainless steel and carbon steel near the surface. Removing the cladding also improves the interpretation of ultrasonic signals during Inservice Inspection of the feedwater nozzles.[52]

The nozzle for the core differential pressure and standby liquid control (SLC) pipe was designed with a transition so that the stainless steel outer pipe of the differential pressure and SLC line (see USAR Section III-3, "Reactor Vessel Internals Mechanical Design") could 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 SLC line to minimize thermal shock effects on the reactor vessel in the event that use of the SLC system is required.

The safe-ends at the recirculation inlet nozzles, recirculation outlet nozzles, core spray inlet nozzles, and the core differential pressure and SLC are fabricated from a low carbon stainless steel (316NG)[60]. Both jet pump instrumentation penetration seals are also fabricated from low carbon stainless steel (316NG). Nozzle ends for carbon steel piping are ASME SA508 Class 1.

2.5.2 Shroud Support

The reactor vessel shroud is a cylindrical shell that surrounds the core assembly and provides a barrier to separate the upward core flow from the downward annulus flow. The shroud support is a flange plate welded to the inner vessel wall and the shroud. The shroud support is designed to carry the weight of the shroud, the jet pumps, and the steam separators and dryers. Stresses due to reactions at the shroud support are within ASME Code, Section III requirements.

The design pressure differential across the core 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 hold down brackets, feedwater sparger brackets, and core spray brackets) are as shown in General Electric Drawing 197R576, Sheet 1 and Table IV-2-3.

2.5.3 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 support assembly consists of a ring girder and the various bolts, shims, and set screws necessary to position and secure the assembly between the reactor vessel support skirt and the support pedestal. The concrete and steel support pedestal is constructed integrally with the building foundation. Steel anchor bolts are set in the concrete with the threads extending above the surface. The anchor bolts extend through the ring girder bottom flange. High strength bolts are used to bolt the flange of the reactor vessel support skirt to the top flange of the ring girder. The ring girder is fabricated of ASTM A36 structural steel according to AISC Specifications.

2.5.4 Vessel Stabilizers

Eight 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 stabilizer rod, threaded at the ends, springs, washers, nut, a plate, and a bumper bracket with tapered shims. The stabilizers are attached to each bracket and apply tension in opposite directions. The stabilizers are evenly pre-loaded with tensioners to the values of the residual loads. The stabilizers are designed to permit radial and axial vessel expansion, to limit horizontal vibration, and to resist seismic and jet reaction forces.

2.5.5 Refueling Bellows

The refueling bellows forms 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 General Electric Drawing 197R576, Sheet 1) consists of a bellows, a backing plate, a spring seal, and a removable guard ring. 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 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. 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 and the reactor well seal bulkhead plate. The reactor refueling bellows assembly is welded to the reactor vessel shell flange (see General Electric Drawing 197R576, Sheet 1) and the reactor well seal bulkhead plate. The reactor refueling bellows assembly is welded to the reactor vessel shell flange (see General Electric Drawing 197R576, Sheet 1) and the reactor well seal bulkhead plate bridges the distance to the primary containment drywell wall. Watertight hinged covers are bolted in place for normal refueling operation. For normal operation, these covers are opened to permit circulation of ventilation air in the region above the reactor well seal.

2.5.6 Control Rod Drive Housings

The control rod drive housings are inserted through the control rod drive penetrations in the reactor vessel bottom head and are welded to the Inconel stub tubes extending into the reactor vessel[9] (General Electric Drawing 919D690BC, Sheet 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 USAR Section III-4, "Reactivity Control Mechanical Design") the weight of a control rod guide tube, one four-lobed fuel support piece, and the four fuel assemblies which rest on the top of the fuel support piece (see USAR Section III-3, "Reactor Vessel Internal Mechanical Design"). The housings are fabricated of Type 304 austenitic stainless steel.

2.5.7 Control Rod Drive Housing Supports

The control rod drive housing support is designed to prevent a nuclear transient in the unlikely event that there is a control rod drive housing failure. This device consists of grid structure located 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 protection provided by the control rod drive housing supports following a CRD housing failure is described in detail in USAR Section III-5.6.2.

2.5.8 In-Core Neutron Flux Monitor Housings

The in-core 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 (General Electric Drawing 919D690BC, Sheet 3). An in-core flux monitor guide tube is welded to the top of each housing (see USAR Section III-3, "Reactor Vessel Internal Mechanical Design") and either a source range monitor/intermediate range monitor (SRM/IRM) drive unit or a local power range monitor (LPRM) is bolted to the seal-ring flange at the bottom of the housing (see USAR Section VII-5, "Neutron Monitoring System").

2.5.9 Reactor Vessel Insulation

The reactor vessel insulation is of the reflective metallic type. It has an average heat transfer rate of less than 80 Btu/Hr-Ft2 at the vessel operating condition of 575°F and ambient drywell air temperature of 135°F. Insulation thicknesses are 4 inches for the upper head, 3.5 inches for the cylindrical shell, and 3 inches for the bottom head.

The top head insulation can be removed in one piece. The insulation on the vessel shell, nozzles, and support skirt can be removed in panel sections over those areas selected for inservice inspection. The shell insulation is supported by a frame at the bottom, and by two other support rings which are permanently welded to the vessel at intermediate positions. The bottom head insulation has a self-supporting frame which bears on the leg of the support skirt.

2.6 Safety Evaluation

2.6.1 Design Loadings

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 (1000 psig at the level of the top head flange) without causing 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 carbon alloy steel is used as the base metal with an internal cladding of stainless steel applied by weld overlay. Use of the ASME Code, Section III, Class A, pressure vessel code design criteria provides assurance that a vessel designed, built, and operated within its design limits has an extremely low probability of failure due to any known failure mechanism.

Stress analysis and load combinations for the reactor vessel have been evaluated for the cycles expected throughout the 40-year life, with the conclusion that ASME Code limits are satisfied. The details of assumed loading combinations are described in USAR Appendix C for Class I equipment.

2.6.2 Brittle Fracture Considerations

2.6.2.1 Compliance with 10CFR50 Appendix G, July 1983

A major condition necessary for full compliance with 10CFR50 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 which were purchased to earlier Code requirements, such as the Cooper vessel with a construction code date of Winter 1966.

Ferritic materials complying with current requirements of 10CFR50 Appendix G must have both drop weight tests and Charpy V-Notch (CVN) tests with the CVN specimens oriented transverse to the principal material working direction to establish the reference temperature RT_{NDT}. The CVN 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 10CFR50 also requires a minimum of 75 ft-lb transverse upper-shelf CVN energy (USE) for unirradiated beltline materials, and at least 50 ft-lb transverse USE at the end-of-life, unless it is demonstrated in a manner approved by the NRC that lower values of USE will provide margins of safety against fracture equivalent to those required by Appendix G of the ASME Code. It also requires at least 45 ft-lb CVN energy and 25 mils lateral expansion for bolting material at the lower of the preload or lowest service temperature (LST).

By comparison, materials for the Cooper RPV were qualified during vessel fabrication by CVN tests on longitudinal oriented specimens and for some materials by drop weight tests. Weld tests were generally conducted at only one temperature, confirming that the material met 30 ft-lb CVN energy at the required test temperature of 10°F. While there was no USE requirement on the beltline materials, full CVN curves were generated for the RPV plate material; thus initial USE data is available for the Cooper RPV beltline plate material. The bolting materials were qualified to a 30 ft-lb CVN 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 Cooper RPV materials cannot be shown to comply directly with the requirements of ASME Code Section III NB-2300. However, Paragraph III.A of 10CFR50 Appendix G states that an approved method may be used to demonstrate equivalence of pre-1972 Code fracture toughness data with post-1972 Code requirements. The method used to develop RT_{NDT} values for Cooper is described in USAR Section IV-2.6.2.2.

2.6.2.2 Method of Initial RT_{NDT} Evaluation

For the purpose of setting the operating limits the initial RT_{NDT} was determined from the toughness test data taken in accordance with requirements of the Code and the General Electric purchase specification to which the RPV was designed and manufactured. These toughness test data, CVN energy and dropweight nil-ductility temperature (NDT) were analyzed to establish compliance with the intent of 10CFR50 Appendix G. Because all toughness testing needed for strict compliance was not required at the time of RPV procurement, some toughness results are not available. To substitute for this absence of certain data, toughness property correlations were derived by General Electric in 1978 for the BWR vessel materials in order to operate upon the available data to give a conservative estimate of RT_{NDT}, compliant with the intent of 10CFR50 Appendix G criteria. These toughness correlations vary, depending upon the specific material analyzed, and were derived from the results of Welding Research Council (WRC) 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 CVN 50 ft-lb temperature minus 60°F, whichever is greater. As a matter of practice where NDT results are missing, NDT is estimated for the longitudinal CVN 35 ft-lb transition temperature. However, for the Cooper vessel plates, dropweight NDT information was available. The transverse CVN 50 ft-lb transition temperature was estimated from longitudinal CVN data in the following manner. The lowest longitudinal CVN energy, if below 50 ft-lb, was adjusted to derive a longitudinal CVN 50 ft-lb transition temperature by adding 2°F per 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. The 2°F/ft-lb correlation is an upper bound estimate, based on test results of 24 A533 plates reported in Welding Research Council (WRC) Bulletin 217[65] and evaluation of 22 plates of SA533 reported in the LaSalle FSAR[66]. Additional discussion of this methodology is provided in GE-NE-523-109-0893, "Basis for GE RT_{NDT} Estimation Method,"[79][91] which was submitted by the Boiling Water Reactor Owners' Group to the NRC in support of industry response to NRC Generic Letter 92-01, Revision 1.[80] The 30°F conversion factor for longitudinal to transverse Charpy energies is based on the results in WRC-217.

For forgings (ASTM A508, Class 2), the predicted limiting property is the same as for the vessel plates, and the RT_{NDT} was estimated in the same way. There was little data available to establish the longitudinal-to-transverse conversion for A508, so the 30°F factor for A533 was used, assuring that the resulting RT_{NDT} values were consistent with A508 NDT values. The A508 forging data for the Cooper vessel have been analyzed using Branch Technical Position MTEB 5-2.

The A508 forging (closure flange and nozzle) materials were subjected to Charpy tests at one temperature, 10°F. For all forgings except one steam nozzle forging, NDT values were documented as well. Branch Technical Position MTEB 5-2, Section B.1.1 (4) states.

> "If limited Charpy V-notch tests were performed at a single temperature to confirm that at least 30 ft-lbs was obtained, that temperature may be used as an estimate of the RT_{NDT} provided that at least 45 ft-lbs was obtained if the specimens were longitudinally oriented. If the minimum value obtained was less than 45 ft-lbs, the RT_{NDT} may be estimated as 20°F above the test temperature."

Table IV-2-4 contains a summary of the resulting data for the Cooper vessel A508 Class 2 forgings.

For the vessel weld metal the predicted limiting property is the CVN 50 ft-lb transition temperature minus 60°F. The CVN 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 CVN 50 ft-lb transition temperature minus 60°F. The initial upper bound RT_{NDT} for the limiting beltline weld was obtained from the evaluations done for pressurized thermal shock[67]. The initial upper bound RT_{NDT} value used is -22°F. The chemistry data for the Cooper weld was not available, however, an identical Heat 12420, with Linde 1092 flux was used in the Salem Unit 1 vessel. The chemistry data were 0.22% Cu and 1.02% Ni. Phosphorus was assumed at 0.020%. The result is that with a copper content as high as 0.28%, the beltline plate remains limiting.

For the vessel weld heat affected zone (HAZ) material the RT_{NDT} was assumed the same as for the base material as ASME Code weld procedure qualification test requirements and post weld heat treatment data indicate this assumption is valid.

Closure bolting material (ASTM A540 or ASME SA540, Grade B23 or B24) toughness test requirements are CVN 30 ft-lb energy at 60°F below the bolt preload temperature. Current 10CFR50 Appendix G requirements are for 45 ft-lb and 25 mil lateral expansion (MLE) at the bolt preload or lowest service temperature (LST). Some closure stud materials do not meet 45 ft-lb absorbed energy at +10°F, and mils lateral expansion results were not reported. Since compliance with current requirements could not be shown, the original requirements were used to establish the closure bolting material LST.

2.6.2.3 Calculated Values of Initial RT_{NDT}

The methods of USAR Section IV-2.6.2.2 were used to calculate initial RT_{NDT} values for the core beltline plates and welds, closure flange region, nozzles and other discontinuities, and LST for the closure bolting material. The calculation methods conservatively estimate RT_{NDT}, in order to meet the intent of 10CFR50 Appendix G criteria. Calculated values of initial RT_{NDT} are presented in Table IV-2-5.

Table IV-2-4

INITIAL RT_{NDT} ESTIMATES FOR COOPER VESSEL A508 CLASS 2 FORGINGS

Component	Charpy Test Temperature (°F)	Minimum Charpy Energy (ft-lbs)	NDT (°F)	RT_{NDT} (°F)
Flanges				
Head Flange	10	74	20	20[a]
Vessel Flange	10	62	10	10
Nozzles				
Recirc. Outlet	10	58	0	10
Recirc. Inlet	10	35	-10	30
Steam Outlet	10	31	N/A	30
Feedwater	10	48	0	10
Core Spray	10	45	0	10
Head Spray	10	69	0	10
Vent	10	74	0	10
Jet Pump Instrument	10	134	-10	10
CRD Return	10	87	-10	10

[a] The RT_{NDT} was taken as 20°F because of the NDT. RT_{NDT} per MTEB 5-2 is 10°F.

Table IV-2-5

EQUIVALENT TRANSVERSE RT_{NDT} VALUES FOR REACTOR VESSEL MATERIALS

Component	Transverse CVN 50 ft-lb Temperature (°F)	Dropweight NDT Temperature (°F)	RT_{NDT} (°F)
Closure Flanges	40	20	20
Plate Connecting to Closure Flanges	74	-20	14
Closure Bolting Material	Meets 30 ft-lb at 10°F		10
Beltline Plates	74	-10	14
Beltline Welds	10	--	-22
Bottom Head Torus Plate	88	-10	28

2.6.2.4 Pumps, Piping, Valves, Bolts[3]

The fracture notch toughness properties and the operating temperature of ferritic materials will be controlled to ensure adequate toughness when the system is pressurized to more than 20 percent of the design pressure. Such assurance will be provided by maintaining the lowest service metal temperature, when the system pressure exceeds 20 percent of the design pressure, at least 60°F above the NDTT. The lowest service metal temperature will be the lowest temperature which the metal will experience in service while the plant is in operation. It will be established by appropriate calculations considering atmosphere ambient temperatures, the insulation or enclosure provided, and the minimum temperature maintained. Further interpretations and requirements are described in USAR Appendix A.

2.6.2.5 Results of the Core Beltline Materials:

	Plate	Weld
Limiting Material for Shift:	Lower intermediate shell plate G-2802-2 (heat no. C2307-2)	Lower shell axial welds 2-233A,B,C (heat no. 12420)
Reference Temperature (Initial RT_{NDT}):	-20°F	-50°F
Total Margin related to Surveillance Results (Defined by RG 1.99):	17°F	56°F
Transition Temperature Shift (ART) at EOL:	131.2°F	120.4°F
Limiting Material for USE:	Lower shell plate G-2802-3 (heat no. C2274-2)	Girth weld lower/ lower intermediate shell circ. weld I-240 (heat no. 21935)
Reference (Initial) USE (L/T): *	72.2 ft-lb	62 ft-lb
Decrease in USE at EOL (L/T): *	12.7 ft-lb	12.3 ft-lb
Adjusted USE at EOL (L/T): *	59.5 ft-lb	49.7 ft-lb

* (Longitudinal/Transverse) plate values converted per Branch Technical Position MTEB 5-2. USE values based on 54 EFPY.

The predicted EOL reference temperatures are below 200°F, and the predicted EOL upper shelf energies are above 50 ft-lb, with the exception of weld heat no. 21935. For weld heat no. 21935, an equivalent margins USE analysis (EMA) was required which shows that the EOL USE reduction is bounded by the BWRVIP-74-A EMA, thereby demonstrating acceptability to 54 EFPY. Therefore, provisions to permit thermal annealing of the RPV in accordance with Paragraph IV.B of 10CFR50 Appendix G are not required.

2.6.3 Operating Pressure-Temperature Limit Curves

Operating limit pressure temperature (P-T) curves are required for the Technical Specifications for three reactor conditions. They are inservice hydrostatic and inservice leakage tests, non-nuclear heatup or cooldown following nuclear shutdown, and heatup or cooldown with core critical. The curves are established by requirements of 10CFR50, Appendix G, and have been developed to conform with ASME Section XI, Appendix G.

The P-T curves were removed from the Technical Specifications in accordance with NRC approved License Amendment 256 in September 2016. The P-T curves now reside in a CNS controlled document identified as a Pressure Temperature Limits Report (referred to as PTLR). The PTLR is included in the Technical Requirements Manual (TRM) for reference. PTLR Figures 1 (Curve A), 2 (Curve B), and 3 (Curve C) located in the TRM show the heatup/cooldown, operation, and pressure test operating curves that are valid through 54 effective full power years. There are three regions of the reactor pressure vessel (RPV) that are evaluated: (1) the beltline region, (2) the bottom head region, and (3) the non-beltline (i.e., feedwater nozzle/upper vessel) region. These regions bound all other regions with respect to brittle fracture.

2.6.3.1 Irradiation Effects on Core Beltline

Estimated maximum changes in RT_{NDT} and upper shelf fracture energy (USE) as a function of the EOL fluence at the one-quarter thickness (1/4 T) of the vessel beltline materials are listed below. The updated predicted peak EOL fluence at the RPV inside surface is 2.23 x 10^{18} n/cm^2 after 60 years of service (54 effective full power years (EFPY)). The updated fluence prediction is based on the Radiation Analysis Modeling Application (RAMA) Code. The RAMA Code has been approved by the NRC and adheres to the guidance in Regulatory Guide 1.190. The period of applicability of the current P-T curves is 54 EFPY. USAR Section IV-2.7.2 describes the RPV Material Surveillance Test Program, as it is used to periodically revalidate and update the P-T curves.

Additional basis for meeting the 10CFR50 Appendix G requirements for beltline material USE at end of reactor life was described in the District's response to an NRC request for additional information concerning Generic Letter 92-01, Revision 1. The District's response[81] referenced an analysis performed by General Electric on behalf of the BWROG to demonstrate equivalent margin for beltline materials as permitted by 10CFR50 Appendix G, and provided as an attachment, applicability verification forms to demonstrate that the analysis bounds Cooper vessel beltline materials. This effort provided an additional means of demonstrating compliance with the USE requirements specified in 10CFR50 Appendix G. The equivalent margin analysis is documented in GE Report NEDO-32205-A, Revision 1.[82]

Adjusted reference temperature (ART) values were developed in accordance with Regulatory Guide 1.99, Revision 2, based on updated fluence data. The most limiting beltline material is the Lower Intermediate Shell Plate. The ART for end-of-life was calculated to be 131.2°F at 54 EFPY.

2.6.3.2 Operating Conditions Versus Limits

An examination of operational transients was made to determine if any transient conditions violate the P-T curves. The worst transient identified is an upset condition where loss of power causes the reactor to scram and significant thermal stratification to occur. The worst pressure-temperature combination is 1180 psig and 250°F in the bottom head of the vessel. The steam space coolant temperature at the same time in the event is fluctuating between 490°F and 560°F.

The appropriate P-T curve is selected based on the operating conditions. Since a scram has occurred and the vessel is at elevated temperature and pressure, curve B of the PTLR applies. As seen on that Figure, the minimum required temperature at 1180 psig is 206°F. Therefore, the worst case transient conditions are acceptable from a brittle fracture viewpoint through 54 EFPY.

2.6.4 Core Flooding Capability

The core flooding capability of a jet pump design is discussed in detail in the Emergency Core Cooling System (ECCS) document filed with the AEC as a G.E. Topical Report.[17] This satisfies safety design basis 3.

Based upon the entire above discussions, it is concluded that safety design bases 1, 2 and 3 as delineated in USAR Section IV-2.2 are met.

2.7 Inspection and Testing

2.7.1 In Service Inspection

Inspection of the RPV and its appurtenances is performed as part of the CNS In Service Inspection Program as required by 10CFR50.55a and Section XI of the ASME Code.

In service inspection was considered during the design to assure adequate working space and access for inspection of selected reactor vessel components and locations. Direct visual examination is proposed whenever possible because it is sensitive, fast, and positive. Insulation panels or portions of panels outside the vessel support are removable to permit inspection of the vessel and vessel support surfaces. Insulation panels on the inside of the vessel support are provided with inspection openings with hinged or sliding closures. All nozzles (except those nozzles inside the vessel support such as the control rod drive, in-core instrument, and drain nozzles in the bottom head) have insulation designed so that it may be removed to expose the entire exterior of the nozzle and the vessel shell.

An ultrasonic examination is performed upon the feedwater nozzles in lieu of the internal dye penetrant examination specified by NUREG-0619. Performing ultrasonic examinations in compliance with ASME Section XI, Appendix VIII as mandated by 10 CFR 50.55a eliminates the need to remove the feedwater spargers, which could damage the thermal sleeve or seal ring, and reduces the total radiation dose to personnel during the performance of this inspection. Ultrasonic examinations performed in accordance with Appendix VIII detect cracks with acceptable reliability and consistency and achieves the level of confidence specified in NUREG-0619 while following ALARA principles.

2.7.2 RPV Material Surveillance Test Program

The RPV Material Surveillance Test Program provides for the preparation of 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 which simulates a welded joint in the reactor vessel. Test specimens of the reactor vessel base, weld and heat affected zone metal subjected to the highest fluence of greater than 1 Mev neutrons are installed in the reactor vessel adjacent to the vessel wall at the core midplane level. These locations are as close as possible to the zone of highest fluence. The reactor vessel surveillance specimens are removed and examined to determine changes in their material properties as required by 10CFR50 Appendix H. The testing results are used to calculate the Adjusted Reference Temperature of the reactor beltline materials per Regulatory Guide 1.99 Revision 2. The results provide a basis for validating the existing P-T curves, or for revising the curves per 10CFR50 Appendices G and H.

The original basis for surveillance program for CNS is described in the GE-APED Topical Report, NEDO-10115, "Mechanical Property Surveillance of General Electric BWR Vessels."[8][10] The specimens and sample program conform to ASTM E 185-73 to the degree possible. However, as provided for in 10CFR50 Appendix H Section III.B.1, conformance to later editions through ASTM E 185-82 are acceptable. CNS has adopted the Boiling Water Reactor Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) as its current licensing basis for specimen withdrawal and testing. The BWRVIP ISP meets the requirements of 10CFR50 Appendix H, Section III.C. The ISP program document is the latest revision of BWRVIP-86, as documented in the CNS Vessel Internals Program. The schedule for the remaining capsules is provided in BWRVIP-86. As part of the ISP, CNS capsules are evaluated using fluence calculations that conform with Regulatory Guide 1.190. Recalculation of fluences for previously pulled capsules are also in conformance with Regulatory Guide 1.190. The ISP is designed to comply with ASTM E 185-82 for those surveillance program elements that are within the ISP scope. ASTM E 185-73 remains applicable to the criteria for capsule design and location within the reactor vessel, including dosimeters used to measure specimen irradiation.

The specimens are hermetically sealed in an inert gas environment in a thin wall stainless steel capsule which is not buoyant and does not present any problems in removing the irradiated capsules. All specimens are encapsulated in tight containers, and tensile specimens have aluminum spacers to keep gamma heating as close as possible to vessel wall conditions. The vessel design does not have provision for later insertion of surveillance material. Sample containers can be withdrawn but not replaced.[8]

Dosimeters are a part of the specimens to measure flux. Iron, nickel and copper are used as flux monitors. One of each is included in each impact specimen capsule. In addition, one separate removable flux dosimeter is also included.[8]

3.0 REACTOR RECIRCULATION SYSTEM

3.1 Safety Objective

The safety objective of the reactor recirculation system is to provide protection against radioactive material release, or loss of coolant, for all normal or abnormal operational transients or accidents.

3.2 Safety Design Bases

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

2. The reactor recirculation system is designed so that a 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 operating during abnormal, accident, and special event conditions.

4. The reactor recirculation system is designed so that the reactor recirculation pump discharge valves (RPDV) close upon LPCI initiation following a loss-of-coolant accident originating in the recirculation loop suction line.

3.3 Power Generation Objective

The objective of the reactor recirculation system is to provide a variable moderator (coolant) flow to the reactor core for adjusting reactor power level.

3.4 Power Generation Design Bases

1. The reactor recirculation system shall provide sufficient flow to remove heat from the fuel over the entire load range.

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

3.5 Description

The reactor recirculation system consists of two recirculation loops external to the reactor vessel which provide the piping path for the driving flow of water to the reactor vessel jet pumps (Figure IV-3-1 and Burns and Roe Drawing 2027, Sheets 1 and 2). Each external loop contains one variable speed, motor-driven recirculation pump and two motor-operated gate valves for pump maintenance. Each pump discharge line contains a venturi-type flow element. The recirculation loops are a part of the Reactor Coolant Pressure Boundary (RCPB) and are located inside the primary containment structure. Table IV-3-1 summarizes the characteristics of the reactor recirculation system.

The recirculated coolant consists of saturated water from the steam separators and dryers which has been subcooled by 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. Each of the two external recirculation loops discharges 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 flows, both driving and driven, are mixed in the jet pump throat section and result in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing section (Figure IV-3-4). The adequacy of the total flow to the core is discussed in USAR Section III-7, "Thermal and Hydraulic Design". Tests have been conducted and documented[11] to show that the jet pump design is sound and that jet pump operation is stable and predictable. A significant feature of the recirculation system is its influence on reactor power control. Reactor power output can be varied by adjusting the reactor coolant flow by varying the speed of the recirculation pumps. An increase in flow increases reactor power and a reduction in flow decreases reactor power. Power change can be accomplished faster using core flow than by using control rod manipulation.[12]

TABLE IV-3-1

REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS

EXTERNAL LOOPS

Number of Loops	2
Pipe Sizes (nominal O.D.)	
Pump Suction	28 in.
Pump Discharge	28 in.
Discharge Manifold	22 in.
Recirculation Inlet Line	12 in.
Design Pressure/Design Temperature	
Suction Piping	1148/562 psig/°F
Discharge Piping	1274/575 psig/°F
Pumps	1500/575 psig/°F

OPERATION AT INCREASED CORE FLOW CONDITIONS

The CNS Increased Core Flow (ICF) analysis assumed original Reactor Recirculation system design conditions. Differences between design data and actual plant data, and system performance changes since initial startup were not considered in the evaluation. Core flow capability could be significantly reduced such that 105% core flow may not be attainable and/or significantly higher speeds, power, and other outputs may be needed to reach 105% core flow.

Recirculation Pump (each)	
Flow	46,000 gpm (approx.)
Flow	17.5×10^6 lb/hr
Total Developed Head	450 ft.
Suction Pressure (static)	1033 psia
Available NPSH* (min)	493 ft.
Water Temperature (max)	529°F
Pump	4455 hp brake
Flow Velocity at Pump Suction	28.1 fps (approx.)
Drive Motor and Power Supply	
Frequency (at rated)	56 cps
Frequency (operating range)	11.5 - 57.5 cps
Required Power to M-G Sets - per set	4740 kW/set
Required Power to M-G Sets - total	9480 kW/total
Jet Pumps	
Number	20
Total Jet Pump Diffuser Flow	77.2×10^6 lb/hr
Throat I.D.	6.86 in.
Diffuser I.D.	17.0 in.
Nozzle I.D.	3.40 in. (typical)
Diffuser Exit Velocity	14.4 fps
Jet Pump Head	84.2 ft.

*Includes velocity head.

All jet pumps have single tap instrumentation and four of the jet pumps have an additional diffuser tap.

Core flow is measured using the single diffuser tap instrumentation. The double diffuser tap instrumentation is not part of the system as such. However, it is an important subsystem since it is used to calibrate the single tap system during startup.

The double tap diffusers are calibrated prior to installation and calibration factors calculated relating the jet pump mass flow to the differential pressure across the diffuser taps.

Since the single tap system depends on the lower plenum pressure as a common reference point, it is not possible to calibrate the system prior to installation in the reactor. Calibration is done during hot startup at or near rated core flow as follows:

1. Find the calibration factors for the single tap system from the double tap system by calculating the flows through the calibrated pumps and using the single tap signals for the calibrated pumps and these flows to calculate the single tap flow factors.

2. Calculate the core flow and adjust the total loop flow instrumentation so that core flow is correctly indicated.

There is no difference in susceptibility to blockage between the single and double tap instrument systems.[13]

In order to avoid a hydraulic lock in the recirculation pump discharge and suction valve when they are closed in the hot pressurized condition, the volume inside the valve disc is vented through a small hole drilled in the disc face closest to the reactor.[60]

The reactor recirculation pump discharge gate valves have an operator-selectable automatic jog-open feature which when selected will automatically jog-open the discharge valves during initial start-up or return to service of an idle recirculation pump. Reactor recirculation pump speed is not increased above minimum until the discharge gate valve is completely open.[58]

The loop selection logic feature of the LPCI system has been removed. (See USAR Chapter VII, Section 4.3.5.) This modification (DC 76-02) included the removal of the loop selection logic feature of the original design and instituted instead the simultaneous opening of both LPCI valves. This was done to ensure that at least one-half of the LPCI capacity could be available after a postulated loss-of-coolant accident (LOCA) (i.e., suction line break). Another essential element of this modification involves the closure of the recirculation pump discharge valves (RPDV) upon LPCI initiation following a loss-of-coolant accident. The closure of the RPDV is necessary to isolate a pipe rupture occurring in the recirculation loop suction line and thereby ensure that LPCI will not discharge makeup water back through the recirculation pump and out of the break. The failure of a RPDV to close upon LPCI initiation has an adverse affect on core cooling similar to the failure of a LPCI valve to open. The failure of a LPCI valve to open is one of the single failures evaluated in the CNS Emergency Core Cooling System (ECCS) analysis.[55]

Since the removal of reactor recirculation system valve internals requires 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 and to provide adequate leak tightness. The design objective of the back seats and trim is to minimize the need for maintenance of the valve internals.

Allowable heatup rates are in the Pressure-Temperature Limits Report. It is possible to keep the idle loop hot during one pump operation by leaving the non-operating loop valves open, permitting the pressure head created by reverse flow through the idle jet pumps to cause reverse flow through the idle loop.

The following conditions apply to operation of the reactor recirculation system:

- Recirculation pumps are not to be started while the reactor is in natural circulation flow and reactor power is greater than 1% of rated thermal power.

- Following one recirculation pump operation, the discharge valve of the low speed recirculation pump is not opened unless the speed of the faster pump is equal to or less than 50% of its rated speed.

The feedwater flowing into the reactor vessel annulus during operation provides subcooling for the fluid passing to the recirculation pumps, thus providing 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 percent, the recirculation pump speed is automatically limited. Therefore, automatic protection against recirculation pump cavitation is provided by the 20 percent feedwater flow limiter. The reactor is designed so that it may be operated with only one recirculation pump.

The recirculation pumps can be operated to heat up the nuclear system 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 nil-ductility transition temperature (NDTT) considerations so that the hydrostatic test can be conducted.

Decontamination connections are provided in the piping on the suction and discharge side of the pumps, as shown in General Electric Drawing 719E415BB, to permit flushing and decontamination of the pump and adjacent piping. These connections are arranged to permit the convenient and rapid connection of temporary piping. The piping low point drain is used during flushing or decontamination to remove crud from the piping low point; it is also designed for the connection of temporary piping.

Each recirculation pump is a single stage, 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 hz.

The recirculation pump shaft seal assembly consists of two seals built into a cartridge which 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 operating. 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. A breakdown bushing in the pump casing reduces leakage in the event of a gross failure of both shaft seals. The pressure drop across each individual seal can be monitored, as well as the cavity temperature of each seal.

Each recirculation pump motor is variable speed, with an AC electric motor that can drive the pump over a controlled range of 20 to 100 percent of rated 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 applicable sections of the NEMA Standards.

A variable frequency, AC motor-generator 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 its motor. Minimum speed corresponds to a frequency of 11.5 hz. The variable speed coupling is a fluid drive unit that operates by varying the amount of fluid in a casing. This is accomplished by positioning a scoop tube with a solid state controller.[12]

The combined rotating inertias of the recirculation pump and motor, the motor-generator set, and the variable speed coupling are chosen to provide a slow coastdown of flow following loss of power to the drive motors, so that the core is adequately cooled during the loss of power transient.

The design objective for the recirculation pump casing is a useful life of 40 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 practical. The design objective is to provide a unit which will not require removal from the system for rework or overhaul at intervals of less than five years.

The recirculation system piping is designed and constructed to the requirements described in USAR Appendix A.

Except for the M-G sets, the reactor recirculation system is designed as Class I seismic equipment in accordance with criteria identified in USAR Chapter XII. As such, it is designed to resist sufficiently the response motion at the installed location within the supporting structure for the design basis earthquake, assuming the pump is filled with water for the analysis. Vibration snubbers located 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 and by sway braces to avoid the use of piping expansion loops, which would be required if the pumps are anchored. In addition, to limit pipe motion, the recirculation loops are provided with a system of restraints so designed 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. 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.

The recirculation system piping, valves, and pump casings are covered with thermal insulation. The type of insulation is either all-metal, reflective or conventional, non-metallic; it is prefabricated into components for field installation. Removable insulation is provided at various locations to permit periodic inspection of the equipment.

3.6 Safety Evaluation

Reactor recirculation system malfunctions that pose threats of damage to the fuel barrier are described and evaluated in USAR Chapter XIV, "Plant Safety Analysis". There 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.

In conformance with NUREG-0737 Item II.K.3.25, the recirculation pump seals can withstand a loss of offsite AC Power for at least two hours. Analyses show that the resulting seal leakage is within the capability of the RCIC system to provide makeup during the two hour duration.

Figure IV-3-5 shows the core flooding capability provided by jet pump design. No recirculation line break can prevent reflooding of the core to the level of the jet pump suction inlet. The core flooding capability of a plant with jet pump design is discussed in detail in the Emergency Core Cooling System (ECCS) systems document[11] filed with the AEC as a General Electric Topical Report.

Piping and pump design pressures for the reactor recirculation system 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 allowance. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the listed code design criteria provides assurance that a system designed, built and operated within design limits has an extremely low probability of failure due to any known failure mechanism.

Closure of the RPDV ensures that LPCI will not discharge makeup water back through the recirculation pump and out through the break. DC 76-02 and License Amendments 31 and 32 provide additional discussion for this evaluation.

From the above, the four Safety Design Bases (USAR Section IV-3.2) are considered to be achieved.

A recirculation pump trip (RPT) feature is incorporated and provides a backup to the scram system by tripping the recirculation pumps in the event of either high pressure or low water level (Level 2) in the reactor vessel.

The pressure switches service RPT and Alternate Rod Insertion (ARI), while the water level switches are used for the following functions in addition to RPT and ARI.

1. Initiate closure of the MSIVs.

2. Operate the Main Steam Line Drain Valves.

3. Operate Reactor Water Sample Valves.

There are two trip divisions, each with two separate channels; each division is powered by a separate critical DC bus. A signal from each of two associated switches, one from each division (eg. NBI-LIS-57A from one division and NBI-LIS-58A from the other division) will trip both recirculation pumps (see Figure IV-3-6). All cabling involved is separated from the Reactor Protection System (RPS) since RPS cables are routed through rigid galvanized steel conduit. The racks holding the components are located on opposite sides of the reactor containment. All components are of protection system quality. This equipment is designed to perform its function in a reliable manner.[16]

The RPT logic is discussed further in USAR Section VII-9, "Recirculation Flow Control System."

3.7 Inspection and Testing

RCPB inservice pressure tests are performed in accordance with ASME Section XI and approved station procedures.

Jet pump consistency tests are performed as specified in Plant Technical Specifications.

The plant operating procedures outline operator monitoring and corrective action regarding jet pump blockage[13].

During the startup test program horizontal and vertical motions of the Reactor Recirculation System replacement piping and equipment were observed and supports were adjusted, as necessary, to assure that components were free to move as designed. Nuclear system responses to recirculation pump trips at rated temperatures and pressures were evaluated during the startup tests, and plant power response to recirculation flow control was determined.

To assure adequate working space and access for inspection of selected components, inservice inspection was considered in the design of the Reactor Recirculation System. Selection of the components and locations to be inspected is described in the applicable Ten Year Interval Inservice Inspection Program for Cooper Nuclear Station (see Appendix J).

The reactor recirculation system is in scope for License Renewal per 10 CFR 54.4(a)(1), (a)(2), and (a)(3) and was subject to aging management review. Aging effects are managed by the following Aging Management Programs: Bolting Integrity (see USAR Section K-2.1.2), BWR Stress Corrosion Cracking (see USAR Section K-2.1.7), External Surfaces Monitoring (see USAR Section K-2.1.14), Flow-Accelerated Corrosion (see USAR Section K-2.1.18), Inservice Inspection - ISI (see USAR Section K-2.1.19), One-time Inspection (see USAR Section K-2.1.29), One-time Inspection – Small-Bore Piping (see USAR Section K-2.1.30), and Water Chemistry Control - BWR (see USAR Section K-2.1.39). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Section K-2.2.2.1).

4.0 NUCLEAR SYSTEM PRESSURE RELIEF SYSTEM

4.1 Safety Objective

The safety objective of the pressure relief system is to prevent overpressurization of the nuclear system; this protects the Reactor Coolant Pressure Boundary (RCPB) from failure which could result in the uncontrolled release of fission products. In addition, the automatic depressurization feature of the pressure relief system acts in conjunction with the Emergency Core Cooling Systems (ECCS) for reflooding the core; this protects the reactor fuel barrier (UO_2 sealed in cladding) from failure due to overheating.

4.2 Safety Design Bases

1. The pressure relief system shall prevent overpressurization of the nuclear system in order to prevent failure of the RCPB due to pressure.

2. The pressure relief system shall provide automatic depressurization so that the LPCI and the core spray systems can operate to protect the fuel barrier.

3. The relief valve discharge piping is designed to accommodate forces resulting from relief action and shall be supported for reactions due to flow at maximum relief discharge capacity so that system integrity is maintained.

4. The pressure relief system is designed to withstand adverse combinations of loadings and forces resulting from operation during abnormal, accident, or special event conditions.

5. The pressure relief system is designed for testing prior to nuclear system operation and for verification of the operability of the pressure relief system.

6. Positive position indication of the safety/relief valves shall be provided in the control room.

4.3 Power Generation Objective

The power generation objective of the pressure relief system is to limit any overpressure which occurs during abnormal operational transients.

4.4 Power Generation Design Bases

1. The relief valves shall prevent the opening of the spring-loaded safety valves during normal plant isolations and load rejections.

2. The relief valves shall discharge to the primary containment suppression pool.

3. The relief valves shall properly reclose following a plant isolation or load rejection so that normal operation can be resumed as soon as possible.

4. The pressure relief system is designed to be used to remove decay heat and depressurize the reactor to achieve safe shutdown in the event of a fire.

4.5 Description

The pressure relief system includes 3 safety and 8 relief valves, all of which are located on the main steam lines, within the drywell, between the reactor vessel and the first main steam isolation valve (MSIV) (Figure IV-4-1). The safety valves provide protection against overpressure of the nuclear system and discharge directly to the interior space of the drywell. Table IV-4-1 shows the set pressures and capacities of the valves.

The relief valves, also referred to as safety/relief valves (SRV), discharge to the suppression pool and provide three main protection functions:

a. Overpressure relief operation. The valves are opened (self-actuated) to limit the pressure rise and to prevent safety valve opening.

b. Overpressure safety operation. The valves augment the safety valves and open (self-actuated operation only) to prevent nuclear system overpressurization.

c. Depressurization operation. The required valves are opened automatically or manually by indirectly operated devices, as part of the ECCS.

Table IV-4-1

NUCLEAR SYSTEM SAFETY AND RELIEF VALVES

	Number Of Valves[21]	Nominal Set Pressure* (psig)[21]	Capacity at 103% of Set Pressure (each), (lb/hr)
Relief Valves	2	1080	862,100***
	3	1090	870,000***
	3	1100	877,900
Total**	8 (6)		
Safety Valves	3	1240	644,543****

* Relief valve setpoint tolerances are provided in Technical Specifications.

** The number in parenthesis indicates the number of relief valves which serve in the Automatic Depressurization System (ADS) capacity.

*** Vendor-certified capacity at 103% of nominal set pressure based on relief valve nameplates.

**** At 103% of set pressure for required pressure accumulation to fully open the safety valve.

The main steam lines on which the relief and safety valves are mounted are designed, installed and tested in accordance with the applicable codes discussed in USAR Appendix A. The safety and 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 General Electric Drawing 731E611, Sheet 1 for location of the valves and piping. The criteria employed for the design and installation of RV and SV include the following considerations:

a. Discharge tees were provided on safety valves to equalize the discharge thrust force.

b. The discharge tees were oriented to ensure that the rejected steam would not adversely affect nearby equipment.

c. Flanges were installed to ensure the valve installation will meet vertical tolerances.

d. Clearances of at least six inches were provided between valves and other equipment.

e. Clearance was provided between header and bottom of flange for bolt removal when valve is installed.

f. Flatness tolerance for surface of groove was provided on the safety and relief valve flanges.

g. A larger flange rating of 1500# was provided for structural stability instead of the 900# flange required for pressure temperature rating.

h. A larger pipe schedule of 160 was used for structural stability instead of Schedule 80 required for pressure temperature rating.

i. The discharge piping on the relief valve provided an equalization of the discharge thrust forces for steady state flow.

For analysis, the special loadings listed below were considered in addition to the usual design loads such as weight, pressure, temperature, and earthquake.

1. The jet force exerted on the relief and safety valves during the first few milliseconds when the valve is open and steady state flow has not yet been established. (With steady state flow, the dynamic flow reaction forces will be self-equilibrated by the relief valve discharge piping or the tee at the safety valve discharge).

2. The dynamic effects of the kinetic energy of the piston disc assembly when it impacts on the base casting of the valve.

All code allowable stresses are met with these special loads acting concurrently with other design loads.[20]

The safety valves are spring-loaded and were designed, constructed, and marked with data in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Article 9. Popping-point tolerance (pressure at which valve "pops" wide open) is ± 3 percent of the spring set pressure. The material on the pressure side of the valve disc, in contact with the steam, is stainless steel. The valves are designed to operate with saturated steam and to have an opening response time equal to or less than 0.3 second.[21]

The relief valves are pilot operated and were designed, constructed, and marked with data in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Article 9. Popping-point tolerance (pressure at which the valve "pops" wide open) is ± 3 percent of the set pressure. Each valve is self-actuating at the set relieving pressure, but it may also be actuated by devices operated indirectly to permit remote-manual or automatic opening at low pressures. For depressurization operation, each relief valve is provided with a power-actuated device capable of opening the valve at any steam pressure above 50 psig.[21] Depressurization continues until the steam pressure decreases to about 50 psig. The control system for the actuator is described in USAR Section VII-4, ECCS. Pressure-containing parts of the valve body are fabricated of ASTM A216, Grade WCB. The relief valve is designed for operation with saturated steam. The relieving pressures for overpressure relief and safety operating modes are adjustable between 1025 and 1190 psig[21] with a maximum back pressure of 40 percent of the set pressure. The delay time (maximum elapsed time between overpressure signal and actual valve motion) and the response time (maximum valve stroke time) are each equal to or less than 0.3 second.[21]

Each safety/relief valve consists of two principle assemblies; a pilot stage assembly and the main stage assembly. These two assemblies are directly coupled to provide a unitized, dual function safety/relief valve. The pilot stage assembly is the pressure sensing and control element and the main stage assembly is a system fluid actuated follower valve which provides the pressure relief function. Self-actuation of the pilot assembly at set pressure vents the main piston chamber, permitting the system pressure to fully open the main assembly and results in system depressurization at full rated flow. This design allows steam leakage by the pilot without valve actuation and with no appreciable change in the relief setpoints. Also, the direct-acting pilot has no pressure sensing bellows or associated leakage detecting pressure switch, which have both had histories of leaks and/or failures.

Operation of the pilot assembly and main assembly is described below. Refer to Figures IV-4-2 and IV-4-3 for schematic illustration of valve in closed and open positions.

The pilot assembly of the safety/relief valve consists of two relatively small, low flow pressure sensing elements. The spring loaded pilot disc senses the set pressure and the pressure loaded stabilizer disc senses and reseat pressure. Spring force (preload force) is applied to the pilot disc by means of the pilot rod. Thus, the adjustment of the spring preload force will determine the set pressure of the valve. Operation of the pilot assembly is as follows:

During assembly, the pilot spring is adjusted to provide a preload force on the pilot disc which will establish the required set pressure of the valve. The spring preload force seals the pilot disc tightly to prevent leakage at normal operating pressures or lower system pressures.

In operation, as system pressure increases and reaches set pressure, the seating force acting on the pilot disc is reduced to zero causing the pilot disc to lift from its seat. Pilot disc lift results in the depressurization of the main piston chamber volume. Initial venting (depressurization) of the main piston chamber creates a differential pressure across the stabilizer disc in a direction causing the stabilizer disc to seat. System pressure acting upon the stabilizer disc via internal porting maintains the pilot disc in the "lifted" position thereby maintaining main piston chamber venting until the required differential pressure across the main piston is achieved, at which point the main stage opens.

When system pressure has decreased to the valve reseat pressure, the pressure sensing stabilizer disc will unseat permitting the pilot disc to reseat in turn causing main piston chamber repressurization, which results in closing of the main stage.

The main assembly of the safety/relief valve is basically a reverse seated, system fluid actuated angle globe valve.

Actuation of the main assembly permits discharge of fluid from the protected system at the valve's rated flow capacity and provides the system pressure relief function of the valve. The major components of the main stage are the valve body, disc/piston assembly and preload spring.

In its normally closed position, the main stage disc is tightly seated by the combined forces exerted by the preload spring and the system internal pressure acting over the area of the disc. Note that in the closed, no flow, position the static pressures will be equal in the valve inlet nozzle and in the chamber over the main stage piston. This pressure equalization is made possible by the internal passages provided; i.e., piston ring gap, vent hole, drain groove and stabilizer disc seat. When system pressure increases to the valve set pressure, pilot stage operation will vent the chamber over the main stage piston to downstream of the valve via internal porting. This venting action creates a differential pressure across the main stage piston in a direction tending to open the valve. The main stage piston is sized such that the resultant opening force is greater than the combined spring preload and system pressure seating force.

Once the main stage disc starts to open the system pressure seating force is reduced, causing a significant increase in opening force and the characteristic immediate full opening action.

When system pressure has been reduced to design reseat pressure, the pilot disc reseats permitting repressurization of the main piston chamber. Flow of system fluid through the main stage piston ring gap and stabilizer seat, then repressurizes the chamber over the piston. Main stage design is such that the repressurization of the piston chamber equalizes system pressure forces permitting the preload spring and flow forces to close the main stage. Once closed, the additional system fluid seating force, due to system pressure acting on the main stage disc, seats the main stage tightly.

A remotely controlled pneumatic operator is fitted to the pilot stage assembly to provide selective operation of the valve at system pressures ranging from 50 psig to valve set pressure. This is a diaphragm type pneumatic actuator which must be actuated to open the valve. It is actuated by means of a solenoid control valve which admits nitrogen to the pneumatic operator piston chamber and strokes the pneumatic operator stem, in turn stroking the pilot disc via the pilot rod. Backup instrument air can be manually supplied to accomplish this action. The main stage then opens as described in previous paragraphs. Deenergizing the solenoid vents the pneumatic operator and permits the pilot disc to reseat due to the set pressure spring preload. The main stage then reseats as previously described.[21]

The relief valves are installed so that each valve discharge is piped through its own discharge line to a point below the minimum water level in the primary containment suppression pool, permitting 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 is again opened. For this reason, two 10 inch[22] vacuum relief valves are provided on each relief valve discharge line in the drywell to prevent drawing water up into the line due to steam condensation following termination of relief valve operation. The 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 of having to remove sections of this piping when the reactor head is removed for refueling. In addition, both the relief valves and the safety valves are more accessible during a shutdown to correct possible valve malfunctions when they are located on the steam lines.

Pressure switches in the eight relief valve discharge lines provide positive valve position indication and annunciation in the main control room. Safety and relief valve position information is also provided in the main control room by tailpipe temperature readings obtained from thermocouples mounted on each safety valve and relief valve discharge line (two thermocouples on each safety valve and one thermocouple on each relief valve). This instrumentation also inputs actuation and reset times to the process computer for sequence of event alarm printout.[23]

As noted above, the discharge from each of the eight relief valves terminates at a point below the minimum water level in the suppression pool. As part of the Mark I Containment Program (see USAR Chapter V), the S/RV discharge lines have been rerouted in the suppression chamber and connected to eight new and symmetrically located T-quenchers (see Figure IV-4-5). These T-quenchers improve heat transfer between pool water and the steam-air mixture during relief valve operation by creating large surface areas of air and steam bubbles for rapid mixing and diffusion. As a result, water and air clearing thrust loads on the piping system within the suppression chamber, and suppression chamber shell pressure loadings are reduced, as compared with loadings associated with the original ramshead blowdown devices. Also, due to the Mark I Containment Program, the S/RV discharge lines in the suppression chamber were modified to suit newly defined LOCA-induced loadings. The changes are summarized in USAR Appendix C, Section C-2.5.7.1.[24][25][26][27] The S/RV discharge piping evaluations are discussed in Appendix C, Section C-3.3.3.5.3.

4.5.1 <u>Automatic Depressurization System</u>

Each of the six relief valves provided for automatic depressurization (see Chapter VI) is equipped with a Class I Seismic accumulator and check valve arrangement. These accumulators provide assurance that the valves can be held open following failure of the pneumatic supply to the accumulators, and they are sized to contain sufficient pressure for a minimum of two valve actuations at 70% drywell design pressure. The five actuations at atmospheric drywell pressure are equivalent to the two actuations at 70% drywell design pressure[103] [104].

The automatic depressurization feature of the pressure relief system serves to back up the HPCI system under LOCA conditions. If the HPCI system does not operate and one of the LPCI or Core Spray pumps is available, the nuclear system is depressurized sufficiently to permit the LPCI and core spray systems to operate to protect the fuel barrier. Depressurization occurs when some of the relief valves are opened automatically to vent steam to the suppression pool. If the HPCI system fails, the nuclear system is depressurized in sufficient time to allow the Core Spray or LPCI systems to cool the core and 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 to remain open is based upon simultaneous signals from: 1) reactor vessel low water level (Level 1), and 2) availability of one LPCI or one Core Spray pump as indicated by pump discharge pressure. Further descriptions of the operation of the automatic depressurization feature are found in USAR Chapter VI, ECCS and in USAR Section VII-4, ECCS Control and Instrumentation.

Depressurization of the nuclear system can be effected manually 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. To control nuclear system pressure, the relief valves are operated by remote-manual controls from the main control room.

The Automatic Depressurization System provides the principle means of venting post-LOCA non-condensable gases from the reactor pressure vessel as required by 10CFR50.44 c) (3) (iii) and in conformance to commitments made to NUREG-0737 Item II.B.1. The ADS valves are operated from the main control room and have positive position indication there as described in USAR Section IV-4.5. The ADS valves and logic control multiple venting paths and are provided with diverse essential 125 VDC power. This assures suitable redundancy and post-accident availability of the venting function.

4.5.2 Low-Low Set

NUREG-0737 Item II.K.3.16 observed that the most likely cause of a small break LOCA was from the opening of an SRV where the SRV fails to reseat. A reduction in this likelihood is achieved by minimizing the number of times individual SRVs must recycle in performance of the system relief function. Additionally, as part of the Mark I Containment Program, G.E. performed an evaluation of the Load Definition Report (LDR) SRV Load Cases for CNS. The primary concerns were the potential high thrust loads on the discharge piping, and the high frequency pressure loading on the containment. It has been concluded that delayed isolation achieved by means of a PCIS Group 1 (MSIV closure) low reactor water level isolation setpoint at Level 1, combined with a 90[68] psi minimum blowdown range low-low set relief logic, produces the maximum potential benefit to the twin concerns of NUREG-0737 Item II.K.3.16 and the Mark I Containment Program issues.

TABLE IV-4-2

LOW-LOW SET SAFETY/RELIEF VALVE SYSTEM

	S/RV							
	A	B	C	D	E	F	G	H
Pressure Relief Function	X	X	X	X	X	X	X	X
ADS Function	X	X	X	-	X	-	X	X
Low-Low Set Relief Function	-	-	-	X	-	X	-	-
Valve Group	III	III	II	I	II	II	III	I
Steam Pilot Opening Setpoint (psig)	1100	1100	1090	1080	1090	1080	1100	1090
Steam Pilot Closing Setpoint (psig)	1067	1067	1057	1048	1057	1048	1067	1057
Low-Low Set Open Allowable Values (psig)	-	-	-	*	-	**	-	-
Low-Low Set Close Allowable Values (psig)	-	-	-	*	-	**	-	-

NOTES:

* See CNS Technical Specifications Table 3.3.6.3-1, Function 2 (Low) for Allowable Values.
** See CNS Technical Specifications Table 3.3.6.3-1, Function 2(High) for Allowable Values.

The low-low set relief logic system is shown in Table IV-4-2. The system consists of two channels with separate initiating logics, each of which operates one relief valve. When the logic is armed by actuation of any relief valve (detected by a discharge line pressure switch) and a high reactor pressure scram signal, the logic will lower the opening and closing setpoints of valves D and F to new preset pressures which are sufficiently below the setpoints of the remaining valves. Once the arming logic for either low-low set logic is satisfied, it is sealed in and annunciated in the control room, and remains sealed in until manually reset by the operator. In addition, the arming logic in either low-low set channel will seal in the arming logic in the other low-low set channel.[32] The opening and closing nominal trip setpoints for valves D and F are separated by a minimum of 90[68] psi, as indicated in the table. The analytical limits for the low-low set setpoints are in NEDE-22197. Thus, more energy will be released each time a relief valve actuates, and more energy will be required for repressurization before a relief valve opens. If the amount of energy release is sufficient to prevent reactor repressurization to a level where the low-low set valve reopens, then subsequent relief valve actuations can be prevented. If the amount of energy release is insufficient to prevent subsequent actuation, the low-low set relief logic will delay relief valve reopening by virtue of the longer time required to repressurize the reactor.

For an anticipated operational transient event, such as a 3-second MSIV closure, the relief logic extends the minimum time between actuations to approximately 35 seconds. If there is no loss of offsite power (LOOP)or early MSIV isolation during a LOCA event, subsequent relief valve actuations will not occur for any break size. If LOOP does occur, the relief logic extends the minimum time between actuations to approximately 31 seconds for break sizes smaller than 0.20 ft^2. No subsequent actuations will occur for breaks of 0.20 ft^2 or larger. The time intervals described above effectively mitigate the relief valve discharge loading conditions of concern.

PCIS Group 1 (MSIV closure) low reactor water level trip setpoint at Level 1 potentially eliminates relief valve actuations for break sizes of 0.15 ft^2 or larger, if earlier isolation due to LOOP does not occur. When combined with the low-low set relief logic, transient analysis results indicate that subsequent relief valve actuations will not occur for any break size.[59]

Relief valve self-actuation (overpressure safety mode) and operation of the low-low set relief logic system is credited with mitigating a Station Blackout event.[99] [100] [101] [102]

4.6 Safety Evaluation

The ASME Boiler and Pressure Vessel Code requires that each vessel designed to meet Section III be protected from overpressure. The code permits a peak allowable pressure of 110 percent of vessel design pressure. The code specifications for safety valves require that: 1) the lowest safety valve be set at or below vessel design pressure, and 2) the highest safety valve be set to open at or below 105 percent of vessel design pressure.

The relief valves are set to open by self-actuation (overpressure safety mode) in the range from 1080 to 1100 psig and the safety valves are set to operate at 1240 psig. This satisfies the ASME Code specifications for safety valves, since the lowest set valve opens at less than 1250 psig (nuclear system design pressure) and the highest set valve opens at less than 1313 psig (105 percent of nuclear system design pressure).

Safety valve capacity is determined by analyzing the pressure rise accompanying the main steam flow stoppage which results from the following hypothetical transient:

a. The plant is operating at turbine-generator design power conditions (105% of rated steam flow, 1020 psig vessel dome pressure).

b. Direct position (valve closure) scrams are neglected.

c. Reactor shutdown is initiated by the backup high neutron flux scram.

d. Relief and safety valve setpoints are assumed to be 1% above their nominal setpoints.

e. Relief and safety valve capacities are at their minimum design values of 61% and 15% of rated steam flow respectively.

Both a turbine trip with bypass failure and closure of all MSIVs produce severe overpressure transients when direct valve position scrams are neglected. Analyses of these two events have shown that the three second closure of the MSIVs is slightly more severe for the final plant configuration and consequently is provided here as the basis for sizing the safety valves.

Figure IV-4-4a shows the time plot of this transient. The sequence of events assumed in this analysis was investigated only to meet code requirements and to evaluate the pressure relief system.

An abrupt pressure and power rise occurs as soon as the reactor is isolated. Neutron flux reaches the scram setpoint at about 1.8 seconds, initiating reactor shutdown. All relief valves open to limit the peak steam line pressure at the safety valves to 1233 psig which is below the nominal safety valve setpoint. The peak pressure at the vessel bottom is 1265 psig (transient pressure rise of 208 psi above the vessel bottom operating pressure of 1057 psig for these conditions). A 110 psi margin below the peak allowable pressure of 1375 psig exists. Consequently, the relief capacity alone provides adequate protection against excessive overpressurization of RCPB. It is concluded that safety design basis 1 has been satisfied. (Refer to USAR Section IV-4.9 for additional information on reactor vessel overpressure protection).

This transient was analyzed using the REDY transient model (References 93, 94 and 95). Calculations using the REDY model are based upon end-of-cycle conditions and utilize conservative multipliers on void, Doppler and scram reactivities (1.25, 0.95, and 0.8) respectively. Therefore, the transient is expected to be less severe than predicted by the code.

An SRV setpoint tolerance analysis has been performed and reported in Reference 96. In Reference 96, the MSIV closure with flux scram event was evaluated using the same initial conditions as in the SAR analysis except conservative end-of-cycle nuclear dynamic parameters for Cycle 11 and certified as-built relief and safety valve capacities were used. The system model ODYN as described in Reference 97 was used to analyze the event. The limiting overpressure event was evaluated for two cases: the 3% tolerance case (all but one relief and safety valves open at +3% of nominal setpoint) and the upper limit case (all but one relief valves open at 1210 psig and all safety valves open at +3%). It was determined that at least a 50 psi margin to the ASME code limit of 1375 psig could be maintained. Figure IV-4-4d shows the time plot of the MSIV closure transient (with flux scram-upper limit).

The adequacy of the plant design for mitigating the consequences of the most severe overpressurization event must be reevaluated with each core reload. Approved methodologies described in References 92 and 97 are used in performing the reload analysis. The analysis is performed at 102% power and 100% core flow condition to bound the fuel reload cycle operating conditions and to account for power level uncertainties specified in Regulatory Guide 1.49. Results are reported in the Supplemental Reload Licensing Report. Recent reload licensing analysis results for Cooper Nuclear Station are reported in Reference 98. Reference 98 also reported the results of an additional analysis of the MSIV closure with flux scram event to extend the applicability of Reference 96 to the current cycle. The MSIV closure with a flux scram event was first analyzed for Cycle 20 with MELLLA and ICF conditions. The analysis is documented in Reference 106.

The impact of various SRVs out-of-service (OOS) such that they can not open is discussed in Section IV-4.9.3 for the High Neutron Flux Scram.

The automatic depressurization capability of the pressure relief system is evaluated in USAR Chapter VI, "ECCS," and in USAR Section VII-4, "ECCS Controls and Instrumentation."

Motive force for relief valve operation other than pressure relief is normally provided by nitrogen. Backup air from the instrument control air system can be supplied. The relief valves which are a part of the ADS are equipped with accumulators which, in the unlikely event the nitrogen pressure is lost, will provide for two valve actuations with the drywell at 70% of its design pressure. Six ADS accumulators are tested to ensure that they will provide sufficient motive force to actuate the main steam relief valves at least five times at atmospheric drywell pressure after being isolated from the nitrogen supply for one hour. The five actuations at atmospheric drywell pressure are equivalent to the two actuations at 70% drywell design pressure [103] [104]. The main steam relief valves associated with low-low set logic operation have two additional and larger accumulators sized to permit fourteen valve operations.[59] A minimum of 70 psig is required to assure 14 actuations under the test conditions for the two larger accumulators. The pressure in the accumulators is continuously monitored for low pressure by means of a pressure switch located in the system downstream of the accumulators and annunciated in the control room. After a Safe Shutdown Earthquake, the ADS accumulators allow operation of the ADS valves that are credited with controlled depressurization for approximately 40 hours. For non-seismic events, the outdoor liquid nitrogen tank can be refilled, as needed, to assure ADS availability long term (100 days).

The remote pneumatic actuators are DC powered solenoid valves. These are normally closed, fail closed valves, and a power or valve malfunction will prevent the relief valve from operating for ADS. Abnormal solenoid valve operation would be detected during the operational tests of the relief valve. A complete rupture of the solenoid valve would result in a low pressure-accumulator alarm. Since ADS criteria is met with one relief valve inoperative, a double failure would be required before the ADS criteria is violated.[28]

The relief valve discharge piping was designed, installed, and tested as outlined in USAR Appendix A, and modified for increased structural safety margins during the CNS Mark I Containment Short Term Program (STP) as discussed in USAR Section V-4.1. The NRC has evaluated the impact of safety/relief valve (SRV) discharge piping on reactor safety and has concluded that the loss of SRV discharge piping may increase transient and accident consequences and probabilities. The Standard Review Plan, NUREG 75-087, also indicates that the SRV discharge piping is safety related.[57] The requirements of the piping design identified in USAR Section V-4.1.4 and USAR Appendix A, the load criteria discussed in USAR Section IV-4.5 and the NRC's evaluation are sufficient to satisfy safety design bases 3 and 4.

As discussed in USAR Section IV-4.8, "Inspection and Testing", safety design basis 5 has also been satisfied.

CNS is committed to conformance with NUREG-0737 Item II.D.3 which specifies that direct indication should be provided in the main control room of relief valve and safety valve position. The relief valve tailpipe pressure switches provide a single channel direct open/closed position indication in the main control room and annunciation for open relief valves. Each channel is powered from a critical bus with automatic bus transfer capability if divisional power is lost to the bus. Relief valve tailpipe temperatures which are recorded and annunciated in the main control room provide a backup position information source to the operators. Redundant safety valve discharge thermocouples provide an effective means of monitoring valve position. Accordingly, safety design basis 6 is satisfied.

It is concluded that all of the safety design bases identified in USAR Section IV-4.2 have been satisfied.

4.7 Power Generation Evaluation

The relief valves are designed to relieve energy from the nuclear system rapidly enough to prevent operation of the safety valves during pressure transients, which can be reasonably expected during the lifetime of the plant. A variety of turbine system malfunctions can initiate a turbine stop valve closure, normally called a turbine trip. Because the limiting overpressure event is the Main Steam Isolation Valve (MSIV) closure, peak pressures resulting from a turbine malfunction remain well below the ASME Code limit of 1375 psig.

The potential for opening the safety valves during an abnormal operational transient is considered during the plant/cycle specific analysis. Results are reported in the Supplemental Reload Licensing Report. The turbine trip and load reject with assumed bypass valve failure must maintain a minimum 25 psid pressure margin between peak steamline pressure at the safety valves and the lowest nominal safety valve setpoint.

4.8 Inspection and Testing

The safety and relief valves were tested in accordance with the manufacturer's quality control procedures to detect defects and to prove operability prior to installation.

The safety and relief 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 relief valves was verified during the preoperational test program.

It is recognized that it is not feasible to test the safety and relief valve setpoints while the valves are in place or during normal plant operation. Accordingly, the valves are mounted on six-inch diameter, 1500-pound 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 relief valves and safety valves are 100 percent visually inspected when the valves are removed for maintenance or bench checks.

At least one of the relief valves is disassembled and inspected each refueling outage.

In response to NUREG-0737 Item II.K.3.28, the ADS accumulators are tested each refueling outage to ensure that they will provide sufficient air to actuate their respective SRV five times at atmospheric drywell pressure after being isolated from the nitrogen supply for one hour (14 actuations for the low-low set SRVs). The five actuations at atmospheric drywell pressure are equivalent to the two actuations at 70% drywell design pressure. A minimum pressure of 88 psig is required to assure five actuations under the test conditions.[104]

CNS Technical Specifications set forth the surveillance requirements for the safety and relief valves.

The pressure relief system is in scope for License Renewal per 10 CFR 54.4(a)(1) and (a)(3) and was subject to aging management review. Aging effects are managed by the following Aging Management Programs: Bolting Integrity (see USAR Section K-2.1.2), External Surfaces Monitoring (see USAR Section K-2.1.14), Flow-Accelerated Corrosion (see USAR Section K-2.1.18), and Water Chemistry Control - BWR (see USAR Section K-2.1.39). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Section K-2.2.2.2).

4.9 Overpressure Protection Analysis

4.9.1 Introduction

This section provides an analysis of the reactor vessel overpressure protection features at CNS. The safety valves are sized to provide pressure protection in addition to the protection provided by the Reactor Protection System. Credit for the high reliability scram function is in accordance with Section III of the ASME Boiler and Pressure Vessel Code.

4.9.2 Design Basis

The primary system safety valves are sized to limit the primary system pressure, including transients, to the limits expressed in the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels. 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, probability of failure of the turbine-generator trip scram or MSIV 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, starting from operation at 105 percent of the reactor warranted steamflow condition.

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 percent above the design pressure at design temperature, in compliance with Paragraph N910.3 of Article 9, ASME Section III.

The pressure settings of all safety/relief valves are significantly below the system design pressure. No spring safety valve has a setting which exceeds 105 percent of vessel design pressure, in compliance with Paragraph N910.4 of Article 9, ASME Section III.

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, ASME Section III. 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 such 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 General Electric Drawing 731E611, Sheet 1.

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 Section III.

4.9.3 Analysis

To determine the required steamflow capacity of the safety valves, a parametric study was undertaken assuming the following:

a. The plant is operating at the turbine-generator design condition, 105 percent rated steam flow, with a vessel dome pressure of 1020 psig, a steamflow of 10.1 x 10^6 pounds per hour, and at a reactor thermal power of 2486 MW.

b. 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. Evaluation of behavior with final plant configuration has shown that the main steam isolation valve closure is slightly more severe when credit is only taken for back-up scrams, therefore it is used as the over-pressure protection basis event.

c. Direct reactor SCRAM - based on MSIV valve position switches (valve closure) -- failed.

d. 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 Boiler and Pressure Vessel Code requirement that the lowest safety valve be set at or below the vessel design pressure of 1250 psig.

e. The design basis takes credit for high neutron flux SCRAM, although the analysis also shows adequacy of the valves even with high vessel pressure SCRAM, as a back-up to high flux SCRAM.

f. Various safety valve total capacities were used with a 1240 psig nominal setpoint, which satisfies ASME Section III requirements that the highest safety valve setpoint be less than 105 percent of vessel design pressure (1.05 x 1250 = 1313 psig).

g. Both the dual safety/relief valves and the spring safety valves were assumed to have one percent (high) error in pressure setpoint throughout the study.

Under Section III of the ASME Boiler and Pressure Vessel Code, the peak allowable pressure is 110 percent of vessel design pressure or 1375 psig at the vessel bottom. Design specifications for safety/relief and spring safety valve capacities, based on the rated steamflow and the above parametric studies, were 61 percent and 15 percent respectively. Eight safety/relief valves are required to meet the specified 61 percent capacity resulting in an actual capacity of 64 percent. Three spring safety valves are required to meet the specified 15 percent capacity resulting in an actual capacity of 20.1 percent.

Using the overpressure protection system consisting of eight dual purpose safety/relief valves and three spring safety valves, analyses were performed to determine the effects on the pressure transient of various combinations of valve failures.

Main Steam Isolation 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. Vessel overpressure protection, with a minimum margin of 25 psi, exists if three relief valves in combination with zero safety valves, or two relief valves in combination with one safety valve, or two relief valves in combination with two safety valves, or one relief valve in combination with three safety valves function properly. Furthermore, vessel overpressure protection is maintained below code limits if two relief valves in combination with zero safety valves, or one relief valve in combination with two safety valves function properly.

High neutron flux SCRAM. The limiting single failure event for overpressure protection (OPP) is the MSIV closure and scram on high neutron flux. The licensing basis for OPP[115] requires 7 of 8 SRVs to be operable. Approval was based on an analysis[116] that showed up to 3 SRVs could be out-of-service (OOS) and still assure sufficient margin to the OPP dome safety limit (1337 psig) and the peak vessel pressure limit (1375 psig which is 110% of design pressure). Nevertheless, allowing only one SRV OOS is conservative since the OPP margin is expanded even more. Figure IV-4-4b shows the time plot of the MSIV closure transient for one SRV OOS at MELLLA core flow initial conditions. Figure IV-4-c shows the time plot of the MSIV closure transient for one SRV OOS at ICF core flow initial conditions.

High vessel pressure SCRAM. General Electric design provides even further vessel overpressure protection by providing sufficient valves to adequately cover the case in which reactor SCRAM is initiated by high vessel pressure, reached at approximately 1.75 seconds after a valve position switch SCRAM would have occurred. Adequate vessel overpressure protection, with a minimum margin of 25 psi, exists with the high vessel pressure SCRAM if eight relief valves in combination with zero safety valves, or seven relief valves in combination with one safety valve, or seven relief valves in combination with two safety, or six relief valves in combination with three safety valves function properly. Furthermore, vessel pressure is maintained below code limit when seven relief valves in combination with zero safety valves, or six relief valves in combination with one safety valve, or five relief valves in combination with three safety valves function properly.

Availability Analysis

As stated above, various combinations of proper valve operation provide adequate vessel overpressure protection subsequent to the severe main steam isolation valve closure transient assuming high neutron flux or a high vessel pressure initiated SCRAM. Table IV-4-3 summarizes the safety valve/SCRAM system availability which 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 with flux SCRAM is greater than 0.99999 while with pressure SCRAM it is 0.99995 when the system has eight safety/relief valves and three 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 downtimes were included in the availability calculations.[29]

TABLE IV-4-3

SAFETY VALVE - SCRAM AVAILABILITY

FLUX SCRAM:

7 of 8 Dual Plus
3 of 3 Spring Valves

PRESSURE SCRAM:

8 of 8 Dual Plus
0 of 3 Spring Valves

or

7 of 8 Dual Plus
1 of 3 Spring Valves

or

Availability = 0.99995

7 of 8 Dual Plus
2 of 3 Spring Valves

or

6 of 8 Dual Plus
3 of 3 Spring Valves

5.0 MAIN STEAM LINE FLOW RESTRICTOR

5.1 Safety Objective

To protect the fuel barrier, the main steam line flow restrictors limit the loss of water from the reactor vessel before Main Steam Isolation Valve (MSIV) closure in case of a main steam line rupture outside the primary containment.

5.2 Safety 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 of the primary containment so that the reactor vessel water level does not fall below the top of the core within the time required to close the MSIVs.

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.

5.3 Description

One main steam line flow restrictor 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 MSIV, and downstream of the main steam line safety and relief valves. The restrictor limits the coolant flow rate from the reactor vessel in the event of a main steam line break outside of the primary containment to the maximum (choke) flow specified. The restrictor assembly consists of a venturi type nozzle insert welded into a carbon steel pipe. The venturi type nozzle insert is constructed utilizing all austenitic stainless steel and is held in place with a full circumferential fillet weld. The restrictor assembly is self-draining.

The flow restrictor is designed and fabricated in accordance with USAS (now ANSI) B31.1.0. Preinstallation inspection and testing is in accordance with the ASME Boiler and Pressure Vessel Code Sections I and III, as specified in Appendix A. The container pipe is also designed and fabricated in accordance with USAS (now ANSI) B31.1.0, and with the ASME Boiler and Pressure Vessel Code Sections I and III, as specified in Appendix A. The flow restrictor has no moving parts, and the mechanical structure of the restrictor is capable of withstanding the velocities and forces under main steam line break conditions where maximum differential pressure is approximately 1375 psi.

The ratio of the venturi throat diameter to a steam line diameter is approximately 0.5. This results in less than a 9 psi pressure difference at design flow. This design limits the steam flow in a severed line to about 200% of its design steam flow, 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 closure of the MSIVs in the event the steam flow exceeds preselected operational limits.

5.4 Safety Evaluation

As described above, the Main Steam Line Flow Restrictor will limit the loss of coolant from the reactor vessel sufficiently to maintain water level above the core following a steam line rupture outside the primary containment. These restrictors will withstand the maximum pressure difference expected across the restrictor following complete severance of a main steam line.

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 phenomena in gas dynamics. This mechanism limits the steam quantity flow rate, thereby reducing the reactor vessel coolant blowdown. The probability of fuel failure and its consequences are therefore decreased. Analysis of the steam line rupture accident (see USAR Chapter XIV, Station Safety Analysis) shows that the core remains covered with water. Thus safety design basis 1 is shown to be satisfied.

Pressure surges caused by a two-phase mixture impinging on the flow restrictor result in stresses which 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 conditions. Thus safety design basis 2 is shown to be satisfied.

5.5 Inspection and Testing

This USAR section contains historical information as indicated by the italicized text. USAR Section I-3.4 provides a more detailed discussion of historical information. The information being presented in this section as historical has been preserved as it was originally submitted to the NRC in the CNS FSAR.

Tests were conducted on a 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 show that the flow restrictor operation at critical throat velocities is stable and predictable. Unrecovered differential pressure across the scale model restrictor is consistently about ten percent of the total nozzle pressure differentials, and the restrictor performance is in agreement with the existing ASME correlation. Full size restrictors have slightly different hydraulic shape and a differential pressure loss of approximately fifteen percent.

Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing or inspection program is planned. Only very slow erosion will occur with time, and such a slight enlargement will not have safety significance.

The main steam line flow restrictors are in scope for License Renewal per 10 CFR 54.4(a)(1) and were subject to aging management review. Aging effects are managed by the following Aging Management Programs: Water Chemistry Control - BWR (see USAR Section K-2.1.39). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Section K-2.2.2.2).

6.0 MAIN STEAM LINE ISOLATION VALVES

6.1 Safety Objectives

Two isolation valves, one as close as practical to each side of the primary containment barrier, in each main steam line close automatically upon receipt of certain isolation signals to:

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

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

6.2 Safety Design Bases

The Main Steam Line Isolation Valves (MSIV's), individually or collectively, shall:

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 will not induce a more severe transient on the nuclear system than closure of the turbine stop valves coincident with failure of the bypass valves to open.

3. Close the pipeline 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 for the motive force to independently close the redundant isolation valves in each steam line.

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

6. Be able to close the pipelines during or after seismic loadings to assure isolation if the nuclear system is breached by the earthquake.

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

6.3 Description

Two isolation valves are provided in series in a horizontal run of each main steam line, as close as practical to the primary containment, one inside (inboard) and the other outside (outboard). The valves, when closed, form part of the primary containment barrier for nuclear system breaks inside the containment and part of the nuclear system process barrier for main steam line breaks outside the primary containment.

The description and testing of the controls for the MSIVs are included in USAR Section VII-3, Primary Containment and Reactor Vessel Isolation Control Systems.

A general drawing of a MSIV is shown in Figure IV-6-1. These valves each employ a pneumatic cylinder operator and closing springs as separate locally stored energy sources for rapid closure. Each valve is a 24-inch globe valve having a Y-pattern body with a cylindrical main disc moving in a centerline 45° upward from the axis of the horizontal main steam inlet line. The valve is of reduced port design in that the main valve seat is of smaller diameter than the inside diameter of the pipe. This design provides stream-line flow through the valve with 6 psi pressure drop through the valve at rated flow with the valve fully open during normal station operation. It also enables the normal steam flow and pressure to aid in closing the valve and holding it closed.

The main disc, guided at the bottom by hard-faced ribs cast integral with the valve body, has a hard-faced seal surface at the bottom which mates with a hard-faced seat welded into the valve body when the valve is closed. The main disc is attached to the lower end of the valve stem which penetrates the bonnet through a stuffing box. The upper end of the stem is connected to a spring seat member. The pneumatic cylinder and an oil dashpot are mounted in tandem on a common shaft which extends downward and which is also connected to the spring seat member. The cylinder and dashpot assembly is also supported by four tie rods which use the valve bonnet as their support surface. These support rods also act as guides for four stacks of helical valve closing springs each of which is fitted between the spring seat member and the pneumatic cylinder mounting plate.

The bottom end of the valve stem is chamfered and seals against a mating hard-face seat in the middle of the main disc to act as a pilot valve. This provides a means of partially balancing the pressure across the main disc just before the main disc is lifted and while it is off its seat. The pneumatic cylinder is capable of lifting the disc with differential pressures across the MSIV in either direction as great as 200 psi.

The upper edge of a shoulder on the valve stem is chamfered and seals against a mating surface on the bottom bonnet to provide a backseat when the isolation valve is fully open. This prevents leakage through the stem packing. The bonnet, which is bolted to the body, has provisions for seal welding in case leaks develop after the valve has extensive service.

Running clearances are provided to permit the disc to align with the seat ring in the body. Other design features which eliminate the possibility of the disc binding in its guides are:

1. The disc with length approximately equal to the diameter.

2. Force from the valve actuation is applied through the valve stem to the bottom of the disc such that the possibility of cocking the disc is minimized.

The pneumatic cylinder is utilized to operate the MSIV. Opening and closing of the valve is effected by the admission of air or nitrogen to the bottom and top, respectively, of the pneumatic cylinder piston. This is accomplished through the control unit which is attached to the pneumatic cylinder and contains the pneumatic, AC, and DC powered control valves. The air or nitrogen is supplied to the control system through a check valve and 50 micron filters.[31] An accumulator is connected to the system between the check valve and the control valve to provide backup operating nitrogen or air. 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. The pressure from the accumulator and the spring force are each capable of closing the valve, except during a LOCA when the valves inside containment require both pressure from the accumulator and spring force to close. During a LOCA, the containment becomes pressurized, thus pressurizing the vented side of the pneumatic cylinder. Therefore, when the valve is going closed during a LOCA, the differential pressure across the pneumatic cylinder is less than normal, and the additional closing force of the springs is required.

The accumulator volume in conjunction with the compressed springs, is adequate to provide full stroking of the valve through one-half cycle (open to close) when nitrogen or air to the accumulator has failed. The supply line to the accumulator is large enough to make up pressure to the accumulator at a rate faster than the valve operation bleeds pressure from the accumulator during valve opening or closure.

The hydraulic (oil) dashpot functions as a velocity damper and is utilized to control the speed with which the isolation valve is closed by the pneumatic actuator. Oil is displaced from one side of the dashpot piston to the other through the hydraulic return line along side 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 valve 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 seconds.

Each of the four spring guide shafts contain stacks of springs which are compressed when the valve is open. These springs expand when pressure is either vented or lost from under the pneumatic cylinder piston and thus exert a downward force against the spring seat member which pushes the valve stem and disc down to close the valve. There are spring guides installed on each guide shaft which 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 attached to 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 (see Ralph A. Hiller Drawing SAA085, Sheet 4) consists of:

1. Normal opening and closing components--pneumatic and spring operated three-way poppet valves,[30] an AC powered solenoid valve, and a DC powered solenoid valve.

2. Exercising components--three-way poppet valve[30] and solenoid valve (part 6).

All control system components except the accumulator and the check valve are bolted to a sub-plate that is fastened to the pneumatic cylinder mounting plate on each isolation valve.

The control power available is 120 volt AC, 60 Hz 0.5 amps control and 125 volt DC, 0.5 amps control.

Remote manual switches in the control room enable the operator to open or close at normal speed (3 to 5 seconds) or at the slow speed (45 to 60 seconds) 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. There are two limit switches located at approximately the 90% open valve position, and one limit switch at the closed position. These limit switches are actuated by the motion of the spring seat member during valve movement. A reactor scram is initiated if either the inboard or the outboard isolation valves, on 3 or more of the main steam lines, actuates either of the 90% open position limit switches as the valve is moving in the closed direction (see USAR Section VII-2, Reactor Protection System).

The isolation valve is designed to pass saturated steam at 1250 psig and 575°F with a moisture content of approximately 0.23%, oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The design objective for the valve is a minimum of 40 years service at the specified operating conditions. 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 inch minimum is added to provide for 40 years service.

In the event that the main steam line breaks downstream from the isolation valve, the steam flow quickly increases to 200% of design steam flow. The flow is limited from further increase by the venturi flow restrictor (see Section IV-5.0) 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 vs. travel characteristic.

The MSIV installations are designed as Class I equipment to resist sufficiently the response motion at the installed location within the supporting building from the design basis earthquake (see USAR Appendix C). 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 stress 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 for this combination of loads is based on the ordinary allowable stress as set forth in the applicable codes. The parts of the MSIVs which constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as described in USAR Appendix A, Pressure Integrity of Piping and Equipment Pressure Parts. 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.

6.4 Safety Evaluation

As described above, the MSIVs will limit the release of radioactive materials by closing the nuclear system process barrier and the primary containment barrier. These MSIVs will prevent damage to the fuel barrier by limiting loss of reactor cooling water in case of a major steam leak outside of containment.

The analysis of a complete sudden steam line break outside the primary containment is described in the USAR Chapter XIV, Station Safety Analysis. It shows that the fuel barrier is protected against loss of cooling if main steam isolation closure takes as long as 10.5 seconds (including up to 0.5 second for the instrumentation to initiate valve closure after the break). The calculated radiological effects of the radioactive material assumed released with the steam are shown to be well within the values of 10CFR100 for such an accident. Thus, safety design basis 1 is shown to be satisfied with considerable margin.

The shortest closing time (approximately three seconds) of the main steam isolation valves is also shown to be satisfactory in USAR Chapter XIV, Station Safety Analysis. A reactor scram is initiated if either the inboard or the outboard isolation valves, on 3 or more of the main steam lines, actuate the 90% open position limit switch as the valve is moving in the closed direction. 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 fuel cladding temperature will be insignificant. The transient is less than that from sudden closure of the turbine stop valves (in approximately 0.1 second) coincident with postulated failure of the turbine bypass valves to open. No fuel damage results. Thus, safety design basis 2 is shown to be satisfied with considerable margin.

The following design features of the valve and the system ensure reliable mechanical operation under the most adverse conditions:

1. Use of the venturi flow limiters upstream of the inboard isolation valve plus ensuring a tortuous flow through main steam piping runs significantly reduce (by approximately a factor of four) impact pressure that could impinge on a partially closed isolation valve as a result of the design steam break accident.

2. Utilization of steam dryer and separator materials and construction which ensure that all associated components can withstand higher than normal loading due to flooding such that no parts are expected to break loose to be carried into steam lines and foul isolation valve closure.

3. Significant margin between maximum yield strengths and maximum operating parameters for all pressure containing parts. The valve body, bonnet, bonnet bolting, valve stem, disc, disc guides, stuffing box and packing are designed with significant margins of safety.

4. Utilization of the pilot valve arrangement to balance differential pressure across the disc during the closing stroke and to ensure that maximum loading cannot be applied to the disc until it is fully seated.

5. Utilization of closure devices capable of applying a mechanical closing force of more than sufficient strength to close the valve and to keep it seated against maximum back pressures expected. Further assurance is obtained by utilizing the orientation of the operator/stem/disc which takes advantage of normal steam flow and higher inlet pressure to assist in closing the valve and maintaining a tight seal.

6. Design of springs such that breakage cannot result in binding of the valve or the application of eccentric forces.

It is therefore concluded that mechanical operation of the valve is extremely reliable, which has been borne out by all test programs which have been conducted. The above considerations contribute to the MSIVs achieving the safety design bases discussed in USAR Section IV-6.2.

The valves are of "fail-safe" design in that they will close in the event of loss of nitrogen or instrument air. The valves are capable of spring only closure except during a LOCA when both springs and pressure from the accumulator are required to close the valves inside containment. They will also close in the event of loss of both AC and DC power to the two solenoids associated with each valve. Both solenoids must be de-energized, however, to effect closure of the isolation valve to prevent spurious closure if one solenoid power supply is lost.

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 inboard valve and the outboard valve and their control systems are separated physically. Considering the redundancy, the mechanical strength, the closing forces, and the leakage tests discussed in USAR Section IV-6.5 below, the MSIVs satisfy safety design bases 3 through 5.

The isolation valves and their installation are designed as Class I equipment for inclusion of seismic loadings, as delineated in USAR Appendix C. Therefore, the seismic loading requirement of safety design basis 6 is met.

With regard to safety design basis 7 the MSIVs may be tested during station operation by individually exercising each valve to the fully closed position when the reactor is less than 75% power.

6.5 Inspection and Testing

This USAR section contains historical information as indicated by the italicized text. USAR Section I-3.4 provides a more detailed discussion of historical information. The information being presented in this section as historical has been preserved as it was originally submitted to the NRC in the CNS FSAR.

A series of tests in dynamic test facilities has demonstrated the ability of the isolation valve to close within the times established by the design basis accidents, under conditions of high pressure differentials and fluid flows, with fluid mixtures ranging from mostly steam to mostly water. A full-size, 20-inch valve produced for actual use in a BWR was tested in a range of steam/water blow-down conditions simulating postulated accident conditions. The test valve was opened and closed more than 400 times (200 cycles) during the test program, during which it shut off 40 flow tests which simulated accident conditions up to those more severe than postulated for the design basis accident in the nuclear power plant. The extensive analytical program utilized resulted in finding no conditions more severe than the design basis accident. The variety of steady flow conditions on which the valve was closed covered the following ranges:

Steam Tests:	*50-1080 lb/sec*
Water Tests:	*240-3490 lb/sec*
Mixture Tests:	*1530-3860 lb/sec (quality 17%-45%)*
Surge Tests:	*520-2970 lb/sec (quality 1%-33%)*

The analysis of valve closing performance on this wide variety of conditions demonstrated that closure is not critically sensitive to temperature, pressure, fluid in the valve, and fluid flow through the valve. In every case, the valve opened and closed when signalled and shut off the flow completely and reliably. It was further observed that steam and water mixture flow assisted valve closure, with closing speeds up to 20% faster than those obtained under cold static conditions. A detailed description and analysis of this test program is contained in "Design and Performance of General Electric Boiler Water Reactor Main Steam Isolation Valves," APED-5750, D. A. Rockwell and E. H. van Zylstra, March, 1969.

The following specific hydrostatic, leakage and stroking tests, as a minimum, were performed by the valve manufacturer in shop tests:

1. Each valve is tested at rated pressure and temperature (1000 psig and 575°F) and no flow to verify capability to close between 3 and 10 seconds. The valve is stroked several times and the closing time recorded. The valve is closed by the air cylinder and springs and also with the springs only. The closing time is usually slightly greater when closed by springs only.

2. At least the first valve of each size is tested to demonstrate that the valve will close at rated pressure and no flow in the specified time after the valve has been held open (energized) for one week.

3. Adjustability of the closing time of each valve between 3 and 10 seconds 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.

4. Leakage with the valve seated and back seated is measured. Seat leakage is measured by pressurizing the upstream side of the valve. The specified maximum seat leakage, using cold water at design pressure, is 2 cc per hour per inch of seat diameter. There must be no visible leakage from either set of stem packing 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.

5. Each valve is hydrostatically tested at USAS (now ANSI) B31.1 specified test pressure (2450 psig) with cold water.

6. During valve fabrication, extensive nondestructive tests and examinations are made, including radiographic, liquid penetrant or magnetic particle examinations of casting, forgings, welds, hardfacings, and bolts.

7. Shop tests prove that the valve seating surfaces can withstand impact loadings from closing even in the event that the hydraulic buffer is inoperative. During valve assembly, the valve was tripped closed a number of times from full open to full closed without providing oil in the dashpot. These tests resulted in closures of less than one second and demonstrated the ability of the valve components, especially the seats, to perform beyond specifications. All tests conducted revealed no damage to any wearing surfaces.

8. A low pressure air seat leakage test is conducted on each complete valve in accordance with the following:

a. With valve seats clean and dry, the valve operator cylinder is pressurized with 90 psig clean, dry air or nitrogen to apply seat loading force to the main valve (and pilot valve) seats.

b. The inlet side of the valve is pressurized with 50 psig clean dry air or nitrogen and the leakage across the seats is collected and measured by means of displacement of a fluid. Duration of the test is nominally five minutes, or more, if required to obtain reliable results.

c. The maximum permissible leakage rate is 1/10 of a standard cubic foot of air per hour per inch of diameter of nominal valve size.

After the valves were installed in the nuclear system, each valve was tested in accordance with Pre-Operational Test Procedures, and Startup Test Procedures. The startup tests were performed at several reactor operating conditions.

The MSIVs are functionally tested during station operation and refueling outages in accordance with the Technical Specifications and are inspected and pressure tested in accordance with the applicable Ten-Year Interval Inservice Inspection Program (see Appendix J).

The valves are tested and exercised individually to the fully closed position in cold shutdown.

The MSIVs are in scope for License Renewal per 10 CFR 54.4(a)(1) and were subject to aging management review. Aging effects are managed by the following Aging Management Programs: Flow-Accelerated Corrosion (see USAR Section K-2.1.18), and Water Chemistry Control - BWR (see USAR Section K-2.1.39). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Section K-2.2.2.2).

7.0 REACTOR CORE ISOLATION COOLING SYSTEM

7.1 Safety Objective

The Reactor Core Isolation Cooling (RCIC) system provides makeup water to the reactor vessel following a reactor vessel isolation in order to prevent the release of radioactive materials to the environs as a result of inadequate core cooling.

7.2 Safety Design Bases

1. The system shall operate 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 which could lead to a release of radioactivity in excess of the values in published regulations.

7.3 Power Generation Objective

The RCIC system provides makeup water to the reactor vessel during shutdown and isolation to supplement or replace the normal makeup sources.

7.4 Power Generation Design Bases

1. The system shall operate automatically.

2. Provision is made for remote manual initiation of the system from the main control room.

3. To provide a high degree of assurance that the system shall operate when necessary, provisions have been made so that periodic testing can be performed during plant operation.

4. The system is designed to provide reactor coolant makeup to achieve safe shutdown in a fire related event.

7.5 Description

The RCIC system consists of a steam driven turbine-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 on Table IV-7-1. Schematic system diagrams are shown in Burns and Roe Drawing 2043 and General Electric Drawing 729E719BC.

The steam supply to the turbine comes from the reactor vessel. The steam exhaust from the turbine dumps to the suppression pool. The pump normally takes suction from the demineralized water in the emergency condensate storage tanks. This supply is backed up by a supply line from the suppression pool. The pump discharges either to the feedwater line or to a full flow return test line to the emergency condensate storage tanks. 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 gland seal condenser is supplied from the discharge of the pump.

TABLE IV-7-1

REACTOR CORE ISOLATION COOLING SYSTEM TURBINE--PUMP DESIGN DATA

Pump

Number Required -- 1	Design Temperature--40°F to 140°F
Capacity -- 100%	Design Pressure--1500 psig
	NPSH--20 ft (minimum)
Developed Head	2800 ft @ 1135 psia reactor pressure
	525 ft @ 165 psia reactor pressure
Flow Rate	Injection Flow--400 gpm
	Cooling Water Flow--16 gpm
	Total Pump Discharge--416 gpm

Turbine

Number Required -- 1	
Capacity -- 100%	
Steam Inlet Pressure Range	150 to 1120 (saturated) (psia)
Steam Exhaust Pressure Range	20 to 25 (psia)

Following any reactor shutdown, steam generation continues due to 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 valves or, if the condenser is isolated, through the relief valves to the suppression pool. The fluid removed from the reactor vessel can be entirely made up by the feedwater pumps if the main steam isolation valves (MSIVs) are open or partially made up from the Control Rod Drive (CRD) system which is supplied by the CRD pumps. If makeup water is required to supplement these primary sources of water, the RCIC system turbine-pump unit either starts automatically upon receipt of a reactor vessel low water level signal at Level 2 (see General Electric Drawing 729E517BC, Sheet 1) or is started by the operator from the control room by remote-manual controls. The RCIC system delivers its design flow within 30 seconds after actuation. The reactor vessel low water level condition also actuates the HPCI system as another source of makeup water.

The RCIC system has a makeup capacity sufficient to prevent the reactor vessel water level after a scram and PCIS Group 1 (MSIVs) isolation from decreasing to the level where the core would be uncovered without the use of Emergency Core Cooling Systems. (See USAR Chapter XIV, "Station Safety Analysis.") The pump suction is normally lined up to the emergency condensate storage tanks. Each of the two emergency condensate storage tanks has a 50,000 gallon reserve for the RCIC system and HPCI system. The emergency condensate storage tank reserve capacity of 100,000 gal was selected to provide the maximum amount of water required over an 8-hour period by an isolated reactor. This value was conservatively arrived at by:

1. Assuming the reactor was at design power at the time of isolation.

2. Using a decay heat curve which is based on the assumption of infinite irradiation of the fuel, thus maximizing fission product inventory and decay heat generation.

3. Ignoring any other inflows to the reactor (i.e., CRD system).

The length of time the system operates is independent of the flow rate of the pump used to inject the water. The only determining factor for duration of operation is the amount of energy which is removed by boiling, and that is independent of the way in which the makeup water is provided.

Note that there is not enough condensate in the ECSTs to maintain a hot standby condition for 8 hours (i.e., at 800 psig) and then proceed with a controlled cooldown to Mode 4. However, with refill of the ECSTs from the main CST, there would be plenty of water to accomplish cooldown.

Note: Emergency Condensate Storage Tank (ECST) reserve capacity at CNS has historically meant total capacity of the two tanks. Thus, when at minimum normal operating water level, the tanks will contain total water volume of at least 100,000 gallons. The usable capacity of the tanks is approximately 96,000 gallons at this level, since the suction elbows are a few inches off the bottom. Analysis has shown that Licensing & Design Basis requirements are met when the ECSTs are at or above the minimum normal operating water level, which is recorded and logged daily.

When the emergency condensate storage tank low water level is reached, at least 10,000 gallons of water remains for use by the RCIC and/or HPCI systems. With the RCIC pump operating at 400 gpm, approximately 25 minutes of operating capacity will use up the 10,000 gallons. For the HPCI pump operating at 4,250 gpm, approximately two minutes of operating capacity remains.[33]

The backup water supply for the RCIC system is the suppression pool. The RCIC system water supply is automatically determined depending upon the emergency condensate storage tank water level. When the water level in the emergency condensate tank reaches a predetermined low water level setpoint, the suction valve between the suppression pool and the RCIC pump automatically opens. Once the suppression pool to RCIC pump suction valve is fully open, the emergency condensate storage tank suction valve to the RCIC pump will automatically go closed.

In response to NUREG-0737 Item II.K.3.22, the following additional design features were accepted for the automatic switchover of RCIC system suction:

1. The capability of remote manual switchover (in addition to automatic switchover), the capability of remote manual RCIC flow termination, and the capability of remote manual containment isolation is retained.

2. The design is such that no single failure of the equipment accomplishing the automatic switchover of RCIC will interfere with operation of the HPCI system or interfere with the transfer of HPCI suction from the ECST to the Suppression Pool.

The turbine-pump assembly is located below the level of the emergency condensate storage tank and below the minimum water level in the suppression pool to assure positive suction head to the pump. The minimum required NPSH for RCIC is 20 ft. There is adequate elevation head between the suppression pool and the RCIC pump such that the required NPSH is available with a suppression pool temperature up to 140°F.

The RCIC system is designed for startup and short-term operation without AC power.[33] Components necessary for initiating operation of the RCIC system require only DC power from the station battery to operate the valves and controls. The power source for the turbine-pump unit is the steam generated in the reactor pressure vessel by the decay heat in the core. The steam is piped directly to the turbine and the turbine exhaust is piped to the suppression pool. The RCIC system is credited with mitigating a Station Blackout event.[99] [100] [101] [102] The RCIC system compartment is normally cooled by equipment area coolers supplied by the Reactor Equipment Cooling System.

For long-term operation, AC power is required in the following areas:

1. Suppression pool cooling.

2. Area cooling.

3. Power supply to 125-volt DC battery chargers.

Assuming a total loss of AC power, the operation of the RCIC system would be limited as follows:

1. A minimum of eight hours of condensate is provided as discussed above. If condensate is not available, RCIC operation would be limited based on available NPSH. Without the RHR system's heat removal capability, the suppression pool would reach 140°F in about two hours and RCIC operation would be limited.

2. The RCIC Turbine and Skid mounted components are designed for continuous operation with ambient conditions of 148°F and 100% relative humidity. The RCIC control panel components located on Rx Building 903' NE are designed for 24 hours of continuous operation with ambient conditions of 139°F and 100% relative humidity. The maximum temperature-time period for which the RCIC will continue to operate has not been determined. Without AC power, RCIC compartment temperature will increase with the rate of suppression pool temperature rise being a significant factor. Considering natural circulation of the air within the reactor building and heat losses through the building walls, air temperature will substantially lag suppression pool temperature. Therefore, RCIC operation can be assured for more than two hours and possibly much longer.

3. DC power from the 125-volt batteries is required for operation of the RCIC system. The time the batteries will last without AC power to the chargers will be dependent on the operator's ability to minimize DC loads. The 250-volt and 125-volt DC systems are conservatively sized for four hour operation based on the accident case with loss of one unit battery[78]; therefore, with no accident, all batteries available and only RCIC operating, it is expected that DC power will be available for from four to six hours.[33] RCIC system operation does not depend on operation of the non-essential gland seal (barometric) condenser or either the condenser condensate or vacuum pump.

In order to ensure rapid delivery of design flow upon system actuation the RCIC system discharge piping is maintained full of water. As shown on Burns and Roe Drawing 2049, Sheet 3, water from the reactor building auxiliary condensate system is supplied for filling the lines, ensuring maintenance of the discharge lines at a predetermined water pressure. Alarm indication of low condensate supply pressure[70] is provided in the main control room to indicate a possible loss of water fill in the lines.[34]

If for any reason the reactor vessel is isolated from the main condenser, pressure in the reactor vessel increases but is limited by actuation of the relief valves. Relief valve discharge is piped to the suppression pool.

A reactor scram would be initiated very early in the transient; exactly which sensed variable would be responsible for the scram would depend upon the cause of reactor isolation. For example, a loss of generator load would result in a turbine speed increase which would in turn result in the governor initiating a rapid closure of the turbine stop valves. Position switches on these valves would trip the Reactor Protection System and cause a scram.

The core void collapse caused by both the scram and the pressure increase would result in a rapid drop in reactor water level to Level 2 which would in turn initiate RCIC operation.

Thus, within one minute after isolation from the main condenser, the reactor would be in a quasi steady-state condition with the RCIC system maintaining an adequate coolant inventory in the vessel and the relief valves controlling the pressure. The fission product decay heat would be generating steam which would be going to the suppression pool via the relief valves and the RCIC turbine exhaust.

The relief valves automatically (or remote manually) maintain vessel pressure within desirable limits by discharging steam to the suppression pool. Thus, during this period of RCIC operation, the suppression pool acts as the heat sink for the steam generated by reactor decay heat. This will result in a rise in pool temperature. Plant operators may terminate the steam flow to the suppression pool by deisolating the reactor pressure vessel, i.e., reopening the main steam isolation valves (MSIVs), if the main condenser is available. For those events with the main condenser unavailable, the reactor is assumed to remain isolated until manual depressurization is initiated. Heat exchangers in the RHR system are used to maintain pool temperature within acceptable limits by cooling the pool directly with the RHR suppression pool cooling mode (Section 8.5.3.2). The suppression pool temperature response is bounded by the response predicted in Section XIV-6.3.

If the reactor is placed into a hot standby mode with RCIC operation required after isolation from the main condenser, the duration of the period of hot standby operation is entirely at the discretion of the plant operator. The only reason to maintain the units at hot standby is the expectation that power generation can soon be resumed. In all probability, if the cause of the isolation cannot be rectified within a short time, the operator will initiate an orderly shutdown of the reactor. However, the capacity of the emergency condensate storage tanks (100,000 gallons total reserve) is such that a hot standby condition could be maintained for eight hours.

In the event that an isolation occurred and the emergency condensate storage tank was unavailable to either the RCIC or the HPCI systems, the systems would be realigned to take suction from the suppression pool and inject water into the reactor. Under these conditions, the operator would not consider going into a prolonged period of hot standby operation and would initiate a shutdown and cooldown of the reactor immediately.[33]

The RCIC system turbine-pump unit is located in a shielded area to assure that personnel access to other areas is not restricted during RCIC system operation.

Three trip mechanisms are utilized to shutdown the RCIC system:

1. One mechanism energizes a solenoid which opens a pressure dump valve to dump pressure from an oil cylinder. This cylinder, when pressurized, is mechanically latched to the mechanical trip device on the turbine trip valve (RCIC-MO14). Operation of the Control Room turbine trip pushbutton will energize the solenoid and depressurize the oil cylinder to shutdown the RCIC system. In addition, several turbine controls (see General Electric Drawing 729E517BC, Sheet 3) provide for automatic shutdown of the RCIC system by energizing the solenoid and depressurizing the oil cylinder:

    a. Pump low suction pressure--to prevent damage to the turbine-pump unit due to a loss of cooling water.

    b. Turbine high exhaust pressure--indicating turbine or turbine control malfunction.

    c. The receipt of a manual or automatic RCIC isolation signal.

2. Use of a hand trip lever to mechanically trip closed the turbine trip valve via the over-speed trip linkage is the second mechanism to shutdown the RCIC system.

3. The third trip mechanism uses a turbine over-speed device to mechanically trip closed the turbine trip valve.

In the first trip mechanism identified, the turbine trip valve (RCIC-MO14) will close and operator action is required to remotely re-open the turbine trip valve to reset the RCIC system for receipt of auto-start signals. In the second and third trip mechanisms, the turbine trip valve will close, but operator actions at the turbine to reset the over-speed device is required in addition to remotely re-opening the turbine trip valve.

There are two additional indirect methods of tripping closed the turbine trip valve (RCIC-MO14):

1. The receipt of a reactor vessel high water level signal (at Level 8) will automatically close the steam admission (RCIC-MO131) valve for the RCIC system. When the RCIC system shuts down, the turbine-driven oil pump will gradually lose pressure and cause the oil cylinder to trip closed the turbine trip valve. When the steam admission and the turbine trip valves are closed, the motor operator for the turbine trip valve (RCIC-MO-MO14) will automatically cycle to open the turbine trip valve (RCIC-MO14). This action resets the RCIC system for receipt of auto-start signals. This feature conforms with the criteria of NUREG-0737 Item II.K.3.13, “RCIC automatic restart.”

2. Operator action to close the steam admission valve (RCIC-MO131) will shut down the RCIC system. When the RCIC system shuts down, the turbine-driven oil pump will gradually lose pressure and cause the oil cylinder to trip closed the turbine trip valve. When the steam admission turbine and turbine trip valves are closed, the motor operator for the turbine trip valve (RCIC-MO-MO14) will automatically cycle to open the turbine trip valve (RCIC-MO14). This action resets the RCIC system for receipt of auto-start signals.

Since the steam supply line to the RCIC system turbine is a primary containment boundary, certain signals automatically isolate this line also causing shutdown of the RCIC system turbine. Automatic shutdown of the steam supply (see <u>General Electric Drawing 729E517BC, Sheet 1</u>) is described in USAR Section VII-3, "Primary Containment and Reactor Vessel Isolation Control System". Operating logic for all other valves is shown in <u>General Electric Drawing 729E517BC, Sheets 2 and 3</u>.

The turbine control system is positioned by the demand signal from a flow controller, and satisfies a twofold purpose:

1. Limit the turbine pump speed to its maximum normal operating value.

2. Position the turbine valve(s) as required to maintain constant pump discharge flow over the pressure range of system operation.

The RCIC system piping within the drywell up to and including the outer isolation valve is designed in accordance with the USA Standard Code for Pressure Piping (now ANSI) B31.1 plus ASME Boiler and Pressure Code Section III. Piping and equipment, including support structures are designed to seismic Class 1 specifications (see USAR Appendix C). All piping and valves are also designed to meet the requirements outlined in USAR Appendix A.

As part of the Mark I Containment Program (see Appendix C, Section C-2.5.7.1), the torus attached piping in the RCIC system was reevaluated to consider the effects of the hydrodynamic loads in the suppression chamber. Modifications were made to the piping to ensure that the originally intended design safety margins were restored. The modifications are:

1. Addition of new pipe supports or reinforcement of existing supports on the torus attached piping.

2. Rerouting and resupporting of the RCIC turbine exhaust piping internal to the suppression chamber to minimize its exposure to submerged structure drag loads.

7.6 Safety Evaluation

The RCIC system is credited with mitigating a Station Blackout. In this scenario, the reactor water level will be initially restored by the HPCI system. Then, the RCIC system will maintain the reactor water level for the 4-hour coping duration by taking a suction from the emergency condensate storage tanks (see USAR Section XIV-5).[99][100][101][102]

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. Adequate water supply is assured by the two 50,000 gallon emergency condensate storage tanks and by the suppression pool. Evaluation of the reliability of the instrumentation for the RCIC system shows that no failure of a single initiating sensor either prevents or falsely starts the system. Safety design basis 1 is therefore satisfied. Safety design basis 2 is satisfied by design of the RCIC system to Class 1 specifications (see USAR Appendix C). It is also noted that the RCIC system turbine-pump unit can be started by the operator from the control room by remote-manual controls.

The RCIC turbine missile analysis indicates that wheel average tangential stresses in the RCIC turbine are sufficiently low that wheel failure is not predicted, even at the theoretical runaway condition of twice rated speed. Therefore, failure of the turbine wheels is considered so improbable as to be of no consequence with respect to becoming a potential missile or affecting safe shutdown of the plant. Additionally, the RCIC turbine is located in a separate concrete room within the reactor building.

7.7 Inspection and Testing

CNS Technical Specifications set forth the surveillance requirements for the RCIC system. Periodic inspection and maintenance of the turbine-pump unit is carried out in accordance with manufacturers instructions. Valve position indication as well as instrumentation alarms are displayed in the control room (see General Electric Drawing 729E517BC, Sheet 2).

The RCIC system is in scope for License Renewal per 10 CFR 54.4(a)(1), (a)(2), and (a)(3) and was subject to aging management review. Aging effects are managed by the following Aging Management Programs: Bolting Integrity (see USAR Section K-2.1.2), External Surfaces Monitoring (see USAR Section K-2.1.14), Flow-Accelerated Corrosion (see USAR Section K-2.1.18), Oil Analysis (see USAR Section K-2.1.28), Periodic Surveillance and Preventive Maintenance (see USAR Section K-2.1.31), and Water Chemistry Control - BWR (see USAR Section K-2.1.39). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Sections K-2.2.2.1 and K-2.2.2.2).

8.0 RESIDUAL HEAT REMOVAL SYSTEM

8.1 Safety Objective

The safety objective of the Residual Heat Removal (RHR) system is to provide core cooling, in conjunction with other Emergency Core Cooling Systems (ECCS), and to provide containment cooling as required during abnormal operational transients and postulated accidents.

8.2 Safety Design Bases

The safety design bases of the RHR system are to:

1. Restore and maintain the coolant inventory in the reactor vessel after a loss of coolant accident as required for core cooling in conjunction with other Emergency Core Cooling systems (Low Pressure Coolant Injection Mode, LPCI).

2. Provide cooling for the suppression pool and thereby remove heat from the containment following a loss of coolant accident to reduce containment pressure (either Suppression Pool Cooling Mode or spray mode can be used to accomplish this function).

3. Maintain suppression pool temperature during normal operation to within the limits assumed in the "Station Safety Analysis," (USAR Chapter XIV).

4. The suppression pool is the source of water for the LPCI mode of operation of the RHR system in order to provide a complete recycle path for water lost from the reactor vessel following reflooding.

5. To provide a high degree of assurance that the RHR system operates satisfactorily during a loss of coolant accident, each active component shall be capable of being tested during operation of the nuclear system.

6. Provide cooling for the drywell and thereby remove heat from the primary containment following a loss of coolant accident to reduce containment temperature.

8.3 Power Generation Objective

The power generation objective of the RHR system is to provide residual heat removal capability when the main condenser heat sink is unavailable.

8.4 Power Generation Design Bases

The power generation design bases of the RHR system are to:

1. Remove residual heat from the nuclear system so that refueling and nuclear system servicing can be performed (Shutdown Cooling Mode).

2. Provide suppression pool cooling for HPCI, RCIC, and Safety Relief Valve testing or operation (Suppression Pool Cooling Mode).

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

4. Provide cooling for the suppression pool and reactor to achieve safe shutdown of the reactor following a fire related event.

8.5 Description

8.5.1 General

The RHR system is designed to satisfy all the objectives and bases previously stated. To provide clarity to the information presented herein, each mode of operation is defined as a subsystem of the RHR system and is discussed separately. It is shown how each subsystem contributes toward satisfying all the objectives and bases of the RHR system.

The modes of RHR system operation are:

1. Shutdown Cooling (SDC) Mode
2. Containment Cooling Mode
    a. Containment Spray Mode
    b. Suppression Pool Cooling (SPC) Mode
3. Low Pressure Coolant Injection (LPCI) Mode

The major equipment of the RHR system consists of two heat exchangers and four main system pumps. The heat exchangers (tube side) are cooled by the Service Water System (USAR Section X-7). The system is equipped with piping, valves, controls and instrumentation, which are provided for proper system operation. A schematic diagram of the RHR system is shown in Burns and Roe Drawing 2040, Sheets 1 and 2.

The main system pumps were sized on the basis of the flow required during the low pressure coolant injection (LPCI) mode of operation (as specified by the LOCA accident analysis in effect at the time of issuance of the original Operating License), which is the mode requiring the maximum system flow rate. (The original LOCA accident analysis has been superseded as a result of the current ECCS performance criteria in 10CFR50.46. Integrated ECCS availability resulting from the limiting single failure, together with assumed pump performance, is used to demonstrate that Peak Cladding Temperature (PCT) remains within the prescribed limit.) An orifice is installed in the discharge piping of each RHR pump, to prevent pump runout to cavitation and the resultant possible loss of long-term containment cooling.[35] The heat exchangers are sized on the basis of their required duty for the containment cooling function which is the mode requiring the maximum heat exchanger capacity. A summary of the design requirements of the main system pumps and the heat exchangers is presented in Table IV-8-1.

One loop, consisting of one heat exchanger, two main system pumps in parallel, and associated piping, is located on one side of the reactor building. The two pumps are located in a compartment which is provided with a duplex sump pump. The other heat exchanger, pumps, and piping, forming a second loop, are located on the other side of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system. These two pumps are also located in a compartment with a duplex sump pump.

RHR system equipment is designed in accordance with Class I seismic design criteria (see USAR Chapter XII and Appendix C). The system is assumed to be filled with water for the seismic analysis.

The system piping and main system pumps are designed, constructed, and tested in accordance with the requirements of USAR Appendix A.

The pumps are designed and constructed in accordance with the Standards of the Hydraulic Institute. The shell side of the heat exchangers is designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III Class C vessels, and the tube side is designed in accordance with Section VIII. The provisions of paragraph N2113 (1968 edition) apply.

Power for the four RHR system pumps is normally provided through the two independent 4160 volt critical buses. USAR Section VII-4.5.5.1 describes the normal and emergency power supplies to the pump motors and valve motor operators.

Additional capability has been provided in the design by the addition of a permanent piping connection from the RHR service water booster pumps to the RHR piping system. This connection is sized to provide 4000 gpm at 0 psig reactor pressure. All piping and equipment in the Service Water system which serves Class I equipment and this additional piping connection are designed to Class I seismic requirements.

The interconnection of the Service Water system and RHR system is manually aligned by closing a tell-tale drain and opening two locked-closed valves. Leaks from either system can be detected by periodic inspections of the open tell-tale drain.

As part of the Mark I Containment Program (see Appendix C, Section C-2.5.7.1), the RHR Pump Test and Pump Suction Lines were reevaluated to consider the effects of the hydrodynamic loads in the torus. Modifications were made to the components to ensure that the originally intended design safety margins were restored. The modifications are:

1. Addition of new pipe supports or reinforcement of existing supports on the torus attached piping.

2. Modification of the discharge configuration of the RHR pump test return line in the suppression chamber. The original 10-inch discharge elbow was replaced by a 14-inch elbow to improve thermal mixing in the suppression pool.

3. Reinforcement of the anchorage for the four RHR pumps to account for increased piping loads.

8.5.2 Shutdown Cooling Subsystem

The shutdown cooling (SDC) subsystem is an integral part of the RHR system and is placed in operation during a normal reactor 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 pressure has decreased to approximately 50 psig the steam supply pressure is no longer sufficient to maintain vacuum in the main condenser and the RHR system is placed in the shutdown cooling mode of operation to complete cooldown of the nuclear system. The shutdown cooling subsystem is capable of reducing reactor water temperatures to 125°F within 20 hours after reactor shutdown so that the reactor can be refueled and serviced. This capability is based on two loops of RHR operating in shutdown cooling mode at a nominal service water temperature of 80°F.[112] Additionally, the shutdown cooling subsystem is capable of achieving cold shutdown within 24 hours assuming limiting heat removal capabilities and a maximum service water temperature of 95°F.[113] In the shutdown cooling mode, reactor coolant is pumped by the RHR main system pumps from one recirculation loop through the RHR heat exchanger(s) where heat is transferred to the Service Water system. Operation of one RHR heat exchanger is adequate to remove decay heat. Reactor coolant is then returned to the reactor vessel through connections to the recirculation loop(s). Temperature control is provided by varying the flow rate in the RHR heat exchanger and by use of the RHR heat exchanger bypass line. It is concluded that power generation design basis 1 is satisfied by this mode of RHR system operation.

TABLE IV-8-1

RESIDUAL HEAT REMOVAL SYSTEM EQUIPMENT DESIGN DATA

MAIN SYSTEM PUMPS

Number Installed -- 4	Design Temperature -- 350°F
Shutoff Head -- 680 feet	Design Pressure -- 450 psi

One Pump per Loop Injection @ 20 psig Reactor Vessel Pressure (LPCI Mode)

Capacity (each)	7700 gpm
Total Dynamic Head	413 feet

Two Pump per Loop Injection @ 20 psig Reactor Vessel Pressure (LPCI Mode)

Capacity	15,000 gpm
Total Dynamic Head	435 feet

HEAT EXCHANGERS

Number Installed -- 2
Shell Side Fluid -- Reactor Water or Suppression Pool Water
Tube Side Fluid -- Service Water
Design Pressure -- 450 psig Design Temperature -- 32-400ºF
Pressure Drop @ Design Conditions -- shell and tube side -- 25/10 psi

Minimum Required Heat Removal Capability[85]

Shutdown Cooling (Mode E*) (Each Heat Exchanger)	155×10^6 BTU/HR with 7700 gpm RHR Inlet @ 281°F and 8000 gpm Service Water @ 75ºF
Containment Cooling (Mode C2*) (Each Heat Exchanger)	77.52×10^6 BTU/HR with 6500 gpm RHR Inlet @ 211.4°F and 4000 gpm Service Water @ 95ºF

* See General Electric Drawing 729E211BB.

Interlocks are provided to prevent shutdown cooling flow unless the reactor vessel pressure is below 75 psig.

8.5.3 Containment Cooling Subsystems

8.5.3.1 Containment Spray Subsystem

The containment spray subsystem provides containment spray capability as a method for reducing containment pressure and temperature following a LOCA. The water pumped through the RHR heat exchangers can be diverted to spray headers in the drywell and above the suppression pool. The spray headers in the drywell condense any steam that may exist in the drywell thereby lowering containment pressure and temperature. The spray collects in the bottom of the drywell until the water level rises to the level of the pressure suppression vent pipes where it overflows and drains back to the suppression pool. Approximately five percent of this spray flow may be directed to the suppression chamber spray ring to cool any non-condensible gases collected in the free volume above the suppression pool. The containment spray subsystem will remove energy from the drywell by condensing steam thereby making available the drywell volume to accommodate additional quantities of gases from any postulated metal-water reactions above that which the containment can inherently accommodate without spray. It is concluded that safety design basis 6 is satisfied by this mode of RHR system operation.

The containment spray mode of the RHR system cannot be operated unless the drywell pressure exceeds 2.0 psig and the level inside the reactor vessel shroud is above the 2/3 core height setpoint. This water level interlock is provided to prevent the LPCI flow from being diverted to the containment spray mode unless the core is flooded. A keylock switch is provided in the control room to permit operator override of the water level interlock.

8.5.3.2 Suppression Pool Cooling Subsystem

The suppression pool cooling subsystem is an integral part of the RHR system and is placed in operation to remove heat from the pressure suppression pool to reduce pressure in the primary containment following a LOCA. This system is also operated as required during planned operations to control suppression pool water temperatures within the limits specified in CNS Technical Specifications.

With the RHR system in the suppression pool cooling mode of operation, the RHR system pumps are aligned to pump water from the suppression pool through the RHR heat exchangers where cooling takes place by transferring heat to the Service Water system. The flow returns to the suppression pool via return lines which discharge below the pool surface.

The RHR system in the suppression pool cooling mode functions to transfer heat from the primary containment to the Service Water system thereby lowering the primary containment pressure. It is concluded safety design bases 2 and 3 are satisfied by this mode of RHR system operation. In the event of reactor vessel isolation, the RHR system in the suppression pool cooling mode is capable of maintaining the Suppression Chamber water temperature below 130°F for at least two hours of RCIC operation (see USAR Section IV-7). It is concluded that power generation design basis 2 is satisfied by this mode of RHR system operation.

8.5.4 Low Pressure Coolant Injection Subsystem

The low pressure coolant injection (LPCI) subsystem is an integral part of the RHR system. It operates to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a LOCA in combination with other ECCS.

A detailed discussion of the requirements and response of the equipment which operates during LPCI for a LOCA may be found in USAR Chapter VI, "Emergency Core Cooling Systems." A detailed discussion of the requirements and response of the controls and instrumentation of LPCI during a LOCA may be found in USAR Section VII-4, "Emergency Core Cooling Systems Control and Instrumentation."

In general, LPCI operation involves restoring the water level in the reactor vessel to a sufficient height for initial cooling after a LOCA. The LPCI subsystem operates in conjunction with the High Pressure Coolant Injection (HPCI) system, the Automatic Depressurization System, and the Core Spray system to achieve this goal as described in USAR Chapter VI, "Emergency Core Cooling System."

The HPCI system is a high head, low flow system and 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 LPCI operates to inject water into the pressure vessel. LPCI is a low head, high flow subsystem. All these operations are carried out automatically. LPCI (in conjunction with Core Spray, as necessary) is designed to reflood the reactor vessel to at least two-thirds core height. After the core has been flooded to this height, the capacity of one RHR main system pump is more than sufficient to maintain the level. This capability satisfies safety design basis 1.

During LPCI operation, the main system pumps take suction from the suppression pool and discharge to the reactor vessel into the core region through both of the recirculation loops.[36] See USAR Section VII-4, "Emergency Core Cooling Systems Control and Instrumentation." Water lost from the vessel through a break in the piping within the primary containment returns to the suppression pool through the pressure suppression vent pipes. It is concluded that safety design basis 4 is satisfied.

Coolant flow to the RHR heat exchangers from the Service Water system is not required immediately after a loss of coolant accident because heat rejection from the containment is not necessary during the time it takes to flood the reactor.

8.5.5 Residual Heat Removal System-Fuel Pool Cooling System Intertie

The RHR system can be intertied with the Fuel Pool Cooling system when the Fuel Pool gates and slot plugs have been removed. This capability increases the spent fuel pool cooling capacity in the event that additional capacity is necessary to maintain fuel pool temperature below 150°F. The RHR system - Fuel Pool Cooling system intertie is sized to assist with removing the decay heat of a full core off-load plus the spent fuel discharged from previous refuelings.[83] It is concluded that Power Generation Design Basis 3 is satisfied by this arrangement. (See USAR Section X-5, "Fuel Pool Cooling and Demineralizer System.")

8.6 Safety Evaluation

Satisfaction of safety design bases stated in USAR Section IV-8.2 are covered in the "Description" and "Inspection and Testing" portions of this subsection.

Safety design bases 1 and 4 are addressed in USAR Section IV-8.5.4, safety design bases 2 and 3 are addressed in USAR Section IV-8.5.3.2, and safety design basis 5 is addressed in USAR Section IV-8.7. Safety design basis 6 is addressed in USAR Section IV-8.5.3.1. It is concluded that all safety design bases are satisfied.

Since the LPCI subsystem acts with other Emergency Core Cooling systems to satisfy the safety objective, it is evaluated in conjunction with the other Emergency Core Cooling systems, USAR Chapter VI, "Emergency Core Cooling Systems." The safety evaluation of the controls and instrumentation of the LPCI subsystem is in USAR Section VII-4, "Emergency Core Cooling Systems Control and Instrumentation."

8.7 Inspection and Testing

CNS Technical Specifications set forth the surveillance requirements for the Technical Specification functions of the RHR system. The discharge valves to the containment spray headers are checked by operating the upstream and downstream valves individually. All main flow path motor operated 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.

No automatic actuation signals are utilized or required when operation or testing of RHR valves is from the Alternate Shutdown panel (see USAR Section VII-18, Alternate Shutdown Capability).

An air test is performed on the drywell and Suppression Chamber headers and nozzles following maintenance that could result in nozzle blockage.

Pump flow rate is tested once/3 months. During single pump LPCI, each RHR pump delivers at least 7700 gpm against a system head equivalent to a reactor vessel pressure of 20 psid above drywell pressure with water level below the jet pumps. At the same conditions, two pump LPCI flow is at least 15,000 gpm. NOTE: Plant systems and equipment support single RHR/LPCI Pump flowrates above 8400 gpm. However, CNS is required to have a 0.6 psi NPSH margin at the RHR pump's suction for all modes of operation (reference USAR Chapter VI, page VI-5-16). RHR/LPCI pump NPSH margins are addressed in calculation NEDC 97-044A[71] for both short and long term DBA-LOCA response.

Recirculation pump discharge valves are tested each refueling outage to verify full open to full closed in less than or equal to 40 seconds.

It is concluded that safety design basis 5 is satisfied.

The residual heat removal system is in scope for License Renewal per 10 CFR 54.4(a)(1), (a)(2), and (a)(3) and was subject to aging management review. Aging effects are managed by the following Aging Management Programs: Bolting Integrity (see USAR Section K-2.1.2), External Surfaces Monitoring (see USAR Section K-2.1.14), Selective Leaching (see USAR Section K-2.1.34), Service Water Integrity (see USAR Section K-2.1.35), Water Chemistry Control - BWR (see USAR Section K-2.1.39), and Water Chemistry Control - Closed Cooling Water (see USAR Section K-2.1.40). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Sections K-2.2.2.1 and K-2.2.2.2).

9.0 REACTOR WATER CLEANUP SYSTEM

9.1 Power Generation Objectives

The power generation objectives of the Reactor Water Cleanup (RWCU) system are:

1. To maintain high reactor water purity in order to limit chemical and corrosive action.

2. To limit the reactor water impurities available for neutron flux activation by removing corrosion products.

3. To provide a method for decreasing reactor water inventory during heatup.

9.2 Power Generation Design Bases

The design of the RWCU system contains provisions for the following:

1. Continuous removal of radioactive waterborne materials which are generated in the reactor coolant as a result of the fission and corrosion processes.

2. Continuous removal of soluble inorganic impurities (e.g., chlorides) which may enter with the reactor feedwater and could, if not controlled, subsequently concentrate to exceed the specified water quality limits.

3. Removal of coolant from the reactor system at acceptable activity levels during startups and shutdowns.

4. Continuous monitoring of the reactor coolant via the Mitigation Monitoring System to monitor the electrochemical corrosion potential of reactor coolant surfaces (used for Optimum Water Chemistry control).

5. Limitation of heat and fluid losses from the nuclear system during the satisfaction of the above design bases.

9.3 Description

The RWCU system removes impurities from the reactor coolant water by continuously removing a portion of the reactor coolant from the bottom head drain and the suction side of a Reactor Recirculation Pump, sending the removed flow through filter-demineralizer units to undergo mechanical filtration and ion exchange processes, and returning the processed fluid back to the reactor via the Reactor Feedwater line. The RWCU system contains two full capacity recirculation pumps. The normal system mass flow rate of 100,000 lbs/hr (115,000 lbs/hr maximum) is provided by one full capacity RWCU recirculation pump with two filter-demineralizer units in service, which provides the necessary system pressure to overcome piping and equipment losses and to return the processed water to the reactor via the Reactor Feedwater line. The system also allows routing of the treated water to the Liquid Radwaste system or the Main Condenser Hotwell during various modes of system operation. (See Burns and Roe Drawing 2042, Sheets 1 through 3, and General Electric Drawing 730E148BB).

The major equipment of the system consists of the two RWCU recirculation pumps, regenerative and nonregenerative heat exchangers, and two filter-demineralizer units with supporting equipment, as shown in Burns and Roe Drawing 2042, Sheets 1 through 3. The entire system is connected by associated valves and piping with appropriate controls and instrumentation to effect the desired system operation. Table IV-9-1 lists the equipment design data for the RWCU recirculation pump heat exchangers, and filter-demineralizers.

The RWCU recirculation pump discharge is sent through the tube sides of regenerative and nonregenerative heat exchangers due to the necessity for reducing the temperature of the reactor water to a level acceptable for the protection and satisfactory performance of the filter-demineralizer ion-exchange resins. A regenerative heat exchanger is utilized for the first stage, as it performs a larger part of the cooling process to satisfy the power generation design basis of minimizing the heat loss from the primary system. This arrangement recovers a good part of the sensible heat in the reactor water by utilizing return (treated) water from the filter-demineralizer units as the shell side cooling medium. Power generation design basis 5 is satisfied by this arrangement.

A bypass line with a throttling type manual valve is provided for bypassing the regenerative heat exchanger for supplemental heat removal during cold shutdown conditions.

Regenerative heat exchanger size and temperature range limitations make further cooling of the water necessary to reduce the temperature to that value acceptable from the standpoint of resin protection and satisfactory ion-exchanger resin performance. The passage of the water through the nonregenerative heat exchanger transfers the remaining heat to the Reactor Equipment Cooling (REC) system. The nonregenerative heat exchanger can maintain this lower temperature even when the effectiveness of the regenerative heat exchanger is reduced. This takes place during reactor startup when the system is used to remove excess coolant inventory ("swell") and Control Rod Drive water from the reactor system by diverting a part of the filter-demineralizer effluent to the Main Condenser rather than sending it back to the Reactor Feedwater system via the shell side of the regenerative heat exchanger. During normal operation the temperature of reactor water from the nonregenerative heat exchanger is 120°F but it can be increased to 130°F during the startup or water removal modes.

A portion of the water cooled by the nonregenerative heat exchangers is recirculated back to the pump suction to subcool the reactor water and prevent liquid flashing and consequently pump cavitation.

The remaining water cooled by the heat exchangers then flows through two parallel filter-demineralizer units for the removal of impurities. These half-capacity units are pressure precoat type filter-demineralizers utilizing filter aid and finely ground, nonregenerable, mixed cation and anion ion exchange resins. Power generation design bases 1 and 2 are satisfied by this filter-demineralizer arrangement. The operating service cycle of a filter-demineralizer unit is terminated by any of the following: a high pressure drop across the unit, a run time determined to limit radioactive isotope loading for burial containers, or by exhaustion of the ion-exchanger resins (normally limiting except during an abnormal condenser leak). When a unit's service cycle is terminated, the unit is isolated by closure of associated isolation valves while the parallel unit remains in operation. The out-of-service unit is backwashed using air and condensate to remove all of the precoat material and accumulated insoluble material. The spent resins and filter aid are sluiced from the unit to either of two RWCU Phase Separator Tanks, where short-lived radioactive decay is allowed to take place, and then is transferred to the Radwaste system for further processing and disposal. The unit is then precoated with a slurry of new filter aid and resins. The unit holding pump is operated to provide sufficient flow to hold the precoat in place until such time as the unit is placed back into RWCU service.

A strainer is installed on the outlet of each filter-demineralizer unit to prevent any precoat from entering the reactor in the event of failure of a precoat holding element. The strainer screens are capable of withstanding a pressure drop greater than the developed RWCU recirculation pump head when the strainer is full of precoat. Each strainer is equipped with a differential pressure switch and an alarm that is energized by high differential pressure, which indicates a clogged strainer.

TABLE IV-9-1

RWCU SYSTEM EQUIPMENT DESIGN DATA

RWCU RECIRCULATION PUMPS

Design Temperature (°F)	575
Design Pressure (psig)	1300
Discharge Head @ Rated Flow (ft)	470
Maximum Shutoff Head (ft)	600
Number Available	2
Min. Avail. NPSH (ft)	10
Capacity (each; one pump and both demin. units)	100%
Discharge flow (gpm/pump; one pump and both demin. units) @ 120°F	200**

HEAT EXCHANGERS

	Regenerative	Nonregenerative
Shell Side Flow (lb/hr)	100,000	195,420
Shell Side Pressure (psig)	1,450	150
Shell Side Temperature (°F)	575	370
Tube Side Pressure (psig)	1,450	1,450
Tube Side Temperature (°F)	575	575
Tube Side Flow (lb/hr)	100,000	100,000

FILTER-DEMINERALIZERS

Design Temperature (°F)	150
Design Pressure (psig)	1,450
Time to remove a unit from service, backwash, precoat, and return to service (minutes)	60
Number Required	2
Capacity (each)	50%
Normal Flow Rate/Unit (lb/hr)	50,000**
(gpm/unit) @ 120°F	101**
Effluent Conductivity (μmho/max)	0.1*
Effluent pH	6.5 to 7.5*
Effluent Insolubles (ppb-measured as residue on 0.45 micron filter paper)	<10

*During a classic noble metal application, the reactor coolant chemistry conductivity and pH will increase beyond the ranges specified in this table. Temporary relaxation of the conductivity limits is permitted during this process.

**During normal operation and refueling with the blow-down lines closed, to increase filter-demineralizer efficiency and improve station chemistry performance, the total mass flowrate through the RWCU system has been evaluated for 115,000 lbs/hr, or 115 gpm per filter-demineralizer.A bypass line with a throttling type remote manual valve is provided for bypassing the filter-demineralizer units whenever necessary.

Normal routing of flow from the filter-demineralizer units is then through the shell side of the regenerative heat exchanger where it is heated by the incoming (untreated) coolant to the temperature range of reactor feedwater. It then returns to the reactor through the Feedwater system via a thermal sleeve which is designed to accommodate without excessive thermal stresses the maximum temperature difference that can occur between the two fluid streams under any mode of plant operation.

Relief valves, alarms, and control instrumentation are provided to protect the system and equipment against over-pressurization and resin overheating. Relief valves are furnished on the shell and tube sides of both regenerative and nonregenerative heat exchangers, at the filter-demineralizer units, and for the low pressure precoat system auxiliary equipment. A high temperature condition at the outlet of the nonregenerative heat exchanger will actuate an alarm in the Main Control Room. In the inlet piping to the RWCU recirculation pumps, two motor-operated isolation valves, one on either side of the Primary Containment, are automatically closed by any of the following conditions, as shown on Figure IV-9-4.

1. High temperature at the outlet of the nonregenerative heat exchanger. This protects the ion exchange resins against damage due to high temperature.

2. Low reactor water level (Level 2). This protects the core in case of a possible break in the RWCU system piping or equipment. (See "Primary Containment and Reactor Vessel Isolation Control System," Section VII-3).

3. Standby Liquid Control (SLC) system actuation (starting SLC Pump A closes the inboard RWCU isolation valve, and starting SLC Pump B closes the outboard RWCU isolation valve). This prevents the filter-demineralizers from removing the boron from the reactor coolant.

4. High flow. This indicates a break in the system.[38]

5. High space temperature. This indicates a leak and/or a break in the system.

Closure of the isolation valves will generate a signal that trips the RWCU recirculation pumps. This protects the pumps against loss of suction when the isolation valves shut.

In the event of a reduction or loss of system flow, the holding pumps associated with each filter-demineralizer unit will automatically start to maintain flow through the unit. Constant volumetric flow through the unit is normally maintained by an automatic flow control valve in the effluent line. This valve will function to close completely if the pressure drop across the unit continues to increase above the value which actuates an alarm. This function is to protect the resin holding elements. Continuous conductivity sampling stations are located in the influent header to the filter-demineralizers and downstream of each filter-demineralizer unit, with the influent sample point also being used as the normal source for reactor water samples. Analyses of the samples provide an indication of the effectiveness of the filter-demineralizer units.

Operation of the RWCU system is effected from the Main Control Room where instrumentation for flow, pressure, temperature, and conductivity indicates or records. The associated alarms also actuate there. Backwashing and precoating operations are controlled from a local control panel in the Reactor Building. During heatup operations, the system is utilized to remove excess coolant inventory resulting from the coolant density decrease during heatup ("swell") and Control Rod Drive cooling water from the reactor. During this operation, the RWCU recirculation pumps are running, the regenerative heat exchanger is under partial load (not receiving all of the filter-demineralizer effluent), the nonregenerative heat exchanger is under maximum startup load, the filter-demineralizer units are in operation, and excess water is routed to the Main Condenser. Power generation design basis 3 is satisfied by this arrangement.

The water removal operation ("blowdown mode") of the system can be utilized to remove excess water from the reactor. In this operation, all of the RWCU system flow is discharged to the Main Condenser Hotwell. The RWCU recirculation pumps are in operation, the regenerative heat exchanger is under no load, the nonregenerative heat exchanger is under full load, and the filter-demineralizer units are in operation. This necessitates a restricted flow rate because of the maximum allowable outlet temperature to the REC water from the shell side of the nonregenerative heat exchanger and results in the maximum temperature differential across the nonregenerative heat exchanger.

During the refueling operation, the RWCU system, in conjunction with the fuel pool cooling and cleanup system, provides continuous cleaning of the reactor water.

A cross-tie spool piece between the RWCU blowdown line and FPC system return line can be installed during Mode 5 with the reactor cavity flooded and the fuel transfer gates removed. This permits the RWCU System to remain in service when the normal return to the RPV is unavailable, such as during “A” Reactor Feedwater line maintenance or during Local Leak Rate Testing.

A sample line and return line with isolation valves is provided to allow the Electrochemical Corrosion Potential (ECP) rack and Mitigation Monitoring System (MMS) panel to routinely monitor the electrochemical corrosion potential of the reactor coolant surfaces and the noble metal deposition. Power generation design basis 4 is satisfied by this arrangement. A discussion of the ECP rack and MMS panel may be found in USAR Section X-19.

9.4 Inspection and Testing

Periodic chemical analyses of reactor water are made to ensure that the RWCU system is functioning to maintain the water within limits. Specific provisions are made to determine the effectiveness of demineralization and ion exchange functions of filter-demineralizer units such that the end of a unit's operating service cycle may be anticipated in a timely fashion. In all other respects, because the RWCU system is normally in operation during all modes of nuclear plant operation, satisfactory operation is demonstrated continuously without the need for any special inspection or testing.

The RWCU System is in scope for License Renewal per 10 CFR 54.4(a)(1), (a)(2), and (a)(3) and was subject to aging management review. Aging effects are managed by the following Aging Management Programs: Bolting Integrity (see USAR Section K-2.1.2), External Surfaces Monitoring (see USAR Section K-2.1.14), Selective Leaching (see USAR Section K-2.1.34), Water Chemistry Control - BWR (see USAR Section K-2.1.39), and Water Chemistry Control - Closed Cooling Water (see USAR Section K-2.1.40). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Section K-2.2.2.2).

10.0 REACTOR COOLANT SYSTEM LEAKAGE RATE LIMITS

10.1 Safety Objective

Reactor Coolant System (RCS) leakage rate limits are established so that appropriate action can be taken before the integrity of the Reactor Coolant Pressure Boundary (RCPB) is unduly compromised.

10.2 Safety Design Bases

The safety design bases for RCS leakage rate limits are as follows:

1. The RCS leakage rate limits are set so that corrective action can be taken:

   a. Before the RCPB is threatened with significant compromise.

   b. Before the rate of leakage exceeds the RCS makeup capability.

   c. Before the total leakage rate within the drywell exceeds the capability for leakage removal from the drywell.

2. Means are provided for the detection of leakage rates so that corrective action can be taken before the integrity of the RCPB is unduly compromised.

10.3 Description

The leakage that is considered in this subsection is limited to that water and steam released from the RCPB inside the primary containment. This released water and steam, after condensation, is collected in the drywell floor drain and equipment drain sumps. RCS leakage inside the drywell is treated here separately from leakage elsewhere in the station because it can not be investigated locally or isolated from the reactor vessel during power operation.

Burns and Roe Drawings 2028 and 2038, Sheet 1, are diagrams of the drywell floor and equipment drainage systems and of the drywell sumps. As shown on the drawings, there are two drywell sumps. G sump, the drywell equipment drain sump, receives drainage from pump seal leak-off, reactor vessel head flange seal leak-off, selected valve stem leak-off including recirculation loop and Main Steam Isolation Valves (MSIV), and other equipment drains through risers or directly connected drain lines. F sump, the drywell floor drain collector sump, receives leakage from the drywell coolers, floor drains, and the Reactor Equipment Cooling (REC) System drains located inside the drywell. The discharge lines from the equipment drain sump and floor drain sump that connect to the radwaste system are provided with flow meters outside of the primary containment.

Total drainage within the primary containment consists of all wastes, identified and unidentified, which flow to the drywell equipment drain and drywell floor drain sumps, respectively.

The criterion for establishing a total leakage rate limit without compromising the steam output of the plant is based on crack propagation studies discussed in depth in Section IV-10.3.2 below and to take mitigating actions before a crack becomes large enough to propagate rapidly.

The equipment drain sump (capacity 1000 gallons) and the floor drain sump (capacity 1000 gallons), which collect all wastes inside the drywell, are each drained by two 50 gpm sump pumps. The total leakage rate limit is therefore established below the removal capacity of the two pumps in each sump. Further, it is unlikely that all the total leakage would collect in one sump.

Each pump has an alarm system and automatic pump starting sequence on rising water level, which acts in the following manner: At the first high water level setting ("high"), the preferred pump (alternately selected for operation by an electronic alternator) is automatically started and a high level alarm is actuated. "On-off" lights in the Main Control Room and at the motor control centers indicate the operational status of each pump. If the water level continues to rise, a higher water level setting (high-high) starts the second pump and also actuates an alarm. Of note is that an interlock exists for the equipment 1G and floor drain 1F sump pumps to trip if the discharge valves are closed.

By observing the sump discharge flow metering instrumentation, a high level alarm can be ascribed to either failure of one or both pumps or to excessive drainage into the sump. On decreasing level, "low" level switches shut down the operating pump(s).

RCS leakage inside the primary containment is monitored by observing the drywell sump system flow monitors.[39][107] As the water which has been collected in the sumps is pumped out, the discharge flow from each sump is individually metered by flow integrators or totalizers, located in the main control room. Total leakage rate is periodically calculated from these flow integrators and a record is maintained in order to detect increases in total leakage rate.

Based on experience at other operating BWRs with similar systems, CNS indicates that variations of 0.5 GPM in the floor drain sump and 2.0 GPM in the equipment drain sump can be easily detected.[39][40][46][47][49] The response time for each is dependent on the amount of background leakage but will not exceed the interval between pumping cycles. The higher the leakage rate, the shorter the response time. Both sumps are equipped with a fill rate timer and alarm. This alarm can be set at or below the technical specification limits and will provide immediate response when this preselected rate is reached or exceeded.[40]

In addition, dewpoint and ambient temperature measurement is provided inside the drywell. Dewpoint and ambient temperature may be used to determine relative humidity in the drywell, which is an indirect indication of possible RCS leakage that is used in conjunction with the other methods discussed in this section. Readout of dewpoint and ambient temperature is on recorders in the Main Control Room.[39][107]

Temperature monitoring of the drywell atmosphere is provided at multiple elevations and azimuth locations within the drywell. Leakage of steam or reactor water will result in temperature increases at affected areas with subsequent indication in the main control room.[39][107]

Leakage detection commitments as contained in Cooper Nuclear Station Technical Specifications provide for evaluation of unidentified leakage and the monitoring of the sump level and air sampling system. In response to IE Bulletin 79-08, a description was provided of "other instrumentation which the operator might have to determine changes in the RCS inventory, e.g., drywell high pressure, radioactivity levels, suppression pool high temperature, containment sump pump operation, etc."

Nebraska Public Power District's response included the following items, which could assist the operator in determining changes in coolant inventory:

a. Drywell equipment and floor drain sump flow recorders.

b. Drywell equipment sump temperature indicator.

c. Three suppression pool water level indicators and one recorder.

d. Three primary containment and one suppression chamber pressure indicator.

e. Primary containment internal temperature and suppression pool temperature.

f. Drywell atmospheric particulate or atmospheric gaseous monitoring system.

The District feels that these leakage detection requirements and available instrumentation mentioned above provide adequate indication of unidentified leakage due to RCS inventory loss.[53] Additional details of leakage detection instrumentation and capability can be found in USAR Section V-2.3.9.3, "Containment Radiation."

10.3.1 Identified Leakage Rate

The identified waste flows or leakage rate is the sum of all component leakage collected from identified sources. In general, these sources drain to the drywell equipment drain sump. Leakage from the reactor vessel head flange gasket is piped to a measuring leg and then to the equipment drain sump. A detailed discussion of the instrumentation for reactor vessel head flange leakage measurement is provided in the USAR Section VII-8, "Reactor Vessel Instrumentation". Most valves and the recirculation pumps in the RCS inside the drywell are equipped with double seals. Leakage from these seals is piped to risers terminating in the equipment drain sump. The recirculation pump seals are instrumented as shown in USAR Section IV-3, "Reactor Recirculation System". Temperature sensors in the main steam relief valve discharge piping identify main steam relief valve leakage. Such leakage would collect in the suppression pool as steam leakage is condensed.

10.3.2 Unidentified Leakage Rate

The unidentified waste flows or leakage rate is the sum of all leakage collected from unidentified sources. These sources drain to the drywell floor drain sump.

A threat of significant compromise to the RCPB exists if the barrier contains a crack, which is large enough to propagate rapidly. The unidentified leakage rate is limited because of the possibility that most of the unidentified leakage might be emitted from a single crack in the RCPB.

A leakage rate of 150 gpm has been conservatively calculated to be the minimum liquid leakage from a crack large enough to propagate rapidly. An allowance for reasonable leakage, which does not compromise barrier integrity and is not identifiable, is made for normal operation.

The unidentified leakage rate limit was originally established at 15 gpm, which is far enough below the 150 gpm leakage rate to allow time for corrective action to be taken before the RCPB is significantly degraded. Section 3.4.4 of the CNS Technical Specifications specifies a more conservative leakage rate of less than or equal to 5 gpm. The originally proposed 15 gpm unidentified leakage rate limit was based on the calculated flow from a critical crack in a primary system pipe. A critical crack length is the length that a crack propagating through a relatively tear-resistant material must attain before it will rapidly continue to complete failure. By establishing a maximum allowable crack length below the critical crack length, catastrophic failure is avoided.

a. The lengths of through-wall cracks that would leak at the rate of 15 gpm given as a function of wall thickness and nominal pipe size, at a representative BWR pressure of 1050 psi, are as follows:

Nominal Pipe Size (Sch 80), In.	Average Wall Thickness, In. (Sch 80)	Crack Length L, in.	
		Steam Line	Water Line
4	0.337	8.4	6.7
12	0.687	12.1	7.5
24	1.218	14.0	7.8

b. The critical crack length, Lc, and the ratios of crack length, L, to the critical crack length as a function of nominal pipe size, are as follows:

Nominal Pipe Size (Sch 80), In.	Critical Crack Length (In.)	Ratio L/Lc	
		Steam Line	Water Line
4	9.6	.875	.70
12	19.6	.618	.382
24	34.8	.400	.224

c. The above information is based on analytical approximations of critical crack size and crack opening displacement in a GE Pipe Rupture Study[42] and on experimental data obtained by GE[43] and BMI.[44] The determination of leakage rates was based on a GE study of blowdown flaws.[45]

d. It is important to recognize the failure of ductile piping with a long, through-wall crack is characterized by large crack opening displacements, which 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 leakage 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 inches at the time of incipient rupture, corresponding to leaks on the order of one square inch 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.[41]

Condensation from the drywell atmosphere occurs as the atmosphere is circulated through the drywell coolers. This condensation is collected and piped to the drywell floor drain sump. Fluid leakage inside the containment from the RCS boundary will result in increased cooling loads on the drywell air coolers, which will result in abnormal temperature measurements on the cooling units. The condensation on the coolers will increase and abnormally high condensate flows to the floor drain sump will result. Condensation on the drywell walls and structures within the primary containment will also collect in the floor drain sump. The integrated floor drain sump flow, the drywell atmosphere pressure and temperature, the drywell atmosphere humidity, and the drywell air cooler temperatures are all employed as indicators of potential leakage from the RCS boundary.

In addition to the existing leak detection system within the drywell during normal operation, a two channel (particulate and gas) radiation monitor is used to draw an air sample from containment. This monitor, the Drywell Atmospheric Monitoring System, has indication and annunciation in the Main Control Room. If the Drywell Atmospheric Monitoring System is inoperable, grab samples of the drywell atmosphere are taken in accordance with the Technical Specifications.

10.3.3 Steam Tunnel Leakage

Steam releases into the tunnel are detected by temperature sensors. When these sensors detect a high temperature condition in the steam tunnel, they initiate main steamline isolation but not RCIC isolation. If the break is in the RCIC steam piping traversing this area, the RCIC high steam flow sensors are the only automatic sensors providing protection for RCIC breaks in the tunnel. (There are no RCIC temperature sensors located in the tunnel.) Breaks that discharge less than three times the RCIC rated flow do not actuate the RCIC isolation valves; therefore, the steam pressure increases in the tunnel unless the operator responds to the emergency and manually isolates the RCIC. Lack of operator action permits the pressure to increase until the steam is eventually relieved through the steam tunnel blowout panels into the turbine building. Continuation of the blowdown causes venting of steam from the turbine building; however, steam leaks without liquid releases produce insignificant radiological doses. A high radiation level will be detected by the turbine area radiation monitoring instrumentation and will annunciate in the control room. In addition, the turbine building main steam line leak detection instrumentation will detect a high temperature. Thus, the operator would be alerted to examine his information display. An indication of RCIC flow without a concurrent reactor low water level but with high tunnel temperature and with main steamline isolation would be indicative of an RCIC steamline break in the tunnel area. The operator could then isolate RCIC (a very important system but not designated as an Emergency Core Cooling System (ECCS)) or could dispatch someone to perform a survey in the affected area. The operator's examination could take as long as 10 minutes before the operator deduces that the

RCIC steamline probably has ruptured and that person manually isolates the RCIC steamline. Therefore, operator action cannot be credited for 10 minutes. The Cooper offsite doses for an undetected 300 percent RCIC steam leak in the tunnel that continues for this long (10 minutes) are similar to those given for Browns Ferry, Docket 50-259, Question 5.3. The doses given for Browns Ferry were 0.0000005% of the 10CFR100 guideline values for the thyroid dose and 0.0027% of the 10CFR100 guideline values for the whole body dose.

The locations of the elbow flow devices for the RCIC and HPCI systems are inside the drywell immediately upstream of the main steam line inboard isolation valves. These devices have been properly located to assure that they will not experience any adverse effects (or false indications) from flow in the main steam line.

Separation of the HPCI steam line ΔP sensors is not required as the HPCI area temperature monitors are installed to provide complete line coverage.

All temperature sensors for the RCIC, HPCI, and main steam line leak detection systems are tested during normal plant operation by the use of permanently installed heat wires for inaccessible areas. All systems are designed in accordance with the provisions of IEEE-279.[48]

10.4 Safety Evaluation

The unidentified leakage rate limit described above is based, with an adequate margin for contingencies, on the calculated leakage from a crack large enough to propagate rapidly. The established limit is sufficiently low so that even if the entire unidentified leakage rate was coming from a single crack in the RCPB, corrective action could be taken before the integrity of the barrier is threatened with significant compromise.

The limit on total leakage rate is established so that in the absence of off-site AC power and feedwater, and without using ECCS, the leakage loss from the RCS could be replaced. Either one of the two CRD pumps are designed to furnish the required makeup flow rate. The limit on total leakage also allows a reasonable margin below the discharge capability of either the floor drain or equipment drain sump pumps. Thus, the established total leakage rate allows sufficient time for corrective action to be taken before either RCS makeup or the drywell sump removal capabilities are exceeded.

The CNS Technical Specifications specify a more conservative leakage rate with appropriate bases given as previously stated in USAR Section IV-10.3.2.

Finally, provided in USAR Section IV-10.3, Description, is a discussion of the leakage detection instrumentation. With this information it is shown that means are provided for the detection of leakage so that corrective action can be taken before the integrity of the RCPB is unduly compromised.

Therefore, based on the previous discussion, it is concluded that safety design bases 1 and 2 as stated in USAR Section IV-10.2 are met.

10.5 Inspection and Testing

Because the sump pumps are automatically started and their operation is verified by the alarms and discharge flow instrumentation, no special inspection or testing during power operation of the station is necessary. The pumps and controls are inspected and tested during scheduled outages.

The functionality of the flow totalizer that is used to detect RCS leakage through both the drywell equipment drain sump and the drywell floor drain sump systems is determined through periodic calibration of the flow transmitter and totalizer.[50]

Operation of the Drywell Atmospheric Monitoring System is verified through calibration with a portable radiation source and testing of the alarm circuits.

11.0 MAIN STEAM LINES AND FEEDWATER PIPING

11.1 Safety Objective

The Safety Objective of the main steam and feedwater piping that is part of the Reactor Coolant Pressure Boundary (RCPB) is designed to prevent uncontrolled release of primary steam and water to the environs under transient and assumed accident conditions and to accommodate all unbalanced forces. The Safety Objective of the main steam piping that is not part of the RCPB is to direct post-accident MSIV leakage to the Main Condenser.

11.2 Safety Design Bases

The portion of the main steam and feedwater lines, which is part of the RCPB, is:

1. Designed so that the steam and fluids within the main steam and feedwater lines which may contain radioactive materials are given the necessary attention to detail in the design, fabrication, inspection and testing to assure that piping failures will be minimized.

2. Designed to accommodate all operational stresses and to withstand the effects of earthquake loadings.

Certain portions of the main steam lines that are not part of the RCPB are required to direct post-accident MSIV leakage to the Main Condenser.

11.3 Power Generation Objectives

1. The power generation objective of the main steam lines is to conduct steam from the reactor vessel through the primary containment to the main steam turbine.

2. The power generation objective of the feedwater lines is to provide a piping path for delivery of water through the primary containment to the reactor vessel.

11.4 Power Generation Design Bases

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

2. The feedwater piping is designed to conduct water to the reactor vessel over the full range of reactor power operation.

11.5 Description

The main steam piping is designed to conduct steam from the reactor vessel through the primary containment to the Main Steam Turbine (see Burns and Roe Drawing 2002, Sheets 1 and 2). Four steam lines conduct steam from the reactor, through a shielded pipe tunnel, to a header that has two branches to the Main Turbine and one branch to the Main Turbine Bypass Valve Manifold that discharges to the condenser. This ensures that the Main Turbine Bypass System, which is discussed in USAR Section XI-5, is connected to the active steam lines. A drain line is connected to the low points of each main steam line both inside and outside the drywell. Both sets of drains are connected by valving to permit drainage to the Main Condenser hotwell. These low point drains are provided to permit draining of the main steam line low points when required. The steam line drains inside the drywell slope downward from the main steam line low point to the orifice outside the drywell. The drain line from the orifice to the condenser hotwell slopes downward to the Main Condenser. This drain line is also connected to the extraction steam piping for Feedwater Heaters 5A & 5B, allowing drainage either to the Main Condenser or Feedwater Heaters 5A and 5B. An additional drain line is provided from the low point of the drains to clean-radwaste to permit purging the lines for maintenance.

The inside and outside main steam line drains are capable of being utilized to equalize pressure across the main steam isolation valves (MSIV) prior to restart following a main steam line isolation. Assuming all MSIVs have closed and the main steam line drains outside the drywell have been depressurized and drained, the MSIVs outside the drywell are then opened first; these drain lines are then used to warm up and pressurize the outside steam lines. Finally, the MSIVs inside the drywell are opened.

Main steam lines running between the High and Low Pressure Turbines, including the Moisture Separators, are mentioned in USAR Section XI-2 and shown on <u>Burns and Roe Drawing 2002, Sheets 1 and 2</u>. The auxiliary steam connections to the Turbine Gland Seals and the Reactor Feed Pump Turbines are also shown in <u>Burns and Roe Drawing 2002, Sheets 1 and 2</u>.

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 USAR Section VII-10, "Feedwater Control System" and USAR Section XI-8, "Condensate and Feedwater Systems".

All main steam and feedwater piping is classified according to service and location. The materials used in the piping are, as a minimum, designed and fabricated in accordance with USAS (now ANSI) B31.1.0-1967. The design, fabrication, inspection, and testing requirements for the piping are specified in Appendix A for each pipe class. In addition, the main steam piping and feedwater piping within the RCPB (i.e., to the second isolation valve of the main steam system and the outboard check valve of the feedwater system located outside the containment) are analyzed in accordance with criteria set forth in Appendix C to assure high reliability.

Information on the evaluations of the main steam and feedwater piping to withstand postulated breaks and ruptures associated with High Energy Line Breaks (HELB) has been analyzed and is described in USAR Section IV-12.

11.6 <u>Safety Evaluation</u>

Differential pressures on reactor internals under the assumed accident conditions of a ruptured main steam line are limited by both the utilization of flow restrictors and the utilization of four main steam lines. Main steam and feedwater piping is designed, as a minimum, in accordance with the USAS (now ANSI) B31.1.0-1967 Code for Power Piping, which describes the requirements for design, fabrication, erection, supports, and tests and other supplemental requirements and the primary and secondary allowable stresses associated with the main steam and feedwater piping including the applicable requirements set forth in Appendix A. Therefore, safety design bases 1 and 2 are met by design of the main steam and feedwater piping within the reactor building to Seismic Class IS criteria as described in USAR, Subsection IV-11.5 and Appendix A.

The Seismic Class IIS Main Steam piping that is not part of the RCPB is credited with directing MSIV leakage from the MSIVs to the main turbine condenser during a Loss-of-Coolant Accident and a Control Rod Drop Accident. For the LOCA, this Alternate Leakage Treatment (ALT) pathway allows crediting the dose consequence mitigation assumptions related to leakage holdup and the resulting iodine plateout within the condenser. As part of the licensing of the LOCA dose calculations, the NRC has required that the ALT pathway be evaluated as capable of withstanding the seismic loadings of a postulated Safe Shutdown Earthquake. Details of the seismic qualification of the ALT pathway to the condenser are included in Section XII-2.3.5.3. The evaluated ALT pathway is shown in CNS-MS-43. Manual actions are required to configure the ALT pathway following a LOCA. Where local valve operation is required, there is sufficient time to perform the evolution before local radiological conditions would become a concern due to the LOCA source term.

11.7 Inspection and Testing

Inspection and testing is carried out in accordance with USAS (now ANSI) B31.1.0-1967. Access requirements for in-service inspection were considered in the design of the main steam and feedwater piping to assure adequate working space and access for inspection of selected Systems, Structures and Components (SSCs).

To assure that main steam piping vibration is within acceptable limits, flow induced vibrations in the main steam piping have been measured on plants whose configuration is similar to that of CNS and have been shown to be insignificant. For this reason, no additional measurements on flow induced vibration in the main steam piping for CNS are considered necessary.

The main steam piping is subjected to two transient conditions that produce dynamic loads acting on it. These two conditions are turbine stop valve closure and relief valve lifting. A conservative dynamic analysis has been made for both of these transients to determine stress levels rather than by actual test measurement. The results of this analysis are documented in the General Electric report, "Dynamic Analysis of the Effects of Turbine Stop Valve Closure and Relief Valve Discharge on Cooper Nuclear Station Main Steam Lines",[18] and discussed in USAR Appendix C, Section 3.3.3.5.[19]

The manual valves that are either: a) closed to configure the boundaries or the ALT pathway, or b) opened to establish a flow path to the Main Condenser, are cycled during each refueling outage to assure their functionality.

The main steam lines are in scope for License Renewal per 10 CFR 54.4(a)(1), (a)(2), and (a)(3) and were subject to aging management review. Aging effects are managed by the following Aging Management Programs: Bolting Integrity (see USAR Section K-2.1.2), External Surfaces Monitoring (see USAR Section K-2.1.14), Flow-Accelerated Corrosion (see USAR Section K-2.1.18), Selective Leaching (see USAR Section K-2.1.34), and Water Chemistry Control - BWR (see USAR Section K-2.1.39). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Section K-2.2.2.2).

12.0 HIGH ENERGY LINE BREAK (HELB) STUDY

12.1 Description

An evaluation has been performed to substantiate that the design of CNS is adequate to withstand the effects of a postulated rupture or break in any high energy fluid piping system outside the primary containment, including the double-ended rupture of the largest line in the main steam and feedwater system. This study or evaluation, which captured the CNS high energy line break (HELB) analyses, is contained in Amendments 20 and 25 to the Final Safety Analysis Report.[108][110] Structural elements were also analyzed, as well as the affected fluid and electrical systems.

All normally pressurized systems in the secondary containment area whose service temperature exceeds 200°F or whose design pressure exceeds 275 psig were considered in the pipe break study. The systems, which satisfied this high energy system definition and were analyzed in the study are listed in Amendments 20 and 25. A high energy line break was postulated to occur, regardless of stress levels, wherever the high energy line passes in close proximity to a safety-related line or equipment. This evaluation exceeded the criteria in many cases since break points were considered where safety-related components existed. The results of this interaction were evaluated in terms of effect on safe shutdown and long term cooling.

Within the HELB study, a pipe break analysis was performed on safety related piping outside the primary containment. This analysis included the effects of pipe whip impact loads and pressure buildup resulting from released steam and feedwater on building elements. Those systems whose service temperature is 200°F or greater and the design pressure is greater than 275 psig were considered in this pipe break analysis. The evaluation included the following piping systems containing high energy fluids.

Main Steam System
Feedwater and Condensate System
Reactor Core Isolation Cooling System
High Pressure Coolant Injection System
Reactor Water Cleanup System
Residual Heat Removal System
Control Rod Drive System

Piping that did not fall within the previously mentioned and defined criteria for pipe whip considered only the environmental effects of certain low energy lines. This consisted of the following systems:

Heating Steam
Sampling

The pipe break study determined that upon the completion of several changes to the plant identified therein, the plant can be shut down safely and can be maintained in safe shutdown condition, considering a postulated pipe break outside primary containment. As a result of the examination of postulated high energy fluid piping breaks outside of the primary containment, the following modifications were made to assure that the safe shutdown capability would not be degraded should any of the postulated pipe ruptures actually occur:

1. Installation of a pipe whip restraining structure or replacement of a section of pipe with heavier wall pipe for certain sections of Service Water and the RHR heat exchanger return lines.

2. Installation of a high temperature alarm to annunciate in the control room in the event of a building heating steam line break.

3. Replacement of hollow metal doors and frames with blast proof doors in potential steam flow paths to the control room.

All other systems studied provide the necessary requirements for safe plant shutdown.

In addition, the effects of high energy pipe breaks were evaluated on the following systems, components, and structures which would be necessary (in various combinations, depending on the effects of the break) to safely shut down, cool down, and maintain cold shutdown conditions of the plant:

A. General

1. Control Room
2. Control and Instrument Cables
3. Electrical Distribution Systems
4. Emergency DC Power Supply (batteries)
5. Emergency AC Power Supply (diesels)
6. Heating and Ventilation Systems

B. Reactor Control

1. Control Rod Drive System
2. Neutron Monitoring System
3. Instrumentation for Reactor Temperature and Water Level

C. Core Cooling Systems

1. Condensate and Feedwater
2. Residual Heat Removal System (Including LPCI Mode)
3. Reactor Core Isolation Cooling System
4. Automatic Depressurization System
5. High Pressure Coolant Injection System
6. Core Spray System

D. Service Systems

1. Service Water System
2. Residual Heat Removal Service Water System
3. Reactor Equipment Cooling System

Moreover, all fluid-containing piping systems (including field-run piping) routed in the vicinity of safety-related equipment were examined for environmental effects resulting from a single open crack in the most adverse location. These systems include those service systems indicated above and cover all other fluid-containing piping systems such as building and instrument air systems, hydrogen and nitrogen piping systems, vent and drain systems, and test lines.

Thus, the CNS HELB evaluation demonstrated that the criteria listed in (1) and (2) below, which is a summary of the requirements set forth, were satisfied when taken into consideration in this study. This included addressing the 21 criteria listed in the AEC (Giambusso) letter to NPPD, dated December 18, 1972, transmitting document entitled "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment"[109] and results of review discussions with DRL dated May 2, 1973 and documented May 7, 1973.[111]

(1) Protection of equipment and structures necessary to shutdown the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, is provided from all effects resulting from ruptures or breaks in pipes carrying high-energy fluid, up to and including a double-ended rupture of such pipes, where the temperature and pressure conditions of the fluid exceed 200°F and 275 psig. Breaks were assumed to occur in those locations specified in the "pipe whip criteria." The rupture effects considered included pipe whip, structural (including the effects of jet impingement) and environmental.

(2) In addition, protection of equipment and structures necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming a concurrent and unrelated single active failure of protected equipment, is provided from the environmental and structural effects (including the effects of jet impingement) resulting in pipes carrying fluid routed in the vicinity of this equipment. The size of the cracks was assumed to be 1/2 the pipe diameter in length and 1/2 the wall thickness in width.

In summary, these analyses and evaluations performed by CNS that covered the specific criteria set forth by the NRC included the areas of pressure buildup resulting from pipe break, pipe whip impact on building elements, structural effects on building elements resulting from pressure buildup and impact forces, the effects of failure of high energy line breaks down to the subsystem level, flooding of safety-related equipment, propagation of steam flow to the control room, and the control room habitability of operators as a result of a postulated pipe break failure. The HELB study also included specific remedial actions and emergency plans for handling a pipe break outside of containment that were automatic, required operator actions and/or followed specific site procedures.

12.2 Subsequent HELB Analyses

In response to IE Bulletin 79-01B, the District also performed additional analyses of the environment created by high energy line breaks. These analyses were performed as input to the Environmental Qualification issue. Additional information discussing the Equipment Qualification (EQ) Program can be found in USAR VII, Section 1.7.2.

The analysis, in FSAR Amendment 25, dealing with the effect of the Main Steam Line Break on the Control Room Habitability System, has been amended by the analysis contained in calculation NEDC 94-118(89). This amended analysis incorporated changes made to the Control Room HVAC System identified by modifications DC 86-060 and DC 93-257. A summary of this revised analysis is contained in USAR Section X-10.4. The analysis, in FSAR Amendment 25, dealing with the effect of the 8" steam line supplying the RHR heat exchangers and the 10" line supplying the HPCI Turbine has been amended by the analysis contained in calculation NEDC 97-024. The analysis dealing with the effect of a break in the Main Steam Line supplying the Reactor Core Isolation Cooling (RCIC) Turbine has been amended by the analysis contained in calculation NEDC 97-062. The analysis dealing with the effect of a break in the Reactor Water Cleanup Line has been amended by the analysis contained in calculation NEDC 97-057. These analyses were performed to evaluate the structural and EQ effects of an increase in time of valve closure for these specific high energy line systems.

For EQ purposes the above mentioned analyses have been replaced by calculation NEDC 00-095D[114], but the previous analyses are still valid for other design bases purposes. The new calculation provides a more conservative environment resulting from all potential HELBs with a more detailed breakdown of the various affected Secondary Containment areas.

13.0 REFERENCES FOR CHAPTER IV

1. Q/A 4.8, 4.27; Amend. 9.
2. Deleted.
3. Q/A 4.1, 4.2; Amend. 11.
4. Q/A 4.30; Amend. 13.
5. Q/A 4.3; Amend. 13.
6. Q/A 4.33; Amend. 17.
7. Q/A 4.4; Amend. 9.
8. Q/A 4.5; Amend. 15.
9. Kobsa, J. R. and Wetzel, V. R.; "Design and Analysis of Control Rod Drive Reactor Vessel Penetrations", General Electric Co., Atomic Power Equipment Department, November, 1968 (APED-5703).
10. NEDO 10115, "Mechanical Property Surveillance of General Electric BWR Vessels" by J. P. Higgins and F. A. Brandt.
11. "Design and Performance of G.E. BWR Jet Pumps", General Electric Company, Atomic Power Equipment Department, September, 1968 (APED-5460).
12. MDC 80-2.
13. Q/A 4.24; Amend. 9.
14. Deleted.
15. MDC 79-55.
16. Letter J. Pilant (NPPD) to V. Stello (NRC) dated 10/6/76 (175220716).
17. Ionni, P. W., "Core Standby Cooling Systems for Boiling Water Reactors", General Electric Company, Atomic Power Equipment Department, March, 1968 (APED-5458).
18. General Electric Company, Atomic Power Equipment Department, APED Specification No. 22A2680, "Dynamic Analysis of the Effects of Turbine Stop Valve Closure and Relief Valve Discharge on Cooper Nuclear Station Main Steam Lines".
19. Q/A 4.19; Amend. 30.
20. Q/A 4.21; Amend. 9.
21. MDC 80-9.
22. MDC 79-42A and DC 95-044-1.
23. MDC 80-10.
24. NEDO 21864-P, "Final Report - Monticello T-Quencher Test", June, 1979.

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