Primary Systems
Chapter 16

ACADs (08-006) Covered

1.2.1.17	3.1.1.1	3.3.2.4.1	3.3.2.4.2	3.3.11.41.2	4.2.4	4.2.7.2	4.25.1.8
5.2.2.9	5.2.2.10	5.3.2.9	5.4.3.1	5.4.3.2	5.4.3.4	5.4.3.8	5.4.3.10
5.4.3.11							

Keywords
Reactor coolant system, vessel, core construction, internals, fuel assembly, reactor coolant pump, pressurizer.

Description
This chapter covers the components that make up the primary system, which includes the purpose, construction, instrumentation, controls, and protection of the system.

Supporting Material

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0.0	2/4/04	Initial Development	TLH	DS
1.0	6/10/04	Instructor Feedback	TLH	DS
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3.0	8/05/04	Incorporated student feedback on OTDT and OPDT runback set points per AI# 2004202117	TLH	DS
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CHAPTER 16

PRIMARY SYSTEMS

16.1 INTRODUCTION

This chapter covers the components that make up the primary system, which includes the purpose, construction, instrumentation, controls, and protection of the system.

16.2 PURPOSE OF THE REACTOR COOLANT SYSTEM

They are four purposes of the Reactor Coolant System, (1) is to transfer heat from the reactor core to the steam generators to produce steam in the secondary plant to drive the turbine generator, (2) acts as a neutron moderator, (3) it carries soluble boron also known as boric acid (chemical shim) for reactivity control of the reactor, and (4) acts as a neutron reflector to minimize leakage from the core.

16.3 OVERVIEW

The Reactor Coolant System is a closed piping system consisting of four loops connected to a single reactor vessel. Each reactor coolant loop contains a steam generator, a reactor coolant pump (RCP), piping penetrations for safety systems and instrumentation for reactor control and protection. Heat generated in the reactor core is removed by coolant which is being circulated through the core by the RCPs. The coolant leaves the core and flows through the steam generators where its heat is transferred to the secondary plant (Main Steam System). The Reactor Coolant System is operated at a pressure high enough to prevent bulk boiling at the elevated operating temperature. Because it is a closed, pressurized system, the Reactor Coolant System also acts as a barrier to prevent the release of any fission products that could possibly escape through the fuel assembly cladding. The RCS is the second of three such boundaries to prevent the release of fission products to the environment. The other two boundaries are the fuel cladding and the containment. The reactor coolant flows from the outlet of the S/G (primary or RCS side) to the suction side of the reactor coolant pump through the intermediate leg piping.

The reactor coolant pumps supply the driving head to the coolant and discharges to the reactor vessel. The coolant inside the vessel flows downward in the passage between the inside surface of the reactor vessel and the outside surface of the lower core barrel to the lower vessel plenum which also known as the "downcomer region". The coolant then is directed upward through the reactor core then exits out of the reactor vessel. The reactor coolant flow is piped to the inlet of the Steam Generators. The reactor coolant flows through the inverted U-tubes of the steam generator in which heat is transferred to the secondary coolant. Normal power operations require all four reactor coolant pumps to be in service. Due to the design of the primary system decay heat removal is possible without the use of reactor coolant pumps. The reactor coolant system arrangement is as such that the steam generators (heat sink) are installed at a higher elevation than the reactor core (heat source). A differential pressure is formed which cause natural flow across the steam generator due the difference in density. The hot water exiting the reactor rises due to coolant density being less than the coolant exiting the steam generator. The secondary coolant cools the reactor coolant in the U-tubes which causes the water to contract due to the density change. This density change is the driving force which is called “natural circulation”. Although “Natural Circulation” is not only reliable and effective, “Force Flow” is always preferred method of cooling.

Nuclear Power plants are built on a fail safe concept to ensure that the public safety is not compromised. A lot of lesson learned have been gained by the mistakes of other designs. “Three Mile Island Unit 2” was also built on a fail safe design, but the lack of knowledge and interference by the operating crew destroyed the newly built plant. The mistakes made at TMI Unit 2 have brought on many costly design changes not only at Plant Vogtle but through out the nuclear industry itself. The design changes also included changes in the Operator training programs. Most of the Fundamentals training are a direct response to the TMI event. The disaster at TMI unit 2 being the most popular is not the only event that has spurred changes through out the industry. Plant Vogtle will continue to change from lessons learned and from new technology. The changes are made to make our plant as safe and reliable as possible.

The goal here at Plant Vogtle is to produce electricity with Nuclear Safety as the number 1 priority. Even though our plant is built on a fail safe concept its design should never be challenged. This means everyone has a great responsibility to use conservative decision making in their everyday life. The use of the human performance tools are highly stressed here at Vogtle for good reason. Human beings are not perfect!

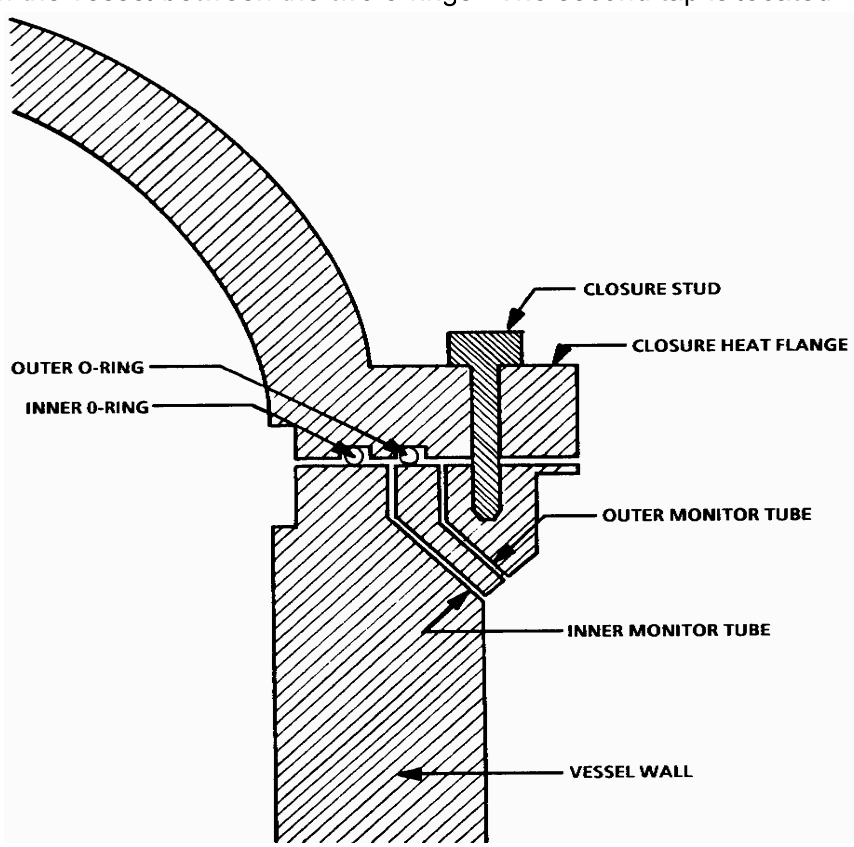
SECTION A

REACTOR VESSEL AND CORE CONSTRUCTION

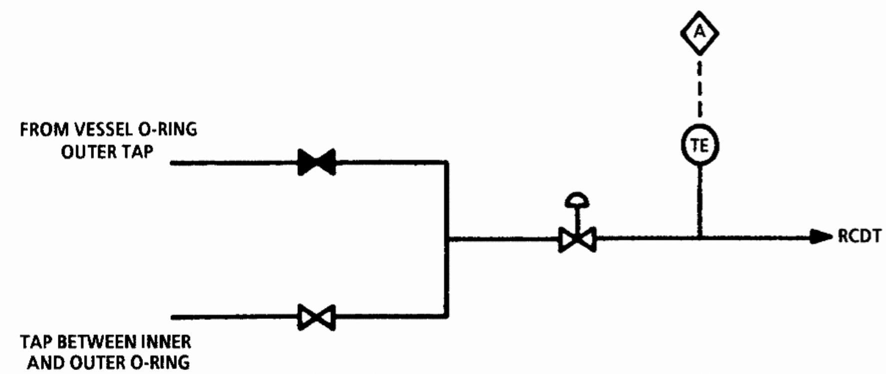
16.4 REACTOR VESSEL

The reactor vessel contains the reactor core, upper and lower internals, core components, in-core thermocouples, and nuclear instrumentation. The reactor vessel is constructed out of manganese-molybdenum steel with a stainless steel inner liner (cladding). The 1/8" thick stainless steel liner prevents corrosion to the reactor vessel caused from boric acid in the RCS. The reactor vessel is 44 feet tall with a diameter of 14.5 feet. The vessel wall thickness varies from 5 3/8" to 8 5/8". Key ways are machined into the bottom of the inner vessel that allow alignment and prevent traverse movement of the reactor internals. The vessel has a removable head for core manipulation, such as refueling and vessel internals disassembly. The vessel head is secured by 54 - 7" diameter studs. The studs are secured by a device called a "stud tensioner". The device actually stretches the stud to a precise length, after the nut has been hand tightened, the stud is then released which applies the correct amount of tension on the stud. This process is repeated on all 54 studs in a prescribed order.

Leakage is prevented by the use of two o-rings which are placed in grooves that are machined on the head and vessel flange. One o-ring is sufficient but the other serves as a backup. An inner and outer o-ring leak detection system alerts the control room of any leakage that may occur. One tap is machined in the vessel between the two o-rings. The second tap is located outside the outer o-ring. The two taps are piped to a resistance thermal detector (RTD) that alarms in the control room if leakage occurs. The inner and outer taps have manual isolation valves prior to joining into a common header. The outer tap is normally isolated. The common piping is routed to the reactor coolant drain tank (RCDT). In the common line there is an air operated isolation valve that can be closed by the control room in the event of a seal failure. Local operation would be necessary; the inner seal tap isolation valve would be required to be closed and the outer seal tap would be un-isolated. The control



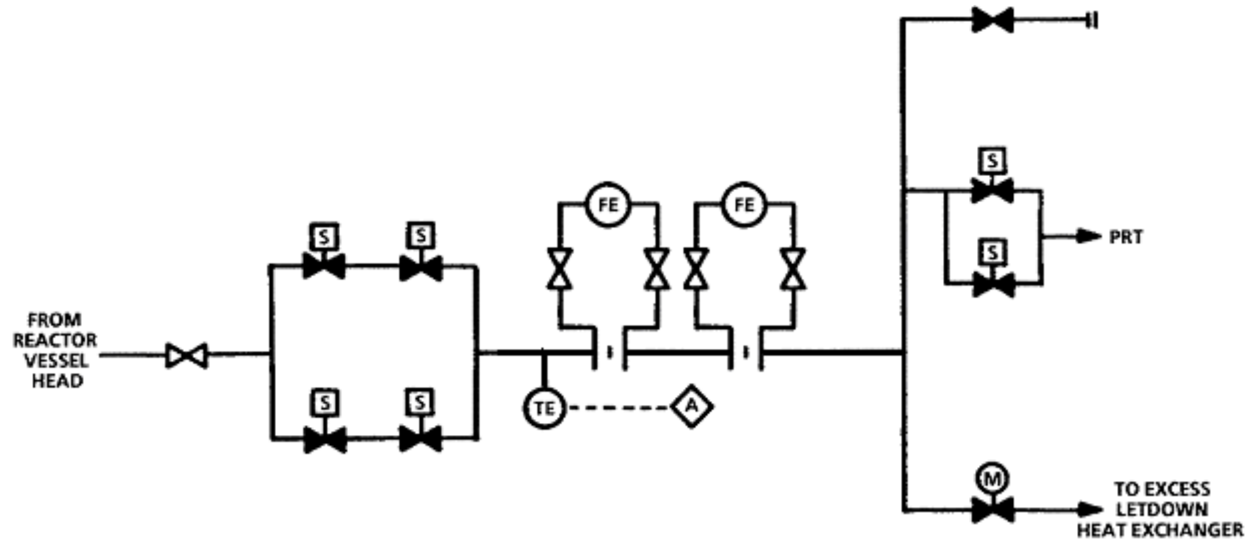
room would then be required to re-open the common air operated isolation valve to monitor the outer o-ring seal integrity.



They are eight nozzles on the reactor vessel. Four inlet and four outlet nozzles separated 45 degrees apart from one another. Hence the term four loop PWR plant. Every nozzle has a support pad that supports the entire weight of the reactor vessel.

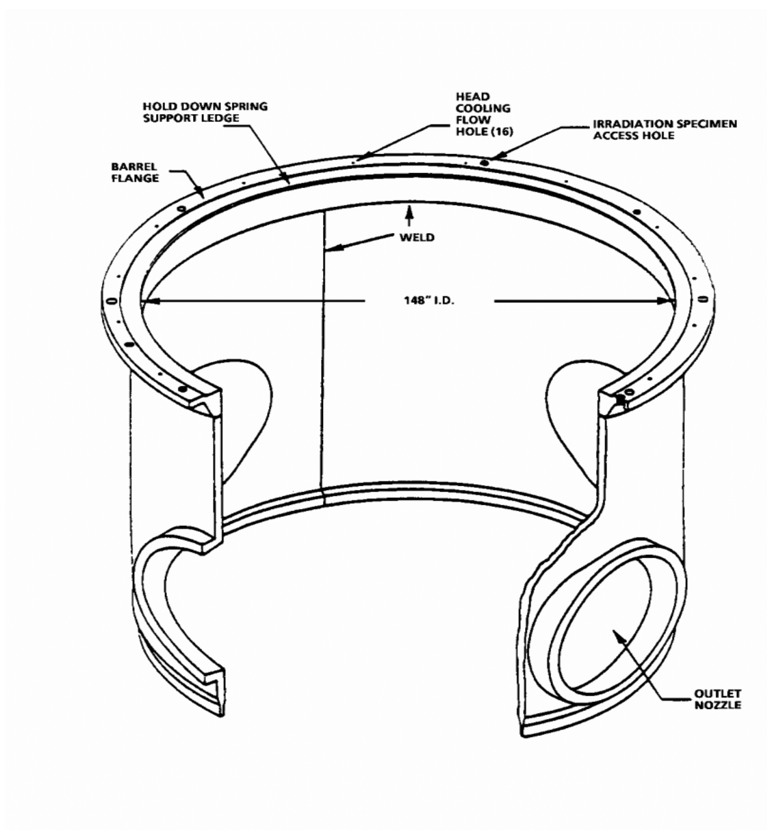
The inlet nozzle diameter is larger than the outlet nozzle diameter. The purpose for this is to reduce the flow rate of the reactor coolant thereby reducing core barrel erosion. Core inlet flow strikes the core barrel; most flow is directed down the vessel and core barrel wall. At the bottom of the vessel, the coolant is directed upward through the active core. Four percent of the Reactor coolant flow does not come in contact the fuel itself. This flow is known as core “bypass flow”, which consists of (1) Nozzle leakage, (2) Baffle plate leakage, (3) Upper head cooling, and (4) RCCA guide thimble and instrument thimble flow. Nozzle leakage is the short circuit flow between the inlet and outlet nozzle which makes up about 1 % of the bypass flow. Baffle plate leakage is flow between the core barrel and the baffle plate, which makes up about ½ % of the bypass flow. Upper head cooling makes up about ½ % of the bypass flow. This is designed to keep the upper head itself cool. The last of the bypass flow which makes up 2 % of the reactor coolant flow is the RCCA guide thimble and instrumentation flow.

Other penetrations in the reactor vessel are for In-Core instrumentation such as core exit thermocouples and In-core nuclear instrumentation. There are 78 penetrations in the upper head. 72 of these penetrations are for control rods with 53 being used now, and 19 spares that could be used in the future to support using plutonium-mixed fuels. 5 penetrations are for core exit thermocouples. Only 4 of these are being used and 1 is a spare. The last penetration in the upper head is for the reactor head vent. Reactor head vent provides a means of removing non-condensable gas during normal and emergency operation. If gases are not vented, RCS flow could become blocked and /or the fuel could become uncovered. The reactor head penetration is divided into two paths. Each path has two solenoid operated valves that can be operated from the control room or the remote shutdown panels. The two paths combine into a common header which discharge into either the pressurizer relief tank (PRT) (normal path) or the excess letdown line (alternate path). The reactor head vent also can serve as the safety grade letdown system which serves as a back up means of maintaining RCS inventory during a loss of instrument air. The lower reactor head has 58 penetrations for moveable in-core detectors used for flux mapping. Head vent flow indication is available in the control room and remote shutdown panels.

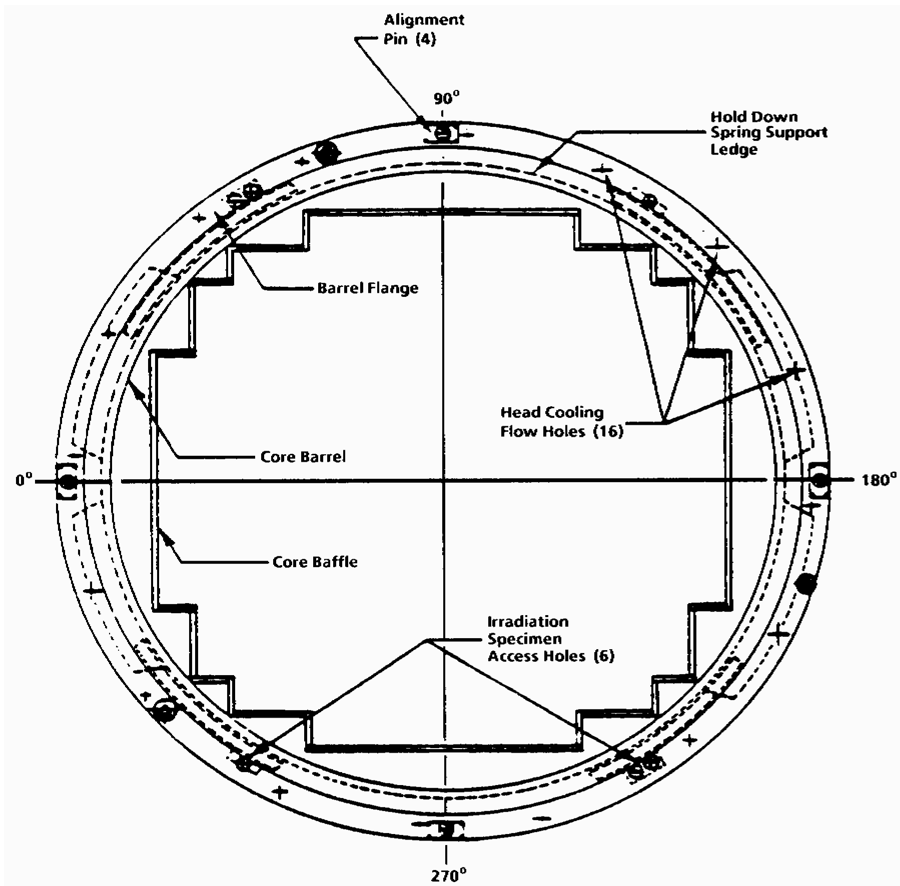


16.5 REACTOR VESSEL INTERNALS

The reactor vessel internals are made up of many components. The Core barrel is the largest of the components. It supports the weight of the core. The core barrel is suspended by the lip of the vessel flange. The core barrel is a stainless steel cylinder that is composed of an upper and lower section. The upper section contains the four penetrations for the hot legs which align with the outlet penetration of the reactor vessel. The lower section contains six keyways that ensure correct alignment. The core barrel lower section, which is the main section, contains: (1) Neutron pads, (2) specimen

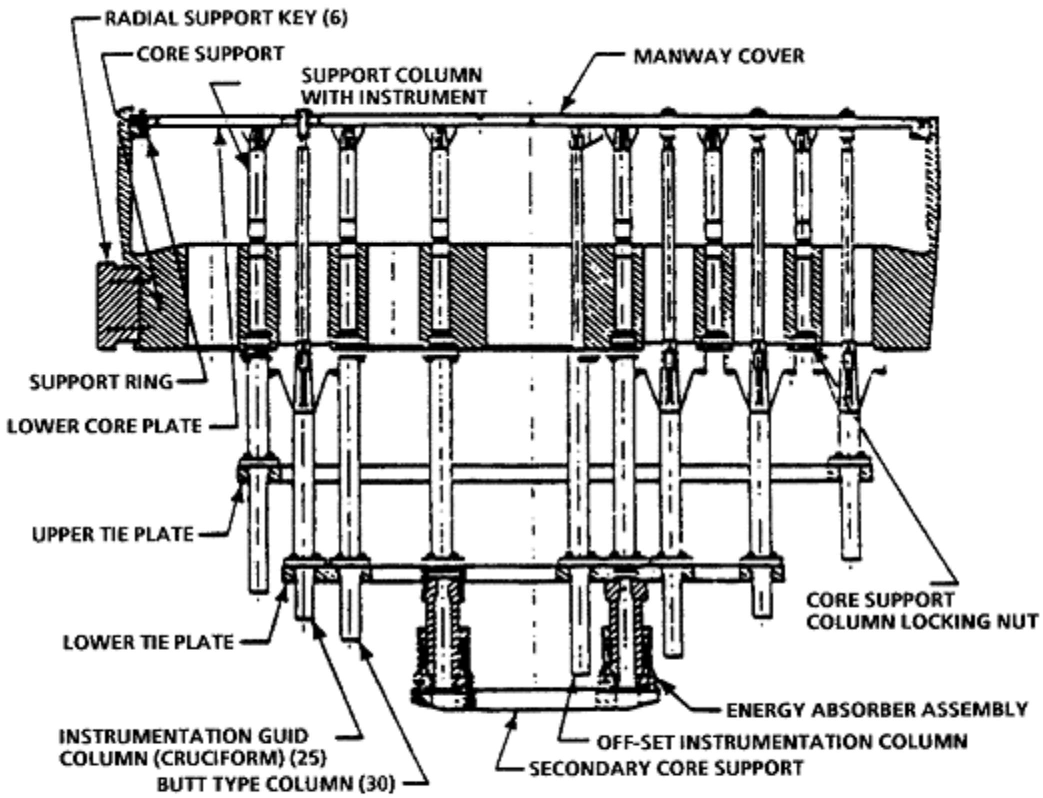


holders, and (3) baffle and former plates. The neutron pads are attached to the outside of the core barrel lower section. The neutron pads reduce the amount of neutron leakage from the core. This minimizes the amount of neutron embrittlement of the reactor vessel. Specimen holders house metal samples that can be retrieved and tested through out core life to determine how much embrittlement has occurred to the vessel. The baffle and former plates provide shape and lateral support for the core. The baffle plates are vertical metal plates that surround the core. The former plates are horizontal plates that bolt to the bottom of the core barrel that connect the baffle plates to the core barrel. The former plates have holes that allow cooling flow between the baffle and core barrel.

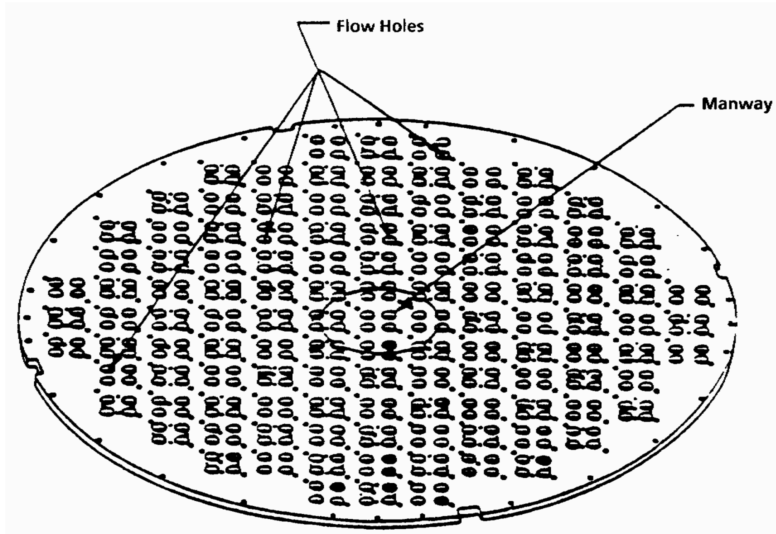


TOP VIEW OF THE CORE BARREL

16.6 LOWER INTERNALS

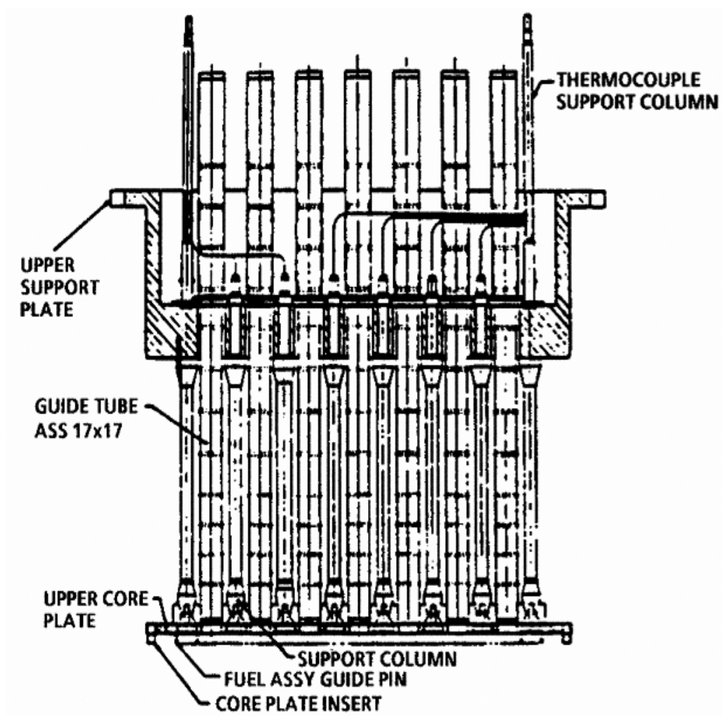


The lower internals consist of (1) Lower core support plate forging, (2) Lower core plate, (3) Secondary support assembly, and (4) Support columns. The Lower core support forging is a thick stainless steel plate with machined circular flow holes. The lower core plate is a stainless steel plate that the fuel assemblies rest on. The lower core plate contains alignment pins for fuel assembly. Both the lower core plate and the lower core forging are welded to the core barrel. The support columns connect between the core plate and the lower support forging. Secondary support assembly is connected under the lower core support forging by a shock absorber. There is a ¾" clearance between the bottom of the assembly and the floor of the reactor vessel. The secondary support assembly is designed for a hypothetical failure of the upper barrel flange. It absorbs the energy as the lower internals fall. This minimizes the impact forces on the bottom of the vessel.

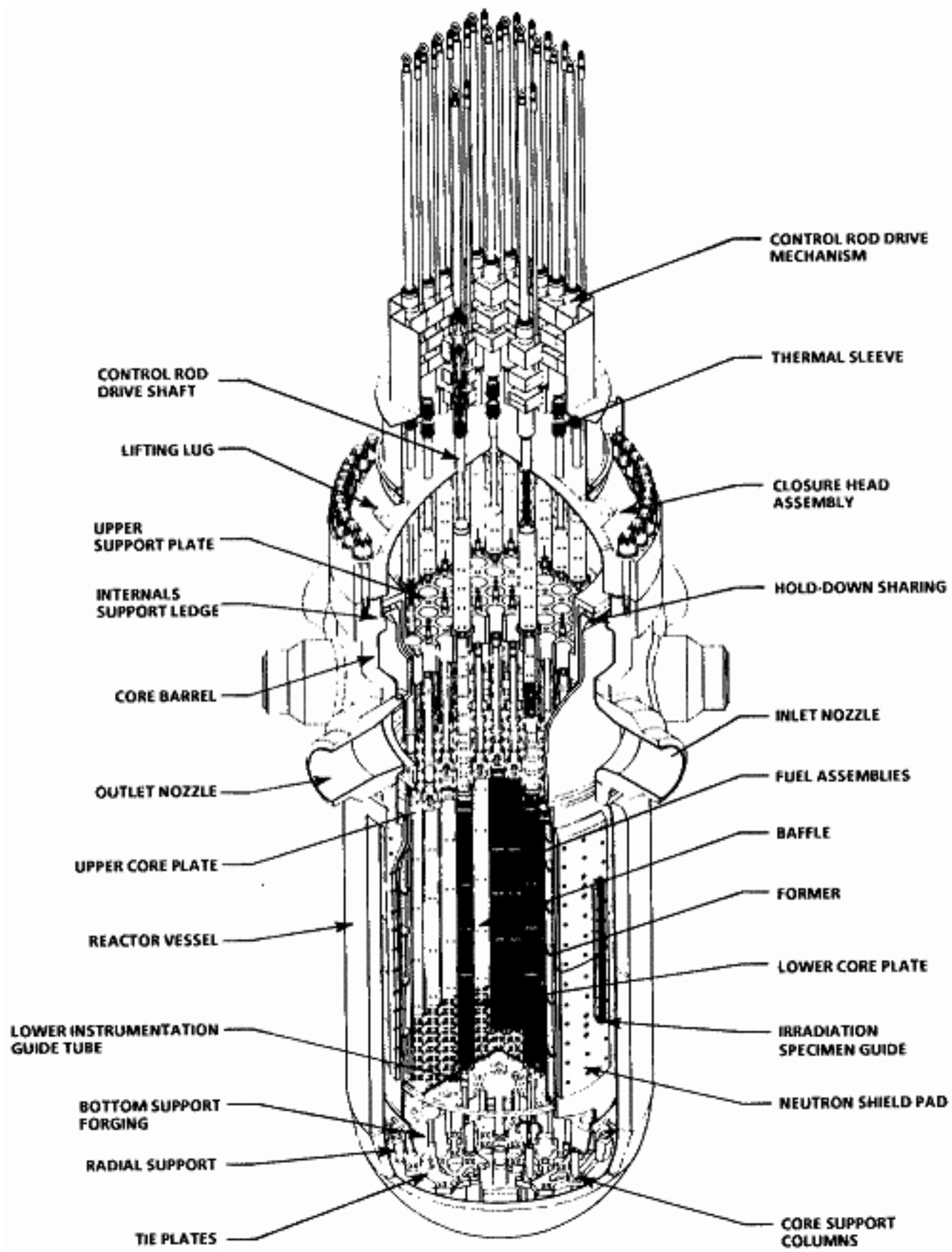


LOWER CORE PLATE

16.7 UPPER INTERNALS



The upper internals consist of (1) Upper core plate, (2) Upper core support plate, and (3) Guide and support columns. The upper core plate is a stainless steel plate that rests on top of the fuel assemblies. This prevents fuel assembly upward movement. The upper core plate has alignment pins which are pressed fitted to mate with the holes of the upper block of the fuel assemblies. The upper core support plate is a thick stainless steel plate which supports the weight of the upper internals. The support columns and guide tubes are attached to upper core and upper core support plates. This ensures separation of the upper core and upper core support plates. The upper core support is aligned with pins pressed into the upper flange on the core barrel. Guide tubes provide alignment for the control rods. Shoulders in the lower end of the guide tubes hold the control rod drive shafts during upper internal removal for refueling. Besides control rod guide tubes, five thermocouple guide tubes are also attached to the upper internals.



REACTOR VESSEL CUT-AWAY VIEW

16.8 REACTOR CORE

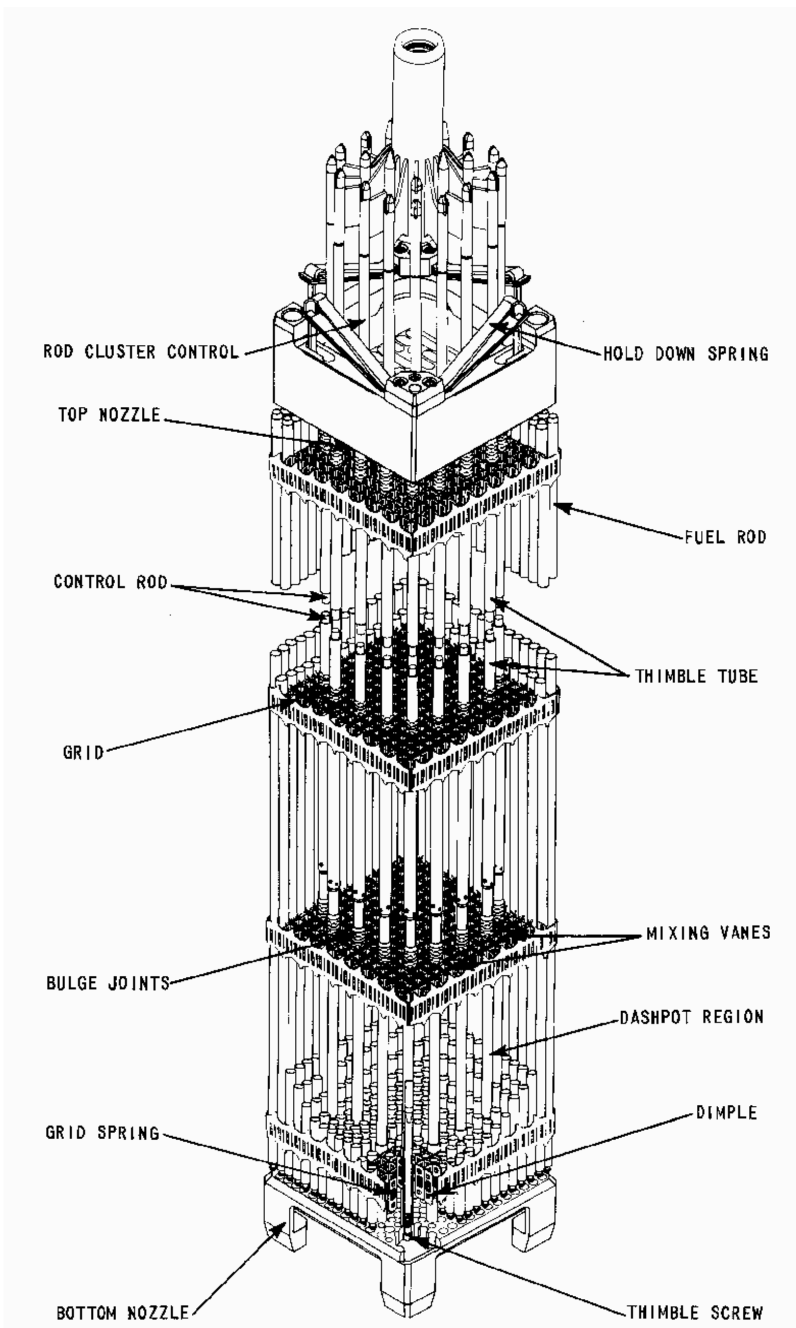
The reactor core has 193 fuel assemblies containing various fuel enrichments of between 2-4.6 % U-235. The fuel is arranged in a "low leakage" loading pattern. The old fuel and enriched new fuel is mixed around the periphery of the core. The higher enriched fuel toward the outside of core decreases chance of neutrons leaking out of the core. This "low leakage" arrangement, results in a more uniform axial flux profile. Control Rods and burnable poisons are also loaded in the core to ensure ample control of the excess reactivity. This ensures MTC will be within acceptable limits, and flattens the radial flux profile.

16.9 FUEL ASSEMBLY CONSTRUCTION

Each fuel assembly has 264 fuel pins arranged in a 17 X 17 array. Each assembly contains 24 "rod cluster control assembly" (RCCA) guide thimbles that provide guidance for the control rodlets when inserted in the fuel assembly.
One center instrument thimble provides guidance for the in-core nuclear instrumentation.

Fuel assembly skeletal parts consist of an upper and lower nozzle block that is mechanically connected by the guide thimbles mentioned above. This frame work gives the fuel assembly all its support.

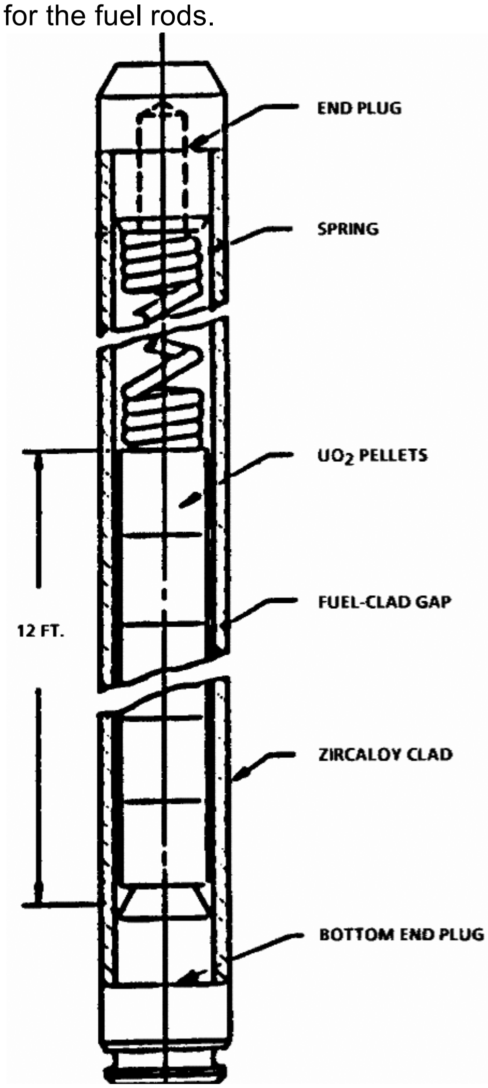
Upper nozzle block can be removed for fuel pin replacement call "fuel reconstitution". Fuel reconstitution is not uncommon. Damaged fuel pins are replaced by a stainless steel pin so that the assembly can be reused during future refueling. This process can be done on site. The upper nozzle block is held together by a lock tube insert. Attached to the top of the upper nozzle block are hold down springs. These hold springs contact the upper core plate to provide fuel assembly stability. Alignment holes are made in the upper nozzle block to



ensure proper attachment of the refueling tools.

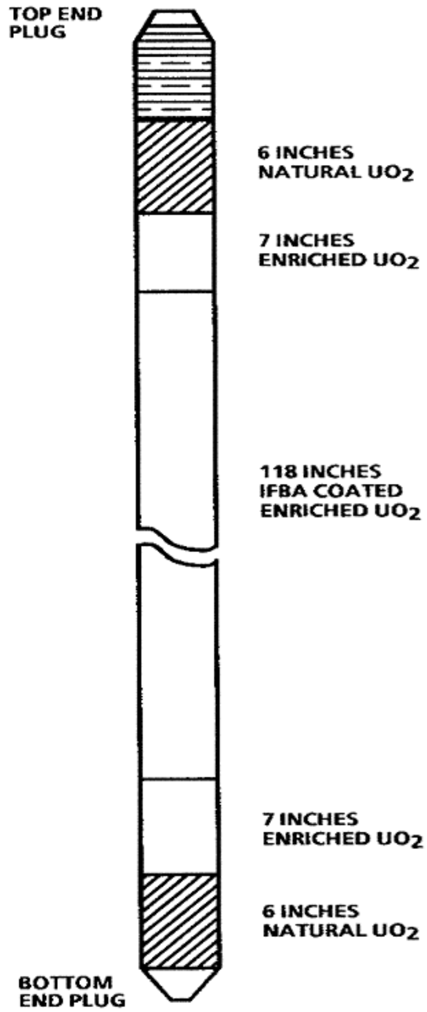
Lower nozzle blocks are secured to the guide tubes by use of screws that are welded in place. The RCCA thimbles are reduced in size near the bottom to cause a hydraulic cushion for the RCCAs when they are dropped in the core. This hydraulic cushion is called a “dash pot”. The “dash pots” slow control rods following a reactor trip in order to minimize impact energy. The lower nozzle block has built in debris filters that minimize fuel failure. The lower core plate alignment pins mate to the lower nozzle block to ensure proper alignment. The fuel assemblies rest directly on the lower core plate.

All 264 fuel pins in each assembly are held together to the guide thimbles by eight grid straps. Grid straps are a grid matrix that are made of zircaloy, except for the top and bottom which are made of inconel. Ziraloy grid straps have less resistance to coolant flow than the larger inconel grid straps. This increases the heat transfer rate along the length of the fuel rod. Machined springs in the grid assembly provide lateral support for the fuel rod. Three intermediate flow mixers increase turbulence in the coolant thus heat transfer is improved. The flow mixers are located in each assembly between the upper three grid straps and do not provide any support for the fuel rods.



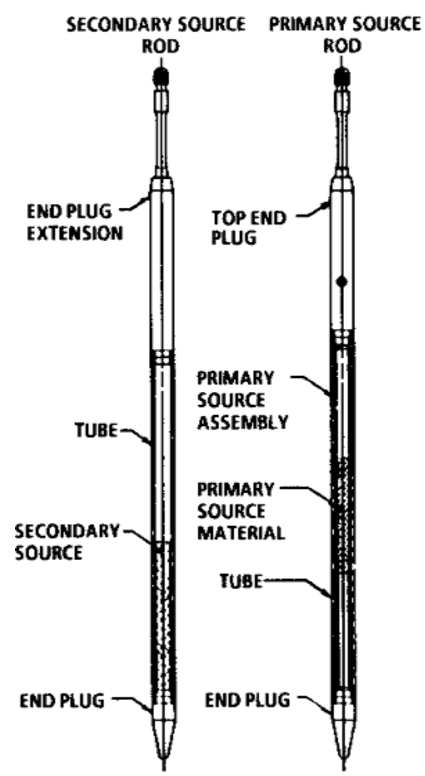
A fuel rod is made up of uranium oxide pellets encased in a zircaloy tube stacked to approximately 12 feet in height. Each fuel pellet measures .36 inches in diameter and .625 inches in length. Each zircaloy tube, known as cladding, is sealed by a weld on each end and pressurized with helium gas to about 100 psig. The reason for pressurizing the fuel rods is to prevent the cladding from collapsing due to the high RCS pressure. This collapsing of the cladding is called “clad creep”. Helium is used because it has a relatively good heat transfer capability and it is chemically inert. Zircaloy is used for the cladding for several reasons; (1) good heat transfer properties, (2) Low absorption of neutrons, (3) High corrosive resistance, and (4) a high melting point. Each fuel rod has a spring installed at the top of the pin. This spring allows for pellet growth and provides stability for the pellets.

Plant Vogtle uses Vantage 5 fuel which allows for 18 month fuel cycles. Burnable poisons are installed in the core to offset excessive reactivity. The installed poisons minimize the amount of soluble boron required. This reduces the moderator temperature coefficient (MTC). The installed burnable poison is called integral fuel burnable absorber (IFBA).



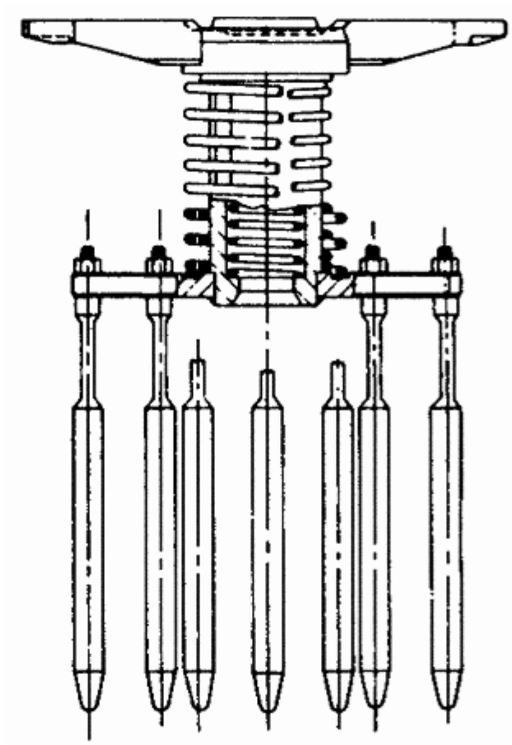
IFBAs are fuel pellets that are coated with zirconium-diboride. Along the length of the rods the enrichment is different. The top and bottom 6” consist of natural uranium. The next 7” from the top and bottom is enriched uranium, and the middle 118” is enriched uranium that is coated with zirconium-diboride. The coating thickness is less than .001” thick. Advantages in using the IFBAs are: 1)the construction is the same as other fuels, 2)replaces the need for burnable poison rod assemblies(BPRAs) and/or wet annular burnable assemblies(WABAs), 3)provides burnable poison for offset of excess reactivity; 4)yields more uniform axial flux profile; 5)increases neutron efficiency; 6)allows for flexibility in core loading patterns.

Installed sources include both primary and secondary sources. The purpose of the neutron source assemblies are 1) to provide a means to monitor reactivity changes in a shutdown reactor, 2) to provide a base neutron level to insure an orderly and controlled approach to criticality and 3) to verify proper operation of the nuclear detectors. Primary sources are self exciting and produce neutrons with no help from the core. The principal primary source is the spontaneous fission of californium 252. Primary sources are normally only used in the first cycle because they have relatively short lifetime. Plant Vogtle does not have a primary source installed at this time. Secondary sources are activated by the neutron flux in the core and are used over and over again. They must be activated at least every 300 days. The secondary source material is antimony-beryllium (Sb-Be). The neutron flux in the reactor during power operation activates the antimony which decays and gives off a gamma ray of sufficient energy to cause the beryllium to eject a neutron.



There are 53 full length rod cluster control assemblies (RCCAs) located within the core to control reactor power. Each RCCA consists of a hub from which radial vanes are attached. Attached to the vanes are 24 rodlets. Each rodlet is a stainless steel tube containing absorber material (Silver-Indium-Cadmium). The rodlets are sealed by a bullet shaped plug on the lower end. This shape of the plug reduces the drag on the rods which reduces its rod drop time.

RCCA guide thimbles that do not contain either a RCCA rodlet or a BPRA/source rod will be equipped with a thimble plug. (See figure 16-14 Thimble plug diagram) Thimble plugs consist of short stainless steel rods attached to a T-handle assembly similar to that of a BPRA. The purpose is to limit the amount of core bypass flow.



THIMBLE PLUG

A fuel pellet is ultimately supported by the vessel concrete pads by:
1) all fuel pellets support each other and distribute their weight to the rod cladding, 2) The rod is supported by the grid assembly, 3) the grid assembly is supported by the thimble tubes, 4) the thimble tube is supported by the lower and upper nozzle block, 5) the lower fuel assembly nozzle block is supported by the lower core plate, 6) the lower core plate transmits its load to the support columns and to the lower core support forging, 7) the lower core support forging is welded to the core barrel which supports the support forging, 8) the core barrel is supported by the vessel flange, 9) The entire weight of the core is transmitted to the reactor vessel flange, and 10) the vessel is supported by 4 concrete pads under each inlet and outlet nozzle.

TECHNICAL SPECIFICATIONS

LCO 3.4.3 RCS Pressure and Temperature (P/T) Limits

The RCS temperature rate-of-change limits are:

a) A maximum heat up of 100°F in any 1-hour period.
b) A maximum cool down of 100°F in any 1-hour period.
c) The RCS P/T limits for heat up and cool down are specified by PTLR. (Pressure Temperature Limits Report)

Applicability: At all times

Bases:

LCO limits are in place to prevent brittle failure of the Reactor Coolant Pressure Boundary which could result in a non-isolable leak or a loss of coolant accident.

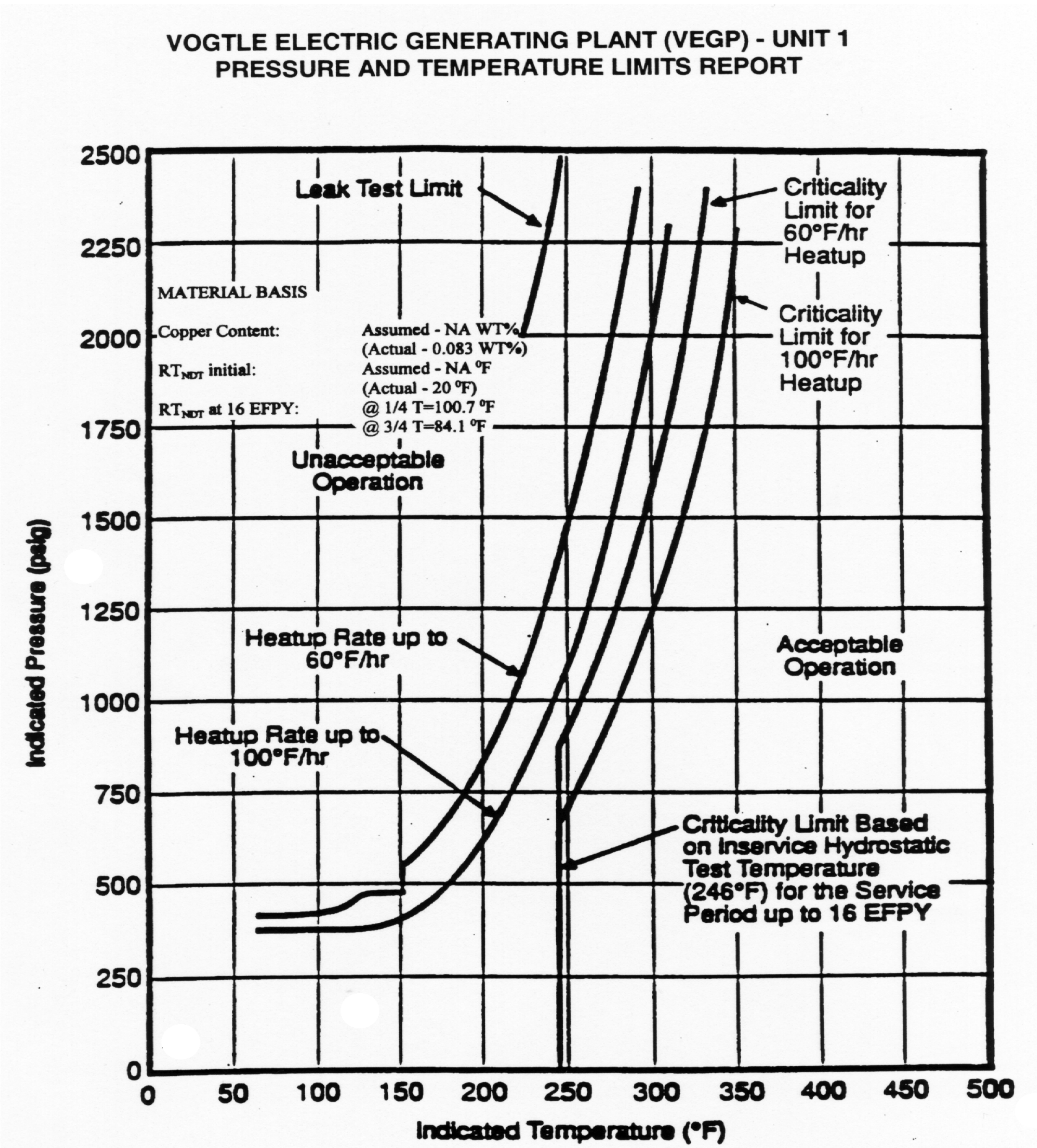
TRM 13.4.3 RCS Vents

Two reactor vessel head vent paths each consisting of two vent valves and a control valve powered from emergency busses, shall be operable and closed.

Applicability: Modes 1,2,3, and 4

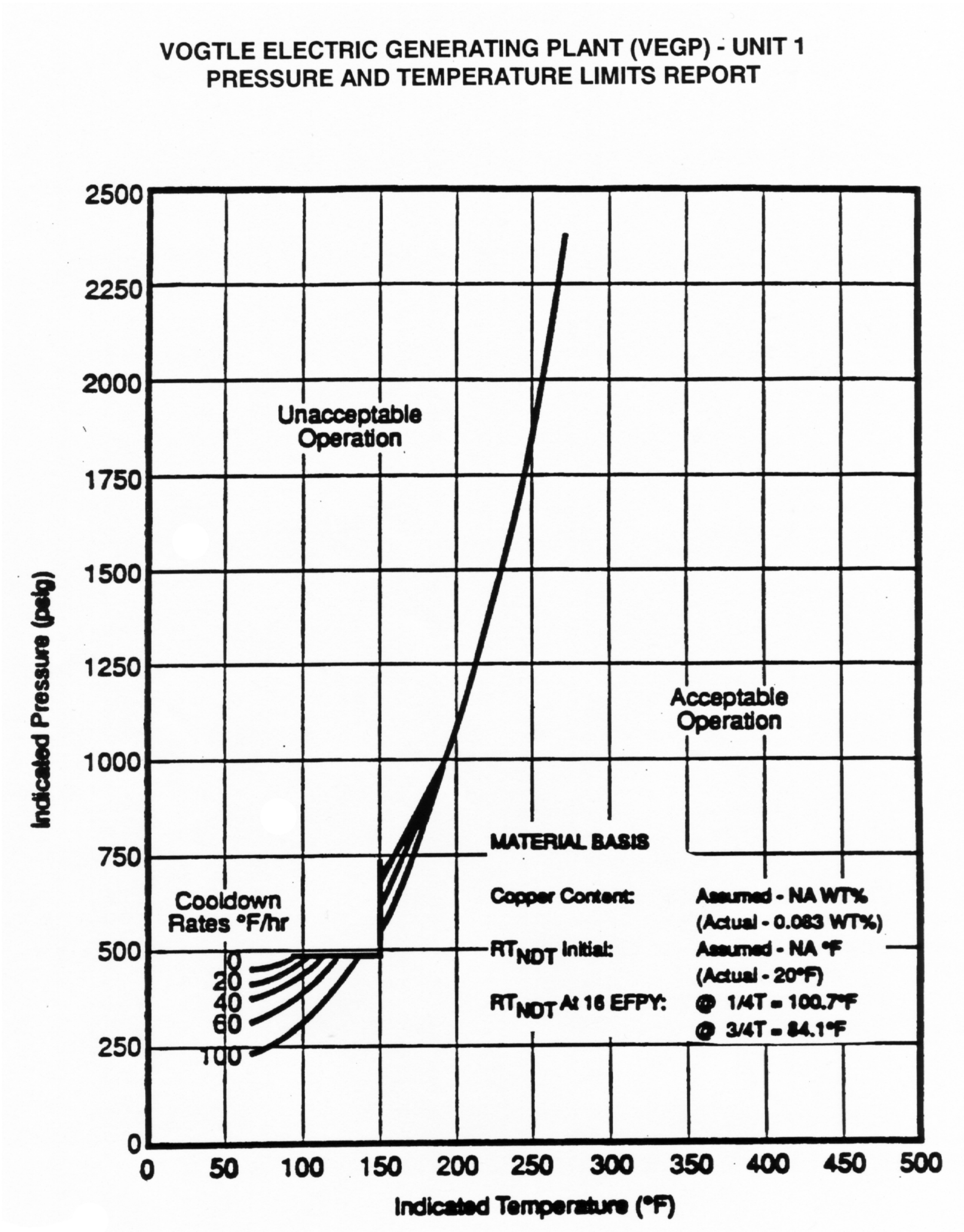
Bases:

Reactor Coolant System vents are provided to exhaust non condensable Gases and/or steam from the Reactor Coolant System that could inhibit Natural circulation core cooling.



VOGTLE ELECTRIC GENERATING PLANT (VEGP) - UNIT 1
PRESSURE AND TEMPERATURE LIMITS REPORT
Leak Test Limit
Criticality Limit for 60°F/hr Heatup
Criticality Limit for 100°F/hr Heatup
MATERIAL BASIS
Copper Content: Assumed - NA WT% (Actual - 0.083 WT%)
RT NDT initial: Assumed - NA °F (Actual - 20 °F)
RT NDT at 16 EFPY: @ 1/4 T=100.7 °F @ 3/4 T=84.1 °F
Unacceptable Operation
Acceptable Operation
Heatup Rate up to 60°F/hr
Heatup Rate up to 100°F/hr
Criticality Limit Based on Inservice Hydrostatic Test Temperature (246°F) for the Service Period up to 16 EFPY
Indicated Pressure (psig)
Indicated Temperature (°F)
0
250
500
750
1000
1250
1500
1750
2000
2250
2500
50
100
150
200
300
350
400
450

UNIT 1 HEAT UP LIMIT CURVE



UNIT 1 COOL DOWN LIMIT CURVE

OPERATIONAL EXPERIENCE

Oconee Unit 3

Cracks were identified in nine control rod drive mechanism (CRDM) nozzles during a visual inspection performed in February 2001. Dye penetrate testing identified significant circumferential cracks above the welds connecting two CRDM nozzles to the reactor vessel head. This was the first incidence of above-the-weld circumferential cracking reported by domestic nuclear stations.

The Oconee CRDM nozzles are 5 feet long with J-groove partial penetration welds at the inner radius of the reactor vessel head. The lower end of each nozzle extends approximately 6 inches below the head. The nozzles are made of 4-inch outside diameter Alloy 600 material, machined to match the head bore. The nozzles were shrink-fitted into the head by cooling them to minus 140 degrees Fahrenheit and then allowed to warm to ambient temperature. The nozzles were welded to the head using Alloy 182 weld material and manual arc welding techniques.

Oconee personnel had modified the reactor vessel service structure and cleaned the reactor vessel head to allow easier detection of the boric acid crystals that are indicative of small cracks in the vessel head penetrations. Because these were extremely low volume leaks, RCS leakage detection systems, containment radiation monitors, and periodic RCS leakage calculations, did not detect them. The leaks were discovered through a detailed visual inspection program.

On June 21, June 28, and July 1, 2001, Palisades discovered axial crack indications in three control rod drive (CRD) seal housings. CRD-21 experienced a through-wall axial crack in the upper housing that was attributed to chloride stress corrosion cracking. Later, a 25 percent through-wall axial crack was discovered on the CRD-25 upper housing, and a 50 percent through-wall axial crack indication was found on CRD-40. During repairs to CRD-21, a detailed metallographic examination also revealed the presence of circumferential indications that were not detected in earlier ultrasonic examinations because of the geometry of the housing. Radiographic examinations of the three seal housings were used to characterize the length of the axial indications.

Discovery of the initial crack on CRD-21 occurred following an increase in unidentified leakage on June 9, 2001. No immediate source of leakage was identified at that time; however, a subsequent containment entry on June 17 revealed a leak on a pressurizer sample line fitting. Unidentified leakage increased again on June 18, and plans were made to shut down the unit on June 20. A walk down inspection after the shutdown revealed a steam leak on the upper housing of CRD-21.

The events at Oconee and Palisades reinforce the importance of visual under-the-insulation inspections and the use of appropriate nondestructive examination methods to characterize any indications discovered during inspections.

Davis-Besse

On February 16, 2002, the Davis-Besse Nuclear Power Station in Oak Harbor, Ohio, began a refueling outage that included inspecting the nozzles entering the head of the reactor pressure vessel (RPV), the specially designed container that houses the reactor core and the control rods that regulate the power output of the reactor. Of these vessel head penetration (VHP) nozzles, the licensee's inspections focused on the nozzles associated with the mechanism that drives the control rods, known as the control rod drive mechanism (CRDM). Both the inspections and their focus were consistent with the licensee's commitments in response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," which the agency issued on August 3, 2001.

In conducting its inspections, the licensee found that three CRDM nozzles had indications of axial cracking, which had resulted in leakage of the reactor's pressure boundary. Specifically, the licensee found these indications in CRDM nozzles 1, 2, and 3, which are located near the center of the RPV head. The licensee reported these findings to the NRC on February 27, 2002, and provided supplemental information on March 5 and March 9, 2002. The licensee also decided to repair the three leaking nozzles, as well as two other nozzles that had indications of leakage but had not resulted in pressure boundary leakage.

The repair of these nozzles included roll expanding the CRDM nozzle material into the material of the surrounding RPV head and then machining along the axis of the CRDM nozzle to a point above the indications in the nozzle material. On March 6, 2002, the licensee prematurely terminated the machining process on CRDM nozzle 3 and removed the machining apparatus from the nozzle. During the removal, the nozzle was mechanically agitated and subsequently displaced (or tipped) in the downhill direction (away from the top of the RPV head) until its flange contacted the flange of the adjacent CRDM nozzle.

To identify the cause of the displacement, the licensee investigated the condition of the RPV head surrounding CRDM nozzle 3. This investigation included removing the CRDM nozzle from the RPV head, removing boric acid deposits from the top of the RPV head, and ultrasonically measuring the thickness of the RPV head in the vicinity of CRDM nozzles 1, 2, and 3.

Upon completing the boric acid removal on March 7, 2002, the licensee conducted a visual examination of the area, which identified a large cavity in the RPV head on the downhill side of CRDM nozzle 3. Follow up characterization by ultrasonic testing indicated wastage of the low alloy steel RPV head material adjacent to the nozzle. The wastage area was found to extend approximately 5 inches downhill on the RPV head from the penetration for CRDM nozzle 3 and was approximately 4 to 5 inches at its widest part. The minimum remaining thickness of the RPV head in the wastage area was found to be approximately 3/8 inch. This thickness was attributed to the thickness of the stainless steel cladding on the inside surface of the RPV head, which is nominally 3/8 inch thick.

The investigation of the causative conditions surrounding the degradation of the RPV head at Davis-Besse is continuing. Boric acid or other contaminants could be contributing factors. Other factors contributing to the degradation might include the environment of the RPV head during both operating and shutdown conditions (e.g., wet/dry), the duration for which the RPV head is exposed to boric acid, and the source of the boric acid (e.g., leakage from the CRDM nozzle or from sources above the RPV head such as CRDM flanges).

SOEER 96-2

Operating Considerations for Reactor Cores

Industry initiatives to optimize fuel cycles have resulted in:

- Longer fuel cycles
- Higher-energy output cores

Core configuration and fuel cycle operating strategies have changed

- New fuel designs
- Increased fuel enrichments
- Improved thermal-hydraulic performance
- Dispersed burnable poisons
- Enhanced corrosion resistance

These changes have resulted in industry events related to:

- Unanticipated core performance problems
- Operator unfamiliarity with core operating strategies
- Reduced margins to operational limits
- Deficiencies in design and reload analysis.

Review of Industry Events:

- Failure of Control Rods to Fully Insert

Since 1983, average burn up of discharged fuel has increased from 36,000 to 46,000 MWD/MTU.

Effects of extended life on fuel assemblies resulted in unanticipated metallurgical effects

South Texas Project Unit 1 (December 1995)

Three control rods indicated 6 steps withdrawn following automatic reactor trip. Subsequent rod drop testing identified several additional control rods were not fully inserting. All but two rods were in assemblies with burnup >43,000 MWD/MTU.

Wolf Creek (January 1996)

Five control rods did not fully insert after manual reactor trip.

All five were in assemblies on their 3rd operating cycle with burnup > 49,000 MWD/MTU.

Ringhals Station Units 3 and 4 (1994 & 1995)Sweden

After several control rods failed to fully insert investigation determined S-shaped bowing of fuel assemblies. Only was detected in assemblies with > 34,000 MWD/MTU burn up.

Axial Power Offset Anomaly

Unanticipated chemistry effects affect on core power distribution, Resulted in ΔFlux levels different than anticipated in core reload predictions. Typically ΔFlux became more negative than predicted during MOL and less negative than predicted at EOL.

Net results are:

- The reduced operational flexibility resulted from being close in proximity to the core operating limits.
- Lower shutdown margin.
- Non conservative ECP errors due to reactivity effects due to Xenon distribution being under prediction.
- Abnormal power distributions may invalidate core design assumptions in determining compliance with accident limits.

Factors affecting this anomaly:

- Flux depression in the region of the upper grid straps.
- High core outlet temperatures.
- High heat fluxes and radial power peaks.
- High boron concentrations.

It is postulated that these factors result in deposition of a boron-lithium compound in the upper regions of the fuel resulting in an unexpected flux depression in these areas.

Fuel assembly Distinctive Crud Pattern

Extended core cycles have resulted in changes to fuel cladding corrosion rates. Results in a crud deposition with marble like texture.

Experienced at Crystal River Unit 3 and TMI Unit 1

TMI Unit 1 experienced 9 through-wall fuel failures in assemblies on their first fuel cycle (< 115 EFPDs)

Potential Contributing Factors:

Elevated boron concentrations

Significant pH level changes early in the fuel cycle

Lower flow velocities between assemblies

Changes in Operating Strategies:

- PWR fuel cycles lengthened by increasing initial reactivity in the core
- increased enrichments
- low leakage core reload patterns
- increase in number of new assemblies
- Results in (+)MTC at BOL and (-)MTC at EOL

Events have occurred due to operator knowledge deficiencies concerning the effects these core physics characteristics have on core response

EOL, (-) MTC

Calvert Cliffs Unit 2 (1995) experienced a reactivity excursion and automatic scram during low power ops due to overfeeding of Steam Generators which resulted in large positive reactivity insertion and trip on high flux-low set point.

BOL, (+) MTC

Vogtle Unit 2 (1997) experienced a cool down of the RCS during low power operations when main turbine was synched to the grid which resulted in T_{avg} lowering below the minimum temperature for criticality.

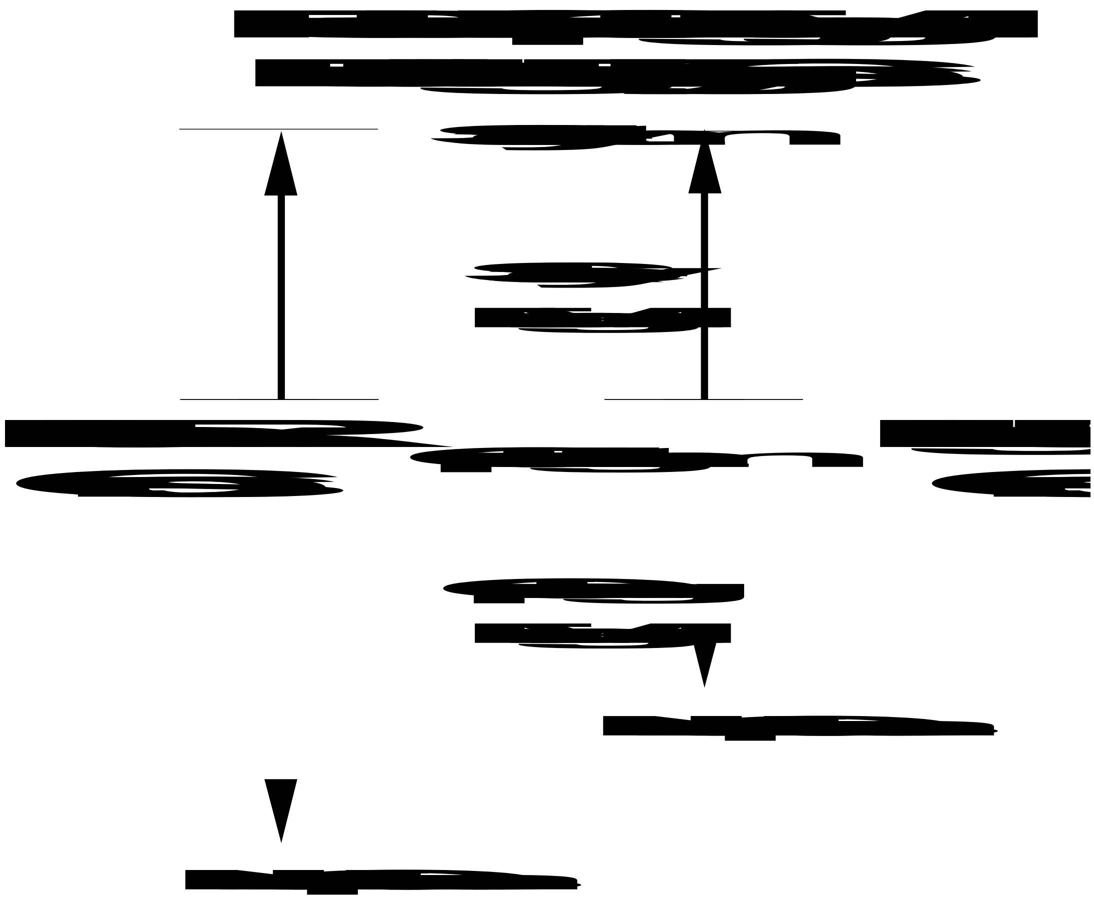
These are just two examples where weaknesses in operator knowledge of core design resulted in exceeding safety and operational limits

Reduction in Operating Margin

Longer fuel cycles, higher fuel enrichments, newer fuel assembly designs, low leakage loading patterns all contribute to changes in factors such as $F_n\Delta h$, kW/ft output, and fuel centerline temperatures.

These changes have resulted in a reduction of the available operating margin of commercial reactors.

The graph below provides a visual representation of the combined effects on commercial nuclear power operation.



Taken in aggregate, these events illustrate how existing weakness in core design and reload analysis may adversely affect plant operations.

REFERENCES

- FSAR section 5.3
- Technical Specification
- Technical Requirement Manual
- SOER 96-002

SECTION B

REACTOR COOLANT PUMPS

16.10.1 REACTOR COOLANT PUMP DESCRIPTION

The reactor coolant pumps are vertical, single stage, controlled leakage; centrifugal pumps designed to move large volumes of reactor coolant at elevated temperatures and pressures. The three phased 13.8 kV motors develop 7000-shaft horse power each. Each pump impeller moves approximately 100,600 gallons of coolant per minute at ~ 120 psid which exceeds the design bases required by the Technical Specifications for DNBR. There are four other design criteria that had to be designed for. (1) Sufficient coast down flow which is accomplished by the use of a flywheel. The flywheel has enough inertia built in to provide the momentum needed to prevent core damage following a loss of offsite power. (2) The RCPs are built with sufficient structural integrity to prevent missile formation from being generated that could possibly damage the reactor pressure boundary. (3) Fast bus transfer scheme provided to maintain electrical power within 6 cycles to the RCPs following a Main Generator trip, and (4) Series 13.8 kV circuit breakers provide over current protection for the motors and the containment building electrical penetration.

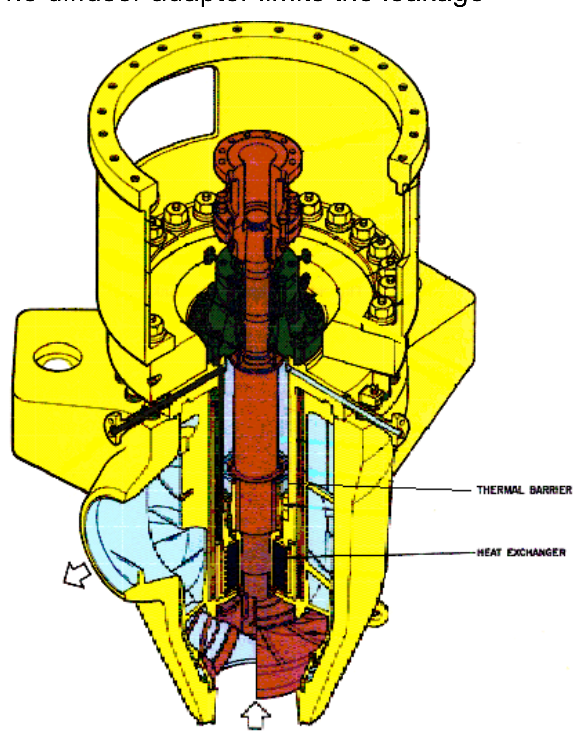
The five general areas of the RCPs: The hydraulic section, the thermal barrier and thermal barrier heat exchanger section, the rotating assembly and radial bearing, the seal package, and the structure components.

16.10.2 REACTOR COOLANT PUMP CONSTRUCTION

The hydraulic section consists of: (1) A pump casing which encloses the hydraulic components of the pump, (2) A counter clockwise rotating stainless steel impeller having seven integral vanes. (3) The "diffuser assembly" which directs the discharge from the impeller and converts part of the velocity head to pressure head. (4) The diffuser adapter limits the leakage of reactor coolant along the outside diameter (O.D.) of the impeller and back to the pump suction. It contains a labyrinth seal and mates with the I.D. of the diffuser.

16.10.2.1 REACTOR COOLANT PUMP THERMAL BARRIER

The thermal barrier is a welded assembly, consisting of a flanged cylindrical shell, a heat exchanger coil assembly, and three flanged water connections. The assembly is supported by its flange, clamped between the pump casing, bolting ring, and motor stand lower flange. The thermal barrier is located below the pump's lower radial bearing. The heat exchanger portion of the thermal barrier comprises of eight double-layered pancake coils that is socket welded into a heavy section of the cylindrical shell



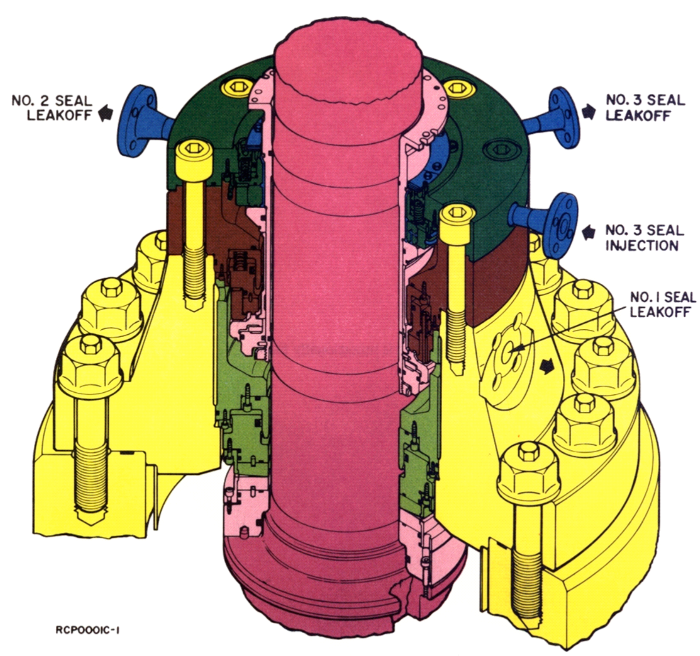
bottom. Normally, cool seal injection is provided by the CVCS system which travels down the shaft past the pump's lower bearing and into the RCS. Upon the loss of seal injection from the CVCS system, the RCS water passes through and cooled by the thermal barrier and heat exchanger as it rises up the shaft. Auxiliary Component Cooling Water circulates through the coils of the heat exchanger which provides the heat removal. The RCS water then can provide cooling and lubrication for the lower pump bearing and seal package. The thermal barrier cooling does not allow for long term protection from a loss of normal seal injection flow. The flow rate of the RCS back flow is lower than seal injection flow therefore it has less cooling effect. The RCP seal inlet and lower pump bearing temperatures must be monitored until normal seal injection restored.

16.13 ROTATING ASSEMBLY AND RADIAL BEARING

The rotating assembly and radial bearing is cobalt-base alloy that is overlaid on the journal and assembled with a shrink fit on the shaft. When the RCP motor/pump are uncoupled during maintenance, a spherical surface on the shaft journal bearing mates with a seating surface on top of the heat exchanger coil assembly acting as a low pressure valve assembly. This LP valve assembly minimizes leakage up the shaft during maintenance called "**RCP back seating**". The impeller and coupling are restrained against axial and angular motion by locking nuts threaded onto the shaft, and by keys and keyways. The coupling hub is machined to permit monitoring of shaft vibration and pickup of a once-per-revolution signal useful in speed monitoring and balancing of the coupled motor/pump shaft assembly. The radial bearing assembly (Pump Guide Bearing) consists of a two-piece horizontally-split housing and a bearing cartridge is weld-overlaid with a cobalt-based alloy and mates with the spherical inside surfaces on the split housing. Carbon graphite rings are shrunk onto the inside surface of the cartridge. The bearing acts against the journal on the pump shaft. During normal operation, the bearing is lubricated and cooled with seal injection water.

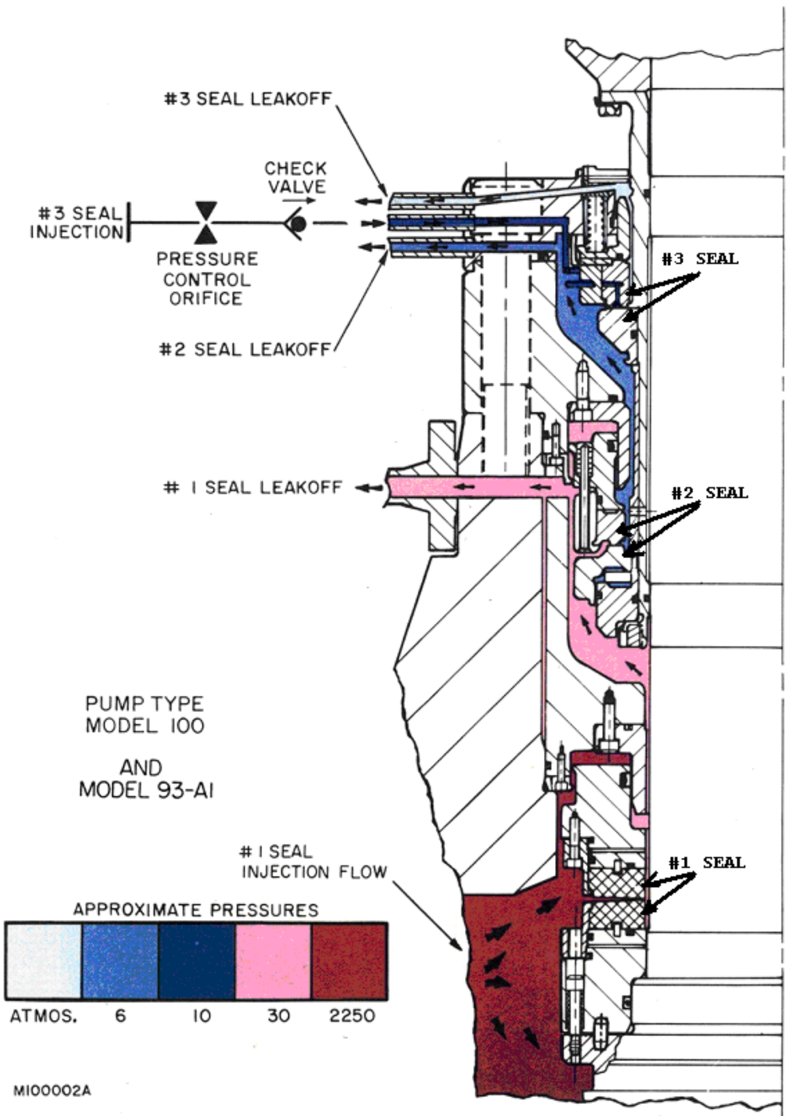
16.14 PUMP SEAL SYSTEM

The pump seal system consists of three different controlled-leakage seals within a sealed housing, and features the assembly of the number 2 and number 3 seal in a single cartridge so that they may be installed or removed together. The number seal 1 is the main controlled-leakage seal of the pump. It is a hydrostatically balanced, film-riding, face seal, consisting of a seal runner which rotates with the shaft and a non-rotating seal ring enclosed by the seal housings. Both the runner and ring have an Silica Nitride faceplate clamped to a stainless steel holder. Seal injection water flows through the separation between the two faceplates, the



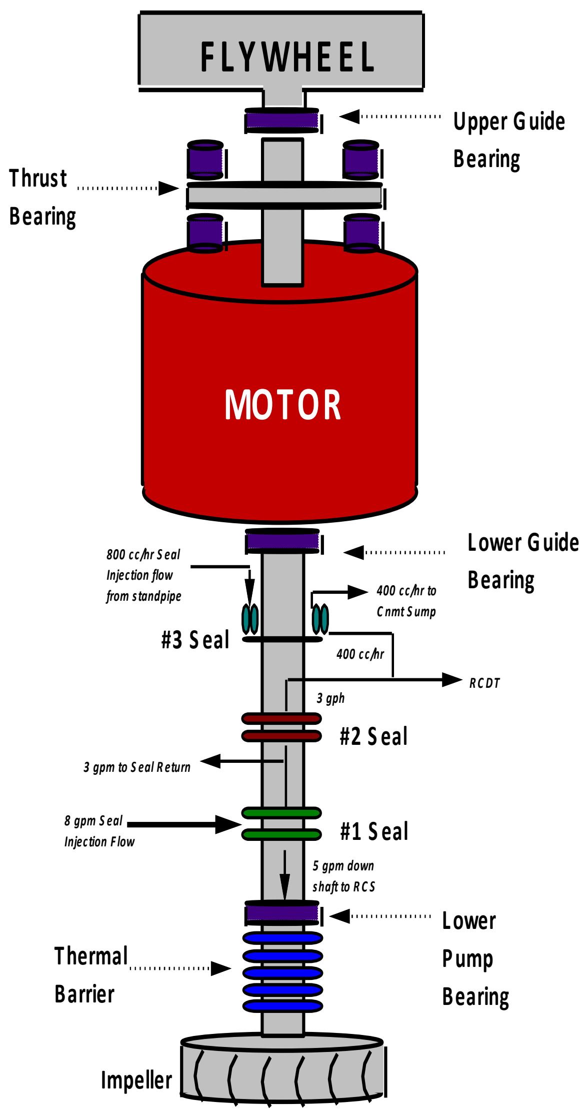
EIGHT-INCH CARTRIDGE SEAL

amount of separation being controlled by the face contours and system pressure. Separation will be maintained and no surface contact will occur as long as minimum operating pressures are maintained. Part of the leakage up through the number 1 seal (normally, injection water from CVCS) supplies the number 2 seal, while the excess flow is piped to the volume control tank through the number 1 seal leak-off pipe. The number 2 seal is a face rubbing seal, consisting of a carbon graphite insert assembled with a shrink fit into a retaining ring. This assembly is attached to a seal ring base with spring loaded pins. Both the retaining ring and the seal ring are made from stainless steel forgings. The assembly is pinned to prevent rotation but allows motion in the axial direction. The insert rubs on a chrome-carbide-coated stainless steel forged runner, which rotates with the shaft. The leakage through the number 2 seal is piped to the reactor coolant drain tank (RCDT) through the number 2 seal leak-off pipe. If the number 1 seal was to fail, the number 2 seal will become a temporary backup. When the seal leak off valve is closed this would expose the number 2 seal to full RCS pressure causing it to become a film riding seal. The number 2 seal should provide backup for at 24 hours to allow the plant to be shutdown. When the number 2 seal becomes a film riding seal while the RCP shaft is still rotating this will tend to score the shaft at the number 2 sealing area. This can cause extensive repairs before returning the RCP back in service. It is best to place the plant in a condition to allow securing the associated RCP from service and allowing the shaft to come to a complete stop before closing the seal leak off. The number 3 seal is also a rubbing-face "double dam" seal, consisting of a carbon-graphite insert assembled with a shrink fit into a stainless steel seal ring. The carbon-graphite insert has two sealing faces called "dams". These dams rub on a chrome-carbide coated stainless steel runner, which rotates with the shaft. Water from the RCP standpipe is injected between the two dams of the seal ring at a pressure greater than in the number 2 seal leak-off connection. Two leakage paths are thus provided for this injected water (thus the term "double dam"). Part of the injected water flows past the outer dam where it joins the leakage from the number 2 seal and passes out of the pump through the number 2 seal leak-off connection. The remainder of the injected water flows past the inner dam



and is diverted to the splashguard to flow out through the number 3 seal leak-off connection to the normal containment sump. A pressure control orifice is installed in the number 3 injection connection to compensate for dam profile variations. A check valve is also provided in this location to allow the inner dam pressure to support the seal faces during number 2 leak-off high pressure conditions.

Seal injection provided by the CVCS system is approximately 8 gallons per minute per RCP number 1 seal. 5 gpm of the 8 gpm total go directly to the lower pump bearing providing lubrication and cooling. 3 gallons is directed through the number 1 seal were a pressure drop of approximately 2220 psid occurs. ALL but 3 gph of the number 1 seal leak off is returned to the volume control tank (VCT). 3 gph of number 1 seal leak off enters the number 2 seal. 3 gph passes through the number 2 seal and its leak off is directed to the reactor coolant drain tank (RCDT). The RCP stand pipe provides 800 cc/hr of seal injection flow to the number 3 seal. Each RCP has its own standpipe which is located at a higher elevation to provide gravity flow. The Standpipe make up is provided by reactor makeup water system tank (RMWST). Number 3 seal injection is injected between the two dams and the sealing surface. The number 3 seal injection is at a slightly higher pressure than number 2 seal injection leak off. This prevents RCS liquids or gases from escaping to the containment environment. The number 3 seal off has two paths: (1) the outer dam leak off (400 cc/hr) combines with number 2 seal leak off and is routed to the RCDT, (2) the inner dam is directed to the containment sump.



Symptoms of a failed number 1 seal are as follows:

- Alarm “RCP Controlled leakage Hi/Lo Flow”
- Hi #1 seal leak off flow
- Excess letdown temperature rising
- Excess letdown pressure rising

Symptoms of a failed number 2 seal are as follows:

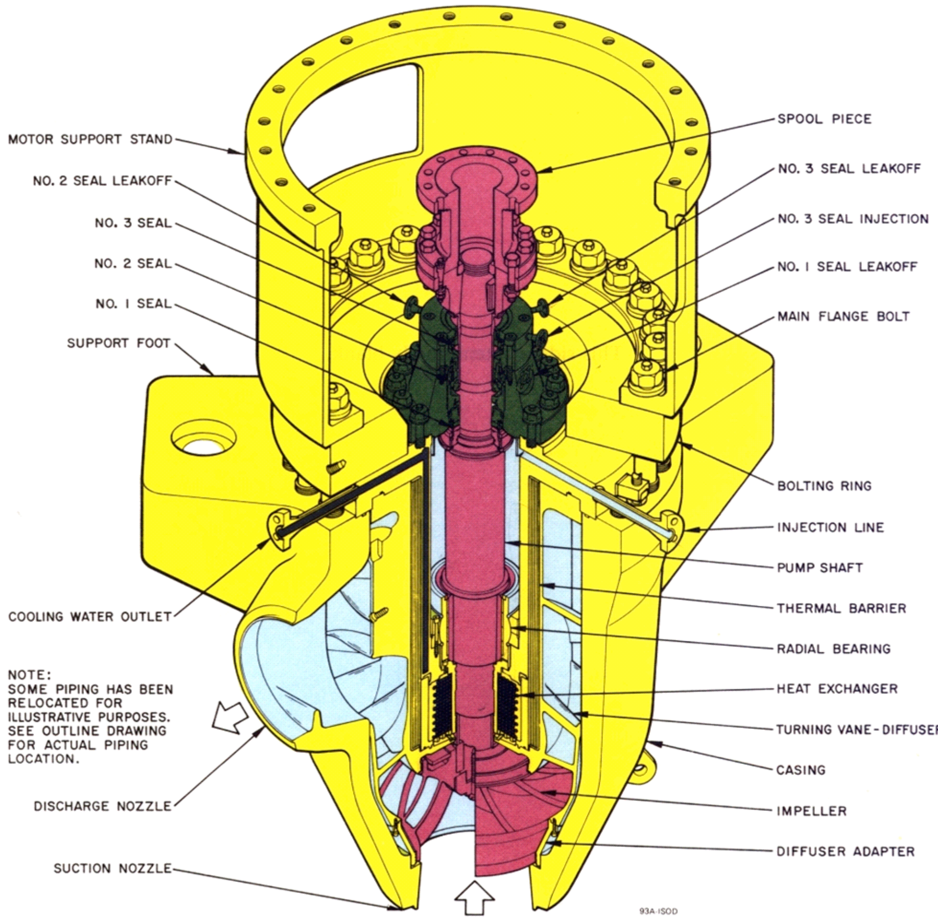
- Alarm “RCP No. 2 seal leak off hi flow”
- Frequent pump down of the RCDT
- Hi #2 seal leak Flow >1 gpm (local gauge inside Containment)

Symptoms of a failed #3 seal are as follows:

- Alarm “RCP No. 2 seal leak off hi flow”
- Hi #2 seal leak Flow >1 gpm (local gauge inside Containment)
- Standpipe high fill frequency
- higher than normal flow rate to sump

16.15 REACTOR COOLANT PUMP STRUCTURAL COMPONENTS

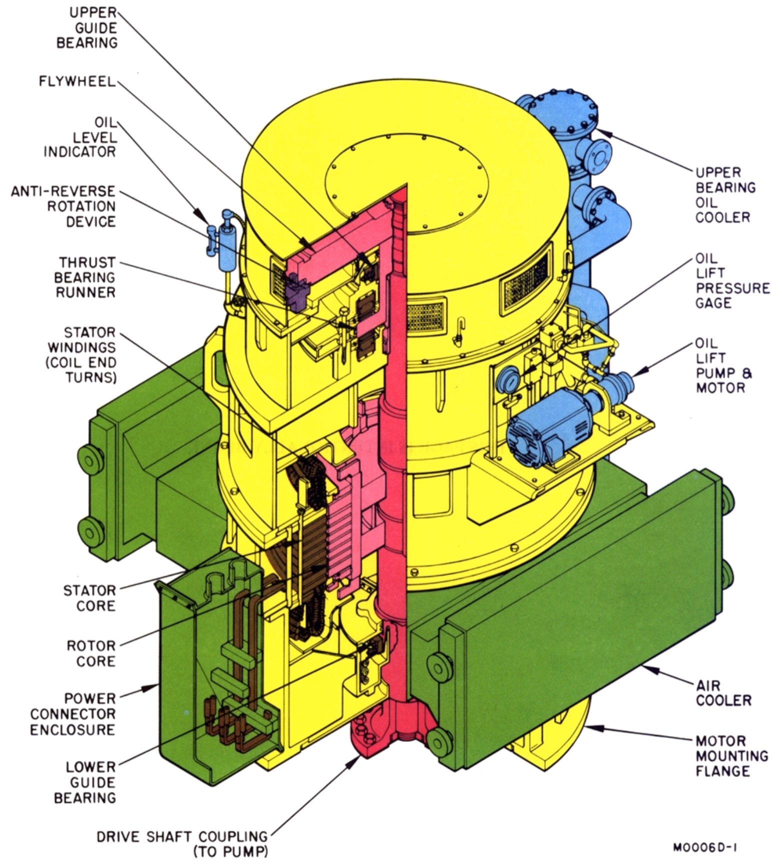
The forged carbon steel bolting ring is the primary pressure-retaining structural member, and also forms the base on which the motor support stand is mounted. The motor stand is a carbon steel weldment consisting of three parts: an upper flange which bolts to the motor lower flange, a lower flange clamped to the pump bolting ring using the pump main flange bolts, and a cylindrical section welded to the upper and lower flanges. Windows cut in the cylindrical portion of the stand permit access for spool and seal removal and replacement. The No. 1 and No. 2 seal housings are pressure boundary components designed to hold the stationary parts of the Seal System. The No. 1 leak-off exits from the No. 1 seal housing. The No. 2 leak-off, the No. 3 leak-off, and the No. 3 seal injection nozzles are all socket-welded to the end closure for the cartridge seal. The No. 2 seal housing is the only pressure boundary of the cartridge seal assembly.



RCP PUMP DIAGRAM

16.16 REACTOR COOLANT PUMP MOTOR

The motor for the reactor coolant pump is a drip-proof squirrel cage induction motor with an air/water heat exchanger to cool the ventilating air. Containment air is drawn in by the blades of the motor's rotor. The air is cooled when it is exhausted into the containment atmosphere. Six detectors sense the temperature throughout the stator winding. Near the top of the motor are the pivoted-pad radial upper guide bearing, the flywheel, the anti-reverse rotation device, and a double-acting Kingsbury-type thrust bearing. A viscosity pump built into the outer periphery of the thrust bearing runner circulates oil through an external oil-to-ACCW heat exchanger (oil cooler) to cool the upper bearing. An oil lift system applies an oil film via the oil lift pump to the thrust bearing shoes before startup. The lower radial guide bearing, also of the pivoted-pad type, is located below the rotor core. It is cooled by an oil-to-water heat exchanger, integral with the oil reservoir.



16.17 MOTOR HEATERS

The RCP motors are equipped with space heaters that are used to prevent moisture accumulation in the windings when the RCP is shutdown. The heaters are powered from 480V MCCs. Accumulation of moisture in the windings could short the windings when the pump is started. The heaters are automatically energized, assuming the 480V MCC power supply is available, when either one of the two pump supply breakers are opened.

16.18 OIL SYSTEM

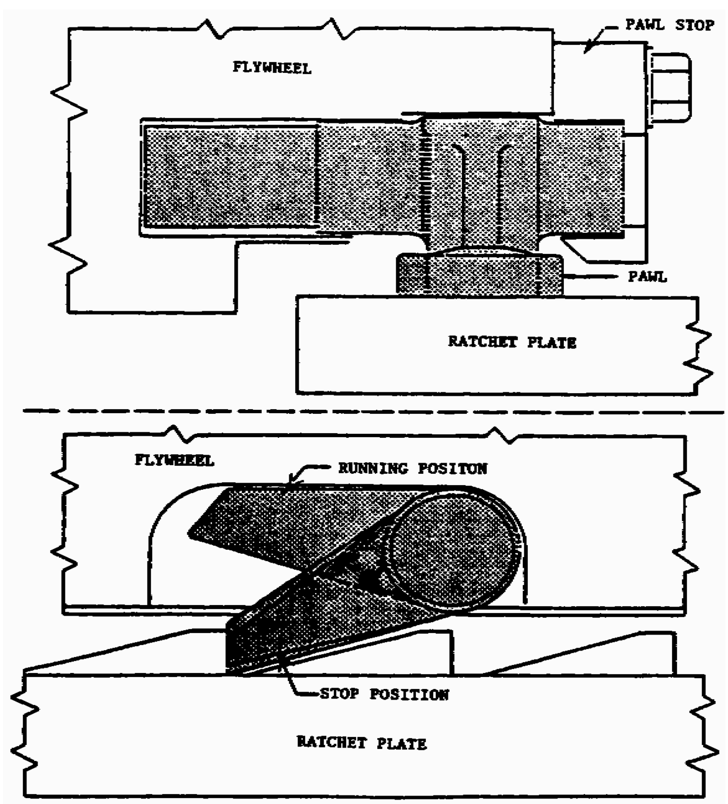
Each RCP is equipped with an upper and lower oil reservoir. Each reservoir has a high and low level alarm. Cooling is provided by the upper bearing oil cooler. The upper radial guide bearing consists of oil-cooled pivoted pads similar to the lower guide bearing. The guide bearing runner is an integral portion of the thrust bearing runner. The lower motor radial is submersed in the lower oil reservoir just as the upper radial and thrust bearing is submersed in the upper reservoir. Each RCP has oil spillage protection system. This system contains and channels any oil that may have leaked to its lube oil drain tank. Each RCP lube oil drain tank is provide a high level alarm, which alerts the control room of any leaks that maybe occurring.

16.19 OIL LIFT SYSTEM

The external Oil Lift System provides lubrication to the upper bearings during motor startup. High-pressure oil ~600 psig is delivered by the oil lift pump simultaneously to both sets of thrust-bearing shoes. The Oil Lift System will provide from 0.001 inch to 0.003 inch of oil film between the runner and the thrust bearing shoes, depending on the amount of pump thrust on the bearings. Thus, regardless of thrust condition (either up thrust or down thrust), an oil film between the shoes and runner is present. At the same time, high-pressure oil is being sprayed into the guide bearing chamber for lubricating the upper radial guide bearings. Oil lift is used during pump startup and coast down only. There are low and high oil level alarms in the upper and lower oil pots. BEARING TEMPERATURE DETECTORS One shoe of each bearing (upper thrust, lower thrust, upper radial, and lower radial) is provided with a temperature detector.

16.20 ANTI-REVERSE-ROTATION DEVICE

The anti-reverse-rotation device used on the RCP motor is a simple ratchet and pawl arrangement requiring no lubrication and having no parts to wear during normal operation. The device prevents reverse rotation with 100 percent torque applied in that direction and with a maximum reverse movement of less than 5 degrees.



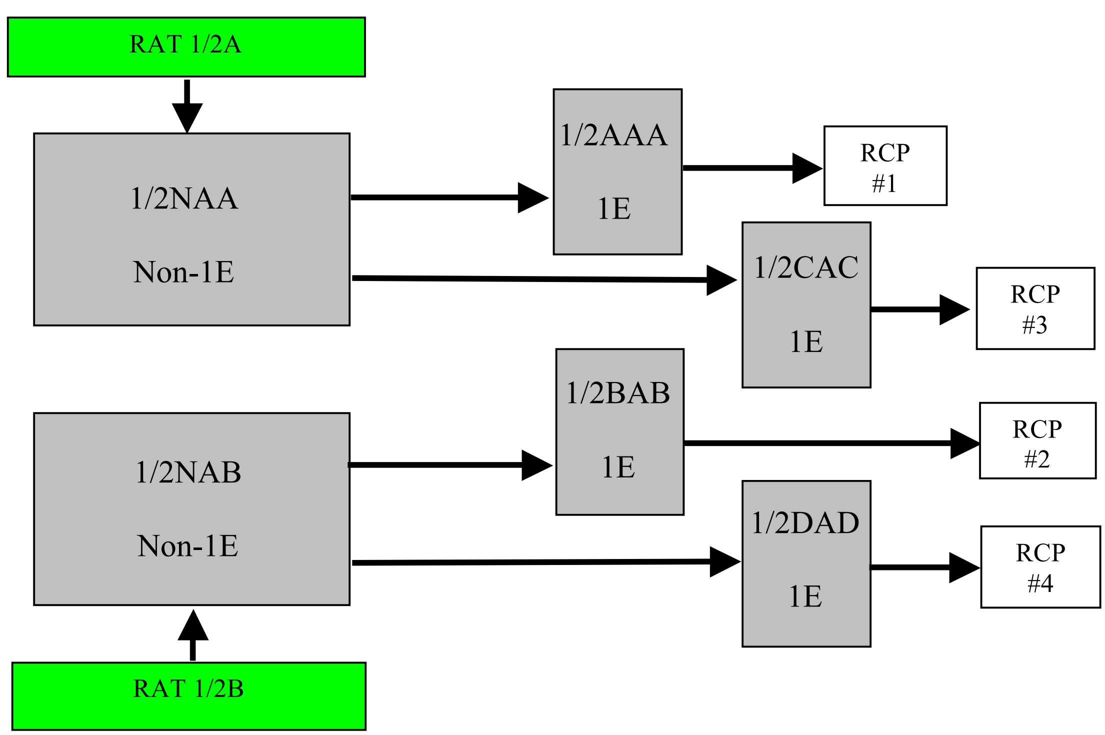
At an approximate speed of 70 rpm the pawls drop and bounce across the ratchet plate. At zero speed, one pawl will engage the ratchet plate, preventing rotation in the reverse direction. The pawl and associated parts are designed to support up to five times normal torque without exceeding safe working stresses. There are a number of such pawls spaced equally around the periphery, and any one can contain the reverse forces. The ratchet plate is normally stationary except when it absorbs shock. It is attached to its support with spring-return shock absorbers which prevent reverse shock from being transmitted to other motor parts. At startup, the pawls are kicked up by the ratchet notches, and they continue to bounce until the motor attains a speed of about 70 rpm. At this speed, the centrifugal force is sufficient to overcome the force of gravity and hold the pawls in the running position. While the motor is running at speed, there is no contact between the pawls and the ratchet plate.

16.21 FLYWHEEL

It is important to reactor protection that the reactor coolant continues to flow for a short time after reactor trip. In order to provide this flow following loss of offsite electrical power, each reactor coolant pump is provided with a flywheel. Thus the rotating inertia of the pump, motor and flywheel is employed during the coast down period to continue the reactor coolant flow. The pump/motor is designed for the safe shutdown earthquake at the site. Hence, it is concluded that the coast down capability of the pumps is maintained even under the most adverse case of loss of offsite electrical power coincident with the safe shutdown earthquake.

16.22 RCP BREAKERS

Reactor coolant pumps are powered from 13.8 KV non-ESF busses through a non-class 1E Tie Breaker and a class 1E motor breaker. RCP 1 and 3 are supplied from bus 1NAA and RCP 2 and 4 are supplied from bus 1NAB. Only one RCP is started at time to prevent over loading its associated 13.8 KV bus. Both the non-class 1E and class 1E breaker are in series. The reactor coolant pump non-class 1E tie breakers (HS-0495B, 0496B, 0497B, 0498B) receive their control power from 125 VDC non-ESF busses. In order to close these breakers the respective oil lift pump must be running and the oil lift pump discharge pressure must be at least (600 psig) as indicated by a blue light on the oil lift pump hand switch. These non-class 1E tie breakers will automatically trip on: over voltage, instantaneous or time delay over current, or phase differential current. The reactor coolant pump class 1E motor breakers (HS-0495A, 0496A, 0497A, 0498A) receive their control power from 125 VDC ESF busses train A, B, C, and D, respectively. Their breakers will automatically trip on: under frequency, or instantaneous or time delay over current.



16.23 <u>VIBRATION MONITORING</u>

Each RCP is equipped with both “Frame” and “Shaft” vibration monitoring. The RCP frame vibration monitors consist of two probes that are mounted 908 apart on the top of each RCP motor frame. The RCP shaft vibration monitors are measured by a vertical and horizontal proximity probe mounted parallel and perpendicular respectively to the pump discharge at a location near the pump coupling. Both frame and shaft vibrations are continuously monitored. Alarms are generated in the control room if the frame vibration exceeds 3 mils and 5 mils. At 5 mils the operators are required to trip the associated RCP. High frame vibrations are indicative of a misalignment or an out of balance condition. Shaft vibration alarms are also generated if they exceed 15 mils and 20 mils. At 20 mils the operators are required to trip the associated RCP. High shaft vibrations are indicative of a possible bearing failure. Local monitoring at the RCP vibration panel is required to determine which RCP has a vibration problem. The Control room is only provided with common alarms. During normal plant operation, RCP vibrations problems are not common. System operator rounds are performed during ever shift in which vibration readings are taking that can be trended for any degradation concerns. Close monitoring is required when starting RCPs after plant outages. Rebalancing after maintenance is usually required. It is a good practice to have personnel stationed locally at the vibration monitoring panel before starting any RCPs.

RCP Vibration Monitoring Panel

Model.	**W-11012 (93-A1)**
Type	Single-Stage, centrifugal
Head, feet	288
Reactor coolant flow, gpm	100,600
Reactor coolant temperature (nominal), Degrees F	558.2
Reactor coolant pressure (nominal), psia.	2250
RCP DATA Impeller type	Seven-vane single-suction
Total rotating inertial (including motor), lb-ft^2	95,000
Heat exchanger water flow (at 105 Degrees F max.), gpm	40
No. 1 seal injection water flow (at 130 Degrees F), gpm	8-13
No. 1 seal leak off flow, gpm	3
No. 2 seal leak off flow, gph	3
No. 3 seal leak off flow (inner and outer dams), cc/hr	400
No. 3 seal injection water flow, cc/hr	800
Number of pumps (per reactor	4
Brake Horsepower	
Hot (sp. gr. of reactor coolant water 0.745)	6,650
Cold (sp. gr. of reactor coolant water 1.00)	8,580
Speed, rpm	
Hot (sp. gr. of reactor coolant water 0.745)	1,187
Cold (sp. gr. of reactor coolant water 1.00)	1,182
Insulation	Class F
Voltage	13,200
Current, Amperes	
Hot (sp. gr. of reactor coolant water 0.745)	253
Cold (sp. gr. of reactor coolant water 1.00)	336
Starting (13,200 volts)	1,750
Frequency, Hz	60
Phases	3
Power input, kilowatts	
Hot (sp. gr. of reactor coolant water 0.745)	5,334
Cold (sp. gr. of reactor coolant water 1.00)	7,010
Cooling water requirements, gpm (1pm) at 105 Degrees F Maximum	
Upper Bearing Oil Cooler	170 (643)
Lower Bearing Oil Cooler	6 (23)
Stator Air Coolers (each unit)	150 (568)
Oil capacities (approximate), gallons (liters)	
Upper Oil Pot	220 (833)
Lower Oil Pot	20 (76)

Item	Normal	Min	Max	Alarm Temp	Trip Temp
Bearing Oil Cooler					
Upper (gpm)	--	170	--	--	--
Lower (gpm)	--	6	--	--	--
Inlet Pressure (psig)	--	--	150	--	--
Inlet Temp (Degrees F)	--	--	150*	115	120
Bearing Temps (Degrees F)					
Upper Guide	160	--	190	190	195
Upper Thrust	160	--	190	190	195
Lower Thrust		160	--	190	190
Lower Guide	160	--	190	190	195
Upper Bearing Oil Temp (Degrees F)					
Into Cooler	131	--	140	--	--
From Cooler	122	--	131	--	--
Motor Winding					
Temp (Degrees C)	120	--	150	150	155
Starting Voltage	--	9,900	--	--	--
Operating Voltage	13,200	11,880	14,520	--	--
Starting Current	1,750	--	--	--	--
Running Current	253	--	370	--	--
Oil Lift Pressure (psig)	1,200	600	2,000	--	--
Air/Water Heat Exchanger					
Flow (gpm)	190	--	--	--	--
Inlet Pressure (psig)	150	--	165	--	--
Inlet Temp (Degrees F)	--	--	105	--	--

* May be up to 130 degrees F for a period not to exceed 4 hours.

* Performance Curves

* Motor Operating Values

REQUIREMENTS FOR REACTOR COOLANT PUMP STARTUP

1) Shutdown Margin Satisfied

2) UOP conditions satisfied

3) No alarms

   a) RCP Oil levels (allowed only in special circumstances)
   b) RCP cooler flows (ACCW)
   c) RCP Standpipe level

2) Number 1 seal leak off per 13003-1 figure 2(RCP SOP)

   Number 1 seal Delta P Greater than 200 psid. Points used to measure the delta p are seal injection pressure and seal return pressure. This differential pressure is required to ensure that a film of exist between the two sealing surfaces of the number 1 seal.

3) 8-13 GPM Seal injection flow

   A minimum VCT pressure of $\geq$18 psig (amount of backpressure required to force some number seal leak off to inject into the number 2 seal).

4) Oil lift pump in service for a minimum of 2 minutes.

RCP STARTING DUTIES

1) Only one RCP shall be started at any one time.

2) Two successful starts are permitted, provided the motor is permitted to coast to a stop between starts.

3) A third start may be made when the winding and core have cooled by running for a period of 20 minutes, or by standing idle for a period of 45 minutes. (Both times are from the second start).

CONDITIONS THAT REQUIRE IMMEDIATE RCP TRIP

(See Figure IPC screen of RCP parameters monitored)

1) Any motor bearing temperature exceeds 195°F.

1) Motor stator winding temperature exceeds 311°F.

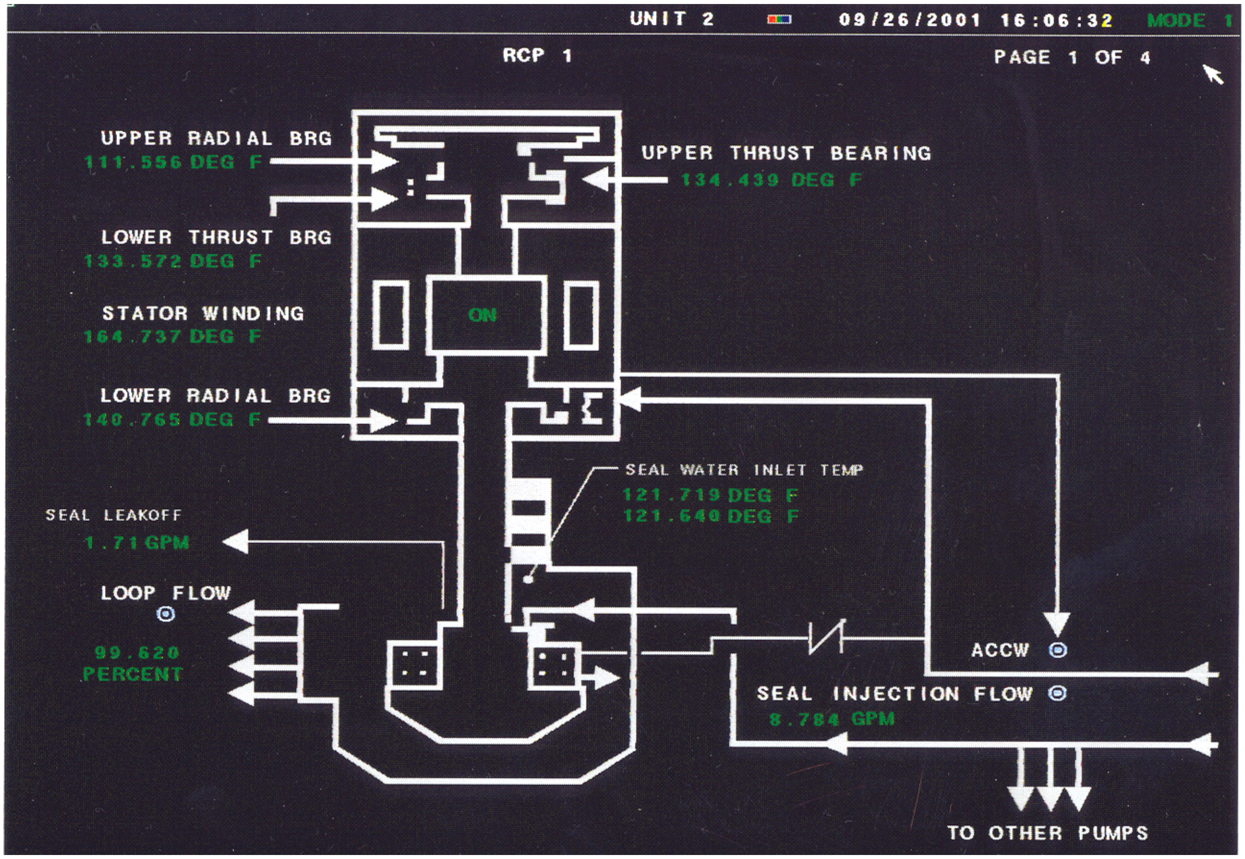
2) Seal water inlet temperature exceeds 230°F.

3) Total loss of ACCW for 10 minutes (except thermal barrier heat exchanger when seal injection is in service).

4) RCP shaft vibration $\geq$ 20 mils (alarms at 15 mils and 20 mils)

5) Frame vibration $\geq$ 5 mils (alarms at 3 and 5 mils)

6) Differential pressure across the number 1 seal < 200 psid.



IPC SCREEN OF RCP PARAMETERS MONITORED

Abnormal Operations

Loss of CVCS seal injection

1) Ensure ACCW flow thru the RCP thermal barriers.

2) Monitor lower pump radial bearing and seal water inlet temperature (Seal water inlet temperature IPC point covers both).

3) Secure pump if ACCW lost or temperature of the "seal water inlet temperature" exceeds 230°F.

4) FSAR addresses operation without seal injection for up to 24 hours.

<u>#1 Seal Failure Symptoms</u>

1) IPC can be used to trend seal leak off flows

2) Actions for number 1 seal failure

   Seal leak off flow > 5.0 gpm consult engineering and shutdown RCP within the next 8 hours if required.

   a) Seal leak off flow > 5.5 gpm take the following actions:

      1) Start the associated RCP lift oil pump
      2) Trip the reactor if power is greater 15%
      3) Stop the affected RCP
      4) If RCP #1 or #4 was stopped, close its associated Pressurizer spray valve.
      5) Close the affected RCP seal leak off valve when the RCP comes to a complete stop. This will be indicated by reverse flow on the loop flow gauges.
      6) Secure the RCP lift oil pump

TECHNICAL SPECIFICATIONS

LCO 3.3.1 Function 11 <u>Undervoltage RCPs</u>

2 channels per bus are required to be operable.

Applicability: Mode 1 ≥ 10% power

Bases:

The undervoltage RCPs reactor trip function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more loops.

LCO 3.3.1 Function 12 <u>Underfrequency RCPs</u>

2 channels per bus are required to be operable.

Applicability: Mode 1 ≥ 10% power

Bases:

The underfrequency RCPs reactor trip function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfequency condition will slow down the pumps, thereby reducing their coast down time following a pump trip. The amount of coast down time is important to ensure force flow for peak decay heat removal.

OPERATIONAL EXPERIENCE

OE 5436

ARKANSAS NUCL 1 EVENT OF 2/29/92. A RCP failed during a coast down testing sequence prior to refueling outage. The pump was stopped then restarted, after two failed attempts to start its oil lift pump. The lift oil pump was successfully started on its third attempt. Thrust bearing temperatures increased rapidly, but were not monitored by the crew. High oil temperature alarms alerted the crew of the problem. The RCP was secured, however extensive damage had already occurred to the RCP. The Upper Guide and Journal bearings were damaged, and the upper thrust bearing was destroyed. Root cause was a leak in oil system. Contributing cause was a failure of the crew to monitor pump parameters on pump start.

On 24 February 2002 at 10:20 pm with Krsko at full power the night shift noticed an increase in upper motor thrust bearing temperature for Reactor Coolant Pump (RCP) Number 2. The shift responded according to Abnormal Operating Procedure PRI-4, "Reactor Coolant Pump Malfunction." While the temperature continued to increase, the shift initiated a reactor shut down with a rate of 6 MW/min at 01:18 am on 25 February 2002. During the plant shut down, the RCP bearing temperature rate increased. At a reactor power of 28 percent and RCP affected bearing temperature at 89 degrees Celsius (192 degrees Fahrenheit) the crew manually tripped the reactor and RCP Number 2 at 02:09 am. The plant was stabilized in the Hot Standby condition (MODE 3) On 25 February 2002, an analysis was started on temperature element (TE) behavior. In RCP Number 2 terminal box, all connections were checked and the resistance of all temperature detectors (thrust bearing upper shoe, lower shoe, upper radial bearing) was measured. The resistance of TE 695B was significantly higher. Simultaneously a ferrographic analysis of both RCP oil samples was performed. Concentrations of wear particles in both samples were normal. As a result of these analysis and vendor (Westinghouse) recommendation, RCP Number 2 was started. On 25 February 2002, at 09:26 pm, the plant was placed in hot standby condition. All RCP Number 2 parameters were normal. Since the replacement of a faulted detector is a complicated activity, it was decided to operate the remaining two months of the operating cycle with a faulted temperature detector on RCP Number 2. The alarm set points of other two bearing detectors was lowered. The vibration alarm levels were maintained at previously lowered values as well. This event is not significant because the shut down was performed according to the procedure and not complicated. Plant safety was not impacted. This event was Noteworthy because a component failure forced the plant to shut down.

Fort Calhoun Unit 1
Forced Shutdown as a Result of Damage to a Reactor Coolant Pump Anti-Rotation Device

On June 7, 1996, the unit shutdown from 100 percent power following detection of an abnormal high-pitched noise coming from reactor coolant pump (RCP) 3B. Over the past several weeks a slow increase in RCP 3B vibration levels had been noted. Vibration levels had increased to 15 mils. However, the vendor had advised continued monitoring of the vibration and recommended shutting down if the vibration increased to 20 mils. On the afternoon of June 7, the vibration reading dropped to approximately 8 mils. The vendor recommended a visual inspection because a sudden temporary drop in vibration level was possible for some types of bearing failure. The system engineer made a containment entry, and immediately upon entering containment detected the abnormal noise coming from RCP 3B. Looking down on the motor he thought he detected lateral movement and recommended securing the pump as soon as possible. A rapid shutdown was performed, and between 6:00 p.m. and 7:00 p.m., RCP 3B was secured. After the pump was secured, a computer display showed intermittent indication that RCP 3B was running backwards. This indication had been noted on previous occasions when the pump was secured after plant shutdowns and was discounted since previous investigations found the pump had stopped. Additionally, annunciators were received intermittently for RCP backwards rotation. Based on past behavior, this too was discounted as a nuisance alarm, and the annunciator card was pulled. The following morning personnel entered containment to remove the RCP 3B motor top hat. They detected burned oil on the top of the motor and noted the top of the secured RCP motor was abnormally hot. They also detected that the RCP shaft was rotating in the reversed direction. The on-shift STA confirmed the reverse rotation by obtaining a reading from the RCP monitoring panel in the auxiliary building. This panel indicated the RCP was rotating 700 RPM in the reverse direction. Several personnel were not aware of this pump speed indication available at the auxiliary building monitoring panel, and the feature had not been used the night before to confirm the absence of reverse rotation. It is believed that RCP 3B ran in the reverse direction at 700 RPM for approximately 12 hours. Investigation of the event is ongoing. However, a check valve in the anti-rotation device lubrication system was found installed backwards. It is believed that the improper check valve installation occurred in May 1995 when corrective maintenance was performed on the RCP lube oil coolers. Incorrect orientation of three check valve could have diminished oil flow to the anti-rotation device during normal RCP operation, resulting in degradation and the upward trend in vibration readings. When RCP 3B was secured, the anti-rotation device catastrophically failed from insufficient lubrication. The unit was not scheduled to start up until June 19. Several flushes of the RCP lube oil system were required to remove debris in the system resulting from the anti-rotation device failure. The motor bearings were inspected, but no damage was found. The RCP seal package was replaced as a precaution because of the extended reversed rotation operation. This event is potentially significant because of the major equipment damage and the extended lost generation time. Probable contributing factors were the improper maintenance and disregarding of supposed nuisance alarm indications for reversed RCP rotation.

REFERENCES

- P&ID 1X4DB111
- P&ID 1X4DB113
- RCP Technical Manual X6AB09-119
- SOP 13003-1/2
- Elementary Diagrams 1X3D-BD-B01A-H
- Elementary Diagrams 1X3D-BD-B01N,P,X,Y
- Elementary Diagrams 1X3D-AA-C01A,C03A
- FSAR Section 5-4.1
- Technical Specification
- OE 5436
- ARP 17008-1/2
- ARP 17011-1/2
- ARP 17063-1/2

SECTION C

PRESSURIZER AND PRT

16-24 Purpose

The Pressurizer System is designed to maintain RCS pressure and primary coolant inventory during steady state operation and expected transients.

16-25 General Overview

The Pressurizer System is designed to maintain saturated water and steam at equilibrium in the pressurizer vessel. The pressurizer is a vertical, cylindrical vessel with a hemispherical top and bottom. This system maintains RCS pressure by affecting the water/steam equilibrium with a combination of electric immersion heaters and a fine spray of relatively cool water. The electric immersion heaters increase the temperature of the water to produce a steam bubble. As the steam bubble temperature and pressure increase, the RCS pressure will in turn increase. The spray decreases RCS pressure by decreasing the temperature and pressure of the steam in the pressurizer vessel. The spray line allows Loop 1 and Loop 4 cold leg water to be sprayed into the top of the pressurizer as needed to reduce system pressure. Three safety valves and two power operated relief valves tap into the top of the vessel and provide for the relief of excessive pressure to the pressurizer relief tank.

Temperature changes in the RCS are caused by normal plant operation and transient conditions. These temperature changes affect the volume of coolant in the RCS. The volumetric expansions and contractions of the reactor coolant cause water to surge into or out of the pressurizer via the surge line. Normal changes in the coolant volume, such as those caused normal temperature increases with increased reactor power, are handled by allowing the water level in the pressurizer vessel to vary directly with RCS Tavg. The programmed level variation is designed to match as nearly as possible the actual volume change resulting from a change in the RCS coolant temperature. Adjustments to the liquid level in the pressurizer vessel are accomplished by varying the Chemical and Volume Control System (CVCS) charging and letdown flow.

When a steam bubble exists in the pressurizer, the pressurizer will naturally stabilize pressure in the RCS without the use of heaters or sprays. This is accomplished by the changing of the boiling point inside the pressurizer due to the pressure change itself. As pressure increases, the boiling point increases, therefore more heat is required to saturate water into steam. The opposite is also true, when the pressure in the system is reduced, the boiling point also reduces, and therefore less heat is required to saturate the water into steam. This natural response inherently stabilizes the primary system pressure. For example, as the volume of liquid in the pressurizer is increased due to a change in RCS temperature or mass, the pressure in the system will increase but will stabilize due to the condensing of the steam bubble in the pressurizer. The condensing of the steam bubble is due to the boiling point being increased with no addition of heat. This will dampen the pressure rise. The opposite holds true with a lowering of the pressurizer level. When the pressure in the system lowers the boiling point also lowers. Flashing of the saturated liquid into steam causes the steam bubble inside the pressurizer to grow which stabilizes system pressure. The use of heaters and sprays enhances this process by changing the heat input in the pressurizer to maintain pressure on program. It is important that a bubble exist that is condensable. Any non condensable gases that may have come out of solution must be removed out of the pressurizer steam volume. This is known as a “Hard Bubble” which reduces the pressure control ability of the system. The non condensable gases are removed by venting through the pressurizer steam space sampling system.

There is a time at lower modes of operation, when a pressurizer steam bubble does not exist; this is called “Solid Plant Operation”. The pressurizer will not act as a surge tank to stabilize primary pressure in this condition. Pressure control is performed by balancing the amount of mass addition (CVCS charging) and subtraction (CVCS letdown) to maintain primary pressure. When in this state, close monitoring and control by the operator is very important. Any temperature change in the primary will result in a direct change in system pressure.

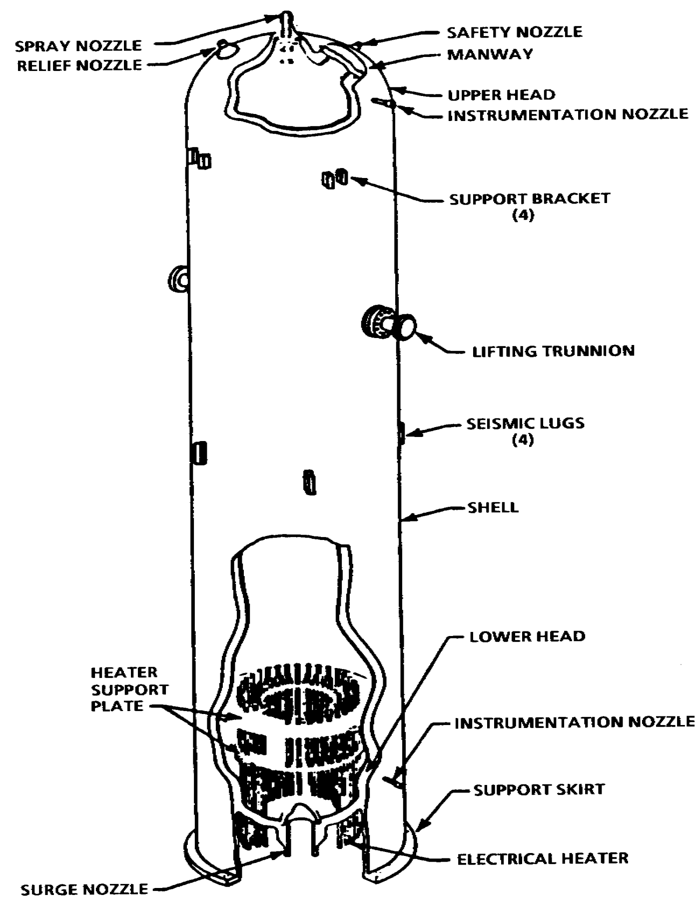
16-26 COMPONENT DESCRIPTION

The Pressurizer System is composed of seven major components:

16.27 Pressurizer Vessel

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads. The vessel is located in the containment building and is approximately 53 feet high and 8 feet in diameter, and has an internal volume of 1800 cubic feet. It is fabricated of manganese-molybdenum steel and internally clad with stainless steel to minimize corrosion.

The lower vessel head has 78 penetrations for the electric immersion heaters and a surge line nozzle. A screen is located above the surge line nozzle to prevent foreign objects from entering the RCS. The upper vessel head has penetrations for a spray nozzle, a power operated relief nozzle, three safety valve nozzles, and a manway. At full power, the pressurizer is approximately 60 percent saturated water and 40 percent saturated steam.



16-28 Surge Line

The surge line connects the hot leg of RCS Loop 4 to the bottom head of the pressurizer. The surge line has a diameter of 16 inches in which it is designed for a maximum flow of 20,000 gpm. This, in combination with maximum flow from the three pressurizer safety valves, will limit the over pressurization of the RCS to 110% of the design pressure. The pressurizer is the hottest point in the RCS. When water surges out of the pressurizer, it is approximately 650°F.

When RCS hot leg water surges into the pressurizer, it is approximately 35°F cooler. The surge nozzle is protected by a thermal sleeve, which minimizes thermal stresses due to the rapid temperature changes that accompany water surges into or out of the Pressurizer. A retaining screen above the nozzle prevents any foreign matter in the Pressurizer from entering the RCS piping.

16-29 Electric Immersion Heaters

The pressurizer electric heaters are used to increase RCS pressure. Each heater is a resistive heating element with a rated capacity of approximately 23 kW at 480 volts. With a total heater capacity of 1800 kW is divided into four groups with separate controls for the proportional group (Group C) and the backup groups (A, B and D). Groups A and B can be controlled from the remote shutdown panel A and B, respectively. Group A and B heaters are tech. spec. related and are powered from 1NB01 and 1NB10. These two buses are energized by 1AA02 and 1BA03 which are safety related buses that can be powered from the emergency diesel generators on a LOSP.

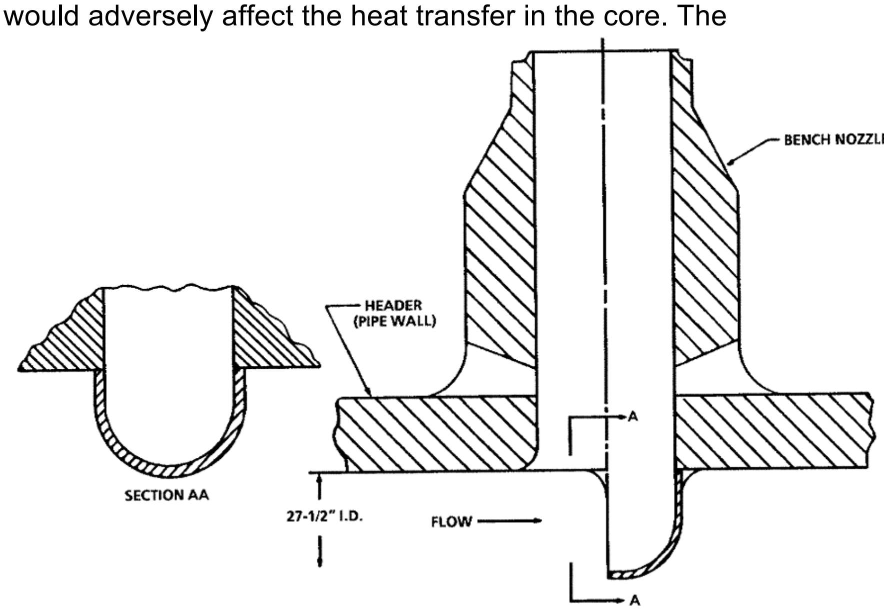
The proportional group heaters are rated at approximately 400 kW and have a variable output depending on the pressure control demand. The backup heaters are rated at approximately 1400 kW, and receive either an ON or OFF control signal. Their primary purpose is to heat the pressurizer to normal operating temperatures from a cold, solid, non-pressurized condition and to react to pressure transients.

The heaters are designed to raise the temperature of the pressurizer at a maximum rate of 50-55°F/hr when the pressurizer is water solid at startup, and 70°F/hr with the plant in a hot standby condition.

Pressurizer heaters are controlled automatically by the Pressurizer Pressure Control System to maintain RCS pressure at 2235 psig. This ensures an adequate degree of subcooling of the RCS and prevents any boiling which would adversely affect the heat transfer in the core. The pressurizer heaters can also be manually controlled.

16-30 Spray System

Pressurizer spray is used to reduce pressure in the pressurizer and RCS. When spray flow is established, relatively cool water from the RCS is sprayed into the steam space of the pressurizer. The spray condenses some of the steam. When the steam is condensed, the liquid occupies approximately one-sixth the volume that it did when it was steam. The volumetric reduction



reduces the vapor space pressure and the force exerted on the liquid in the pressurizer. This reduces pressurizer and RCS pressure.

The pressurizer spray comes from the cold legs of RCS Loops 1 and 4. The driving force for the spray water is the reactor coolant pumps in loops 1 and 4. It is aided by use of a scoop that protrudes into the RCS piping and directs flow through the spray piping. The two 4-inch spray lines from the cold legs tie together after passing through the spray control valves, and supply water to a single spray nozzle in the top of the pressurizer vessel. The common spray line connects via a thermal sleeve to the Pressurizer vessel and spray nozzle. The nozzle is designed to produce a narrow angle cone spray pattern, which prevents cold water impingement on the Pressurizer walls. The spray nozzle also has been designed to withstand the thermal stresses resulting from introducing cold auxiliary spray water into the Pressurizer. The spray nozzle design assumes that the spray valve leak by flow exists which protects the spray nozzle from excessive thermal shock.
The spray nozzle disperses the water into a spray and increases the total heat transfer area of the water. This enhances the effectiveness of the spray to reduce pressure.

Pressurizer spray is controlled by two pressurizer spray valves; one from RCS loop 1 and one from RCS loop 4. Each valve has a design flow rate of 450 gpm (900 gpm total spray flow). The valves are air operated fail close ball-type valves and will allow variable flow rates.

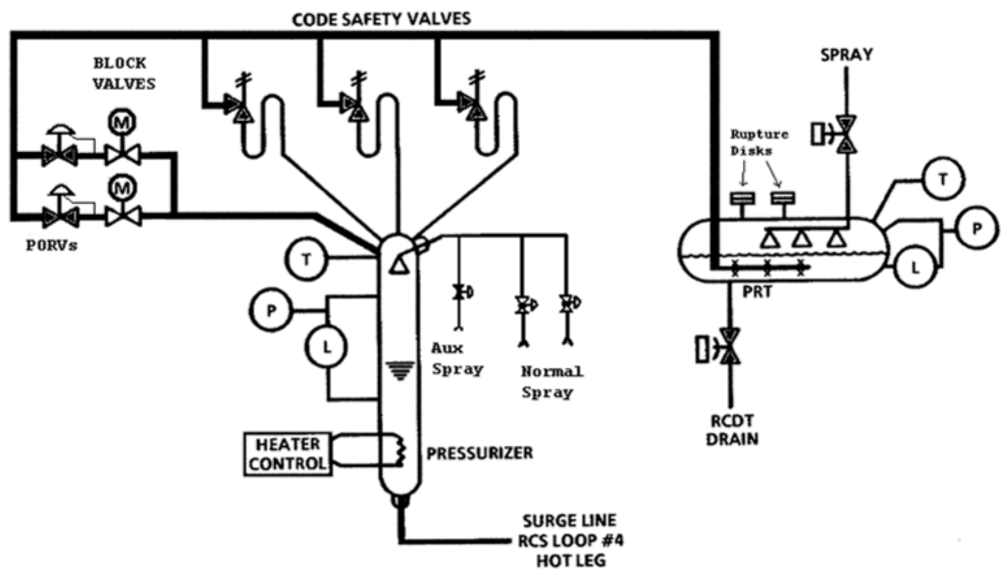
Like the pressurizer heaters, pressurizer spray is automatically controlled by the Pressurizer Pressure Control System. Each spray valve has a MANUAL/AUTO station on the QMCB. Pressurizer pressure control will signal the spray valves based on the deviation of pressure from 2235 PSIG. The higher the deviation, the more pressurizer spray flow will result.

Each spray control valve is provided with a bypass line to allow a small continuous flow around the valve. This small flow (about 2 gpm) is provided to prevent excess cooling of the spray system, thus limiting thermal shock to the lines when spray is initiated. The continuous flow also ensures equalization of the water chemistry between the RCS and pressurizer, particularly boron water chemistry.

An auxiliary spray line from the CVCS is provided to supply spray water when the normal supply is not available. The auxiliary spray line ties into the spray system between the spray control valves and the pressurizer. The auxiliary spray is supplied from CVCS charging at the outlet of the regenerative heat exchanger. The maximum differential temperature difference across the spray nozzle is 625°F. The maximum limit is to protect the spray nozzle from the thermal shock.

16-31 Safety Valves

The three pressurizer safety valves are spring loaded, enclosed, quick-acting type valves. They are set to open at a pressure of 2460 psig and have a combined capacity of 1.26 million pounds mass per hour. The capacity is equal to or greater than the maximum credible RCS surge rate into the pressurizer. The design basis for the relief capacity is the complete loss of load without a reactor trip. The safety valves discharge to the pressurizer relief tank. Steam or hydrogen leakage past the valve seats is inhibited by a loop seal in the piping from each safety valve. Condensation collects in the loop seal. The collection of water in the seals prevents the hydrogen from passing out of the pressurizer. The loop seals are provided with drain lines which are routed to the pressurizer relief tank.



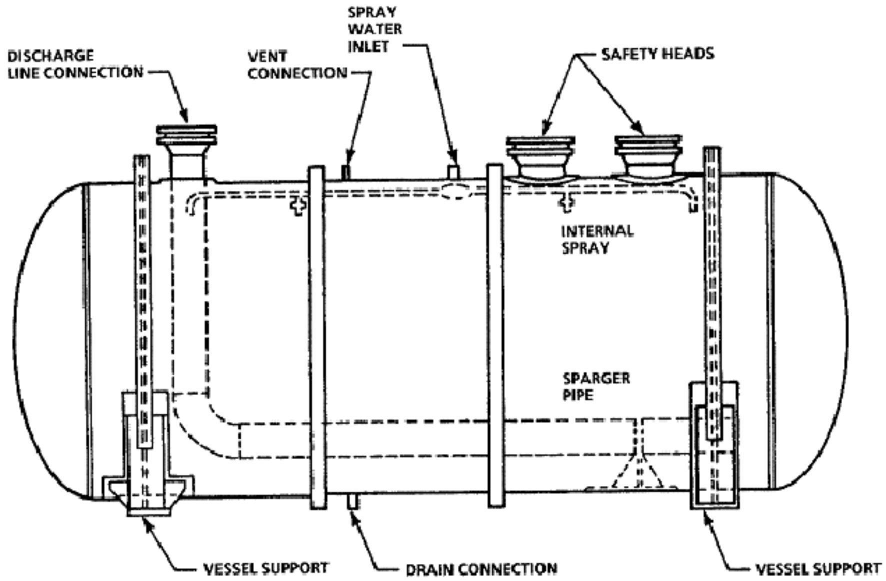
16-32 POWER OPERATED RELIEF AND ISOLATION VALVES

A 6-inch relief line is attached to the upper head of the pressurizer. The line divides into two parallel 3-inch lines, each containing a power operated relief (PORV) and motor operated isolation valve. The two PORVs are solenoid operated steam ported valves controlled from the QMCB and remote shutdown panels. PORV PV-455 relief set point is 2345 psig and PORV PV-456 relief set point is set at 2335 psig. Each valve has a capacity of 210,000 lbs/hr. Actuation pressure is set to prevent operation of the pressurizer safety valves. A normally open motor operated isolation valve called “block valves” are located upstream of each relief valve. It is closed when necessary to isolate a PORV because of leakage. Isolation of the relief valves is allowed because the pressurizer safety valves provide the RCS with sufficient protection in the event of an accident. The PORV's were not taken credit for in the accident analysis.

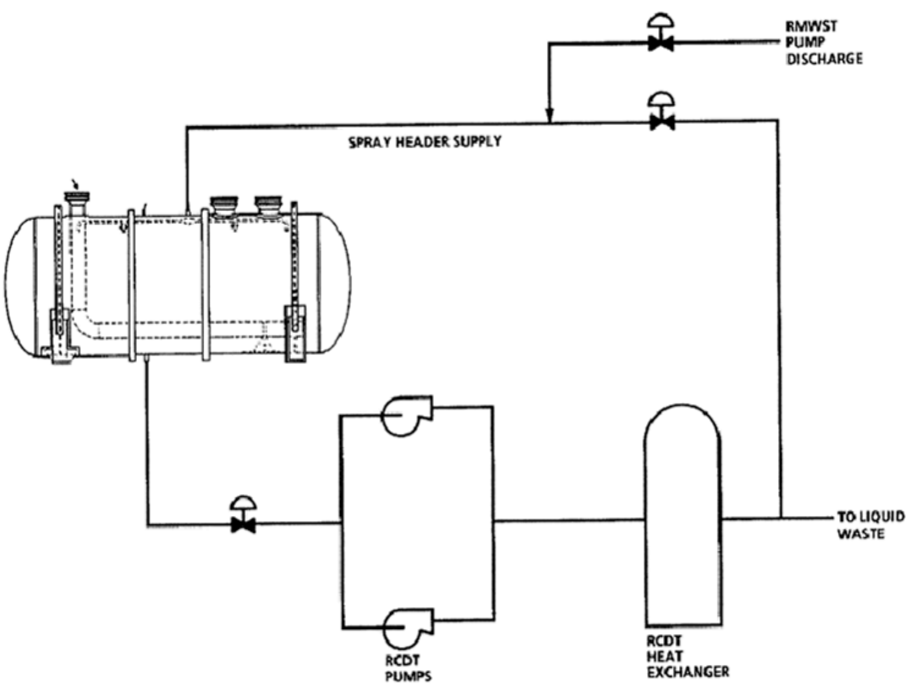
Downstream of the power-operated relief valves, the two 3-inch lines combine into a common discharge line from the safety valves and dumps to the pressurizer relief tank.

In addition to the function of providing overpressure protection for the pressurizer and RCS when operating, the PORVs also protect the RCS when the plant is shut down and water solid. This is accomplished by varying the relief opening set point of the PORVs to open. Based on certain conditions, the set point will change. This is accomplished by the Cold Overpressure Protection System.

16-33 Pressurizer Relief Tank



The pressurizer relief tank (PRT) is located on the base slab (level C) of in the containment building. The tank is approximately 27 feet long, 10 feet in diameter, and has an internal volume of 1800 cubic feet. A water volume of 1350 cubic feet is maintained in the tank. The water is used to cool any discharge from the PORVs and safety valves, the Reactor Head Vent System, RHR and CVCS relief valves, and valve stem packing leak offs from the PORV block valves. Any discharged steam enters the tank through a sparger line under water. The steam exiting the many holes in the sparger under water cools and condenses the steam.



The PRT water can be cooled less than 120°F by re-circulating the water in the PRT through the Reactor Coolant Drain Tank (RCDT) pumps and heat exchanger. A drain line from the PRT is piped to the suction header of the RCDT pumps. The pumps direct the water through the heat exchanger where it is cooled by ACCW which is circulated through the shell side of the heat exchanger. The cooled water is then returned to the PRT through a spray header in the vapor space of the PRT. The spraying action condenses and cools the steam in the PRT. The contents in the PRT can also be cooled by the “feed and bleed” method. The spray header is provided with water from the Reactor Makeup Water System (RMWST) via the RMWST pumps. A drain line from the PRT is aligned to the suction of the RCDT pump. The RCDT pump would discharge PRT contents to the liquid waste system.

Two 100 psig rupture discs protect the pressurizer relief tank from over pressurization. The discs relieve directly to containment atmosphere. The tanks are not designed to receive continuous discharges.

The tank's gas volume of 450 cubic feet is filled with inert nitrogen gas. Nitrogen gas is used to prevent the intrusion of oxygen into the tank. This is to prevent explosive mixtures of hydrogen from the pressurizer and oxygen from forming in the tank.

SYSTEM INTERFACES

The Pressurizer System has physical connections with the following plant systems:

Chemical and Volume Control System (CVCS)

The Chemical and Volume Control System connects to the pressurizer spray header between the spray line loop seal and the spray valves. The CVCS supplies auxiliary spray to the pressurizer when the normal spray line sources are not available.

Reactor Makeup Water System

The pressurizer relief tank is supplied water from the Reactor Makeup Water System to maintain a cool volume of water for condensing steam relieved to the tank.

Nitrogen Supply System

The pressurizer relief tank is pressurized to 3-5 psig with N_2 gas supplied by the Nitrogen Supply System to prevent the buildup of an explosive mixture of oxygen and hydrogen in the tank.

Waste Gas System (WPSG)

The Waste Gas System connects to the pressurizer relief tank and is used when venting the PRT of gases.

Reactor Coolant Drain Tank (RCDT)

The RCDT is used as a drain collection point when draining the RCS. The RCDT also collects valve steam packing leak off for most RCS-related valves. The RCDT is also used to cool the PRT by circulating its contents through the RCDT heat exchanger.

Design Summary

The Pressurizer System is designed to maintain the pressure of the RCS high enough to ensure that no boiling in the core occurs that would affect the heat transfer from the fuel rods to the coolant. The Pressurizer System also ensures that over pressurization of the RCS does not occur, so the RCS remains intact as a barrier to prevent radio nuclides from reaching the atmosphere.

INFREQUENT OPERATIONS

Infrequent operation of the Pressurizer System includes the following:

Cool down of the PRT

When pressurizer or other relief valves open and admit hot water/steam to the PRT, it may require cooling to prevent over pressurization. This is accomplished by opening the PRT drain to the RCDT and circulating the water through the RCDT pumps and heat exchanger. The cooled water is returned to the PRT through the spray header which condenses any steam that may be present in the tank.

Pressurizer Boron Equalization

To equalize pressurizer boron concentration with the RCS, the backup heaters are energized. This increases pressurizer pressure which opens the pressurizer spray valves. This is maintained until boron concentration is consistent.

ABNORMAL OPERATIONS

The pressurizer is designed to respond to all expected abnormal operations, through the operation of its automatic controls or passive safety valves.

TECHNICAL SPECIFICATIONS

LCO 3.4.9 Pressurizer

The pressurizer shall be OPERABLE with:

a) Pressurizer water level ≤ 92%; and
b) Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 KW and capable of being powered from an emergency power supply.

Applicability: Modes 1, 2, and 3

BASES: The limit on the maximum water volume assures that level is maintained within the normal steady-state envelope of operation assumed in the FSAR. This limit also ensures that the RCS is not a hydrostatically solid system (steam bubble can be maintained). The heater operability is to enhance the capability of the plant to control RCS pressure and establish natural circulation.

LCO 3.4.10 SAFETY VALVES

Three pressurizer safety valves shall be OPERABLE with a lift settings ≥ 2410 psig and ≤ 2510 psig.

Applicability: Modes 1, 2, and 3

BASES: The pressurizer code safety valves operate to prevent the RCS from being pressurized above its safety limit of 2735 psig. Each safety valve is designed to relieve 420,000 lbs/hour of saturated steam at the valve 2560 psig.

LCO 3.4.11 RELIEF VALVES

Each PORV and its associated block valves shall be OPERABLE.

Applicability: Modes 1, 2, and 3.

BASES: The PORV's and steam bubble function to relieve RCS pressure during all design transients up to and including the design step load decrease with steam dumps. Operation of the PORV's minimizes the undesirable opening of the spring-loaded pressurizer code safety valves. Each PORV has a remotely operated block valve to provide a positive shutoff capability should a relief valve become inoperable.

TRM 13.4.2 PRESSURIZER

The pressurizer temperature (TI-0453, TI-0454) shall be limited to:

a. A maximum heat up of 100°F in any 1-hour period.
b. A maximum cool down of 200°F in any 1-hour period.
c. A maximum auxiliary spray water temperature difference of 625°F (TI-0126)

Applicability: At all times.

BASES: There temperature limits ensure the compatibility of operation with the fatigue analysis performed in accordance with the ASME code requirements.

OPERATING EXPERIENCE

SOER 81-15

Millstone Unit 2 on Jan. 1981, a PEO inadvertently caused loss of DC control power which de-energized the Reactor Coolant Pump busses. When DC power was restored, the busses fast transferred to the offsite source. When power was simultaneously applied to two RCPs and condensate pump motor, the starting current tripped the supply breakers. The plant was maintained in hot standby with the two remaining RCPs, while completing the recovery from the loss of DC power. The existing combination of RCPs provided no significant pressurizer spray flow. The operator did not associate the ineffectiveness of spray with greatly reduced spray control, but concluded that a "hard bubble" had resulted from a collection on non-condensable gasses in the pressurizer. Approximately two hours and fifteen minutes into the event, pressurizer pressure increased to 2380 psia, causing both PORVs to open for a short duration. The auxiliary spray valve was subsequently used to control pressure. (The other RCPs could have been re-energized but were not.)

EAR PAR 99-029 Continuous uncontrolled operation of pressurizer heaters during cold shutdown at Civaux Unit 2

On September 18, 1999, during initial startup at Civaux Unit 2 (0 percent power), the pressurizer heaters remained in operation and over pressurized the reactor coolant system (RCS) while the RCS was at a low temperature. The new N4 series control room is fully computerized, and also consists of a conventional panel called the auxiliary panel. Important safety related functions can be controlled on the auxiliary panel. While operators were performing a surveillance test to verify the operability of alarms and equipment on the auxiliary panel, the pressurizer heaters started automatically and the operators shifted back the heater control from the auxiliary panel to the normal panel. The pressurizer heaters continued to heat up the water in the pressurizer. No alarm was installed to detect these unusual consequences. Pressure and the water temperature in the pressurizer increased and the water level in the pressurizer decreased rapidly. An alarm indicating high discharge flow was received. After the operators identified that the heaters were in operation, they stopped the heaters and made up the water to the RCS. The steam temperature in the pressurizer was 430 degree F and the water temperature in the RCS was 86 degree F. As a result, the delta temperature between the RCS and the pressurizer was 376 degree F exceeding the maximum delta temperature limit of 230 degree F. This event is Significant to the Plant because the pressurizer was subjected to thermal condition greater than the design limit. No new lessons learned for domestic plants.

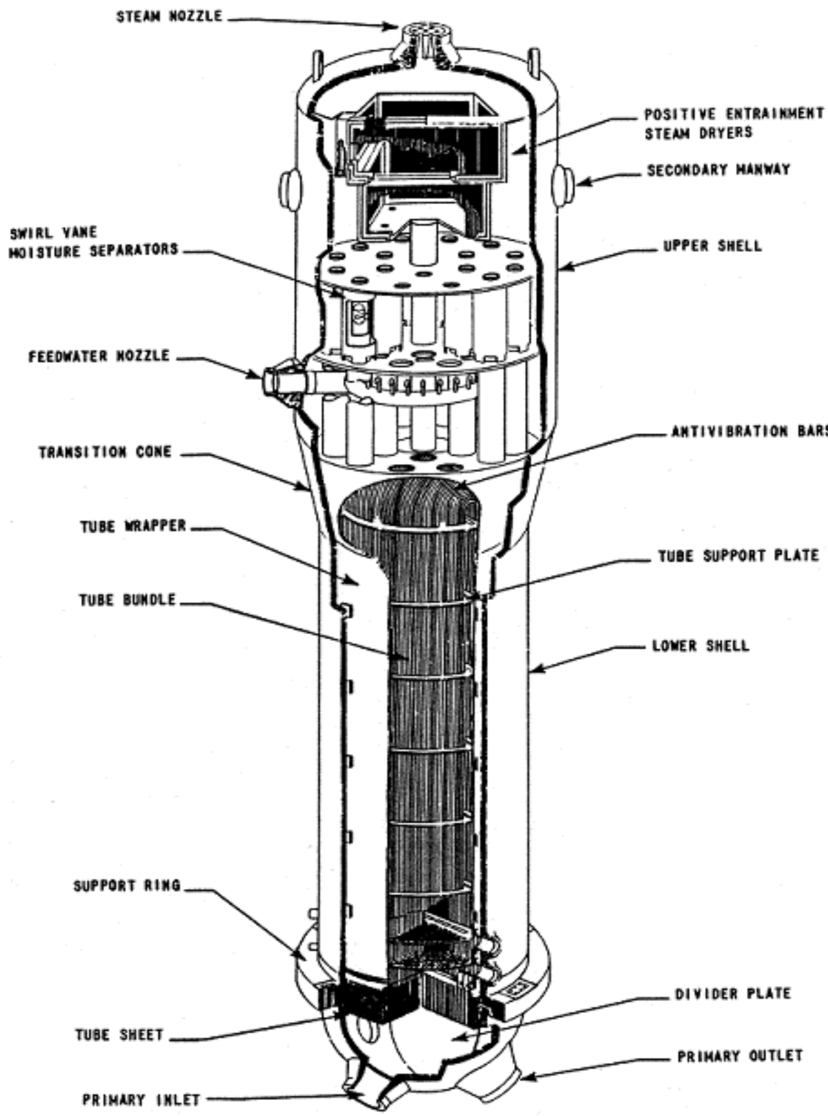
Technical Specification violations due to exceeding pressurizer cool down rate at Robinson Unit 2

Event number 261-940822-1

Analysis completed on August 22, 1994 determined that on February 26, 1994 with the unit in cold shutdown, the technical specification cool down rate limit for the pressurizer of 200 degrees per hour was exceeded. Pressurizer spray was actuated and there was an insurge of relatively cool reactor coolant system water when there was a large temperature differential between the pressurizer and the primary plant. The pressurizer spray actuation and resultant insurge was the result of normal shutdown operations as the operators attempted to change reactor coolant system pressure. There were no precautions or restrictions in the operating procedures that would have alerted operators to the possibility of exceeding the technical specification limits. Analysis is still ongoing on the potential impact of this event on pressurizer structural integrity. The analysis was done in response to an adverse condition report received from a PWR in the same utility. The analysis has also shown that pressurizer cool down limit has been exceeded on at least four other occasions during the life of the plant. This event is noteworthy due to the lack of guidance in operating procedures that resulted in violation of a technical specification cool down limit. Revision 1 to the LER documents the results of the analysis performed and provides additional insight on the root cause. Earlier in plant life the pressurizer was taken solid at temperatures greater than 200 degree F. This reduced the temperature difference between the reactor coolant system and the pressurizer and consequently minimized the potential for exceeding the 200 degree per hour cool down rate. The issue is the cool down rate in the pressurizer because plant procedures did not require monitoring of pressurizer temperature when the RCS temperature decreased below 200 degrees F. This was because station personnel assumed that temperature inside the pressurizer would closely follow RCS temperature. It was this assumption that was flawed. The results of vendor analysis indicated that there had been 13 reactor cool downs since 1980 where plant practice and conditions could have resulted in exceeding the TS heat up and cool down limits. Results of individual analyses also indicated that none of the transients adversely affected the structural integrity of the pressurizer.

REFERENCES

- P&ID 1X4DB112
- FSAR Chapter 5
- FSAR Table 7.5.2-1
- PLS AX6AA04-30
- Technical Specification
- Technical Requirement Manual



SECTION D

STEAM GENERATORS

16-34 Overview

The primary side of the steam generator consists of these components and assemblies:

- Tubeplate
- Tubes and Tube Bundle Assembly
- Channel Head
- Primary Side Manway Closure Seals
- Main Support System

The reactor coolant flows through the inverted U-tubes transferring its contained heat energy to the steam-secondary side. The reactor coolant enters the steam generator through the inlet nozzle located in the bottom head of the steam generator. The bottom head is divided into inlet and outlet chambers by a vertical partition plate extending from the bottom head to the tube sheet. After the reactor coolant has entered this inlet chamber, it flows, through the U-tubes, to the outlet chamber and exits through the outlet nozzle.

16-35 TUBEPLATE

The tubeplate is a low-Alloy steel forging. That portion of the tubeplate primary side in direct contact with the primary coolant is clad with Inconel (Ni-Cr-Fe Alloy). The outer circumferential portion of the tubeplate forging is a flat ring into which the main vessel supports are machined. The tubeplate, together with the U-tubes, comprises the boundary between the primary and secondary sides of the steam generator. Tube holes are drilled through the tubeplate and the tubes are inserted into the tube holes to form the tube bundle.

16-36 TUBES AND TUBE BUNDLE ASSEMBLY

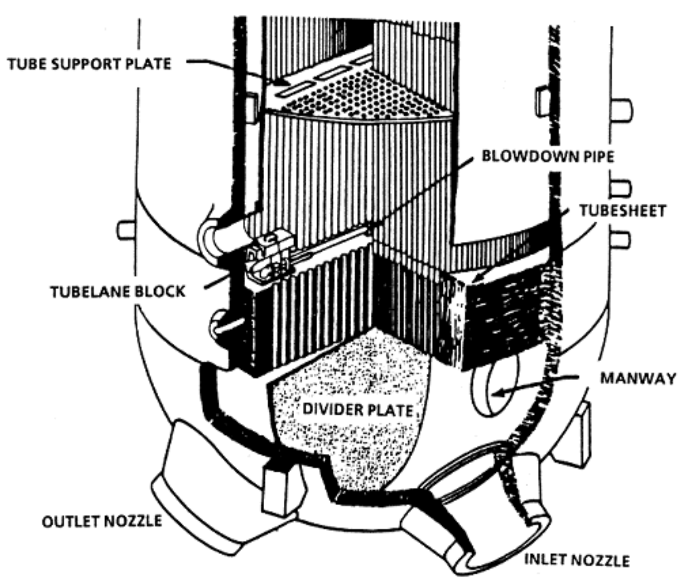
The tube bundle consists of 5,626 thermally treated U-tubes, fabricated from Inconel. The outside diameter of each U-tube is 0.688 inches and the nominal tube wall thickness is 0.040 inches. The ends of the tubes are expanded the full depth of the tubeplate and welded to the Inconel clad on the tubeplate primary side.

The tubes are supported on the secondary side by seven tube support plates. The tube support plates are fabricated from Type 405 stainless steel. All tube support plates have Quatrefoil-shaped holes, formed by broaching, to reduce tube dry out and chemical concentration in the region where the tubes pass through the tube support plates. Broaching is simply cutting to alter the shape of the hole.

A flow distribution baffle, located between the lowest tube support plate and the tubeplate, is designed to minimize the number of tubes exposed to low velocity flow in the vicinity of the tubeplate. This flow distribution baffle, fabricated from Type 405 Stainless Steel has round tube holes. The effective annular flow area between the tube and the flow distribution baffles is less than for a tube support plate. Also, the center portions of the flow distribution baffle is cut out. The flow distribution baffle controls the cross-flow velocity so that the low-velocity region (and sludge deposition zone) is located at the center of the tube bundle, near the blowdown intake.

Three sets of anti-vibration bar assemblies stiffen the tube bundle in the U-bend region and restrain tube vibration. These anti-vibration bar assemblies also maintain proper tube spacing and alignment in the U-bend region. These assemblies are fabricated from chrome-plated Inconel.

16-37 CHANNEL HEADS



The hemispherical channel head is a carbon steel casting. Integrally cast into the channel head are two primary manways and two primary nozzles. The 16-inch diameter primary manways permit access to the primary chamber for inspection and maintenance. Each manway is equipped with a closure system, consisting of a cover, insert disk and gasket. The manway cover is secured to the manway pad with bolts. The primary nozzles are equipped with primary nozzle closure rings. These rings provide a means of attaching the temporary maintenance covers, which should be installed prior to primary chamber maintenance. The channel head is partitioned into inlet and outlet chambers by a permanent Inconel divider plate. The divider plate has a small opening in its bottom edge at the lowest point of the channel head, allowing the use of a single drain connection for draining both primary chambers. This small opening provides negligible bypass flow during operation. All internal surfaces of the channel head are clad with austenitic stainless steel.

16-38 MAIN SUPPORT SYSTEM

The steam generator is supported vertically at four locations, 90 degrees apart, by surfaces and bolt holes machined into the outer circumferential ring of the tubeplate forging. High strength bolts are used to secure the Steam Generator Support System to the field support arrangement. Three flats are machined into the support ring rim providing an interface for the Lower Internal Support System.

SECTION E

REACTOR COOLANT SYSTEM PIPING

16.39 <u>REACTOR COOLANT SYSTEM PIPING</u>

The reactor coolant piping forms the flow path between the major components of the Reactor Coolant System. The reactor coolant piping is composed of three sections of piping. One section of pipe comprises the loop hot leg. This piping section connects the reactor vessel to the steam generator and has an inner diameter (I.D.) of 29 inches. There is an intermediate section of RCS piping between the steam generator (SG) and the reactor coolant pump suction which has a 31-inch inside diameter (I.D.) to minimize the pressure drop. A flow splitter at the suction of the reactor coolant pump further improves the flow conditions. It enables the velocity profile of the water at the reactor coolant pump suction to be more uniform. There is one remaining 27 1/2-inch I.D. section of the RCS piping referred to as the RCS cold leg. This is the section connecting the RCP discharge nozzle to the reactor vessel.

All the reactor coolant piping, fittings, and penetrations into the piping are constructed of austenitic stainless steel to reduce the formation of corrosion products in the RCS. Smaller piping, such as the pressurizer surge line, spray and relief line, loop drains, and connecting lines to other systems are also austenitic stainless steel. All joints and connections are welded except for the pressurizer relief and safety valves, where bolted flanged joints are used.

Piping connections with auxiliary systems are normally made above the horizontal centerline of the reactor coolant piping, with the exception of the following:

- RHR pump suction which is 45 degrees down from the horizontal centerline. This enables water in the Reactor Coolant System to be lowered in the reactor coolant pipe while continuing to operate the residual heat removal loop, should this be required for maintenance.

- Connections for temporary level measurement of water in the Reactor Coolant System during refueling and maintenance operation. Permanent taps for RCS mid loop monitoring system and level sight glass taps are included.

- The differential pressure taps for flow measurement downstream of the steam generators.

- Letdown piping for circulation of RCS water through the CVCS system.

- Excess letdown piping that allows an alternate letdown pathway.

Penetrations which extend into the reactor coolant flow path are limited as follows:

- The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray head driving force.

- The Reactor Coolant Sample System taps are extended into the coolant stream to obtain a more representative sample of the reactor coolant.

- The resistance temperature detector (RTD) hot leg and cold leg wet thermowells extend into the coolant to expose the RTDs to the RCS coolant.

- The wide range temperature detectors are located in thermowells that extend through the reactor coolant pipes.

These penetrations serve to inject cool, borated water in ALL loop cold legs for emergency core cooling in accident conditions. This cool, borated water is from the Refueling Water Storage Tank (RWST), through the centrifugal charging pumps, and the Boron Injection Tank (BIT). The BIT on Unit 1 is piped in but the inlet valves are open and de-energized. On Unit 2 the BIT itself was not installed but the terminology was carried over to maintain consistency in nomenclature. These penetrations serve the High Head Safety Injection System (HHSI) for injection of high pressure (about 2300 psig), cool, borated water into the RCS.

16-40 SAFETY INJECTION COLD LEG PENETRATIONS:

These penetrations serve to inject cool, borated water into ALL loop cold legs for emergency core cooling in accident conditions. The injection water comes from THREE sources:

NOTE: The SIS penetrations are actually in the Accumulator penetrations on all cold legs. This limits the number RCS penetrations.

1. Safety Injection System - This system takes suction on the RWST with two Intermediate Head Safety Injection Pumps and injects this cool, borated water into the RCS at about 1500 psig.

2. Accumulators - This system consists of 4 passive accumulator tanks pressurized with nitrogen to about 650 psig. When the RCS pressure falls below 650 psig, these accumulators will discharge cool, borated water into the RCS.

3. Residual Heat Removal System - This system takes suction on the RWST with two Low Head RHR pumps and injects cool, borated water into the RCS at about 150 psig.

16-41 SAFETY INJECTION HOT LEG PENETRATIONS:

These penetrations serve to inject coolant into ALL hot legs during the hot leg injection phase of emergency core cooling under accident conditions. This "reverse flow" cooling is necessary following an accident to preclude boron plating on the upper vessel internals.

NOTE: The SIS penetrations are actually in the RHR penetrations on Loops 1 and 4 Hot Legs.

1. RHR In the hot leg injection phase of emergency core cooling following an accident, these penetrations serve to inject coolant into Loops 1 and 4 Hot Legs for the same purpose, and uses the same piping as the SIS penetrations.

2. Safety Injection System – intermediate head safety inject into all 4 hot legs.

16-42 CVCS NORMAL CHARGING

This penetration serves to inject borated water into RCS loop 1 cold leg from the Chemical and Volume Control System under normal operating conditions to maintain RCS inventory.

16-43 ALTERNATE CHARGING

This penetration serves as an alternate flow path for the charging flow. This flow path is used during alternating fuel cycles to equalize piping erosion and thermal and mechanical cycling time, and if the normal charging flow path was inoperable. This penetration is in loop 4 cold leg.

16-44 CVCS LETDOWN

This penetration serves to remove coolant from the RCS for demineralization and possible boron concentration changes by the CVCS. This coolant will normally be re-injected into the RCS via the normal charging penetration. This penetration is on loop 3 cold leg.

16-45 EXCESS LETDOWN

This penetration serves to supplement the letdown flow capacity to assist in startup operations such as drawing a pressurizer bubble or RCS heat up. This penetration is in loop 4 intermediate leg.

16-46 PRESSURIZER SPRAY

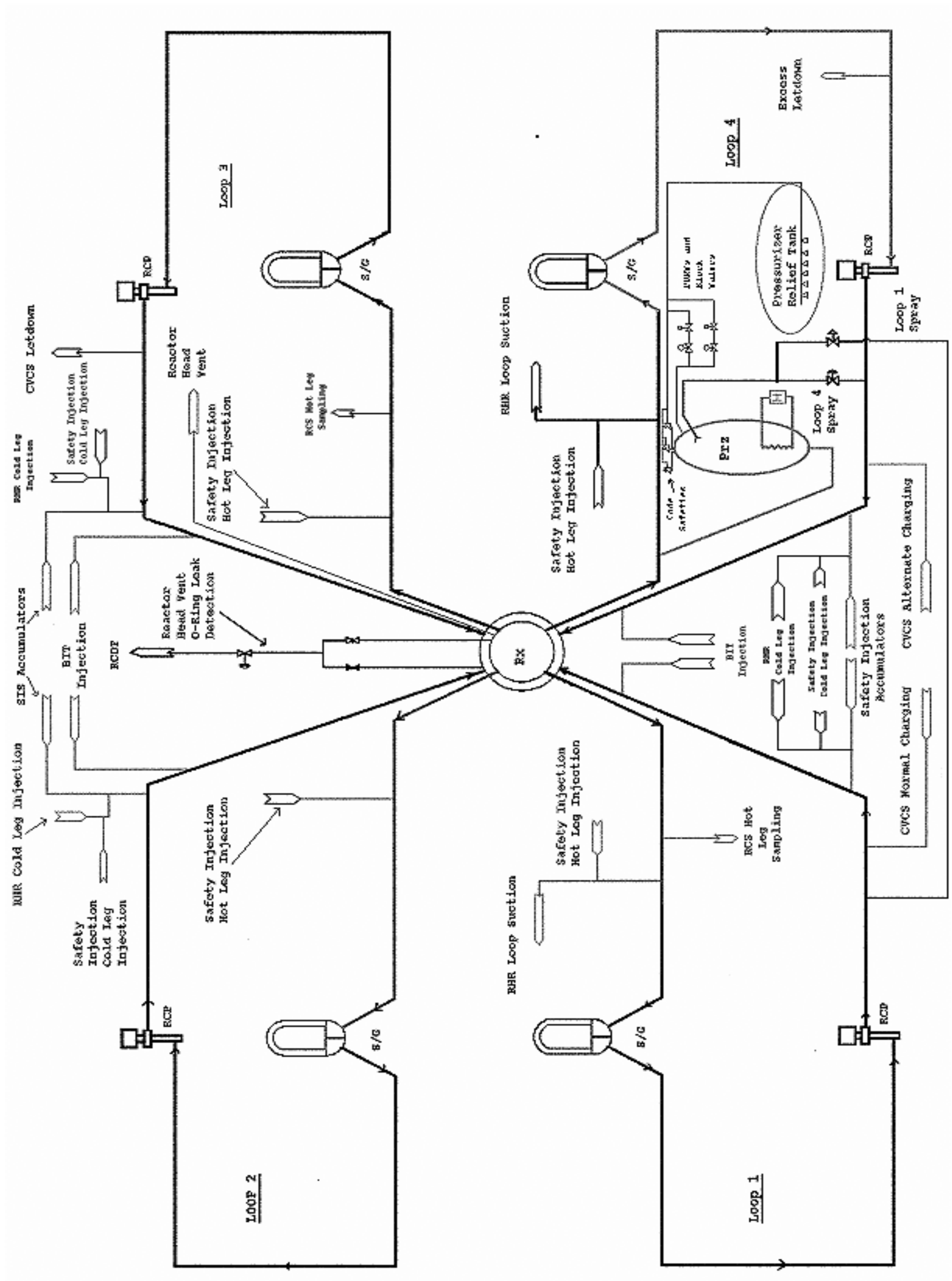
This penetration provides spray water for use in the pressurizer to aid in controlling RCS pressure. The PZR Spray is controlled by the Pressurizer Pressure Control System. These penetrations are on loops 1 and 4 cold legs.

16-47 PRESSURIZER SURGE LINE

This penetration serves to connect the RCS with the Pressurizer. This penetration is in Loop 4 Hot Leg.

16-48 SAMPLING

These penetrations serve to allow sampling of the RCS coolant. These sample lines are in Loops 1 and 3 Hot Legs.



RCS Schematic Drawing

RCS OPERATING PARAMETERS

Pressure

Design: 2485 psig
Normal Operating: 2235 psig
Safety Limit: 2735 psig (see Tech Specs)
Full power delta P across vessel: 45.7 psid

Temperature

Design: 650°F (680°F for pressurizer)
Normal Operating: Tavg ramped from 557°F at 0% power
586.4°F at 100% power

Rated Thermal Power

3565 MWt
RCPs add 18.048 MWt to total heat transferred

Volume

Total: 12,462 ft^3 (includes Pzr and surge line)
Liquid at 100% power: 11,720 ft^3
(includes Pzr liquid)

Flow

384,509 gpm total (Tech Spec value)

TECHNICAL SPECIFICATIONS

LCO 3.4.1 <u>RCS Pressure, Temperature, and Flow DNB Limits</u>

RCS DNB parameters for pressurizer pressure, RCS average temperature, And RCS total flow rate shall be within the limits specified below:

a) Pressurizer pressure ≥ 2199 psig;
b) RCS average temperature ≤ 592.5°F; and
b) RCS total flow rate ≥ 384,509 gpm.

Applicability: Mode 1

Bases: The limits placed on RCS pressure, temperature, and flow rate that the **DNB** design criterion will be met for each of the transients analyzed.

LCO 3.4.2 <u>RCS Minimum Temperature for Criticality</u>

Each RCS loop average temperature (Tavg) shall be ≥ 551°F

Applicability: Mode 1, 2 with Keff ≥ 1.0

Action: Tavg in one or more RCS loops not within limit, be in mode 3 within 30 minutes.

Bases:

(1) Ensures that MTC is within the design analyses,
(2) instrumentation are within their operating envelope,
(3) pressurizer operable with a bubble, and
(4) the reactor vessel is above its minimum nil ductility limit.

LCO 3.4.4 <u>RCS Loops</u>

Four RCS loops shall be OPERABLE and in operation.

Applicability: Modes 1 and 2

Bases: To provide adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the S/Gs.

LCO 3.4.13 <u>RCS Operational Leakage</u>

RCS leakage shall be limited to:

a) No pressure boundary LEAKAGE;
b) 1 gpm unidentified LEAKAGE;
c) 10 gpm identified LEAKAGE;
d) 1 gpm total primary to secondary LEAKAGE through all steam generators (SGs)
e) 500 gpd through any one SG.

APPLICABILITY: Modes 1,2,3,and 4

Bases:

Pressure boundary leakage of any magnitude is unacceptable since it may Be indicative of an impending gross failure of the pressure boundary.

Unidentified leakage limit is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable period of time.

Identified Leakage limit is considered allowable because leakage is From known sources that do not interfere with detection of unidentified Leakage and is well within the capability of the RCS makeup system.

Primary to Secondary leakage through all Steam Generators- This limit produces acceptable offsite doses in the accident analyses involving steam discharge to the atmosphere.

Primary to Secondary leakage through any one S/G- This is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a Main Steam Line Rupture.

Definitions of Operational Leakage

<u>Pressure Boundary Leakage</u>

PB leakage shall be leakage (except steam generator tube leakage) through a non-isolable fault in the Reactor Coolant System component body, pipe wall or vessel wall.

<u>Identified Leakage</u>

a. Leakage (except RCP seal leak off) into closed systems, such as pump seal or valve packing leaks that are captured and conducted to a sump or collecting tank, or

b. Leakage into ctmt. atmos. from sources that are both specifically located and known either not to interface with the operation of leakage detection systems or not to be pressure boundary leakage, or

c. RCS leakage through a Steam generator tube to the secondary.

Unidentified Leakage

All leakage that is not identified leakage.

LCO 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

Leakage from each RCS PIV shall be within limit.

Surveillance Requirement: Verify leakage from each RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.

Applicability: Modes 1,2,3, and 4 except for RHR valves when RHR is in Service.

Bases:

The main purpose of this limit is to prevent over pressurization of low pressure portions of connecting systems. Failure consequences could be a loss of coolant accident outside of containment, unanalyzed accident, that could degrade the ability for low pressure injection.

LCO 3.4.16 RCS Specific Activity

The specific activity of the reactor coolant shall be within Limits.

Applicability: Modes 1,2, and 3 with RCS average temperature ≥500°F.

Bases:

The limits on specified activity ensure that the doses are held To a small fraction of the 10 CFR 100 limits during analyzed transients and accidents.

TRM 13.4.1 RCS Chemistry

RCS chemistry shall be maintained within the limits specified:

	Steady State Limit	**Transient Limit**
Dissolved Oxygen	≤0.10 ppm	≤1.0 ppm
Chloride	≤0.15 ppm	≤1.5 ppm
Fluoride	≤0.15 ppm	≤1.5 ppm

Applicability: At all times, except for dissolved oxygen when Tavg ≤250°F.

Bases:

The limitations on Reactor Coolant System chemistry ensure that Corrosion of the Reactor Coolant System is minimized and reduces the potential for Reactor Coolant System leakage or failure due to stress corrosion.

LCO 2.0 Safety Limits

LCO 2.1.1 Reactor Core Safety Limits

The combination of Thermal Power, Reactor Coolant System highest loop average temperature, and Pressurizer pressure shall not exceed the Safety Limits specified in figure 16-34.

Applicability: Modes 1 and 2

Bases:

The reactor core safety limits ensure that the fuel design limits are exceeded during steady state operation, normal operational transients, and anticipated operational occurrences. This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level that DNB will not occur on the limiting fuel rods and by requiring that the centerline temperature stays below the melting temperature.

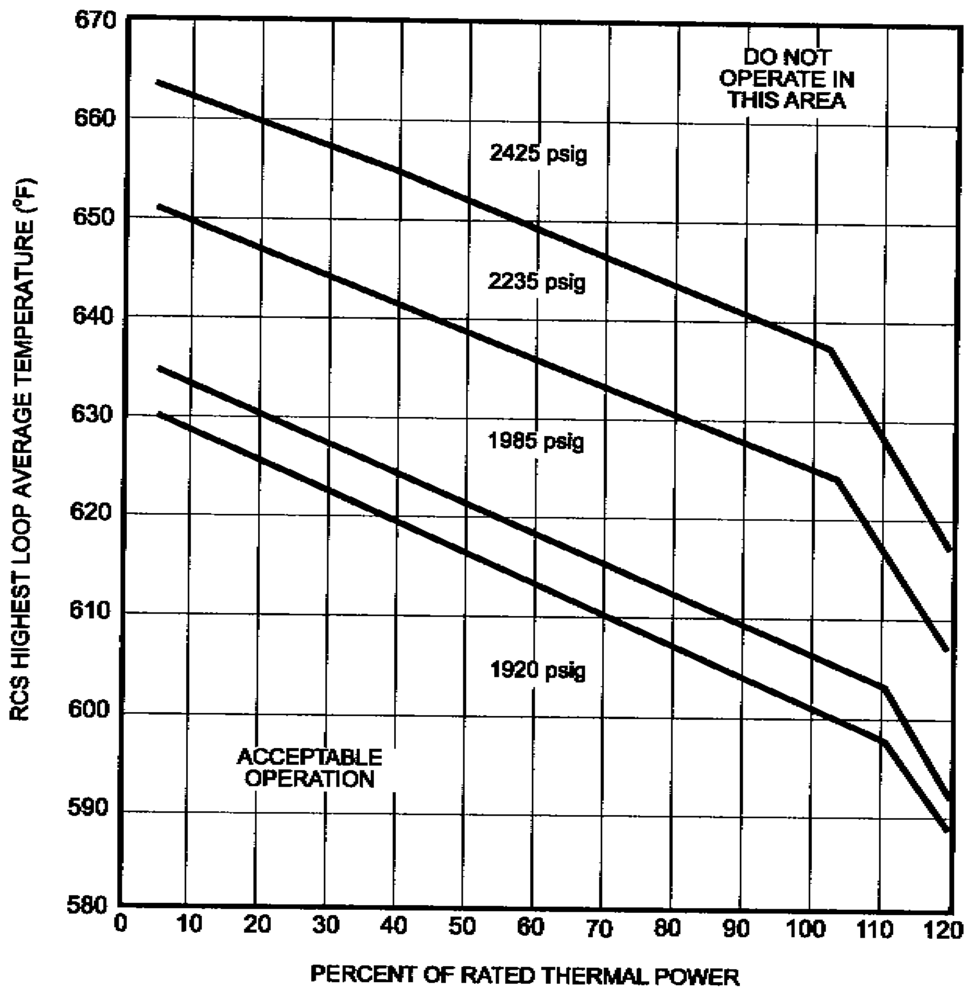
LCO 2.1.2 RCS Pressure Safety Limit

The RCS press shall be maintained ≤ 2735 psig.

Applicability: Modes 1,2,3,4, and 5

Bases:

The reactor coolant system pressure safety limit protects the integrity of the RCS against over pressurization. The design pressure of the RCS is 2500 psia. The safety limit is no more than 10% above the design limit.



REACTOR CORE SAFETY LIMITS VS. BOUNDARY OF PROTECTION

OPERATION EXPERIENCE

REFERENCES

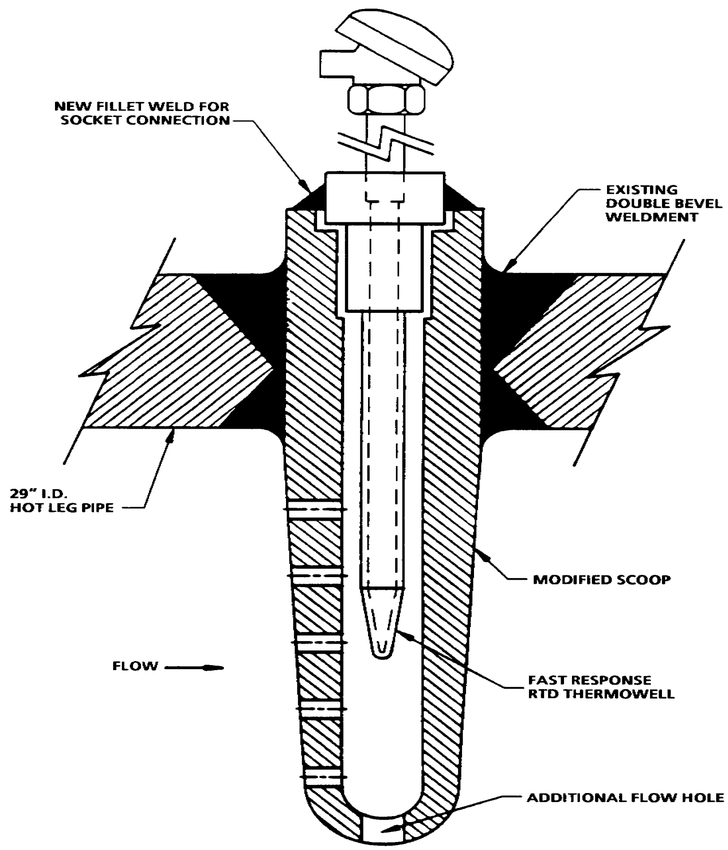
- P&ID 1X4DB111
- P&ID 1X4DB112
- P&ID 1X4DB113
- Heat Balance Drawing 1X4DC103
- FSAR Chapter 5.1, 5.2, and 5.3
- Technical Specifications
- Technical Requirement Manual

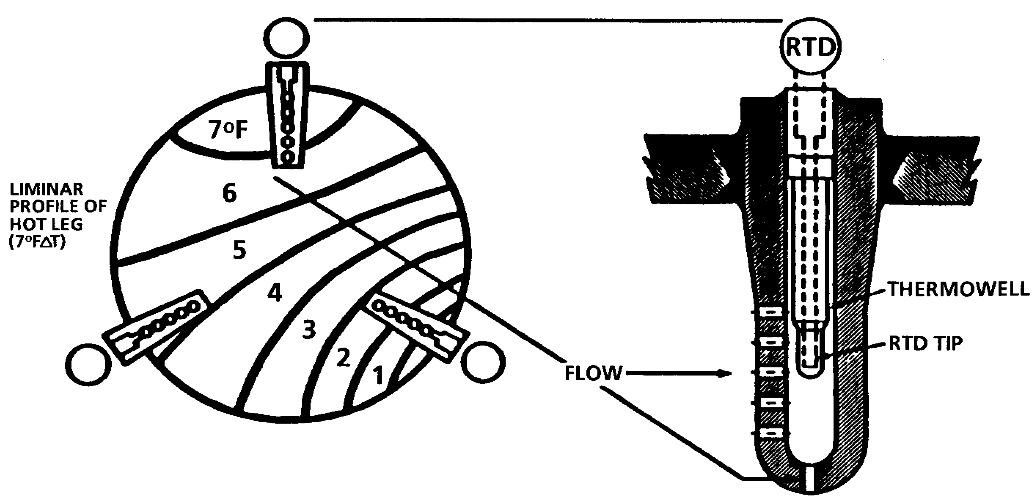
SECTION F

RCS TEMPERATURE INSTRUMENTATION

16.49 NARROW RANGE TEMPERATURE ELEMENTS

The temperature of the coolant exiting the vessel is measured in the hot legs. The temperature of the coolant (T_{hot}) is determined by the use of Fast Response Resistance Temperature Detectors (RTDs) located in wet thermowells in the hot legs. There are three thermowells, 120 degrees apart, on each hot leg. The figure below demonstrates the arrangement of the thermowells that account for the thermal stratification of the coolant in the hot leg. The three outputs are averaged together for a T_{hot} temperature. The temperature of the coolant entering the vessel is measured in the cold legs. Fast Response RTDs located in wet thermowells are also utilized to measure the temperature of the coolant in the cold legs (T_{cold}). However, due to the turbulent condition of the coolant after being discharged from the RCPs, only one thermowell is utilized in each cold leg. Turbulence created by the RCPs breaks up the laminar profile of the coolant, thereby providing adequate mixing of the coolant.





They are actually two RTDs located in each thermowell. One of the two RTDs is an installed spare that can be placed in service by I&C without having to enter containment.

16.50 Loop Average Temperature

Loop Average Temperature known as Tavg is calculated by the following:

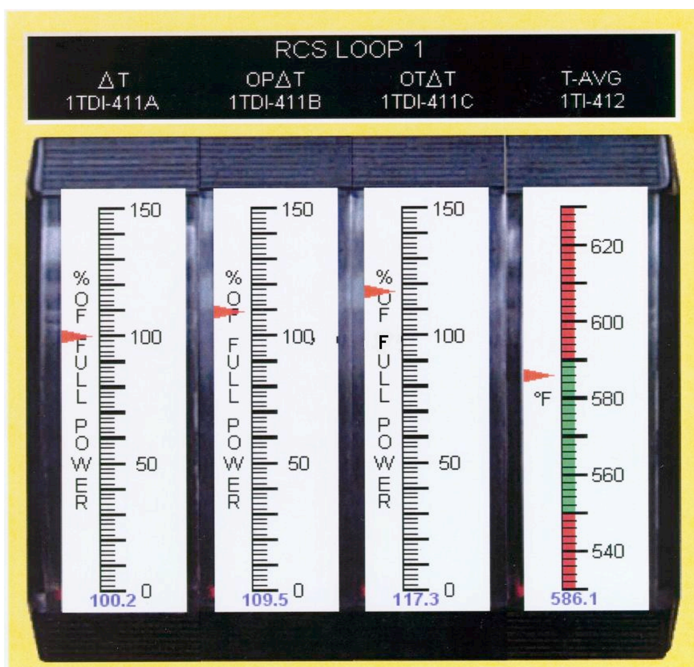
$$\mathbf{Tavg = \frac{Thot+Tcold}{2}} \qquad \mathbf{586.4°F = \frac{615.8°F + 557°F}{2}}$$

This calculation is performed on all four loops also known as channels. Each loop or channel instrumentation has its own instrument power supply.

Alpha train instrument power 1/2AY1A for loop 1.
Bravo train instrument power 1/2BY1B for loop 2.
Charlie train instrument power 1/2CY1A for loop 3.
Delta train instrument power 1/2DY1B for loop 4.

The instrument power buses are safety related 120Vac and have battery backup power supply.

The Tavg meters have scales that range from 530°F to 630°F. The loop Tavg indications are located on the “C” panel in the main control room. The instrument tag number for each indicator is TI-412, TI-422, TI-432, and TI-442 for each loop respectively. Tavg also is indicated on the Integrated Plant Computer (IPC) which can be displayed on any terminal in the control room.



From 0% (no load) to 100% (full load) power, Tavg ranges from 557°F to 586.4°F. This ramped Tavg is called “Program Tavg.” “Program Tavg” is ramped to ensure high quality steam is produced thus preventing turbine blade erosion. The “Program Tavg” computer gets its input from “Turbine impulse pressure.” Turbine impulse pressure” also known as “1st stage pressure” (PT-505) is correlated as turbine power. The Indicated turbine power is input into the Tavg program computer. From this the computer calculates the “Reference Temperature” (Tref).

Different control systems received input from Auctioneer High Tavg. Auctioneer high circuit is the highest loop Tavg. The control systems are Rod Control, Pressurizer level control, and Steam Dump control.

16.51 Loop Differential Temperature

One of the three ways that reactor power can be measured is Loop Delta T (ΔT). Loop ΔT is the difference between T_{hot} and T_{cold}. This difference at 100% power is approximately 59°F. With Tavg being maintained on program T_{cold} will remain at 557°F from 0 to 100% power. Only T_{hot} will vary. This holds true only if Tavg is on program. Loop ΔT is indicative of the amount of heat transferred across the core and is a direct correlation of reactor power. In the formula below **Q** is the heat transfer rate or reactor power. Any change in T_{hot} or T_{cold} can only be the result of a changes in reactor power.

$$\mathbf{Q = mCp(Thot\text{-}Tcold)}$$

An example of why Tavg cannot be used as an indication of power. Assume due to Feed water transient which causes T_{cold} to drop from 557°F to 553°F. Tavg would actually lower from 586.4°F to 584.4°F which would appear that reactor power had lowered slightly. Using the formula above would prove otherwise.

615.8°F - 557°F = 58.8°F = <u>100% ΔT</u>

615.8°F - 553°F = 62.8°F = <u>106.8% ΔT</u>

As you can see actual reactor power increased substantially to unacceptable level, which could not be directly measured by Tavg. The example maybe exaggerated slightly but the point can still be made.

The loop ΔT meters have scales that range from 0% to 150% power. The instrument tag numbers are as follows TDI-411A, TDI-421A, TDI-431A, and TDI-441A for each loop respectively. Indicators are located on the “C” panel in the control room. Loop ΔT also can be retrieved from the IPC.

16.52 Temperature Instrument Failures

Narrow range temperature instrument failures cannot be directly identified from the control board indicators. However, the symptoms can be diagnosed to determine which instrument has failed. Narrow range T_{hot} and T_{cold} are not displayed any where on the control boards or on the IPC. I&C can determine from readings taking from the individual temperature transmitter, the failed instrument. In the examples below, an operator can determine if the failure was a T_{hot} or T_{cold} failure and which loop is affected.

DIAGNOSTIC TOOL

	Tavg	**ΔT**
NR T_{hot} fails high	Hi	Hi
NR T_{hot} fails low	Lo	Lo
NR T_{cold} fails high	Hi	Lo
NR T_{cold} fails low	Lo	Hi

Keep in mind that a single failure of hot leg RTD will not be automatically removed from the calculated T_{hot}. So, T_{hot} output should not fail off scale in any direction unless its instrument power is lost.

EXAMPLE #1

Unit 1 was at 100% power at normal operating temperature and pressure with control systems in auto. During the operator shift relief, several alarms were received. The operator observed the following:

Loop 1	**Tavg = 586.5°F**	**ΔT = 100%**
Loop 2	**Tavg = 586.0°F**	**ΔT = 99%**
Loop 3	**Tavg = 571.0°F**	**ΔT = 52.5%**
Loop 4	**Tavg = 586.5°F**	**ΔT = 101%**

In Loops 1, 2, and 4 Tavg and ΔT appear to be normal. It is easy to determine which loop has an instrument problem. There is a distinct difference between Loop 3 and the other temperature instruments. Using the diagnostic tool above you can determine the instrument that has failed. Since Loop 3 Tavg has failed low we know that either T_{hot} or T_{cold} has failed low. The ΔT indication is low also. Loop 3 ΔT indicating low can only be from either T_{hot} failing low or T_{cold} failing high. So, what is common about the two instrument indications?

Answer: Loop 3 T_{hot} failed low.

EXAMPLE #2

Unit 1 was at 100% power at normal operating temperature and pressure with control systems in auto. During the operator shift relief, several alarms were received with rod control automatically inserting rods at 72 steps per minute. The operator observed the following:

Loop 1	**Tavg = 586.5°F**	**ΔT = 100%**
Loop 2	**Tavg = 591.0°F**	**ΔT = 120%**
Loop 3	**Tavg = 586.0°F**	**ΔT = 99%**
Loop 4	**Tavg = 586.5°F**	**ΔT = 101%**

In Loops 1,3, and 4 Tavg and ΔT appear to be normal. It is easy to determine which loop has an instrument problem. There is a distinct difference between Loop 2 and the other temperature instruments. Using the diagnostic tool above you can determine the instrument that has failed. Since Loop 2 Tavg has failed high we know that either T_{hot} or T_{cold} has failed high. The ΔT indication is high also. Loop 2 ΔT indicating high can only be from either T_{hot} failing high or T_{cold} failing low. So, what is common about the two instrument indications?

Answer: Loop 2 T_{hot} failed high.

16-53 Protection / Control

Protection Circuits that take input from narrow range temperature instruments:

Over Temperature Differential Temperature (OTΔT) compares actual Tavg to full-load Tavg. If Tavg increases above the full load Tavg, the set point will be reduced. This set point is compared to its actual loop ΔT. If the set point gets within 3% of its ΔT on 2 out of 4 loops a "**C-3 OTΔT rod stop and turbine runback**" will occur. If the set point continues to lower to its actual ΔT power level on 2 out of four loops, a reactor trip will be generated. OTΔT circuit protects the RCS from Departure from Nucleate Boiling (DNB). OTΔT circuit has two other inputs that affect its set point which are Pressurizer pressure and Power range Δ flux. OTΔT set point at low power levels can be as high as 121.6% on U-1 and 118.7% on U-2, but at 100% rated power the set point drops to 119.4% on U-1 and 116.5% on U-2%. The OTΔT set point increases as the plant is cooled down due to the Tavg input lower. This temperature reward is limited or clamped at 585.4°F.
Over Power Differential Temperature (OPΔT) also compares actual Tavg to full-load Tavg. If Tavg increases above full-load Tavg, OPΔT set point lowers from its normal set point of 110%. This set point is compared to its actual loop ΔT. If the set point gets within 3% of its ΔT on 2 out of 4 loops a "**C-4 OPΔT rod stop and turbine runback"** will occur. If the set point continues to lower to its actual ΔT power level on 2 out of four loops, a reactor trip will be generated. This circuit is very similar to OTΔT but for different reasons. OPΔT circuit protects the Fuel from

being damaged due to overpower, based on KW/ft being produced. Its set point is capped at 108.9% in which Tavg is its only input to penalize.

"P-12 Low Low Tavg Steam Dump Interlock" occurs when 2 out 4 Tavg loops drop to **550°F.** This interlock protects the RCS from a cool down accident by preventing the steam dumps from opening. This interlock can be bypassed to allow normal cool down of the plant.

"Low Tavg FWI" occurs when 2 out of 4 Tavg loops drop to **564°F in conjunction with P-4 (Rx Trip).** The Feed Water Isolation protects the RCS from a cool down accident due to over feeding the Steam Generators.

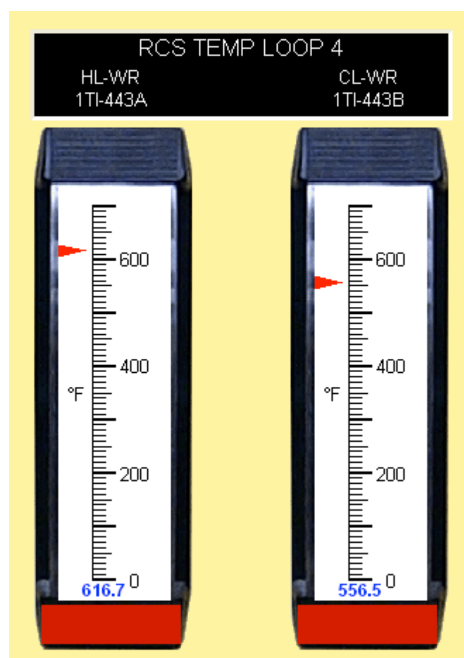
Control Circuits that take input from Narrow Range Temperature Instruments:

Auctioneered high Tavg circuitry compares Tavg values from each of the four RCS loops. The most limiting value from the loops (highest Tavg) is selected for conservatism in calculating control set points. Control Systems that utilize Auctioneer High Tavg are as follows:

1. Rod Control System
2. Pressurizer Level Control
3. Steam Dump System

Auctioneered Low Tavg circuitry compares Tavg from, all loops (lowest Tavg) is selected for conservatism in calculating actuation/control set points. Two things receive input from Auctioneered Low Tavg is:

1."**C-16 Low Tavg Turbine Stop Loading" Tavg ≤ 553°F or Tavg ≥ 20°F below Tref.** Protects the RCS from cooling down below the minimum temperature for criticality. This interlock prevents the Main Turbine load increase which can be bypassed for testing purposes only.



2. Tavg/Tref deviation meter (TI-412A) on "C" panel in the control room.

Auctioneered High ΔT provides input for the Rod Insertion Limit (RIL) computer which generates an alarm set point based on power level and rod height.

Both loop ΔT and Tavg inputs into control circuits can be defeated by the operator at the control panel if Narrow Range temperature instrument is to be removed from service.

Tavg defeat switch TS-412T is located on the "C" panel in the control room. It allows input from a single Tavg channel to be defeated from various control circuits. (1)Defeats input into auctioneer low Tavg calculation such as C-16 and the Tavg / Tref deviation meter, and (2) defeats selected channel input into auctioneered high Tavg output circuitry for rod control, steam dump control, pressurizer level control, Tavg / Tref Deviation alarm, and Auctioneer Tavg Hi alarm.

ΔT defeat switch TS-411T is located on the “C” panel in the control room. It allows defeat of a single ΔT channel into auctioneered high ΔT calculation. Defeats input into Rod insertion limit computer.

16-54 RCS WIDE RANGE TEMPERATURE INSTRUMENTATION

RCS wide range temperature transmitters measure both the hot and cold legs of the RCS just like the narrow range instruments. The differences in the two are: (1) only one RTD per leg, (2) the thermowells are dry (RTDs do not contact the fluid), (3) they are scaled from 0°F to 700°F, (4) there is no installed spare RTD, (5) located both in control room and Remote Shutdown Panels, and (6) they are rated as part of the Post Accident Monitoring System (PAMS). PAMS instruments are designed to withstand the harsh environment caused by any design based accident. All PAMS instruments can be identified by the red stripe on the bottom bezel of the instrument. (See Figure 16-38 RCS LOOP 4 WIDE RANGE TEMPERATURE INSTRUMENTS)

During the loss of force flow (Natural Circulation) both narrow and wide range instruments respond nearly the same until Tavg drops below the narrow scale of 530°F. Dry thermowells are slightly slower than the wet well type but due to the loop transit time being lower during natural circ conditions this is not a factor.

The only system that the wide temperature instruments provide input to is the “Cold Over pressure Protection System (COPS)”. Wide range T_{hot} is used by alpha train COPS and wide range T_{cold} is used by bravo train.

Technical Specifications

LCO 3.3.1 Function 6 <u>Over Temperature ΔT (Reactor Trip)</u>

4 channels are required to be operable.

Applicability: Modes 1 and 2

Bases:

OTΔT trip function is provided to ensure that the design limit DNBR is met.

LCO 3.3.1 Function 7 <u>Over Power ΔT (Reactor Trip)</u>

4 channels are required to be operable.

Applicability: Modes 1 and 2

Bases:

The OPΔT trip function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded under all overpower conditions.

LCO 3.3.2 Function 5b <u>Low RCS Tavg with P-4 FWI (EFAS)</u>

4 channels are required to be operable.

Applicability: Modes 1 and 2 except when one MFIV or MFRV, and its associated bypass valve per feed water line is closed and deactivated or isolated by a closed manual valve.

Bases:

The Low RCS Tavg signal is interlock with P-4 to avert of reduce the continued cool down of the RCS following a reactor trip. An excessive cool down of the RCS following a reactor trip could cause an insertion of positive reactivity that could cause a return to criticality.

LCO 3.3.3 Function 2 <u>RCS T_{hot} (wide range) (PAMS)</u>

1 channel per loop is required to be operable.

Applicability: Modes 1, 2, and 3

Bases:

RCS hot and cold temperatures are used to determine RCS subcooling margin. RCS subcooling margin will allow

LCO 3.3.3 Function 3 <u>RCS T_{cold} (wide range) (PAMS)</u>

1 channel per loop is required to be operable.

Applicability: Modes 1, 2, and 3

Bases:

RCS hot and cold temperatures are used to determine RCS subcooling margin. RCS subcooling margin will allow

LCO 3.3.4 Function 3 <u>RCS T_{cold} (wide range) (Remote Shutdown System)</u>

1 channel per loop is required to be operable

Applicability: Modes 1, 2, and 3

Bases:

The Remote Shutdown System provides the operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room.

LCO 3.3.4 Function 4 RCS T_{hot} (wide range) (Remote Shutdown System)

2 channels are required to be operable.

Applicability: Modes 1, 2, and 3

Bases:

The Remote Shutdown System provides the operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room.

REFERENCES

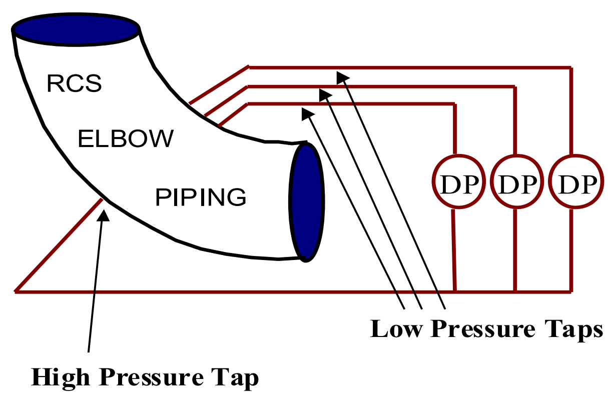
- P&ID 1X4DB111
- P&ID 1X4DB113
- FSAR Chapter 7
- Technical Specifications

SECTION G

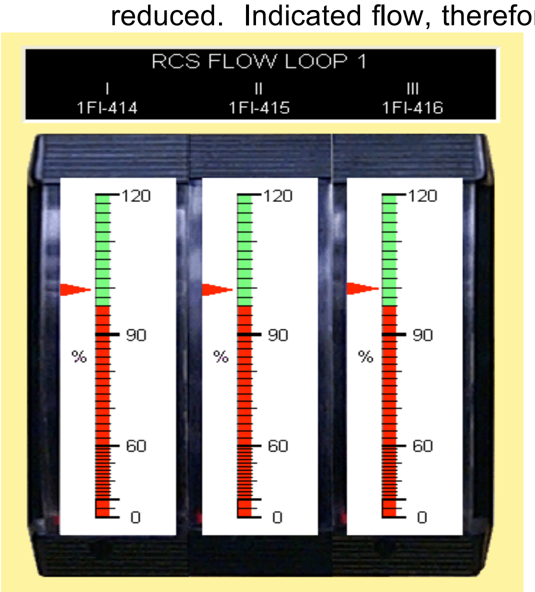
RCS FLOW MEASURING INSTRUMENTS

16-55 <u>RCS Loop Flow Instrumentation</u>

RCS flow is a measure of the differential pressure across the RCS loop elbows which are located between the RCPs and the steam generators. A tap off of the outer radius of the elbow provides high side RCS pressure to the three ΔP flow transmitters. Three taps off of the inner radius of the elbow provide low side RCS pressure to the three ΔP transmitters.



In theory, it would be desirable to have only one tap off of the high side and the low side thereby limiting the number of RCS penetrations. The reason for the actual piping arrangement is to ensure that, in the event of a single failure of the instrument sensing lines, RCS flow will fail or be inaccurate in a conservative direction. For example, if a leak develops on the high side pressure tap, the high side pressure that the transmitter senses will be reduced causing the differential pressure to be reduced. Indicated flow, therefore, will also be reduced. If there was only one tap on the low side, a low side failure would result in a failure of RCS flow in the non-conservative direction (i.e. all three flow indications would increase). With three low side taps, a single failure of one tap will cause only the associated transmitter to fail high; the other two transmitters will be available to trip the reactor as required.



The calculated RCS loop flows provide input to the Reactor Protection System to protect the reactor core from a loss of flow. A reactor trip will be initiated for the following conditions:

* Above P-7 (10% power), 2/3 flow transmitters indicate less than 90% flow in any 2 loops
* Above P-8 (48% power), 2/3 flow transmitters indicate less than 90% flow in any 1 loop

The “C” panel in the control room has a total of 12 RCS loop flow indicators, 3 per loop. The flow indicators are logarithmic scaled and range from 0% to 120%.

TECHNICAL SPECIFICATIONS

LCO 3.3.1 Function 10a. Reactor Coolant Low Flow Single Loop (Rx Trip)

3 channels per loop are required to be operable.

Applicability: Mode 1 above P-8 interlock (48% power)

Bases:

In mode 1 above the P-8 set point, a loss of flow in one RCS loop could result in DNB conditions in the core. This reactor trip is design to prevent this from occurring.

LCO 3.3.1 Function 10b. Reactor Coolant Low Flow Two Loops (Rx Trip)

3 channels per loop are required to be operable.

Applicability: Mode 1 above P-7 interlock (10% power)

Bases:

The Reactor Coolant Low Flow (two loops) trip function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS loops. Below the P-7 interlock all reactor trips on low flow are automatically blocked because power is not high enough to cause a DNB concern.

OPERATING EXPERIENCE

REFERENCES

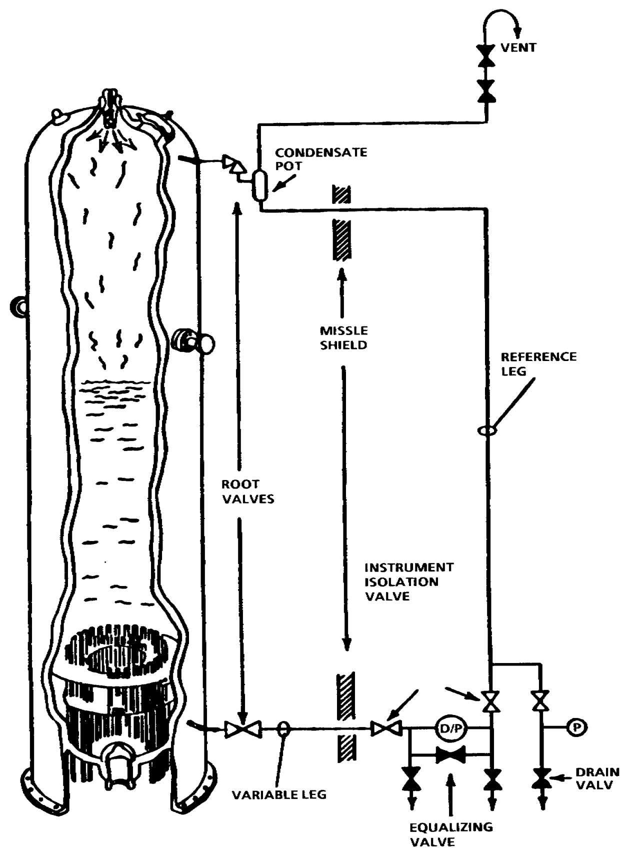
- P&ID 1X4DB111
- FSAR Chapter 7
- Technical Specification

SECTION H

PRESSURIZER LEVEL CONTROL

16-56 <u>CONTROL FUNCTIONS AND INTERLOCKS</u>

The function of the Pressurizer Level Control System is to maintain a constant mass in the RCS for all operating conditions (Tavg 557°F to 586.4°F). Since the volume of coolant increases as Tavg increases, the programmed level set point rises from 25% at no load Tavg of 557°F, to 60% for Tavg of 588.4°F. Since program level is based on Auctioneer high Tavg, at 100% power, program level is set to 57.8%, due to full load Tavg being 586.4°F. The Pressurizer Level Protection System protects the pressurizer from becoming water solid or from completely draining during plant operation.



16-57 <u>Pressurizer Level Instrumentation</u>

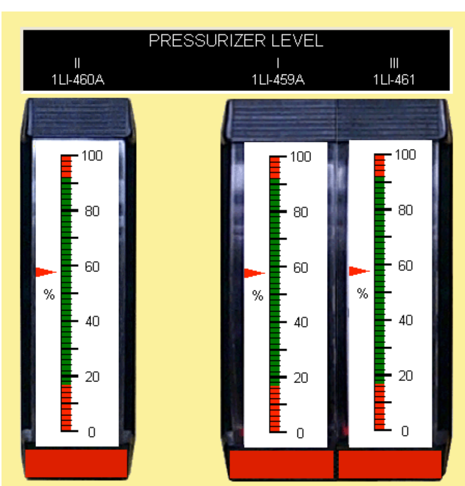
The Pressurizer System uses four differential pressure (ΔP) transmitters to sense water level in the pressurizer. The transmitters send a level signal to control room indicators, alarms, and protection and control circuits. All four pressurizer level detectors use the same principle of operation.

Each level instrument is made up of a closed reference leg, a differential pressure (ΔP) transmitter, and a condensing pot. The ΔP transmitter compares water level pressure of the reference leg to the water level pressure in the pressurizer. The condensing pot is located on top of the reference leg and acts as a collection point for condensation. The condensing pot, which is located on the top of the reference leg, ensures that under normal steady state conditions the reference leg remains full of water in order to correctly indicate pressurizer level. The steam from the pressurizer enters the reference leg condensing pot. The condensing pot is not insulated which causes the steam to condense when cooled by containment ambient temperature. The condensate pot also seals the reference leg from the hydrogen gas in the pressurizer vapor space which might give erroneous level indications if allowed to mix with the water in the reference leg. To minimize the penetrations made in the pressurizer, the reference legs are shared by other instruments. Unwanted actuations could occur if proper planning is not performed before draining the common reference legs. (Reference drawing 1X4DB112)

During normal operation and when the plant is in hot standby condition, Level Transmitters LT-459, LT-460 and LT-461 are used to provide pressurizer level information. These three instruments are known as “hot calibrated instruments”. These transmitters are calibrated for the normal operational conditions and take into consideration the fact that the reference leg water temperature is close to the containment ambient temperature of 90°F, and the pressurizer liquid temperature of 653°F. These temperatures produce a relatively constant difference in density, and therefore different head pressures felt by the detectors. As the plant is cooled down, however, the level indicated by these instruments becomes less accurate and appears to be higher than the actual level. Level Transmitter LT-462 is calibrated for cold plant conditions and is used when heating up or cooling down the plant. Unlike the hot calibrated level instruments, the cold calibrated level instrument is calibrated assuming that the water in the pressurizer is at a lower temperature and more dense. When the water is cooler, it exerts more force (pressure) on the level transmitter than an equal level of water in the pressurizer under high temperature conditions.

It is important to understand the principles of operation and the limitations of these levels transmitters.

ΔP type level transmitters that are calibrated for normal operating conditions may be inaccurate under abnormal conditions such as a LOCA or steam line break in the containment. Specifically, the reference leg piping and condensing pots are exposed to the containment atmosphere. At elevated containment temperatures, the reference leg pipe and the water it contains will heat up, decreasing the density of the reference leg. This causes the indicated level to be greater than the actual level. As the reference leg is heated up, the volume of the water in the reference leg increases and forces some of the liquid from the reference leg. The pressure that the reference exerts on the level transmitter is less than the pressure that the water exerted prior to being heated up. The result is an indicated change in level (increase) although the actual level may not have changed. The severity of the error will depend on the actual containment conditions. Redundant level channels of the pressurizer may uniformly present inaccurate indications and, under such conditions, must be considered unreliable. Other conditions that may affect pressurizer level indication are reference leg leaks or partial draining due to instrument calibration or other maintenance activities, and a phenomena caused by hydrogen gas coming out of solution in the reference leg. Since the reference leg temperature is cooler than the pressurizer, it has a higher affinity for absorbing hydrogen gas. The hydrogen gas could come out of solution during transients. The results from all of the above mention would be reduction in the ΔP. This reduction in ΔP would cause the pressurizer level indication being higher than actual.



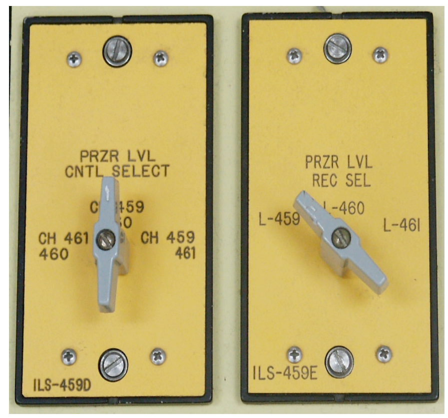
16-58 <u>Pressurizer Level Control System</u>

The Pressurizer Level Control System utilizes three hot calibrated level channels (LT-459, LT-460, and LT-461) for control. Two of these channels are selected at any given time by a three-position selector switch (LS-459D). The possible combinations are: Channels LT-459 and LT-460, Channels LT-461 and LT-460, or Channels

LT-459 and LT-461. Only channels LT-459 and LT-461 can be selected for primary level control and only channels LT-460 and LT-461 can be selected for secondary control. The pressurizer level control uses the primary channel input to compare its value to the calculated level set point to control pressurizer level. The secondary channel is used for protection only. A three-position recorder selector switch (LS-459E) is provided to select the actual level to be recorded along with the program level on LR-459.

The reference level signal is generated by auctioneered high Tavg (No-load Tavg 557°F, to 100% Full Power Tavg of 586.4°F) which generates a program level of 25% to 57.8%, which corresponds to the difference between No-load Tavg and full load Tavg. The program level is compared to one of the selected level channels, LT459 or LT461, to produce a level error signal.

The level error produced is used as input by the master level controller. The master controller is sensitive to both the magnitude of the difference and the time duration that the difference is present. A large level error will result in a large controller output. The integral portion of the controller will also produce a high output for small errors that are present for long time durations. To change the level in the pressurizer, either the temperature or the mass balance of the RCS must change. The master controller responds to level errors by changing CVCS charging flow.



During steady state operation with no pressurizer level change, CVCS letdown flow is equal to CVCS charging. If charging flow changes and letdown flow remains constant, then the mass balance of the RCS will change. Pressurizer level control operates on this principal. Charging flow is varied by controlling the position of the flow control valve (FCV-121).

The demand signal from the level master controller (LIC-459) is sent to the charging flow controller (FIC-121). The charging flow controller compares demand flow from the pressurizer level master controller with actual flow. If there is a difference between the two, the controller will position FCV-121 accordingly to correct the error. Both controller MANUAL/AUTO stations are located on the “C” panel in the control room.

The Pressurizer Level Control System will automatically isolate CVCS letdown when pressurizer level decreases to 17%. Both letdown isolation valves, LV-459 and LV-460, close as well as the letdown orifice isolation valves. This prevents draining the pressurizer if a leak occurs in CVCS system. Damage would occur if the heaters were energized and not fully immersed in water. Therefore, the level control system also de-energizes the pressurizer heaters when the water level decreases to 17%. This prevents damage to the wall of the pressurizer vessel due to overheating and to the heaters themselves. The heaters would be exposed if the pressurizer level decreased below 14%. (See Pressurizer Level Control Logic Drawing) The pressurizer Level control system is designed to accommodate the following without a reactor trip:

a. Ramp unloading rate of 5% per minute with auto rod control.

b. Instantaneous load reduction of 10% with auto rod control.

c. Step load reduction of 50% with both auto rod control and steam dump control.

Level control selector switch LS-459D

To further explain its operation the following example is given:

Level transmitter 459/460 is selected on LS-459D

LT-459 is selected as the primary channel for the master level control. If the level sensed by LT-459 drops to ≤ 17% it will cause the following to occur:

a. CVCS Charging Flow increases by opening FCV-121

b. All pressurizer heaters will automatically trip.

c. CVCS Letdown Isolation valve LV-459 will automatically close.

d. All three CVCS Letdown Orifice Isolation valves will automatically close.

LT-460 is selected for the secondary channel. If level sensed by LT-460 drops to ≤ 17% it will cause the following to occur:

a. All Pressurizer heaters will automatically trip.

b. CVCS Letdown Isolation valve LV-460 will automatically close.

c. All three CVCS Letdown Orifice Isolation valves will automatically close.

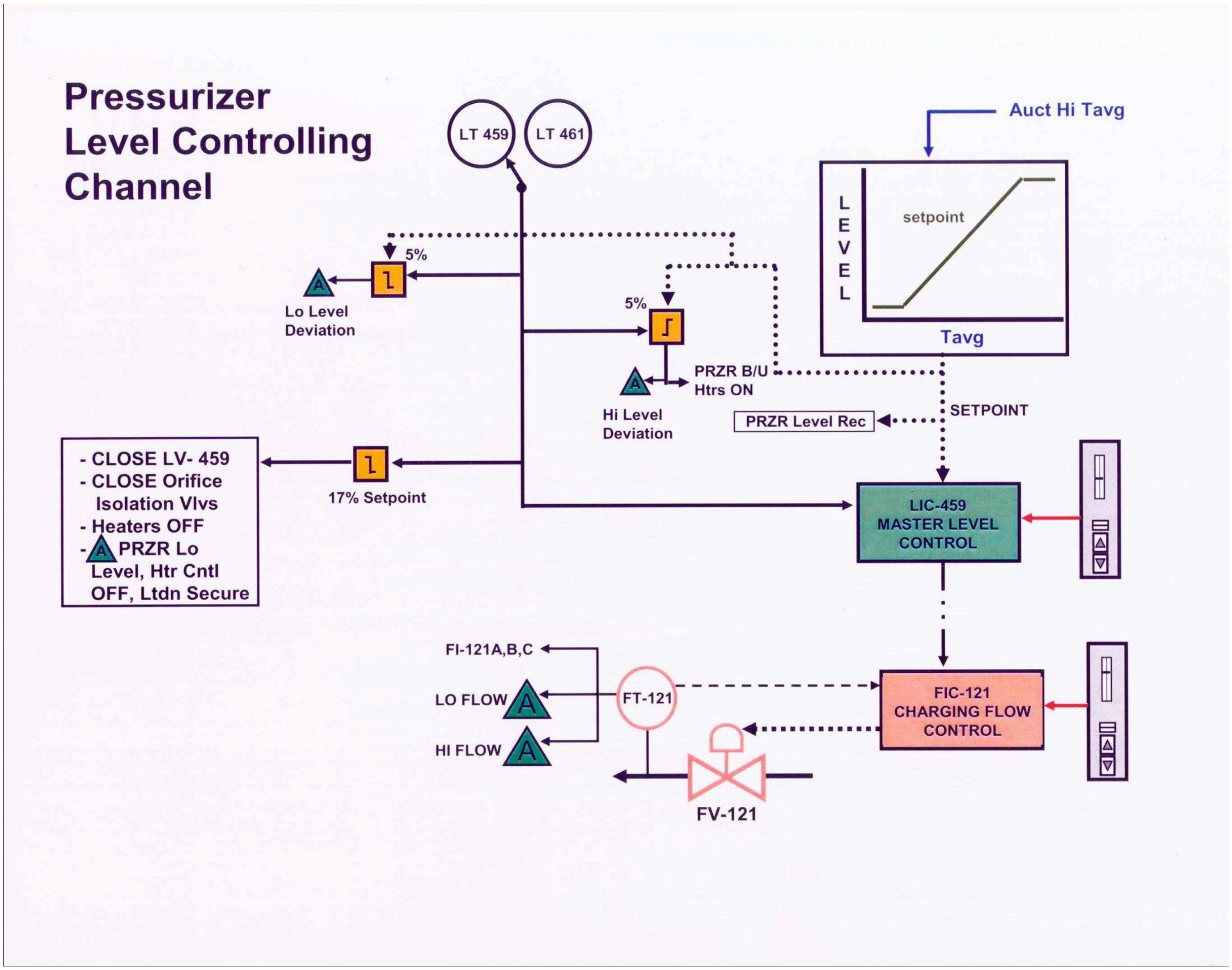
If the primary level control channel sense pressurizer level ≥ 5% above program pressurizer level, a signal is generated that energizes the pressurizer backup heaters. Alarm ALB11-C01 "Przr Hi Level Dev and heaters on" annunciates. The purpose for this design is to heat the in surge of water to saturation in anticipation of a possible sudden out surge to maintain pressurizer pressure. Typical pressurizer temperatures are as follows:

- Pressurizer Surge Line Temperature ~ 645°F
- Pressurizer Liquid Temperature ~ 650°F
- Pressurizer Steam Space Temperature ~ 650-655°F

This example applies to all possible selections on LS-459D.

16-59 Pressurizer Level Protection System

The Pressurizer Level Protection System also utilizes the same level transmitters as the Control System. The level indications provide the information to the Reactor Protection System (RPS). The Reactor Protection System will automatically trip the reactor if the pressurizer level reaches a high level set point of 92% when the reactor is above 10% power. This function however looks at all three level channels and is not based on the switch position of LS-459D. Reactor trip will occur if two out of the three level transmitters are indicating ≥92%. This Reactor trip function protects the RCS from the over pressurization that might occur if the pressurizer were to go water solid (Loss of bubble). When the plant is shut down, the pressurizer is cooled down and is



allowed to go water solid. The high level trip is automatically disabled by the RPS trip permissive P-7, which happens when the reactor power decreases to <10%.

TECHNICAL SPECIFICATIONS

LCO 3.3.1 Function 9 <u>Pressurizer Water High Level (Trip)</u>

3 channels are required to be operable.

Applicability: Mode 1 ≥10% power

Bases:

A reactor trip signal is given prior to the pressurizer going water solid to provide a backup signal for the Pressurizer pressure high trip and also provides protection against water being relief through the pressurizer safety valves.

LCO 3.3.3 Function 6 <u>Pressurizer Level (PAMS)</u>

2 of the 3 channels are required to be operable.

Applicability: Modes 1, 2, and 3

Bases:

Pressurizer level (loops 459,460, and 461) is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition. See Figure 16-42. The red bezel on the bottom of the instruments identifies it as being PAMs qualified.

LCO 3.3.4 Function 8 <u>Pressurizer Level (Remote Shutdown System)</u>

Pressurizer level channels LT-459 and LT-460 must be operable.

Applicability: Modes 1, 2, and 3

Bases:

The Remote Shutdown System provides the operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room.

OPERATING EXPERIENCE

<u>Pressurizer Level control during startups</u>

Pressurizer level control system should be placed in manual control any time transients occur which involve an RCS Temperature change. Since Pressurizer program level is based on Auctioneer High Tavg, any deviation from Tref greater than 62°F could cause unwanted results to occur if level control is left in automatic. These unwanted results include lowering CVCS seal injection flow below minimum, and lowering CVCS charging flow to the point that flashing in the CVCS letdown system could occur. Placing pressurizer level control in manual eliminates many problems that may occur associated with this system. After the transient has been stopped and Tavg is returned back to within 61°F of Tref, minor adjustment can be made to CVCS charging and RCP seal injection flow to return pressurizer level back to program level. Once this has been accomplished pressurizer level control can be returned to automatic.

<u>Using Pressurizer Level Control and CVCS system for rough RCS leak rate calculation</u>

A rough RCS leak rate calculation can be made if RCS temperature is stable. To do the calculation the operator should subtract the CVCS Letdown and Seal return flow rate from the CVCS charging flow rate. The difference will be the leak rate. The calculation is a quick rough estimate because the numbers are obtained from the control board indicators with no correction factors used. The use of surveillance procedure 14905-1/2 should be used for precise measurement as time permits.

REFERENCES

- P&ID 1X4DB112
- P&ID 1X4DB116
- FSAR Chapter 7 and 15 thru admin 16
- Technical Specification
- PTDB
- OSP 14905-1/2
- IEN 84.070
- SER 83.076

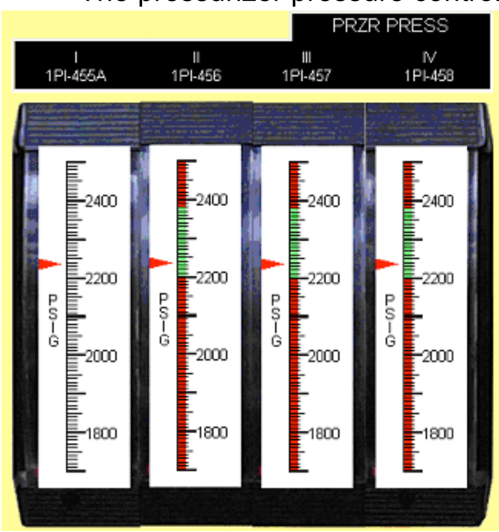
SECTION I

PRESSURIZER PRESSURE CONTROL AND PROTECTION

16-60 Pressurizer Pressure Control System

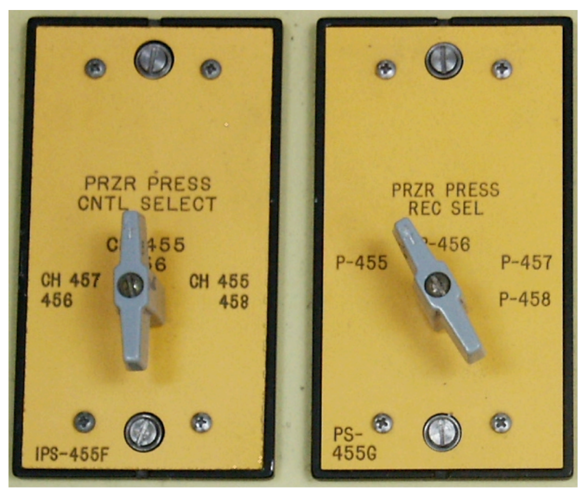
The purpose of the Pressurizer Pressure Control System is to maintain RCS pressure at 2235 psig for normal power operation. This prevents the reactor coolant from boiling in the RCS and limits the transient fluctuations of pressure so that the pressure does not exceed the design limitations of the system. The pressurizer pressure control system is designed to respond to both under pressure and over pressure conditions that may occur.

The pressurizer pressure control system uses four narrow-range pressure channels (PT-455, PT-456, PT-457, and PT-458) for control. The transmitters for these pressure channels use the same reference legs as the level channels.



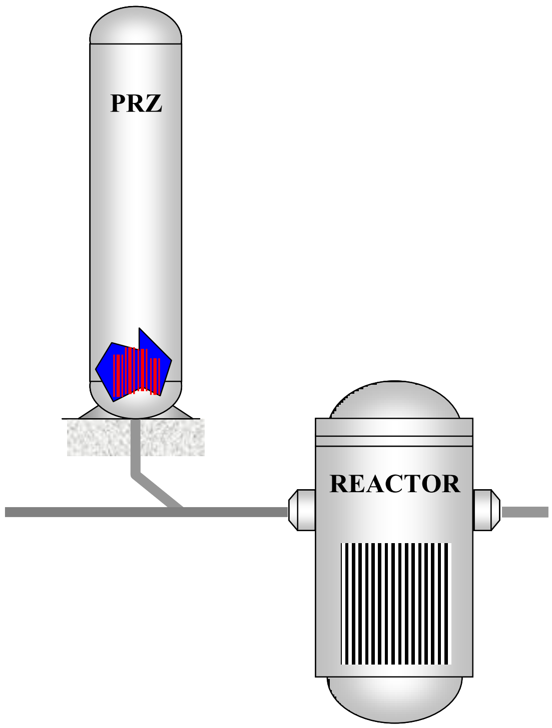
Two channels are selected at any given time using a three-position selector switch (PS-455F). The possible switch selections are as follows:

- channels PT-455 and PT-456 or
- channels PT-457 and PT-456 or
- channels PT-455 and PT-458



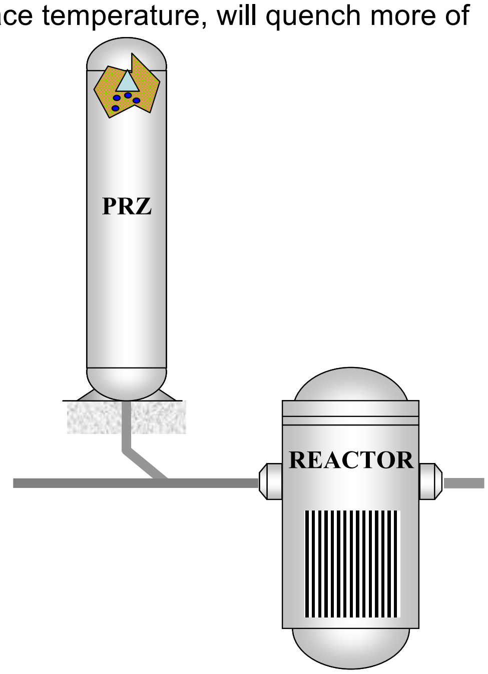
During plant operations, the pressurizer has a mixture of saturated water and steam. Approximately 60% of the total pressurizer volume is water and approximately 40% is steam at 100% reactor power. The pressurizer has heaters with a total heating capacity of 1800 kW. Backup heaters contain 1400 kW of the total capacity while the proportional heaters make up the remaining 400 kW. The backup heaters only have the capability of 0% or 100% output (i.e. on or off). However, the proportional heaters have a variable output range of 0 kW to 400 kW. The heaters are broken up into four groups depending on the power supply for each. They are supplied with 480 volts AC. Groups "A," "B," and "D" are identified as the "backup heaters". Group "C" is the proportional heaters. The backup heaters are used for large pressure changes in the pressurizer.

A decrease in RCS average temperature will result in an out surge from the pressurizer. As the water volume decreases the steam bubble expands to maintain pressure. The control heater



current will increase as pressure decreases to add energy to the water and halt the pressure decrease. If pressure continues to decrease, the larger capacity backup heater banks will energize to add additional energy to the pressurizer water. This increase in energy to a saturated water volume will convert some of the water at the water-steam interface to steam. Remember, the specific volume of saturated steam is greater than that of the same temperature water. Since the steam volume expands faster than the water volume decreases, the net effect is to stop the pressure decrease. The heaters will continue to add energy to the water to return pressurizer pressure to normal conditions. As pressure rises, the backup heaters will turn off. As pressure continues to increase, control heater current will decrease to stabilize pressure at 2235 psig.

In surges into the pressurizer are more complex. An increase in RCS average temperature will cause an insurge into the pressurizer. This insurge will increase the pressure by compressing the steam bubble. This compression will cause some of the steam to condense. Since water has smaller specific volume than steam the pressure increase should be arrested. In addition, as pressure rises above 2235 psig, control group heater current decreases to reduce heat input into the pressurizer water. If the pressure increase continues, spray valves will open to spray cold leg water into the steam volume. This water, almost 100°F cooler than the pressurizer steam space temperature, will quench more of the steam bubble causing its volume to decrease rapidly. Since the steam volume decreases faster than the water volume increases from the insurge, pressurizer pressure will decrease. As pressure decreases, the spray valve will close and control group heater current will increase to stabilize pressure at 2235 psig. On large insurges, the relatively cooler water from the hot leg will decrease the pressurizer water temperature. This will tend to cool the water volume causing it to contract retarding the pressure increase. As the sprays respond to the increase in pressure caused by the insurge, the decrease in steam temperature coupled with the decrease in water temperature can result in pressure decreasing faster than the control and backup heaters can respond to arrest the decrease (there is a significant delay in the heat input from the heaters after they energize). To prevent large pressure decreases from an insurge, the backup heaters will energize if pressurizer level rises significantly.

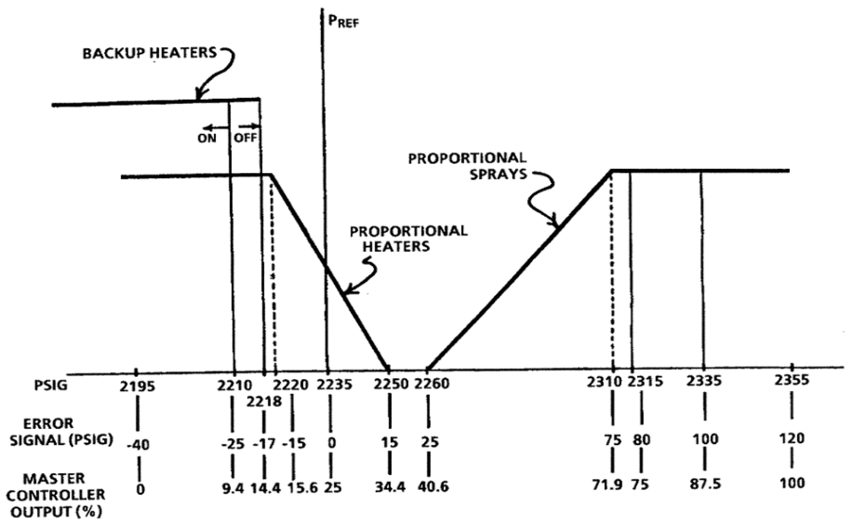


This action, in anticipation of the cool down expected from the insurge, reduces the time to feel the impact of the heaters in effect limiting the size of the pressure reduction.

If the pressure transients exceed the capability of the pressurizer sprays, two power-operated relief valve (PORVs) will open. The PORVs are solenoid piloted steam operated valves that relieve to the PRT.

The pressurizer pressure control uses a master controller that compares actual pressurizer pressure from one of the selected pressure channels to the reference pressure of 2235 psig. If there is a difference, the controller will energize the heaters or open the pressurizer spray. The master controller is a proportional plus integral controller. Because of this, its output is dependent on the magnitude of the difference and the integrated time that the difference is present.

Normally, the master controller has an output of approximately 25%, controlling pressure at 2235 psig. At 25% controller output, the proportional heaters are approximately 50% (200 kW) energized. This is necessary to account for the depressurizing effects from pressurizer bypass spray and ambient heat losses. As pressurizer pressure increases to 2250 psig, control heater power gradually decreases turning the proportional heaters off. As the error increases to 2260 psig, a controller output of 40.6%, pressurizer spray valves begin to open. If pressurizer pressure continues to increase, the spray valves will be fully open at 2310 psig with a controller output of 71.9%. Pressurizer pressure can be lowered manually by depressing the up arrow on PIC-455A (Pressurizer Master Pressure Controller) which will increase the controller output. This produces the same responses as the automatic control.

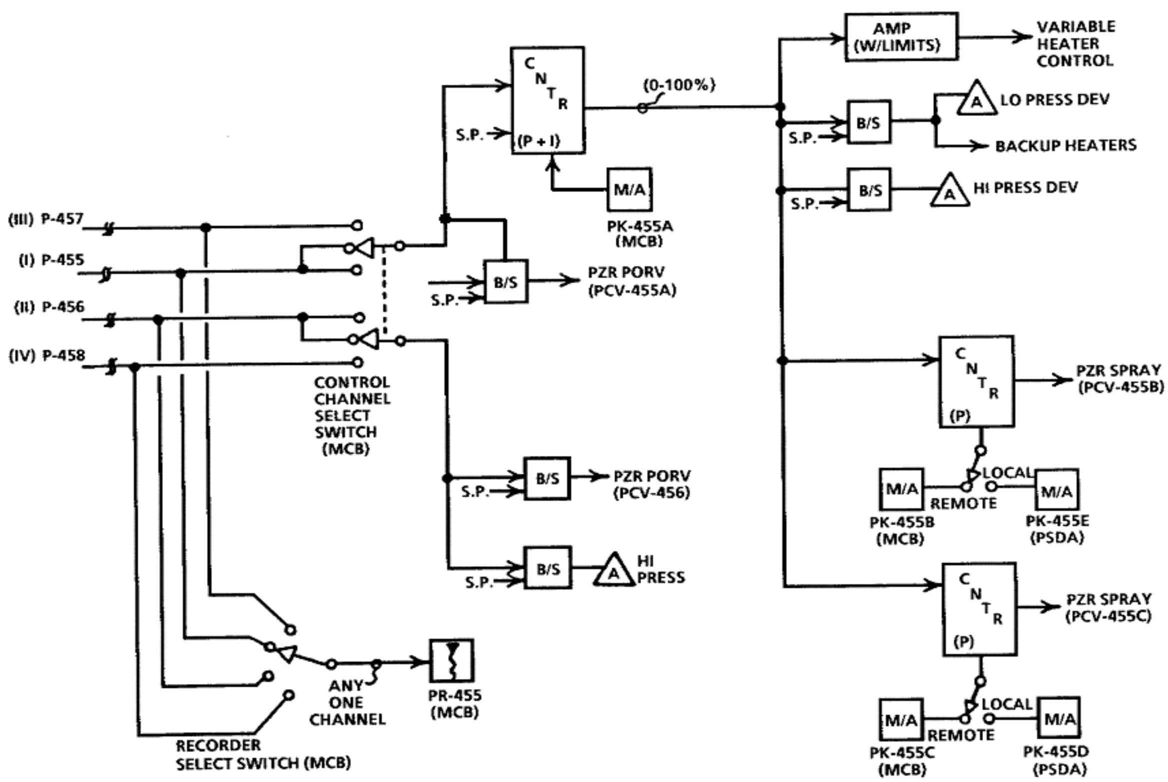


The controller output will decrease as pressurizer pressure decreases. As pressure decreases below 2235 psig, the controller output decreases below 25%. More power is supplied to the proportional heaters until they are fully energized at 2220 psig (controller output at 15.6%). If pressure continues to decrease, the backup heaters will energize at 2210 psig (9.4% output). When pressure returns to 2218 psig (14.4%percent output), the backup heaters de-energize. Pressurizer pressure can be raised manually by depressing the down arrow on 1-PIC-455A (Pressurizer Pressure Controller) to lower the controller output.

It is important to remember that the pressure set points discussed above may not be the exact set points that the respective pressurizer pressure control component will actuate. The integral portion of the master controller will modify the output signal for as the pressure error signal integrates (builds up). As the difference between the set point and actual pressure persists, the output of the controller continues to increase. In anticipation of the possible pressure transient that may occur, the pressurizer pressure controller actuates heaters and sprays before the pressure set points are reached.

Note that PORV PV-455 and PV-456 are not controlled by the master controller. PORV PV-455 responds to the primary pressure channel selected by PS-455F, (either PT-455 or PT-457). PORV PV-455 opens at 2345 psig and closes at 2325 psig. PORV PV-456 uses the secondary channel, (either PT-456 or PT-458) selected by PS-455F. PORV PV-456 opens at 2335 psig and closes at 2315 psig. However, it is important to note that the pressurizer control components will always energize or de-energize at the controller outputs discussed above. The master controller is also selected to control from PT-455 or PT-457 using hand switch PS-455F.

The pressurizer spray valves have separate controllers, one for each valve. These "slave controllers" are a proportional only controller and receive input from the master controller. The MANUAL/AUTO stations are located on the QMCB. Pressurizer Spray Valves can also be controlled from Shutdown Panel “A”.



16-61 Pressurizer Pressure Protection System

The Pressurizer Pressure Protection System is designed to protect the pressurizer and RCS from overpressure and under pressure transients that the Pressurizer Pressure Control System is unable to correct.

The Pressurizer Pressure Protection System uses the same pressure channels as the Pressurizer Pressure Control System but is independent of the PS-455F. Pressurizer pressure information is supplied to the Reactor Protection System (RPS). The RPS will take appropriate safeguard actions to protect the plant when conditions warrant it. The RPS will not, however, take safeguard action based on one pressure channel. At least two channels must supply the same information before the RPS will act.

Pressurizer Pressure Protection System provides the following safeguard actions:

1. Pressurizer High Pressure Reactor Trip - 2/4 channels ≥ 2385 psig.

2. Pressurizer Low Pressure Reactor Trip - 2/4 channels ≤ 1960 psig > P-7 (> 10% power)

3. Pressurizer Low Pressure Safety Injection - 2/4 channels ≤ 1870 psig.

The pressurizer low pressure safety injection signal can be blocked (P-11) to allow for cool down and depressurization following a plant shutdown. This requires manual blocking at the P-11 set point of 2000 psig sensed by 2/3 channels. The permissive is automatically unblocked when pressure increases above 2000 psig and also sends a signal to open the SI accumulator outlet valves.

The pressurizer pressure protection system includes an interlock to close the PORVs and the block valves when 2/4 channels indicate a low pressure ≤ 2185 psig. This prevents depressurization from a failed open PORV.

INDICATIONS AND ALARMS

ALARM	SETPOINT
Przr. Heater Overload Trip (ALB11F03)	Breaker Trip
Przr. Vapor Hi Temp (ALB11E03)	667.5°F
Przr. Liquid High Temp (ALB11E05)	667.5°F
Przr. Surge Line Low Temp. (ALB11E05)	578°F
Przr. Spray Line Low Temp. (ALB11F05)	542°F
Przr. Relief Discharge High Temp (ALB12E01)	192 F
Przr. Safety Relief Discharge High Temp (ALB12F01)	192 F
Przr. Heaters In Local Control (ALB11F04)	CS-LR-Local
Przr. Lo Press SI Alert (ALB11A02)	1870 psig (1/4)
Przr. Lo Press and heaters on	2210 psig (1/2)
Przr. Rel Tank Hi Pressure (ALB12E02)	(8 psig)
Przr. Rel Tank Hi/Low Level (ALB12F02)	High 88% Low 57%
Przr. Rel Tank Hi Temp (ALB12E03)	115 F
Pressurizer Proportional Heater Trouble	Alarm Relay

OPERATIONS

NORMAL OPERATIONS

The normal operation of the Pressurizer System is divided into three conditions.

Routine Operations

RCS average temperature varies with power. These temperature changes cause RCS coolant volume changes which result in surges into and out of the pressurizer.

The Pressurizer System is designed to allow:

* A 10% step plant load increase without uncovering pressurizer heaters.
* A 50% reduction in plant load without the coolant in surge raising the pressurizer water level to the high water level reactor trip set point (92%).
* A complete loss of load without the water level in the pressurizer vessel reaching the power operated relief or safety valves' lift set points.

Reactor Coolant System Heat up

The status of the Pressurizer System prior to RCS heat up is:

- the pressurizer is full of water,
- heaters and sprays are off,
- power operated relief and safety valves are closed, and
- pressurizer relief tank (PRT) is partially full of water.

The initial pressurization of the Reactor Coolant System is accomplished by starting a charging pump and controlling the pressure increase by adjustment of the CVCS letdown line pressure control valve (PCV-131). All pressurizer
Heaters are energized to heat up the pressurizer volume.

The pressurizer remains water-solid during the first phase of RCS heat up. The pressurizer temperature is increased to form a steam bubble in the pressurizer during the second phase of heat up. The coolant will expand as temperature rises; causing an increase in the letdown flow rate. PCV-131 throttles open to limit system pressure. When the pressurizer liquid temperature reaches saturation for the existing system pressure, steam begins to form at the top of the pressurizer. The flashing of the liquid into steam results in an increase in letdown flow and a decrease in pressurizer level.

The operator assists in the bubble formation by reducing the CVCS charging flow to reduce pressurizer level. The operator stabilizes the pressurizer level when it reaches the normal operating band, and during the remainder of the heat up, RCS pressure is controlled by the saturation condition of the steam-water interface in the pressurizer.

Reactor Coolant System Cool down

The cool down of the reactor coolant system differs from the heat up in that the pressure is always maintained by the steam-water equilibrium in the pressurizer vessel. Thus, the steam bubble is maintained in the pressurizer vessel until the reactor coolant system is completely cooled to the value specified in the system operating procedures. The purpose of maintaining the steam bubble in the pressurizer is so that reactor coolant system pressure is not allowed to fall below the reactor coolant pumps' minimum operating pressure. When the reactor coolant system cool down is completed, the steam bubble in the pressurizer can be collapsed. This is accomplished by spraying the steam bubble with cool water from the Chemical and Volume Control System (Auxiliary Spray) while increasing charging flow. The spray flow is continued after the pressurizer vessel is full of water and the pressurizer internal temperature equals the reactor coolant system temperature.

ABNORMAL OPERATION

Pressurizer Pressure Control responses:

Example #1

With the Pressurizer Pressure Control Selector Switch selected to 457/456 position, PT-456 fails high.

Response:

- PORV PV-456A opens. This reduces pressurizer pressure
- Pressurizer pressure master controller responses by closing the pressurizer spray valves and signals for maximum heater power all 4 banks.
- Pressurizer heaters are not able to maintain pressure under this condition, so when pressurizer pressure drops to 2185 psig both PORVs and the block valve receive a close signal from the Solid State Protection System (SSPS).
- Pressurizer pressure will remain approximately 2185 psig as the PORV PV-456A cycles on the PORV interlock since no operator action is taken.

Alarms received during this instrument failure:

- ALB11-C03 “PRZR HI PRESS CHANNEL ALERT”
- ALB12-F04 “PV-0456A OPEN SIGNAL”
- ALB12-D03 “PRZR PRESS LO PORV BLOCK” INTERMITTENTLY
- ALB12-E01 “PRZR RELIEF DISCH HI TEMP” OVER TIME

Example #2

Unit 2 is 100% power with all control systems in automatic. Pressurizer Pressure Control Selector Switch is selected to 457/456 position. If PT-457 fails high this is what the plant response will be if no operator actions are performed.

Response:

- PORV 2-PV-455A opens. This reduces pressurizer pressure.
- Pressurizer Spray valves fully open, Pressurizer heaters cut back to minimum.
- When pressurizer pressure drops to 2185 psig sensed by 2 out of 4 channels both PORVs and the block valve receive a close signal from the Solid State Protection System (SSPS).
- Pressurizer pressure will continue to lower due to maximum spray flow called for by the pressurizer pressure control system. Since there is no operator action performed the reactor will trip when pressurizer pressure drops to 1960 psig sensed by 2 out of 4 channels.
- Safety injection will occur when pressurizer pressure lowers to 1870 psig sensed by 2 out of 4 channels.

Alarms received during this instrument failure:

- ALB11 B03 “PRZR HI PRESS”
- ALB11 C03 “PRZR HI PRESS CHANNEL ALERT”
- ALB12 E04 “PV-0455A OPEN SIGNAL”
- ALB12 D03 “PRZR PRESS LO PORV BLOCK”
- ALB12 E01 “PRZR RELIEF DISCH HI TEMP”
- ALB09 B04 “PRZR LO PRESS/P7 REACTOR TRIP”
- ALB09 A04 “PRZR PRESS SI RX TRIP”

The Immediate Operator Actions (IOAs) performed by the operator in response to the instrument failure will prevent the Reactor from tripping and Safety Injecting.

Example #3

Unit 2 is 100% power with all control systems in automatic. Pressurizer Pressure Control Selector Switch is selected to 455/456 position. If PT-455 fails low this is what the plant response will be if no operator actions are performed.

1) The pressurizer pressure controller would close the spray valves and demand maximum heater power on all 4 banks.

2) Pressurizer pressure will increase to the point that PORV 2PV-456A opens when pressure sensed by 2PT-456 reaches 2335 psig.

3) 2PV-456A will close when pressure sensed by 2PT-456 drops to 2315 psig.

4) Since no operator action is taken, pressurizer pressure will continue to cycle between 2315 psig to 2335 psig.

Alarms received during this instrument failure:

- ALB11 D02 “PRZR CONTROL LO PRESS AND HEATERS ON”
- ALB11 B02 “PRZR LO PRESS ALERT”
- ALB11 A02 “PRZR LO PRESS SI ALERT”
- ALB12 A06 “OVERTEMP ΔT ALERT”
- ALB10 E03 “OVERTEMP ΔT ROD BLOCK AND RUNBACK ALERT”

Example #4

Unit 1 is at 92% power with all controls in automatic except for rod control. With a startup in progress, a malfunction occurs that causes PORV 1-PV-455A to fail full open. If no operator action is performed, the plants response will be.

1) Pressurizer pressure lowers

2) Pressurizer pressure master controller responds by closing the pressurizer spray valves and signals for maximum heater power on all 4 banks.

3) Pressurizer heaters are not able to maintain pressure under this condition, so when pressurizer pressure drops to 2185 psig both PORVs and the Block valve receive a close signal from the Solid State Protection System (SSPS).

4) Pressurizer pressure will remain approximately 2185 psig as the PORV Block valves cycle on the PORV interlock since no operator action is taken.

Alarms received during this instrument failure:

- ALB11-C03 “PRZR HI PRESS CHANNEL ALERT”
- ALB12-F04 “PV-0455A OPEN SIGNAL” (may or may not occur)
- ALB12-D03 “PRZR PRESS LO PORV BLOCK” INTERMITTENTLY
- ALB12-E01 “PRZR RELIEF DISCH HI TEMP” OVER TIME

Example #5

**Unit 1 is at 78% power with all controls in automatic except for rod control.
With a startup in progress, a malfunction occurs that causes Pressurizer spray valve 1-PV-455B to fail full open. If no operator action is performed, the plants response will be.**

1) The pressurizer pressure will lower. The Pressurizer Pressure Master Controller demands that the pressurizer spray valves are closed and maximizes heater power on all 4 banks.

2) When pressurizer pressure drops to 2185 psig sensed by 2 out of 4 channels both PORVs and the block valve receive a close signal from the Solid State Protection System (SSPS).

3) Pressurizer pressure will continue to lower due to continuous spray flow from 1-PV-455B. Since there is no operator action performed the reactor will trip when pressurizer pressure drops to 1960 psig sensed by 2 out of 4 channels.

4) Safety injection will occur when pressurizer pressure lowers to 1870 psig sensed by 2 out of 4 channels.

Alarms received during this instrument failure:

- ALB11 D02 “PRZR CONTROL LO PRESS AND HEATERS ON”
- ALB12 D03 “PRZR PRESS LO PORV BLOCK”
- ALB09 B04 “PRZR LO PRESS/P7 REACTOR TRIP”
- ALB09 A04 “PRZR PRESS SI RX TRIP”

TECHNICAL SPECIFICATION

LCO 3.3.1 Function 6 Over Temperature ΔT (Rx Trip)

4 channels are required to be operable.

Applicability: Modes 1 and 2

Bases:

OTΔT trip function is provided to ensure that the design limit DNBR is met.

LCO 3.3.1 Function 8a. Pressurizer Pressure Low (Rx Trip)

4 channels are required to be operable.

Applicability: Mode 1 ≥ 10% power

Bases:

The Pressurizer Pressure- Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

LCO 3.3.1 Function 8b. Pressurizer Pressure High (Rx Trip)

4 channels are required to be operable.

Applicability: Mode 1, 2

Bases:

The Pressurizer Pressure- High trip function ensures that protection is provided against over pressuring the RCS.

LCO 3.3.2 Function 1d. Pressurizer Pressure Low (SI)

4 channels are required to be operable.

Applicability: Modes 1, 2, and 3 > 2000 psig (P-11)

Bases:

This signal provides protection against the following accidents:

1. Inadvertent opening of a steam generator (SG) relief or safety valve;
2. Steam Line Break;
3. Rod ejection accident;
4. Inadvertent opening of a pressurizer relief or safety valve;
5. Loss of Coolant Accident; and
6. Steam Generator Tube Rupture.

LCO 3.3.2 Function 8b. Pressurizer Pressure P-11

PT-455, PT-456, and PT-457 are required to be operable.

Actions:

With one are more Pressurizer Pressure, P-11 channels inoperable, Verify P-11 interlock is in its required state for the existing unit condition within 1 hour.

Applicability: Modes 1, 2, and 3

Bases:

The P-11 interlock (PT-0455, PT-0456, PT-0457) permits a normal unit cool down and depressurization without actuation of SI or main steam line isolation.

OPERATING EXPERIENCE

REFERENCES

- P&ID 1X4DB112
- Elementary Diagrams 1X3D-BD-B01J
- Elementary Diagrams 1X3D-BD-B01K
- Elementary Diagrams 1X3D-BD-B01L
- FSAR Chapter 7 and 15
- ARP 17009
- ARP 17011
- ARP 17012
- PLS AX6AA04-30
- ASMS Steam Tables

SECTION J

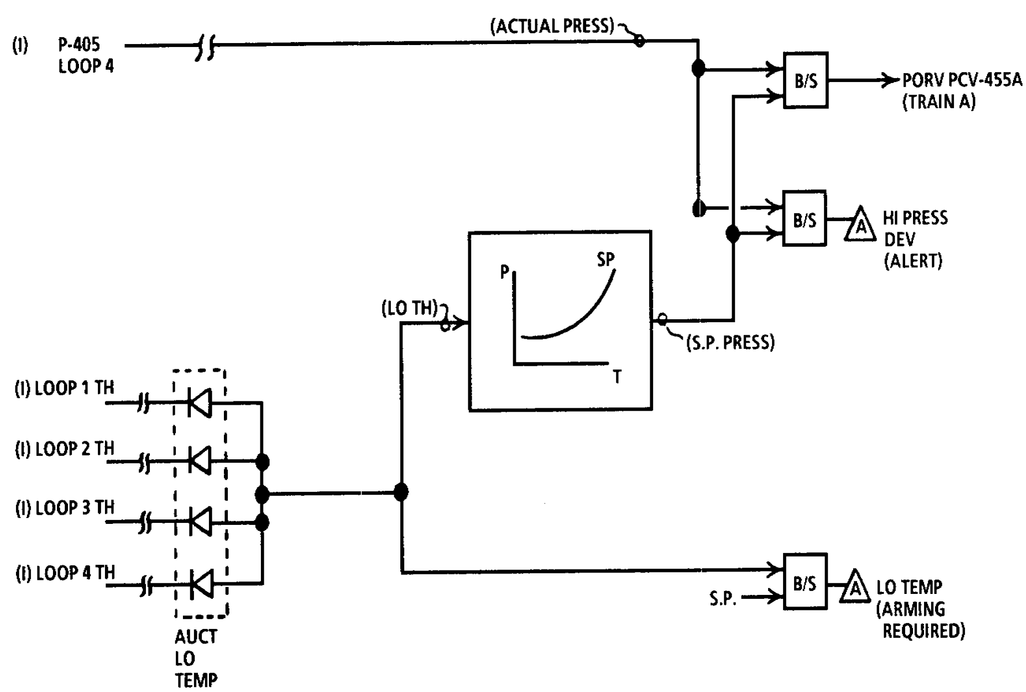
COLD OVERPRESSURE PROTECTION SYSTEM

16-62 Cold Overpressure Protection System (COPS)

Operating the RCS during overpressure conditions, particularly at low temperatures, can lead to failure of the Reactor Coolant System Boundary. Several features are built into the plant to assist in avoiding these conditions, one of which is the Cold Overpressure Protection System (COPS). COPS consist of two PORVs with variable lift set points and two RHR loop suction relief valves. Because of its importance to vessel integrity and because the system requires direct operator action, it is important that the operator understand the operation of this system.

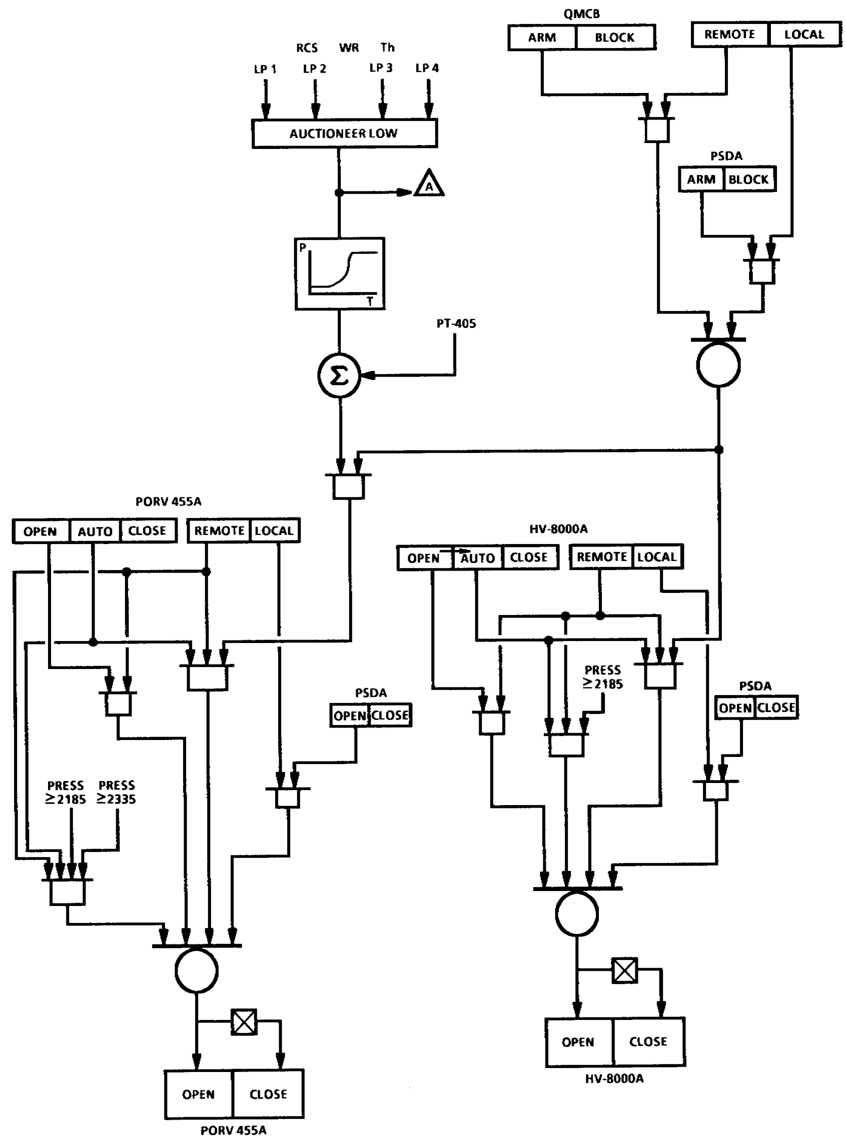
During normal plant operation, the pressurizer is a mixture of saturated water and steam. The steam in the pressurizer acts as a shock absorber during pressure transients. However, when the plant is shutdown and cooled down, the RCS and pressurizer may be water solid. Water, for all practical purposes, is incompressible. What this means is that the threat of over pressurization of the RCS can happen very quickly when the RCS is water solid. An overpressure event could still occur even with a steam bubble existing in the pressurizer.

The relief setting of the pressurizer code safety valves is relatively close to the design pressure of the RCS, but an adequate safety margin exists because of the shock absorber nature of the pressurizer when a steam bubble is present. When the plant is water solid, this margin is not great enough. COPS, when armed, removes the PORVs from the pressurizer pressure control system. COPS varies the relief set point of the PORVs based on RCS temperature. The reason for this is that the colder the RCS gets the more susceptible the vessel is to failing due to an overpressure event.

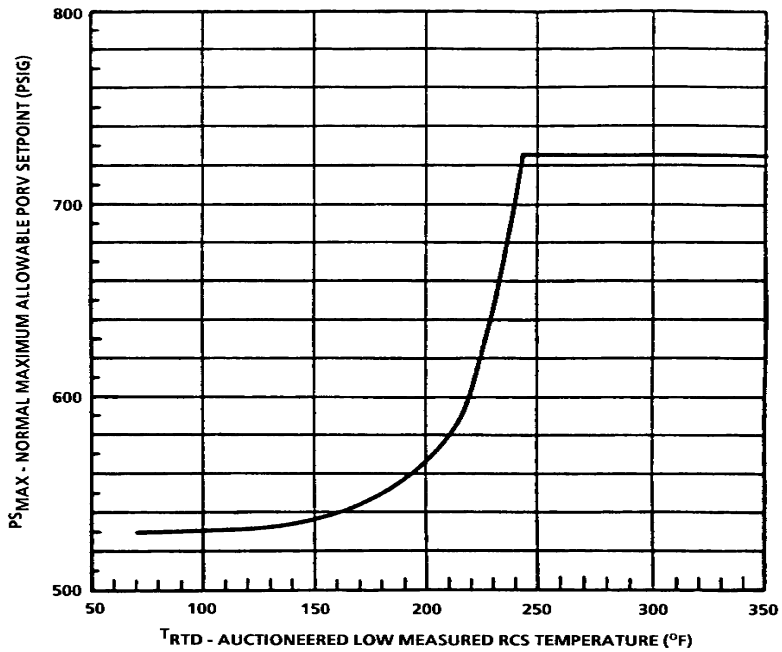


Because of the threat of rapid over pressurization with the RCS being water solid, the set point of the PORVs are reduced to increase the safety margin of over pressuring the RCS. COPS circuitry adjusts the set point of the PORVs for varying RCS temperatures when the plant is shutdown.

There are two trains of COPS, train Alpha and train Bravo. Train Alpha COPS is associated with PORV PV-455A; train Bravo with PORV PV-456A. The COPS circuitry calculates the PORV opening pressure set point based on auctioneered low RCS temperature. RCS wide range hot leg temperature instruments are used for train “A” and RCS wide range cold leg temperature instruments for train “B”. COPS compares its calculated pressure set point to the actual RCS pressure. The two pressure instruments are RCS Wide Range Pressure transmitter PT-405 (Train A) and PT-403 (Train B). If the actual pressure reaches the calculated set point value, its associated PORV will open.



The COPS circuitry requires manual arming by the operator. COPS is normally armed when the RCS is being cooled down and RCS temperature in the hot or cold legs reaches 350°F. The Emergency Operating Procedures call for Arming COPS based on Cold Leg temperatures only. The reason for this is that RCPs are not safety related therefore they cannot be taken credit for in the safety analysis. The Belt line region of the vessel is the weakest part of the primary system due to neutron embrittlment. Therefore, this makes it most susceptible to a cold overpressure condition. Due to the lack of mixing that occurs during natural circulation flow (RCPs off), the wide range cold leg temperatures are used because their location is closest to this region. Two hand switches, one for each train, are required to be placed in the "arm" position by the reactor operator. When COPS is armed, the interlock that closes the PORVs and block valves at 2185 psig from the pressurizer protection system is overridden. Arming COPS opens the block valves and allows the PORVs to be opened if needed. The **actual** COPS set points can be found in the Precautions, Limitation, and Set points (PLS) which are more conservative than Technical Specification limits listed in the Pressure and Temperature Limits Report (PTLR). Each unit and train have different calculated lift set points. (**Example** of the COPS Lift Set Point Calculation **(Do Not Use for determining true lift set point, the operator must use the PLS for actual set points)**)



RHR loop suction relief valves with a lift set point of 450 psig can be used to provide protection from cold overpressure conditions. The loop suction valves must be open to provide this protection. Normally during shutdown conditions no more than one loop suction is open at a time. The other RHR train is aligned to provide low pressure injection. Two COPS trains are required per tech spec. A combination of one RHR loop suction relief and one PORV can be used to satisfy this requirement also. (See Tech spec 3.4.12 for details)

All wide range temperature and pressure indications that are used as input into COPS are available on the QMCB. The following alarms are associated with COPS:

- COLD OP AUCT RCS TEMP – set point is 350 degrees F; alerts the operator that COPS should be armed
- RCS PRESS APPROACHES COLD OP LIMIT – set point is 20 psig below PORV set point; alerts the operator that RCS pressure is within 20 psig of PORVs opening
- COLD OP ACTU VLV HV-8000A NOT FULLY OPEN - alerts the operator that the PORV block valve did not open when COPS was armed

Most of the discussion has been focused on Control room operation of COPS. The remote shutdown panels also provide controls for the cold overpressure protection system. There currently is no procedural guidance for placing COPS in service from the shutdown panels, but the capability is there if necessary. Per the logic drawing (See Train "A" COPS Logic Diagram) to place COPS in service from the Remote Shutdown Panel (PSDA):

- the Local/Remote switch for the COPS Arm/Block switch must be in local,
- Arm/Block must be in "Arm" position, Local/Remote switch for the PORV Block valve HV-8000A must be in local,
- Block Valve HV-8000A must be in the open position, and
- The PORV PV-455A local/remote switch left in the remote position with its control room hand switch in automatic.

TECHNICAL SPECIFICATION

LCO 3.4.12 Cold Overpressure Protection Systems (COPS)

A COPS shall be OPERABLE with all safety injection pumps incapable of injecting into the RCS and the accumulators isolated and either a or b below.

a) Two RCS relief valves, as follows:

1. Two power operated relief valves (PORVs) with lift settings within the limits specified in the PTLR, or

2. Two residual heat removal (RHR) suction relief valves with set points ≥ 440 psig and ≤ 460 psig, or

3. One PORV with a lift setting within the limits specified in the PTLR and one RHR suction relief valve with a set point within specified limits.

b) The RCS depressurized and a RCS vent of ≥ 2.14 square inches (based on an equivalent length of 10 feet of pipe).

Applicability: Modes 4, 5, and 6 when the reactor vessel head is on

1hr or less Action:

An accumulator not isolated when the accumulator pressure is greater than or equal to the maximum RCS pressure for existing cold leg temperature allowed in the PTLR. Isolate affected accumulator within 1 hour or Increase RCS cold leg temperature to > 350°F or Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR within 12 hrs.

Bases:

The Cold Overpressure Protection System provides RCS overpressure protection by minimizing coolant input capability while ensuring adequate pressure relief capability for pressure increases due to mass addition transients (i.e. Inadvertent SI, excessive charging flow) or heat addition transients (i.e. pressure spike due to RCP start with excessive RCS-to-SG temperature delta-T, loss of RHR cooling, inadvertent pressurizer heater operation).

OPERATING EXPERIENCE

SER 82.002

Cold Overpressure of RCS at Turkey Point

1. Event Description
    a. Starting of RCP while on RNR caused a pressure surge which resulted in closure of RHR inlet isolation valves.

    b. Continuation of seal injection caused RCS pressure to increase (note: letdown to CVCS was isolated when RHR was isolated)

    c. Pressure increased to 1100 psig before operator opened relief valve

    d. COPs failed because of electronic circuit failure

    e. Following recovery, a transmitter failure caused RHR inlet isolation valves to close a second time

    f. Again, pressure increased, this time to 750 psig before operator opened PORV

2. Event demonstrates susceptibility of RCS for over pressure transients at low temperatures

    a. Start of RCPs can create pressure surges high enough to trip RHR inlet isolation valves (Vogtle Technical Specifications prohibit start of RCP if secondary temperature exceeds primary by more than 50°F also per the UOP and SOP limits the difference to no more than 10°F)
    b. Source of water into RCS should be isolated if RHR inlet isolation valves close. (Vogtle disabled the Auto closure of the RHR loop suction Valves on High Pressure)

IEN 82.045

Failure of COPS System

1. Several instances have occurred in industry where both trains of COPS were inoperable simultaneously

2. Causes of COPS failures
    a. Operation with both PORVs isolated (block valves closed) because of known PORV leakage
    b. Operator error during maintenance
        1) Wiring errors
        2) Improper valve lineups(e.g. isolation valve for pressure transmitter closed)
        3) Circuit failures

REFERENCE

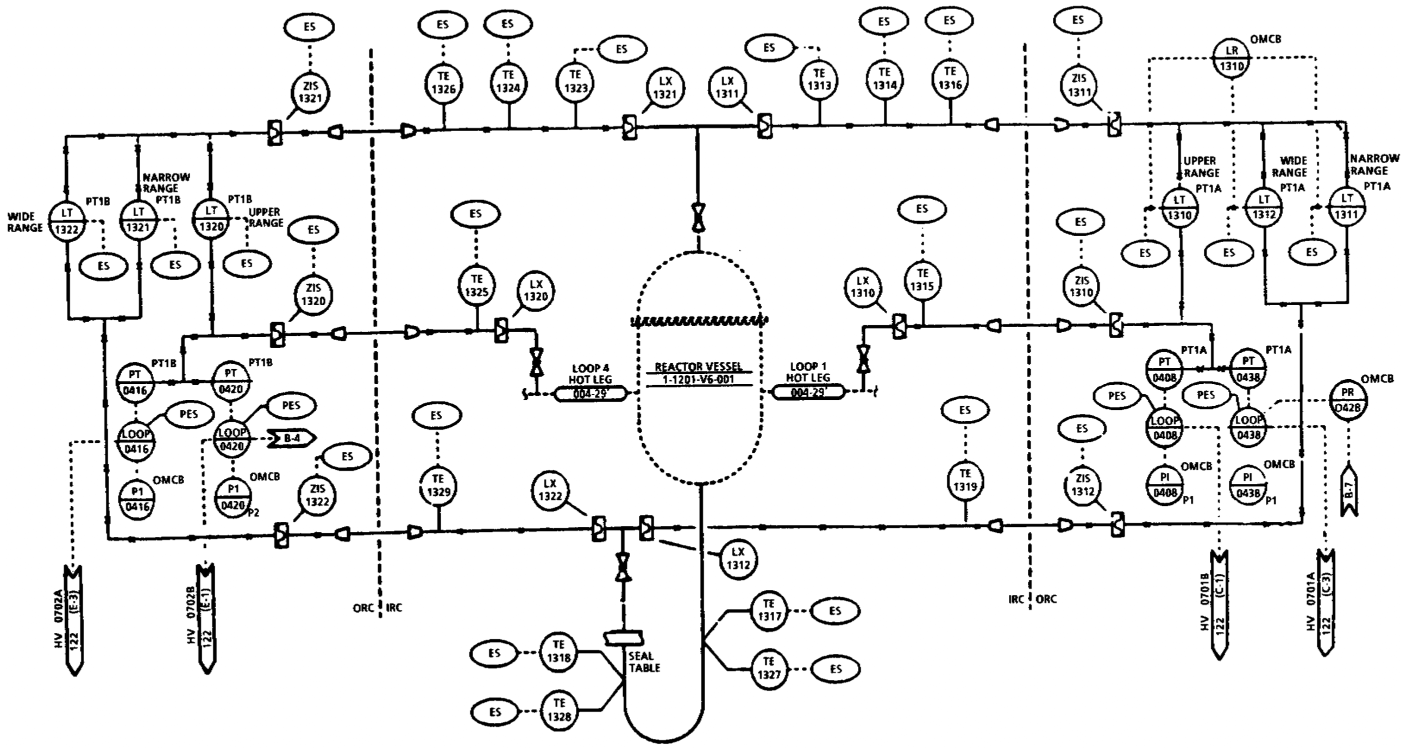
- PLS AX6AA04-30
- FSAR 5.2.2, 7.6.7
- Technical Specification
- SER 82.002
- IEN 82.045

SECTION K

REACTOR VESSEL LEVEL INDICATION SYSTEM

16-63 Purpose

The Installation of the Reactor Vessel Level Indicating System (RVLIS) was a result of the events that occurred at Three Mile Island. Significant voiding in the core had occurred, but at the time, the operators were unsure of how much of the core was covered with water. RVLIS



is a post accident monitoring system (PAMS) that provides the operators with reactor vessel water level indication. Reactor vessel water level can be determined with or without RCPs in operation. The three functions of RVLIS are:

a. detect voids and non-condensable gas bubbles in the reactor with no core flow.
b. to assist in the identification of Critical Safety Function (CSF) challenges for inadequate core cooling.
c. determine void fraction of the RCS under forced flow conditions.

16-64 RVLIS

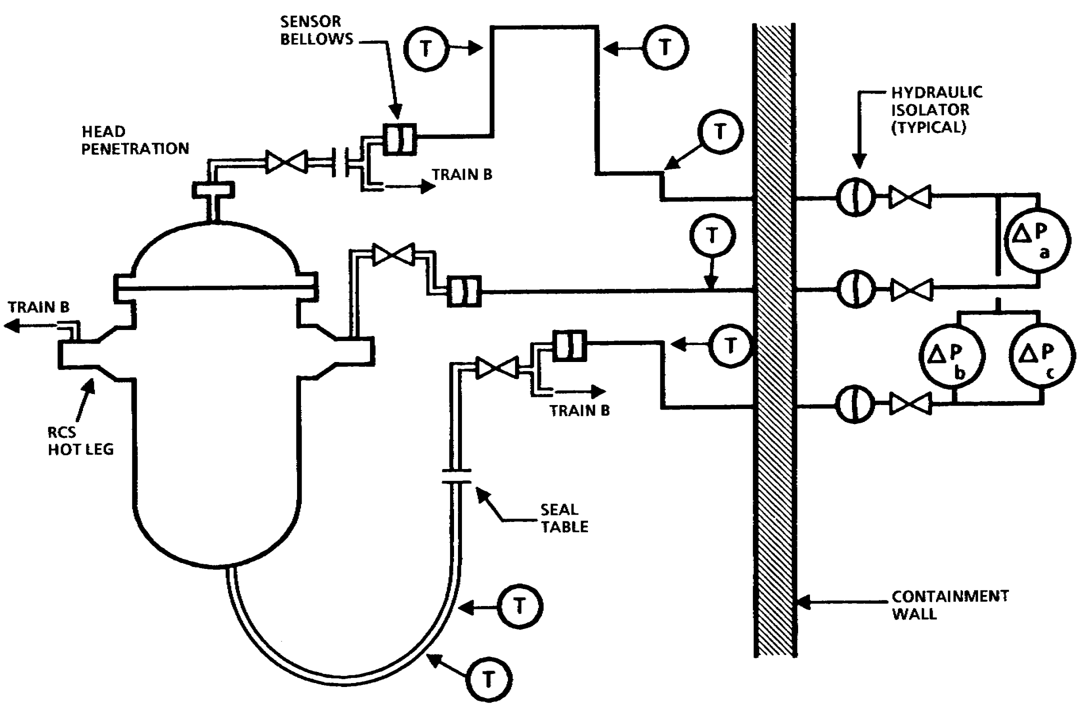
RVLIS consist of two redundant trains, Train A and Train B. Each train has three ΔP transmitters; ΔPa, ΔPb, and ΔPc. Each has its own purpose.

The **ΔPa** measures a narrow range static water level in the reactor vessel from the hot leg nozzle to the top of the vessel's head. This indicates the mass of water in the upper head. This information is necessary to ensure that a void has not enlarged to the point that the water level drops below the nozzles. At this point the void would block natural circulation flow. This information is also necessary for operation of the Head Vent System. A reference leg water level is compared by ΔPa to the actual level in the vessel. If there is a difference in level, a differential pressure at the transmitter will exist and RVLIS will indicate this in the control room. Because ΔPa is measuring static head, it is not accurate when the RCPs are in operation. The computer uses RCP breaker positions to determine if the RCPs are running or not. If any RCPs are running, the computer shows a downscale low indication on all static level scales and a message reads "RCP ON".

The **ΔPb** measures the static full range water level in the vessel from the bottom of the vessel to the top of vessel. This indicates the water level in the entire vessel, in particular, the core area. Both ΔPa and ΔPb are not a valid indication of the water level with the RCPs in operation.

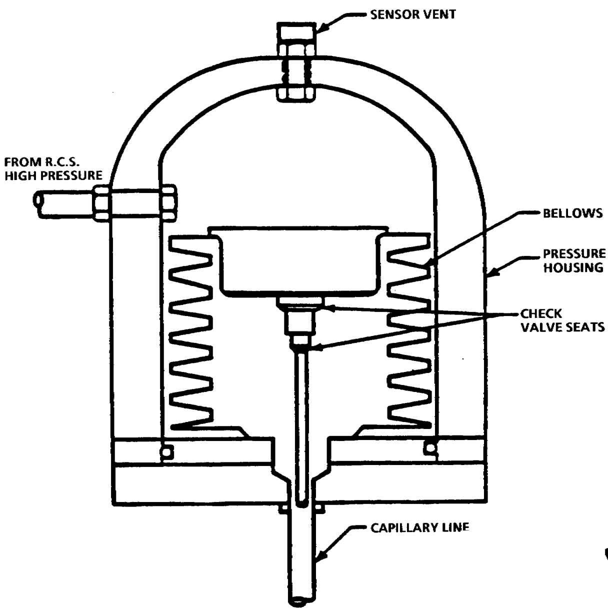
The **ΔPc** measures the differential pressure of RCS flow across the core. As the temperature of the RCS charges, so does the differential pressure across the core. RVLIS compares the readings from ΔPc to known values of ΔP with no voiding in the core.

The ΔP transmitters are actually located outside of containment. ΔPb and ΔPc use the same high side and low side taps. The tap is from the incore instrumentation guide tubes which connect to the bottom of the reactor vessel. The sensing line is actually connected to the incore instrumentation at the seal table. The high side tap is from the reactor vessel head penetration at the top of the head. ΔPa also uses this same high side tap, but uses a tap off the RCS hot leg for the low side tap. There are a total of three sensing lines for each train providing pressure information to the transmitters located outside of containment.

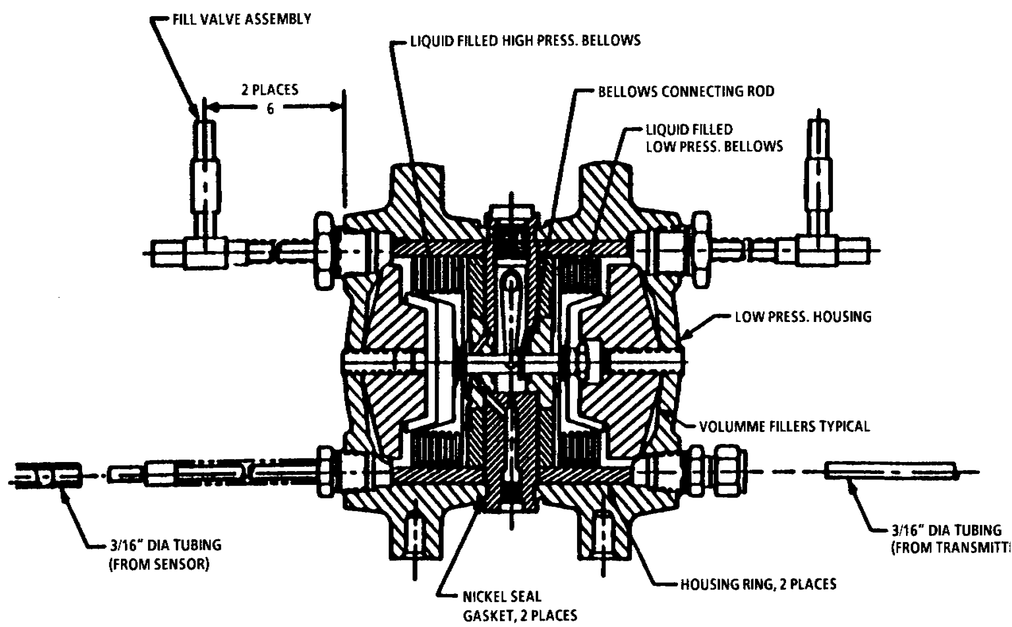


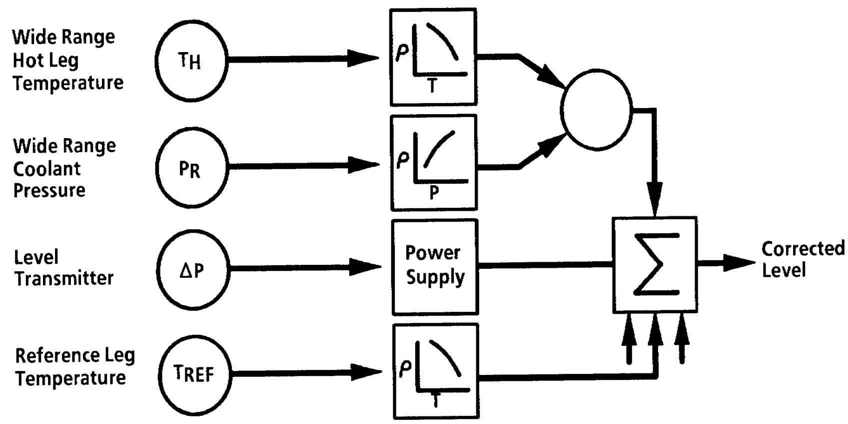
Also located outside of containment are the hydraulic isolators. There is an isolator for each of the three sensing lines for the transmitters. The isolators act as a containment isolation valve of sort. The pressure from the hydraulic fluid from inside of containment does not actually reach the transmitters outside of containment. The hydraulic force is transferred through the isolator to the transmitters. This is accomplished by hydraulic fluid in each sensing line that reacts to the pressure from the RCS side and transfers this force to a fluid in the capillary tubes that run to the transmitters.

To minimize the potential of developing a RCS leak in the level transmitter sensing lines inside containment, the RCS pressure is transferred to the hydraulic isolator by a another hydraulic coupler. The coupler consists of bellows that are free to move. RCS pressure is on one side of the bellows. Attached to the bellows housing is a capillary tube that runs to the respective hydraulic isolator outside of containment. As the pressure from the RCS moves the bellows the hydraulic force is transferred to the capillary tube and the isolators which in turn transfer the force to the transmitters. There is a hydraulic coupler for each of the three sensing lines.



The design and construction of the bellows also allows for automatic isolation of RCS water in the event of a leak in one of the capillary tubes to the hydraulic isolators. When the capillary side of the bellows is depressurized, as would be the case if a leak developed, the pressure from the RCS forces a plunger into a seat that provides an effective isolation barrier of RCS pressure.





The ΔP transmitters have compensating circuitry to account for changes in density in reference legs and the core. As the temperature of water changes, the density also changes which is directly related to the pressure exerted on the ΔP transmitter. If the transmitters were not density compensated, it is possible that vessel level could remain constant, but the ΔP transmitter indicates a change in level. The reference legs are also density compensated to account for changes in temperature, particularly from hostile environments expected in accident conditions. Pressure also affects the density of the liquid in the vessel, and if the changes in pressure were not accounted for, erroneous readings would result. For this reason, the density compensation circuitry also uses pressure for feedback and correction.

RCS wide range T_{hot} and RCS wide range pressure are used for density compensation. The reference legs also have several thermocouples that sample reference leg temperature. They provide the information to the density compensation circuitry for the calculation of reference leg density corrections.

<u>Train A</u>

Temperature input- TE-443A Loop #4 Hot Leg WR Temp
Pressure input- PT-408 and PT-438 WR Pressure
RCP status input- Non-1E and 1E feeder breakers

<u>Train B</u>

Temperature input- TE-433A Loop #3 Hot Leg WR Temp
Pressure input- PT-418 and PT-428 WR Pressure
RCP status input- Non-1E and 1E feeder breakers

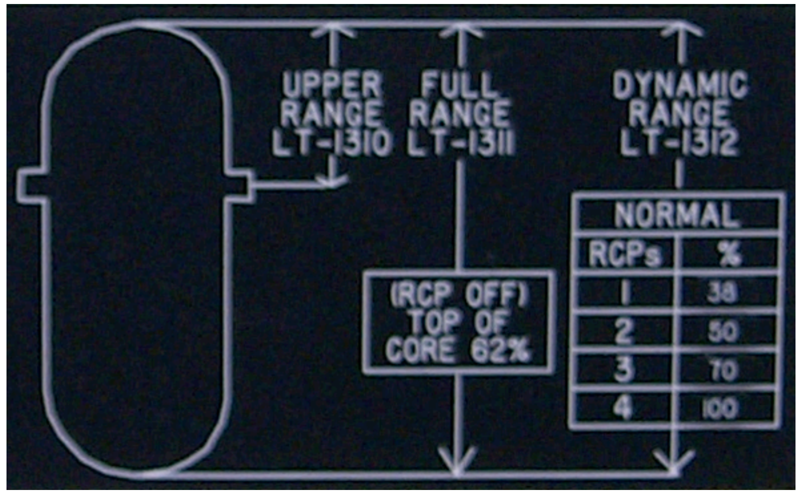
<u>RVLIS</u>

Indication of RVLIS outputs is available to the operator at the following locations:

* Plant Safety Monitoring System (PSMS)
* Integrated Plant Computer (IPC)

OPERATIONS

16-64 NORMAL OPERATIONS



RVLIS normally monitors reactor vessel level at all times. Indications of vessel level are available to the operator when unit is shutdown or operating. However the ΔPa and ΔPb vessel level indicators are not accurate with RCPs in operation. If any of the RCPs are in operation, both indications will read off-scale low. The dynamic level indicator ΔPc is accurate with all RCPs in operation, but the expected readings will vary if all RCPs are not in operation.

16-65 Potential Ambiguous Indications

The RVLIS will provide useful information for breaks in the RCS ranging from small leaks to breaks in the limiting small break range. For breaks in this range, the system conditions will change at a slow enough rate that the RVLIS indication will accurately trend with RCS inventory.

For larger breaks, the response of the RVLIS may be erratic, due to rapid pressure changes in the vessel, in the early portion of the blowdown. The
RVLIS reading will be useful for monitoring accident recovery when other corroborative indications can also be observed.

Several instances have been identified when the RVLIS may give an ambiguous indication. These include: 1) a break in the upper head, 2) periods of reactor vessel upper plenum injection, 3) periods of accumulator injection into a highly voided downcomer, 4) periods when the reactor vessel upper head behaves like a pressurizer, and 5) periods of void redistribution in the RCS. Several additional instances have been identified which may result in biased RVLIS indications. These include: 1) reverse flows in the reactor vessel, and 2) core blockage. These areas are discussed in the following subsection.

Break in the Upper Head

In order to assess the impact of a break in the upper head, a 2-3/4 inch equivalent break was investigated. This break size corresponds to that expected in the event of a control rod ejection accident. This is the largest break size that is credible for a design such as Vogtle. As the break size decreases, the effect on the RVLIS indication diminishes.

Immediately after the break occurs, subcooled liquid flows out the break; this is followed by a brief period of two-phase break flow. During this early period, the flow to the upper head is sufficient to cause the RVLIS to read off scale high on the Full Range (there would still be an indication on the Dynamic Head Range after approximately two minutes). After four to five minutes, however, the upper head and upper plenum have drained sufficiently such that steam is flowing through the break, as well as from the upper plenum to the upper head. The system stabilizes in a quasi-steady state mode with the RCS pressure slightly above the secondary pressure and the level in the vessel at the hot leg elevation. The RCS remains at these conditions until the upper portions of the RCS has drained. After approximately an hour, the vessel begins to drain.

During the vessel draining the RVLIS trends with the two-phase mixture level. The RVLIS reads higher that it would if the break were located elsewhere in the RCS due to flow pressure drop through the guide tubes.

The RCS pressure remains near the secondary pressure throughout the transient since the secondary is required for decay heat removal. The pressure drop through the guide tubes due to steam flow at 1100 psig RCS pressure corresponds to an 11 percent error on the RVLIS indication.

The RVLIS indication would still provide the operator with useful information concerning the trend in vessel level. The operator would still have sufficient information to monitor the Core Cooling Critical Safety Function (CSF).

Periods of Accumulator Injection into a Highly Voided Downcomer

When the downcomer is highly voided and the accumulators inject, the cold accumulator water condenses some of the steam in the downcomer which causes a local depressurization. The local depressurization will lower the pressure at the bottom of the vessel which will lower the d/p across the vessel, causing an apparent decrease in level indication. The lower pressure in the downcomer also causes the mixture in the core to flow to the lower plenum, causing an actual decrease in level. The period of time when the RVLIS indication is lower than the actual collapsed liquid level will be brief.

An example of this phenomenon may occur if the reactor coolant pumps are running for a long period during a small break LOCA transient. After the RCS loops have drained and the pumps are circulating mostly steam, the level in the downcomer will be depressed. A large volume of steam will be present in the downcomer, above the depressed mixture level, which will allow a large amount of condensation to occur if the accumulators begin to inject. For most small break transients, the reactor coolant pumps will be tripped early in the transient and downcomer mixture level will remain high, even in cases where significant core uncovery occurs. When the downcomer level is high the effect of accumulator injection on the RVLIS indication will be minor.

Periods when the Reactor Vessel Upper Head Behaves Like a Pressurizer

When the upper head begins to drain, water in the upper head starts to flash and slows the rate of pressure decrease in the upper head relative to the rest of the RCS. This phenomenon is termed the "pressurizer effect". The higher resistance across the upper support plate relative to the rest of the RCS prevents the upper head from draining quickly. This situation only exists until the mixture level in the upper head falls below the top of the guide tubes. At this time, steam is allowed to flow from the upper plenum to the upper head and the pressure equilibrates. While the upper head is behaving like a pressurizer, the RVLIS indicates a lower than actual collapsed liquid level.

Analyses have shown that the pressurizer effect has a small impact on the vessel d/p early in the small break transient and no impact on the results after the level drains below the top of the guide tubes. The interval of time when the upper head behaves like a pressurizer is brief and the RVLIS will resume trending with the vessel level after the top of the guide tubes uncover. The reduced RVLIS indication is expected early in the transient and should have no impact on the Core Cooling CSF.

Periods of Void Redistribution in the RCS

During any time when the distribution of voids in the vessel is changing rapidly, there can be a large change in the two-phase mixture level with very little change in collapsed liquid level. The only event that has been identified which could cause a large void redistribution is when the reactor coolant pumps are tripped when the vessel mixture is highly voided. When the RCPs are tripped the Dynamic Head Range will decay with reduced flow induced pressure drop and the Full Range will come on scale. After the RCPs' performance has degraded enough following trip that the flow pressure drop contribution to the vessel differential pressure is small, the change in RVLIS indication will be small. Prior to RCP trip an ORANGE path on the Core Cooling Status Tree would be indicated when the Dynamic Head Range indication corresponds to a 50 percent void fraction. If the RCPs were tripped at this time, the core would still be covered. The operator should know that the core may uncover if the RCPs are tripped with a dynamic head range indication lower than that value. If the RCPs trip, the two phase level may equilibrate at a level below the top of the core. The Full Range indication will provide an indication of core cooling ability at this time.

Reverse Flows in the Reactor Vessel

Reverse flows in the vessel will tend to decrease the d/p across the vessel which would cause the RVLIS to indicate a lower collapsed level than actually exists. It is important to note that large reverse flows are not expected to occur for breaks smaller than six inches in equivalent diameter during the time that the core is uncovered. Large reverse flow rates may occur early in the blowdown transient for large diameter breaks, but it is not necessary to use the RVLIS as a basis for operator action for breaks in this range.

Core Blockage

Blockage in the core will tend to increase the frictional pressure drop and the total differential pressure across the vessel, resulting in a higher RVLIS indication. The increase in the RVLIS indication would be most significant under forced flow conditions.

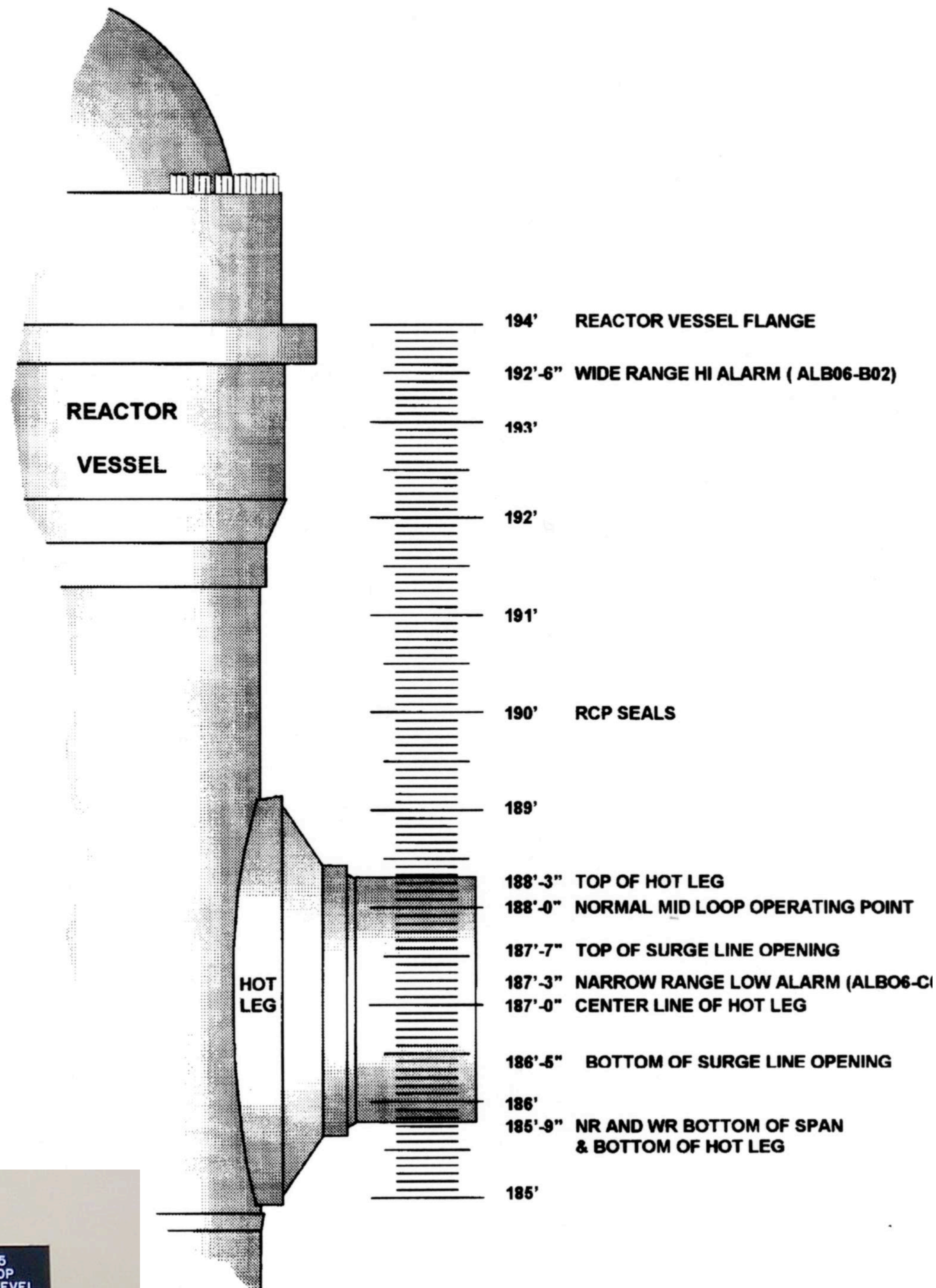
In order for blockage to be present, the core would have to have been uncovered for a prolonged period of time. A low RVLIS indication along with a high core exit thermocouple indication would have occurred during this time. If the reactor coolant pumps had been operating throughout the transient, there would have been sufficient cooling to prevent core damage and thus flow blockage. Therefore, for significant blockage to be present with RCPs operating, the RCPs would have to have been tripped initially and then restarted after an Inadequate Core Cooling (ICC) condition had existed for a period of time. Based on the history of the transient, the operator should be aware that the RVLIS indication may be higher due to blockage. Although the RVLIS would read high, it would still follow the trend in vessel inventory and monitor the recovery from the accident.

16-67 <u>RCS LEVEL MONITORING AT MIDLOOP</u>

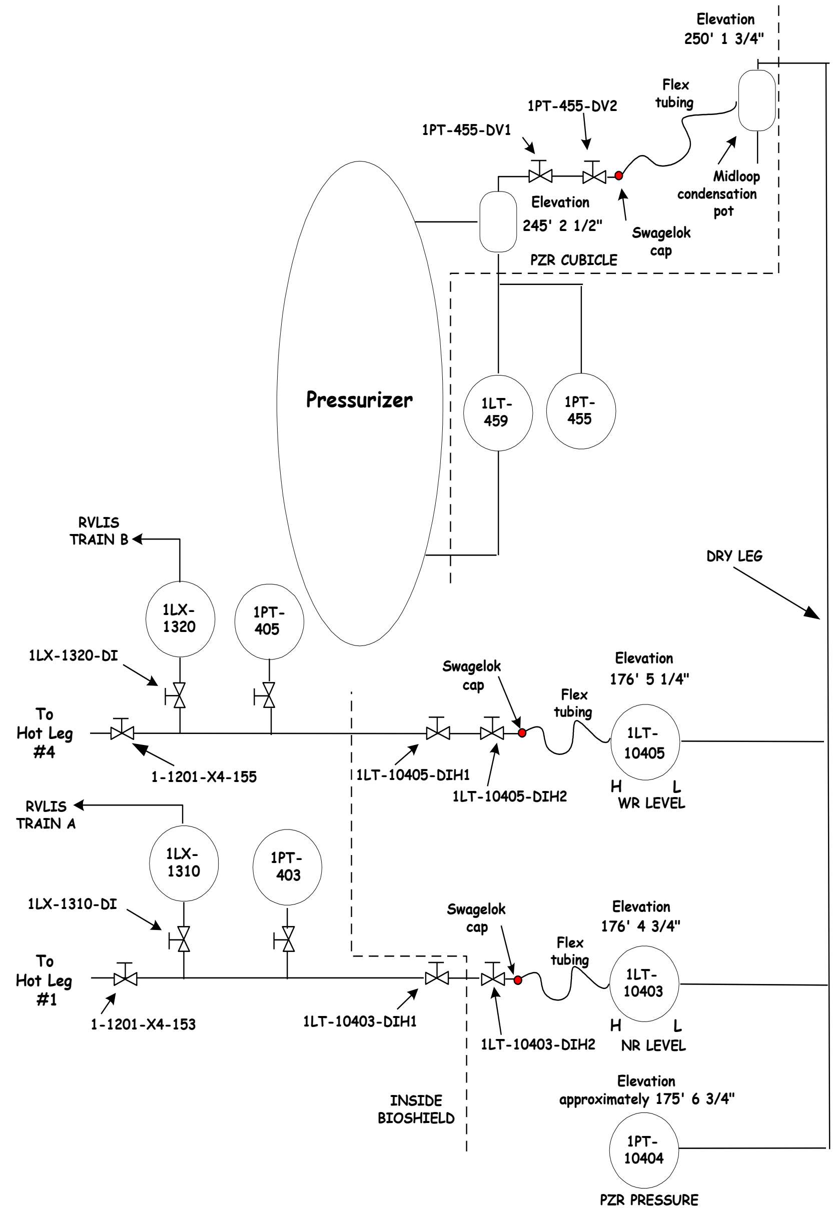
Many times it is necessary to drain the RCS piping to a point where the piping is no longer water solid, or drain down to "MIDLOOP" (procedurally limited to 188 feet elevation to prevent getting to the actual mid loop level of 187'). Reactor vessel level must be drained to midloop any time it is necessary to enter the primary side of the steam generators. There are very strict administrative controls when operating with vessel level at mid-loop. In order to prevent lowering the reactor vessel water level to a point in which the RHR system may experience a loss of Net Positive Suction Head (NPSH), three RCS level indicators are installed. The three indicators are as follows:

RCS Midloop Narrow Range Level Indicator LIS-10403
RCS Midloop Wide Range Level Indicator LIS-10405
Local Sight Glass indicator

All three indicators are required to be placed in service during plant refueling outages for vessel level monitoring. Unlike the local sight glass, both the narrow and wide range midloop instruments are permanent plant equipment.



The RCS midloop narrow and wide range level detectors are ΔP cells that share the same hot leg taps as RVLIS and the high side tap of pressurizer level transmitter LT-459. Narrow range LIS-10403 is scaled from 185’9” to 193’9”. Wide range LIS-10405 is scaled from 185’9” to 205’9”. The midloop instrumentation connection is made with flexible stainless steel lines that are disconnected when the instruments are no longer required.



The RCS sight glass is a vacuum resistant tygon tube that spans from loop #1 intermediate leg to the top of the pressurizer. Periodic checks between the remote vessel level indicators and the tygon hose are required. This is to ensure instrument reliability of the remote indications as well as to identify any problems that may have developed with the tygon hose (such as a kink in the hose or any air bubbles that may have become trapped in the hose). Control Room indication and the sight glass must agree within 7% of scale. Continuous sight glass watch is required anytime level is being changed while below 207’ elevation or if neither Control Room level indicators are available.

Many factors can cause erroneous sight glass readings. Operators should always be alert to abnormal trends. The following is a list of known factors that will affect the level indication:

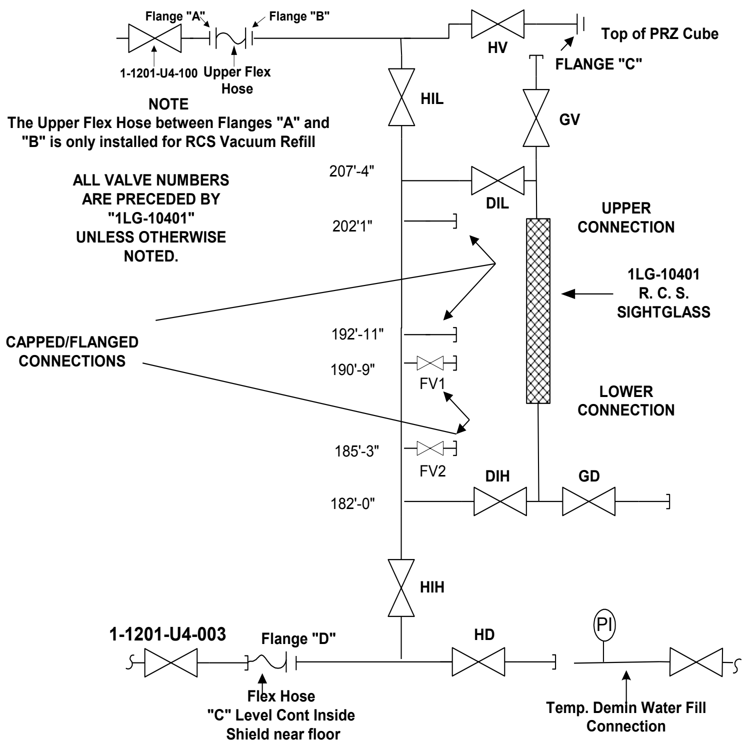
1. Improper valve alignment.
2. Improper routing of sight glass which results in air being trapped in the tube.
3. Fast level changes in the vessel can cause indicated level to lag behind the actual level.
4. The sight glass measures level from the intermediate leg while the ΔP transmitters measure level in from the hot legs.
5. For the indicators to be accurate the fluids in the system should be the same temperatures or errors will result.
6. If the pressurizer surge line is covered with water (as it normally is at midloop), a pressure difference can develop between the pressurizer air volume and the RCS on the other side of the surge line.

Prior to draining the vessel water level less than 191', procedure 11899 "RCS Drain down Configuration Checklist" must be performed. This checklist requires the operator to walk down the entire sight glass from the loop #1 intermediate leg to the top of pressurizer. This walk down prevents erroneous sight glass readings by checking the following:

1. Proper valve alignment.
2. Check for no obstruction that may cause pinching or kinks in the sight glass.
3. Check for no loop seal.
4. No vent obstruction.
5. Channel comparison between control room indications and sight glass.

Consequences of erroneous level indication could result in the water level being lowered to the point that a loss of suction may occur to the RHR pump. This would result in a loss of shutdown cooling which could lead to core damage. This makes accurate water level measurement very important.

UNIT 1 INSTALLATION OF RCS SIGHTGLASS FOR MIDLOOP



RCS SIGHT GLASS DRAWING

TECHNICAL SPECIFICATION

LCO 3.3.3 Post Accident Monitoring Instrumentation- Function 18 <u>Reactor Vessel Water Level (RVLIS)</u>

2 channels are required to be operable.

Applicability: Modes 1, 2, and 3

Bases:

Reactor Vessel Water Level is provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy. A RVLIS channel consists of Full Range, Upper Range, and Dynamic Range transmitters.

OPERATING EXPERIENCE

WOLF CREEK LOSS OF INVENTORY (CO 0041562)

On September 17, 1994, Wolf Creek Generating Station Experienced a Loss of Reactor Coolant Inventory while in a shutdown condition when operators performed two incompatible activities concurrently. Preceding the event, operators were controlling the reactor coolant system in Mode 4 (hot shutdown) at approximately 340 psig and 300°F. RHR train A was in service for cool down. RHR train B was being prepared for recirculation flow to the RWST to correct a low boron concentration within the RHR train B piping system that developed during the previous cycle due to check valve leakage. The RWST recirculation line taps off the RHR cross tie header between the crosstie isolation valves. Coincident with train B valve alignments, maintenance was adjusting the packing for the “A” train cross tie isolation valve (HV-8716A). Maintenance requested that the control room operator stroke the HV-8716A valve. An operator was dispatched to open the manual isolation valve from the RHR cross tie header to the RWST to initiate RHR train B recirculation flow to the RWST. At maintenance’s request and with the supervisor’s approval, the BOP operator opened the “A” train cross tie isolation valve and unknowingly established a flow path from the RCS to the RWST through the in service “A” train RHR pump. Over 9000 gallons of relatively hot RCS fluid were transferred to the RWST in just over one minute. Control room operators promptly diagnosed the condition when pressurizer level rapidly decreased and RWST level increased. They terminated the incident by closing the “A” train RHR cross tie valve.

Uncertainties that affect a conditional core damage probability calculation for Wolf Creek are largely dependent on time delay values used for operator actions. Wolf Creek personnel worked with Westinghouse to model the thermal hydraulic aspects of their event to determine the consequences if the event had not been terminated promptly. The evaluation for the worst case found that the reactor vessel began to void at about two minutes after establishment of the drain down flow path. The RHR pump failed about 30 seconds later and mid-loop level was reached in about another 70 seconds. Core uncovery was estimated to begin at about 24 minutes into the scenario. At the two-minute mark, the 24" common ECCS suction header was filled with a highly voided steam/water mixture rendering all ECCS pumps and gravity flooding from the RWST unavailable. At this time, starting any of the ECCS pumps would result in pump failure due to voiding in the pump suction.

PEACH BOTTOM REACTOR VESSEL INVENTORY REDUCTION DURING FLUSHING

On October 8, 2001, Peach Bottom Unit 2 was in cold shutdown for a refueling outage. Operators noticed that reactor vessel level was decreasing and took action to terminate the vessel drain down. The reactor RCS level decreased ~42 inches in 4 and one half minutes.

The event occurred during a planned flush of the residual heat removal (RHR) system crosstie line to reduce a radiation hot spot. The evolution was controlled in accordance with the station troubleshooting, rework, and testing (TRT) process.

The D RHR pump within the B train RHR loop was cross tied to the A RHR loop torus cooling return line to flush the hot spot. The lineup was intended to be from the torus to the torus. However, because the non-operating B RHR pump was still aligned to the reactor vessel for shutdown cooling, when the torus cooling return valve was opened, an unanticipated drain down path existed from the reactor vessel to the torus. The outage restoration team and the on shift crew had not considered the potential for a vessel drain down during the preparation of the flush procedure or the pre-job briefing because they assumed that the shutdown cooling isolation valves were closed.

The pre-job brief did not include all individuals involved with the flush, and only addressed issues specific to flushing the hot spot in the crosstie line. The on-shift Unit 3 control room supervisor and reactor operator were not included in the briefing. The participants were one SRO and one RO from the outage restoration team and two radiation protection personnel.

The control room supervisor over relied on the outage restoration team's preparation of the TRT and did not independently verify if the existing valve lineup was appropriate for the flush. The restoration team performed control room manipulations associated with the TRT flush procedure in parallel with the on-shift crew conducting other outage activities.

The outage restoration team had performed numerous successful flushes using the TRT process during the outage. Therefore, the individuals developing the TRT flush procedure did not recognize that cross-tying the A and B RHR trains versus flushing within a single loop was a first time evolution with complex elements that required further evaluation. The original procedure developed for the flush assumed the shutdown cooling isolation valves were closed because the system was to be aligned in the low pressure coolant injection (LPCI) mode. Further, the procedure did not require valve position verification. Later, the outage restoration team decided to perform the flush earlier than originally planned, necessitating a revision to the requirement for system alignment in the LPCI mode. The restoration team considered having shutdown cooling secured to be equivalent to the LPCI mode alignment because they assumed the shutdown cooling valves would be closed. The restoration team was unaware that the on-shift crew had left the shutdown cooling isolation valves open as allowed by plant procedures.

RCS Gas Accumulation

HADDAM NECK/CONNECTICUT YANKEE

From late August through early September 1996, control room operators were unaware of nitrogen gas leaking and being injected into the reactor vessel. Over the four day period, nitrogen displaced approximately 5000 gallons of water within the reactor vessel head causing a decrease in water level to approximately three feet below the vessel flange. Operator response to the unusually high nitrogen usage detected the event. As nitrogen usage continued, the operators began investigating. It was determined that as nitrogen came out of solution in the VCT, it leaked back through the VCT spray line into the normal makeup system. From there, the nitrogen gas made its way into the charging pump suction via a leaking valve in the normal makeup flow path.

A total of six additions to the RCS from the RWST were initially made at about 15 minute intervals. Vessel level stabilized when the amount of nitrogen that was accumulating in the vessel head equalized with the vessel vent path flow rate. The event was fully terminated when VCT pressure was restored to 30 psig and the normal makeup line was manually isolated.

Even after plant managers became aware of the problem, they were slow to appreciate the significance of the event, according to an NRC augmented inspection team review. A further drop in water level could have jeopardized the plant's decay heat removal system. The inspection team determined that several operational procedures were inadequate; and that plant operators did not follow plant procedures, did not exhibit a questioning attitude as nitrogen accumulated in the RCS and made inappropriate decisions while draining the reactor vessel and opening a reactor coolant loop on September 1. It also found that senior operators did not convey expectations to less experienced field operators during pre-job briefings. A $300,000 fine has been proposed for these violations.

Summary:

Gas accumulation in the RCS still exists as a potential problem. There have been several PWRs that have experienced this phenomenon. As discussed earlier, this accumulation can lead to more serious consequences (inaccurate level indication, impedance of natural circ, etc.). The non-Tech Spec CR rounds provide guidance for the detection and removal of non-condensable gasses in the vessel.

If the RVLIS full range indicates < 98% (95% upper range) when water level is still indicated in the PRZR, this is an indication of gas formation in the reactor head. The RVHV system should be utilized to remove the gas accumulation. Other means of gas removal include using the manual head vent path or sweeping the gasses out of the U-tubes (reference 13001, RCS Filling and Venting).

REFERENCE MATERIALS

- Westinghouse Owners Group ERG
- P&ID 1X4DB112
- P&ID 1X4DB113
- SOP 13005-1/2
- SOP 13521-1/2
- ARP 17006-1/2
- UOP 12008-C
- LU 11899-C “RCS Drain down Configuration Checklist”
- 28917-C

- 23984-1/2
- Technical Specification

SECTION L

DIGITAL METAL IMPACT MONITORING SYSTEM

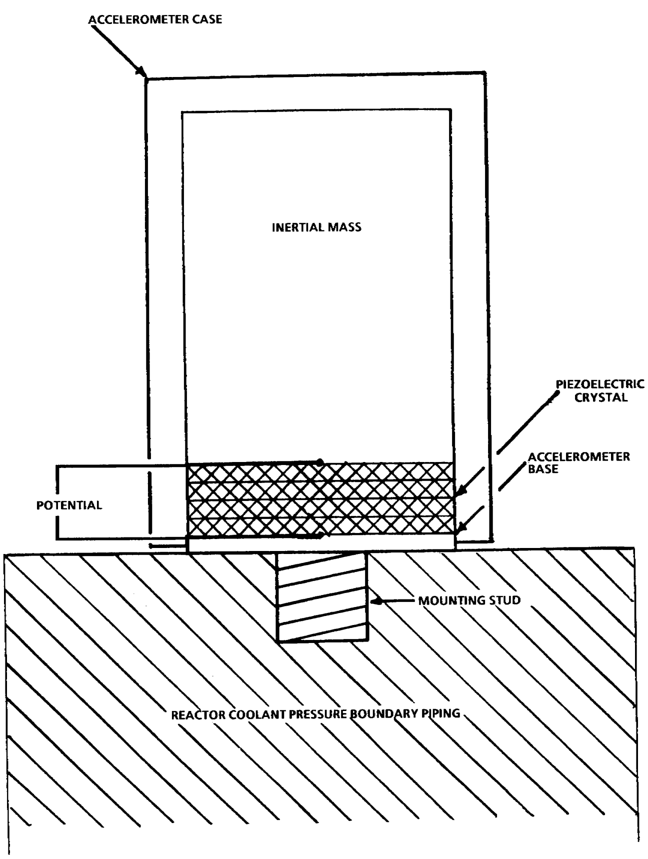
16-68 Purpose

The primary purpose for the Digital Metal Impact Monitoring System DMIMS is to provide early detection of loose metallic parts in the primary system. This allows time to avoid or mitigate a malfunction from weakening or failure of safety related components due to impact, wear or flow blockage caused by the loose part. The secondary reason is to minimize the radiation exposure to plant personnel by minimizing wear generated crud production and the need for extensive structural repairs. It also minimizes the chance of failure of the two primary fission product barriers. (Clad and RCS boundaries)

16-69 DMIMS

DMIMS monitors the RCS for the presence of metallic loose parts. It consists of twelve active instrumentation channels, each comprising a piezoelectric accelerometer (sensor), signal conditioning, and diagnostic equipment.

Metal debris can be any piece of metal which has detached itself from the inside of the RCS, or a bolt, tool, or other parts left inside after RCS repairs. This debris is carried through the system by coolant flow.



Loose parts can also come from components from systems that interface with the RCS such as CVCS and Residual Heat Removal system. Metal debris inside of the Reactor Coolant System (RCS) could cause major damage when it strikes the internal parts of the RCS. As metallic parts travel at high velocities through the RCS piping, it generates pressure waves in the water. These pressure waves are unlike any other that is normally present in the RCS, such as from the RCPs. DMIMS instrumentation detects these pressure waves by the use of accelerometers that are placed throughout the RCS System on the RCS piping. If DMIMS detects loose parts, a control room alarm will sound.

The Digital Metal Impact Monitoring System uses accelerometers installed at the reactor pressure vessels and steam generators to detect coolant pressure waves. The accelerometer is a device that changes pressure waves into electrical signals which is basically a microphone. The accelerometer is composed of a piezoelectric crystal sandwiched between a heavy mass and the accelerometer base. A piezoelectric crystal is a material that produces electricity when it is squeezed or otherwise deformed. The base is attached to the system where the pressure waves are to be detected. Any pressure waves cause the base to move, while the heavy mass will remain stationary due to inertia. This causes the piezoelectric crystal to deform and generate a small amount of electricity. The electricity produced is directly proportional to the intensity of the pressure wave. This electricity is amplified by the signal processing devices, and sent as an input signal to the DMIMS. The DMIMS logic circuitry compares accelerometer inputs with the typical signature of a metal impact to distinguish between normal conditions and impacts.

12 sensors are fastened mechanically to the following potential loose parts collection regions:

A. Reactor pressure vessel: (2) Upper head region
B. Reactor pressure vessel: (2) Lower head region
C. Each steam generator:
   (1) Reactor coolant inlet region (Primary)
   (1) Secondary Side above the Tube Sheet (Secondary)

The output signal from each accelerometer is amplified by a preamplifier and amplifier. The amplified signal is processed through a discriminator to eliminate noises and signals not indicative of loose parts, and the processed signal is compared to a preset alarm set point. Loose parts detection is accomplished at a frequency of approximately 25 kHz, where background signals from the RCS are low.

If a measured signal exceeds the preset alarm level, audible and visible alarms at the DMIMS console in the control room are activated. A microprocessor records the times that the first subsequent impact signals reach various sensors. This provides a basis for locating the loose part. The DMIMS also has provision for audio monitoring of any channel. The audio signal can be compared with a previously recorded audio signal if desired.

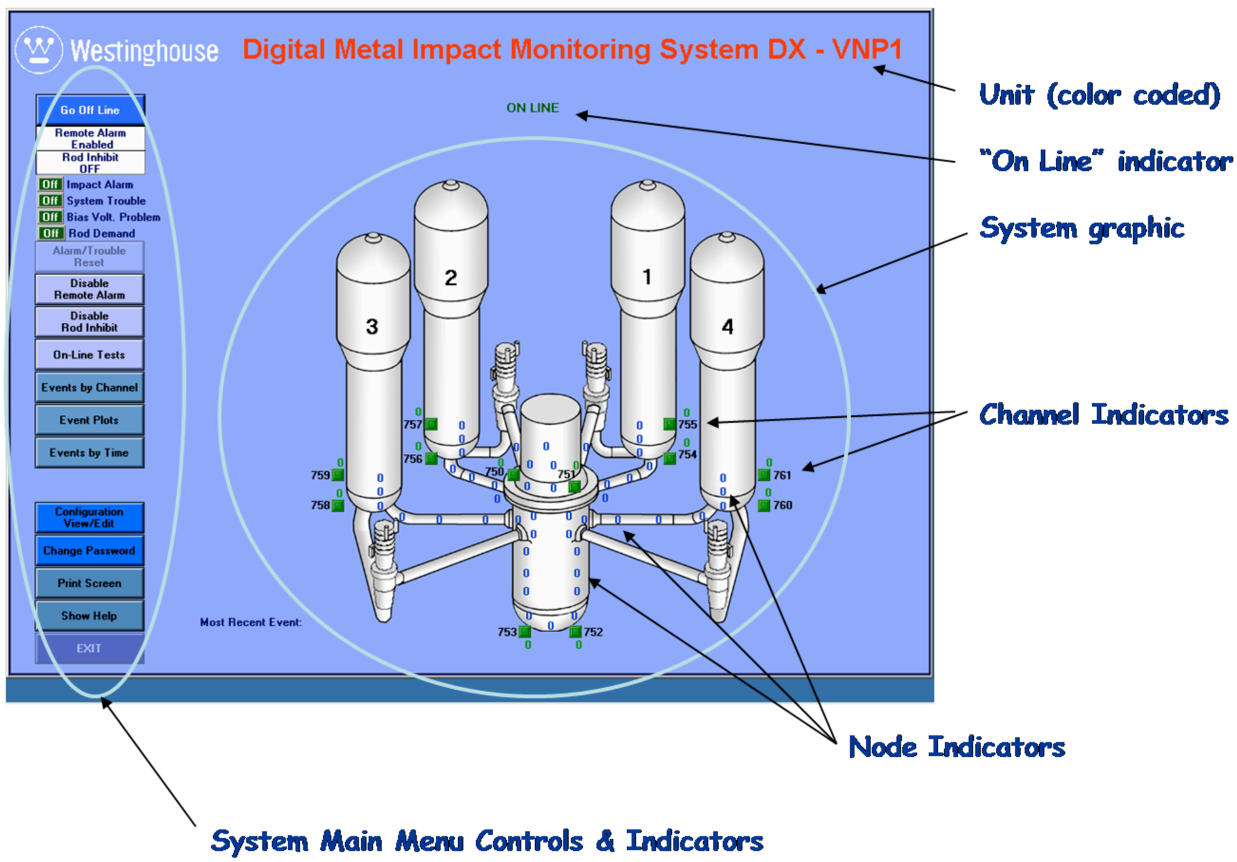
The online sensitivity of the DMIMS is such that the system will detect a loose part that weighs from 0.25 to 30 lbs and impacts with a kinetic energy of 0.5 ft-lb on the inside surface of the RCS pressure boundary within 3 ft of a sensor.

The piezoelectric sensors and hard-line cables inside containment are designed for LOCA or steam line break temperatures, pressures, and humidity. The preamplifiers and other cables inside containment are designed for a peak temperature of 150°F but the same pressure and humidity as the sensors. All of the equipment inside the containment is designed to remain functional through an operating basis earthquake and radiation exposures anticipated during a 40-year operating lifetime. Physical separation of the two instrument channels, associated with the redundant sensors at each RCS location, exists from the sensor to the output of the signal conditioning devices.

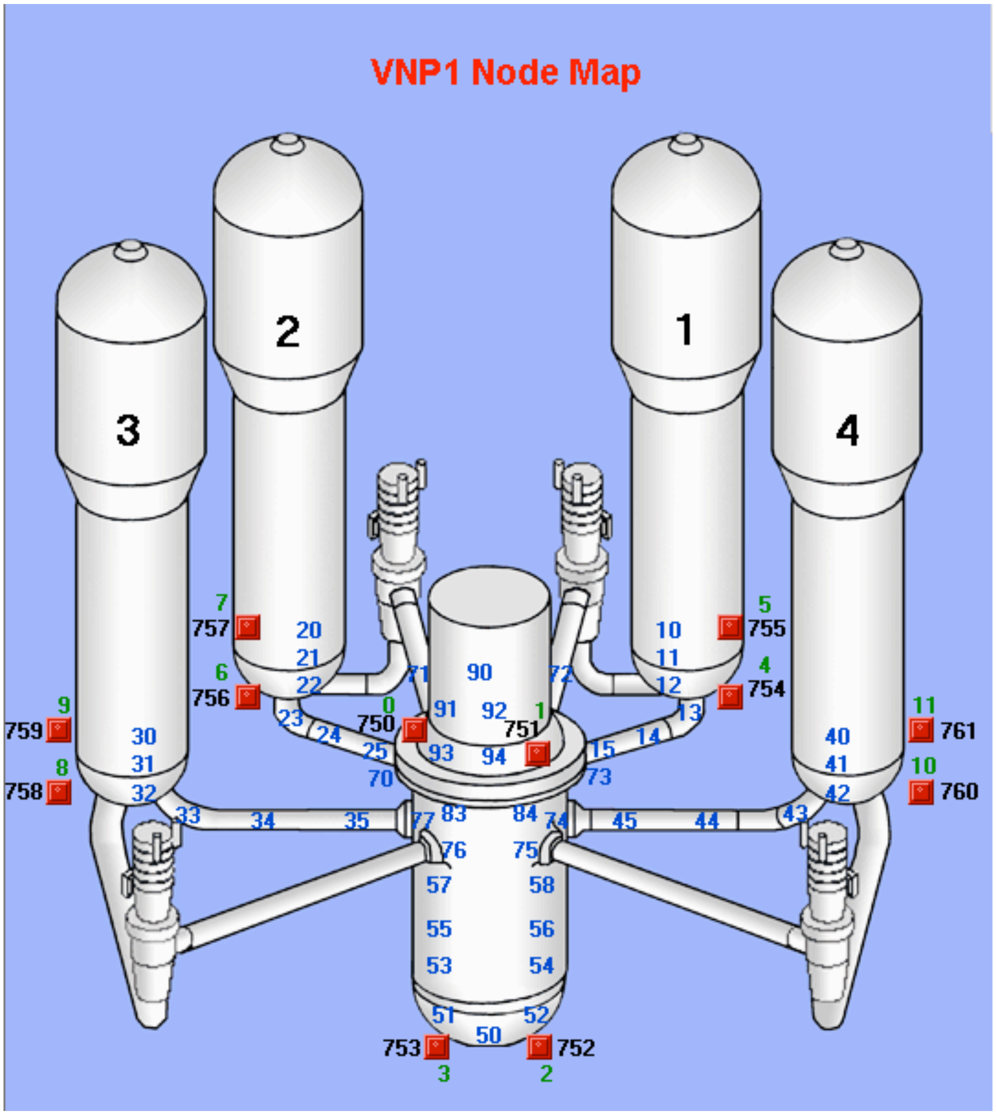
DMIMS control panel is located behind the QMCB in the control room. DMIMS is activated by depressing the "Go on-line" pushbutton on the touch screen monitor. Once activated, the DMIMS continually monitors the twelve locations in the RCS. If an event occurs, an alarm on the QPCP annunciates and the recorder which is a part of DMIMS records the event. The panel has an audio system that will allow the operators to listen to any impacts. The operator can select each channel (accelerometer) and listen to its output. DMIMS also will print on a printer the outputs of any channel event or trend or any screen view, by simply touching the screen print button. A DVD/CD Burner/Reader and 25 GB tape drive machine on the panel can be used to save the data of events for further analysis.

METAL IMPACT MON SYS PNL ALARM on the QPCP alerts the operator that one of the accelerometers has detected an event. The alarm circuit has conditioning circuitry that will prevent spurious alarms caused by events of known frequency, such as, the noise from the RCPs when operating. The alarm is also inhibited when the control rods are moved.

The DMIMS controls are mostly performed by using the touch screen display "Overview of DMIMS Panel" which is shown below.



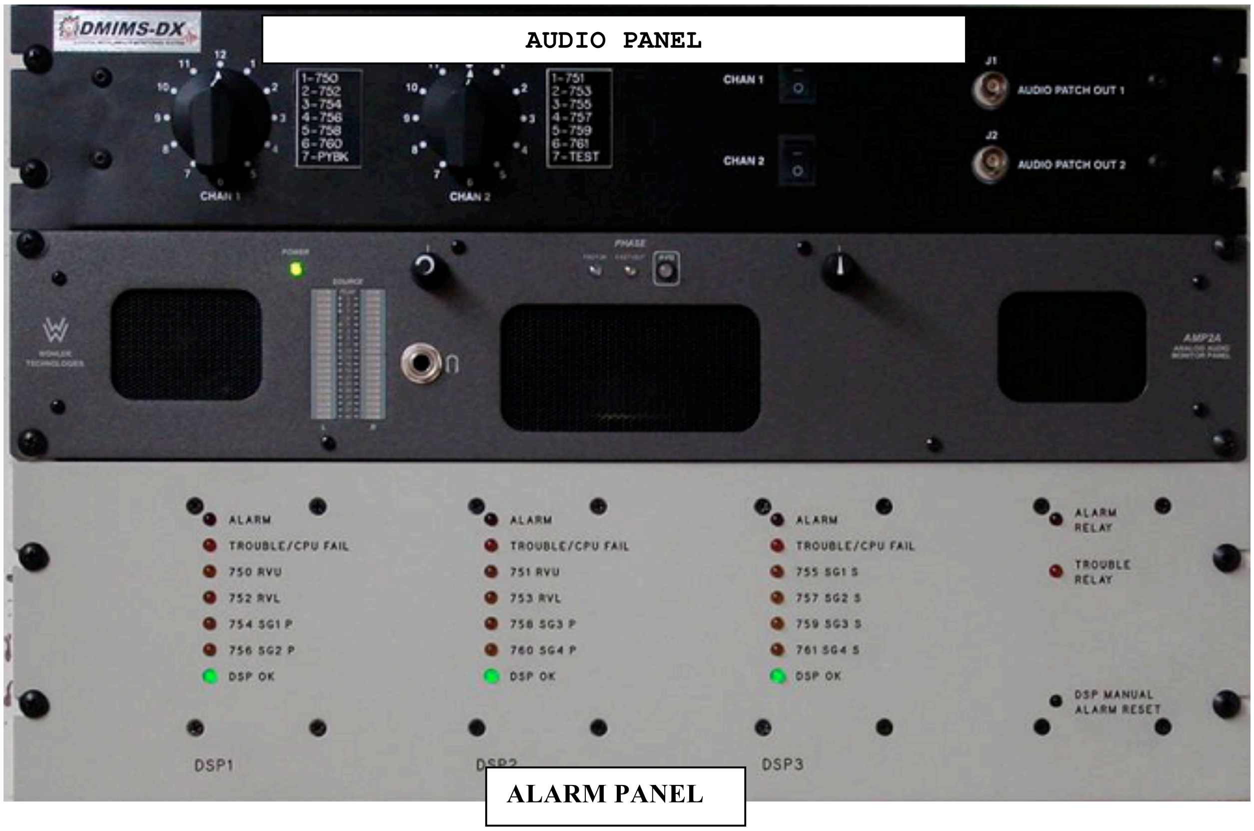
On the left hand side of the Overview screen is the "System Main Menu Controls and indicators" By touching the virtual pushbuttons the operator can place the DMIMs system on-line or off-line, Disable or Enable QPCP alarm (Metal Impact Mon Sys Pnl Alarm), and Disable or Enable the Control Rod movement discrimination. On-line testing can be performed to verify operability of the system, also trends and status of each channel can be monitored. All of which can be printed to a hard copy via the print screen virtual pushbutton. Each channels location 750 thru 761 is shown on the virtual Reactor Coolant System. The green square located besides each channel number shows the alarm status of each. The green status allows the operator to quickly determine that no channel has detected any impacts that exceeded their setpoints.



Shown above is the "Overview Screen" with the channels in alarm status as indicated by the "red squares." The green numbers indicate average amplitude of the impacts. The blue numbers are called "nodes" which are signals the computer uses to determine by triangulation the weight, location, and the path the object as traveled. This information can be useful by engineers in determining what the loose part could be.

All of the functions and how to retrieve information on DMIMs are covered in great detail in the System Operating Procedure (SOP) 13902-1/2.

The Audio Panel shown below allows the operators the ability to listen to each channel in stereo. This can be done by either the external speakers or by use of headsets. There are also LED bars which sound activity can be visually monitored. Volume can be controlled and the stereo left to right balance adjustments can also be made.



The Alarm panel shown above when channel or a trouble occurs the panel will illuminate the appropriate cause of the alarm. The alarm relay shown in the upper right hand corner when illuminated will trigger the alarm on the QPCP.

See the System Operator Procedure for more detail of the operation of the DMIMs.

OPERATING EXPERIENCE

Event number 1-96-003

On May 28, 1996, with Vogtle Electric Generating Plant Station Unit 1 at 100 percent power following a trip due to a feed water isolation valve problem, the DMIMS system channels (primary and secondary) associated with SG #4 alarmed continuously. Procedures directed the operating crew to record the DMIMS information for engineering analysis. Engineering forwarded the DMIMS information to the NSSS vendor for further analysis which included: verification of the existence of a valid loose part, safety significance, and the size and approximate location of the loose part. Within approximately 15 hours after the continuous DMIMS alarm, the NSSS vendor confirmed the presence of the loose part (approx. ½ lb.) in the SG #4 hot leg channel head (primary side) and began mobilization of personnel to travel to the site to assist with retrieval and identification of the loose part. The plant was shutdown within the following 7 hours. Plant operation was focused on preparations to retrieve the loose part: cooling down the plant, draining the RCS to permit SG access, and loose part retrieval. In order to ensure that the loose part remained in the SG, RCP #4 was kept in operation throughout the cool down. The final RCP (#4) was stopped on June 1, 1996; about 90 hours after the continuous DMIMS alarms began. Contributing to the length of the shutdown was an ineffective degasification of the pressurizer steam space to reduce the RCS hydrogen concentration to less than 5 cc/kg to permit opening the RCS. As the pressurizer was filled solid, hydrogen in the steam space was forced into solution resulting in an increase in concentration from approximately 2.5 cc/kg to 32 cc/kg. Consequently, a pressurizer bubble was reestablished to enhance the degasification process. When conditions for opening the RCS were attained, a vent path for draining the RCS was established. The RCS was drained to midloop on June 2, 1996; the SG channel heads were drained, and the SG 4 hot leg manway was removed. A loose part, later identified as a nut from a control rod guide tube support pin assembly, was located. The loose part measured approximately 30 Rem on contact, complicating the retrieval process. The part was removed from the SG 4 channel head and was prepared for shipment to Westinghouse, the NSSS vendor, for positive identification. The SG 4 tube sheet was videotaped for an initial assessment of damage. Later, a complete inspection of the SG 4 tube sheet revealed that multiple welds of SG tubes to the tube sheet on the primary side were significantly impacted by the loose part. Furthermore, a second part was found lodged in one of the SG tubes at the tube sheet. During the following two days, the remaining SG hot leg channel heads were inspected and determined to be undamaged. The loop 4 hot piping was inspected for additional loose parts or damage and no additional problems were identified. The second loose part, later identified as the locking device from a control rod guide tube support pin assembly, was retrieved and sent to the NSSS vendor with the first part. A third loose part was retrieved from the cold leg side of SG 4 on June 9, 1996. This third part was also shipped to Westinghouse for positive identification and failure analysis. It was determined to be a fragment from the support pin nut. (The support pin nut weighs about 0.26 lbs. and locking device about 0.035 lbs. The missing dowel pin weighs approximately 0.01 lbs.)
Contributing to the extent of the SG tube sheet damage was the delay in retrieval of the loose parts due to unsuccessful initial degasification and the lack of pre-established guidelines for control of plant conditions upon validation of a loose part. Focus was maintained on capturing the loose part versus minimizing the impacts to SG4.

Unplanned Shutdown due to Loose Part in Steam Generator

On May 13, 2002, with Wolf Creek Nuclear Generating Station at 100 percent power, control room personnel commenced a reactor shutdown based on the continued indication of a loose part in the steam generator D hot leg bowl and concurrence from Westinghouse. The loose part was identified through acoustic monitoring instrumentation. The steam generator was opened and personnel found one control rod guide tube split pin nut and a locking device. The steam generator tube sheet experienced generalized penning to various degrees of the entire bowl region/bottom face of the tube sheet and divider plate. There were no indications of large dents in the tube or indication of a foreign object present in any of the tubes. The cause of the loose split pin assembly is unknown. An investigation is ongoing and will be completed later. The station evaluated the damage and determined to be insignificant in light of the depth of the impact locations, and the thickness of the various components. The station concluded that plant components and safety systems will not be adversely affected during normal operation and accident conditions due to the broken guide tube support pin(s) for the current operating cycle, and the situation does not represent an un-reviewed safety question. Engineering disposition determined it was acceptable to operate the plant until the next refueling outage, at which time a detailed eddy current and visual inspection will be performed. Corrective actions include removing the loose parts and evaluating the repair options to be performed at the next refueling outage. This event is not significant because the damage was not sufficient to cause steam generator tube leakage or extended outage. This event is NOTEWORTHY because of the potential long-term effect on steam generator reliability.

REFERENCES

- Westinghouse vendor Manual 1X6AJ01-62 and 63
- FSAR 4.4.6.4
- Regulatory Guide 1.113
- ARP 17063-1/2
- SOP 13902-1/2
- INPO Webpage
- Event Report 1-96-003