General Electric Advanced Technology Manual

Chapter 4.10

Shutdown Plant Problems

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4.10 Shutdown Plant Problems

Learning Objectives:

1. Recognize the reasons that risk during outages is significant even though the reactor is shutdown.

    a. Recognize how licensees monitor risk
    b. Identify the primary strategies used to minimize shutdown risk
    c. Recognize how maintenance on a shutdown unit can impact the risk on multi-unit sites.

2. Identify the major accident sequences that contribute to core damage frequency during shutdown plant conditions.

3. Recognize the alignment of the RHR system and Recirculation system during shutdown cooling mode of RHR and potential paths that could drain the vessel and/or result in loss of decay heat removal.

4. Identify the primary strategies used by licensees to limit the likelihood of loss of SDC and drain-down events while shutdown.

5. Recognize the definition of the term "operation with potential to drain the reactor vessel (OPDRV)"

6. Recognize additional requirements necessary to minimize the likelihood, or consequences, of draining the vessel.

4.10.1 Introduction

In 1989 the Nuclear Regulatory Commission initiated a program to examine the potential risks presented during low power and shutdown conditions. Two plants, Surry (PWR) and Grand Gulf (BWR), were selected to be studied. These studies (NUREG/CR-6143) along with operational experiences indicated that the risk during low power and shutdown conditions may be significant.

The risk associated with Grand Gulf operating in modes 4 and 5 was shown to be comparable with the risk associated with full power operation, 10^{-6} range. While the risk is low, very few systems/features of the plant are required to be available to attenuate a release should it occur. Technical specifications permit more equipment to be inoperable during low power and shutdown conditions. In certain plant conditions, primary containment is not required.

Figure 4.10-1 presents a comparison of the mean core damage frequency percentages for the major classes of accidents from both the full-power NUREG-1150 and the low power and shutdown mode analyses NUREG/CR-6143. From this figure, obvious similarities and differences can be seen. The major similarity observed is that in both analyses the station blackout (SBO) class is important. In the full power analysis SBOs are dominant accident sequences due to the loss or degradation of multiple systems. In operating mode 3 and 4 SBOs also show up because they still cause loss or degradation of multiple systems. However, there are additional accidents that can cause loss or degradation of multiple systems because of considerations unique to those modes of operation.

The major differences in the accident progression associated with the SBOs are:

$ Almost all low power and shutdown mode SBOs sequences lead to an interfacing system LOCA where as the full power sequences do not.
$ The containment is always open at the start of the low power and shutdown accidents whereas it is isolated at the start of the full power accidents.
$ The probability of arresting core damage in the vessel is greater for full power accidents than for low power and shutdown conditions.

The remaining classes of accidents indicate major differences between the two analyses. In the full power analysis, the anticipated transient without scram (ATWS) class is the second most important class while in the low power and shutdown analysis the second most important is SBO, with LOCA being number one. Given the plant conditions analyzed in the two studies, the first point that can be made is that ATWS sequences were simply not possible with the plant already in a shutdown state. On the other hand, since LOCAs were possible in both analyses, why did this class only show up in low power and shutdown results? While no detailed examination of this phenomenon was undertaken, the most likely reason for the appearance of LOCAs results is the intentional disabling of the automatic actuation of the suppression pool makeup system which is unique to the Mark III containment. Defeating automatic actuation of the suppression pool makeup is done for safety reasons. As a result, the continued use of injection systems during a LOCA requires operator intervention. The difference in reliability between automatic actuation and operator action generally accounts for the fact that LOCAs survived in the low power and shutdown analysis but not in the full power analysis.

In a more recent paper published by Idaho National Laboratories in 2010 entitled *Development of Probabilistic Risk Assessment Model for BWR Shutdown Modes 4 and 5 in SPAR Model,* the investigators concluded:

Because of the very limited number of automatic equipment actions that are typically functional during shutdown, operator actions are more dominant during shutdown than during at-power conditions. The risk is dominated by the operator's understanding of the event and the ability to respond appropriately. In the example BWR, more than 90% of the core damage frequency was dominated by operator actions. Several core damage

cutsets include three or more operator actions. Therefore, understanding and modeling dependency of operator actions is a very important aspect of the total risk.
Based on analyses using SD-SPAR models, the risk to fuel damage (per hour) during shutdown operations may be comparable to at-power operations. Including shutdown events in plant PRA models could provide a more complete understanding of plant risk.

4.10.2 Monitoring and Strategies for Managing Risk

The monitoring of risk is accomplished through use of PRA, performance indicators, the required quality assurance program, and supervisory oversight.

Licensees are well aware of the risk involved in a Shutdown plant. Special procedures, increased supervisory oversight, proper scheduling and planning, and an increased sensitivity to the use of human performance tools are all used to minimize the shutdown risk.

Outages for plants on multi unit sites may impact the other unit(s). Some sites share diesel generators. The shared diesel is typically called a swing diesel. Some dual plant sites have the ability to cross connect Steam systems, Service Water systems, and share Switchyards. Errors in maintenance, testing, or restoration of systems can adversely affect the other unit(s) on site.

The following are a few of the tools used by licensees to minimize risk:

a) Human performance Tools
    a. STAR
    b. Pre-job Briefs
    c. Peer Check
    d. Procedural Adherence
    e. Flagging
    f. 3-way communication
b) Restricted access during maintenance of redundant equipment or trains required for accident mitigation.
c) Inspections
d) Observations
e) Corrective Action Program
f) Increased supervisory oversight

4.10.3 Interfacing System LOCA (ISLOCA)

The term "interfacing system LOCA" (ISL) refers to a class of nuclear plant loss of coolant accidents in which the reactor coolant system pressure boundary interfacing with a support system of lower design pressure is breached.   This could cause an over pressurization and breach the support system, portions of which are located outside of the primary containment. Thus, a direct and unisolable coolant discharge path would be established between the reactor coolant system and the environment. Depending on the configuration and accident sequence, the emergency core cooling systems as well as other injection paths may fail, resulting in a core melt with primary containment bypassed.

4.10.3.1 PRA Insight

NUREG/CR-5928, ISLOCA Research Program, primary purpose is to assess the ISLOCA risk for BWR and PWR plants. Previous reports (NUREG/CR-5604, 5745, and 5744) have documented the results of ISLOCA evaluations of three PWRs and to complete the picture a BWR plant was examined. One objective of the Research Program is identification of generic insights. Toward this end a BWR plant was chosen that would be representative of a large percentage of BWRs.
The reference BWR plant used as the subject of ISLOCA analysis was a BWR/4 with a Mark-I containment. Power rating for the plant is 3293 MWt. BWRs of similar design include:

- Brown's Ferry 1,2, & 3
- Peach Bottom 2 & 3
- Enrico Fermi
- Hope Creek
- Susquehanna 1 & 2
- Limerick 1 & 2

NUREG/CR-5928 document describes an evaluation performed on the reference BWR from the perspective of estimating or bounding the potential risk associated with ISLOCAs. A value of 1 x 10-8 per year was used as the cutoff for further consideration of ISLOCA sequences.

A survey of all containment penetrations was performed to identify possible situations in which an ISLOCA could occur. The approach taken began with an inventory of these penetrations to compile a list of interfacing systems. Once the list was complete, the design information for each system was reviewed to determine the potential for a rupture given that an over pressure had occurred. The systems included:

$ reactor core isolation cooling system

$ high pressure coolant injection system

$ core spray system

$ residual heat removal system

$ reactor water cleanup system

$ control rod drive system

The results of NUREG/CR-5928 concluded that ISLOCA was not a risk for the BWR plant analyzed. Although portions of the interfacing systems are susceptible to rupture if exposed to full RPV pressure, these are typically pump suction lines that are protected by multiple valves.

With two series check valves the probability of at least one of the check valves being seated and not leaking would be extremely high. In addition, if leakage were to occur to the point of causing a LOCA in the low pressure piping, the high differential pressure across the valve should cause the valves to seat, which would terminate the accident. However, actual operating experiences indicate that both check valves have failed to properly close in the past.

4.10.3.2 ISLOCA

Cooper Nuclear Station

The HPCI testable check valve failed to remain fully closed due to a broken sample probe wedged under the edge of the valve disc. The origin of the sample probe was traced to the feedwater system. The failure was not recognized until backflow of feedwater to the HPCI pump suction occurred.

LaSalle event on October 5, 1982

A testable check valve was tested with the plant at 20% power. The test was accomplished by opening the check valve bypass valve to equalize pressure across the check valve disc and then opening the check valve from the control room. Following the test, both the bypass valve and the testable check valve failed to reclose.

Pilgrim event on February 12, 1986 and April 11, 1986

On February 12, both the testable check valve and the normally closed LPCI outboard injection valve leaked, resulting in frequent high pressure alarms. These alarms occurred repeatedly for approximately two weeks prior to this event. Operators simply vented the piping after each alarm. On this date, the outboard injection valve was manually closed and its closing torque switch replaced. The plant continued operation until April 11, at which time, more high pressure alarms occurred. It was discovered that the outboard injection valve started leaking again and subsequently required a plant shutdown to facilitate repairs.

Dresden Unit 2 Event

On February 21, 1989, with Dresden Unit 2 operating at power, temperature was greater than normal in the HPCI pump and turbine room. The abnormal heat load was caused by feedwater leaking through uninsulated HPCI piping to the condensate storage tank. During power operation, feedwater temperature is less than 350°F, and feedwater pressure is approximately 1025 psi. Normally, leakage to the condensate storage tank is prevented by the injection check valve, the injection valve, or the discharge valve on the auxiliary cooling water pump.

On October 23, 1989, with the reactor at power, leakage had increased sufficiently to raise the temperature between the injection valve and the HPCI pump discharge valve to 275°F and at the discharge of the HPCI pump to 246°F. Pressure in the HPCI piping was 47 psia. On the basis of the temperature gradient and the pressure in the piping, the licensee concluded that feedwater leaking through the injection valve was flashing and displacing some of the water in the piping with steam. This conclusion was confirmed by closing the pump discharge valve (M034) and monitoring the temperature of the piping. As expected, the pipe temperature decreased to ambient.

The event at Dresden is significant because the potential existed for water hammer or thermal stratification to cause failure of the HPCI piping and for steam binding to cause failure of the HPCI pump. Further, failure of HPCI piping downstream from the injection valves would cause loss of one of two feedwater pipes.

The licensee had not heard the noise that is usually associated with water hammers. Never the less, loosening of pipe supports, damage to concrete surfaces, and the pressure of steam in the piping strongly indicated that water hammers had occurred in the HPCI system, probably during HPCI pump tests or valve manipulations.

4.10.4 Operations with the Potential for Draining the Vessel (OPDRV)

Certain safety systems must be operable during OPDRV activities to mitigate draindown events and to provide protection against untreated fission product release in the event that the reactor pressure vessel (RPV) water level drops and uncovers irradiated fuel. TS do not define the term OPDRV or identify specific plant actions that constitute OPDRV activities. Because a definition is not provided, the U.S. Nuclear Regulatory Commission (NRC) staff expects BWR licensees to use the plain language meaning of the OPDRV wording for determining applicable TS requirements. This means that any activity that could potentially result in draining or siphoning the RPV water level below the top of the fuel, without taking credit for mitigating measures, would be an OPDRV activity.

4.10.4.1 Minimizing the risk of an RPV draindown event

In order to minimize the risk of a. RPV draindown event, the NRC requires the following measures be taken by the licensees:

1. The licensee shall consider any activity that could potentially result in draining or siphoning the RPV water level below the top of the fuel, without taking credit for mitigating measures, to be an OPDRV activity. The licensee shall declare (log) that

they are in an OPDRV and document the actions being taken to ensure water inventory is maintained and defense-in-depth criteria are in place prior to entering the OPDRV activity.

2. The licensee shall meet the following requirements, which specify the minimum makeup flow rate and water inventory:

   a) During OPDRV activities the water level shall be equal to or greater than 23 feet (RHR – High Water Level) over the top of the RPV flange and the gate to the spent fuel storage pool and to the upper containment cavity to dryer pool (as applicable) shall be removed.

   b) During OPDRV activities, at least one safety-related pump shall be available (preferably aligned to the division with the required operable EDG) and shall be aligned to a makeup water source with the capability to inject water equal to, or greater than, the maximum potential leakage rate from the RPV for a minimum time period of 4 hours. If at any time the water inventory requirement is not met or inventory makeup capability is lost, then actions shall be initiated to immediately suspend OPDRV activities.

   c) During OPDRV activities, the time to drain down the water inventory from the RHR-High Water Level to the top of the RPV flange shall be greater than 72 hours based on the calculated maximum leak rate for OPDRV activities.

3. OPDRV activities shall be performed, to the maximum extent practicable, in a manner that maintains defense in depth against the release of fission product inventory. The following limitations shall apply:

   a) OPDRV activities are prohibited during Mode 4 with secondary containment inoperable.

   b) During OPDRV activities movement of irradiated fuel is prohibited.

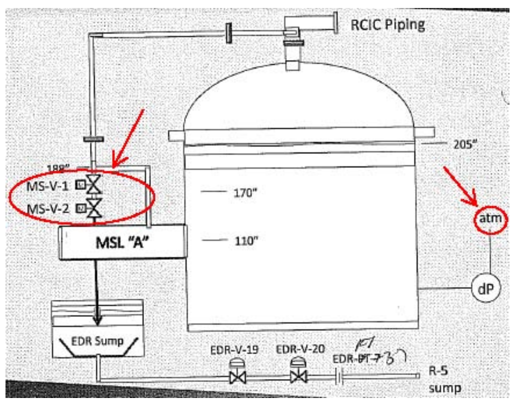
   c) The capability to isolate the potential leakage path during OPDRV activities before the water inventory reaches the RPV flange shall be maintained.

   d) At least two independent means of monitoring the RPV water level shall be available for identifying the onset of loss of inventory events during an OPDRV activity; at least one of these shall be an alarming indicator in the control room. One of the two indications may be by direct observation of the RPV water level, provided that such observation is continuous. It is not necessary to modify existing instrumentation to provide the required indication (e.g., recalibration to cold-shutdown conditions). The RPV water level monitoring capability shall ensure that a draining event is detected with sufficient time to (1) close at least one secondary containment access door in each access opening before water reaches the top of the RPV flange and (2) close secondary containment equipment hatches before water reaches the top of the RPV flange.

4. Licensees must follow all other TS Applicability and Action requirements for Mode 5 and Mode 5 OPDRV activities. If a licensee has a TS requirement that is more restrictive or conservative than the criteria stated herein, it must follow its TSs.

4.10.4.2 Inadvertent RPV Draindown

Columbia Generating Station (3 events) - On April 12, 2011 licensee began raising reactor water level to transition to MODE 5. Due to a lack of procedural compliance, Main Steam vent valves (MS-V-1 & MS-V-2) (see image below) remained tagged open allowing a drain path to under-vessel sump. Approximately **4000 gallons** was inadvertently drained from RPV to under-vessel sumps.



On July 29, 2011 licensee began lowering reactor water level while in MODE 4. Inadequate procedures & communications contributed to RPV vent path not being properly established during down activities. Since RPV level instrumentation remained calibrated to previous outage conditions (vented to atmosphere), accurate level detection was lost. The RPV drain without proper venting created a vacuum in the RPV. This event was compounded by a clearance issue with Main Steam vent valves (MS-V-1 & MS-V-2) when operators incorrectly cleared caution tags and repositioned valves with RPV level too high (>190 inches). Approximately **4400 gallons** drained to under-vessel sumps.

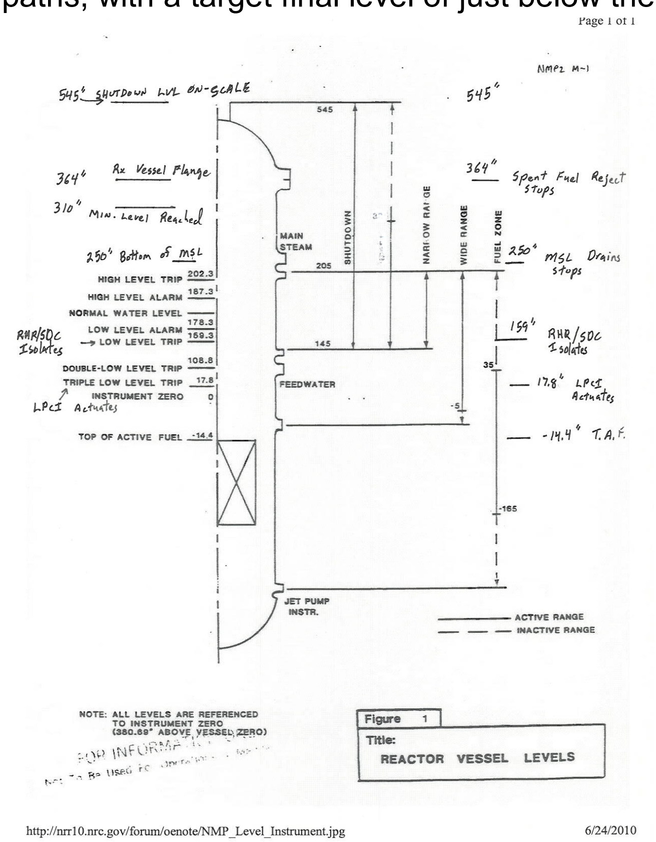
The ‘B’ RHR system, when aligned for shutdown cooling, takes a suction from the ‘B’ recirculation suction piping and discharges to the B Recirculation discharge piping.
On September 10, 2011 during plant restart activities, operators incorrectly aligned 'B' train of residual heat removal (RHR) to suppression pool cooling mode. Operator failure to identify and use the correct procedure caused the RHR suction flow path to remain aligned to the reactor vessel via the Recirculation system (vice suppression pool). Approximately 20 seconds after operator started the 'B' RHR pump, the "RPV

DRAINDOWN RHR-V-6B AND RHR-FCV-64B OPEN" alarm actuated; operator immediately tripped the 'B' RHR pump. Approximately **260 gallons** was pumped to suppression pool.

Nine Mile Point Unit 2 - On April 24, 2010, while performing a reactor cavity drain down, the licensee inadvertently drained the reactor vessel four and one half feet lower than planned when they failed to adequately account for the narrowing effect that occurred while draining down. No fuel was uncovered, however, radiation levels on the refueling floor increased to ~300 millirem/hour at the cavity hand rail due to the steam dryer being partially exposed

Detailed Description

The reactor vessel drain down was being conducted using the appropriate procedure (N2-PM-082). An SRO and RO were in the control room performing the evolution with a plant operator in the field monitoring vessel level from the Refuel Floor RP Office using video cameras. The Shift Manager and Control Room Supervisor (CRS) were providing general oversight of the evolution. At 0808, the vessel was being drained using Shutdown Cooling (SDC) to the suppression pool via 2RHS*FV38B, with some of the flow from RHS B was also being diverted to radwaste. Spent fuel pool cooling was also being used to drain to the main condenser, along with the Main Steam Line (MSL) drains, for a total drain down rate of approximately 7000 gpm. When vessel level was lowered to approximately 400" on the shutdown range, the lead operator planned to start throttling back on his letdown paths, with a target final level of just below the flange (364").



At 545" the control room operators observed level come onto the shutdown level instrument. However, the operators did not notice that the meter subsequently hung up at 410" (apparently due to static charge on the meter), and so, continued to drain beyond the point that they had intended to start throttling back. At around 0915, the refuel floor level watch reported level at the bottom of the fuel transfer canal ("cattle chute"), which translates to a level of 372". This was not known by the control room operators, who continued to rely on the shutdown range level indication of 410". The lead SRO then observed a rapid drop in shutdown range level indication of approximately 40". At 0918, reactor level was at the flange (364") and continuing to lower. The Lead RO had already commenced closing down on 2RHS*38B to reduce inventory loss to the suppression pool via RHS. The lowest level reached before the flow was secured was 310" on the Shutdown Range instrument (4 and ½ ft below the vessel flange).

Refuel Floor radiation levels over the handrail at the reactor cavity area rose to approximately 300 mrem/hr and the upper portion of the steam dryer had become uncovered. The drain down was secured and CRD flow was raised from 18 gpm to 76 gpm along with using LPCI "A" to inject with condensate. Level was restored to the flange at 1025.

The residents reviewed this event and determined that the drain down would have stopped itself (without operator action) well above Top of Active Fuel (TAF). They were draining by four paths (1) RHR to the suppression pool, (2) SDC to radwaste, (3) main steam line drains, and (4) SFP reject. The SFP reject stopped at the RV flange, MSL drains would have stopped at about 250 inches, and RHR/SDC would have stopped due to a level 3 isolation at 159 inches.

Browns Ferry Nuclear Plant - on day three of the Unit 2 outage, the potential for the reactor vessel to be drained during replacement of a reactor vessel drain isolation valve was not assessed sufficiently. A freeze seal was used as an isolation boundary, but contingency plans were informal and were not well implemented.

Hope Creek Generating Station - on day 19 of a refueling outage, functional testing of the main steam safety relief valves (SRVs) was performed with the main steam line plugs removed. This resulted in the inadvertent opening of an SRV, allowing reactor vessel water to drain to the suppression chamber and causing reactor vessel level to decrease by 10 inches. The outage schedule logic tie had been broken and the plugs removed without personnel fully understanding how the change in plant configuration could affect the plant.

4.10.5 Loss of Shutdown Cooling

The loss of Shutdown Cooling may be caused in a variety of ways:

- Improper lineups
    - As discussed earlier the RHR system (Fig. 4.10-2) when in shutdown cooling mode takes a suction from the vessel and discharges to the vessel via the Recirculation discharge piping. If the minimum flow valve is open then a portion of the RPV inventory will be discharged to the Suppression Pool. In addition, if B RHR is in Shutdown Cooling mode and inadvertently used in another mode, not only will this drain the vessel to the Suppression Pool but there will also be a loss of Shutdown Cooling.
- Loss of power
- Human performance errors
- Failed Circuitry
- Failed Equipment

Columbia Generating Station - On August 27, 2011 reactor protection system channel 'B' tripped on loss of power. This caused a loss of SDC for approximately 34 minutes due to the closure of a common suction valve (RHR-V-9). Licensee discovered a failure of the 'B' Electrical Protection Assembly breaker under voltage coil due to a faulty logic card. This logic card was sent to vendor's lab for failure analysis. A contributing cause to the event was identified to be from inadequate implementation of industry operating experience.

LIMERICK UNIT 1 - On March 9, 2008, Limerick Unit 1 (a GE-4 BWR with a Mark 2 containment) was shutdown and cooled down to approximately 100 degrees, with the reactor cavity flooded up to support a refueling outage. Failure to control reactor cavity level within the required band resulted in a loss of shutdown cooling and adverse radiological conditions on the refuel floor. The licensee was performing local leak rate testing on the residual heat removal (RHR) suction valves for normal shutdown cooling, which required these valve to be closed. This necessitated the use of alternate decay heat removal (ADHR).

Description of ADHR Flow Path

The normal shutdown cooling flow path consists of an RHR pump taking suction from one of the recirculation system loops upstream of the recirculation pump, and discharging through the RHR heat exchanger, low pressure coolant injection valves, and into the discharge of the same recirculation pump. While the local leak rate testing was ongoing, the normal suction source for shutdown cooling was isolated. ADHR (see Fig 4.10-3) provides a method of removing decay heat that is largely independent of the recirculation system and is used at times when the reactor cavity is flooded up. While in ADHR, the RHR pump takes suction on the skimmer surge tank and discharges to the RHR heat exchanger and into the reactor vessel through the low pressure injection valves. The skimmer surge tank communicates with the reactor cavity through weirs on the north and south side of the cavity. Each weir is a 12 inch high opening which allows water to flow from the reactor cavity to the skimmer surge tank. ADHR requires the weirs supply at least 10,000 gpm of water to the skimmer surge tank to support maximum ADHR flow rate. The drawing below shows the ADHR flow path:

Reactor cavity level is indicated by the shutdown range and upset level range recorders, and is typically monitored in the control room with a camera. Reactor cavity level range is measured from between 0 inches and 500 inches. The top of the weir is at 494 inches and the bottom is at 482 inches. Reactor cavity level is normally maintained around one or two inches below the top of the weir opening. Because of system design, indicated level is affected by changes in core flow and coolant temperature.

Summary of the Event

On the day of the event, operations staff made a number of changes in ADHR flow, which resulted in reactor cavity level changes, and also made several changes to reactor cavity letdown flow. At approximately 10:45 PM, plant staff on the refuel bridge identified a crud burst in the reactor vessel and began to see bubbles, reduced visibility, and a rust color throughout the water. The refuel bridge area radiation monitor alarmed and the refuel bridge was evacuated. Visibility continued to deteriorate and more bubbles were seen in the cavity. Within a few minutes the licensee made the decision to evacuate the refuel floor, as well, based on the report of large bubbles observed in the entire reactor vessel coming to the surface. The ADHR lineup was secured. The licensee checked reactor cavity level and identified that cavity level was approximately one inch below the bottom of the weir and that the skimmer surge tank level had dropped from a normal level of greater than 20 feet to three feet. Failure to properly monitor and control reactor cavity level had resulted in level dropping below the bottom of the weir opening, preventing the skimmer surge tank from being refilled from the reactor cavity. This allowed the running RHR pump to draw down level in the skimmer surge tank. Once level dropped to approximately three feet, the pump began to ingest air, which was then sent directly to the reactor vessel.

Radiological Consequences

While this event did not result in any dose rate alarms or significant increase in dose to personnel, the licensee did identify an increase in dose rates and airborne contamination on the refuel floor. Following identification of the crud burst, dose rates on the refuel bridge rose from four mrem/hr to 40 mrem/hr, resulting in a refuel bridge area radiation monitor alarm. Contact dose rates on the surface of the water rose to 200 mrem/hr and 125 mrem/hr at 30 centimeters. There was no significant loose surface contamination and no personnel contamination as a result of this event. Airborne activity increased to 1 DAC for less than one hour.

Peach Bottom 3 - On October 2, 2007, Peach Bottom Unit 3 lost shutdown cooling for approximately 2½ hours. The plant had been shutdown for ten days, and the time to boil was approximately 31 hours. At the time, the B loop of shutdown cooling was in operation using the D residual heat removal (RHR) pump. The B loop uses the C and D RHR pumps and the A loop uses the A and B RHR pumps.

The licensee was attempting to swap from the B loop of shutdown cooling to the A loop. The swap was completed, and the A RHR pump had been running for approximately 11 minutes, when the pump tripped unexpectedly. There was no indication, either at the pump or the breaker, to explain why the pump had tripped. The licensee swapped back to the B loop of shutdown cooling using the D RHR pump. During the time without shutdown cooling, temperature rose from 108 °F to 120 °F. After approximately seven hours of troubleshooting, Peach Bottom attempted a second swap to the A loop. This time, the A RHR pump was started successfully with no abnormalities noted. The licensee made the decision to move forward with tagging out and performing planned maintenance on the B loop without positively identifying the cause for the trip of the A RHR pump.

The licensee believes that the failure was the result of a problem with the non-safety-related pump protection logic, which is driven off of finger limit switches in the motor operator for the manual and normally locked closed shutdown cooling suction line off of the recirculation header. After building a scaffold to get to the motor-operated valve, the licensee found that the finger switches in the operator were at the 45 degree position vice the 90 degree position. This can allow some of the functions controlled by the finger switches to make up, while others may not.

From INPO SOER 09-1:

Perry Nuclear Power Plant - the protected DHR pump tripped while operating in the shutdown cooling mode late in the outage. This occurred when an instrument and control technician attempted to install a jumper in a protected reactor protection system control panel to support testing. Decay heat removal was lost for approximately one hour, resulting in a temperature increase of 3°F. The activity could have been performed at a less risk-sensitive location, during a less risk-sensitive time of the outage, or in a different manner without the use of intrusive jumpers.

Brunswick Steam Electric Plant Unit 2 - valve technicians stroked a DHR motor-operated pump suction valve in a protected equipment train without Operations approval. When the valve started to close, it lost its open limit, causing the running DHR pump to trip. This resulted in a loss of DHR for approximately 15 minutes.

James A.FitzPatrick Nuclear Power Plant - an emergency distribution bus was inadvertently deenergized during testing of a lockout relay on its normal AC distribution bus. This, in turn, resulted in the loss of a reactor protection system bus that caused a loss of DHR. Shutdown cooling was restored in 30 minutes. Reactor coolant system temperature increased 6°F.

Columbia Generating Station - shutdown cooling was lost for approximately 46 minutes when an unexpected trip of the running DHR pump occurred on closure of the containment inboard suction isolation valve. The plant was in day three of the outage, with reactor vessel level at 70 inches. Reactor coolant system temperature increased 34°F before shutdown cooling was restored.

4.10.6 Configuration Control

It is the responsibility of the Licensee to know the position of each valve, switch, and breaker in the plant. If a component is out of position then operation of this component or associated equipment and systems can be adversely impacted. The consequences can be as extreme as to challenge the safety of the reactor and personnel.

On September 9, 2011, the licensee commenced control rod scram time testing. Shortly after testing began, operators noticed control rod speeds were faster than anticipated. This was incorrectly assessed to be from a higher than normal differential pressure due to a RPV leak test, which was in progress at the time. During control rod (#1451) withdrawal activities the control rod inserted from notch 38 to 30. The control rod was isolated/disarmed and improperly diagnosed to be the result of directional & scram valve maintenance that had been performed earlier in the outage. Technicians continued with rod testing. During control rod (#1851) withdrawal activities the control rod inserted from notch 34 to 26 then withdrew immediately to notch 40. The Shift Manager then directed all CR activities to be suspended. It was determined the control rod drive (CRD) exhaust header configuration had not been properly aligned. This was corrected; exhaust header filled & vented; subsequent control rod testing completed satisfactorily. Contributing causes to the event included; inadequate use of procedures, failure to verify valve line-ups, lack of configuration control, and non-conservative decision making.

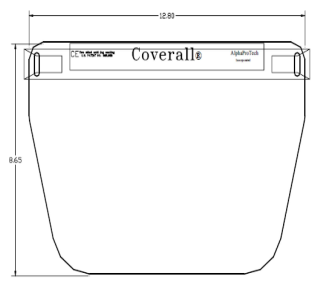
4.10.7 Industrial Safety and FME OE

FERMI 2 & SOUTH TEXAS PROJECT 1 - WORKER PROTECTIVE FACE SHIELDS LOST IN REACTOR CAVITY

This OpE COMM was drafted to inform agency staff of two recent events associated with personnel protective face shields. Both events occurred at domestic power facilities during refueling outages (RFO). Aside from obvious benefits face shields provide to personnel working in hazardous locations; they also become sources of foreign material intrusion (FMI).

Discussion:

Fermi 2 (November 2010); Licensee completed reinstallation of Steam Dryer assemblies. During cavity decontamination & drain down activities, a worker dropped a face shield into the reactor cavity. The Polyethylene Terephthalate (PET) face shield (see diagram) was believed to have "knifed" into the reactor cavity and immediately sank to bottom of core. At the time of event, Division II RHR was operating in SHUT DOWN COOLING mode and face shield was believed to have been drawn into the RHR line. There were no definitive sightings or exact knowledge of where the face shield relocated. Following a lengthy search of (approximately 17 hours) plant personnel were unable to find & retrieve lost face shield. The licensee made a decision to proceed with reactor pressure vessel (RPV) head setting activities and made preparations to perform a reactor plant startup/heatup.



Size: 12-3/4" x 8-5/8" x 7 mils.

This decision was promptly challenged by Agency staff. With an object consisting of this size and material composition, there were concerns and several unanswered questions.

Questioning included:

1. Specifics regarding fuel bundle/assembly geometry; orifice sizing & quantities, etc.

2. Vendor (GE) chemical & destructive analysis (behavioral characteristics of face shield materials in an RCS environment). Impacts on metals.

3. Core flow/Fuel channel characteristics & concerns associated with DRYOUT (worst case scenarios)

4. Startup (heatup) "SOAKING" requirements (times & temperatures) to ensure face shield materials would fully dissipate and not cause blockage related issues.

5. Startup checklist and contingency planning (incl. specialized Reactor Operator training)

6. 10 CFR 50.59 submittal; Changes, Tests, or Experiments, (plant startup with a lost object in RCS was not an analyzed condition). Is a reactor start-up with unknown foreign objects or debris located in the core classified as an "experimental startup" (??). The staff discussed this and concluded the licensee was required to submit a 10 CFR 50.59 - Changes, Tests, & Experiments, prior to reactor start-up. This was further supported by NEI 96-07 guidance document for implementing 50.59s.

The Agency's position was the loss of the face shield into the primary system should be considered a maintenance-related activity which failed to restore systems to the "as designed" configuration (potential for fuel channel blockage, RHR HXs, etc.), a 50.59 evaluation was required to be completed to evaluate these conditions. (Note: Items restricted transitioning to MODE 2 until adequately addressed)

<u>EVENT #2:</u> South Texas Project 1 (April 2011); most recently, a worker inadvertently dropped a face shield into the reactor cavity. The face shield immediately sank to bottom of reactor cavity and was drawn into the '1C' Residual Heat Removal (RHR) pump. The '1C' RHR pump started exhibiting both excessive vibrations & low flow conditions and was secured. 23 fuel assemblies were off-loaded to facilitate removal of face shield debris. Over the course of the next few days, licensee successfully removed all but a 2" x 2" piece of the face shield from the RCS.

<u>Conclusion:</u>

Both events could have been avoided by adhering to proper foreign material exclusion controls in the vicinity of an open reactor coolant system, core area, or refueling cavity. Both events resulted in significant evaluations by the licensees, vendors, and inspectors to ensure continued <u>safe</u> nuclear plant operation. Both events resulted in significant outage delays, recovery resources, and man-hour expenditures.

Hatch - Mobile Crane Strikes a 500 kv Switchyard Disconnect, Causes Loss of One Bus

While positioning a crane to support removing a microwave tower, the boom contacted a support column and damaged a portion of the 500 KV ring bus (a 500kv switchyard disconnect). The affected bus was manually de-energized, temporary repairs were made and re-energized. The licensee concluded all Offsite qualified circuits remained operable during the event. Hatch has two switchyard sections, a 500kv side and a 230kv side cross-tied via an Auto Bank Transformer. All Start-up Auxiliary Transformers are supplied via the 230kv switchyard. Therefore, the impact of this particular event had little safety significance.
The planned path of the crane in the switchyard was walked down prior to the crane

entering the switchyard. An Infrequently Performed Test or Evolution briefing was held for all involved personnel. The crane operator was assisted by two spotters. As the crane moved near a support column, the crane boom struck the column, knocking it down. The preliminary cause was determined to be a lack of clear communications between the spotter and crane operator

4.10.8 Summary

Shutdown risk can be high for deficiencies that occur when vital SSCs are not available. Due to potentially high number of out-of-service SSCs during the fuel handling period of a refueling outage and the potential off-normal plant configurations during non-fuel handling outage periods, the risk of deficiencies can be high.

A refueling outage contributes one-third of the overall core damage frequency, according to one plant’s all-mode probabilistic risk assessment model. This is notable because the plant is in an outage only 5 percent of the time. This vividly underscores the importance of shutdown safety and the measures station staffs should undertake to ensure sufficient safety margins during outage periods.
In 2008, the U.S. industry experienced more loss-of-shutdown-cooling events (nine) than any other year in the past five years. Unacceptable events have adversely impacted each of the shutdown safety functions.
Recent shutdown safety events often involved individuals taking actions that initiated the problem, because of procedure or process inadequacies or insufficient barriers to human error. The pattern of events that challenge shutdown safety indicates that renewed management attention is needed to ensure that outage planning and execution are rigorous and provide conservative margins to shutdown safety functions. The events also reveal challenges to nuclear safety culture principle. Reactivity control, continuity of core cooling, and integrity of fission product barriers are valued as essential, distinguishing attributes of the nuclear station work environment.

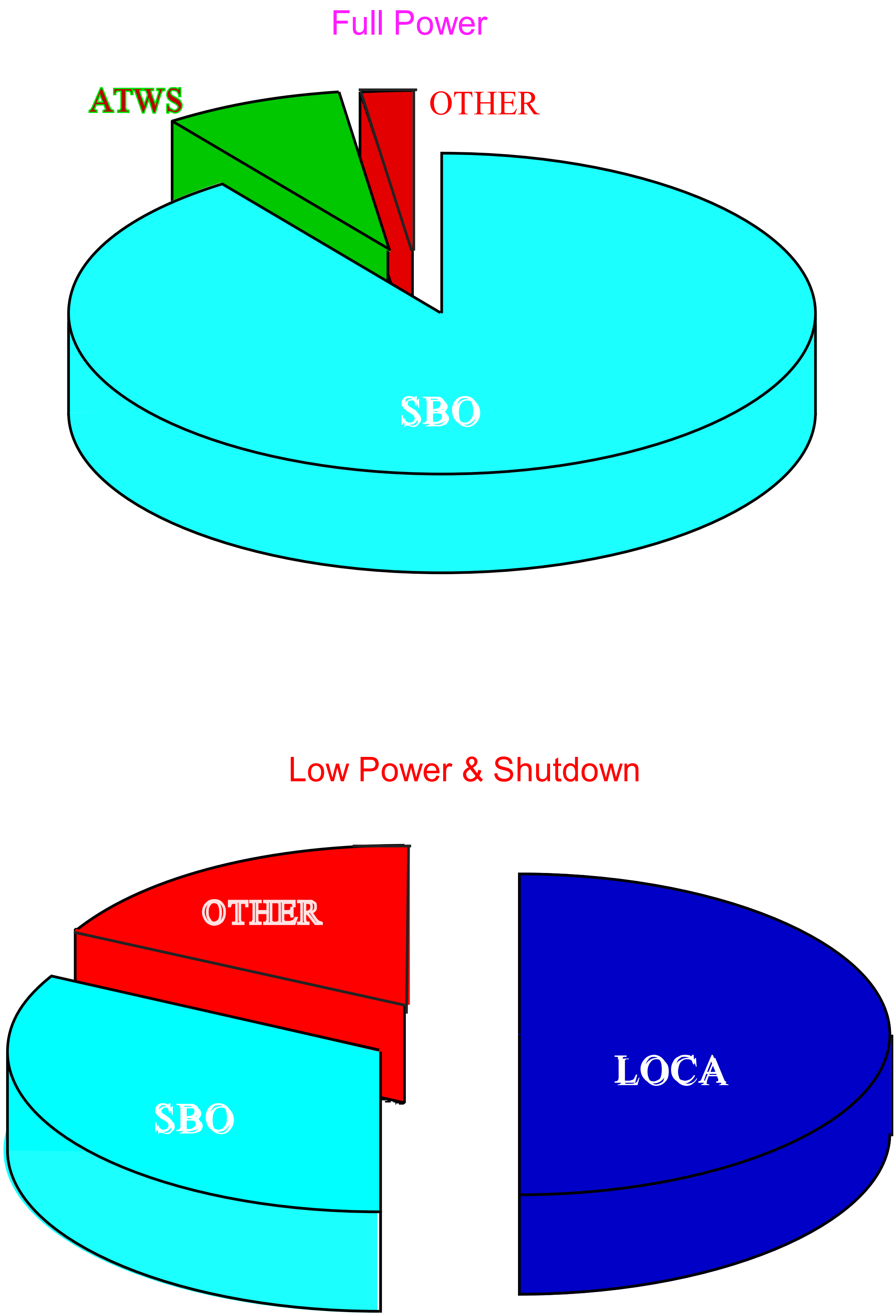


Figure 4.10-1 Accident Sequence Comparison

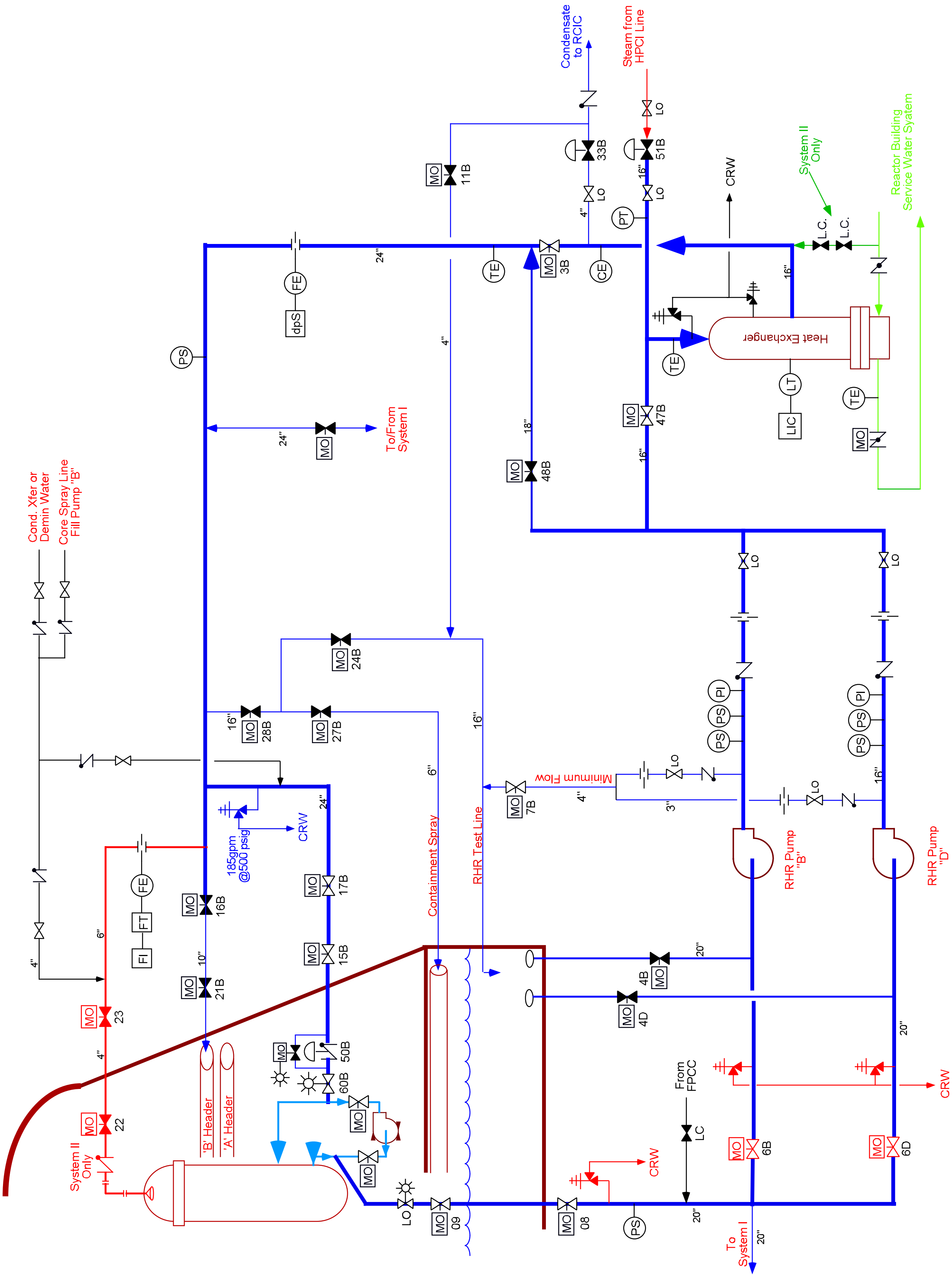


Figure 4.10-2 RHR System Shutdown Cooling Mode

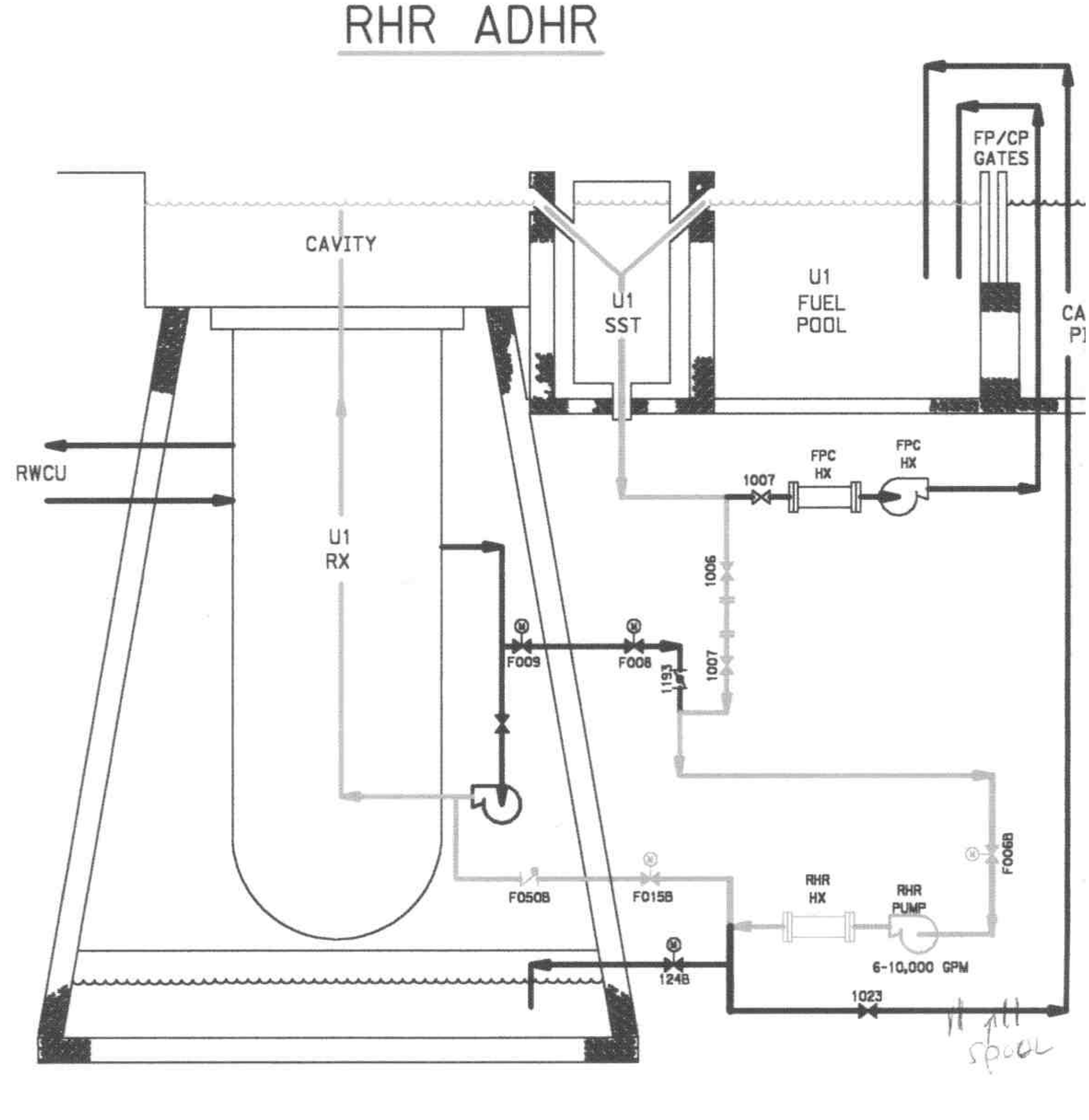


Figure 4.10-3 RHR in ADHR Mode