NUREG/BR-0051
Vol. 6, No. 4

POWER REACTOR EVENTS

United States Nuclear Regulatory Commission

Date Published: February 1985

Power Reactor Events is a bi-monthly newsletter that compiles operating experience information about commercial nuclear power plants. This includes summaries of noteworthy events and listings and/or abstracts of USNRC and other documents that discuss safety-related or possible generic issues. It is intended to feed back some of the lessons learned from operational experience to the various plant personnel, i.e., managers, licensed reactor operators, training coordinators, and support personnel. Referenced documents are available from the USNRC Public Document Room at 1717 H Street, Washington, DC 20555 for a copying fee. Subscriptions and additional or back issues of Power Reactor Events may be requested from the NRC/GPO Sales Program, (301) 492-9530, or at Mail Stop P-130A, Washington, DC 20555

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Editor: Sheryl A. Massaro
Office for Analysis and Evaluation
of Operational Data
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Period Covered: July-August 1984

1.0 SUMMARIES OF EVENTS

1.1 Refueling Cavity Water Seal Failure

During a refueling outage at Haddam Neck* on August 21, 1984, the reactor refueling cavity water seal failed, draining the refueling pool water to the containment floor in about 20 minutes. The plant had been shut down for refueling on August 1. After several days of surveillance testing, reactor disassembly began on August 12 in preparation for refueling. Core cooling was maintained using the residual heat removal (RHR) system. The cavity seal, which covers the 28-inch annulus between the reactor and the bottom of the reactor pressure vessel refueling cavity, was installed and tested on August 18 and the refueling pool was filled early on August 21. At 7:58 a.m. on August 21, the seal assembly failed, dumping 200,000 gallons of borated water around the neutron shield tank surrounding the reactor vessel and into the containment sump below the vessel. This sump overflowed into the containment floor drains and onto the lower level of containment. Water also leaked out around the reactor coolant loop penetration piping and wetted components inside the loop areas of containment.

During the first three minutes of the event, operators were responding to control room alarms and indications including 480 V grounds, high containment sump level, and decreasing reactor cavity level. Flooding was reported in containment. Upon identification of the loss of refueling cavity integrity, the operators took action to minimize the drainage to containment by realigning the RHR system to pump the cavity water (and subsequently containment sump water) to the refueling water storage tank (RWST). By 8:22 a.m., the refueling cavity had emptied and the RHR system was returned to a normal lineup. Core cooling was maintained throughout the event and reactor coolant temperature did not change. The containment lower level filled to a depth of 18 inches, and 40,000 gallons of coolant were returned to the RWST.

The licensee restricted containment access and replaced the reactor vessel head to minimize radiation exposure. The licensee suspended refueling operations until a failure analysis and corrective actions were completed and until the NRC reviewed and approved the plant recovery program. Since the spent fuel transfer tube was isolated and all of the spent fuel assemblies were located in either the spent fuel pool (SFP) or the reactor vessel, no fuel was uncovered during this event. Radioactivity in the ongoing releases of air from the reactor containment building increased, but remained well within allowable limits. The only significant actual consequences were exposing equipment and structures

*Haddam Neck is a 569 MWe (net) PWR located 13 miles east of Meriden, Connecticut, and is operated by Connecticut Yankee Atomic Power.

in the containment to water damage, and extensive cleanup efforts. After considerable review, evaluation, and plant modification, refueling operations resumed on October 5, 1984.

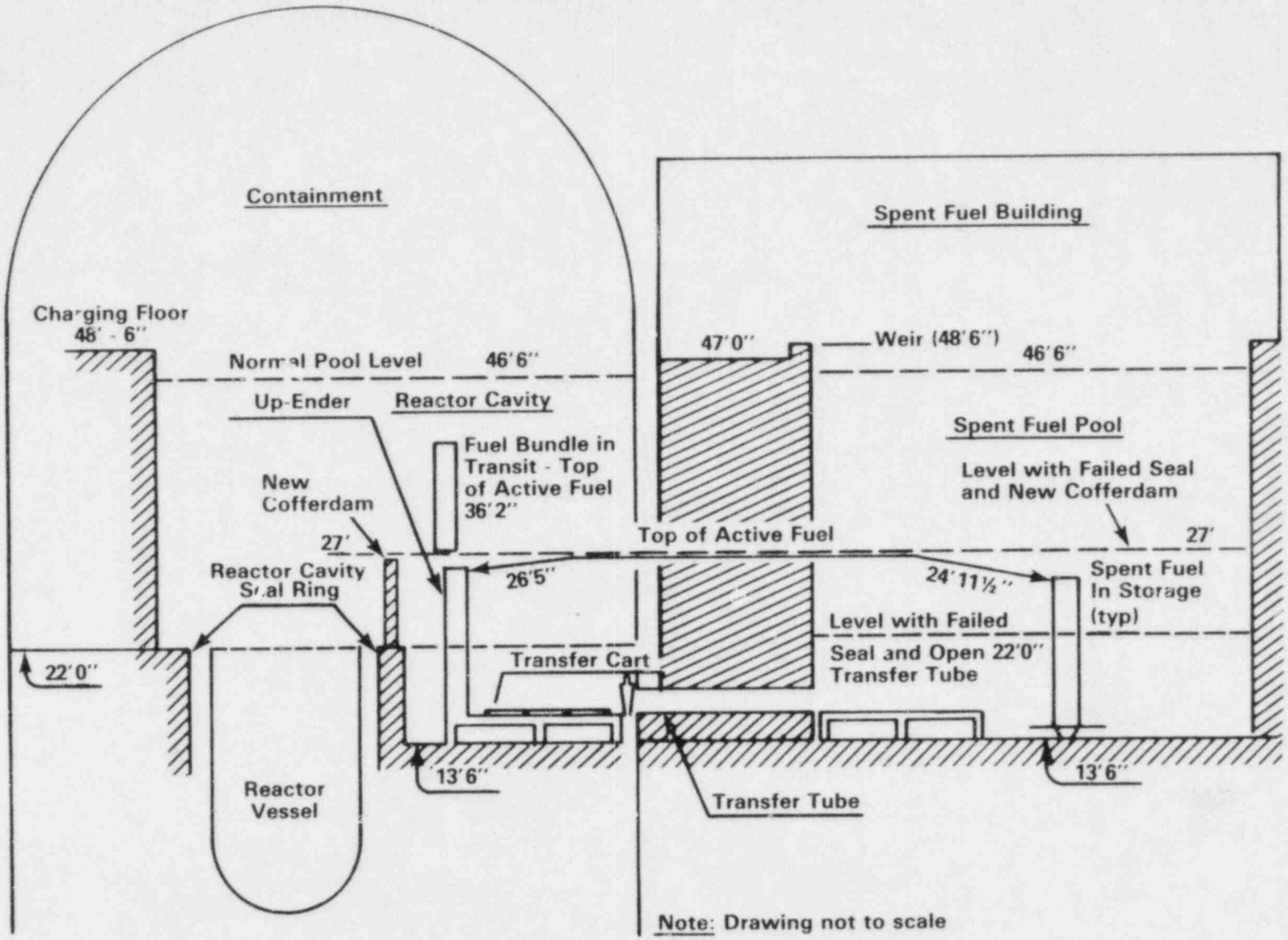
However, there were serious potential safety consequences which could have occurred not only during this refueling but also could have occurred during the previous refueling operations when the same design seal was used. For example, the SFP gates would have been opened within an hour of the seal design failure and handling of spent fuel assemblies in the refueling cavity could have been in progress within 18 hours. If refueling had been in progress, as many as four spent fuel assemblies could have been partially or fully uncovered as the reactor cavity drained. In addition, the top 3 feet of all fuel assemblies in the SFP would have been uncovered if the pool had drained through the transfer tube. Fuel assemblies recently removed from the reactor vessel would be even more radioactive (and generate considerably more decay heat) than spent elements stored for some time in the SFP. In all cases, there was a potential for fuel rod damage from overheating with subsequent release of gaseous fission products from the damaged fuel rods. In addition, loss of the water would reduce the radiation shielding for spent fuel. This would have increased the radiation field in the refueling areas which could have precluded those operator actions necessary to prevent overheating of fuel being moved to or stored in the SFP. Preliminary calculations indicated that a dose rate at 30 feet from a single uncovered assembly (6-day decay, 33,000 MWD/metric ton irradiation history) is about 50,000 R/hr.

The event was caused by inadequate design of the replacement pneumatic seals used in the cavity seal assembly. The top of the reactor vessel is at the bottom of the refueling cavity, with a 28-inch annulus between the vessel and the bottom of the cavity. (See Figure 1.) This annulus is sealed using a 2-foot-wide stiffened annular plate with inflatable rubber pneumatic seals around the inside and outside diameters.

This seal assembly fits around the reactor vessel and is held in place by nine strongbacks resting on the reactor vessel flange on the inside and on the refueling cavity bearing plate on the outside. When the pneumatic seals are inflated, the bulging of the lower seal section pulls the wedge-shaped upper seating surfaces of the seal down into the two 2-inch gaps. This was intended to create and maintain a tight seal. The refueling cavity is then filled with borated reactor coolant to cool and shield the spent fuel elements moved during refueling. This is a new seal assembly design, first implemented in January 1983 and used successfully on two occasions during the 1983 refueling outage. The pneumatic seals were neither specified nor properly tested to withstand, with a suitable safety margin, the hydrostatic pressure expected to occur during normal use. Post-event inspection of the seal assembly revealed that the outer pneumatic seal had extruded between the steel plates for about one quarter of the seal circumference. After subsequent testing, the licensee concluded that there was not sufficient margin in the seal design to prevent extrusion of the rubber pneumatic seal through the 2-inch gap. The design verification by an independent engineer, the safety evaluation, and the review by the onsite and offsite review committees all failed to identify the inadequate seal design.

The licensee immediately initiated a recovery program which included NRC and industry notification, containment dewatering/decontamination, equipment damage

Figure 1. Schematic of Reactor Cavity Pool Seal Failure With Transfer Tube Open



assessment, seal failure analysis, seal modifications, integrated event safety analysis, and procedure review.

The standing water in the containment, which was mildly contaminated (0.01 mCi/ml), was pumped to the RWST through the filter and ion exchanger of the refueling purification system. Removal of this water was completed on August 23, 1984. Two days of manual decontamination and cleanup followed. On August 25, routine access to the containment lower level was restored.

The licensee conducted inspections of equipment and structures in the containment in order to assess the potential for equipment damage. A comprehensive list of submerged or water-soaked equipment was developed. Each item was repaired, flushed and/or evaluated to reaffirm the ability of each component to perform its design function. Major equipment affected included the reactor vessel, reactor coolant piping, nuclear instrument detectors, motor-operated valves, electrical cables and conduits, and containment sump pumps.

As stated previously, the licensee's failure analysis identified that there had been insufficient design margin to prevent the pneumatic seals in the seal assembly from extruding through the 2-inch gap in the seal structure. To correct this design error, the licensee reinforced the upper portion (solid rubber) of the pneumatic seals by pressing 3/16-inch steel pins through the elastomer at 3-inch intervals around the circumference of the seals. Subsequent testing confirmed that a safety factor of 4 with respect to extrusion of the pneumatic seal had been established by this modification.

In addition, the licensee installed a leak-limiting back-up cavity seal and a 5-foot-high cofferdam at the mouth of the refueling transfer canal. In the event of another failure of the pneumatic seal, the back-up seal limits the leak rate such that operators have enough time to recognize and react to the event and return spent fuel in the reactor cavity to a safe position prior to uncovering any fuel. The back-up seal also provides a measure of impact protection to the primary rubber seals. The cofferdam prevents uncovering fuel in the spent fuel pool for any future reactor cavity seal problem.

The licensee performed an integrated safety analysis for reactor cavity seal failure events. This analysis showed that a significant reduction in the probability and consequences of such an event had been achieved, and that public health and safety would not be jeopardized during a subsequent seal failure event.

On August 24, 1984, NRC issued Inspection and Enforcement (IE) Bulletin No. 84-03 to inform licensees of this occurrence. The bulletin required each licensee to evaluate the potential for a similar event at their facility and to summarize this evaluation in writing to the NRC prior to refueling. On December 17, 1984, NRC issued IE Information Notice 84-93 to inform licensees of features in some PWRs and BWRs that may have a significant potential to cause loss of water in the refueling cavity, as discussed below:

- While evaluating the potential for loss of water from refueling cavities at other plants, the NRC staff learned from the Electric Power Research Institute (EPRI) that reactor cavity seal development testing had been previously performed. This seal testing was sponsored by EPRI as part of a "Refueling Outage Availability Improvement Program." These tests (completed in 1981) initially resulted in a failure mode very similar to that experienced by the Haddam Neck plant. However, this failure mode was not observed in further testing with a modified seal design. This EPRI testing indicates that the performance of pneumatic seals is very sensitive to seal design details and to plant-specific refueling cavity design details, including variations in cavity gap dimensions.

- Other potential failure modes of the refueling cavity seal have been identified, since the incident at the Haddam Neck plant, which could cause a rapid loss of water in the refueling cavity at some plants. San Onofre Unit 2* recently experienced several problems while installing the reactor cavity seal in preparation of the unit's first refueling. This unit has redundant (inner and outer) pneumatic seals. The inner pneumatic seal was punctured during installation. The seal was replaced with a spare. The spare seal also failed during testing as a result of a manufacturing defect in the seal wall. Both the above failures were discovered and corrected before flooding the reactor cavity. Failures, like those reported at San Onofre Unit 2, could cause a rapid loss of cavity water (if the cavity were flooded) at plants with nonredundant pneumatic seals. Some pneumatic/flexible seals also may be susceptible to damage from the impact of dropped objects after the cavity is flooded.

- In addition to the refueling cavity seal, pneumatic seals also are used as hot and cold leg nozzle dams in PWRs and, for some plants, in gates between the spent fuel pool and the fuel transfer canal. The failure modes and concerns expressed above for the pneumatic refueling cavity seal also apply in many cases to these other pneumatic seals. Nozzle dams are of particular concern, when the steam generator primary is open during refueling.

- The refueling cavity also can be partially drained (PWR or BWR) by certain misalignments of the RHR valves while in shutdown cooling mode (assuming that shutdown cooling is in use when the cavity is filled). GE SIL No. 388, "RHR Valve Alignment During Shutdown Cooling Operation For BWR 3/4/5 and 6," dated February 1983, and IE Information Notice 84-81, "Loss of Reactor Pressure Vessel Coolant Inventory in Boiling Water Reactors," dated November 16, 1984, discuss these possibilities in a BWR. Nuclear Safety Analysis Center report, NSAC-52, "Residual Heat Removal Experience Review and Safety Analysis, Pressurized Water Reactors," dated January 1983, discusses these possibilities in a PWR.

- Finally, there are numerous ways in which the refueling cavity of a PWR or BWR could be drained at a slower rate through one of the attached drain lines. Adequate emergency procedures and properly calibrated refueling cavity water level instrumentation are considered to be important in the mitigation of any loss-of-cavity-water accident. (Refs. 1 through 3.)

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*San Onofre Unit 2 is a 1070 MWe (net) PWR located 5 miles south of San Clemente, California, and is operated by Southern California Edison.

On December 13, 1984, the NRC forwarded to the licensee a Notice of Violation and Proposed Imposition of a Civil Penalty in the amount of $80,000; in addition, an Order modifying the license was imposed. The Order requires a review and appraisal by an independent organization of (1) design modification packages approved since January 1, 1979 to determine the adequacy of design control and to determine whether each such modification introduced any previously unanalyzed failure mode or mechanism; and (2) the process for initiating, evaluating, reviewing, approving and implementing design change modifications to determine if deficiencies exist in the process, and to provide recommendations for improvement.

1.2 Testing Results in Station Blackout

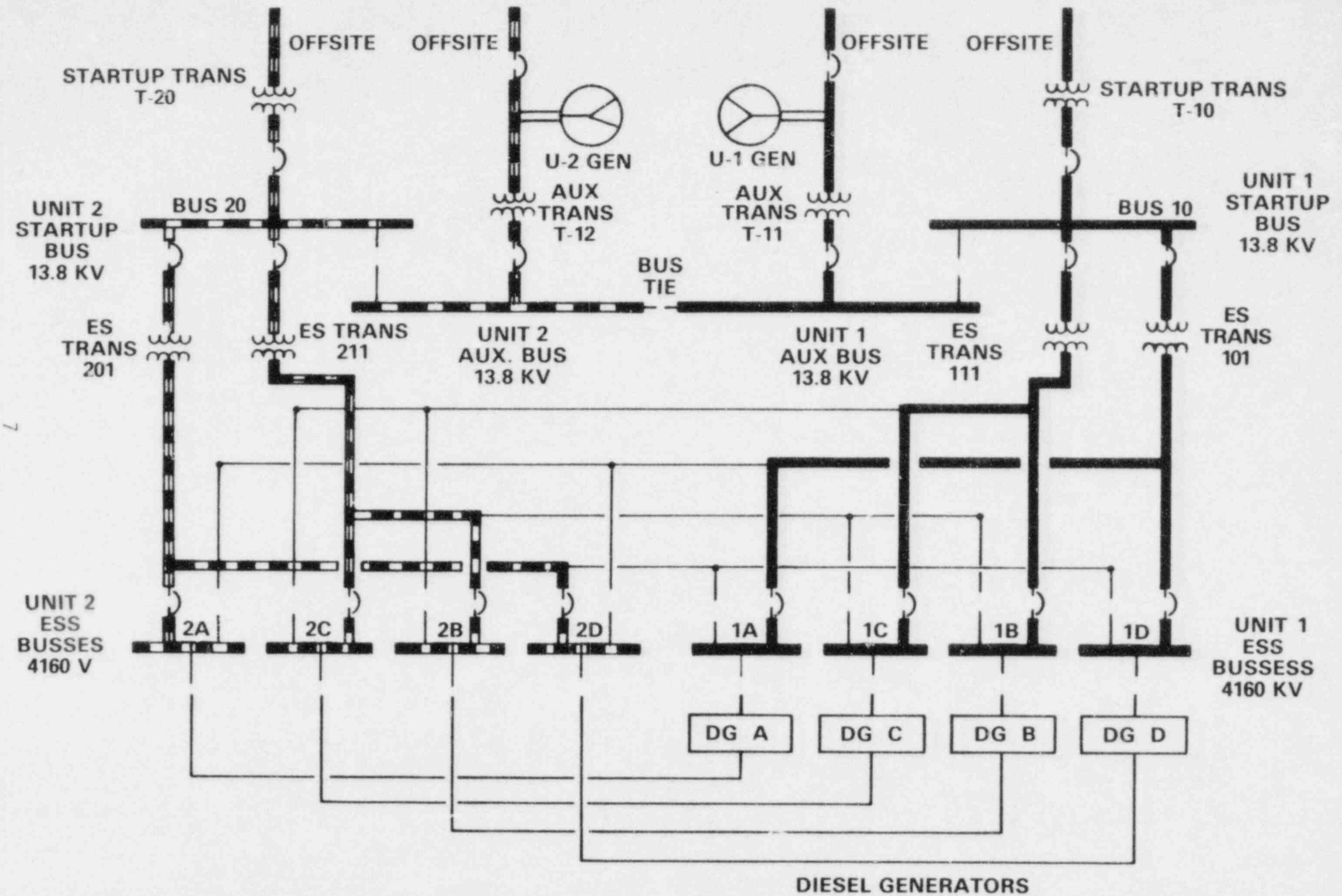
On July 26, 1984, Susquehanna Unit 2 experienced an event involving a temporary loss of all ac power including failure of the emergency diesel generators (EDGs) to supply power to the engineered safety system (ESS) busses. Unit 2 had received a full power operating license on June 27, 1984. The licensee was conducting planned startup testing at 30% power at the time of the event. Unit 1 operated at 100% power throughout the event at Unit 2.*

A loss of offsite power is an event which may occur one or more times during the life of a nuclear power plant; thus, all plants are designed to respond to such events. The purpose of the startup test ("Loss of Turbine Generator and Offsite Power") was to demonstrate that the dynamic response of Unit 2 was in accordance with design. Initial conditions of the test required Unit 2 to be at approximately 30% power and its electrical distribution system to be separated and isolated from the Unit 1 system. (See Figure 2.) The test would be initiated by opening the Unit 2 turbine-generator output breakers and simultaneously opening the Unit 2 output breaker from the startup transformer, simulating a turbine generator trip (load reject) and loss of offsite power, respectively. Thirty minutes after the test initiation, the test would be terminated. The test results would then determine whether test acceptance criteria are satisfied; i.e., (1) all safety systems such as the reactor protection system (RPS), EDGs, reactor core isolation cooling (RCIC) system and high pressure coolant injection (HPCI) system, must function properly without manual assistance, and (2) HPCI and/or RCIC action, if necessary, shall keep reactor water level above the initiation level of the core spray system, low pressure coolant injection (LPCI) system, and automatic depressurization system (ADS). The actual test did not proceed as intended, as discussed later.

Separation and isolation of electrical supplies for this test required (1) feeding all Unit 1 4160 V ESS busses from the Unit 1 startup transformer, (2) feeding all Unit 2 4160 V ESS busses from the Unit 2 startup transformer, (3) racking out all feeder breakers from the Unit 1 startup transformer to the Unit 2 4160 V ESS busses, (4) racking out the 13.8 kV tie breaker between Unit 1 and Unit 2 auxiliary busses, and (5) placing all common loads on Unit 1 supplies. This electrical configuration and other test prerequisites were established by 1:05 a.m. on July 26, 1984.

*Susquehanna Unit 1 is a 1032 MWe (net) BWR, and Unit 2 is a 1065 MWe (net) BWR. Both are located 7 miles northeast of Berwick, Pennsylvania, and are operated by Pennsylvania Power and Light.

FIGURE 2. INITIAL TEST CONDITIONS



The startup test was initiated at 1:37 a.m. by opening the Unit 2 main generator output breakers and the Unit 2 startup transformer feeder breaker to the Unit 2 startup bus. This resulted in a reactor scram due to turbine control valve fast closure on the simulated load reject, deenergization of the 13.8 kV busses and deenergization of the four Unit 2 4160 V ESS busses. The turbine bypass valves properly opened automatically to limit the initial pressure transient, and the loss of power to the RPS motor generator sets properly initiated primary and secondary containment isolations. The above sequence was as expected; however, the operator at the electrical distribution panel noted that none of the four EDGs started and that the feeder breakers from the two Unit 2 ESS transformers to the four 4160 V ESS busses remained closed. These breakers should have automatically opened and the diesels should have started upon ESS bus deenergization due to the deenergized startup transformer. As a result of the diesels not starting, and providing emergency ac power, all ac power for Unit 2 was lost.

As discussed later, this total loss of ac power resulted in most instrumentation in the control room failing downscale which complicated operator response to the event. Also as discussed later, simultaneously with the total loss of ac power, the plant was further degraded due to the lack of dc power to the ESS bus logic circuitry for all four electrical divisions. The operators were unaware of this lack of dc power since the plant design did not provide control room annunciation of this condition. The consequences of the deenergized ESS bus logic circuitry resulted in loss of the following functions: (1) automatic transfer capability of ESS busses to alternate power sources, (2) automatic diesel generator start on loss of bus sources, (3) ability to reenergize 4160 V ESS busses from an offsite source from the control room, (4) automatic bus load shedding, (5) degraded grid and undervoltage protection, (6) 4160 V bus feeder breaker overcurrent or differential current protection, and (7) core spray or residual heat removal (RHR) pump automatic or manual start capability even with bus power available; hence the low pressure emergency core cooling systems (ECCSs) were disabled.

Upon noting that the EDGs did not start, the operator opened the feeder breakers from the two Unit 2 ESS transformers to the four 4160 V ESS busses. When the EDGs still did not start, the operator manually started all four diesels. EDG D tripped on overvoltage and B tripped on overvoltage and underfrequency. EDG C stabilized at an idle. EDG A exhibited large frequency oscillations and was manually tripped by the operator. The operator tried to manually close the EDG C breaker onto the associated ESS bus, but the breaker did not close (probable operator error). The operator next attempted to close the Unit 2 startup bus feeders to the two Unit 2 ESS transformers, but the feeder breakers would not close due to the deenergized condition at the startup bus. The operator then reenergized the startup bus by closing the Unit 2 startup transformer feeder breaker to the startup bus and reenergized the two Unit 2 ESS transformers. The operator next attempted to close the Unit 2 ESS transformer feeder breakers to the 4160 V ESS busses, but the feeder breakers would not close. The Unit Supervisor then instructed a Nuclear Plant Operator in the Unit 2 reactor building to rack in the feeder breakers from the Unit 1 startup transformer to the four Unit 2 4160 V ESS busses.

As the Unit 1 feeder breakers to the Unit 2 4160 V ESS busses were racked in, the preferred Unit 1 and 2 ESS transformer feeder breaker to each 4160 V ESS bus closed, reenergizing the bus, and the EDGs B, D, and A automatically started at 1:48 a.m., 1:50 a.m., and 1:54 a.m., respectively. Power was restored to the first bus within 11 minutes and the last bus 17 minutes into the event. When power was restored to all four Unit 2 ESS busses, EDGs A, B, and D had high priority alarms and were remote-manually shut down. The operator in the EDG building reset the high priority alarm on EDG A, but could not reset the High Priority alarm on EDGs B and D (operator error).

During the loss of all ac power to Unit 2, most instrumentation in the control room failed downscale. However, dc powered instrumentation was available to the operators, including two narrow range instruments (0-60 inches) for monitoring reactor water level and the HPCI and RCIC supply pressure indicators for monitoring reactor pressure. The full core display provided erroneous indication that all rods had not inserted into the core, which initially confused the operators, but operators determined the reactor was shut down because the source range monitor instrumentation indication and reactor pressure trends supported that conclusion. (Subsequently, after power was restored, a computer printout verified that all rods were inserted.) The control room operators had no indication of suppression pool temperature and no indication of reactor water level, below narrow range instrument zero. Personnel stationed at the local instrumentation racks as part of the startup test provided information to the control room when reactor water level dropped below this zero reading. Prior to the test, the control room operators reviewed some of the procedures for responding to a loss of control room instrumentation and were prepared for some of the occurrences.

During the event, one safety relief valve controlled reactor pressure and removed decay heat by lifting eight times. At 2:18 a.m., RCIC was manually initiated at -28 inches reactor water level on the wide range instrument (a level above the automatic initiation level of -31 inches) to restore reactor vessel level.

There was no direct impact on public health or safety by the event. Even though some safety-related equipment designed to mitigate the consequences of design basis accidents, in the unlikely event that one occurred, was disabled, the HPCI and RCIC systems were available to provide makeup water to protect the core until power was restored. During the event, no makeup water was being added to the reactor vessel. However, had the water level decreased sufficiently, HPCI and RCIC would have automatically initiated to restore water level, since power from the vital power system was available to them. As discussed previously, RCIC was manually initiated before the automatic initiation level was reached.

The causes of this event are attributed to inadequate implementation of corrective action for previously identified problems, inadequate human engineering of the local control panels, ineffective independent verification, imprecise procedures, inadequate operator training, and operator error. One example of potentially confusing operational panel layouts is the control room diesel generator horizontal panel layout showing the ESS busses, synchronization switches, and manual switches in an A-C-B-D, left-to-right arrangement for divisional separation. However, the layout on the vertical panel just above the horizontal panel is arranged in an A-B-C-D, left-to-right configuration. During abnormal events, verifying proper diesel generator operation requires more than normal attention.

The process utilized to rack out each of four Unit 1 startup transformer supplies to Unit 2 4160 V ESS busses (one of the steps necessary before initiating the startup test) was incorrectly performed. The normal practice for racking out a 4160 V breaker is to ensure the breaker is in the open position, enter the breaker cubicle and open the dc knife switch supplying dc control power for the breaker, and then to rack out the breaker. However, for these four breakers the operator was confronted with two dc knife switches and mistakenly opened the wrong switch, thereby removing dc power to the ESS bus logic circuitry for the bus rather than the dc control power to the breaker. The operator repeated the above error on all four 4160 V ESS busses. As discussed previously, one of the consequences of removing dc power to this ESS bus logic circuitry was to prevent EDG start on loss of bus sources, and to complicate recovery of alternate power sources.

The Unit 1 startup transformer supply breakers to the Unit 2 4160 V ESS busses are located in the 01 cubicle of each bus. Each 01 cubicle has two knife switches whereas all other breakers in the 4160 V ESS bus have only one knife switch. The knife switch labels used in cubicles containing a single knife switch read "BREAKER CONTROL SWITCH AND TRIP CIRCUIT FUSES." This knife switch removes dc control power for the breaker. The operators commonly refer to this knife switch as "DC control power." The 01 cubicle breaker labels for the two knife switches read: "BREAKER CONTROL SWITCH AND TRIP CIRCUIT FUSES" (for the knife switch that removes dc control power for the breaker) and "DC CONTROL" (for the knife switch that provides dc power to the ESS bus logic circuitry for the bus). When the operator opened the first 4160 V ESS 01 cubicle door, he called the control room, informed them he was at the breaker and requested confirmation that they desired the breaker be racked out and dc control power removed. After receiving confirmation from the control room, the operator subsequently opened the knife switch labeled "DC CONTROL" and racked out the breaker. An experienced startup test engineer was with the operator to verify the adequacy of his actions, but did not detect the error. The same operator and startup test engineer repeated the same action at each of the 4160 V ESS busses.

No alarm indication of these actions was available in the control room, although an examination of local indicator lights on the front of the cubicle door would have shown an abnormality, i.e., the bus feeder protection relay power light would have been extinguished. Also, an examination of the breaker position lights in the control room as the knife switch was opened in the breaker cubicle could have alerted operators that the incorrect knife switch had been opened. (Opening the knife switch labeled "BREAKER CONTROL SWITCH AND TRIP CIRCUIT FUSES" should have deenergized all indicating lights associated with the breaker. This would not have occurred when the knife switch labeled "DC CONTROL" was opened.) This anomalous indication that could have alerted the control room of the error was subsequently lost when the breaker was racked out.

During the investigation of the event by the licensee and NRC, two previous events were identified involving improper operations of the "DC CONTROL" knife switch during the preoperational test program in June and October 1983. Following the second event, the licensee had conducted additional operator training. The operator who performed the breaker alignments on July 26, 1984, did not receive this particular training nor had he previously, according to his recollection, racked out a 4160 V breaker in an 01 cubicle. He was, however, an experienced operator who had performed numerous breaker rackouts.

The difficulties associated with the manual start of the EDGs and reset of the high priority alarms were primarily due to inadequate procedures, inadequate operator training, and operator error. The trips of EDGs B and D both were the result of the frequency sensitivity of the overvoltage relays coupled with the manual voltage adjust having been set, per procedure, at too high a level. The underfrequency trip of EDG B is believed to have been received as a result of the shutdown of EDG B following the overvoltage trip. It should be noted that during an automatic initiation of the EDG these two trip signals would be bypassed.

The cause of the frequency oscillations of the EDG A which led the operator to manually trip this EDG has not been determined. Seven successful manual starts of EDG A were performed after the event, with no observed frequency oscillations. The inability to manually load EDG C onto the dead ESS bus is believed to have been caused by operator error, in that post-event analysis determined the capability to have been available, even under event conditions, and subsequent testing was performed to demonstrate this capability.

The difficulties associated with reset of the high priority alarms on EDGs B and D were due to the operator not being aware that the design required that the protection relay seal-in reset button be operated prior to the system reset button. In addition, operating procedures were not available locally at the EDG and, even if they were, existing procedures did not specify this particular reset sequence. The proper reset sequence determination was made during the event by the licensee reviewing the EDG control schematics, and approximately 35 minutes was required to complete and actually reset the alarms.

Immediately after the incident, the licensee initiated an investigation into the cause(s) and instituted immediate and long-term corrective actions. Immediate corrective actions included: revising labeling of knife switches, adding caution labels for ESS logic circuitry knife switches, and painting the ESS bus logic circuitry knife switch handles red; providing training in the proper rackout operation; revising procedures to include status of breaker position indicating light checks; performing seven successful starts on EDG A; revising procedures and providing training in EDG operation and alarm reset; successfully testing EDG C's capability to close manually on a dead bus; examining all fuses in the dc control system for size and type; revising the reset procedure for the full core display and training operators in the methods to get rod position information; revising procedures to reset the suppression pool temperature monitoring system after a loss of power; and revising surveillance procedures to assure monthly surveillance procedures do not adversely affect EDG automatic start capability.

The long-term corrective actions include: review and determination of adequacy of the station program for independent verification; review of station standard electrical operating practices for acceptability; development of operating instructions for each type of breaker rackout, including light observance during the manual sequence; incorporation of proper terminology into training procedures; revision of procedures, drawings, and checkoff lists; review and evaluation of the EDG testing program to determine adequacy; determination of adequacy of procedures for remote emergency start of EDGs; development of procedures for remote manual emergency start of EDGs; evaluation of overvoltage protection; determination of whether instrumentation available on loss of ac power is sufficient in number, location, and range for on-shift staff to safely handle a loss of ac power; performance of as-built verification of fuse size, type, and labeling on all 13.8 kV, 4160 V, 480V load centers and DC power circuits; review of all surveillance, preventive maintenance, startup test, and operating procedures that require entry into the 13.8 kV, 4160 V, 480 V, and dc cubicles for technical adequacy and adequacy of control; and evaluation of the present design for compliance with Regulatory Guide 1.47 with respect to annunciation of loss of dc control power. The licensee assessed the event's impact and lessons learned on Unit 2 and applied the appropriate immediate and long term corrective actions to Unit 1 as well.

NRC resident inspectors and a region-based specialist were in the control room witnessing the conduct of this test. They observed the event and the recovery. On July 26, 1984, a team of NRC technical specialists were sent to the site to investigate the circumstances of the event, and it was agreed by the licensee and the NRC that Unit 2 should be brought to a cold shutdown condition and should not be restarted until a thorough investigation of the cause, its implication, and deficiencies thus identified were corrected. Unit 2 restart was approved by the NRC on July 31, 1984, following the successful testing of EDG C's ability to manually load on a dead bus.

The NRC investigation, while not fully documented at the time of this report, has identified several possible generic implications from this event which may require further review. These include: (1) adequacy of annunciation and control room indications; (2) restart capability of emergency diesel generators under abnormal conditions; and (3) adequacy of human engineering aspects including labels, administrative controls, and independent verification requirements. On October 19, 1984, the NRC issued Inspection and Enforcement Information Notice No. 84-76 to inform all licensees, holding an operating license or construction permit, of the event. (Refs. 4 and 5.)

1.3 Overpressurization of Core Spray Piping

During the performance of a core spray logic test at Browns Ferry Unit 1* on August 14, 1984, a Reactor Operator failed to open a breaker, allowing the inboard injection valve (FCV-75-25) to open while the outboard injection valve (FCV-75-23) was in its normally open position. The unit was operating at 100% power. During normal operation, logic interlocks prevent this situation from occurring. This surveillance test, however, simulates automatic core spray actuation; therefore, administrative controls, specifically the opening of the FCV-75-25 breaker, are necessary to prevent valve movement. In this configuration, isolation from the reactor vessel to the core spray system is provided by the testable check valve, FCV-75-26. However, as post-incident investigations indicated, maintenance previously performed on the testable check valve caused it to be held open while indicating closed.

*Browns Ferry Unit 1 is a 1065 MWe (net) BWR located 10 miles northwest of Decatur, Alabama, and is operated by Tennessee Valley Authority.

During the test, at about 9:38 a.m., the core spray system was aligned to the reactor. The Operator in the control room and the Operator conducting the test were aware that FCV-75-25 had opened. This action was not addressed in the procedure, however, and the operator conducting the test proceeded to review the test instruction to ascertain if this operation was erroneous. A core spray system high pressure annunciator, which would have been expected to alarm if the testable check valve was not holding, did not alarm. Also, the Control Room Operator did not notice a system pressure change.

At about 9:45 a.m., a roving fire watch noticed smoke near the Loop I core spray piping, and phoned in a fire alarm. The fire brigade entered the reactor building and correctly assessed that reactor water was leaking back into the core spray system. The Unit 1 Assistant Shift Engineer phoned the Unit 1 Operator and instructed him to close the injection valve to isolate the system. The Operator responded and terminated the event. The duration of the event was approximately 13 minutes. The fire brigade had also noted a water/steam mixture being sprayed from the core spray pump A seal area. Several workers received clothing contamination as a result of walking in this water.

Core spray Loop I was isolated and tagged, which placed the unit in a 7-day limiting condition of operation, and an investigation of the event was begun. Site engineering and maintenance staffs inspected all affected components and found no damage. The extent of the pipe heating was determined by examination of paint damage on the piping. The maximum temperature experienced was estimated to be below 400°F. Paint damage extended from the injection valves down to the system relief valve. The licensee analyzed the system piping and supports for the transient, and found that integrity for continued use was assured. The pump A seal was removed, and no damage was observed. Also, there was no evidence that hot water entered the pump area piping, which indicated that the pump discharge check valve was holding. This apparent seal leakage was attributed to backflow through the above seal leakoff from the clean radwaste drain system header. The system relief valve ties to the same local header.

The investigations and analyses suggested that the testable check valve was not holding. The affected unit was shut down on August 21, 1984, and the drywell was entered for a physical inspection of the valve. This inspection indicated that the testable check valve was being held open because of an improper insert in the testable actuator solenoid resulting in reverse operation. Improper operation of the solenoid apparently caused confusion which resulted in the valve position indicator's wiring being altered to provide the apparent correct indicated position. Maintenance history was researched, but it could not be conclusively determined when the error was made.

The event was determined to be caused by (1) the improper insert in the rebuilt testable actuator solenoid, which caused airflow inside the solenoid to be misdirected; (2) improper wiring of the check valve's position indicator such that the position indicator showed closed when the valve actually was open; (3) the operator error which caused FCV-75-25 to open, and which in part could have been prevented by improved wording in the procedure regarding valve breaker manipulations; and (4) inadequate maintenance instructions.

Immediate corrective action was to correct the solenoid assembly and position indicating circuitry. To prevent recurrence, procedures have been revised to be more descriptive in valve and actuator maintenance and return to service checks. In addition, operator training was conducted on this event with particular attention to valve breaker manipulation, and a change is being made to this surveillance instruction which will make the wording more specific. On September 28, 1984, NRC issued Inspection and Enforcement Information Notice 84-74, describing the Browns Ferry event along with some other related events. Also, the NRC has proposed imposition of a civil penalty in the amount of $100,000 for apparent violations which resulted in overpressurization of the core spray system. (Refs. 6 through 9.)

1.4 Temporary Loss of Shutdown Cooling System Pump Suction

On August 29, 1984, following a reactor trip from 100% power that had occurred approximately 36 hours prior to this event, Arkansas Unit 2* was in cold shutdown and the reactor coolant system (RCS) was being drained in preparation for a reactor coolant pump seal replacement. During this operation, a temporary loss of decay heat removal capability via the shutdown cooling (SDC) system occurred due to cavitation and vapor binding of the B SDC pump. Inadequate water volume in the RCS hot leg piping, which led to the B SDC pump cavitation and vapor binding, was caused by operator actions in response to incorrect RCS level indication.

The RCS was being maintained at approximately 140°F by the B SDC pump and heat exchanger. The A SDC pump was aligned in normal emergency core cooling system standby with pump suction aligned to the refueling water tank (RWT). The RCS level was being maintained at approximately 2 inches above the RCS hot leg (42-inch inside diameter) centerline by draining to the boron management system and monitoring a temporary local level indicator. The local level indicator consisted of a tygon tube standpipe connected to the bottom of the RCS hot leg and vented to atmosphere. A nitrogen purge of the RCS was in progress to " sweep" hydrogen from the system prior to maintenance. The RCS was being vented via the upper vessel head vent. So that vent sampling could be performed, a gas sample canister had been placed on the vent line. The vent path flow rate was exceeded by the nitrogen addition rate which slightly pressurized the RCS. This pressurization resulted in an erroneous reading of level. The Operator did not account for the reactor vessel pressurization when comparing the liquid level with the reference leg which was open to the atmosphere. As a result of the inaccurate RCS level indications, the water level in the RCS hot leg was decreased by draining such that inadequate SDC pump suction resulted. Operations personnel at Arkansas are accustomed to seeing minor RCS level increases during this evolution due to delayed draining of the steam generator U-tubes.

During the RCS draining, the B SDC pump flow indication, monitored in the control room, began oscillating between 2000 gpm and 4000 gpm and the indicated RCS level began oscillating between 2 and 5 inches above the hot leg centerline. The B SDC pump and nitrogen purge were secured by operations personnel in an attempt to determine the true RCS level. During the following 10 minutes, indicated RCS level increased to approximately 14 inches above the hot leg centerline as the RCS was refilled by gravity flow from the RWT through the A

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*Arkansas Unit 2 is an 858 MWe (net) PWR located 6 miles northwest of Russelville, Arkansas, and is operated by Arkansas Power and Light.

SDC pump into the RCS and as the RCS fluid expanded due to heatup. The B SDC pump was restarted to reestablish flow. However, flow oscillation was again observed and pump discharge pressure and flow ultimately decreased to zero approximately 5 minutes later, indicating vapor binding and loss of suction. Operations personnel secured the B SDC pump at this time and decay heat removal alignment was shifted to the A SDC pump and heat exchanger. The A SDC pump was started, and normal flow of approximately 3000 gpm was established.

SDC flow had been lost or degraded for approximately 1 hour. During this time, the RCS bulk average temperature increased from approximately 140°F to approximately 205°F, resulting in an inadvertent plant operational mode change from cold shutdown to hot shutdown. The highest indicated incore thermocouple temper ature reached approximately 259°F. The core remained fully covered during the temporary loss of SDC. Subsequent testing of the B SDC pump revealed that it was not damaged or degraded during this event.

To prevent recurrence of erroneous RCS level indication, the temporary level system reference leg has been changed from venting to atmosphere to venting to the pressurizer steam space. In addition, the licensee has modified the normal and abnormal operating procedures to enhance operator recognition of such events and to improve response time for restoration of SDC flow. (Ref. 10.)

Another event involving the use of a tygon tube for temporary level indication and a temporary loss of residual heat removal cooling was reported in Power Reactor Events, Vol. 6, No. 3, Item 2.6, pp. 34-35. The event occurred at the Trojan plant.

1.5 Residual Heat Removal System Letdown Line Break due to Water Hammer

At approximately 2:45 a.m. on August 6, 1984, Operators at McGuire Unit 2* discovered a broken socket weld on the residual heat removal (RHR) system letdown line to the chemical and volume control system (CVCS). The RHR system was in service at the time and water was spraying from the broken pipe and from the stem on valve 2NV-121, which controls flow from the RHR system to the letdown heat exchangers, into the B train RHR heat exchanger room. An Operator had entered the room to check 2NV-121, which was not working properly. Upon discovering the leak, he called the control room and the leaking line was isolated.

At the time of the event, the unit was in cold shutdown and was drained down to about 220 inches for maintenance. Operators were preparing to fill the reactor coolant system, which required 2NV-121 to be verified closed. After the operators began letdown flow, indications were received that 2NV-121 seemed to be at least partially open. Chemistry personnel reported a high level alarm in the floor drain tank sump at about the time the operator sent to check on the valve entered the B RHR heat exchanger room and discovered the leak. Contaminated water from the leak was contained in the heat exchanger room, containment spray sump, and the B floor drain sump and tank. Total leakage appeared to be between

*McGuire Unit 2 is a 1180 MWe (net) PWR located 17 miles north of Charlotte, North Carolina, and is operated by Duke Power.

3000 and 7000 gallons. A subsequent inspection found a number of support-restraints (S/Rs) damaged and the broken socket weld completely separated.

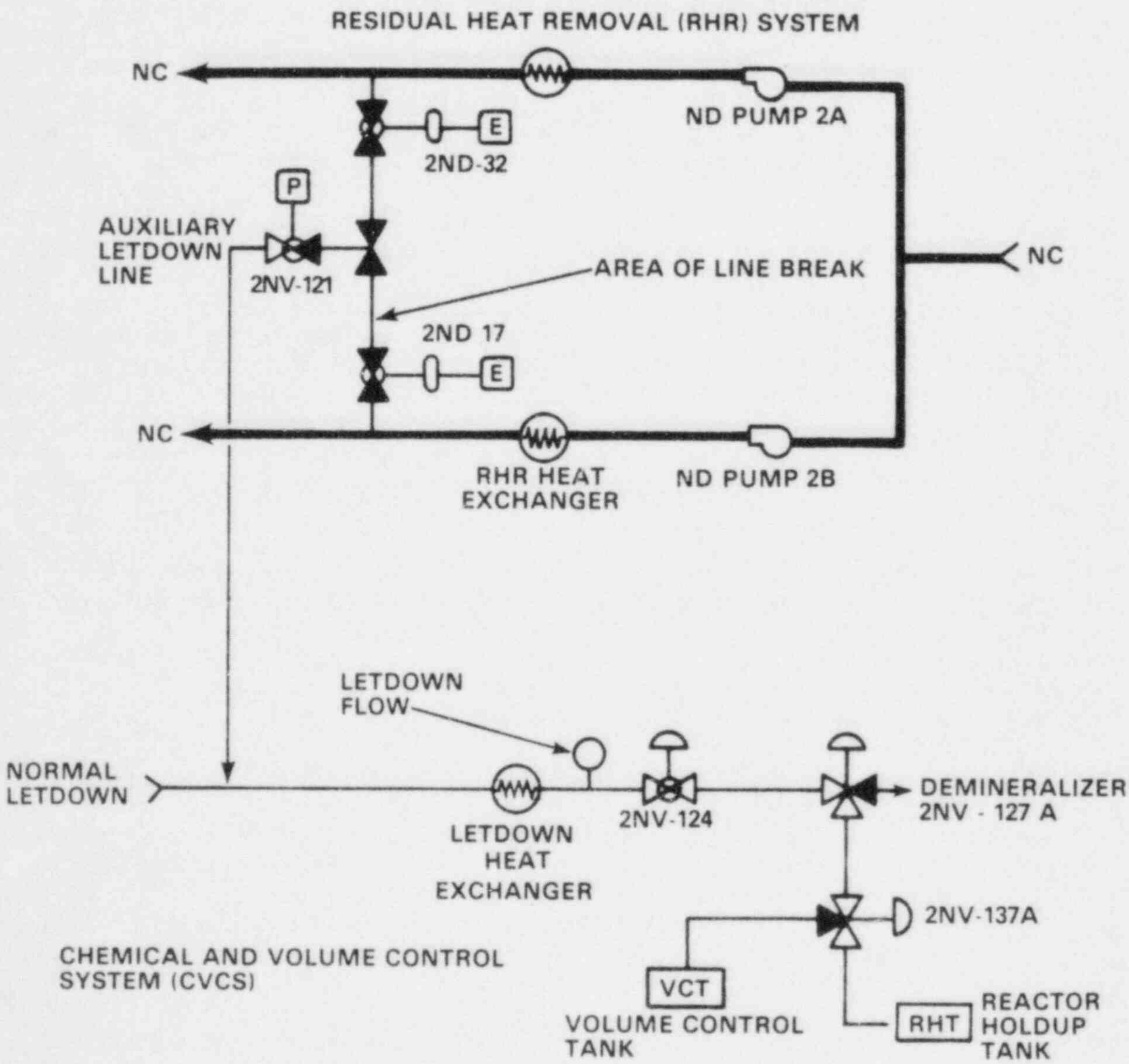
The auxiliary RHR to CVCS letdown path connects the two RHR headers (see Figure 3) to the normal CVCS letdown line. The path is isolated from each header by motor-operated Kerotest valves 2ND-17 and 2ND-32. Flow to the letdown line is controlled by piston operated, Fisher regulating valve 2NV-121. The weld that was broken was immediately downstream of 2ND-17. The pipe was completely separated at the break location. Maintenance personnel also found that the packing assembly on 2NV-121 had moved away from the valve body, along the valve stem. The two nuts that secure the packing flange were completely off of the studs, and were later found on the floor of the RHR heat exchanger room. Both of the studs were undamaged, indicating that the flange was forced from the stud during the event. Since the nuts were relatively undamaged, the packing flange must have been loose prior to the event.

The licensee determined that the forces causing the damage were the result of a water hammer. Work activity had been performed on August 4, 1984, which could have introduced air into the letdown piping downstream of 2NV-121. Limit switches on divert valve 2NV-137A were being adjusted and the valve was open to the recycle holdup tank (RHT) for about 2 hours. During this time, a drain path existed from 2NV-121, which is located near elevation 750, to the RHT, which is located on the 716 elevation. The vent for this draining operation would have been through the loose packing on 2NV-121. The RHT pressure was maintained near atmospheric during this time, which would not have prevented draining. In this configuration, at least some of the water in the line might have been replaced with air.

The morning of the event was the first time the auxiliary letdown line was used after the air was drawn into the line. Valve 2NV-121 was leaking through the seat extensively, as shown by the letdown flow rate observed by the operators when the line was put in service. This prevented the operators from gradually increasing flow in the line. Isolation valve 2ND-32 (Figure 3) is an open/shut valve with seal-in circuits and a relatively quick opening Kerotest body. When the operators opened 2ND-32, flow increased rapidly in the auxiliary letdown line. The rapidly increasing flow combined with the air pocket resulted in the severe water hammer.

Although the water hammer is thought to have occurred about 12:55 a.m., major leakage did not appear until 2:30 a.m. All of the damage to the system, including the broken weld, S/R damage, and stem packing blown out of 2NV-121, apparently resulted from the same event. The only explanation found during investigation was that the weld was broken at 12:55 a.m., but did not completely separate until 2:30 a.m. Chemistry personnel have stated that the major leakage could not have occurred much more than 10 minutes prior to the high level alarm at 2:40 a.m. Control operators also saw a marked change in the volume control tank (VCT) level and letdown flowrate about that time. The VCT level, which had been steady for about 1-1/2 hours, began to drop, indicating that letdown flow or makeup flow to the VCT had decreased. Letdown flow dropped from 20 gpm to about 8 gpm, although this flow instrument is not accurate at low flows and the actual flow might have been less than 8 gpm. (The letdown flow drop was caused by water being directed through the leak instead of going to the letdown line.) Preliminary analysis of the broken weld found no evidence that would explain a delay in pipe separation after the break.

FIGURE 3
SIMPLIFIED DRAWING
OF
AUXILIARY LETDOWN LINE
AT McQUIRE UNIT 2



Reactor coolant level throughout the event was above the minimum level necessary to operate the RHR pumps, thus reducing the possibility of a water hammer caused by air entrainment in the RHR suction line. Prior to August 4, the date when the letdown line is postulated to have been drained, the letdown line was used several times to reduce reactor coolant level without any apparent problems.

The auxiliary letdown line consists of 2-inch diameter, schedule 40, 304 stainless steel piping connected to 3000 psig rated fittings by socket welds. All of the piping up to and including 2NV-121 is contained in the RHR heat exchanger rooms between elevations 740 and 752. Piping supports consist of gravity hangers, seismic supports, and sometimes rigid supports that are designed to prevent thermal growth of a pipe in a direction that would impose excessive stresses on joints or components. The systems were designed to prevent vibrations and water hammer problems. In addition, preoperational testing was used to help identify problem areas. When problems were found, the system design or operating methods were revised to eliminate them.

The broken weld was a 2-inch socket weld (see Figure 4). It had been properly installed and tested using dye penetrant. Proper gap had been maintained between the end of the pipe and the socket during the fitup. Although there was some lack of penetration of the weld metal, this had been minimal and not unusual for this type of weld. Following the event, the weld was inspected at McGuire, using a glove box and unmagnified observation. It was then further decontaminated and sent to a research laboratory for more detailed examination. A preliminary report showed the weld broke in a ductile fashion, probably due to one high stress event; however, it was also found that a majority of the weld break area had been fatigued. A crack had started on the inside diameter of the weld and progressed radially outward. Although the crack appeared to have included 360° of the weld, it had not penetrated the outer surface of the weld at any point. Therefore, the welded area was not leaking prior to the failure.

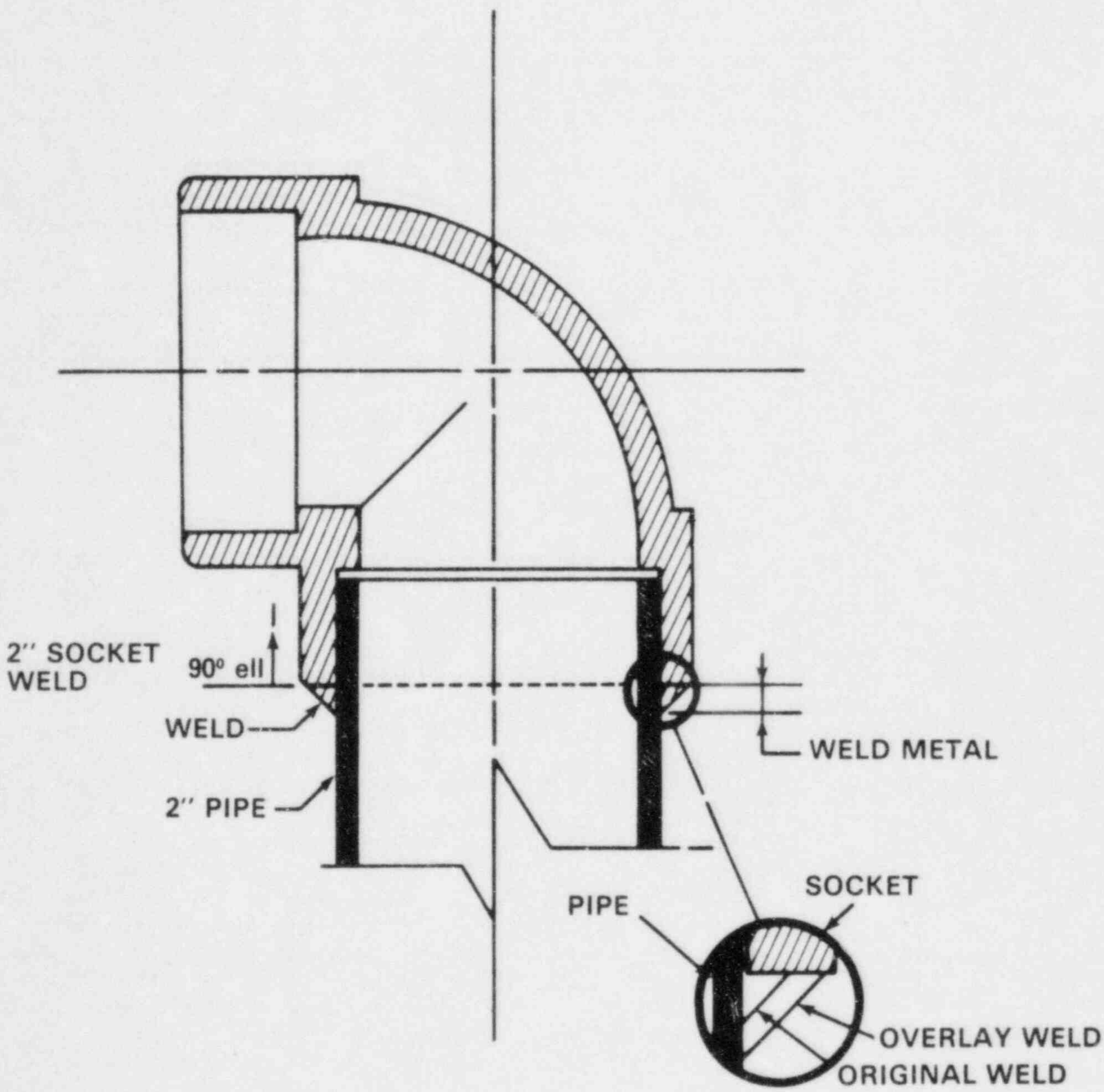
Sixteen S/Rs were found damaged. The majority of these were located in the RHR heat exchanger rooms. Additional damaged S/Rs were found in the auxiliary letdown line downstream of 2NV-121. Spring supports were readjusted, but none of them were damaged in a way that would prevent continued support of the piping. Rigid support damage consisted of anchors loosened or pulled from concrete walls. Some mechanical snubbers were loosened or pulled from the walls.

Two facts are known about the condition of valve 2NV-121 prior to the event. The valve would not control flow in the letdown line, and the packing flange was loose. Maintenance technicians who rebuilt the valve found no visible signs of damage or wear on the internals. Due to time and exposure considerations, the entire valve internals package was replaced along with the positioner and stem mounted limit switch package. The valve was repacked, and jam nuts were used to secure the valve stem packing flange. The valve was verified installed with the normal flow in the correct direction.

All S/Rs, piping, and valves damaged during the event have been repaired. Extensive radiographic and/or dye-penetrant testing was performed on RHR system welds to verify that no cracks existed. Evaluations have been performed which verify the suitability of existing bolt holes in concrete walls for reinstalling S/Rs.

FIGURE 4.

SOCKET
WELD
(NO SCALE)



A vibration measurement program was conducted to determine the cause of the fatigue damage found on the broken weld. The problem was found to be caused by backflow through the Kerotest valves when operators pressurized idle RHR trains from operating trains. The RHR system startup procedure was changed to use the 8-inch crossover line including the A and B RHR heat exchanger bypass valves. Vibration of the RHR and auxiliary letdown system will be monitored during the next unit cooldown. (Refs. 11 and 12.)

1.6 Reactor Coolant System Sight Glass Failure

On August 20, 1984, during the filling and venting of the upper head injection (UHI) system at McGuire Unit 2,* the reactor vessel head vent sight glass failed, releasing reactor coolant system water and steam into the containment building. The sight glass failed when reactor coolant water, at a temperature and pressure greater than the design limit of the sight glass, leaked by the UHI line high point vent valve and flowed through the sight glass. Approximately 1000 gallons of primary coolant leaked through the damaged sight glass into the lower containment. An unusual event was declared, and the unit was cooled from hot standby to hot shutdown. The leaking sight glass was isolated after 4 hours.

This event is attributed to a design deficiency because the sight glass was not designed to withstand a high enough temperature and pressure. A component failure also contributed to the event because the UHI line high point vent valve (2NI-341) did not fully seat when a nominal amount of torque was applied.

The design limits of the sight glass (Jacoby Tarbox type XX37N) are as follows: Teflon rotor-450°F; neophrene gasket-180°F; stainless steel housing-800°F; glass-850°F at 100 psig. During venting of the UHI injection lines on the vessel head on August 19, 1984, valve 2NI-341 was manually opened and then closed, but it did not fully seat when closed. This is a Kerotest valve with internals that are easily damaged when they are overtorqued. To prevent seat damage, operators are trained to close the valves hand tight, as was the case in this event.

When reactor pressure exceeds 1600 psig, the UHI accumulator discharge lines are vented per procedure. Three UHI system vent isolation valves are opened, and then the UHI accumulator discharge lines are normally filled with water from the refueling water storage tank. This water has a temperature range between 70°F and 100°F, and is well within the design limits of the sight glass.

With valve 2NI-341 not fully closed after being cycled on August 19, a flow path existed from the reactor vessel directly to the pressurizer relief tank (PRT) through the sight glass. Reactor water, at approximately 450°F and 1700 psig, was throttled as it flowed through a 0.375-inch orifice, valve 2NI-341 (which was almost closed), and piping before reaching the sight glass. This decreased the temperature and pressure of the water, but it was still above the design limits for the sight glass. (Note: The pressure of the water at the sight glass could only exceed the 100 psig setpoint of the PRT rupture disk by the pressure drop between the glass and the tank; therefore, the pressure at

*McGuire Unit 2 is a 1180 MWe (net) PWR located 17 miles north of Charlotte, North Carolina, and is operated by Duke Power.

the sight glass could only be 100 psig plus the flow loss pressure drop. This pressure was exceeded as evidenced below.) Approximately one minute after opening the UHI line vent isolation valves on August 10, the operators heard a loud blast and a rush of steam. They promptly left the containment. An unusual event was declared due to an estimated 40 gpm leak inside containment (the leak was calculated later to be approximately 5 gpm), and the unit was reduced in temperature to hot shutdown. Four hours after the break, the leak was isolated by closing the three UHI vent isolation valves and 2NI-341 was identified as the valve that leaked.

The sight glass was replaced, and Unit 2 was returned to hot standby the same day. Electrical equipment that was close to the leak was inspected for evidence of possible degradation and meggered (tested for grounds or electrical shorts). No degradation was found. The alarm printout was reviewed for equipment problems due high humidity (such as high temperature or fire alarms). No alarms were found.

One previous sight glass failure had been experienced at Unit 2, and five at Unit 1.* Three of the Unit 1 failures occurred while filling and venting the UHI and reactor coolant systems during plant startup. The other Unit 1 failures were discovered while the plant was shut down. The other Unit 2 failure was discovered prior to plant operation. During venting of the UHI injection lines, the reactor coolant system water is at approximately 50 psig and can be up to 200°F. Reactor coolant water will be cooled some (as it passes through the vent piping), but it may be close to the design temperature limit of the neoprene gasket of 180°F. This may be a contributing factor to some of the previous sight glass failures. The licensee has proposed a modification to the safety injection and reactor coolant systems to better facilitate venting of the reactor coolant system. This proposal points out the personnel and equipment hazards associated with the present method of reactor coolant system venting, and requests the installation of a third isolation valve in each of the vent lines with the capability of being operated from a remote location, and also the replacement and relocation of the sight glass. The proposed modification is presently in the design review stage.

Corrective actions suggested by the NRC include the following:

- Independent verification should be performed on all vents and drains connecting with the reactor coolant pressure boundary.

- A program should be established for the systematic replacement of Kerotest valves utilized in the reactor coolant pressure boundary with another type of valve less prone to plugging, seat damage, and overtorquing.

- A preventive maintenance program should be established for Kerotest valves, particularly when they are utilized in the reactor coolant pressure boundary where leakage is limited by technical specifications. An alternate maintenance would be the replacement of a percentage of these valves at each refueling outage.

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*McGuire Unit 1 is a 1180 MWe (net) PWR located 17 miles north of Charlotte, North Carolina, and is operated by Duke Power.

- Further investigations, including consultation with the vendor, should be performed regarding the feasibility of establishing a standard torque to be applied to Kerotest valves when closing; i.e., when the "standard torque" has to be exceeded to stop leakage, a maintenance request would be written.

- Interim safety precautions and equipment modifications should be implemented to alleviate the concerns and personnel hazards described in the proposed modification package.

- Kerotest valves which are difficult to operate or to verify the position of due to obstructions such as cable trays, piping, and walls, should be relocated or adequately modified. (Refs. 13 through 15.)

1.7 Reactor Vessel Flaw

On August 5, 1984 during a planned 10-year inservice inspection of the Indian Point Unit 2* reactor vessel, an ultrasonic indication of a flaw was identified at or near the outside of one of the vertical weld seams in the beltline region. The indication was initially reported as within 0.25 inches of the outside surface, with a size of approximately 2 inches vertically and 2 inches radially (depth).

To more accurately evaluate the indication, the licensee reviewed the original fabrication records, field fabrication records, and field installation photographs. In addition, an alternate ultrasonic technique was applied. Westinghouse (the nuclear steam system supplier) performed laboratory tests on full thickness mockups using the same instruments used for inspection of the reactor vessel. From this information Westinghouse concluded that the flaw depth was approximately 0.3 inches deep.

In a letter to the licensee dated August 16, 1984, the NRC staff requested additional information and indicated that NRC review and approval for restart would be required.

In accordance with 10 CFR §50.55(a), the need for repair or additional inspection would be based on ASME Code Section XI requirements. Using depth estimates from the licensee analyses only (the NRC staff performed independent analyses), normal operation and inspections at 10-year intervals could be resumed if the depth is less than 0.31 inches. If the depth is between 0.31 inches and 2.7 inches, operation could be resumed with augmented inspection. If the depth is greater than 2.7 inches, repairs would have to be accomplished prior to restart.

The licensee, together with its consultants (i.e., Westinghouse, the prime contractor for the reactor vessel examination; and Combustion Engineering, the vessel manufacturer) concluded that the best estimate of size of the ultrasonic indication is a maximum depth of 0.26 inch and no longer than 0.85 inch. The licensee further concluded that the indication size is within ASME Code Section XI requirements for allowable flaw size and therefore requires neither repair nor augmented inservice inspection.

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*Indian Point Unit 2 is an 849 MWe (net) PWR located 25 miles north of New York City, New York, and is operated by Consolidated Edison.

As described in the NRC's safety evaluation, the NRC concluded that insufficient vessel inspection data exists to conclusively support the licensee's estimate of indication size (i.e., 0.26 inch deep and 0.85 inch long). However, the NRC did have reasonable assurance that a through wall dimension of 1.2 inches and a length of 2 inches should conservatively bound the actual flaw; this flaw size is well within the maximum allowable flaw size as calculated by fracture mechanics analyses. Fatigue crack growth of the flaw during the remaining life of the vessel will be negligible and is not considered a significant factor in the fracture evaluation of the flaw. Further, even if a low-temperature, overpressure (LTOP) event should occur, the probability of failure of the vessel is considered negligible. The NRC agreed that the vessel is acceptable for continued service.

Although Unit 2 was approved for restart, since the NRC was unable to conclude that the flaw size is within ASME Code Section XI allowable, augmented inspection of the pressure vessel will be necessary during the next 10-year inservice inspection program. The licensee has submitted a license amendment request to incorporate appropriate technical specifications regarding the augmented inservice inspections. (Ref. 16.)

1.8 High Pressure Coolant Injection System Lockout

On April 16, 1984, Vermont Yankee* experienced a transient while testing the main steam isolation valves (MSIVs). The plant was operating at 100% power when the event occurred. While one of the MSIVs was undergoing a partial closure test, it continued to shut past the 10% position instead of returning to the open position. Although a power reduction was immediately attempted, a primary containment isolation occurred due to high steam flow in the other three steam lines. The consequent closure of the remaining MSIVs resulted in a reactor scram and operation of primary relief valves. Variations in reactor vessel level and pressure also occurred during the transient, with water level reaching a high of 184 inches. The plant operators used the appropriate plant procedures to recover from the scram and to maintain the plant in the hot standby condition. The plant remained in hot standby for approximately 13 hours while the pneumatic pilot valve assembly, that caused the MSIV problem, was replaced.

On April 20, 1984, while the plant was operating at 100% power, the operators were performing the monthly high pressure coolant injection (HPCI) valve operability test. When the auxiliary oil pump was started, an operator observed that the turbine throttle valve had not opened as expected. A second attempt also proved unsuccessful. The Senior Control Room Operator (SCRO) then recalled the high vessel water level condition that occurred during the transient on April 16, and correctly assumed that the high vessel water level trip signal in the HPCI logic circuit was still sealed-in, locking out the HPCI system. He then pushed the high level reset button which cleared the trip signal. The throttle valve opened, and the HPCI system testing was successfully completed.

The high vessel water level trip signal in the HPCI system logic circuit is designed to seal in and trip the HPCI turbine in order to bypass the high drywell pressure initiation signal to prevent the system from cycling around the

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*Vermont Yankee is a 504 MWe (net) BWR located 5 miles south of Brattleboro, Vermont, and is operated by Vermont Yankee Nuclear Power.

high level setpoint during an accident. The trip signal will automatically reset on a low vessel water level initiation signal, but needs to be manually reset otherwise.

During the transient on April 16, 1984, the reactor water level reached the high level trip setpoint of the HPCI system and sealed in the trip, although the HPCI system itself was not called on to operate. During the vessel level increase, the control room annunciator did alarm a high level condition (HPCI high-level trip), but the alarm cleared when the level subsequently fell below the alarm setpoint. However, the high level trip signal remained sealed in. At Vermont Yankee, no direct indication of this condition is provided. The plant start-up procedure does instruct the operators to reset all reset buttons, but does not provide individual sign-offs for each required reset button. Since the HPCI system was not called on to operate during the transient, and since no relevant alarm was present during the period when the reactor was in the hot standby condition, the particular reset button was overlooked by the operators during subsequent startup. Therefore, until April 20, 1984, when the HPCI valve operability test was performed, the high level trip signal remained sealed-in, locking out automatic actuation of the HPCI system on high drywell pressure initiation and manual initiation. (The automatic initiation on low reactor water level was fully operable during the entire period.)

The licensee has modified the plant scram procedure to ensure that all logic resets are accomplished in accordance with the reactor startup procedure. The "HPCI hi-level trip" annunciator response will contain instructions to depress the HPCI logic pushbutton. Further training on HPCI logic will be included as part of the plant operator requalification program. The plant Control Room Design Review Committee will be considering this event as part of their Human Factors Analysis of the control room design of Vermont Yankee (NUREG-0737 Supplement 1 commitment).

Since the HPCI system logic scheme at Vermont Yankee is similar to those at other operating BWRs, an NRC review was performed of this HPCI system lockout problem for its generic applicability. The consequence of such a lockout is that the HPCI system will not perform its safety function upon high drywell pressure initiation or manual initiation. Further, since no direct indication of the lockout condition is provided to the operator, he is unaware that the system is inoperable. It was found that the HPCI (and high pressure core spray) system logic at other operating boiling water reactors (BWRs) have the same high vessel water level trip signal seal-in feature. The limited NRC review of the HPCI system at seven operating BWR units showed that direct indication and/or alarms are provided at those units to alert operators of such a lockout condition. However, since the high vessel water level signal seal-in feature is utilized at all operating BWRs, it is possible that there are other BWR units where a direct indication of the seal-in condition is not provided, and/or detailed procedures requiring resetting the condition may not be available. (Refs. 17 and 18.)

1.9 Update on Valve Operator Problem During Loss of Shutdown Cooling at Browns Ferry

The June 1984 issue of Power Reactor Events summarized a February 14, 1984 event at Browns Ferry 1 where the shutdown mode of the residual heat removal (RHR) system could not be placed in operation to bring the unit to cold shutdown. (See Vol. 6, No. 1, pp. 14-15.) RHR shutdown cooling suction valve FCV-1-74-48, located within the drywell, could not be opened remotely and could only be opened manually after the inerted primary containment had been purged to permit entry.

The March 6, 1984 Licensee Event Report (LER 84-12-00) stated that the B phase winding of the motor on the valve had failed, but that it was not known whether this was the root cause of the valve failure. Valve FCV-74-48 is a 20-inch Walworth gate valve with a Limitorque operator and a Reliance Electric Company motor.

An August 28, 1984 update of this report (LER 84-12-01) reports the results of subsequent investigation. It was found that the "close" torque switch for FCV-74-48 was set at 2.5. This torque switch setting is higher than recommended by the manufacturer. Limitorque recommends a maximum torque switch setting of 2.0 for FCV-74-48. A Limitorque Corporation factory representative stated that a "close" torque switch setting of 2.5 could cause damage to the valve operator or motor and/or cause the valve seat to stick closed due to overtightening.

A series of tests have been conducted under various reactor operating conditions in order to obtain specific data about the operating characteristics of FCV-74-48. These tests entailed the use of a multichannel recording oscillograph to obtain voltage and current recordings as FCV-74-48 was operated. The results of these tests are summarized as follows:

(1) After the reactor has been in operation, substantially greater than usual torque is required to initially "break loose" the valve when opening and going into shutdown cooling mode as compared to subsequent cycling of the valve.

(2) After the "close" torque switch was readjusted to within the range specified by Limitorque, there was a substantial reduction in the torque required to initially "break loose" the valve upon opening and going into shutdown cooling mode.

Electrical maintenance instructions are being revised to improve recording and review of acceptance criteria and data recording of torque switch settings. A modification is under evaluation to install torque limiter plates on the torque switch to prevent a setting higher than the maximum recommended value. (Limitorque has installed these limiting plates on all torque switches made since 1974.) The failed motor has been returned to the Reliance Electric Motor factory for an additional failure analysis. (Ref. 19.)

1.10 References

(1.1) 1. NRC, Preliminary Notification PNO-I-84-70, "Refueling Cavity Water Drainage," August 21, 1984.

2. NRC, IE Bulletin 84-03, "Refueling Cavity Water Seal," August 24, 1984.

3. NRC, IE Information Notice 84-93, "Potential for Loss of Water from the Refueling Cavity," December 17, 1984.

(1.2) 4. NRC, Preliminary Notification PNO-I-84-62 (July 25, 1984) and -62A (July 27, 1984), "Loss of AC Power."

5. NRC/Region I, Inspection Report 50-388/84-34, September 18, 1984.

(1.3) 6. NRC, Preliminary Notification PNO-II-84-49, "Possible Core Spray Loop Overpressurization," August 15, 1984.

7. Tennessee Valley Authority, Docket 50-259, Licensee Event Report 84-32, September 13, 1984.

8. NRC/Region II, Inspection Report 50-259/84-39, October 1, 1984.

9. NRC, IE Information Notice 84-74, "Isolation of Reactor Coolant System from Low Pressure Systéms Outside Containment," September 28, 1984.

(1.4) 10. Arkansas Power and Light, Docket 50-368, Licensee Event Report 84-23, October 1, 1984.

(1.5) 11. NRC, Preliminary Notification PNO-II-84-46, "Chemical and Volume Control System Letdown Line Break," August 6, 1984.

12. Duke Power, Docket 50-370, Licensee Event Report 84-17, October 5, 1984.

(1.6) 13. NRC,Preliminary Notifications PNO-II-84-52 (August 20, 1984) and -52A (August 21, 1984), "Leak Inside Containment."

14. Duke Power, Docket 50-370, Licensee Event Report, September 19, 1984.

15. NRC/Region II, Inspection Report 50-369/84-26, September 21, 1984.

(1.7) 16. Letter from S. Varga, NRC, to J. O'Toole, Consolidated Edison Company of New York, forwarding the safety evaluation of the ultrasonic flaw indication detected in the Indian Point Unit 2 reactor pressure vessel, Docket 50-247, October 16, 1984.

(1.8) 17. Vermont Yankee Nuclear Power, Docket 50-371, Licensee Event Report 84-05, May 21, 1984.

18. NRC, AEOD Engineering Evaluation E245, "HPCI System Lockout," October 11, 1984.

(1.9) 19. Tennessee Valley Authority, Docket 50-259, Licensee Event Report 84-12-01, August 28, 1984.

These referenced documents are available in the NRC Public Document Room at 1717 H Street, Washington, DC, for inspection and/or copying for a fee. (AEOD reports can also be obtained by contacting AEOD directly at 301-492-4484, or by letter to USNRC, AEOD, EWS-263A, Washington, DC 20555.)

2.0 EXCERPTS OF SELECTED LICENSEE EVENT REPORTS

On January 1, 1984, 10 CFR 50.73, "Licensee Event Report System" became effective. This new rule, which made significant changes to the requirements for licensee event reports (LERs), requires more detailed narrative descriptions of the reportable events. Many of these descriptions are well written, frank, and informative, and should be of interest to others involved with the feedback of operational experience.

This section of Power Reactor Events includes direct excerpts from LERs. In general, the information describes conditions or events that are somewhat unusual or complex, or that demonstrate a problem or condition that may not be obvious. The plant name and docket number, the LER number, type of reactor, and nuclear steam supply system vendor are provided for each event. Further information may be obtained by contacting the Editor at 301-492-4499, or at U.S. Nuclear Regulatory Commission, EWS-263A, Washington, DC 20555.

2.1 Unresolved Feedwater Transient

Peach Bottom Unit 3; Docket 50-278; LER 84-11; General Electric BWR

On August 21, 1984, with Unit 3 at 100% power, a sudden runback of all three reactor feedpumps resulted in a reactor low level scram, Groups I, II, and III isolations, and automatic initiation of the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. Normal reactor level was immediately restored. The isolations were reset and essential systems were promptly returned to service. The cause of the feedpump runback is believed to have been intermittent failure of a component in the feedwater control system.

The feedwater master controller and three proportional amplifiers in the feedwater control system were calibration checked and found to be fully operational. A visual inspecton of the wires connecting the master controller, the proportional amplifiers, and the individual feedpump turbine speed controllers indicated that all connections were intact. The ribbon cables connecting the master controller, proportional amplifiers, and speed controllers were inspected, continuity checked, and found acceptable. The feedwater runback instrumentation setpoints were checked and found acceptable.

Because testing could not reproduce the failure, components capable of producing a similar failure were replaced. The replaced components included the master controller, three proportional amplifiers, and four ribbon cables. In addition, a recorder was installed to monitor signals to the master controller.

Upon return to power operation, the "B" reactor feedpump was placed in manual control and the automatic control of the "A" and "C" reactor feedpumps was observed for proper control ability. No feedwater control deficiencies have been identified since the unit was returned to power operation.

2.2 Loss of Essential 4160 V Bus Attributed to Misapplication of Degraded Voltage Relay Devices

Brunswick Units 1 and 2; Dockets 50-325 and -324; LER 84-16; General Electric BWRs

An essential 4160 V bus was temporarily lost on Unit 2 during its refueling/maintenance outage. This resulted in power interruption to one train of essential equipment in the shut down Unit 2 and to one RHR pump and one RHR service water pump in operating Unit 1.

On August 7, 1984, while placing an equipment clearance to permit preventive maintenance on Unit 2 dc electrical battery bank 2A-2, the normal power supply feeder breaker, 2D, to plant 4160 V ac emergency bus E-3 automatically opened when the feeder breaker 125 V dc control power supply was changed from the normal to the alternate power source. Unit 2 Group 6 and 8 isolations occurred. Within ten seconds plant emergency diesel generator (DG) No. 3 automatically started to reenergize E-3. The Control Building Emergency Air Filtration (CBEAF) System isolated due to a spurious chlorine alarm. The Unit 2 Reactor Building Standby Gas Treatment Train (SBGT) 2B automatically started.

Within approximately four minutes of the event SBGT 2B and the CBEAF were returned to standby. Within eight minutes E-3 feeder circuit breaker 2D was reclosed and DG No. 3 was secured and returned to standby.

To permit routine preventive maintenance on Unit 2 dc electrical battery bank 2A-2, the circuit breaker of the 125 V dc alternate control power supply to 4160 V ac emergency bus E-3 switchgear was closed and the respective circuit breaker of the 125 V dc normal control power supply to the E-3 switchgear was opened. By design, when normal power supply voltage to the 125 V dc control power bus decreased to 70% of its normal value, transfer of the power supply to the 125 V dc alternate control power supply began. The subject transfer occurred within a time frame of 50-75 milliseconds after the 70% value was reached. When the 125 V dc normal control power supply circuit breaker was opened, the output trip electrical contacts of the E-3 degraded voltage relay devices closed. This, by design, formed part of the trip circuit for the E-3 normal feeder circuit breaker 2D. Following completion of the transfer of normal to alternate 125 V dc control power supply to E-3 switchgear, the output trip contacts, by design, opened within a time frame of 16-48 milliseconds (1-3 cycles). At the same time the auxiliary trip relay of feeder circuit breaker 2D, by design, actuated within 8 milliseconds of the subject transfer and the 2D feeder circuit breaker trip coil actuated within 23-30 milliseconds of the transfer.

As a result of the inherent time response characteristics of the involved E-3 protective devices, the investigation of this event concluded that the output trip electrical contacts of the E-3 degraded voltage relay devices did not reopen within 16 milliseconds after the transfer before the 2D feeder circuit breaker trip coil relay initiated a trip of 2D.

The presently installed degraded voltage relay protective devices on plant emergency buses E-1 through E-4 result in a situation of unpredictable transfers involving the 125 V dc control power to the swithchgear of those buses.

Therefore, appropriate plant modifications will be implemented to replace the presently installed devices with another type of device which is better suited to this particular design application.

Until installation of these modifications, appropriate plant administrative controls will be utilized to ensure that the presently installed subject protective devices are deactivated prior to restoring or transferring between the normal and alternate 125 V dc control power to the E-1 through E-4 switchgear.

2.3 Emergency Shower Causes Inverter Failure, Scram, and Safety Injection

Cook Unit 1; Docket 50-315; LER 84-18; Westinghouse PWR

On August 14, 1984, during full power operation, an alarm was received from "CRID-IV," one of four static inverters supplying the 120 V ac vital instrument buses. The operator dispatched to the switchgear room reported water on the floor of the room. A temporary blower located on the floor was being used to cool the inverters and was spraying a fine mist into the back of the inverter. As power was being reduced, the inverter failed, resulting in a reactor trip and safety injection. The inverter was later replaced and the unit was restarted.

The reactor trip was caused by a low reactor coolant flow signal in coincidence with being above the P-8 permissive setpoint. The cause of the train A safety injection was low steamline pressure (signal given by loss of the inverter concurrent with high steamline flow via the steam dumps). A train B safety injection did not occur because the train B output relays were powered from the affected inverter, so they did not energize to give a safety injection signal.

The inverter was switched over to its alternate power supply and trip recovery procedures were followed. The inverter was damaged by the water sprayed on it and a new spare inverter was installed.

The cause of the occurrence was a leaking emergency shower which is located in an adjacent battery room. Earlier in the afternoon, a surveillance was being performed on the battery room emergency shower and eyewash station. The technician could not get water flow from the station and requested assistance from the control room. The operator checked the valve lineup and discovered that the demineralized water make-up plant was out of service at the time which resulted in no water pressure for the emergency shower and eyewash stations in the 4 kV switchgear rooms. The operator cycled the emergency shower valve and then left the area. The make-up plant was later returned to service, which pressurized the eyewash station header. The emergency shower valve had not been fully seated, and when the header repressurized, the valve leaked. This caused the water accumulation on the floor, which was picked up by the temporary blower.

A design change is being processed which upgrades the ventilation in the inverter room so blowers will not be needed in hot weather. The surveillance procedure has been changed to require direct control of an eyewash station if no flow is obtained during a test until the problem is corrected.

Also reported in connection with this event was an emergency boration due to control bank C control rod N-13 indicating 15 steps out with the rod bottom light on following the reactor trip. The rod position indication eventually drifted down to indicate the rod fully inserted. Subsequent withdrawal of the control rod did not evidence any mechanical binding or other problems.

2.4 Potential Containment Leakage through Unqualified Pressure Differential Gages on Airlock Doors

Salem Unit 1; Docket 50-272; LER 84-20; Westinghouse PWR

On August 22, 1984, a review of a design change request to add an alarm for containment airlock pressurization revealed a design discrepancy involving the existing gages for monitoring differential pressure across the airlock doors. It was determined that the installed gages for both Unit 1 and Unit 2 airlocks were not qualified for containment design pressure and that their failure would compromise containment integrity. Although their failure would result in an unisolable leakage path from the containment to the mechanical penetration area, it would not result in an unmonitored release to the atmosphere, since the penetration area ventilation is provided by the auxiliary building supply and exhaust fans, the discharge of which is monitored. The gages in question were removed, and the gage lines were capped. The gages served only as a redundant indication to the airlock design feature which assures that the pressure is equalized across the door prior to opening, and their absence does not affect door operation or personnel safety. Therefore they will not be replaced.

2.5 Break in Fire Main with Leakage into Switchgear Room of Adjacent Shut-Down Unit

San Onofre Unit 2; Docket 50-361; LER 84-33-01; Combustion Engineering PWR

On June 16, 1984, with Unit 2 operating at full power and Units 1 and 3 in cold shutdown, hydrostatic testing was being performed on a new section of the Unit 2/3 fire main piping. Leakage occurred through the hydrostatic test boundary valves and pressurized the entire fire main above the operating pressure. A break occurred in the fire main piping outside of the hydrostatic test boundary.

Flooding occurred in the area of the break and water flowed through newly installed telecommunication ducts into the 4 kV swithchgear room of shut down Unit 1. The three Unit 2/3 fire pumps, which had started on low pressure, were shut off. The entire Unit 2/3 fire main was isolated. In accordance with Technical Specifications, fire watches were established with portable extinguishers, however, the requirements for backup fire suppression equipment could not be satisfied. The leak was isolated and the fire main was repressurized.

The failure was attributed to cracking in the pipe caused by cyclic stress fatigue from recent heavy construction traffic concentrated immediately above the fire main break, in conjunction with the moderate increase in pressure in the fire main from the leaking hydrostatic test boundary valves.

2.6 Fire Barrier Causes Overheating in Cable Tray

Palisades; Docket 50-255; LER 84-10; Combustion Engineering PWR

On July 3, 1984 while trouble shooting wiring to containment sump level switch personnel discovered that a section of the cable tray, which was enclosed by a fire barrier, was extremely hot to the touch. Further investigation of the cables inside the fire barrier revealed that 47 of the 73 cables were damaged as a result of excessively high temperatures. At the time of discovery, the plant was being taken from cold shutdown toward hot shutdown, for eventual return to power operation from a long refueling outage.

Subsequent evaluation determined that the damage to the cable insulation resulted from long term thermal degradation, attributed to excessive heat buildup inside the fire barrier. High ambient temperatures, the lack of ventilation in the area and the design of the fire barrier contributed to a condition which precluded proper dissipation of the heat produced by the energized cables in the area enclosed by the fire barrier.

The fire barrier was one of three similar barriers installed in the containment building during 1979. The remaining two barriers were subsequently inspected to verify the condition of the cables passing through the respective barriers. No evidence of excessive temperatures or thermal degradation was apparent.

Corrective action to the damaged cables consisted of removing the damaged portion of the cables and replacement with spliced sections of cable. Additionally, the fire barrier was redesigned and relocated along the cable tray to facilitate proper heat dissipation.

A temperature monitoring device was installed in the cable tray within the fire barrier to monitor the fire barrier temperature.

2.7 Gland Flange Failures on Rockwell Edwards 3/4-inch Globe Valves

Turkey Point Unit 3; Docket 50-250; LER 84-20; Westinghouse PWR

On July 12, 1984, a reactor shutdown was commenced due to a Reactor Coolant System (RCS) leak of approximately 13.5 gpm. The cause was a packing leak on the lower isolation valve, 3-538, on the instrument sensing line to pressurizer level transmitter LT-3-460.

The leak was identified during a containment entry as a broken gland flange on valve 3-538. An RCS cooldown was initiated to affect repairs on the valve. A second containment entry resulted in isolating the leak by fully backseating valve 3-538. The cooldown was terminated and preparations made to repair valve 3-538 at hot shutdown conditions. A plant change modification (PCM 84129) was prepared, reviewed, and approved to fabricate and install a "strongback" plate and washer to replace the original valve packing gland flange that was damaged. The replacement parts were fabricated, the valve repacked, the "strong-back" and washer installed, bolted in place, and torqued to comply with Engineering's recommendations. Subsequently, an inspection of all Rockwell Edwards 3/4 inch globe valves was conducted on both units. The inspection resulted in five additional gland flanges being found as unacceptable. Three valve gland flanges were cracked and two were degraded. Incorporation of the strong-back device was effected on these valves as well. An evaluation is underway to determine the root cause of these similar failures and a satisfactory permanent fix.

2.8 Improper Material in a Feedwater Regulating Valve Results in Reactor Scram

Indian Point Unit 3; Docket 50-286; LER 84-09; Westinghouse PWR

On June 16, 1984, a reactor trip was initiated automatically on a low level in No. 33 steam generator. Reactor power was 100 percent at the time of the trip.

Investigation determined that the low level in No. 33 steam generator was caused by the inadvertent closure of FCV-437 (Copes-Vulcan, Serial No. 6810.67430.2.3), the main feedwater regulating valve for loop No. 33. The lower portion of the valve operator's yoke was found severed on one side. Analysis of the failure area determined that a crack had been present prior to the failure. The crack propagated through the yoke, aided by the force of the operator's spring. When the yoke failed the cap screws attaching the yoke assembly to the diaphragm also failed. The spring force was then released, closing the valve, and causing the reactor to trip on a low steam generator level.

A metallurgical evaluation of the yoke found the piece to be cast iron rather than cast steel, as was indicated on vendor drawings. The vendor has been notified of this problem. New valve operators with steel yokes have been ordered to preclude future failures.

2.9 Commercial Grade Actuators on Class 1E Valves

McGuire Unit 2; Dock 50-370; LER 84-14; Westinghouse PWR

Commercial grade Limitorque actuators are installed on component cooling system containment isolation valves 2KC-424B and 2KC-425A. Fisher Controls, the supplier for both Class 1E active valves, failed to provide environmentally qualified actuators as required by specifications. The commercial grade actuators were discovered during an attempt to install T-drain plugs in the motor housing of valve 2KC-424B when it was discovered there was no provision for the plugs.

This error went undetected because Limitorque model numbers/nameplates do not distinguish qualified actuators and their qualification level from commercial type actuators. Only Limitorque can determine the qualification level by tracing their factory order number back to a bill of material.

2.10 Cracking of Charging Line Suction Header Piping

Salem Unit 2; Docket 50-311; LER 84-16; Westinghouse PWR

On July 5, 1984, during routine power operation, a leak was discovered on the common suction line to the Charging Pumps in the vicinity of vent valve 2CV372.

A Technical Specification Limiting Condition For Operation was entered and a controlled shutdown was initiated, due to the questionable operability of all Charging Pumps and both Emergency Core Cooling System (ECCS) Subsystems (Safety Injection and Residual Heat Removal).

The section of piping containing the defect was removed and sent to an independent laboratory for evaluation and determination of the failure mechanism. A crack was physically located in the schedule 10, eight-inch charging pump suction line, and orginated in the toe of the weld where the vent valve piping is attached to the main suction header. Fractographic analysis attributed the failure to fatigue, which was most probably caused by normal system vibration of the vent valve piping. Relative dimensions of the crack (e.g., 3-1/8 inches on the O.D. and 2-5/8 inches on the I.D. of the pipe), and the presence of a ductile shear lip on the I.D. edge of the crack, confirmed that the failure had initiated from the O.D. of the pipe. Although fatigue failures (a total of nine in both Units) have previously been experienced in various Charging System vent and drain valve piping, this was the first defect located in the main header piping.

The affected Charging System piping was replaced utilizing schedule 40 piping, in place of the original schedule 10 piping. Dye-penetrant inspections of the weld areas of 33 Charging System vent and drain connections (15 located on the suction header and 18 on the discharge header) were performed to ensure no undetected defects, prior to authorizing a Unit startup.

In addition, Design Change Requests have been issued, which will reduce the length of certain Charging System vent and drain line piping. This will reduce the moment arm, and consequently reduce the stress on the weld area caused by normal system vibrations.

2.11 Application of Unqualified Protective Coatings on Containment Ventilation Ductwork

North Anna Units 1 and 2; Dockets 50-338 and -339; LER 84-06; Westinghouse PWRs

The Air Cooling and Purging System galvanized ductwork and supports in the lower level of Unit No. 1 and Unit No. 2 containments are coated to mitigate corrosion. Review of station records indicated that the coating materials selected were not known to be qualified for application within the containment when applied over a galvanized substrate. Subsequent DBA and adhesion tests were performed on test panels removed from the ductwork which verified that the coating did not meet the required performance criteria. The cause of the event was determined to be primarily inadequate classification of the work and secondarily a failure of personnel to follow site procedures controlling application of coatings within the containment. The corrective action taken was to install a Type 304 stainless steel wire mesh screen over the coated surfaces of the ductwork and supports. The wire screen will retain the coating material, which may disbond from the ductwork following a loss-of-coolant accident (LOCA), and therefore ensure that there will be no impact on the operation of safety related equipment. Site procedures have been strengthened in order to prevent recurrence, and training has been provided.

2.12 Foreign Material in Charging Pump Suction Lines Causes Charging Pump Failure

Salem Unit 1; Docket 50-272; LER 84-17; Westinghouse PWR

On July 16, 1984, during a refueling outage, while performing surveillance testing of No. 12 Charging Pump, the pump seized after running for approximately thirty seconds. No. 12 Charging Pump was declared inoperable. The redundant charging pumps remained in an operable status.

Upon disassembly of the pump, a small amount of resin particles and metal filings were discovered in the pump casing. As a result of these findings, an investigation ensued to determine the source and extent of the problem. Similar material was found in the common suction line of all charging pumps.

The resin originated from either the Spent Fuel Pit Demineralizer or the Mixed Resin Bed Demineralizer during previous resin flushing operations. The metal filings, entrained in the resin and released to the system during the resin flushes, apparently entered the system from maintenance activities. Due to the close internal tolerances of the centrifugal charging pumps, and the lack of any other positive findings upon inspection of the pump, it is felt that the metal filings (although a very small amount) could possibly have contributed to the seizure of No. 12 Charging Pump. In addition, inspections of the Refueling Water Storage Tank revealed that it contained a significant amount of resin.

If the failure of No. 12 Charging Pump was actually caused by the metal filings introduced into the Charging System, it is reasonable to assume that if the redundant centrifugal charging pump (No. 11) had been operating, it could possibly have experienced a similar failure.

Since the positive displacement type pump (No. 13 Charging Pump) had been operated on numerous occasions since the suspected intrusion of the resins and metal filings, it appears that the clearances in that pump were sufficient to allow the material to pass without causing damage. However, had that pump also failed, the charging pumps and boration flow paths would not have been available. This is an acceptable condition during Mode 5 and 6 operation, provided there are no evolutions in progress which would result in a positive reactivity addition to the core. This is not an acceptable condition during Modes 1 through 4 operation, since the loss of the charging pumps would also result in a loss of seal injection to the Reactor Coolant Pumps and the inoperability of both Emergency Core Cooling System trains. The loss of both centrifugal charging pumps during an accident is not an analyzed condition.

The rotating element in No. 12 Charging Pump is being replaced. Inspections of No. 11 Charging Pump revealed wear; therefore, as a precautionary measure, the rotating element of that pump is also being replaced. Boroscope inspections and extensive cleaning of the charging pump suction lines has been performed. The horizontal portion of the suction header was hydrolazed, and the Refueling Water Storage Tank was cleaned. Temporary strainers were installed in the suction to the charging pumps. These strainers will be utilized during the final flushes of the Charging System.

2.13 Both Pressurizer PORVs Left Disabled during Power Operation

Calvert Cliffs Unit 2; Docket 50-318; LER 84-07; Combustion Engineering PWR

On August 24, 1984, during normal power operation, the override switches of both power operated relief valves (PORV) were discovered to be in the "OVERRIDE" position. With the handswitches in this position, the relief valves were inoperable and would not have opened on high pressurizer pressure. The handswitches were immediately placed in the "AUTO" position, which allows the relief valves to open on pressurizer high pressure, thus returning the valves to operable status.

The override handswitches had been placed in the "OVERRIDE" position in accordance with operating procedures during the last reactor cooldown over two weeks ealier, and they had evidently remained in that position since the cooldown and throughout twelve days of resumed power operation. The PORVs were not required to open during this period. The pressurizer code safety valves remained operable.

The undetected condition of inoperability led to violation of the technical specifications, which require that the block valves associated with inoperable PORVs be shut and that power be removed within one hour. Closing the block valves would prevent depressurization of the reactor coolant system if an inoperable PORV were to open, and this function was already effectively fulfilled by the improper position of the override handswitches, which prevented the valves from opening.

Failure to return the PORV override handswitches to the "AUTO" position resulted in part from an inadequacy of the operating procedure for Plant Startup from Cold Shutdown to Hot Standby, which did not contain a step to direct the operator to return the handswitch to the "AUTO" position. The procedure did contain a "NOTE" to ensure that the handswitches were placed in the "AUTO" position, but the note was apparently overlooked by the control room operator. The operating procedure has been changed to require that the override handswitches be in the "AUTO" position prior to entering Hot Standby. All applicable operating procedures were reviewed to ensure that other functions are not bypassed unless the bypass is annunciated or unless the operating procedures contain specific steps to return the bypasses to normal.

Consideration will be given to requesting revision or deletion of the portion of the technical specifications that appears to unnecessarily require closing of the block valves when the associated PORV is failed shut.

2.14 Interruption of Emergency Feedwater Flow

Oconee Unit 3; Docket 50-287; LER 84-05; Babcock & Wilcox PWR

On August 14, 1984 at 1126 hours, Unit 2 tripped from full power when the instrument air line to the outlet valves of the Powdex condensate demineralizer was accidentally sheared. The loss of air to the outlet valves caused the valves to fail shut which resulted in a loss of condensate flow to the condensate booster (CB) pumps. The CB pumps tripped and caused the main feedwater (MFDW) pumps to trip on low suction pressure. The loss of the MFDW pumps initiated a reactor anticipatory trip.

Approximately 16 minutes after the trip, the "3A" MFDW pump was restarted to reestablish MFDW flow. The Emergency Feedwater (EFDW) control valves, 3FDW-315, 316, closed on an indication of 750 psig discharge pressure from the "3A" MFDW pump as designed. The Once Through Steam Generators (OTSGs) were isolated from all feedwater flow for approximately 9 minutes as a result of the automatic closing of the EFDW control valves and lack of MFDW flow due to insufficient discharge pressure from "3A" MFDW pump.

The EFDW control valves had not been placed in manual control, as specified by procedure, prior to resetting the MFDW pump. As a result, level in both steam generators approached dry-out conditions, decreasing to 12 inches indicated. Primary temperature increased from 555°F to 575°F over 6 minutes. Primary system pressure was maintained below 2200 psig by the pressurizer spray system. The operators observed the increasing primary temperature and manually opened the EFDW control valves. Primary temperature began to decrease and stabilized at 555°F 10 minutes later.

The operators were following emergency procedure for loss of steam generator feedwater. A procedure step describing the restart of a main feedwater pump has a caution statement alerting the operator that FDW-315 and FDW-316 must be placed in manual prior to resetting MFDW pumps. However, the caution statement is located below the step so that the operator overlooked it. He did not read the entire step before starting his actions.

The EFDW control logic is designed to initiate automatic SG level control at 25 inches upon starting the EFDW pumps. The actuation signals are 75 psig (decreasing) hydraulic oil pressure or 750 psig (decreasing) feedwater discharge pressure on both MFDW pumps. In the increasing direction the same setpoints will transfer FDW-315 and FDW-316 from automatic level control to the manual mode. Since the manual loader is normally set in the closed position the EFDW valves went closed.

The response of the EFDW control valves after the MFDW pump was restarted is under evaluation. The need for changes in the control logic will be evaluated. The emergency procedure for loss of feedwater has been changed to highlight the caution notice at the beginning of the step in question. Other plant procedures are being reviewed for similar deficiencies.

2.15 Loss of Offsite Power during Refueling with Failure of One Diesel Generator Breaker to Close on Bus

Haddam Neck; Docket 50-213; LER 84-14 and 84-23; Westinghouse PWR

On August 24, 1984 at 1325 hours the plant and reactor (RCT) were shutdown for refueling activities for three weeks, and station service power was being supplied by one of two 115 kV offsite power supplies through one of two station service step-down transformers. The second supply line and transformer were undergoing maintenance work. A licensed operator closed a breaker from the main control board to start a second circulating water pump, and a loss of offsite power occurred. Undervoltage protection logic caused non-vital loads to be shed and started the emergency diesel generators. However, one of the two emergency buses was not reenergized when the diesel generator breaker failed to automatically close on the dead bus.

Since the bus supplying the running residual heat removal pump was not reenergized the operator started the backup pump supplied by the energized diesel bus. There was a five-minute delay before restoring flow, resulting in residual heat outlet temperature increasing from 108 to 115 degrees F.

Offsite power was restored 20 minutes after it was lost. During the restoration process of resetting lockout relays, the diesel generator breaker which hadn't operated automatically closed onto its dead bus. The operator noted at that time that diesel generator voltage was slightly lower and frequency was slightly higher than normal (i.e., approximately 4100 volts and 61 Hz vs 4300 volts and 60 Hz).

Subsequent investigation found that a differential relay current transformer lead was pulled out of its terminal lug inside the main control board. It was determined that the wire was inadvertently pulled out of its lug earlier the same day while maintenance of electrical penetration fire barrier seals was performed in close proximity. Since plant load at the time was very low, there was insufficient current to activate the differential relay scheme. However, when the circulating water pump was started, the motor inrush current provided sufficient current as seen by differential logic to actuate and isolate the station service transformer, resulting in a loss of offsite power.

Initially it was thought that the diesel voltage regulator was left slightly below the breaker voltage permissive relay setpoint when it was previously shut down. The X relay eventually closed due to vibration of resetting nearby relays. The X relay failure was caused by dirt and corrosion accumulation on the relay mechanism.

No previous event of this nature has occurred. If the initiating event (current transformer wire pull) had occurred at power, the station service transformer would have tripped immediately due to a higher plant load. However, there would not be a total loss of offsite power since there would still be both offsite lines available as well as the second station service transformer. It should be noted that both station service transformers are sized such that they are normally half loaded.

Though a diesel generator breaker failed to close automatically, it could have been closed manually if necessary. The opposite safety train diesel generator did automatically energize its bus and was capable of immediately power safeguard equipment if required.

Corrective actions included: (1) a station directive to limit access near electrical equipment panels, (2) revision of operating procedures to adjust diesel voltage regulator well above the permissive setpoint prior to shutdown, (3) cleaning of all X relay mechanisms in the plant and initiation of preventive maintenance at refueling intervals, (4) inspections for other open terminations, (5) initiation of procedure and training enhancements, and (6) initiation of permissive setpoint evaluations.

During subsequent breaker testing an intermittent failure of the automatic start circuit X relay was identified. When the X relay stuck in the breaker closed position during the previous breaker manipulation, the automatic breaker closure circuit remained open preventing the breaker from closing on demand.

2.16 Broken Terminal Screw on Pressure Transmitter Acutates Safety Injection

Yankee-Rowe; Docket 50-029; LER 84-14; Westinghouse PWR

On August 14, 1984, at 2254 and again at 2310, two successive actuations of safety injection occurred with the reactor at hot standby and 2000 psi in preparation for return to power. There was no injection of Emergency Core Cooling System water into the Main Coolant System from either initiation. The determined to be a Loop No. 1 main coolant pressure channel transmitter failure caused by failure of a terminal screw.

As a result of the second initiation, the pressure in the Safety Injection System nitrogen bottles fell below the technical specification limit. Inspection of the safety injection accumulator room following the low bottle pressure alarm revealed that a 3/8-inch swaglock cap had blown off an unused line on the accumulator safety valve header.

The broken screw was replaced in kind, nitrogen bottles were replenished, and the swaglock cap was reinstalled. The terminal screws within the Model 1153B pressure transmitter are hollow to facilitate the installation of test leads. Rosemount, Inc., has been contacted about this problem and is currently investigating replacement screws which are not hollowed.

2.17 Both High Pressure Safety Injection Trains Inoperable

San Onofre Unit 3; Docket 50-362; LER 84-35; Combustion Engineering PWR

On August 21, 1984 at 1815, with Unit 3 in Mode 1 at 100 percent power, a review of operator logs by the Control Room Supervisor revealed that both Trains A and B High Pressure Safety Injection (HPSI) pumps were inadvertently inoperable at the same time during full power operation.

Investigation determined that the saltwater side of Train B CCW heat exchanger was removed from service for cleaning. Train B components cooled by CCW, including the Train B HPSI pump, were therefore inoperable. One hour later, the Train A HPSI bypass valves MU184 and MU186 were opened in accordance with the approved surveillance procedure for subgroup relay testing. Opening Train A bypass valves rendered HPSI Train A inoperable. The bypass valves were shut about 18 minutes after they were opened, restoring Train A to operable status.

The cause of this event was failure of the Control Operator and Control Room Supervisor to follow procedure precautions in the subgroup relay testing procedure. Both individuals received disciplinary action and counseling on the importance of attention to detail and strict compliance with procedural requirements.

2.18 Misoriented Steam Jet Air Ejector Valve Discs

Quad-Cities Unit 1; Docket 50-254; LER 84-17; General Electric BWR

On August 16, 1984, at 4:30 p.m., Unit One was in the STARTUP mode being returned to operation The unit was at less than 1% core thermal power after completion of a refueling outage. The mechanical vacuum pump was on, drawing the initial vacuum on the main condenser. A short time after having started the mechanical vacuum pump, it tripped. Repeated attempts to restart the pump were unsuccessful, each time the pump would trip due to high temperature. This condition had occurred during past outages and was attributed to steam being removed from the condenser. This was believed to be the cause of the trips in this case, also. Therefore, condenser flow was reversed which alleviated the vacuum pump trips. Further investigation revealed that the south Steam Jet Air Ejector (SJAE) suction valves, AO 1-5401A & B, were actually closed when they indicated open. This was verified when the SJAE's were in use and condenser flow was reversed. The SJAE flow went to zero, indicating no suction path. Power ascension was halted until repairs could be accomplished. These valves, which had recently been replaced by a modification, were taken out of service to be inspected. Upon removing the valve operators, visual examination verified that the valve discs had been installed 90 degrees out of proper orientation for these Butterfly valve operators. Actual valve position was exactly opposite of the indicated position in the control room. The valves were repaired and returned to service.

During the course of the investigation, it was recognized that had a main steam line high radiation signal been initiated during the time the mechanical vacuum pump was running, the pump would have tripped but would not have been automatically isolated by the SJAE valve closure. The two faulty valves would have actually opened when given the CLOSE isolation signal.

The probability of an actual release occurring due to this event was very small and highly unlikely. The mechanical vacuum pump is normally in a standby mode, manually isolated. The length of time the pump was not isolated during this event was approximately 90 minutes. This short time duration, combined with the very low powers encountered during startup operations, minimized the potential consequences that might have been associated with this event.

2.19 Cracked Shunt Trip Paddles in Reactor Trip Breakers

Maine Yankee; Docket 50-309; LER 84-11; Combustion Engineering PWR

On August 24, 1984, while performing routine preventive maintenance on a spare General Electric AK-2A-25-1 reactor trip breaker, maintenance personnel found a steel shunt trip paddle cracked. A second spare breaker paddle was cracked during a manufacturer-approved shunt trip overtravel service adjustment. Metallurgical analysis of the two paddles revealed a high surface carbon content and fully hardened surface structure. These mechanical properties appear incompatible with the application and resulted in cracking.

The cracked paddles appear to be a new design supplied only recently by the manufacturer. They were replaced with paddles from older breakers that have not exhibited this phenomenon. No cracking has been observed in the older design paddles installed in the other reactor trip breakers inspected, nor has any cracking been observed in any other General Electric AK-2A-25-1 breakers in service at Maine Yankee. The manufacturer has been notified of the problem.

Since an undervoltage device operates in parallel with the shunt trip mechanism, a possible eventual failure of a shunt trip paddle from this type of cracking would not render a reactor trip breaker inoperable. No shunt trip mechanisms actually failed and no recurrence of this problem is anticipated; therefore no further corrective actions are planned.

2.20 Plant Shut Down due to Failure of Control Air Compressors

Sequoyah Unit 1; Docket 50-327; LER 84-45; Westinghouse PWR

On June 25, 1984, the A-A auxiliary control air compressor became inoperable. A broken crankshaft was found during the teardown. A spare shaft was not available, so a new shaft was ordered on emergency basis. On July 9, 1984 with the A-A compressor still inoperable, the B-B compressor began making a knocking noise and was removed from service. The NRC Resident Inspector, during a plant walkdown, noticed both compressors out of service and notified Operations of a potential technical specification problem with both air compressors out of service. A meeting was held by plant management, and it was determined that both units should enter Technical Specification 3.03 (the "motherhood" clause). Both units entered 3.03. Power reduction was initiated and continued down to 88%. At that point the B-B auxiliary control air compressor was returned to service and 3.03 was exited.

The auxiliary control air compressors are not technical specification equipment but are attendant equipment for various safety systems. This system is designed to remain operable during a maximum probable flood, and the design basis earthquake following a service air isolation.

This system supplies air to the following safety-related equipment:

1. Control bay heating and ventilation system.
2. Auxiliary building gas treatment system.
3. Containment vacuum relief isolation valves.
4. Emergency gas treatment system.
5. Auxiliary feedwater system.
6. Steam generator pressure relief valves.
7. Pressurizer spray valves.

The compressors involved are Model No. 4-ESV-NL manufactured by Inger-Soll Rand. The cause of failure of the A-A compressor is unknown at this time. The B-B compressor's problem has been attributed to a broken lock-tab washer which allowed a locknut to back off. The piston rod then became disconnected from the cross-head.

A review of the spare parts inventory will be made and the quantity of each stock item will be adjusted to ensure adequate parts are available for future repairs. A detailed maintenance procedure is being prepared specifically for these compressors and will be used for future repairs. The preventive maintenance program will be upgraded to ensure better reliability of the compressors.

2.21 Reactor Scram due to Loss of Instrument Air

Grand Gulf Unit 1; Docket 50-416; LER 84-33; General Electric BWR

While in Cold Shutdown and transferring instrument air service from the Unit 2 compressor to the Unit 1 compressor, an inadvertent loss of system pressure occurred resulting in a reactor scram and a Secondary Containment isolation. The Unit 2 compressor was shut down as the transfer was made, yet the Unit 1 compressor failed to maintain the system pressure greater that 60 psig. An investigation for proper valve lineup and an attempt to restart the Unit 2 air compressor prior to the pressure drop to 60 psig was made but was unsuccessful. The scram occurred when the scram pilot valves drifted open due to low pressure and caused a high scram discharge volume.

The valve lineup investigation revealed that the Unit 1 air dryer outlet valve was closed. The system operating instructions required this valve to be open. The reason or time the valve was closed could not be determined. To prevent a recurrence, the system operating instructions will be revised to require the valve to be locked open on each Unit. This is the only manual valve between the air dryer trouble alarm (indicative of low pressure at the dryer outlet) and the Unit 1/Unit 2 cross connection.

2.22 Personnel Error Causes Reactor Scram

Davis-Besse Unit 1; Docket 50-346; LER 84-10; Babcock & Wilcox PWR

On June 24, 1984, while operating at approximately 94% of full power, the Essential Instrumentation Bus Y4 deenergized due to the Essential Inverter YV4 blowing an input fuse. This deenergizes Channel 4 instrumentation systems including Channel 4 of Safety Features Actuation System, SFAS, Channel 4 of th Anticipatory Reactor Trip System, ARTS, and Channel 4 of the Reactor Protection System, RPS, which opens one set ("A" and "C") of control rod drive breakers.

The YV4 inverter was repaired and returned to service with the Y4 bus back to normal. In order to return Channel 4 of the RPS back to service, Surveillance Test "RPS Monthly Functional Test" was performed and its associated set of control rod drive breakers then were to be closed. The Instrument and Control mechanic who had been doing the test, intending to close the open control rod drive breaker, which he thought was Breaker "D," proceeded to Control Rod Drive Breaker "D" and accidentally opened it, causing a reactor scram.

The cause of the reactor shutdown was due to personnel error when Control Rod Drive Breaker "D" was opened while the Control Rod Drive Breaker set "A" and "C" was still open from the loss of Essential ac Bus Y4. The Instrument and Control mechanic had intended to reset the open breaker following completed surveillance testing which was to restore Y4 to operable status.

It is also noted that an anomaly exists in the identification scheme used with RPS channels and the Control Rod Drive Breakers B, A, D, and C, respectively. The existing control rod drive breaker labeling does not provide RPS channel information.

The loss of Essential Inverter YV4 was caused by a failure of a zener diode and resistor in its logic power supply circuit board.

The personnel involved with the incident are aware of the error in judgement they made and the consequences that followed. This event will be reviewed by all Instrument and Control shop personnel. Signs are being made and will be posted on the control rod drive breaker cabinets stating "CAUTION, verify flag position before opening or closing breaker." This will be a visible means to the mechanics and/or operator of what to look for prior to resetting any breaker.

The control rod drive breakers will additionally be labeled to indicate the associated RPS channel. The licensee is investigating the use of protective "flip-up" covers to be placed over the control rod drive breaker "trip" switches to prevent inadvertent actuations.

2.23 Stuck Control Rod

Surry Unit 1; Docket 50-280; LER 84-17; Westinghouse PWR

On June 20, 1984, a reactor startup was in progress. While withdrawing Control Bank A, the first control bank of rods to be withdrawn, rod position indicator (RPI) B-6 stopped at 30 steps and was suspected to be malfunctioning. After the RPI was verified to be correct, the reactor trip breakers were opened and all rods dropped into the core except B-6. Rod B-6 was verified stuck at 30 steps using the rod's search coil. The control rod was exercised using abnormal procedure AP-1.5. This action did result in some movement of B-6, however, when it was tripped from the fully withdrawn position, it became stuck at 56 steps and could not be moved in or out.

A Westinghouse representative was unsuccessful in freeing rod B-6 using a special control box that extends the time the lift coil is energized. Rod drop testing was satisfactorily completed on other rods to verify operability. In another unsuccessful attempt to free B-6, the unit was cooled down to 250°F and the Westinghouse control box was used. After a return to hot shutdown, rod drop testing was successfully completed on all rods except B-6.

The safety analyses required for continued operation with an inoperable rod were completed prior to station approval for a startup. During the performance of the safety analysis, it was revealed that the control rod insertion limit curve for one inoperable rod contained in Technical Specifications was not appropriate for this situation. A more restrictive insertion limit curve was generated for use. Also, before startup was approved, a Special Test was written. This test delineates the monitoring requirements to insure that operation remains within the bounds of Technical Specifications during operation with B-6 partially withdrawn.

Following a startup, reactor power was held at 29% for a flux map. The results of this map indicated that the hot channel factors were within Technical Specification limits, but a quadrant power tilt (QPT) of 5.52% existed. A flux map taken at 50% power yielded a QPT of 3.58%. Another map taken at 80% power indicated a QPT of 3.13%. The results of all flux maps have indicated that the hot channel factors are within Technical Specification limits. However, since the QPT exceeded 2.0% for greater than 24 hours, this event is reportable.

Nuclear Engineering has performed a safety analysis to verify that continued operation with rod B-6 stuck can be safely accomplished. This analysis included revision of insertion limits, re-evaluation of the potential ejected rod worth and transient power distribution peaking factors, and included the effects of non-uniform fuel depletion in the area of the stuck rod.

The results of this analysis indicate that with the revised insertion limits, all applicable safety limits will continue to be met with rod B-6 stuck.

Reanalysis or reevaluation of the accidents potentially impacted has confirmed that the results of the current licensing analysis remained bounding. Reactor power has been administratively limited to 80% with a Technical Specification limit of 88%, therefore, an unreviewed safety question is not created.

The quadrant power tilt was created because control rod B-6 was stuck at the 56 step position.

The cause of the stuck rod is unknown at this time, however, Westinghouse representatives could not rule out debris or a bent or broken rod cluster control assembly spider vane. The cause will be determined with the reactor disassembly and inspection during the upcoming refueling.

Extensive efforts were made to free the stuck rod. A program was developed to monitor the flux tilt as long as it exists.

2.24 Reactor Scram due to Lightning Strike

Susquehanna Unit 1; Docket 50-387; LER 84-28; General Electric BWR

The transmission line which supplies one of the two offsite power sources to the site was hit by lightning on June 13, 1984. This caused the Unit 1 Startup Transformer (T-10) supply breaker to open. The resulting voltage transient tripped the Units 1 and 2 "A" RPS EPA breakers. The loss of "A" RPS caused many division 1 alarms to annunciate including ½ scram, various area radiation monitors and neutron monitoring trips. Actual initiations caused by the loss of RPS were division 1 primary containment isolation and trips of Zone 1 (Reactor Building, Unit 1) heating, ventilation, and air conditioning (HVAC), Zone II (Reactor Building, Unit 2) HVAC; Zone III (Common Area Refueling Floor) HVAC; and initiation of Standby Gas Treatment system (SGTS). After the lightning strike, the supply breaker to startup bus 10 opened on under voltage. This caused the supply breakers to the ESS busses supplied by T-10 to open. ESS busses 1A, 1C and 2C transferred to their alternate sources, ESS transformers 201 and 211. The transfer of bus 2A occurred late causing the "A" Diesel Generator to start. The transfer finally did occur and the diesel never loaded to the bus. The tie breaker between bus 0A106 0A107 also closed on low voltage of startup bus 10.

The momentary loss of power to the 1A and 1C ESS busses during transfer caused a loss of signal to the feedwater level control circuits, to the reactor recirculation runback circuitry for both pumps and to the "A" Reactor Recirc. Pump. This caused all the reactor feed pumps speed to fail constant, the "A" Reactor Recirc. Scoop Tube to lock, and the "B" Reactor Recirc. to runback. The "A" Reactor Recirc. Runback was prevented by the scoop tube lock.

Due to the feedwater pumps locking up, feedwater flow was constant and reactor power (steam flow) decreased due to recirc. runback. This caused the reactor vessel level to rise. At a vessel level of +54 inches the main turbine tripped due to control valve fast closure, resulting in a scram. Reactor power level on Unit 1 was 100%. Reactor power level on Unit 2 was less than 1%.

2.25 Positive Moderator Temperature Coefficient

Turkey Point Unit 4; Docket 50-251; LER 84-12; Westinghouse PWR

On June 11, 1984, at 10:30 p.m., the reactor was operating at a power level above 70% with a slightly positive moderator temperature coefficient (MTC) which did not comply with Technical Specifications. The root cause was determined to stem from inadequate procedural guidance to take into account the affect of a large change in xenon concentration on the ability to maintain a zero or negative MTC.

The Technical Specification states that with the reactor power greater than or equal to 70% RATED THERMAL POWER, the MTC shall not be more positive than 0 delta K/K/°F. The unit was returned to service after approximately 15 hours in the hot shutdown condition. Power was increased to just under 70% to hold for chemistry sampling and other verifications. The reactor coolant system (RCS) boron concentration was determined to be 1390 ppm and Bank D control rod drive position at 180 steps withdrawn. Under these conditions, with no significant reduction in xenon concentration allowed, the reactor power could be increased to 100% without violating the Technical Specification. However, the previous unit shutdown and changes in the xenon production and removal rates that occurred during power ascension resulted in the xenon concentration diminishing such that negative reactivity had to be added (i.e., inserting rods, borating) to control reactor power. The problem arose when the ability to add reactivity was limited to the addition of boron, since any insertion of Bank D control rods would have driven the neutron axial flux outside its target band in violation of the Technical Specification. Thus, boron was added to control reactor power, compensating for the reducing xenon concentration, resulting in exceeding the MTC curve due to a slightly positive MTC.

The initial identification of the problem was when chemistry sampling indicated the RCS boron concentration to be 1540 ppm. Power was reduced from 91% to approximately 80% and a back-up sample was requested which verified (1550 ppm) that the problem existed. Power was reduced below 70% and Reactor Engineering was notified and their assistance requested. Reactor Engineering determined what conditions were required (i.e., xenon build-up, boron concentration, and Bank D rod position) to reach and exceed 70% power without adversely impacting axial flux or MTC requirements. After 8-1/2 hours, the RCS boron concentration was at 1429 ppm, which was low enough to allow power to be increased to 70% and above while complying with the Technical Specification. The ascension to full power recommenced and full power was achieved with no further problems.

2.26 False Signals from Electronic Keying of Two-way Radios Causes Scram

Brunswick Unit 1; Docket 50-325; LER 84-14; General Electric BWR

On August 1, 1984, at 1417, a Unit 1 scram was automatically initiated by the Reactor Protection System (RPS) due to an instrument upscale trip of the reactor Average Power Range Monitor (ARPM) System. At the time, the unit was operating at 94.6% power with a planned increase to rated power in progress. The unit High Pressure Coolant Injection System was out of service pending the performance of periodic testing.

Reactor level was controlled during scram recovery through use of the Reactor Core Isolation Cooling System (RCIC). A Group 1 isolation occurred, as per design, when the reactor pressure decreased to the low pressure setpoint while the unit mode switch was in Mode 1. Reactor pressure, which peaked at 997 psig, was controlled by manual opening of safety-relief valves 1-B21-F013A, E, J, and B. Following the Group 1 isolation, it was discovered that inboard main steam line isolation valve (MSIV) 1-B21-F022A did not automatically close. An attempt to manually close the valve proved unsuccessful.

The APRM System upscale trip resulted from the reactor recirculation loop flow instrumentation receiving erroneous input signals that caused the instruments to sense simultaneous decreasing flow spikes in each reactor recirculation loop. This resulted in an automatic reduction of the ARPM System high reactor power scram setpoint to less than the actual reactor power, thereby causing the APRM System upscale trip. The cause of the erroneous signals was electronic keying of two-way radios in use in the immediate vicinity of instrumentation in the reactor building.

An investigation was conducted to determine why the inboard MSIV did not close. The three-way ac/dc air operator actuation solenoid pilot valve for F022A apparently failed and was continuously sending an air signal to the four-way pilot valve. With electrical power to both of the ac and dc pilot valve solenoids, resulting from either a Group 1 isolation or a manual command to close, the three-way ac/dc solenoid pilot valve should have actuated to remove this air signal. However, the investigation revealed the subject air signal was still present. The F022A three-way ac/dc solenoid pilot valve, ASCO part number ER8320A183E, was replaced and the removed component was subsequently bench-tested.

An inspection of the removed three-way ac/dc solenoid pilot valve revealed an outward discoloration of the pilot valve body, but no evident signs of failure were noted.

As a result of this event, various types of communication radios utilized in both units will be electronically keyed in the vicinity of the Unit 2 instrumentation racks in the reactor building to determine if control room instrumentation is adversely affected. Following this testing, signs prohibiting the use of plant communication radios within specific identified plant areas will be appropriately posted in those areas. In addition, plant Engineering will be requested to evaluate the apparent failure of the MSIV F022A solenoid pilot valve to determine applicable corrective action.

On December 19, 1983, the NRC provided a warning of the potential for this type of event in IE Information Notice 83-83, "Use of Portable Transmitters Inside Nuclear Power Plants."

2.27 Galling Target Rock Valves

San Onofre Unit 2; Docket 50-361; LER 84-36; Combustion Engineering PWR

A deficiency has been identified with the High Pressure Safety Injection (HPSI) motor operated loop isolation valves. These valves are two-inch Y-pattern globe valves manufactured by Target Rock Corp. (Model Number 74R002).

On February 27, 1984, during the performance of a surveillance on high pressure safety injection (HPSI) check valves, isolation valve 3HV9327 failed to stroke more than approximately 20 percent stem travel when attempting to open the valve. An inspection of the valve's internals determined that 0.280 inches of "free stem movement" (FSM) existed between the stem and disc assembly. Normal FSM on a newly assembled valve would be below 0.025 inches.

An analysis was performed on the stem assembly from 3HV9327 which revealed excessive wear on the stem and retaining ring. The material of the stem and retaining ring on the subject valves is 17-4PH hardened stainless steel. Under high stress, this material is susceptible to galling. When the valve is opened under pressure, the stem rotates relative to the disc, because the differential pressure holds the disc against the seat, momentarily keeping the disc from rotating with the stem. Galling is most severe at the point of greatest stress (the bearing surface between the bottom of the retaining ring and the stem), and repeated openings under pressure result in wear. As wear increases, the disc and stem become misaligned, and, ultimately, the valve will not open. The valve's internals were replaced, and the valve was retested satisfactorily and restored to service.

Following the repair to 3HV9327, a failure analysis was conducted which concluded that data was needed for similar valves, and a special test with the units in Modes 4 or 5 would be required. Since no previous failures had occurred on this type of valve, operations continued until the remaining valves could be examined. A Special Test Procedure which measures FSM as an indication of potential internal wear, was developed for the purpose of assessing the condition of similar valves.

These special tests were then conducted on HPSI cold leg and hot leg injection valves on Units 2 and 3. The following FSM data was obtained at the conclusion of the testing.

Unit 2

Train A		Train B	
2HV9324	0.042 inches	*2HV9326	0.250 inches
2HV9327	0.088 inches	2HV9329	0.180 inches
2HV9330	0.084 inches	2HV9332	0.085 inches
2HV9333	0.180 inches	2HV9323	0.050 inches
#2HV9420	0.070 inches	#2HV9434	0.038 inches

* FSM after replacement of valve internals - 0.041 inches

Hot leg injection valve

Unit 3

Train A		Train B	
3HV9324	0.112 inches	3HV9326	0.135 inches
**3HV9327	0.280 inches	3HV9329	0.030 inches
3HV9330	0.170 inches	***3HV9332	0.320 inches
3HV9333	0.005 inches	****3HV9323	0.225 inches
#3HV9420	0.060 inches	#3HV9434	0.028 inches

\# Hot leg injection valve
** FSM after replacement of valve internals 0.025 inches
*** FSM after replacement of valve internals 0.019 inches
**** FSM after replacement of valve internals 0.040 inches

On June 21, 1984 during performance of a surveillance on HPSI check valves conducted in parallel with the data gathering, 2HV9326 could not be stroked beyond approximately 20 percent stem travel. All other Unit 2 and 3 valves opened satisfactorily. However, based on the failure of 2HV9326 at 0.250 inches free stem movement, a criterion of 0.187 inches (75 percent of 0.250 inches) was established as the basis for repair. As a result, 3HV9323 and 3HV9332 were repaired in addition to 2HV9326. The stem assembly for 3HV9332 was replaced with a spare assembly. The retaining rings for 2HV9326 and 3HV9323 were redesigned using a different material alloy and shape to reduce wear. The valves were retested and restored to service.

An evaluation of the flow characteristics of the HPSI System with the reduced valve stroke was conducted. It was concluded that an average 0.187 inch stroke reduction (free stem movement) and subsequent flow reduction, is within the present safety analysis, The actual average stroke reduction is less than 0.187 inches, therefore, HPSI system flow remains acceptable.

The investigation was then expanded and the plant valve list was reviewed for similar valves which could show the same type degradation. Six additional valves per unit were identified as having a similar design. Two of the six valves are three-inch HPSI hot leg injection isolation valves (Model 74R003), and four are eight-inch Low Pressure Safety Injection (LPSI) System isolation valves. Free stem movement test was conducted on each unit's HPSI hot leg injection valves, and the results are included in the FSM tabulation discussed above. Although some wear was observed, there was no significant reduction in flow, and these valves were considered acceptable for use. The free movement test will also be conducted each time a unit enters Mode 5 from Mode 1 on hot leg injection valves that have been stroked under differential pressure. The LPSI valves, although similar in design to the HPSI valves, were found to have significant differences. The stem and retainer ring surface area is greater, and the differential pressure across the valve is considerably less. Additionally, the disc is in a guide cage during its travel. No failures have occurred on these valves, and no corrective action is planned.

As long-term corrective action, during the first refueling on each unit, stem assemblies on the model 74R002 valves will be replaced with stem assemblies of a different alloy which has a greater resistance to galling. Additionally, a new stem and retaining ring design will be used which increases the surface area and lower stress levels. The 74R003 valve stem assemblies will also be replaced during a suitable subsequent outage. Until the stem assemblies have been replaced with the new design, the free stem movement testing will be conducted each time a unit enters Mode 5 from Mode 1 on valves that have been stroked under differential pressure. Valves with FSM of greater than 0.187 inches will be repaired. Procedures will be changed to include the performance of free stem movement test as part of the integrated system operation required to bring the plant from Mode 5 to Mode 3. In addition, procedures will be changed to include the criterion of 0.187 inches free stem movement as the basis for valve repair.

2.28 Potential Valve Failure due to Reversal while Valve is in Mid-Stroke Position

Salem Unit 2; Docket 50-311; LER 84-18-01; Westinghouse PWR

On July 25, 1984, during routine power operation, conditions were being restored to normal in the final steps of the Pressurizer Overpressure Protection System (POPS) functional test. The POPS functional test is performed on two independent trains. It requires that the Power Operated Relief Valve (PORV), for the train being tested, be isolated from the Pressurizer. This is done by closing the associated PORV block valve. With the PORV block valve closed, the PORV can be stroke timed, as required, without affecting normal system operation.

The test was started and satisfactorily completed on Train B of the POPS. The system was then returned to normal (i.e., the PORV block valve was opened). The test on Train A of the POPS was also satisfactorily completed. When the PORV block valve (2PR6) was opened, Reactor Coolant System pressure began to rapidly decrease. The Reactor Operator immediately initiated a close signal to block valve 2PR6. However, when the valve failed to close in the required time (less than ten seconds), the operator immediately reverified that the PORV on Train A (2PR1) and the PORV and associated block valve on Train B (2PR2 and 2PR7 respectively) were closed. He then attempted to reduce the severity of the transient by manually starting a centrifugal charging pump. At the same time, the other operator began shedding load, in approximately 100 MWe increments, to further reduce the effects of the transient.

This action reduced the rate of pressure drop slightly; however, pressure continued to decrease. When pressure had decreased to 1865 psig, the logic for a reactor trip was met, and a reactor trip did occur. Pressure continued to drop to the safety injection initiation setpoint of 1765 psig, at which time an automatic safety injection occurred. Following the safety injection and the subsequent closure of 2PR6, the plant recovered to normal operating parameters.

The depressurization transient was initiated by the inadvertent opening, and failure to reseat, of Pressurizer Overpressure Protection System (POPS) relief valve 2PR47. The transient was not able to be immediately terminated, due to the failure of 2PR6 to close in the required time frame, resulting in the reactor trip and safety injection. The failure of 2PR6 to close in the required time was attributed to either a broken wire in the valve operator, a minimum recommended torque switch setting, attempted reversal of the valve direction (while the valve was in a "mid-stroke" position), or a combination of all three.

After extensive research and testing, the following conclusions were reached and corrective actions were taken:

Inspection of valve 2PR47 revealed that the valve was open. Particles from the valve magnet had lodged in the pilot stem, preventing the pilot valve from closing. 2PR47 is a solenoid valve; these type valves are known to "burp" (pop open and reseat during pressure transients). The valve apparently "burped" while testing 2PR1, and the magnetic particles wedged in the pilot stem and prevented the valve from reseating.

2PR47 and 2PR48 (POPS Relief Valves) served no purpose, because the relief function of these valves had been previously replaced with modifications to the circuitry of the PORV valves (2PR1 and 2PR2). This had been accomplished due to previous problems with 2PR47 and 2PR48, and the valves were scheduled for removal in the near future. Due to this occurrence, both valves were removed from the system.

Motor Operated Valve Analysis and Testing Systems (MOVATS) tested 2PR6. The valve operated satisfactorily, with a closure thrust of 6700 pounds. Per Velan (the valve manufacturer), the required valve closure thrust is 4900 pounds, indicating that the valve should have closed. Records indicate that this valve was reworked in April 1984, at which time the wedge and Limitorque operator were replaced. A calculation of the valve thrust and torque values, with information supplied by Limitorque, indicated that a light torque switch spring was installed in the operator. The close torque switch setting was found to be 1½. Velan's minimum recommended setting is 1¼. Although the valve tested satisfactorily, Velan recommended that this setting be 2½. This setting would represent approximately 8000 pounds of thrust; and even if a heavy torque spring was present in the operator, it would not be damaging to the valve. The close torque switch setting of 2PR6 was raised to the recommended value.

Upon electrical disconnection of the valve for internal inspection, the Limitorque operator was found to contain a broken wire. This seven strand wire carries control voltage to the valve for opening and closing functions. Oxidation of the strands indicated that two of the strands were broken for some time, with the other five strands indicating a more recent break. The bolts at the base of the valve were found to be slightly loose, which allowed a small amount of valve operator movement. Since the wire run was taut, it is suspected that vibratory action of the valve broke the wire. The break was enclosed in sleeving, and the wire apparently was making intermittent contact during valve vibration. The broken wire was repaired. 2PR7 was also inspected; however, no similar problems were noted.

Upon investigation of 2PR6 design, which allows reversing of valve direction at any time, the Station was informed by Limitorque that this was an undesirable design, due to the possibility of shearing the keyway on the pinion gear. In addition, while performing calculations for required valve torque, it was discovered that the coefficient of friction value (which is used in the calculation) may not be valid during periods of direction reversal while the valve is in a "mid-stroke" position. What this means is that the required torque, during valve reversal operations, may be greater than previously calculated. Since this possibility exists, and because Limitorque has expressed the opinion that this is an undesirable design, 2PR6 and 2PR7 valve circuitry has been modified to prevent direction reversal until the valves have completed their stroke (open or shut). In addition, 27 valves of a similar design have been identified in various safety-related systems. The licensee will obtain further clarification from Limitorque on what they mean by the term "undesirable." Based on the results, a determination will be made as to which, if any, Limitorque motor operated valves require modification. In the interim, the appropriate procedures have been changed to caution the operators against reversing direction until the valves have completed their stroke.

2.29 Failure of Both LPCI Injection Valves

Quad-Cities Unit 1; Docket 50-254; LER 84-14

During a Refueling Outage, while the Operator was in the process of starting the Shutdown Cooling mode of the Residual Heat Removal System, it was discovered that both the 1-1001-29A and 1-1001-29B Low Pressure Coolant Injection valves would not open.

The cause of this deviation was personnel error. In 1980, Modification M-4-1-73-76 was installed. This modification consisted of a change in the logic circuits of the 1-1001-29A and 1-1001-29B valves in order to prevent them from hammering. Hammering is a condition where the motor continues to drive the valve closed until a high torque signal stops the motor. When the motor is stopped, the valve relaxes and the high torque signal is removed. With a close signal still present, the motor then again tries to drive the valve closed, until high torque is experienced. This chattering continues until the breaker is tripped or the close signal is removed.

A mistake was made when the wiring diagrams were drawn. In 1980, these logic circuits were installed as per the faulty wiring diagrams and thus, the possibility of hammering still existed. No problems were experienced with these two valves after the installation of the modification, however, because the motor operators present on the valves at that time were equipped with brakes. The intended purpose of the brakes is to stop the momentum of the valve at the desired valve position. An additional feature of the brakes is that the brakes also stopped the valve at the end of its closed stroke and thus, prevented the hammering condition. During the past refueling outage these motor operators were replaced with Environmentally Qualified motors. Brakes cannot be qualified for Environmentally Qualified motors and these valve operators were analyzed as not requiring brakes.

When these valves experienced a continuous closed signal, as from a control switch held in the closed position, or an LPCI Loop Select signal during surveillance testing, they continuously tried to close and both valve stems were damaged. The damage was such that the valves would no longer fully open.

They were visually inspected immediately and the 29B valve found to be 25 percent open and the 29A valve was found fully closed. The wiring diagram problem affected only the anti-hammer circuit of the 29A and 29B valves and did not affect their LPCI Loop Select logic.

The valve stems were removed and are being replaced. The wiring correction has been done and the wiring diagram has been corrected to reflect that change.

3.0 OTHER NRC OPERATING EXPERIENCE DOCUMENTS

3.1 Abnormal Occurrence Reports (NUREG-0090) Issued in July-August 1984

An abnormal occurrence is defined in Section 208 of the Energy Reorganization Act of 1974 as an unscheduled incident or event which the NRC determines is significant from the standpoint of public health or safety. Under the provisions of Section 208, the Office for Analysis and Evaluation of Operational Data reports abnormal occurrences to the public by publishing notices in the Federal Register, and issues quarterly reports of these occurrences to Congress in the NUREG-0090 series of documents. Also included in the quarterly reports are updates of some previously reported abnormal occurrences, and summaries of certain events that may be perceived by the public as significant but do not meet the Section 208 abnormal occurrence criteria.

Date Issued	Report
7/84	REPORT TO CONGRESS ON ABNORMAL OCCURRENCES, JANUARY-MARCH 1984, NUREG-0090, VOL. 7, NO. 1

There were six abnormal occurrences during the report period. Three occurred at licensed nuclear power plants, and the others occurred at NRC and Agreement State licensed radiographers.

The occurrences at the plants involved (1) an inoperable containment spray system at Indian Point Unit 2; (2) a through-wall crack in the vent header inside the BWR containment torus at Hatch Unit 2; and (3) serious degradation of the reactor depressurization system at Big Rock Point. The other occurrences involved (1) an overexposure to a member of the public at University of Cincinnati Hospital in Cincinnati, Ohio; (2) a therapeutic medical misadministration at Henry Ford Hospital in Detroit, Michigan; and (3) overexposure of a radiographer and an assistant at Industrial NDT, Inc., in Charleston, South Carolina.

Also, the report provided update information on (1) the nuclear accident at Three Mile Island (79-3), first reported in Vol. 2, No. 1, January-March 1979; (2) blockage of coolant flow to safety-related systems and components at various plants (81-7), first reported in Vol. 4, No. 4, October-December 1981; and (3) seismic design errors at the Diablo Canyon Plant (81-8), also first reported in Vol. 4, No. 4, October-December 1981.

In addition, discussion of items of interest that did not meet abnormal occurrence criteria included (1) a fire at the Edlow International, Inc., uranium storage facility in East St. Louis, Missouri; (2) a cobalt-60 contaminated steel incident in

New Mexico; (3) a stuck open main steam relief valve at the Davis-Besse plant; and (4) contamination levels exceeding environmental standards at the Kerr-McGee Chemical Corporation Rare Earths Facility in West Chicago, Illinois.

3.2 Bulletins and Information Notices Issued in July-August 1984

The Office of Inspection and Enforcement periodically issues bulletins and information notices to licensees and holders of construction permits. During the period, one bulletin and 17 information notices were issued.

Bulletins are used primarily to communicate with industry on matters of generic importance or serious safety significance (i.e., if an event at one reactor raises the possibility of a serious generic problem, an NRC bulletin may be issued requesting licensees to take specific actions, and requiring them to submit a written report describing actions taken and other information NRC should have to assess the need for further actions). A prompt response by affected licensees is required and failure to respond appropriately may result in an enforcement action. When appropriate, prior to issuing a bulletin, the NRC may seek comments on the matter from the industry (Atomic Industrial Forum, Institute of Nuclear Power Operations, nuclear steam suppliers, vendors, etc.), a technique which has proved effective in bringing faster and better responses from licensees. Bulletins generally require one-time action and reporting. They are not intended as substitutes for revised license conditions or new requirements.

Information Notices are rapid transmittals of information which may not have been completely analyzed by NRC, but which licensees should know. They require no acknowledgement or response, but recipients are advised to consider the applicability of the information to their facility.

Bulletin	Date Issued	Title
84-03	8/24/84	REFUELING CAVITY WATER SEAL

Information Notice	Date Issued	Title
84-53	7/5/84 OTHER	INFORMATION CONCERNING THE USE OF LOCTITE 242 AND ANAEROBIC ADHESIVE/SEALANTS
84-54	7/5/84	DEFICIENCIES IN DESIGN BASE DOCUMENTATION AND CALCULATIONS SUPPORTING NUCLEAR POWER PLANT DESIGN
84-55	7/6/84	SEAL TABLE LEAKS AT PWRs
84-56	7/10/84	RESPIRATOR USERS NOTICE FOR CERTAIN 5-MINUTE EMERGENCY ESCAPE SELF-CONTAINED BREATHING APPARATUS
84-57	7/27/84	OPERATING EXPERIENCE RELATED TO MOISTURE INTRUSION IN SAFETY-RELATED ELECTRICAL EQUIPMENT AT COMMERCIAL POWER PLANTS
84-58	7/25/84	INADVERTENT DEFEAT OF SAFETY FUNCTION CAUSED BY HUMAN ERROR INVOLVING WRONG UNIT, WRONG TRAIN, OR WRONG SYSTEM

Information Notice	Date Issued	Title
84-59	8/6/84	DELIBERATE CIRCUMVENTING OF STATION HEALTH PHYSICS PROCEDURES
84-60	8/6/84	FAILURE OF AIR-PURIFYING RESPIRATOR FILTERS TO MEET EFFICIENCY REQUIREMENT
84-61 (PWR)	8/8/84	OVEREXPOSURE OF DIVER IN PRESSURIZED WATER REACTOR REFUELING CAVITY
84-62	8/10/84	THERAPY MISADMINISTRATIONS TO PATIENTS UNDERGOING COBALT-60 TELETHERAPY TREATMENTS
84-63	8/13/84	DEFECTIVE RHR REPLACEMENT PIPING
84-64	8/15/84	BWR HIGH-PRESSURE COOLANT INJECTION (HPCI) INITIATION SEAL-IN AND INDICATION
84-65	8/16/84	UNDERRATED FUSES WHICH MAY ADVERSELY AFFECT OPERATION OF ESSENTIAL ELECTRICAL EQUIPMENT
84-66	8/17/84	UNDETECTED UNAVAILABILITY OF THE TURBINE-DRIVEN AUXILIARY FEEDWATER TRAIN
84-67 RATES	8/17/84	RECENT SNUBBER INSERVICE TESTING WITH HIGH FAILURE
84-68	8/21/84	POTENTIAL DEFICIENCY IN IMPROPERLY RATED FIELD WIRING TO SOLENOID VALVES
84-69	8/29/84	OPERATION OF EMERGENCY DIESEL GENERATORS

3.3 Case Studies and Engineering Evaluations Issued in July-August 1984

The Office for Analysis and Evaluation of Operational Data (AEOD) has as a primary responsibility the task of reviewing the operational experience reported by NRC nuclear power plant licensees. As part of fulfilling this task, it selects events of apparent interest to safety for further review as either an engineering evaluation or a case study. An engineering evaluation is usually an immediate, general consideration to assess whether or not a more detailed protracted case study is needed. The results are generally short reports, and the effort involved usually is a few staffweeks of investigative time.

Case studies are in-depth investigations of apparently significant events or situations. They involve several staffmonths of engineering effort, and result in a formal report identifying the specific safety problems (actual or potential) illustrated by the event and recommending actions to improve safety and prevent recurrence of the event. Before issuance, this report is sent for peer review and comment to at least the applicable utility and appropriate NRC offices.

These AEOD reports are made available for information purposes and do not impose any requirements on licensees. The findings and recommendations contained in these reports are provided in support of other ongoing NRC activities concerning the operational event(s) discussed, and do not represent the position or requirements of the responsible NRC program office.

Case Study	Date Issued	Subject
C404	7/84	STEAM BINDING OF AUXILIARY FEEDWATER PUMPS

This case study evaluated the generic safety implications of backleakage to the auxiliary feedwater (AFW) system. Backleakage is defined as the leakage of hot main feedwater or steam from the steam conversion system to the AFW system. The AFW system is a safety system on a pressurized water reactor (PWR) whose safety functions are to provide a source of water for the steam generators when the main feedwater system is not available, and to mitigate design basis accidents.

Operational experience has shown that on numerous occasions an AFW pump was rendered inoperable due to steam binding resulting from the leakage of hot feedwater to the AFW system. Multiple valves in series between the steam conversion system and the AFW system leaked and failed to provide isolation between the interfacing systems. The safety implication of these operating events was that backleakage represents a potential common cause failure for the AFW system that can cause the loss of its safety function.

Case Study	Date Issued	Subject

Operating experience involving backleakage to the AFW system since 1981 included 22 events at six operating PWRs in the United States and one foreign plant. These events involved the misoperation or failure of about 60 check valves and five motor-operated valves installed to prevent reverse leakage. Other plants were known to have experienced backleakage, but the events were not considered as reportable occurrences. The events at Surry Power Station Unit 2, H. B. Robinson Unit 2, and Joseph M. Farley Units 1 and 2, provided evidence that more than one AFW pump can be simultaneously adversely affected by backleakage.

The major findings of the study are:

(1) The trend of the operating events involving backleakage to the AFW system increased sharply in 1983 when 13 of the 22 events occurred at five Westinghouse-designed plants.

(2) AEOD's assessment of the safety significance of the events showed that (a) the loss of a single train due to steam binding is significant because it is presently an undetectable failure that jeopardizes the capability of the AFW system to meet single failure criterion, i.e., potential common mode failure; and (b) the unavailability of the AFW system due to steam binding contributes significantly to risk of core melt in PWRs.

(3) The potential for backleakage into the AFW system is generic to all operating PWRs. The review of the AFW designs for the three PWR vendors found that check valves and remotely-operated valves in some designs isolate the AFW system from the steam conversion system. The AFW designs at Westinghouse-designed plants appeared more susceptible to backleakage and steam binding of the pumps because the remotely-operated valve is often normally open. Operating experience showed that backleakage occurred primarily at Westinghouse-designed plants.

(4) The potential for common mode failure of the AFW system is present whenever one pump is steam bound because the pumps are connected by common piping (discharge header and/or recirculation piping) with only a single check valve to prevent backleakage of hot water to a second or third pump.

Case Study	Date Issued	Subject

(5) While a potential exists for backleakage to other safety systems in both PWRs and boiling water reactors (BWRs), there is no known report of steam binding of a pump in other safety systems. The standby safety systems are isolated from operating systems at higher pressures and temperatures by check valves and motor-operated valves similar to the AFW systems. The potential for steam binding is minimized because the remotely operated valve is normally closed and is leak tested (the AFW valves are not). However, leakage through an upstream check valve has caused the remotely-operated valve to fail to open due to thermal binding and other reasons--a separate concern from steam binding.

(6) The analyses of the causes for check valve leakage did not identify any pattern or single major cause of the failures of the check valves. The causes differed between plants and involved different valve designs.

(7) The study did not identify any regulatory requirements or uniform plant practices to reduce the likelihood of steam binding of the AFW pumps and common mode failure of the AFW system.

Engineering Evaluation	Date Issued	Subject
E417	7/2/84	LOOSENING OF FLANGE BOLTS ON RHR HEAT EXCHANGER LEADING TO PRIMARY TO SECONDARY SIDE LEAKAGE

On June 20, 1984, an event occurred at Browns Ferry Unit 1 in which a residual heat removal (RHR) heat exchanger was found leaking during a routine operability test. This leakage was detected by a pressure increase in the secondary side of the heat exchanger which indicated a leak of primary coolant into the RHR service water system which discharges to the Wheeler Reservoir. Six additional events found in this review had similar leakage. Three were at Browns Ferry 1, the others at Browns Ferry 2. These were recurrent events. The leaks in two of these events resulted in release of radioactivity into the environment. These radioactive fluid releases were in excess of the technical specification limit. The RHR heat exchangers at these two units are identical and manufactured by Perfex Inc.

Engineering Evaluation	Date Issued	Subject
		The leakage occurred at a gasket joint of the floating head flange in the RHR heat exchanger and was due to loosened nuts at the flange. It was believed that the loosening of nuts was due to flow-induced vibration and/or thermal cycling. These two operational conditions had not been fully considered in the design of these RHR heat exchangers. Flow-induced vibration and thermal cycling could produce a combined loading on the floating head gasket joint such that torque application alone could not provide adequate compression on the gasket to tighten the joint. The stud elongation approach was needed in order to preclude occurrence of nut loosening on the floating head joint. Generic Safety Issue C-9 listed in the Task Action Plans, which addresses the safety significance of leaks in RHR heat exchangers at BWR plants, has been downgraded in a recent NRC priority ranking plan and dropped from further consideration for resolution. The bases for the risk significance estimate and assumptions for the prioritization of this safety issue are (1) tube failure is the only source of leaks in RHR heat exchangers and (2) in all BWR plants the RHR service water system is designed to have pressure greater than that of the RHR system in the RHR heat exchanger whenever the heat exchanger is in service. Hence, a leak in the RHR heat exchanger may not necessarily cause radioactivity to release into the environment. However, in the events of this review, the leaks in the RHR heat exchanger were from the floating head joint due to loosened nuts, not tube failures, and the service water pressure was lower than that of primary coolant in the RHR heat exchangers at the Browns Ferry units which are BWR plants.
E418	7/24/84	FEEDWATER TRANSIENTS DURING STARTUP AT WESTINGHOUSE PLANTS This analysis was performed to determine if Westinghouse designed plants had more scrams due to feedwater transients, particularly during startup, than did the other two PWR vendor designs. The analysis showed that 29% of the PWR scrams in the U.S. during 1983 were due to feedwater transients. One-third of the scrams which occurred at Westinghouse plants were due to feedwater transients and 54% of these occurred during startup; the number of feedwater transients per reactor increased as

Engineering Evaluation	Date Issued	Subject
		the number of coolant loops increased. On a percentage basis, the number of scrams due to feedwater transients was about 10% greater for Westinghouse plants than for CE or B&W plants.
E420	8/23/84	OPERATIONAL EXPERIENCES INVOLVING SHORTED LAMP SOCKETS OF INDICATION LIGHTS

This report documents the review and evaluation of events involving shorted lamp sockets of indication lights in Class 1E circuits at operating nuclear plants. The study of the problems associated with shorted lamp sockets was initiated by an event that occurred at Peach Bottom Unit 3 on March 29, 1984. The event involved the blowing of the B core spray logic circuit fuse during surveillance testing due to a shorted socket of an indicating light in the circuit.

The blown fuse disabled the 3B core spray logic and also part of the redundant initiating logics of other ECSSs.

A search of the Sequence Coding and Search System (SCSS) was conducted, and 17 other events that occurred in 1981, 1982 and 1983 were obtained. A review of these events showed that this type of problem occurred at 12 nuclear units during these three years. The events occurred in various types of circuits--logic circuits, valve control circuits, pump control circuits, DG control circuits, etc. Most events involved the blowing of the control circuit fuse associated with the shorted light or light socket. However, no common root cause for the shorted lights or sockets is apparent from the review of these events. At certain plants where such failures occurred in the same or similar circuits repeatedly, the licensees have taken or are planning to take corrective actions to prevent recurrence. Plants that fall into this category are Calvert Cliffs 1 and 2 and Crystal River 3. Most of the shorting problems of indication lights occurred during or subsequent to replacement of the lamps and, in general, the licensees have concluded that extra care should be exercised by plant personnel when replacing the lamps and have accordingly briefed their plant personnel. The indicating lights in general are the miniature type, which are small and delicate and not easily replaceable. Hence, damage to the light and socket during replacement will continue to occur at operating nuclear plants. However, the extra care recommended to plant operators, when followed, should reduce the incidence of lamp related failures.

Engineering Evaluation	Date Issued	Subject
E421	8/27/84	LOSS OF PRESSURIZER HEATERS DURING PRECORE HOT FUNCTIONAL TESTING

During precore hot functional testing at Waterford-3 on March 10, 1983, a plant with a construction permit, the primary coolant level in the pressurizer unknowingly decreased, uncovering the energized pressurizer heaters. This resulted in damage to most of the heaters, and all 30 heaters were subsequently replaced.

The reduction of actual pressurizer level was undetected due to leaks in the instrument tubing of the liquid filled reference leg on the level instrumentation channel that had been selected to control pressurizer level. Operational experience has shown that liquid filled reference legs of level measuring instruments are vulnerable to a variety of malfunctions. When a malfunction occurs, the liquid level indication will be nonconservative and will display a higher tank level indication than the actual level of liquid in the tank. During this event, the pressurizer heaters were inadvertently uncovered and most of heaters burned out.

The inoperability of the pressurizer heaters such that the pressurizer pressure control system is ineffective is addressed in CEN-152, "Combustion Engineering Emergency Procedure Guidelines" and does not involve any new unrecognized safety issues.

E422	8/27/84	HIGH PRESSURE COOLANT INJECTION AT E.I. HATCH UNITS 1 AND 2

A study was conducted of the performance of the high pressure coolant injection (HPCI) system at E.I. Hatch Units 1 and 2. It was found that while problems have continually been experienced in the HPCI systems of both Hatch units, these faults were consistent and comparable to those experienced in all domestic boiling water reactors (BWRs) having an HPCI system. The principal faults were found to be in the areas of pressure instrumentation, valves, turbine trip and throttle system components, and human factors. These areas were consistent with other BWR facilities. Likewise, the effects of these faults on the availability of the HPCI system were similar. The pressure instrumentation problems usually had little effect on the system availability, but the valve and turbine trip and throttle system faults almost always adversely affected the system availability.

3.4 Generic Letters Issued in July-August 1984

Generic letters are issued by the Office of Nuclear Reactor Regulation, Division of Licensing. They are similar to IE Bulletins (see Section 3.2) in that they transmit information to, and obtain information from, reactor licensees, applicants, and/or equipment suppliers regarding matters of safety, safeguards, or environmental significance. During July and August 1984, six letters were issued.

Generic letters usually either (1) provide information thought to be important in assuring continued safe operation of facilities, or (2) request information on a specific schedule that would enable regulatory decisions to be made regarding the continued safe operation of facilities. They have been a significant means of communicating with licensees on a number of important issues, the resolutions of which have contributed to improved quality of design and operation.

Generic Letter	Date Issued	Title
84-15	7/2/84	PROPOSED STAFF ACTIONS TO IMPROVE AND MAINTAIN DIESEL GENERATOR RELIABILITY (Issued to all licensees of operating reactors, applicants for an operating license, and holders of construction permits)
84-16	7/27/84	ADEQUACY OF ON-SHIFT OPERATING EXPERIENCE FOR NEAR TERM OPERATING LICENSE APPLICANTS (Issued to all licensees of operating reactors, applicants for operating license, and holders of construction permits)
84-17	7/3/84	ANNUAL MEETING TO DISCUSS RECENT DEVELOPMENTS REGARDING OPERATOR TRAINING, QUALIFICATIONS, AND EXAMINATIONS (Issued to all power reactor licensees, applicants for operator licenses, NSS vendors, reactor vendors, and architect engineers)
84-18	7/6/84	FILING OF APPLICATIONS FOR LICENSES AND AMENDMENTS (Issued to all non-power reactor licensees)
84-19	8/6/84	AVAILABILITY OF SUPPLEMENT 1 TO NUREG-0933, "A PRIORITIZATION OF GENERIC SAFETY ISSUES" (Issued to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits)
84-20	8/20/84	SCHEDULING GUIDANCE FOR LICENSEE SUBMITTALS OF RELOADS THAT INVOLVE UNREVIEWED SAFETY QUESTIONS (Issued to all licensees of operating reactors and applicants for operating license)

3.5 Operating Reactor Event Memoranda Issued in July-August 1984

The Director, Division of Licensing, Office of Nuclear Reactor Regulation (NRR), disseminates information to the directors of the other divisions and program offices within NRR via the operating reactor event memorandum (OREM) system. The OREM documents a statement of the problem, background information, the safety significance, and short and long term actions (taken and planned). Copies of OREMs are also sent to the Office for Analysis and Evaluation of Operational Data, and of Inspection and Enforcement for their information.

No OREMs were issued during July-August 1984.

3.6 NRC Document Compilations

The Office of Administration issues two publications that list documents made publicly available through the NRC.

- The quarterly Regulatory and Technical Reports (NUREG-0304) compiles bibliographic data and abstracts for the formal regulatory and technical reports issued by the NRC Staff and its contractors.

- The monthly Title List of Documents Made Publicly Available (NUREG-0540) contains descriptions of information received and generated by the NRC. This information includes (1) docketed material associated with civilian nuclear power plants and other uses of radioactive materials, and (2) non-docketed material received and generated by NRC pertinent to its role as a regulatory agency. This series of documents is indexed by Personal Author, Corporate Source, and Report Number.

- The monthly Licensee Event Report (LER) Compilation (NURGE/CR-2000) contains Licensee Event Report (LER) operational information that was processed into the LER data file of the Nuclear Safety Information Center at Oak Ridge during the monthly period identified on the cover of the document. The LER summaries in this report are arranged alphabetically by facility name and then chronologically by event date for each facility. Component, system, keyword, and component vendor indexes follow the summaries.

Copies and subscriptions of these documents are available from the NRC/GPO Sales Program, P-130A, Washington, D.C. 20555, or on (301) 492-9530.

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