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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 PHIL-016, Washington, DC 20555.

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1.0 SUMMARIES OF EVENTS

1.1 Pressurizer Code Safety Valve Problem

On October 14, 1982, Oconee Unit 2* was shut down after the licensee determined that, based on known valve ring settings, pressurizer code safety valve design flow could not be fully maintained if called upon. Unit 1 remained operating at full power, and Unit 3 was shut down for maintenance. The licensee action was prompted by notification from the nuclear steam system supplier, Babcock & Wilcox (B&W) of a generic concern regarding the possibility that adequate flow might not be obtained for the pressurizer code safety valves, manufactured by Dresser Industries, for some combinations of backpressure and valve adjustment. The concern arose from B&W's review of data from the generic relief and safety valve test program recently completed by the Electric Power Research Institute (EPRI). The EPRI testing had been performed in response to NRC's NUREG-0737, "Clarification of TMI Action Plan Requirements," which required that a relief and safety valve test program be conducted to verify operability of these valves under postulated accident conditions. The results of the testing, released on July 1, 1982, indicated that with ring settings of +11, -40, -48 (lower, middle, upper rings), the Dresser 31739A safety valve provided adequate relief under all expected conditions. However, at Oconee Unit 2, these ring settings could result in an increase in blowdown (a rapid depressurization) in some cases.

Based on these findings, the licensee began a three-phased approach to complete the analysis of Oconee safety valve performance. First, the licensee initiated an analysis using the RELAP 5 computer code, as benchmarked in the EPRI testing, to determine the backpressure which the valves would experience under various conditions. Second, B&W was contracted to analyze the significance of safety valve blowdown on plant performance. And third, the licensee initiated a detailed analysis of Oconee valves, using the valve dynamic analysis code COUPLE, to determine the optimum ring settings to be used. These ring settings were expected to be fine tuned adjustments of the EPRI tested settings.

On October 8, 1982, preliminary results from initial analysis by the licensee showed that under full flow of the safety valves the backpressure could be high enough to affect valve performance if the ring settings were less than optimum. The licensee requested Dresser to provide what the ring settings were on the Oconee valves. On October 12, Dresser provided ring settings of five of the eight valves (two on each unit pressurizer plus two spares), taken from field data sheets when the valves were last refurbished at Wyle Laboratories. Discussions with Dresser revealed that they did not know what ring settings were set into new valves when they were delivered, and that the ring settings were first recorded when valves were refurbished at Wyle. Two valves were new and, thus, no data were obtained for them. Upon receipt of these ring settings, the licensee became concerned with the difference between the Dresser recorded values and the recommended ring settings from the EPRI testing. However, the ring settings obtained from Dresser had neither been verified by actual inspection, nor had a safety evaluation been completed using various assumed conditions of safety valve operability.

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* Oconee Units 1, 2, and 3 are each 860 MWe (net) PWRs located 30 miles west of Greenville, North Carolina, and are operated by Duke Power.

The licensee immediately (October 12), shipped the two spare Oconee valves to Wyle for inspection to determine the actual ring settings. The "as found" ring settings were obtained from Wyle on the afternoon of October 13. While the "as found" settings differed somewhat from the numbers provided by Dresser, the settings on the two most important rings (lower and middle) were significantly different from the EPRI recommended settings. However, this alone did not determine whether or not the safety valves were functionally operable and capable of performing their design basis function of relieving overpressure conditions during anticipated occurrences and design basis events. To answer these questions, the licensee already had initiated an around-the-clock analytical effort to attempt to derive valve performance from the EPRI test data and to determine actual safety valve relief requirements based on transient analysis.

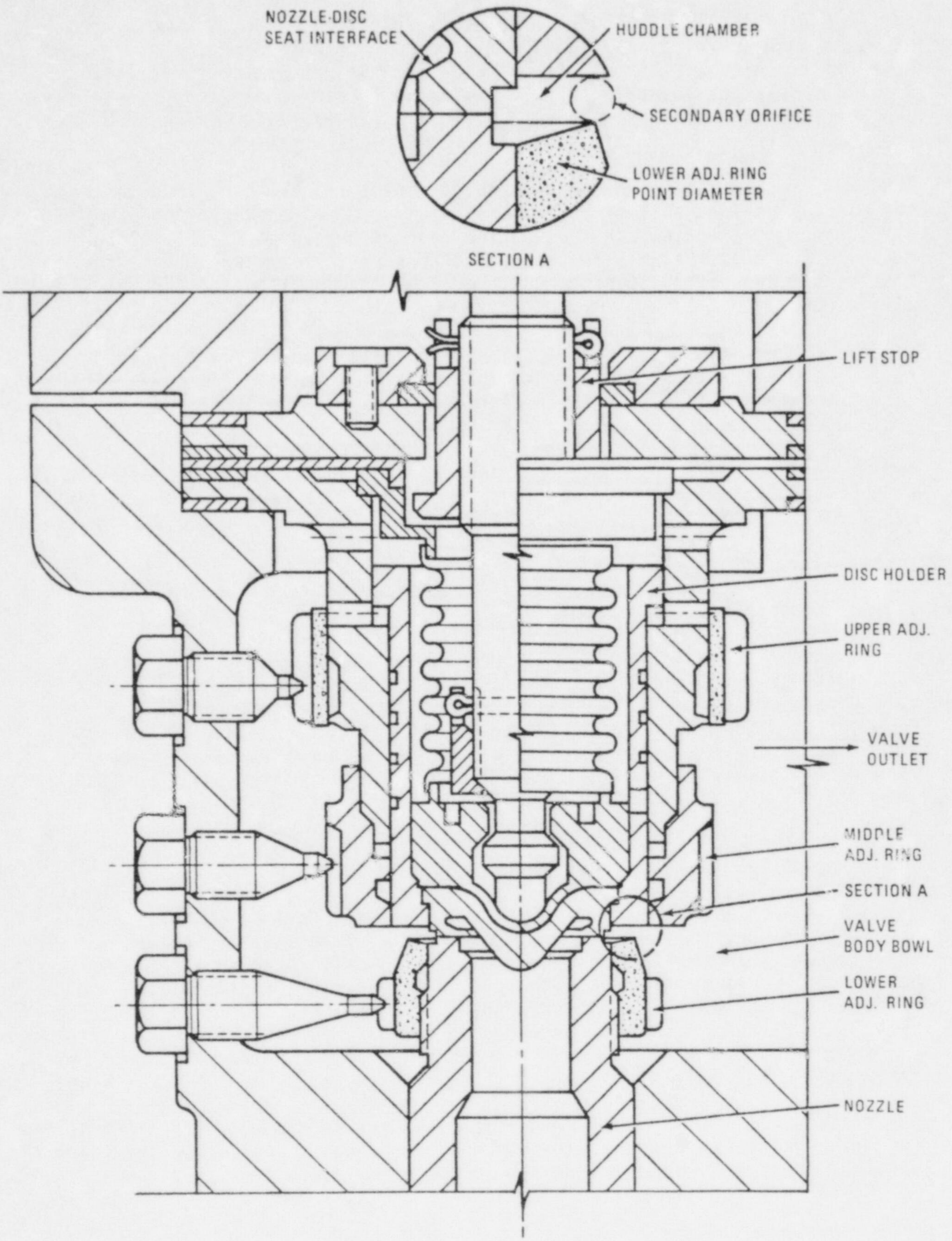
Since no EPRI tests were performed with middle ring settings comparable to Oconee, no absolute values could be obtained regarding expected performance. However, the results of these analytical efforts completed on October 14 indicated that, for the valves with positive middle ring settings, performance would be substantially degraded from rated valve performance. When that determination was made, those valves were declared not to meet the requirements of plant technical specifications.

One of the two new valves for which ring settings had not been obtained was removed from Unit 3 and shipped to Wyle to determine "as found" ring settings, which were -11, 0, -23 (lower, middle, upper). The expected valve performance with these ring settings would have been substantially better than the older Oconee valves.

Prior to the EPRI relief and safety valve test program, actual valve performance for various conditions with backpressure from discharge piping had never been tested. Previously, valves had been tested to determine lift setpoint and the rings had been adjusted to control blowdown within desired tolerances. The relationship between ring settings and valve relief in the presence of various backpressures was not known. The reason why the older Oconee valve ring settings were so different from the newer valves is not known. Since Dresser did not record valve ring settings as they were set when supplied to the customer, there was no way to retrieve that information.

Since no tests have been conducted with Dresser 31739A safety valves with ring settings similar to the Oconee valves, actual valve performance under various conditions is unknown. In general, degraded valve performance from the tests can be characterized by chatter or by reduced lift in the presence of high backpressure. The EPRI tests indicated that valves with short inlet pipe configuration (as is the case at Oconee) were much less prone to chatter than long inlet piping. Also, even in the presence of chatter the valves that were tested provided substantial relief. (The short inlet configured Dresser 31739A valve did not experience any chatter even in the worst ring setting tested.)

During the EPRI tests, the Dresser 31739A valve was shown to achieve less than rated lift in the presence of high backpressure when the "huddle chamber" shown in Figure 1 (Section A) was opened up with ring



DRESSER SAFETY VALVE

Figure1

settings of -13, 0, -48 (lower, middle, upper). In the tests, the percent of rated flow achieved was significantly higher than the percent of rated lift achieved (which is reasonable since valves are conservatively derated from actual expected flow). In actual plant conditions, high backpressure is caused by high relief flows; if relief flow is reduced, then the backpressure is also reduced.

A number of plant transients and accidents involve a pressure transient in the reactor coolant system (RCS). The safety systems provided for overpressure protection are the reactor protection system (RPS), through the high RCS pressure trip function, and the pressurizer safety valves. Most of the events involving an RCS overpressure condition are adequately mitigated by the RPS.

Because of the unknown valve relieving capability, the licensee decided to immediately initiate steps to reset the valve ring settings to proven EPRI values and thus ensure that the health and safety of the public would not be jeopardized.

Unit 2 was shut down to remove the safety valves and to replace them with valves with proper ring settings. Unit 3 valves were replaced with reset valves prior to restart. Permission was received from the NRC to delay Unit 1 shutdown for up to two weeks to allow a phased work process at Oconee. All units now have valves with reset ring settings installed. All valve refurbishments and ring measurements and settings were accomplished at Wyle Laboratory.

The licensee is participating in a program to fine tune these EPRI test ring settings using the valve dynamic code COUPLE. The results of all safety valve related analyses should be completed in time to allow any fine tuning adjustments to be made to the ring settings on the valves now installed during the next refueling outage for each unit. However, the EPRI recommended values used in resetting the Oconee valves have provided satisfactory valve performance under all expected conditions. (Refs. 1 through 3.)

1.2 Control Rod Drive Failure and Reactor Trip

At about 4:45 p.m. on September 30, 1982, with Zion Unit 1* at full power, control room operators noticed that power had been lost to the balance of plant manual/automatic (M/A) control stations. They found that the 115V AC power supply breaker had tripped. When the breaker was reclosed, it immediately tripped open again. To locate the fault, the power supplies to all balance of plant M/A control stations were unplugged and the power supply breaker reclosed. The intent was to reenergize each M/A control station individually until the fault was found.

The first M/A control station reenergized was the feed pump master controller. Upon reenergization, the operator waited a few seconds and pushed the "manual" button. The speed of the B feed pump dropped to idle. The C feed pump

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* Zion Unit 1 is a 1040 MWe (net) PWR located 40 miles north of Chicago, Illinois, and is operated by Commonwealth Edison.

speed remained unchanged. The operators immediately ran the turbine back to 50% power in an effort to keep the unit from tripping. The control rods which should have automatically stepped inward in response to the increasing T-ave failed to do so. The operator attempted to insert rods in the manual mode, but the rods still did not move. Seeing that primary plant pressure and temperature were still increasing, and that the control rods were not responding, the shift engineer ordered a manual trip of the reactor. This occurred at 4:50 p.m. on September 30. The steam dump valve controller was without power due to the unplugging of its M/A control station power. Thus, with no steam dump valves operable and the turbine valves closed by the reactor trip, the heat in the primary system could only be released via the steam generator code safety valves. All 20 safety valves lifted for approximately 30 seconds, relieving secondary system pressure.

Immediately after the reactor trip, operators observed that there was no bottom light indication for five of the control rods. The operators commenced emergency boration of the reactor coolant system until the faulty rod bottom lights and position indicators were corrected and all rods were verified to be inserted. The emergency boration lasted about six minutes. Within three minutes after the reactor trip, power to the steam dump valves was restored, making them available for decay heat removal. Forty minutes after the trip, a fire alarm from a containment smoke detector was received. The station fire brigade entered containment and found no fire. There was a leaking steam trap in the vicinity of the smoke detector, which may have caused the spurious alarm. The alarm cleared itself shortly thereafter. The plant was maintained in hot shutdown pending evaluation of the various problems identified.

The licensee determined that the rod insertion problem was due to a malfunction in the pulser circuit on the pulse-oscillator card. The result was that when the difference between T-ref and auctioneered T-ave exceeded 5°F, the master cycler would send a sequence start signal to the slave cycler before the slave cycler had finished its previous sequence. The slave cycler receiving a start signal while in the middle of a sequence resulted in a rod system urgent failure condition. This precluded any further rod motion. This was verified using test inputs to simulate T-ref/T-ave mismatches in excess of 5°F. The rods would move about 1-1/2 steps and then an urgent failure alarm would occur. When the pulse-oscillator card was replaced and the test procedure repeated, no urgent failure or rod system lockup occurred.

Since the pulser circuit malfunction resulted in an urgent failure condition only when T-ave differed from T-ref by 5°F or more, the malfunction could have existed undetected for some period of time. The licensee has committed to perform appropriate surveillance testing at every refueling outage so that the problem may be detected in advance. The licensee is also determining if any surveillance testing can be performed with the unit at power.

In addition, the licensee investigated the loss of power to the balance of plant M/A control stations and loss of 1B feedwater pump that occurred when power was restored. The loss of power to the M/A control stations was caused by a short circuit in an Amphenol connector which supplied power to the M/A control station for the C steam generator PORV. This connector had been unplugged at about 3:00 p.m. on September 30 to allow removal and repair of the M/A control station. The short caused the tripping of the power supply breaker for all balance of plant M/A control stations, which are designed to maintain their last signal on loss of power. Since the unit was operating at steady state, it was not immediately apparent that M/A control station power had been lost.

When an M/A control station is reenergized, the auto light energizes while the circuitry matches the output to that existing at the time of deenergization. This is the auto hold mode, and takes 15 to 20 seconds to complete the matching. When the output is matched, the auto light goes out and the M/A control station reverts to the manual mode. When the operator went to manual on the feedwater master M/A control station prior to completion of the auto hold phase, there was still a large discrepancy between the last existing signal and the M/A control station output. The M/A control station output went to zero. Since the C feed pump slave M/A control station was in manual, it was separated from the output of the master M/A control station. The B feed pump slave M/A control station was in auto and transmitted the zero output of the master M/A control station to the B feed pump controller. This caused the B feed pump to run back to idle speed. As a result of this occurrence, instructions on reenergizing M/A control stations at power are being written for the use of operations personnel. (Refs. 4 and 5.)

1.3 Inoperable Containment Spray System

On October 28, 1982, with Farley Unit 2* in cold shutdown for refueling and maintenance, the licensee found the containment spray system header isolation valves locked closed. The valves were found in this position during scheduled maintenance, when the licensee was attempting to close the containment spray manual isolation valves to both A and B train headers. Since these valves were supposed to be locked open, an investigation was begun immediately to determine whether the Unit 2 valves had been closed after the shutdown of the reactor on October 22, 1982, or had been closed during the entire first cycle of reactor operations. The licensee's investigation determined that the valves had been closed and locked since before the plant achieved initial criticality on May 8, 1981. Both redundant containment spray systems had thus been inoperable and unable to fulfill their safety function for nearly a year and a half. (The unit began commercial power operation on July 30, 1981.)

The safety function of the containment spray system is to discharge borated water into the containment atmosphere. The spray will limit the maximum pressure and temperature in the containment to less than design conditions following certain sized steam line breaks or loss-of-coolant accidents (LOCAs). The system is also designed to add sodium hydroxide to the spray fluid to remove radioactive iodine (which could be released in the event of a break in the fuel cladding following a LOCA) to limit iodine doses to less than 10 CFR Part 100 limits.

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* Farley Unit 2 is an 814 MWe (net) PWR located 28 miles southeast of Dothan, Alabama, and is operated by Alabama Power.

Farley also has a containment fan cooler system which, during normal operation, recirculates and cools the containment atmosphere. Following a LOCA or steam line break accident, the system acts in conjunction with the containment spray system to reduce containment temperature and pressure. The amount of pressure and temperature reduction depends upon the number of operable containment spray rings and fan coolers. The containment fan cooler system working alone, even with only one out of two fans operable, can be expected to protect the integrity of the containment and the safety equipment inside. The bases for the technical specifications indicate that the fans are redundant to the containment spray system for temperature control. However, since the containment fan cooler system does not have the radioactive iodine removal capabilities of the containment spray system, a postulated LOCA could result in offsite dose calculations exceeding 10 CFR Part 100 limits.

Conservative calculations were made by the NRC and the licensee to determine the effect on containment pressure, containment temperature, and iodine doses had a LOCA or a main steam line break (MSLB) accident occurred while the containment sprays were inoperable.

In regard to containment pressure, the most limiting accident would be an MSLB of 0.7 square feet at 30% power with a single failure of the containment fan coolers. With two out of four fan coolers in operation, the calculated peak pressure would be 55.1 psig. With only one fan cooler in operation (based on the plant's technical specifications requiring only one fan cooler per train such that the worst single failure would result in only one cooler being operational), the analysis predicts a peak containment pressure of 61.6 psig. Both calculated pressures are higher than the containment design pressure of 54 psig. However, even for the more conservative calculation, containment integrity would likely be maintained since the containment has been tested at 62.1 psig.

Peak containment temperature, based on the most limiting MSLB, was conservatively calculated by the licensee to compare to the equipment qualification temperatures. Generally, the calculated peak temperature exceeded the qualification temperatures by less than 20°F. In one case, the difference was about 50°F. However, the required operating times for many components are short and the thermal lag inside the equipment housings would be expected to preclude damage to the internal components prior to performing their specified functions.

The radiological consequences at both the exclusion area and the low population zone boundaries were conservatively calculated based on a LOCA and rupture of fuel cladding. Calculations were made by the NRC staff for the maximum allowable containment leak rates permitted by the licensee's technical specifications and for leak rate as measured at the plant when last tested. In both cases, analyses indicate that thyroid doses would exceed 10 CFR Part 100 limits at both the exclusion area and the low population zone boundaries.

The licensee also made calculations based on what the licensee considered more "realistic" assumptions. The licensee concluded that offsite exposures could be expected to be less than 10 CFR Part 100 guideline values, based on the "realistic" assumptions. However, since the valves had been closed since before initial plant startup, variations could be expected in such parameters as containment leak rates (last performed and reported to the NRC in mid-1980) and meteorological conditions.

The containment spray header isolation valves are normally locked open during plant operation. Valve positions are shown on the valve lineup check sheets. During a valve position verification completed in March 1981, and a locked valve check and a separate check by the plant operations superintendent in February 1982, the position of the valves was verified by visual inspections to be "locked open." However, the stems of these two valves were not in accordance with design drawings in that the stems were approximately 6 inches too long, thus giving a false indication that the valves were open. The nuclear steam system supplier, Westinghouse, had provided the valves with longer stems to accommodate a motor operator, if desired. However, they did not provide documentation of the design change to the licensee. These are rising stem valves, such that the stem rises above the handwheel. If these valves had been in accordance with design drawings, the stems would have been nearly flush with the retainer on top of the handwheel when in the closed position, rather than extending up 6 inches. Thus, although the fully open stem travel (extension) by design is 8 inches, the fully open stem as installed showed 14 inches. The plant operators erroneously assumed that the valves were in the locked open position when they observed the extended valve stem. This deviation from design, in combination with an inadequate procedure used for valve verification and check, resulted in the incident. The valve verification procedure involved the following step:

> Locked Open - Verify locking device is securely locked and in good condition. Visually verify that valve stem is at full travel in open direction. (Ref. 7.)

The two principal corrective actions included restoration of the valve stem to the design drawing length and changing valve position verification procedural guidance as follows:

> Locked Open - Attempt to move handwheel or operator in the closed direction only enough to verify valve movement. The handwheel or operator should turn, indicating the valve is open. Return valve to original position. If unable to move the operator due to locking device, remove the locking device and attempt to move the operator, or handwheel, in the closed direction only enough to verify valve movement. Return valve to original position. Re-install the locking device and verify that it is securely locked and in good condition. If the locking device was unlocked, a second verification of the locking device is required. (Ref. 7.)

In addition, another step in the verification sequence was added for locked valves, in which the locking device is verified to be properly secured and locked if the valve was unlocked to verify position.

After the locked valves were found on Unit 2, the licensee checked the similar containment spray valves on Unit 1. The valves were found to be locked open as required. Since the Unit 1 valves are identical to those of Unit 2, the corrective actions described above are applicable to both units. (Refs. 6 and 7.)

A check with the valve supplier (Westinghouse) revealed that the only other nuclear plant using valves of this design is Trojan.* The Trojan licensee was contacted, and subsequently reported that similar valve position errors had not been made.

1.4 Plant Trip and Partial Loss of Offsite Power

On October 18, 1982, at 8:17 a.m., a plant load reduction was begun at Beaver Valley Unit 1** to allow investigation of a continuing control problem with the 1B main feed regulating valve, which was causing level oscillations in the 1B steam generator. At 8:26 a.m., with the load reduction in progress, a high-high level signal in the 1B steam generator was received. This resulted in a turbine trip, reactor trip, and a feedwater isolation signal. The feedwater isolation signal caused a trip of the motor-driven main feed pumps and the automatic start of the auxiliary feed pumps.

At 8:40 a.m., operators attempted to restore the main feedwater system to service by restarting one of the motor-driven main feedwater pumps. While starting the 1B main feed pump, an apparent overcurrent condition was detected by the 1B system station service transformer primary side overcurrent relay. This caused the auxiliary relay to trip the transformer secondary feeder breakers, resulting in the temporary loss of one of the two station sources of offsite AC power. AC emergency loads previously being supplied through the 1B transformer were maintained by the No. 2 diesel generator. At 9:10 a.m., the relay overcurrent target, or flag, was cleared and its auxiliary reset. Offsite AC power was restored by 9:23 a.m.

The cause of the relays' operation has not been determined; however, misoperation is suspected since the overcurrent relays providing transformer secondary side and 4kV bus protection were not targeted during this incident.

Followup actions have included the replacement and testing of the affected relay, which is manufactured by ITE Imperial Corporation. The overcurrent relays will be tested during a future outage to ensure their proper operation. (Refs. 8 and 9.)

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* Trojan is a 1080 MWe (net) PWR located 42 miles north of Portland, Oregon, and is operated by Portland General Electric.

** Beaver Valley Unit 1 is an 810 MWe (net) PWR located in Pennsylvania, five miles east of East Liverpool, Ohio, and is operated by Duquesne Light.

1.5 Emergency Bus Loss Due to Breaker Problems

On October 10, 1982, with Brunswick Unit 2* at 60% power, the licensee began an orderly shutdown of the reactor at 6:00 p.m. after finding a steam and water leak of 20 to 40 gallons per minute in a cracked weld of a non-safety-related heater drain pipe. With the reactor at 17% power, the manual transfer of electrical feed to bus 2-D failed and an attempt was made to effect an automatic transfer. This automatic transfer attempt also failed, resulting in a loss of voltage to 2-D, and thus a loss of voltage to emergency bus E-3. The loss of E-3 caused a Group I** primary containment isolation and a resultant reactor scram. At the time of the event, two balance-of-plant fuses, which fed two emergency buses, were available.

The event occurred when the unit auxiliary transformer (UAT) output breaker was manually opened and the unit startup transformer (SUT) output breaker failed to automatically close to energize bus 2-D. Prior to this event, the No. 3 diesel generator had been started under control room manual control and was brought up to operating speed with the diesel generator output breaker open. This was done so that the diesel would be up to speed if the transfer failed. Emergency bus E-3 is normally supplied from bus 2-D, and the No. 3 diesel generator is the emergency standby power source to E-3. Immediately following the failure of the SUT output breaker, the No. 3 diesel generator failed to close on bus E-3. This rendered bus E-3 dead, which caused a scram and Group I isolation.

Shortly after this event, a quick trouble check of the SUT output breaker indicated a problem in closing the breaker. The interchangeable UAT output breaker was then installed in the SUT output breaker compartment, and power to bus 2-D was restored from the SUT within an hour and 45 minutes of the event, and bus E-3 was reenergized. A close inspection and troubleshooting of the failed SUT output breaker revealed the breaker had failed to automatically close as a result of a sheared breaker charging spring motor actuator. The charging spring motor casing mounting screw had backed out of the motor housing, causing the motor actuator to shear and separate from the breaker. This prevented charging of the breaker charging springs for breaker closing capability. The failed breaker from the SUT output breaker compartment was then repaired using a replacement charging motor assembly, tested satisfactorily for operation, and installed in the UAT output breaker compartment.

While the unit was in cold shutdown pending repair of the cracked heater drain pipe, the licensee conducted an investigation into the failure of the output breaker of the No. 3 diesel generator to close to energize bus E-3. The investigation revealed that simultaneous close and open signals to the breaker prevented automatic closing of the breaker on loss of voltage to bus E-3.

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* Brunswick Unit 2 is a 790 MWe (net) BWR located three miles north of Southport, North Carolina, and is operated by Carolina Power and Light.

** Group I: main steam isolation valves, steam line drains, and reactor vessel water sample lines.

The plant emergency buses use a high speed undervoltage relay which applies to a 1-second trip open signal to the applicable diesel generator output breaker on loss of voltage to the bus. This relay ensures that the diesel generator is separated from an emergency bus on loss of voltage. In addition, plant emergency buses utilize an inverse time undervoltage relay (1.5 seconds), which causes loads to be shed from the emergency bus on loss of bus voltage. This permits tying the diesel to its applicable bus after the bus is stripped. While the diesel generator is running in the control room manual or local manual mode, a loss of voltage to the E-bus will result in a failure of the diesel to close on the E-bus. This condition conflicts with the normal operation system design, in that the design accounts for an instantaneous voltage drop on the E-bus. In reality, a voltage drop on the bus will occur somewhat slower, and varies with the loads on the bus.

The bus inverse time undervoltage relay will sense the voltage drop condition when voltage decreases to approximately 82% of normal, and the high speed undervoltage relay senses the voltage drop condition at some percentage less than 40% of normal. As a result, bus loads are shed and a close signal to the diesel generator output breaker occurs before the high speed undervoltage relay 1-second trip signal is removed, preventing the output breaker from closing. To close the diesel generator output breaker in this situation, the close signal must be removed and reapplied. The licensee investigation determined that a short-term system procedural change can be accomplished by placing the keylock remote shutdown switch on the applicable E-bus switchgear breaker compartment to the local position, and then back to normal.

As a result of this event, the procedural changes were approved and implemented to provide plant operators with directions for dealing with a loss of normal power source to the E-bus with a diesel generator running, and not tied to the E-bus, in either the control room manual or local manual controlling mode. Since this condition does not apply if the diesel generator is automatically started from its normal standby configuration, these procedural changes should provide a sufficient short-term method to overcome the design deficiency associated with this condition. The licensee is evaluating this condition, and will develop an applicable design modification to eliminate the problem. As a result of the SUT output breaker failure, applicable plant surveillance procedures have been revised as required to perform a check of plant 4160 V switchgear charging spring mounting attachment bolts during periodic preventive maintenance operability inspections of the breaker mechanism. (Refs. 10 and 11.)

1.6 Recurring Operator Errors Make Equipment Unavailable

In the months between March 1982 and September 1982, Trojan* experienced three events where safety-related equipment was removed from service for maintenance or test purposes, but controls placed on the equipment were inadequate to ensure return to service. In all cases, the control operator or assistant control operator failed to inform the shift supervisor at the time the equipment had been removed from service. Descriptions, causes, and corrective actions for each event are summarized below.

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* Trojan is a 1080 MWe (net) PWR located 42 miles north of Portland, Oregon, and is operated by Portland General Electric.

Event Descriptions

(1) On March 2, 1982, with the plant operating at 100% power, a walk-down of the control boards was being conducted by the oncoming control operator. The B train containment spray pump control switch was found to be in the "pull-to-lock" position at this time. The previous shift control operator had failed to return the pump control switch to auto after completing design basis accident sequence surveillance testing, although he had signed for the surveillance test as being completed and the equipment returned to service. Fifteen minutes later, during a follow-up control board walk-down, the shift technical advisor found that the B train centrifugal charging pump control switch had also been left in the "pull-to-lock" position. Both pumps were immediately tested and returned to service. The pump control switches had been mispositioned for approximately seven and a half hours.

(2) On August 20, 1982, preparations were being made to return the plant to power from a refueling outage which had begun on March 30, 1982. Prior to entering hot shutdown, both trains of automatic safety injection were unblocked in accordance with a general operating instruction, but were subsequently reblocked without the use of a safety-related equipment outage worksheet as required by an administrative order. Both trains were blocked to prevent a spurious safety injection in cold shutdown while preparations for plant heat-up were still underway. Both trains remained blocked upon entry into hot shutdown and subsequent entry into hot standby for a total duration of 43 hours, 39 minutes. Operations shift personnel knew that automatic safety injection was blocked, and had discussed the contingency action to be taken should safety injection be required. They did not realize that a technical specification requiring that automatic safety injection actuating logic be operable in Modes 1-4 (power operation through hot shutdown) was being violated. This occurrence was discovered by the operations supervisor during a routine walk-down of the control room.

(3) On August 24, 1982, with the reactor in startup testing, power at 1%, and preparations being made for initial turbine roll following the annual refueling outage, a periodic test to cycle emergency core cooling system (ECCS) valves for inservice testing was conducted. During this test, valves in the residual heat removal (RHR) system, including the pump suction valve, are closed and then reopened. Although not required to do so by the test procedure, the control operator placed the B train RHR pump control switch in the "pull-to-lock" position to prevent pump damage, should an auto start be received while the suction valve was closed. Upon completion of the test, the pump was left in the "pull-to-lock" position. This would have prevented an automatic start of the pump in a low-pressure safety injection mode. During a walk-down of the control board, approximately five hours later, the oncoming shift technical advisor found the RHR pump in the "pull-to-lock" position. The shift supervisor was informed and the pump was immediately returned to automatic control.

Causes

In each case, the cause of the occurrence was personnel error. In case (1), this was compounded by nonspecific steps for equipment realignment in the controlling test procedure. In case (3) the control operator deviated from the ECCS valve inservice testing procedure without initiating the required documentation to do so as outlined in the plant operating manual procedures. Although the intent of the control operator was to prevent possible equipment damage, taking the RHR pump switch to "pull-to-lock" was an action that was not outlined in the controlling procedure and should have been documented by initiating a procedure deviation or safety-related equipment outage form. In case (2) the operators on shift were not cognizant of the technical specification requirement that both ECCS trains be in service before entering hot shutdown. Contributing to this error was the fact that the action was taken without utilizing a safety-related equipment outage work sheet.

Corrective Actions

The licensee developed corrective actions based on the following perspectives: to improve and provide better implementation of existing procedural controls rather than develop additional procedures; to develop or improve operator aids and tools rather than set additional requirements; and, to keep from overburdening the operator with unnecessary or redundant administrative controls.

In events (1) and (3), corrective action involved counselling of the operations personnel and review of the occurrence with all crew operators by the shift supervisors, emphasizing the importance of following procedures and documenting any necessary plant test deviations. Reviews and revisions of test procedures have been submitted to (a) ensure adequate detailed instructions/check-offs are provided for equipment realignment after testing, and (b) to add specific sign-off steps for necessary pump control switch manipulations. A special report concerning case (2) was prepared by the assistant operations supervisor on August 20 and was routed to all shift supervisors for their review. A meeting was held on September 1, 1982, by the operations supervisor with the shift supervisors, during which time this event was discussed in detail. They were directed to be more aware of the potential for similar events. In addition, the operations staff was directed that any time safety-related equipment, components, or systems are removed from service, the safety-related equipment outage work sheet must be used, regardless of who requests or initiates the outage. (Refs. 12 and 13.)

1.7 Insufficient NPSH Causes Inoperable Charging Pump Service Water Pumps

On September 1, 13, 18, and 20, 1982, with Surry Unit 2* at full power, charging pump service water pump (SWP) 2-SW-P-10A experienced a loss of

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* Surry Units 1 and 2 are each 775 MWe (net) PWRs located 17 miles northwest of Newport News, Virginia, and are operated by Virginia Electric and Power.

suction pressure, which resulted in a loss of discharge pressure. On September 13 and 14, 2-SW-P-10B experienced a similar loss of suction pressure. Unit 2 shares four charging pump SWPs with Unit 1, with each unit having separate air conditioner chiller units.

The charging pump SWPs supply cooling water to the charging pump intermediate seal oil coolers and the charging pump lubricating oil coolers. During the short periods when these pumps were inoperable (a maximum of 20 minutes), the charging pump bearing temperature did not show any significant increase. In all cases, the SWPs were restored to service within the time limits of the plant's limiting conditions for operation.

The loss of discharge pressure was due to insufficient net positive suction head (NPSH). The charging pump SWPs and air conditioner chiller units are located in the same equipment room, and are supplied with service water, via rotating strainers, from two 6-inch supply lines. Each supply line is gravity fed from the intake canal. Two-inch branch lines supply service water to the charging pump SWPs, while the service water lines to the chiller units are 4-inch lines. In addition, the Unit 1 and Unit 2 B charging pump SWP is located at a higher elevation. Experience has shown that the performance of the charging pump SWPs, especially the B pump, is sensitive to the available NPSH.

To resolve this NPSH problem, the licensee has reduced service water flow through the air conditioning chillers, thereby increasing the available NPSH to the charging pump SWPs. In addition, the associated SWP suction strainer was inspected. The setpoint for the B air conditioning chiller service water flow control valve was checked, and minor adjustments were required. The licensee plans to check the setpoints for the remaining flow control valves. In addition, a design change has been initiated that will relocate two of the charging pump SWPs; i.e., the pumps will be lowered and the size of the suction piping to the pumps will be increased. In an effort to reduce air in-leakage in the suction header, the licensee has implemented a preventive maintenance procedure. (Refs. 14 and 15.)

1.8 Failure of Control Rod Drive Coils

On October 6, 1982, during startup of Zion Unit 2* following an outage since September 7, 1982 for turbine blade repairs, plant operators discovered several defective control rod drive coils. All of the defective coils were located in the vicinity of a primary coolant leak that had occurred in November 1981, on the reactor vessel level indicator piping. This indicates that the steam and/or boric acid from the coolant leak may have had a long term detrimental effect on the control rod drive coils.

While proceeding through startup procedures on October 6, shutdown bank A was withdrawn but rod P-12 did not move. The stationary gripper coil fuses were found to be blown. Measurements taken by the licensee indicated low internal resistance for the stationary gripper coil. A check of other rod banks showed several other rods with blown fuses and low coil resistances.

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* Zion Unit 2 is a 1040 MWe (net) PWR located 40 miles north of Chicago, Illinois, and is operated by Commonwealth Edison.

The licensee performed resistance to ground and internal resistance checks for all three coils on all the control rods. These checks indicated that a total of 12 stationary coils, one moveable coil, and one lift coil needed to be replaced due to low internal resistance. The primary plant was taken to cold shutdown and the 12 coils were replaced.

The licensee and the nuclear steam system supplier (Westinghouse) plan to dissect the faulty coils in an attempt to determine the failure mode. (Ref. 16.)

1.9 Malfunctioning Isolation Condenser Isolation Valve

At certain older boiling water reactors, isolation condensers are used to depressurize and remove decay heat if the main condenser is unavailable as a heat sink. An isolation condenser's inlets and outlets are equipped with double isolation valves (AC and DC) that should automatically close on high steam or high condensate flow, which indicates a break in the isolation condenser piping. Failure of these valves to close would result in degradation of the reactor coolant pressure boundary. Although the following event happened more than a year ago, recent licensee responses (Ref. 18) to an NRC Notice of Violation emphasize the importance of maintenance inspection when equipment malfunctions.

During surveillance testing at Oyster Creek* on December 3, 1981, the A isolation condenser's isolation valve V-14-30 failed to properly close until the third stroke attempt. The valve was successfully cycled two more times. Based on the shift supervisor's knowledge of recent incidents of valve binding due to tight packing, and several instances of torque switches out of adjustment, the supervisor concluded that the original failure to operate had been corrected by the cycling. A maintenance job order to inspect the switches was issued, but was not immediately followed up.

After discussions on December 4 with the NRC Resident Inspector, who questioned the operability/reliability of V-14-30 based on the previous night's testing, a decision was made to stroke the valve again to demonstrate its operability. The valve again failed to fully close, and the A isolation condenser was declared inoperable. The B isolation condenser's isolation valves were successfully operated, per plant technical specifications.

The Limitorque operator for valve V-14-30 then was inspected, and the lower 1-1/2 threads of the stem nut were found damaged. These damaged threads were machined onsite by the licensee. The A isolation condenser was declared operable on December 6 after a successful isolation valve operability test.

On December 7, in a subsequent action to determine the possibility of a generic actuator problem, the B isolation condenser, which was in need of packing repair on valve V-14-32, was removed from service. The stem nut on V-14-32 was inspected and found to have three damaged lower threads and also

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* Oyster Creek is a 620 MWe (net) BWR located nine miles south of Toms River, New Jersey, and is operated by Jersey Central Power and Light.

showed indications of radial cracking, approximately 2 inches in length up to the stem nut.

In a further effort to investigate a possible generic problem, a reactor shutdown was commenced on December 9 in order to complete further Limitorque operator inspections. As a result of internal inspections of valve V-14-32, crack indications have been discovered on the stem in the area of the stem backseat.

The licensee determined that the valve damage was caused by the multiple number of backseating operations performed over the life of the plant, in addition to the stresses induced by the thermal cycling of the valves while in the backseated position. After disassembly of valve V-14-32 (steam inlet to the B isolation condenser) it was determined the stem backseat had been severely damaged, enabling the stem to travel a distance further than designed. This resulted in damage to the Limitorque operator stem nut by engagement of the unthreaded portion of the valve stem into the stem nut.

These identified failures had the potential of preventing a safety system from operating, causing a degradation in those systems provided to contain fission products, and/or creating a situation leading to high primary coolant system leakage. However, since a surveillance test demonstrated that the redundant isolation valve, V-14-31, was operable, the event resulted in a loss of redundancy but not a loss of function.

Although at no time were plant technical specifications knowingly violated, the NRC and the licensee have agreed that the event also resulted from an error in judgment. To help preclude recurrence, all shift supervisors have been reinstructed to (1) be conservative in situations involving technical specifications (as has historically been the case at Oyster Creek), regardless of any impact on plant operation; (2) contact operations management without hesitation; and (3) be critical in accepting completed maintenance. (Refs. 17 and 18.)

1.10 References

1. NRC Preliminary Notification PNO-II-82-111, October 14, 1982.

2. Letter from H. Tucker, Duke Power Company, to H. Denton, NRC/NRR, transmitting Proposed Facility Operating License Amendment for Docket Nos. 50-269, 50-270, and 50-287, October 14, 1982.

3. Letter from H. Tucker, Duke Power Company, transmitting Reportable Occurrence Report No. RO-269/82-18, October 28, 1982.

4. USNRC, Preliminary Notification PNO-III-82-106, October 1, 1982.

5. USNRC/R-III, Inspection Reports Nos. 50-295/82-22 (DPRP) and 50-304/82-19 (DPRP), November 4, 1982.

6. USNRC, Preliminary Notification PNO-II-82-118, November 1, 1982.

7. Alabama Power Company, Docket No. 50-364, Licensee Event Report No. 82-43, November 10, 1982.

8. USNRC, Preliminary Notification PNO-I-82-65, October 18, 1982.

9. Duquesne Light Company, Docket No. 50-334, Licensee Event Report No. 82-48, November 16, 1982.

10. USNRC, Preliminary Notification PNO-II-82-109, October 12, 1982.

11. Carolina Power and Light Company, Docket No. 50-324, Licensee Event Report No. 82-123, November 9, 1982.

12. Portland General Electric Company, Docket No. 50-344, Licensee Event Report No. 82-04 (April 2, 1982), 82-15 (September 3, 1982), and 82-14 (September 14, 1982).

13. Letter from B. Withers, Portland General Electric Company, to R. Engelken, NRC/R-V, transmitting licensee responses to NRC's October 6, 1982 Notice of Violation, October 26, 1982.

14. Virginia Electric and Power Company, Docket No. 50-280, Licensee Event Report No. 82-27, September 30, 1982.

15. Virginia Electric and Power Company, Docket No. 50-281, Licensee Event Report No. 82-57, September 30, 1982.

16. USNRC/R-III, Inspection Reports Nos. 50-295/82-22 (DPRP) and 50-304/82-19 (DPRP), November 4, 1982.

17. Jersey Central Power and Light Company, Docket No. 50-219, Licensee Event Report No. 81-65, December 23, 1981.

18. Letter from P. Fiedler, JCPL/Oyster Creek, to R. DeYoung, NRC/R-I and Attachment A transmitting licensee responses to NRC's November 30, 1982 Notice of Violation and Proposed Imposition of Civil Penalties, December 30, 1982.

2.0 ABSTRACTS OF OTHER NRC OPERATING EXPERIENCE DOCUMENTS

2.1 Abnormal Occurrence Reports (NUREG-0090) Issued in September-October 1982

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.

No Abnormal Occurrence Reports were issued during September-October 1982.

2.2 Bulletins, Circulars, and Information Notices Issued in September-October 1982

The Office of Inspection and Enforcement periodically issues bulletins, circulars, and information notices to licensees and holders of construction permits. During the period, one bulletin and one revision, and six information notices, one revision, and one supplement, 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, such as an order for suspension or revocation of a license. When appropriate, prior to issuing a bulletin, the NRC may seek comments on the matter from the industry (Atomic Industrial Forum, nuclear steam system suppliers, vendors, etc.), a technique which has proven 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.

Circulars notify licensees of actions NRC recommends be taken. Although written responses are not required, the licensees are asked to review the information and implement the recommendations if they are applicable to their facility.

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	Subject
82-03	10/14/82	STRESS CORROSION CRACKING IN THICK WALL, LARGE DIAMETER, STAINLESS STEEL, RECIRCULATION SYSTEM PIPING AT BWR PLANTS This bulletin was to notify all licensees and construction permit holders about a matter that may have a high degree of safety significance, and to require specific action for several licensees. This matter involved the degradation of recirculation system piping in the reactor coolant pressure boundary (RCPB) at the Nine Mile Point Unit 1 nuclear generating station. The affected licensees were required: (a) to provide a reasonable level of assurance that inspections which were recently being performed or scheduled were sufficient to detect cracking in

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* No circulars were issued in September-October 1982.

Bulletin	Date Issued	Subject
		BWR thick wall recirculation piping welds; and (2) to assist the NRC in determining the generic significance of the piping degradation found at Nine Mile Point. The affected licensees were owners whose plants were currently in or scheduled to be in a refueling outage mode or extended outage through 1/31/83.
82-03 Rev. 1	10/28/82	STRESS CORROSION CRACKING IN THICK-WALL, LARGE-DIAMETER, STAINLESS STEEL, RECIRCULATION SYSTEM PIPING AT BWR PLANTS This bulletin notified all licensees and construction permit holders about a matter that may have a high degree of safety significance, and to require for certain licensees several more actions than originally stated in Bulletin 82-03. This matter involved the degradation of recirculation system piping in the reactor coolant pressure boundary (RCPB) at Nine Mile Point Unit 1. The actions to be taken were required of all licensees whose plants were in or scheduled to be in a refueling mode through 1/31/83.

Information Notice	Date Issued	Subject
82-36	9/02/82	RESPIRATOR USERS' WARNING FOR CERTAIN FIVE-MINUTE EMERGENCY ESCAPE SELF-CONTAINED BREATHING APPARATUS This information notice was provided to inform licensees of a Department of Health and Human Services "Respirator Users' Warning" concerning unreliability of some SurvivAir Models 0028-00 and 0028-03 respirators. This information notice was sent to all nuclear power reactor facilities holding an operating license or construction permit, fuel facilities, and priority I material licensees.
82-37	9/16/82	CRACKING IN THE UPPER SHELL TO TRANSITION CONE GIRTH WELD OF A STEAM GENERATOR AT AN OPERATING PRESSURIZED WATER REACTOR This information notice provided early notification of a potentially significant problem which arose in the spring of 1982 at Indian Point Unit 3. The problem concerned a leak in the upper shell to transition cone girth weld (secondary side) of a steam generator. Subsequent ultrasonic examinations of these welds on all four steam generators revealed that each generator had extensive indications of cracking. This notice was sent to all licensees and construction permit holders.

Information Notice	Date Issued	Subject
82-38	9/22/82	CHANGE IN FORMAT AND DISTRIBUTION SYSTEM FOR IE BULLETINS, CIRCULARS, AND INFORMATION NOTICES This information notice advised recipients of IE bulletins, circulars, and information notices of a change to the format and the distribution systems for those documents. This information notice was sent to all NRC licensees.
82-39	9/21/82	SERVICE DEGRADATION OF THICK WALL STAINLESS STEEL RECIRCULATION SYSTEM PIPING AT A BWR PLANT This information notice provided licensees and construction permit holders with available information about the degradation of the primary pressure boundary at Nine Mile Point Unit 1 due to intergranular stress corrosion cracking. Further licensee action may be requested. This notice was sent to all BWR facilities holding an operating license or construction permit.
82-40	9/22/82	DEFICIENCIES IN PRIMARY CONTAINMENT ELECTRICAL PENETRATION ASSEMBLIES This information notice provided early notification of a potentially significant problem pertaining to electrical connections in electrical penetration assemblies supplied by the Bunker Ramo Corporation of Chatsworth, California. Several deficiencies of the containment's electrical penetration assemblies supplied by Bunker Ramo, have been identified. A summary of these deficiencies was provided. This notice was sent to all plant facilities holding an operating license or construction permit.
82-41	10/22/82	FAILURE OF SAFETY/RELIEF VALVES TO OPEN AT A BWR This notice provided information concerning the July 3, 1982, event at Georgia Power Company's Hatch Unit 1 where eight of eleven safety/relief valves (SRVs) failed to actuate once pressure setpoints were reached during a reactor scram. The SRVs installed on Hatch 1 are two-stage Target Rock Model No. 7667F. This notice was sent to all facilities holding an operating license or construction permit. (See PRE Vol. 4, No. 5, pp. 19-22.)

Information Notice	Date Issued	Subject
82-34 Rev. 1	9/17/82	REV. 1: WELDS IN MAIN CONTROL PANELS This revision was made to provide the specific time period during which the potentially significant problem pertaining to welds in main control panels may have existed. The panels of concern were supplied to a number of operating plants and construction sites by System Control of Iron Mountain, Michigan prior to 3/80; Reliance Electric of Stone Mountain, Georgia prior to 3/82; and Comsip of Linden, New Jersey prior to 3/82. Only those panels manufactured prior to these dates are now included in the list of sites which may have panels with defective welds. This notice was sent to all licensees and construction permit holders.
80-35 Suppl. 1	10/6/82	SUPPLEMENT NO. 1: LEAKING AND DISLODGED IODINE-125 IMPLANT SEEDS This information notice supplemented IE Information Notice No. 80-35. It served as a reminder for licensees to review the supplier's guidance accompanying the radioactive sources and the applicators used to implement the sources. This supplement was sent to all medical licensees holding specific licensees for human use of byproduct material in sealed sources.

2.3 Engineering Evaluations and Case Studies Issued in September-October 1982

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 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 staffdays of investigative time.

Case studies are in-depth investigations of apparently significant events or situations. They may 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.

Engineering Evaluation	Date Issued	Subject
E238	8/25/82	WATER IN THE LUBE OIL IN S. I. PUMP 1A-A AT SEQUOYAH A review of the high pressure injection (HPI) lube oil system design was completed to ascertain the potential for a common mode failure of the HPI pumps. The licensee has verified that there were no leaks in the system and the source of water was from condensation. A monthly surveillance test will be performed on the quality of the lube oil as a precaution to limit water accumulation.
E239	9/24/82	MSIV CLOSURES AND PRESSURIZER SAFETY VALVE ACTUATIONS AT ST. LUCIE UNIT 1 On December 19, 1981, following operation in a long-term steady state condition at 98% power, both main steam isolation valves (MSIVs) at St. Lucie Unit 1 closed for no apparent reason. The cessation of normal steam flow from the steam generators caused the reactor coolant system (RCS) pressure to increase rapidly, and the power-operated relief valves (PORVs) on the pressurizer opened to limit RCS pressure. The pressurizer code safety valve, V-1200, also apparently lifted but it was not realized at the time that this valve had also activated to assist the PORVs. Though fully analyzed, the cause of the MSIV closure is not fully understood.

Engineering Evaluation	Date Issued	Subject
E240	9/29/82	PRELIMINARY ACCOUNT OF EVENTS ASSOCIATED WITH A REACTOR TRIP AT HATCH UNIT 2 On August 25, 1982, the Hatch Unit 2 reactor tripped, from approximately 98% power, as a result of an over-power condition on the average power range monitor (APRM-HI). The high APRM flux was due to a transient reactor pressure increase, caused by the spurious closure of one of the two valves on the C main line. The licensee concluded that the disk separation from the valve stem on either the inboard or outboard isolation valve initiated the transient.
E241	10/1/82	EMERGENCY DIESEL GENERATOR SYSTEM PROBLEMS AT JAMES A. FITZPATRICK NUCLEAR PLANT On May 1, 1982, the licensee initiated routine monthly full load testing of the emergency diesel generator (EDG) systems. The licensee was testing both EDG systems A and B. After 45 minutes, the licensee declared EDG-A inoperable when its frequency and output power began oscillating. Simultaneously with the oscillation of EDG-A, the licensee noted the ground detector on the A 125 V DC system indicated momentary grounds. The licensee could find no root cause for the event.
E242	10/21/82	FUEL ASSEMBLY DEGRADATION WHILE IN THE SPENT FUEL STORAGE POOL On December 16, 1981, at Prairie Island, a top nozzle separated from a fuel assembly that was being transferred to the new high density fuel storage racks. The failure occurred at a mechanical ball joint between stainless-steel and Zircaloy. The failure was at all sixteen joints in the area of maximum curvature and was caused by stress corrosion cracking of the stainless steel. The cracks were intergranular and exhibited oxidation on the surface. (See PRE, Vol. 4, No. 5 pp. 17-18.)
E243	10/21/82	PLANT TRIP FOLLOWED BY A SAFETY INJECTION CAUSED BY LOSS OF "A" COOLING TOWER PUMP On February 4, 1982, with the Palisades Nuclear Power Plant at 98% power, a series of events occurred that resulted in a reactor trip, and an unanticipated safety injection. The scenario began when the pump to the A cooling tower tripped. The loss of coolant

Engineering Evaluation	Date Issued	Subject
		flow to one of the two cooling towers caused a rapid loss of vacuum in the condenser, at which time the operator immediately began ramping down turbine and reactor power. At about 89% power, the power dependent insertion limit was reached and rod insertion was terminated. Boration was started; however, it was not possible to decrease reactor power as quickly as turbine power was being decreased. Consequently, the average primary coolant temperature increased and this caused a thermal margin/low pressure reactor trip.
E244	10/21/82	LOSS OF RESIDUAL HEAT REMOVAL (RHR) SYSTEM EVENT AT PILGRIM NUCLEAR POWER STATION On December 21, 1981, after a refueling outage had been completed and with the reactor vessel head still off, maintenance personnel attempted a live transfer of power from the normal power feeder for a Y80V bus to an alternate power bus so that work on the normal power feeder transformer could be accomplished. Due to unknown problems, the alternate feeder breaker broke contact. This resulted in the momentary power loss to the original bus which caused a momentary power interruption to a primary containment isolation system control panel. Two components which receive control signals from the panel are the residual heat removal pump suction shutdown cooling isolation valves. Upon power interruption the control logic dictates these valves will close, even if motive power becomes available; the valves performed as designed.
E245	10/21/82	FAILURE OF WESTINGHOUSE TYPE SC-1 NO. 1876-072 RELAYS On November 5, 1981, at the Yankee Nuclear Station during normal station operation in Mode 1 (power operation), a surveillance of the low main coolant flow system was being performed. During the surveillance the undercurrent relays failed to drop out when deenergized. The root cause of the event was assumed to be residue buildup resulting from bushing wear on the relay actuation plunger.
E246	10/21/82	EVENTS INVOLVING LOSS OF ELECTRICAL INVERTERS INCLUDING ATTENDANT INVERTERS TO VITAL INSTRUMENT BUSES This evaluation discusses a number of events at several facilities involving loss of electrical inverters with no apparent common cause. Causes, comments, and recommendations pertaining to each event are provided.

Engineering Evaluation	Date Issued	Subject
E247	10/26/82	TURBINE/REACTOR TRIP AT RANCHO SECO ON AUGUST 7, 1981 On 8/7/81, Rancho Seco underwent a reactor trip as a result of two failures in the turbine electro-hydraulic control system which led to an improper turbine stop valve closure. Several unusual responses occurred before the plant could be stabilized at normal post-trip conditions. These included: (1) failure of the normal auxiliary to start up transformer transfer, (2) reactor coolant pump motor undervoltage trip, (3) loss of the operating main feedwater pump, (4) dissimilar secondary loop pressure response, (5) actuation of all radiation monitor alarms, (6) very low grid voltage, and (7) manual diesel generator start and load. This engineering evaluation also discusses the probable causes of the incidents above. However, the main concern is that the licensee's report on the event (LER-81-39) notes only the low grid voltage incident. (This engineering evaluation was amended as E249; see <u>PRE</u>, Vol. 4, No. 7.)

Case Studies	Date Issued	Subject
C206	10/82	INADVERTENT LOSS OF REACTOR COOLANT EVENTS AT THE SEQUOYAH NUCLEAR PLANT, UNITS 1 AND 2 This survey report provides: (1) an analysis of the February 11, 1981 inadvertent containment spray event at Unit 1, and the August 6, 1981 inadvertent discharge of primary water to the containment sump event at Unit 2; (2) an analysis of the factors common to both events; (3) recommendations to improve communication between licensed and non-licensed operators; and (4) recommendations to improve Inspection and Enforcement, Bulletins and Information Notices on the subject of loss-of-coolant accidents during residual heat removal (RHR) shutdown. The report concludes that all containment penetration piping in the RHR system was not designed with redundant isolation valves operating in the normal decay heat removal mode.

2.4 Regulatory and Technical Reports Issued in September-October 1982

The abstracts listed below have been selected from the Office of Administration's quarterly publication, Regulatory and Technical Reports (NUREG-0304). This document compiles abstracts of the formal regulatory and technical reports issued by the NRC staff and its contractors. Bibliographic data for the reports are also included. Copies and subscriptions of NUREG-0304 are available from the NRC/GPO Sales Program, PHIL-016, Washington, D.C. 20555 or on (301) 492-9530.

Report	Title
NUREG-0744 Vols. 1-2 Rev. 1 October 1982	RESOLUTION OF THE TASK A-11 REACTOR VESSEL MATERIALS TOUGHNESS SAFETY ISSUE This report provides the NRC position with respect to the reactor pressure vessel safety analysis required according to the rules given in the Code of Federal Regulations, Title 10. An analysis is required whenever neutron irradiation reduces the Charpy V-notch upper shelf energy level in the vessel steel to 50 ft-lb or less. Task A-11 was needed because the available engineering methodology for such analysis utilized linear elastic fracture mechanics principles, which could not fully account for the plastic deformation or stable crack extension expected at upper shelf temperatures. The Task A-11 goal was to develop an elastic-plastic fracture mechanics methodology, applicable to the beltline region of a pressurized water reactor vessel, which could be used in the required safety analysis. The goal was achieved with the help of a team of recognized experts. Part I of this volume contains the "For Comment" NUREG-1744 originally published in September 1981 and edited to accommodate comments from the public and the NRC staff. Part II of this volume contains the staff's responses to, and resolution of, the public comments received. This report completed the staff resolution of the Unresolved Safety Issue A-11, "Reactor Vessel Materials Toughness."
NUREG-0802 October 1982	SAFETY/RELIEF VALVE QUENCHER LOADS: EVALUATION FOR BWR MARK II AND III CONTAINMENTS Boiling water reactor (BWR) plants are equipped with safety relief valves (SRVs) to protect the reactor from overpressurization. Plant operational transients, such as turbine trips, will actuate the SRV. Once the SRV opens, the air column within the partially submerged discharge line is compressed by the high-pressure steam released from the reactor. The compressed air discharged into the suppression pool produces high-pressure bubbles. Oscillatory expansion and contraction of these bubbles create hydrodynamic loads on the containment structures, piping, and equipment inside containment. This report presents the results of the staff's evaluation of SRV loads. The evaluation, however is limited to the quencher devices used in Mark II and III containments. With respect

Report	Title
	to Mark I containments, the SRV acceptance criteria are presented in NUREG-0661 issued July 1980. The staff acceptance criteria for SRV loads for Mark II and III containments are presented in this report. In conjunction with NUREG-0661, NUREG-0763, and NUREG-0783, the issuance of this report concludes NRC Unresolved Safety Issue A-39, "Determination of Safety Relief Valve (SRV) Pool Dynamic Loads and Temperature Limits for BWRs."
NUREG-0936 Vol. 1, No. 3 October 1982	NRC REGULATORY AGENDA The NRC Regulatory Agenda is a compilation of all rules on which the NRC has proposed or is considering action and all petitions for rulemaking which have been received by the Commission and are pending disposition by the Commission. The Regulatory Agenda is updated and issued each quarter. The agendas for April and October are published in their entirety in the Federal Register while a notice of availability is published in the Federal Register for the January and July Agendas.
NUREG-0940 Vol. 1, Nos. 1-2 September 1982; Vol. 1, No. 3 October 1982	ENFORCEMENT ACTIONS: SIGNIFICANT ACTIONS This compilation summarizes significant enforcement actions that have been resolved during three quarterly periods (January - September 1982) and includes copies of letters, notices, and orders sent by the Nuclear Regulatory Commission to licensees with respect to enforcement actions. It is anticipated that the information in this publication will be widely disseminated to managers and employees engaged in activities licensed by the NRC, in the interest of promoting public health and safety as well as common defense and security. The intention is that this publication will be issued on a quarterly basis to include significant enforcement actions resolved during the preceding quarter.
NUREG/CR-1363 Rev. 1 October 1982	DATA SUMMARIES OF LICENSEE EVENT REPORTS OF VALVES AT U.S. COMMERCIAL NUCLEAR POWER PLANTS FROM JANUARY 1, 1976 TO DECEMBER 31, 1980 This report presents data summaries of Licensee Event Reports (LERs) of valves at U.S. commercial (light water reactor) nuclear power plants from January 1, 1976, through December 31, 1980. LERs are written reports filed with the NRC whenever certain failures or incidents occur concerning nuclear plant safety systems. The LERs are sorted according to plant, type of event, human factors, and valve type. The valve failures or incidents reported in the LERs were used to estimate gross standby and operating failure rates, in per-hour and per-demand units. The report includes a variety of different statistics calculated to highlight or show important

Report	Title
	failure modes or other failure information. In addition to the quantitative failure rate information, there is also considerable qualitative information tabulated to allow the user to make additional valve failure rate calculations or inferences. This revised report updates and supersedes the original three-volume June 1980 printing of NUREG/CR-1363.
NUREG/CR-1369 Rev. 1 September 1982	PROCEDURES EVALUATION CHECKLIST FOR MAINTENANCE, TEST, AND CALIBRATION PROCEDURES USED IN NUCLEAR POWER PLANTS This report describes a checklist to be used by the United States Nuclear Regulatory Commission (NRC) inspectors during their evaluation of maintenance, test and calibration procedures. The objective of the checklist is to aid inspectors in identifying procedural characteristics that can lead to human performance deficiencies. A companion document, "Development of a Checklist for Evaluating Maintenance, Test, and Calibration Procedures Used in Nuclear Power Plants," NUREG/CR-1368, SAND80-7053, describes how the checklist was developed. Revision 1 of the checklist, presented herein, is the result of a one-year field test by NRC inspectors in all five NRC regions. It incorporates improvements that were suggested by inspectors based on their experience with the checklist in performing evaluation of licensee procedures.
NUREG/CR-2182 Vol. 2 September 1982	STATION BLACKOUT AT BROWNS FERRY UNIT ONE - IODINE AND NOBLE GAS DISTRIBUTION AND RELEASE This is the second volume of a report describing the predicted response of Unit 1 of the Browns Ferry Nuclear Plant to a postulated Station Blackout, defined as a loss of offsite power combined with a failure of all onsite emergency diesel generators to start and load. The Station Blackout is assumed to persist beyond the point of battery exhaustion and the completely powerless state leads to core uncovery, meltdown, reactor vessel failure, and failure of the primary containment by overtemperature-induced degradation of the electrical penetration assembly seals. The sequence of events is described in Volume 1; the material in this volume deals with the analysis of fission product noble gas and iodine transport during the accident. Factors which affect the fission product movements through the series of containment design barriers are reviewed. For a reactive material such as iodine, proper assessment of the rate of movement requires determination of the chemical changes along the pathway which alter the physical properties such as vapor pressure and solubility and thereby affect the transport rate. A methodology for accomplishing this is demonstrated in this report.

Report	Title
NUREG/CR-2331 Vol. 2, No. 1 October 1982	SAFETY RESEARCH PROGRAMS SPONSORED BY THE OFFICE OF NUCLEAR REGULATORY RESEARCH This progress report describes current activities in the programs sponsored by the Division of Accident Evaluation, Division of Engineering Technology, and Division of Facility Operations of the U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research. The projects reported are the following: HTGR Safety Evaluation, SSC Development, Validation and Application, Generic Balance of Plant Modeling, Thermal Hydraulic LWR and LMFBR Safety Experiments, RAMONA-38 Code Modification and Evaluation, LWR Plant Analyzer Development, LWR Code Assessment and Application, Stress Corrosion Cracking of PWR Steam Generator Tubing, Standards for Material Integrity in LWRs, Probability Based Load Combinations for Structural Design, Mechanical Piping Benchwork Problems, Soil Structure Interaction, Human Error Rate Data Analysis, and Criteria on Human Engineering Regulatory Guides. The previous reports have covered the period October 1, 1976 through December 31, 1981.
NUREG/CR-2378 October 1982	NUCLEAR POWER PLANT OPERATING EXPERIENCE 1980 This report is the seventh in a series of reports issued annually that summarize the operating experience of nuclear plants in commercial operation in the United States. Power generation statistics, plant outages, reportable occurrences, fuel element performance, and occupational radiation exposure for each plant are presented and discussed, and summary highlights are given. The report includes 1980 data from 67 plants: 24 boiling water reactor plants, 42 pressurized water reactor plants, and 1 high-temperature gas-cooled reactor plant.
NUREG/CR-2409 September 1982	REQUIREMENTS FOR ESTABLISHING DETECTOR SITING CRITERIA IN FIRES INVOLVING ELECTRICAL MATERIALS Due to increased public awareness and regulatory actions, significant strides have been made in the capabilities of fire technology as it applies to fire detection systems. However, these advances in detector selection, siting, reliability and approvals tests have not substantially addressed the overall fire protection requirements within nuclear reactors. This report emphasizes some of the basic requirements and considerations needed for establishing siting criteria for early-warning detection of electrical cable fires. Recent research in electrical cable flammability and damageability characteristics are discussed. Also, current work in systemizing detector siting criteria is described. Confirmatory tests linking assessment of electrical-cable damageability with electrical cable fire detection is stressed.

Report	Title
NUREG/CR-2655 September 1982	EVALUATION OF THE PROMPT ALERTING SYSTEM AT FOUR NUCLEAR POWER STATIONS This report presents evaluations of the prompt notification siren systems at the following four U.S. nuclear power facilities: Trojan, Three Mile Island, Indian Point, and Zion. The objective of these evaluations was to provide examples of an analytical procedure for predicting the 10-mile emergency planning zone (EPZ) surrounding nuclear power plants. This analytical procedure is discussed in NUREG/CR-2654.
NUREG/CR-2673 September 1982	EVALUATION OF THERMAL DEVICES FOR DETECTING IN-VESSEL COOLANT LEVELS IN PWRs From investigations conducted immediately after the Three Mile Island nuclear power plant accident, some safety areas needing improvement were identified. A resulting requirement was the unambiguous detection of the approach to adequate core cooling. Designs to meet this requirement have generally included new instrumentation to monitor the coolant level in the reactor vessel. Thermal sensors proposed for use in pressurized-water reactor (PWR) vessels were tested and evaluated. The thermal devices tested use pairs of K-type thermocouples or resistance temperature detectors to sense the cooling capacity of the medium surrounding the device. One sensor of the pair is heated by an electric current, while the unheated one senses the ambient fluid temperature. The temperature difference between the heated and unheated sensors provides an indication of the cooling capacity of the surrounding fluid. Experiments that simulated the thermal-hydraulic conditions of a postulated PWR loss-of-coolant accident (LOCA) were run, including both natural- and forced-convection two-phase flow tests. Results suggest thermal level devices generally indicate the existence of poor cooling conditions in LOCA environments. Preliminary evaluation of these protection systems is given.
NUREG-CR-2814 Vol. 1 October 1982	NUCLEAR REACTOR SAFETY The work that is highlighted here represents accomplishments for the period January 1-March 31, 1982 in reactor safety research. Presented are brief overviews compiled by project, along with bibliography of Technical Notes and publications written during this quarter. Progress is reported in the following programs, TRAC Code Development, Thermal-Hydraulic Analysis for Reactor Safety Research, TRAC Independent Assessment, TRAC Applications to 2D/3D, Advanced Converter Safety Research, Upper Structure Dynamics Experiments, Methods for Safety Analysis, TRAC Calculational Assistance and User Liaison, and the Severe Accidents Sequence Analysis Program (SASA).

Report	Title
NUREG/CR-2818 October 1982	PROTECTIVE MEASURES AND REGULATORY STRATEGIES FOR CORE MELT ACCIDENTS

The effort that is documented in this report was initiated in the summer of 1980, at a time when the Nuclear Regulatory Commission (NRC) was considering rulemaking that would likely require significant design modifications to nuclear power plants in order to deal with (i.e., prevent and/or mitigate) core-damage and core-melt accidents. During the period of draft review of this report, the NRC began to focus on the concept of a safety goal. This development will allow, in NRC's opinion, a more rational basis for evaluating the need for and extent of possible rulemaking for core-melt rulemaking (e.g., based on risk) and, subsequently, a consistent strategy for implementing regulatory changes, if any. Consequently, this report does not now offer any particularly unique or innovative recommendations. It does, however, summarize the key issues associated with attempts to develop regulatory modifications to address core-melt accidents.

NUREG/CR-2828 September 1982	NUCLEAR CONTROL ROOM MALFUNCTIONS AND THE ROLE OF TRANSFER OF TRAINING PRINCIPLES

The goal of this project was to survey applied and theoretical studies dealing with the effect of control room change on operator performance under high stress conditions. The survey did not find any directly applicable applied studies, hence attention centered on the theoretical literature dealing with transfer of training. These findings were then used to develop a series of examples which illustrate the kinds of modifications that enhance control room performance and those that detract from it. Crews will readily adapt to or learn to use many control room additions and modifications. In other words, there is a positive transfer of training from the original design to the modified design. However, there is a possibility that some changes, though they conform to good human engineering standards, promote negative transfer of training. That is, the habits and patterns crews used before the modification interfere with learning and use of the changed controls, displays, or procedures. In every case modifications must be examined to assess whether or not they will disrupt or facilitate the process of transfer from the old to the new control room situation.

NUREG/CR-2828 October 1982	OPERATOR ACTION EVENT TREES FOR THE ZION 1 PRESSURIZED WATER REACTOR

Operator Action Event Trees for transient and LOCA initiated accident sequences at the Zion 1 PWR have been developed and documented. These trees logically and systematically

Report	Title
	portray the role of the operator throughout the progression of the accident. The documentation includes a delineation of the required operator response and the key symptoms exhibited by the plant at each stage of the tree. These operator action event trees were based on the best-estimate computer analyses performed by EG&G Idaho, Inc. and Los Alamos National Laboratory under the NRC Severe Accident Sequence Analysis (SASA) Program.
NUREG/CR-2919 September 1982	USER GUIDE FOR XOQDOQ: EVALUATING ROUTINE EFFLUENT RELEASES AT COMMERCIAL NUCLEAR POWER STATIONS
	Provided is a user's guide for the NRC's computer program XOQDOQ which implements Regulatory Guide 1.111. This NUREG supersedes NUREG-0324 which was published as a draft in September 1977. This program is used by NRC meteorology staff in their independent meteorological evaluation of routine or anticipated intermittent releases at nuclear power stations. It operates in a batch input mode and has various options a user may select. Relative atmospheric dispersion and deposition factors are computed for 22 specific distances out to 50 miles from the site for each directional sector. From these results, values for 10 distance segments are computed. Program features, including required input data and output results, are described. A program listing and test case data input and resulting output are provided.
NUREG/CR-2932 Vol. 1 October 1982	EQUIPMENT QUALIFICATION RESEARCH TEST OF ELECTRIC CABLE WITH FACTORY SPLICES AND INSULATION REWORK TEST NO. 2, REPORT NO. 1
	Electric cables with flame-retardant chemically crosslinked polyolefin extruded insulation containing factory-made center-conductor splices and insulation repairs manufactured by the Rockbestos Company were used in a methodology test of the IEEE Standard 383-1974. This standard is concerned with the ability of cables to function during and following exposure to aging and loss-of-coolant accident/main steam line break LOCA/MSLB environments. Cable specimens were radiation aged at a low-dose rate and then thermally aged to simulate a 40-year containment exposure. After aging, the specimens were subjected to LOCA radiation and a 33-day steam and chemical spray exposure. The cables were electrically loaded and functioned without failure during and after LOCA steam and chemical spray exposure. Insulation resistance measurements were taken during the exposure sequence. Subsequent to the exposures, hipot and mandrel bend tests were conducted. Test results indicate that the methods given in IEEE 383-1974 are adequate to show that cables can function and support power and control operations during and after a LOCA/MSLB of the severity simulated by the test. Further, the presence of the center-conductor splices and insulation repairs did not appear to degrade cable performance.

2.5 Operating Reactor Event Memoranda Issued in September-October 1982

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 signficance, and short and long term actions (taken and planned). Copies of OREMs are also sent to the Offices for Analysis and Evaluation of Operational Data, and of Inspection and Enforcement for their information.

No OREMs were issued during September-October 1982.

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